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	)	**Case No. 2013-00199**
ELECTRIC CORPORATION FOR A	)	
GENERAL ADJUSTMENT IN RATES	)	

REBUTTAL TESTIMONY

ORIGINAL

FILED: December 17, 2013

SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC

ATTORNEYS AT LAW

Ronald M. Sullivan
Jesse T. Mountjoy
Frank Stainback
James M. Miller
Michael A. Fiorella
Allen W. Holbrook
R. Michael Sullivan
Bryan R. Reynolds
Tyson A. Kamuf
Mark W. Starnes
C. Ellsworth Mountjoy
Susan Montalvo-Gesser

December 16, 2013

Mr. Jeff Derouen
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

In the Matter of:

Application of Big Rivers Electric Corporation for a General Adjustment in Rates – Case No. 2013-00199

Dear Mr. Derouen:

Enclosed for filing on behalf of Big Rivers Electric Corporation ("Big Rivers") are an original and ten (10) copies of (i) Big Rivers' rebuttal testimony and (ii) a petition for confidential treatment.

I certify that on this date, a copy of this letter and a copy of the responses were served by hand delivery or by Federal Express to the persons on the attached service list.

Should you have any questions about this matter, please contact me.

Sincerely yours,

Tyson Kamuf
Counsel for Big Rivers Electric Corporation

cc: Service List
Billie J. Richert

Telephone (270) 926-4000
Telecopier (270) 683-6694

100 St. Ann Building
PO Box 727
Owensboro, Kentucky
42302-0727

Service List
PSC Case No. 2013-00199

Jennifer B. Hans
Lawrence W. Cook
Assistant Attorneys General
1024 Capital Center Dr.
Suite 200
Frankfort, KY 40601

Mr. David Brevitz
3623 SW Woodvalley Terrace
Topeka, KS 66614

Mr. Bion C. Ostrander
1121 S.W. Chetopa Trail
Topeka, KS 66615

Mr. Larry Holloway
830 Romine Ridge
Osage City, KS 66523

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.
Boehm, Kurtz & Lowry
36 E. Seventh St., Suite 1510
Cincinnati, Ohio 45202

Lane Kollen
J. Kennedy & Associates
570 Colonial Park Drive
Suite 305
Roswell, GA 30075

G. Kelly Nuckols
President and CEO
Jackson Purchase Energy Corporation
2900 Irvin Cobb Drive
P.O. Box 4030
Paducah, KY 42002-4030

Melissa D. Yates
Denton & Keuler, LLP
555 Jefferson Street
Suite 301
Paducah, KY 42001

Burns Mercer
Meade County RECC
1351 Hwy. 79
P.O. Box 489
Brandenburg, Kentucky 40108

Thomas C. Brite, Esq.
Brite & Hopkins, PLLC
83 Ballpark Road
Hardinsburg, KY 40143

Gregory Starheim
President & CEO
Kenergy Corp.
3111 Fairview Drive
P.O. Box 1389
Owensboro, KY 42302-1389

J. Christopher Hopgood, Esq.
318 Second Street
Henderson, Kentucky 42420

Joe Childers
Joe F. Childers & Associates
300 Lexington Building
201 West Short Street
Lexington, Kentucky 40507

Shannon Fisk
Senior Attorney
Earthjustice
1617 John F. Kennedy Blvd., Suite 1675
Philadelphia, PA 19103

Thomas Cmar
Earthjustice
5042 N. Leavitt Street, Suite 1
Chicago, IL 60625

Kristin Henry
Senior Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441

Laurie Williams
Associate Attorney
Sierra Club
50 F Street, NW, Eighth Floor
Washington, DC 20001

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2013-00199

VERIFICATION

I, Mark A. Bailey, verify, state, and affirm that I prepared or supervised the preparation of my Rebuttal Testimony filed with this Verification, and that Rebuttal Testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Mark A. Bailey

Mark A. Bailey

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark A. Bailey on this the 2nd day of December, 2013.

Paula Mitchell

Notary Public, Ky. State at Large
My Commission Expires 1-12-17

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

VERIFICATION

I, Billie J. Richert, verify, state, and affirm that I prepared or supervised the preparation of my Rebuttal Testimony filed with this Verification, and that Rebuttal Testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Billie J. Richert

Billie J. Richert

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Billie J. Richert on this the 2 day of December, 2013.

Mary Boulet

Notary Public, Ky. State at Large
My Commission Expires 8-8-2016

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

VERIFICATION

I, Ted J. Kelly, verify, state, and affirm that I prepared or supervised the preparation of my Rebuttal Testimony filed with this Verification, and that Rebuttal Testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Ted J. Kelly
Ted J. Kelly

STATE OF MISSOURI)
COUNTY OF JACKSON)

SUBSCRIBED AND SWORN TO before me by Ted J. Kelly on this the 2 day of December, 2013.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI
PAULA M. ANNAN
My Commission Expires
January 19, 2015
Jackson County
Commission #11992872

Paula M Annan
Notary Public
State of Missouri
My Commission Expires 1-19-15

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

VERIFICATION

I, Ralph R. Mabey, verify, state, and affirm that I prepared or supervised the preparation of my Rebuttal Testimony filed with this Verification, and that Rebuttal Testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

R R Mabey
Ralph R. Mabey

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Ralph R. Mabey on this the 16th day of December, 2013.

Paula Mitchell
Notary Public, Ky. State at Large
My Commission Expires 1-12-17

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

VERIFICATION

I, Daniel M. (Dan) Walker, verify, state, and affirm that I prepared or supervised the preparation of my Rebuttal Testimony filed with this Verification, and that Rebuttal Testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Daniel M. (Dan) Walker

COMMONWEALTH OF VIRGINIA)
COUNTY OF HENRICO)

SUBSCRIBED AND SWORN TO before me by Daniel M. (Dan) Walker on this the 26th day of November, 2013.

Notary Public, ~~Ky.~~ VA comm. State at Large
My Commission Expires July 31, 2015

AMY B MULLER
NOTARY PUBLIC
COMMONWEALTH OF VIRGINIA
MY COMMISSION EXPIRES JULY 31, 2015
COMMISSION # 7510547

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2013-00199

VERIFICATION

I, DeAnna M. Speed, verify, state, and affirm that I prepared or supervised the preparation of my Rebuttal Testimony filed with this Verification, and that Rebuttal Testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

DeAnna M. Speed

DeAnna M. Speed

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by DeAnna M. Speed on this the 2 day of December, 2013.

Joy P. Wright

Notary Public, Ky. State at Large
My Commission Expires______

Notary Public, Kentucky State-At-Large
My Commission Expires: July 3, 2014
ID 421951

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2013-00199

VERIFICATION

I, Robert W. (Bob) Berry, verify, state, and affirm that I prepared or supervised the preparation of my Rebuttal Testimony filed with this Verification, and that Rebuttal Testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Robert W. (Bob) Berry

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Robert W. (Bob) Berry on this the 3 day of December, 2013.

Jay P. Wright
Notary Public, Ky. State at Large
My Commission Expires________

Notary Public, Kentucky State-At-Large
My Commission Expires: July 3, 2014
ID 421951

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2013-00199

VERIFICATION

I, Lindsay N. Barron, verify, state, and affirm that I prepared or supervised the preparation of my Rebuttal Testimony filed with this Verification, and that Rebuttal Testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Lindsay N Barron

Lindsay N. Barron

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Lindsay N. Barron on this the 10 day of December, 2013.

Joy P. Wright

Notary Public, Ky. State at Large
My Commission Expires_______

Notary Public, Kentucky State-At-Large
My Commission Expires: July 3, 2014
ID 421951

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

VERIFICATION

I, Thomas W. (Tom) Davis, verify, state, and affirm that I prepared or supervised the preparation of my Rebuttal Testimony filed with this Verification, and that Rebuttal Testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Thomas W. (Tom) Davis

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Thomas W. (Tom) Davis on this the 2 day of December, 2013.

Joy P. Wright
Notary Public, Ky. State at Large
My Commission Expires________

Notary Public, Kentucky State-At-Large
My Commission Expires: July 3, 2014
ID 421951

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2013-00199

VERIFICATION

I, John Wolfram, verify, state, and affirm that I prepared or supervised the preparation of my Rebuttal Testimony filed with this Verification, and that Rebuttal Testimony is true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

John Wolfram
John Wolfram

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by John Wolfram on this the 16th day of December, 2013.

Paula Mitchell
Notary Public, Ky. State at Large
My Commission Expires 1-12-17

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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REBUTTAL TESTIMONY

ORIGINAL

FILED: December 17, 2013

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	) Case No. 2013-00199

REBUTTAL TESTIMONY

OF

MARK A. BAILEY
CHIEF EXECUTIVE OFFICER

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: December 17, 2013

REBUTTAL TESTIMONY
OF
MARK A. BAILEY

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REBUTTAL TESTIMONY
OF
MARK A. BAILEY

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Mark A. Bailey. My business address is 201 Third Street, Henderson, Kentucky 42420.

Q. Are you the same Mark A. Bailey who provided direct testimony in this proceeding?

A. Yes.

II. PURPOSE AND OVERVIEW OF TESTIMONY

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

A. The purpose of my rebuttal testimony is to clarify the context in which this rate application should be viewed. While Big Rivers is encouraged by and thankful for the regulatory support the Commission showed in its order in Case No. 2012-00535, the impending termination of the Sebree smelter's electric service agreement poses still more significant challenges for Big Rivers, its Members, and each of their retail customers.

No one—Big Rivers included—wants electric rates to go up. Big Rivers has a skilled and savvy management team that takes pride in their service to our Members and their retail customers, and they are working hard to help ensure that Big Rivers will not have to adjust its rates any more than necessary. We are taking all reasonable steps to reduce our costs, and we are actively pursuing numerous rate mitigation strategies to help create long-term benefits for our Members and their retail customers. This proceeding is intended to simultaneously accomplish two equally important objectives: (i) keep electric rates at a level that remains fair, just, and reasonable; and (ii) protect the company's financial integrity during this period of transition to a "smelter-less" system.

Despite the current challenges, Big Rivers' outlook remains hopeful, and with continued regulatory support, it can avoid the dangerous uncertainty of bankruptcy.

III. THE CASE IS ABOUT FAIR, JUST, AND REASONABLE RATES BASED ON A <u>FORECASTED TEST PERIOD</u>

Q. You stated that the purpose of your rebuttal was to clarify the context in which this rate application should be viewed. How do you clarify that context?

A. To properly understand the reasonableness of our application in this matter, one has to remember that the electric generation business is not a business that lends itself to swift changes of course based on snapshots of isolated moments in time. Electric generation plants are extremely expensive, and they take a long time to construct. Thankfully, they also tend to have long useful lives. For these reasons, the costs associated with financing, constructing, operating, and maintaining those facilities can typically be spread out over a long period of time. As a result of the ability to spread those costs out over a long period of time, ratepayers benefit in the form of lower monthly rates.

During the normal course of business, this is not controversial. But, it quickly gets more complicated when two customers who comprise approximately two-thirds of the total native demand on that system unilaterally give notice that they intend to terminate their electric service agreements. This is precisely what happened to Big Rivers, which—to the best of my knowledge—is the only electric G&T utility in the country to simultaneously serve two aluminum smelters. Century gave notice that it would terminate its agreement for the Hawesville smelter in August of 2013. That notice gave rise to Case No. 2012-00535. Alcan subsequently gave notice that it would terminate its agreement for the Sebree smelter (since purchased by Century) in January of 2014. That notice gave rise to this case.

Given the long-term nature of the electric generating business, the Commission should not accept the knee-jerk reactions of Kentucky Industrial Utility Customers ("KIUC"), the Office of the Attorney General of Kentucky ("Attorney General"), and Ben Taylor and the Sierra Club ("Sierra Club") (collectively, the "Opposing Intervenors") that favor abandoning any attempt to stabilize Big Rivers and risking everything on bankruptcy. Instead, the Commission should stay the course of supporting Big Rivers' transition to a smelter-less generation and transmission ("G&T") cooperative and providing time for Big Rivers to mitigate the effect of the smelter contract terminations.

Q. **What steps has Big Rivers taken in response to the smelter contract terminations?**

A. In response to the smelter contract terminations, Big Rivers began instituting its Load Concentration Analysis and Mitigation Plan ("Mitigation Plan"). The Mitigation Plan included reducing the scale of Big Rivers' operations based on the new circumstances and filing the previous rate case and this rate case. Our goal is to provide fair, just, and reasonable rates given the revenue loss from the smelters and the reduced scale of operations, while also providing for ongoing benefits to our Members and their retail customers.

It is hard to overstate the impact that the two smelter terminations have caused. The smelters contributed approximately $360 million ($205 million from Century and $155 million from Alcan) in revenues to Big Rivers in 2012. From a high-level perspective, if Big Rivers were only trying to "pass the buck" from the smelter contract terminations by recovering those lost revenues from the remaining customers, as some have suggested, Big Rivers would be asking to recover that same approximately $360 million in rates through these rate adjustments. But, that is clearly not what we have done. Our aggregate additional revenue requirement in these two smelter-related cases does not approach even half of that number.

Instead of trying to simply recover the revenues that are leaving the system, we have worked diligently to reduce costs and scale-back our operations so that we are operating as leanly as possible while still satisfying our debt obligations, prudently operating and maintaining our generation fleet, and planning for the future. This is no small task, and although it has made for some difficult decisions, we have been resolute in our efforts to ensure that we achieve those goals.

Q. Has Big Rivers reduced costs and scaled-back its operations?

A. Yes, dramatically so. If you look at the figures in Case No. 2012-00535, you will see that we turned a $205 million dollar per year revenue loss from the Hawesville smelter into a revenue request of only $68.4 million dollars per year. In the present case, we have turned a $155 million dollar per year revenue loss from the Sebree smelter into a revenue request of only $71.2 million dollars per year. Put differently, our skilled and dedicated management team has responded to the smelter terminations by finding approximately

$220.4 million dollars of cost reduction to help mitigate the impact of these rate adjustments on our members and their retail customers. $136.6 million dollars of cost reduction was reflected in Case No. 2012-00535, and $83.8 million dollars of additional cost reduction is now reflected in the present case.

These cost reductions have come predominantly from Big Rivers' plans to temporarily idle the Coleman and Wilson generating stations. Temporarily idling these plants is necessary to ensure that the required rate adjustments are as small as reasonably possible; nevertheless, this decision was difficult. The temporary idling of the two generating stations means that Big Rivers will have to terminate approximately 180 positions. Big Rivers has tempered the negative impact on Western Kentucky families of the elimination of these positions by freezing hiring since June of 2012, but this too has a consequence, as current employees have to cover additional responsibilities of those employees who retire or find other jobs.

Q. Why should ratepayers be expected to pay for generating plants that are no longer needed to serve native load?

A. The simple answer is that they are still valuable to Big Rivers' Members, and any other alternative is unacceptable. Without the revenues necessary to cover the fixed costs of the idled plants, Big Rivers will have little choice but to file a bankruptcy petition, the consequences, costs, and risks of which are explained in the Rebuttal Testimony of Ralph R. Mabey.

Moreover, Big Rivers' generating stations were prudent at the time they were constructed, and they have provided benefits to Big Rivers' Members and their retail customers for decades. The Opposing Intervenors cannot reasonably claim that our decisions to invest in our generating capacity were imprudent. This, of course, places the Opposing Intervenors in the position of arguing that the prudent, long-term investment in our generation assets is somehow suddenly of no value to our Members and their retail customers. That is not a reasonable argument.

Even if some of these generating assets are temporarily idled to reduce costs, they provide value to our Members and their retail customers. As explained in the Rebuttal Testimony of Robert W. Berry, these plants continue to provide benefits because they give Big Rivers the best opportunity to mitigate the effects of the smelter contract terminations. We are already beginning to see encouraging developments in our mitigation efforts, even as the regulatory cloud of uncertainty over this case and the rehearing in Case No. 2012-00535 lingers. In addition, as Mr. Berry further testifies, the electric power market is also showing signs of a market rebound. As it does, Big Rivers will be able to leverage its generation capacity to create additional revenues. These assets also allow us a previously unavailable opportunity to encourage additional economic development in the region while at the same time giving us some measure of insurance against a catastrophic shutdown at the other generating stations and against any possibility that the smelters' historically vacillating power purchasing preferences could ever result in them attempting to seek a return to the system, despite their contractual acknowledgements that they will not do so.

IV. BIG RIVERS' RATE APPLICATION PLACES IT ON STABLE FINANCIAL FOOTING AND PROTECTS THE MEMBERS BY PROVIDING THE ONLY REASONABLE OPPORTUNITY TO AVOID BANKRUPTCY

Q. Why are the Opposing Intervenors' positions that the Commission should disallow all or a significant portion of the forecasted test period revenue requirements not reasonable courses of action?

A. Big Rivers' other witnesses testify in detail regarding why our forecasted test period revenue requirements are reasonable and why the Commission should grant the requested rate relief. Ms. Billie J. Richert, Mr. Ralph R. Mabey, and Mr. Daniel M. Walker explain the dangerous financial consequences flowing from the Opposing Intervenors' proposals.

Ultimately, our status as a not-for-profit cooperative incentivizes us at every moment to keep waste to a minimum. Our Members are our owners, and they ensure that we operate efficiently. Our mission is to safely deliver low-cost, reliable wholesale power consistent with sound business practices and prudent management. Our corporate structure reinforces that objective. We acknowledge that we are in a difficult transition period. But with the rate relief we seek in this proceeding, Big Rivers can reestablish a stable financial footing that supports the pursuit of our mitigation efforts. Our Members and their retail customers, in turn, can thereby also avoid the overwhelming risk and uncertainty associated with a potential bankruptcy.

Q. You mentioned bankruptcy. Have the Opposing Intervenors asked the Commission to force Big Rivers into bankruptcy?

A. The Opposing Intervenors generally go to great lengths to avoid explicitly endorsing bankruptcy as their recommendation for resolving this matter. The Sierra Club has even taken the position that the Commission should take action to ensure that Big Rivers meets its debt covenants while holding Big Rivers on the brink of default. From any reasonable perspective, however, the end result is the same: great uncertainty and unreasonable risk. Although Ms. Richert and Mr. Mabey testify in more detail on this subject, I emphasize that any of these alternative "solutions" will only demonstrate to Big Rivers' creditors, vendors, and potential load replacement customers a lack of regulatory support stemming from a crisis of confidence in management's ability to continue the successful implementation of our Mitigation Plan.

Q. Has Big Rivers evaluated how bankruptcy could affect it?

A. Yes. As I noted during the previous rate case, the extreme nature of the Opposing Intervenors' positions has caused us to retain expert assistance to evaluate the Opposing Intervenors' theories that undermining Big Rivers' financial integrity is somehow beneficial to its Members and their retail customers. In short, there is no question that any Opposing Intervenor proposal or Commission action undermining Big Rivers' financial integrity would be less reasonable than the regulatory support we seek. Mr. Mabey and Ms. Richert testify in detail on this issue.

Q. If bankruptcy is not a feasible option for Big Rivers, why has Big Rivers not pursued voluntary restructuring with its lenders?

A. As Mr. Mabey and Ms. Richert explain, Big Rivers recently was able to complete a significant refinancing that reduced interest expense by millions of dollars per year; however, it is simply not rational to assume that Big Rivers' lenders would make principal concessions or loan additional funds to Big Rivers.

V. TRANSMISSION REVENUES FROM THE SMELTERS SHOULD BE USED TO REPLENISH THE ECONOMIC RESERVE

Q. Does Big Rivers intend to take steps to ensure that any transmission revenues received from the Century Hawesville and Century Sebree smelters go to the benefit of its Members and their retail customers?

A. Yes. As discussed in more detail by Ms. Richert and Mr. Berry, Big Rivers is adding a request in this proceeding for the Commission's authorization to direct any transmission revenue received from the smelters to replenish the Economic Reserve. This approach will ensure that the Members realize the benefit of any and all transmission revenue Big Rivers receives from either Century smelter, eliminating the uncertainties about when and in what amounts any such revenues will be received . Ms. Richert also explains the accounting treatment Big Rivers proposes with respect to any such revenues.

VI. THE RURAL ECONOMIC RESERVE FUND SHOULD BE USED ONLY FOR THE BENEFIT OF THE RURAL CLASS, AS THE COMMISSION INTENDED AND AS PROVIDED IN BIG RIVERS' PROPOSAL

Q. What has Big Rivers done to mitigate the effect of a second rate adjustment following on the heels of Case No. 2012-00535?

A. As I have noted, Big Rivers is sensitive to the rate impact that will result from the individual and combined effects of Case No. 2012-00535 and the present case, and Big Rivers has proposed to postpone the impact of the rate adjustment sought in this proceeding for many months by accelerating the use of the reserve funds created in the Unwind Transaction. In this manner, the rate adjustment proposed in this proceeding, if accepted by the Commission, would be postponed until April of 2015 for the Rural class and until July of 2014 for the Large Industrial class.

Q. You mentioned that Big Rivers' proposal will result in the Large Industrial class being insulated from the proposed rate adjustment until July of 2014 while the Rural class would be insulated from the proposed rate adjustment until April of 2015. What accounts for the difference in time periods?

A. The different time periods result from the fact that the Large Industrial class is not a beneficiary of the Rural Economic Reserve. The Rural Economic Reserve funds were established by the Commission specifically to protect the Rural class against future rate increases.

Q. Is Big Rivers discriminating against the Large Industrial class by excluding it from disbursements from the Rural Economic Reserve?

A. No. The Commission reaffirmed in Case No. 2012-00535 that the Large Industrial class should not benefit from the Rural Economic Reserve. Ms. Richert discusses this issue in her rebuttal testimony.

VII. ONGOING EVALUATION OF THE MITIGATION PLAN IS IMPORTANT TO BIG RIVERS AND ITS MEMBERS, BUT ADDITIONAL STUDIES AND ANALYSES SHOULD BE ADDRESSED IN FUTURE PROCEEDINGS

Q. Some of the Opposing Intervenors have suggested that Big Rivers should be required to develop revised and improved analyses as a basis for appropriate resource planning. Do you agree?

A. No. This is a rate case, not a proceeding to construct new generating facilities. This case should focus on the rates Big Rivers needs based on its revenues and expenses forecasted for the test period. That forecast is reasonable and is adequately supported by studies.

Including the cost of temporarily idled generating plants in rates is justified not by the fact that it would be reasonable to construct those facilities at this time, but by the fact that doing so is the only reasonable means of avoiding bankruptcy. Those facilities were prudent when constructed, they have benefited Big Rivers' Members and their retail customers for decades, and the Members have accumulated significant equity in those plants. The decision for Big Rivers and the Commission is whether to throw in the towel as a knee-jerk reaction to the smelter contract terminations or whether Big Rivers should seek and the Commission should grant rates that put Big Rivers on stable financial footing, and giving Big Rivers time to use the plants to mitigate the rate impact of the smelter contract terminations.

Additional studies will not change the nature of that decision. Nevertheless, Big Rivers performed studies and analyses to inform and support its decision making. Big Rivers has filed numerous production cost model runs in this proceeding, alone. But contrary to the Opposing Intervenors' insinuations, the modeling Big Rivers has done is not a determination of when to restart the Wilson and Coleman generating stations. Those generating stations have not even been idled yet.

Big Rivers will continue to evaluate the status of the Wilson and Coleman generating stations on an ongoing basis. Any decision to return a plant to service will be based upon appropriate analyses that show doing so is economically beneficial to Big Rivers and its Members at that time.

As discussed in more detail in the Rebuttal Testimony of John Wolfram, the Commission, too, will have the opportunity to monitor the status of the Wilson and Coleman generating stations. Information about the plants will be available in the context of Big Rivers' triennial Integrated Resource Planning ("IRP") proceedings, the next of which is due in May of 2014.[1] The Commission will also hear any applications by Big Rivers seeking Environmental Cost Recovery ("ECR") for environmental projects required prior to the restart of an idled generating plant. And, the Commission always has the authority under KRS Chapter 278 to proactively investigate the activities of its jurisdictional utilities. Accordingly, the Commission should reject the suggestion that Big Rivers should perform additional studies in the context of this rate case, as it would be unduly burdensome to Big Rivers and the Commission and would not impact the rates Big Rivers needs.

VIII. BIG RIVERS HAS BEEN TRANSPARENT AND FORTHCOMING

Q. Has Big Rivers been transparent and forthcoming with information?

A. Yes. As a matter of corporate and personal philosophy, Big Rivers is transparent and forthcoming with information, both with the Commission and the Opposing Intervenors. It is important for everyone to be fully informed about the basis for and details of Big Rivers' proposed rate adjustments.

Q. Concerns have been raised regarding Big Rivers' disclosure of knowledge and information regarding SSR revenues at issue in the previous rate case, Case No. 2012-00535. Can you comment on these concerns?

A. Mr. Berry goes into more detail about this, but I can say that this concern appears to stem from a misunderstanding about the timing of the SSR negotiations between Big Rivers, Century, and MISO. MISO's November 1, 2013, FERC filing budgeted for higher SSR revenues than Big Rivers anticipated at the time of the hearing in Case No. 2012-00535 (July 1-3, 2013). In fact, Big Rivers had not yet proposed a budget to MISO at the time of that hearing. Big Rivers also did not know whether MISO would agree with Big Rivers' proposed budget until after the Commission issued its order in Case No. 2012-00535. In addition, it remains uncertain if FERC will approve the filed budget, especially given that Century is protesting that budget in the FERC proceeding.

In addition, as Mr. Berry explains, the SSR revenues are strictly tied to and offset by Big Rivers' actual expenses—Big Rivers will not make a profit on the operation of the Coleman Station as an SSR resource, and there will be no impact to Big Rivers' revenue requirement, except for a handful of fees that were already included in the revenue requirement in this proceeding, which Big Rivers is adjusting out of its revenue requirement in the Rebuttal Testimony of John Wolfram.

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[1] *In the Matter of Big Rivers Electric Corporation's Request for an Extension of Time to File its Next Integrated Resource Plan*, Case No. 2013-00034, Order dated January 29, 2013, pg. 2.

IX. CONCLUSION

Q. Do you have any closing comments?

A. Yes. For the reasons stated above and in the testimonies of the other Big Rivers witnesses, Big Rivers needs the Commission's continued regulatory support through an order granting our proposed rate adjustment. We have reduced our costs and scaled back our operations so that we can survive with a greater than $360 million revenue reduction since 2012. Similarly, we have asked for rates required to meet our debt service and to continue funding an appropriately reduced scale of operations in light of the two smelters' exits from the system. The rates we have requested are fully supported by our data, and our proposed rates are fair, just, and reasonable under the totality of circumstances. Moreover, by proposing to accelerate the use of reserve funds, we have offered the Commission a way to directly help ratepayers—by postponing the financial impact of the proposed adjustments—without harming Big Rivers.

Big Rivers acknowledges that it is facing significant rate pressures in the immediate term, which we have tried to address through cost-cutting and accelerated use of reserves, but with the continued support of the Commission, our prospects remain very good. The generation investments driving our revenue requirement were prudent investments, and those assets remain valuable for the present and offer future benefits that—as described more fully in the testimony of Mr. Berry—continued ownership of that generation capacity provides to our Members and their retail customers. Denying recovery of the costs associated with these investments would place Big Rivers in the untenable position of recovering insufficient revenues to meet all of its obligations. This would, in turn, likely force Big Rivers into bankruptcy, a scenario that would be more detrimental to our Members and their retail customers than the regulatory support we seek.

Q. What are your conclusions and recommendations to the Commission in this proceeding?

A. Big Rivers has proposed fair, just and reasonable rates. The Commission should adopt those rates and grant Big Rivers the relief it seeks in this proceeding.

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. 2013-00199)

REBUTTAL TESTIMONY

OF

BILLIE J. RICHERT
VICE PRESIDENT ACCOUNTING, RATES, AND CHIEF FINANCIAL OFFICER

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: December 17, 2013

REBUTTAL TESTIMONY
OF
BILLIE J. RICHERT

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REBUTTAL TESTIMONY
OF
BILLIE J. RICHERT

I. INTRODUCTION

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

A. My name is Billie J. Richert. I am employed by Big Rivers Electric Corporation ("Big Rivers"), 201 Third Street, Henderson, Kentucky 42420, as the Vice President, Accounting, Rates, and Chief Financial Officer ("CFO").

Q. Are you the same Billie J. Richert who provided direct testimony in this proceeding?

A. Yes.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my rebuttal testimony is to rebut the views expressed in this case by the witnesses for the Office of the Attorney General of Kentucky ("Attorney General"), Kentucky Industrial Utility Customers, Inc. ("KIUC"), and Sierra Club ("Sierra Club") (collectively, the "Opposing Intervenors"). Specifically, I will: (i) explain that Big Rivers' proposed rates will put it on stable financial footing and protect its Members, and that the Kentucky Public Service Commission ("Commission") has a choice in this case between granting the relief requested by Big Rivers and forcing Big Rivers into bankruptcy; (ii) explain why the Wilson and Coleman Station costs should be included in Big Rivers' rates, including why the Commission should authorize Big Rivers to continue to depreciate temporarily idled power plants as part of the execution of Big

Rivers' Load Concentration Analysis & Mitigation Plan (the "Mitigation Plan"); (iii) explain why the Rural Economic Reserve Fund should continue to be used solely for the benefit of the Rural class as originally intended by the Commission and as proposed by Big Rivers in its application; (iv) explain why the Attorney General, KIUC, and Sierra Club's claims are unsubstantiated; and (v) summarize why the Commission should not accept the positions of the Attorney General, KIUC, and Sierra Club.

I am also testifying to provide the Commission information on the financial impact of a denial of Big Rivers' proposed rates. Specifically, I will explain how long Big Rivers could operate before the Economic Reserve and the Rural Economic Reserve (the "Reserve Funds") are depleted and explain the impact on Big Rivers' cash flow. I am also testifying about contracts with certain third parties that may require cash deposits if the Opposing Intervenors' position is adopted by the Commission. Finally, I am testifying about the benefits Big Rivers realized in its July 2012 refinancing with the Cooperative Finance Corporation ("CFC") and CoBank.

Q. **Do you have any changes to make to Big Rivers' requests in this case?**

A. Yes. As discussed in detail in the Rebuttal Testimony of Robert W. Berry, Big Rivers is proposing to direct any transmission revenue received from the Century Hawesville and Century Sebree smelters to replenish the Economic Reserve. Under this proposal, the Economic Reserve would continue to benefit the same retail customers it currently benefits—it would simply be supplemented with additional funds, as described in the following paragraph.

Upon billing Century for transmission revenue, Big Rivers would debit the "Accounts Receivable – Century" account and credit the "Economic Reserve –

Deferred" account. When Big Rivers receives cash receipts from Century for billed transmission revenue, Big Rivers would debit the "Cash – Economic Reserve" account and credit the "Accounts Receivable – Century" account. Upon application to offset Member rates, Big Rivers would debit the "Economic Reserve – Deferred Account" and credit the "Revenue" account; and debit "Cash – General Fund" and credit "Cash – Economic Reserve".

This proposed accounting treatment has been discussed with Big Rivers' auditors, and the auditors have approved the proposed accounting treatment provided that the Commission grants its approval. Accordingly, Big Rivers respectfully requests that the Commission authorize Big Rivers to use any transmission revenues received from the smelters to replenish the Economic Reserve and to treat that transmission revenue as a deferred amount, increasing the Economic Reserve – Deferred Account which is used to offset Member billings.

Q. Do you have any other changes to Big Rivers' requests in this case?

A. Yes. For accounting purposes, Big Rivers originally requested authority to establish a regulatory account to record certain severance costs. Recently, however, Big Rivers confirmed with its auditor, KPMG, that it is appropriate under generally accepted accounting principles ("GAAP") to accrue these severance costs in 2013. Therefore, Big Rivers is withdrawing its request for authority to establish a regulatory account to record these severance costs. The Commission has granted Big Rivers' motion to withdraw that request in its order dated December 10, 2013 in Case No. 2012-00535.

III. RATE RELIEF IS A BETTER CHOICE THAN BANKRUPTCY

Q. What is Big Rivers' goal in this proceeding?

A. Big Rivers seeks to protect its Members by establishing a reasonable rate that will restore its financial stability. Its proposed rates are designed to do exactly that, and they provide the only reasonable course of action to avoid bankruptcy. If the requested rate adjustment is granted, Big Rivers' financial stability will not depend on increasing off-system sales or any other element of its Mitigation Plan. In fact, as discussed in more detail in the Rebuttal Testimony of Robert W. Berry, with the departure of the smelters, Big Rivers has increased opportunities to market available energy and capacity. Therefore, success of the Mitigation Plan will simply provide additional benefits to Big Rivers' Members.

Q. How do you view the recommendations of the Opposing Intervenors regarding the rate relief requested in this case?

A. As in the previous rate case, Case No. 2012-00535, the recommendations of the Opposing Intervenors would all likely require Big Rivers to file for relief under Chapter 11 of the U.S. Bankruptcy Code.

Q. Why is it clear that the Opposing Intervenors' recommendations will force Big Rivers into filing for bankruptcy?

A. KIUC's and the Attorney General's proposals, if approved, would not provide Big Rivers the revenues that it requires to meet its operational and financial obligations. Some of the Opposing Intervenors attempt to create the impression that there are alternative ratemaking approaches that would allow Big Rivers to avoid imposing rate increases on its Members, but these are illusory. Sierra Club, for example, proposes providing just enough to keep Big Rivers "afloat" long enough to shed assets, but, as I discuss later, that approach would have the same practical effect as bankruptcy. The fact is that the Opposing Intervenors present the Commission with two very different and mutually exclusive alternatives for Big Rivers: the proposed rate relief or bankruptcy. This stark contrast in the choices presented to the Commission is also discussed in the Rebuttal Testimony of Mark A. Bailey. As discussed in more detail the Rebuttal Testimony of Ralph R. Mabey, bankruptcy is not a viable solution, nor does it assure rates lower than those proposed by Big Rivers.

Bankruptcy would have dire consequences for Big Rivers, its Members, and their retail member-customers. As an initial matter, Big Rivers' credit ratings would be adversely, and probably permanently, affected. As discussed in the Rebuttal Testimony of Daniel M. Walker, Big Rivers would be effectively blocked from accessing the capital markets on which it relies to continue operating. As discussed in the Rebuttal of Ralph R. Mabey, bankruptcy (or the serious threat of bankruptcy) is not likely to yield meaningful concessions from Big Rivers' creditors. In fact, rather than a productive restructuring benefiting Big Rivers' Members, bankruptcy is much more likely to lead to a disastrous liquidation that will negatively impact Big Rivers' Members, Western Kentucky, and utilities and utility customers throughout the Commonwealth.

In the sections that follow, I will describe why the Commission should choose to accept Big Rivers' position rather than those of KIUC, the Attorney General, or Sierra Club.

Q. Big Rivers raised concerns in Case No. 2012-00535 about the possibility of bankruptcy in the event the Intervenors' positions were accepted. What is the status of those concerns?

A. Big Rivers still has serious concerns about the possibility of bankruptcy if its proposed rates are rejected. Thankfully, the Commission's final order in Case No. 2012-00535 was well-received by the investment and creditor communities, in part, because not all of the Commission's adjustments will impact the MFIR and TIER calculations. For example, although the Commission excluded certain expenses from ratemaking treatment, it permitted Big Rivers to record Coleman depreciation costs—more than $6 million of the excluded amount—as a regulatory asset for future rate recovery. Moody's Investor Service issued a "Credit Positive" comment after the Commission's final order, in which it pointed to the Commission's ongoing support of Big Rivers' financial health as a primary reason for its positive outlook: "we note several supportive comments made by the KPSC in the rate order about prudent steps made by BREC, which we believe factored into the recent decision, and should bode well for BREC as it awaits another decision in a separate pending rate case expected in the early part of 2014." In short, Big Rivers believes that creditors and rating agencies saw the final order in Case No. 2012-00535 as a signal of ongoing regulatory support and therefore did not take actions that could lead to a Big Rivers' bankruptcy. However, if the Commission withdraws its support in this case by denying Big Rivers' proposed rate adjustment or disallowing the recovery of depreciation expense for Wilson Station (as described in more detail in Section IV, below), the creditors and rating agencies will likely also withdraw their support of Big Rivers and leave Big Rivers with no realistic option but to enter bankruptcy.

Q. What will happen to Big Rivers' ability to repay its lenders if the requested rate relief is denied?

A. As of September 30, 2013, the stated amount of Big Rivers' total outstanding long-term debt principal was $965.9[1] million in outstanding loans from the lenders in the following principal amounts: RUS: $326.0 million; CoBank: $225.9 million; the CFC: $330.7 million; the Ohio County Bondholders: $83.3 million. If the Attorney General secures the result he seeks and Big Rivers is granted no rate relief and no access to the Reserve Funds, Big Rivers' TIER for the fiscal year ending December 31, 2014 will be a negative (0.38) and ending cash balance in the General Fund will be $25.13 million. (Exhibit Richert Rebuttal-1.) This leaves Big Rivers in default of its loan covenants; unable to draw down on its line of credit with CFC, and with a cash balance approximately $10 million less than what it requires to cover normal operations. This would require significant and immediate reductions in Big Rivers' secured long-term debt obligations which, as discussed by Mr. Walker and Mr. Mabey, are unrealistic.

Q. Would Big Rivers' ability to make other payments also be affected by a denial of its proposed rate adjustment?

A. Absolutely. As I discuss throughout my testimony, a denial of rate relief would significantly harm Big Rivers' cash flow and access to credit, eventually making it unable to make basic payments necessary for continued operations. In addition, Big

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[1] On a GAAP basis, Big Rivers' total outstanding long-term debt, as of September 30, 2013, was $856.9. In accordance with GAAP, for financial reporting purposes, the RUS Series B Note, with no stated interest rate and a stated outstanding principal amount of $245.5 million due December 2023, is recorded at an imputed interest rate of 5.80%; and the RUS Series A Note, with a stated outstanding principal amount of $80.5 million and quarterly principal payments becoming due October 2019, is recorded at effective interest rate of 5.84%.

Rivers' normal credit terms with third parties could become constricted. For example, certain companies that contract with Big Rivers, such as fuel suppliers, could begin to demand cash deposits to cover deliveries. In fact, due to Big Rivers' current financial and regulatory circumstances, MISO has already demanded a $7.5 million deposit and has terminated Big Rivers' unsecured credit support.

Q. **What effect do you believe the July 2012 refinancing with CFC and CoBank will have on future negotiations with the lenders urged by the Opposing Intervenors?**

A. The July 2012 refinancing with CFC and CoBank, under which Big Rivers is paying a historically low all-in effective interest rate of 4.11%, coupled with Big Rivers' below investment grade ratings, provides little room for even a meaningful interest rate reduction. However, as a result of the July 2012 refinancing, which took many months to negotiate, Big Rivers has realized a reduction in annual debt service cost of approximately $4.3 million for its Members which is reflected in rates after the Commission's October 29, 2013, order in Case No. 2012-00535 (the "Century Order").

Q. **Did the July 2012 refinancing include any reductions of loan principals?**

A. Big Rivers used the CFC and CoBank loan proceeds to pay down RUS debt, but there were no other principal loan reductions. In particular, none of the creditors involved in the refinancing wrote down any principal as a concession.

Q. **According to Big Rivers' most recent monthly financial update for the nine months ending September 30, 2013 which was filed in this case, Big Rivers' year-to-date margins are currently favorable compared with budget by approximately $22.5 million. Can you please discuss this?**

A. The favorability of actual results compared with budget primarily stems from the following items:

- Revenues were favorable $20.8 million primarily due to higher off-system sales volumes and the retroactive rate order on January 29th, 2013 by the PSC involving the 2011 rate case. These higher sales volumes were made possible in part because Big Rivers deferred a planned Coleman maintenance outage. This deferral is discussed in more detail in the Rebuttal Testimony of Robert W. Berry.
- Maintenance expense was favorable $7.1 million, a significant portion of which is due to the deferral of the planned Coleman outage.
- Operations Expense was unfavorable $7.3 million driven by higher purchased power, somewhat offset by fuel, reagent and non-variable operations expense.
- Interest expense on long-term debt was favorable $1.7 million primarily due to the payoff of the 1983 pollution control bonds which maturated on June 1, 2013.
- Patronage capital was $0.8 million favorable compared to the budgeted $0.5 million due to higher than anticipated patronage from the CFC loan. The actual patronage allocation from CFC during September 2013 was approximately $1.3 million and was based on total interest expense during CFC's preceding fiscal year (*i.e.* the twelve months ending May 31, 2013) of approximately $13.1 million and an allocation factor of 9.6% of total interest expense during that period. The patronage allocation factor for CFC ranges between 8% - 10%

based on CFC's actual results during the preceding fiscal year. The 9.6% allocation factor was higher than the historical average.

Financial results for fiscal year-end December 31, 2013 are expected to be favorable compared to budget, although Big Rivers anticipates that its 2013 margins will be lower than the YTD net margins at the end of September. Final results are dependent upon year-end accruals as part of the normal year-end closing process; stable off-system sales prices; and no major unplanned outages. The above financial results have not caused a change in Big Rivers' forecast or the revenue deficiency in this proceeding.

IV. THE WILSON AND COLEMAN STATION COSTS, INCLUDING WILSON DEPRECIATION EXPENSE, SHOULD BE INCLUDED IN BIG RIVERS' RATES

Q. In Case No. 2012-00535, the Commission permitted Big Rivers to record Coleman Station depreciation expense as a regulatory asset but excluded those amounts from the rates. Should the Commission take the same approach with respect to Wilson Station depreciation expense?

A. No. As an initial matter, the Commission's decision to defer recovery of Coleman Station depreciation expense was based in part on its finding that the "deferral will reduce [Big Rivers'] cash flow" but would not jeopardize Big Rivers' ability to make "its principal debt payments." (Century Order at p. 33.) However, deferring the Wilson Station depreciation expense, which is approximately $21 million annually, would have a much greater impact on Big Rivers' cash flow than deferring the Coleman Station depreciation expense of approximately $6 million.

As discussed in the previous rate case, cash flow is a critical issue for Big Rivers at this juncture and a key factor to its ongoing financial viability. Deferring the Wilson Station depreciation expense results in decreasing cash available for both debt service and for necessary capital expenditures required in the normal course of business. For example, for the 2014 fiscal year, Big Rivers' total debt service is approximately $63.6 million dollars. Of this amount, approximately $8.2 million represents imputed interest on the RUS Series B Note. This means that the total cash required to meet Big Rivers' debt service in fiscal year 2014 is approximately $55.4 million. The source or basis of cash collected through base rates for servicing debt is comprised of interest and depreciation expense (excluding Coleman's deferred depreciation expense per the Century Order). These expenses for fiscal year 2014 are approximately $42.5 million interest expense and $38.5 million depreciation expense for a total of $81.0 million included in requested base rates. The difference of approximately $25.6 million provides funding for capital expenditures required by Big Rivers to support its operations without having to borrow these amounts and incur increased interest expense. Excluding Wilson's depreciation expense of approximately $21 million as described in KIUC's proposed rate plan would leave Big Rivers with only $4.6 million for ongoing capital requirements. This would require Big Rivers to seek financing (if the funds could even be borrowed, which would be highly unlikely if the KIUC plan is accepted) for its annual budgeted capital expenditures and would increase the interest costs Members pay through increased rates. KIUC acknowledges that there will be a "lower cash flow resulting from the cessation of depreciation on the Wilson and Coleman plants . . . ." (Kollen Testimony at p. 57:5-6.) However, Mr. Kollen erroneously believes that these cash flow reductions "will be offset by the elimination of the capital expenditures for MATS compliance during that same period . . . ." (*Id.* at p. 57:6-7.) In reality, no such offset will take place because the financial model assumed Big Rivers would borrow the funds for the MATS capital expenditures. Now that Big Rivers does not plan to complete the MATS projects at Wilson and Coleman at this time, Big Rivers will not borrow the funds for those projects. Thus, the decision not to complete the MATS projects at Wilson and Coleman at this time does not free up any cash. Moreover, all of this assumes, of course, that the KIUC's proposed rate plan is even feasible, which it is not for reasons described in more detail in this testimony and the Rebuttal Testimony of Ralph R. Mabey.

Recovery of Wilson Station depreciation expense is also different because the Commission's decision to defer recovery of Coleman Station depreciation expense was driven in part by its concerns about "the expected length of time that the Coleman Station will be idled . . . ." (Century Order at p. 32.) This is another important distinction between the two power plants that supports granting, rather than deferring, Big Rivers' recovery of Wilson Station depreciation expense. The Wilson Station has a lower per unit operating cost than the Coleman Station, and so, the Wilson Station is more likely to return to service sooner. As discussed more thoroughly in the Rebuttal Testimony of Robert W. Berry, Big Rivers' management is regularly evaluating the timing of the Wilson Station's return to active status, and based on its most recent evaluations, it anticipates that gross margins on generation from the Wilson Station will soon outweigh the fixed cost savings from idling the plant.

In addition, the Wilson Station was a prudent investment (as was the Coleman Station) that remains used and useful, as discussed in the Rebuttal Testimony of Robert W. Berry. It would be unreasonable and inequitable to remove the Wilson Station depreciation expense, particularly given that the circumstances leading to the Wilson Station's idling were brought about by a third party's unilateral contract termination. Furthermore, the Wilson Station is not being retired; it is simply expected to be temporarily idled in order to reduce costs while wholesale market conditions recover or other sales options develop. As further described in the Rebuttal Testimony of Robert W. Berry, the Wilson Station will continue to provide benefits to Big Rivers' Members and their ratepayers, even in its temporarily idled status. It is appropriate to continue depreciating assets in such circumstances.

Q. What position does KIUC take with respect to the depreciation expense of idled power plants?

A. Mr. Kollen argues that Big Rivers should not recover any depreciation expenses for the Wilson Station or Coleman Station because of depreciation standards allegedly requiring Big Rivers to "cease all depreciation expense on the plants after they are shutdown." (Kollen Testimony, p. 45:1-16.) KIUC made a similar argument in the previous rate case, Case No. 2012-00535, and the Commission has already disagreed with that argument, finding that "[w]e likewise agree with Big Rivers that there are valid reasons for not discontinuing depreciation when a plant is temporarily idled."

(*See, e.g.*, Kollen Testimony, Case No. 2012-00535, pp. 63-67; KIUC Post-Hearing Brief, Case No. 2012-00535, pp. 40-47; Century Order at p. 32.)

Q. How do you respond to the KIUC's position?

A. First, as a factual correction, KIUC argues that the Wilson Station and Coleman Station should be considered "Plant Held for Future Use." That accounting treatment only applies to (i) property not yet used or (ii) property retired but held pending its reuse in the future. (Kollen Testimony, pp. 47-48 (*quoting* RUS uniform system of accounts ("USOA") Account 105).) However, both stations have been used and neither have been retired, only "temporarily idled," as acknowledged by the Commission. (Century Order at p. 32.) In other words, KIUC's entire argument is invalid because it is premised on a factual misunderstanding.

Second, even the USOA standards relied upon by Mr. Kollen do not support his position. Those standards define depreciation as a "loss in service value" which includes "decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities." (Kollen Testimony, p. 48:19-28.) The Wilson Station in its temporarily idled status will experience a loss in service value for several of those reasons. As just one example, the temporary idling of the plant does not stop the energy industry from developing technologies or public authorities from passing laws or regulations that could render certain equipment obsolete.

Third, KIUC's assertion that GAAP or RUS USOA standards prohibit continuing depreciation is directly contradicted by the Northern States Power Company case relied on by Mr. Kollen. (*See* Kollen Testimony, p. 56:1-7.) In that case, the public service commission did not find that GAAP and RUS USOA standards prohibit continuing depreciation during idling. In fact, faced with a generation plant in an extended period of idling, the commission did not prohibit recovery of the depreciation expenses related to that plant, which would be the likely outcome if accounting standards prohibited continued depreciation. Instead, the commission ordered the utility to defer depreciation expenses, explicitly keeping open the possibility of future rate recovery. This decision is inconsistent with Mr. Kollen's assertion that GAAP and RUS USOA accounting standards require a utility to "cease depreciation on generating assets removed from service . . . ." (Kollen Testimony, p. 46:13-14.)

Fourth, although KIUC spends much of its energy attempting to establish which set of depreciation standards apply, the simple truth is that all depreciation policies and standards (including those of the International Accounting Standards Board ("IASB")) have instructional value regardless of whether they are formally binding on Big Rivers.

Fifth, exclusion of depreciation expense, as proposed by KIUC, would have several major adverse consequences. Big Rivers' depreciation rates must be approved by the RUS before any change in depreciation rates can be included in a rate case. Big Rivers has undertaken an affirmative covenant to RUS in the Loan Contract to adopt as its depreciation rates only those that have been previously approved for Big Rivers by RUS. There are no exceptions to that covenant. The depreciation expense included in this proceeding is based upon depreciation rates already approved by the RUS. In addition, depreciation expense is the means by which Big Rivers (and any entity) recovers its investment in its plant over the useful lives of the underlying plant assets.

Eliminating it would remove Big Rivers' ability to recover its prudent investment in its plant.

Finally, as discussed above, although depreciation expense is a non-cash expense item, the inclusion of depreciation expense in base rates represents the mechanism by which cash flow is generated, in part, for the purposes of making debt principal payments in compliance with all debt agreements. Without the ability to include 100% of Big Rivers' approved depreciation expense for Wilson in base rates, Big Rivers is at a distinct disadvantage in collecting the cash flows necessary to meet its debt obligations and in internally financing its capital expenditures. This could jeopardize Big Rivers' ability to regain its investment grade ratings, to access the credit markets, undermine Big Rivers' ongoing financial viability, and, ultimately, lead to a bankruptcy that would bring increased uncertainty and risk, yet with no counterbalancing guarantee of rates lower than those proposed by Big Rivers.

Q. **Is your above reference to RUS approval intended to suggest that RUS has statutory authority to set depreciation rates for ratemaking purposes or that its authority somehow overrides the Commission's authority to set rates?**

A. No, the Commission is the only agency with ratemaking authority over Big Rivers. (*See* Century Order at p. 32.) The issue of RUS approval is a practical one. Although RUS may not have statutory or regulatory authority to determine Big Rivers' rates, the fact remains that it is a creditor and can declare Big Rivers to be in default if Big Rivers does not meet its loan obligations. As a result, Big Rivers must operate within the constraints of its agreements with RUS, which include its covenant to only adopt depreciation rates previously approved by RUS.

Q. Mr. Kollen suggests that Ted Kelly, Big Rivers' depreciation expert, agrees with KIUC's basic premise about stopping depreciation on idled units. Is this correct?

A. No, that is not correct, and that conclusion is not supported even by the quotes from Mr. Kelly that Mr. Kollen relies on. (Kollen Testimony, p. 50:4-5.) As set forth in his rebuttal testimony, Mr. Kelly agrees with Big Rivers that it is appropriate to continue depreciating the Wilson Station in its temporarily idled status.

Q. KIUC suggests that Century should be required to pay depreciation expenses in the event MISO requires a plant to operate under an SSR agreement. (Kollen Testimony, pp. 59-60.) Does Big Rivers agree?

A. KIUC did not argue in Case No. 2013-00221 that Century should be required to pay depreciation expenses, and cannot raise that argument now that the case has completed and the Commission has approved the relevant agreements, which do not require Century to pay depreciation expenses.

Q. Did KIUC provide any studies or new authority showing that a change to the depreciation of an idled plant is appropriate?

A. No.

Q. What is your recommendation regarding the inclusion in rates of depreciation expenses associated with Wilson Station?

A. For the reasons provided herein and in the Rebuttal Testimony of Robert W. Berry, the Commission should reject KIUC's proposal to exclude the depreciation on Wilson Station from Big Rivers' revenue requirement.

V. THE RURAL ECONOMIC RESERVE FUND SHOULD BE USED AS ORIGINALLY INTENDED

Q. What is Big Rivers' position on KIUC's proposal, outlined by Mr. Baron, to redirect approximately $15.7 million of the Rural Economic Reserve Fund (the "RER") to Large Industrial customers at the expense of Rural customers?

A. KIUC's proposal is inappropriate, and KIUC has not shown how circumstances have changed in a way that justifies repurposing the RER. Also, as the Commission properly addressed in the Century Order, "[t]he time for KIUC to raise its challenge to the RER expired over four years ago." (Century Order at p. 51.) KIUC has waived any argument it may have once had about the RER being discriminatory. Big Rivers believes the Commission should once again reaffirm its prior findings in Case No. 2007-00455 and Case No. 2012-00535 that the RER should "be used exclusively to credit the bills rendered to the Rural Customers" and 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 . . . ." (March 6, 2009, order in Case No. 2007-00455, Appendix A, ¶ 24.)

Q. Do Big Rivers' proposed changes to the Economic Reserve ("ER") fund and the RER, along with the Commission's change to the transition reserve, change the original purpose of those funds?

A. No. Neither the change to the transition reserve nor Big Rivers' proposed changes to the ER and RER change the intended purposes or intended beneficiaries of those funds. KIUC's proposal, in contrast, would change those intended purposes and the intended beneficiaries, and it should be rejected for those reasons.

Q. What is Big Rivers' position on KIUC's complaint that Large Industrials did not sufficiently benefit from the Unwind Transaction?

A. That complaint is unfounded and moot. The Commission already rejected this assertion in the Century Order. As explained by the Commission, KIUC—representing the smelters, Aleris, Domtar, and Kimberly-Clark—was an intervenor in the Unwind Transaction case which established the RER, and it did not claim that the Unwind Transaction would lead to unfairly high rate increases for Large Industrials. (Century Order at pp. 49-50.) KIUC did not request a rehearing or appeal the decision in that case. Finally, in the previous rate case, Case No. 2012-00535 (over four years after the RER was established), KIUC tried for the first time to challenge the conditions of the RER, and the Commission rightly rejected that attempt in the Century Order. Nothing has changed in the six weeks since the Century Order was issued to suggest that the Commission's rejection of KIUC's argument was incorrect. The bottom line is that the Unwind Transaction was a complex transaction that was properly approved by the Commission, after a lengthy proceeding involving all stakeholders, as fairly and reasonably allocating the risks implicated by the transaction. It would be inappropriate for the Commission to go back now and change the terms of the Unwind that are specific to the RER.

Q. KIUC argues that not amending the RER would be unreasonably discriminatory, on the grounds that a utility cannot charge customers different rates without reasonable justification. Is KIUC's argument correct?

A. No. As an initial matter, despite KIUC's accusations, the total rates granted in Case No. 2012-00535 and requested in this rate case are <u>not</u> larger for Large Industrial customers than Rural customers, so it is unclear how KIUC believes the Large Industrials are being discriminated against. In fact, Big Rivers' proposed rates in this proceeding (and in the last rate case) are designed to eliminate any subsidization between the Rural and Large Industrial rate classes. This is described in the Direct Testimony of John Wolfram and further demonstrates that no discrimination exists in the proposed ratemaking. Second, KIUC's argument is based on Mr. Baron's incorrect assumption that there is no material difference between Large Industrial and Rural customers, but that is not true. The Large Industrials and Rurals were treated differently in the Commission's Unwind Order and have long been subject to different rates because they are different classes of customers with different needs. The member bylaws cited by Mr. Baron, which grant each customer one vote, do not somehow undo the longstanding law that a utility can make reasonable classifications between customers for ratemaking purposes.

Q. KIUC also argues that circumstances have changed, and that those changed circumstances require amending the RER conditions. Is that correct?

A. No. KIUC made that same basic argument in Case No. 2012-00535, and the Commission rejected it just over six weeks before the filing of this testimony. In the Century Order, the Commission wrote: "KIUC has presented no evidence to demonstrate that there has been a change in circumstances since March 6, 2009, sufficient to justify a relitigation of the need and purpose for the RER fund." Similarly, here, KIUC has presented no evidence to demonstrate that there has been a change in circumstances since October 29, 2013, the date of that decision, sufficient to justify a relitigation of the need and purpose for the RER.

In any event, the only circumstances KIUC focuses on relate to the departure of the smelters, but that was a possibility expressly taken into account when the Commission approved the Unwind Transaction to which KIUC acquiesced. Mr. Baron suggests that the Commission may have been "reluctan[t]" to apply the RER to Large Industrials at the time of the Unwind Transaction because of "a link between the smelter rate and the Large Industrial rate," but he provides absolutely no basis for that statement, and it is contradicted by the fact that the Commission already reaffirmed the RER conditions after both smelters terminated their service contracts.

Q. **Mr. Baron also suggests that portions of the RER should be directed away from Rural customers because they do not compete on a national and international basis like the Large Industrial customers do. What is your response?**

A. First, Mr. Baron did not provide anything to support his conclusion that no Rural class customers compete at that level or that all Large Industrials do. Moreover, his assertion is immaterial. Even if true, it would not justify stripping the Rural customers of assets that belong to them and that have been repeatedly promised to them by the Commission.

Q. **Mr. Baron recommends that the Large Industrial tariff should be modified to permit customers, at their option, to initially receive up to 15% (increasing to a maximum of 25% over three years) of their demand and energy requirements priced at market-based rates rather than the standard tariff. What is your response?**

A. Mr. Baron provides no analysis on the impact this would have on the remaining customer base. Implementing such a solution without asking the Rural class to make up the difference would result in revenue shortfalls, insufficient MFIR, and Big Rivers defaulting on its loan obligations, and there is no justification for requiring the Rural class to pay for the costs of that proposal. I would point out that Big Rivers just eliminated all the Large Industrial cross-class rate subsidization in Case No. 2012-00535.

VI. <u>THE KIUC, ATTORNEY GENERAL, AND SIERRA CLUB CLAIMS ARE BROADLY UNSUBSTANTIATED AND SHOULD BE DISREGARDED</u>

Q. The Opposing Intervenors' witnesses make numerous claims regarding the likelihood of bankruptcy and the likely effects of bankruptcy. Do you believe they have properly supported these claims?

A. No. The Opposing Intervenors' witnesses offer unsupported conjecture and speculation instead of evidence, and they offer drastic, potentially disastrous, proposals far outside their respective areas of expertise. Most notably, although their proposals as addressed in Mr. Mabey's testimony would almost certainly lead to Big Rivers' bankruptcy, none of the Opposing Intervenors' witnesses are experts in utility bankruptcy, and none of them conducted any analyses or studies about the possible effects of bankruptcy (including whether bankruptcy would result in lower rates for Big Rivers' Members). Because these witnesses are not qualified to opine as experts on these matters and because they provide no evidence to support their speculation, the Commission should disregard their testimony on this topic.

Q. Are there other examples of the Opposing Intervenors' claims that should be disregarded for lack of support?

A. There are many. For example, Mr. Kollen criticizes Big Rivers' retention of its generation assets, but he admits he has not analyzed the impact of the reduced Members' equity, margins, TIER, and available collateral that would result from Big Rivers retiring its Wilson and Coleman generating stations on Big Rivers' ability to borrow and on the interest rate Big Rivers would pay if it were able to borrow. (Kollen Testimony, p. 9:13-15; KIUC Response to BR 1-28.) As a result, it appears that there is no factual basis for Mr. Kollen's opinion.

Q. Do you have any other examples of the Opposing Intervenors' claims that should be disregarded for lack of support?

A. Yes. Mr. Ostrander proposes setting Big Rivers' TIER at 1.10, but he has no expertise in such matters, and his proposal is unsupported and unsupportable. The TIER proposed by Big Rivers is not intended to fix everything on its own—it is just one part of the overall rate proposal. Furthermore, Mr. Ostrander does not seem to appreciate the role of TIER, or the very real danger that setting TIER too low could undo all of Big Rivers' careful and prudent work to pursue its Mitigation Plan to protect its Members from the financial impact of the smelters' contract terminations.

Similarly, Mr. Ostrander appears to be confused about Big Rivers' references to the G&T Directory that lists other utilities' earned TIERs. (Ostrander Testimony, p. 11:15-12:8.) He argues that the directory does not bind the Commission, but Big Rivers makes no such claim. Rather, the directory provides two years of verifiable evidence as to what is a reasonable TIER, and this is the type of comparison relied upon by ratings agencies and creditors. Big Rivers' intent is to provide this information to help guide the Commission by providing some context. Notably, although Mr.

Ostrander criticizes references to the G&T Directory, he provides no information whatsoever—only his unsupported, inexpert conjecture—as to what is an appropriate TIER.

Mr. Ostrander also appears to believe that Big Rivers is suggesting that its goal is to achieve the average of the G&T Directory TIERs, and then argues that there is no guarantee of that happening; however, once again, Big Rivers does not make that argument. It provides the G&T Directory as general information for the Commission's consideration.

Finally, Mr. Ostrander criticizes Big Rivers for not accounting for operational differences between various G&T utilities. However, the rating agencies and lenders rely on comparisons like the one Big Rivers provided. Once again, Big Rivers seeks only to help guide the Commission's decision on TIER by providing the same kind of information that is used in the day-to-day decision-making of Big Rivers' creditors, and rating agencies.

Mr. Ostrander's substantive proposals related to TIER are of even more concern. Mr. Ostrander proposes using a 1.10 TIER. (Ostrander Testimony, p. 9:4.) This is the same basic proposal he made in the previous rate case, Case No. 2012-00535, and which the Commission rejected, holding that a 1.10 TIER "will not provide any 'cushion' in the event of either an unexpected decline in revenues or unavoidable increase in expenses." (Century Order at p. 42.) As I explained in the previous case, the use of a 1.10 MFIR for ratemaking purposes is inappropriate because that value represents the absolute minimum threshold that Big Rivers must achieve pursuant to its financial obligations and debt covenants. In short, Mr. Ostrander's proposal leaves no margin of error for ordinary business fluctuations, and as a result it could lead to Big Rivers defaulting on its credit obligations and, ultimately, filing for bankruptcy. Accepting such a proposal would be viewed negatively by the credit rating agencies and lenders, provide no room for error, and exacerbate the uncertainty of Big Rivers' current financial and regulatory position.

There is also no basis for Mr. Ostrander's argument that the lack of a cap on Big Rivers' TIER means TIER should be set at minimum. As already acknowledged by the Commission, the TIER used in ratemaking must provide at least some "cushion"—the presence or absence of a cap does not affect that basic function. Even for a best case scenario in which no unexpected business circumstances arise, Mr. Ostrander's proposed used of a 1.10 TIER would make it impossible for Big Rivers to approach the capital market like East Kentucky is currently doing. In fact, his approach would negate the crucial revenue stream recently approved by the Commission.

Finally, Mr. Ostrander suggests that Big Rivers' earned TIERs from 2010 to 2012, ranging from 1.12 to 1.25, "clearly demonstrates" that Big Rivers' financial problems are more precarious and insurmountable than Big Rivers has represented. This is not correct, and Mr. Ostrander's concern appears to stem from his lack of expertise with respect to TIER. First, the 2012 earned TIER of 1.25 is not "precarious," and Mr. Ostrander points to absolutely no evidence or authority suggesting that it is. It was effectively the highest that Big Rivers could have earned as a result of the smelter agreement Contract TIER mechanism. Second, Big Rivers' relatively narrow range of earned TIER over those three years does not "clearly demonstrate" that Big Rivers' financial situation is hopelessly precarious. Each year, Big Rivers' earned TIER was just above the minimum required to meet Big Rivers' credit obligations but still lower than the average earned TIER among G&T utilities. This demonstrates that Big Rivers has been able to reasonably and appropriately manage operations despite difficult circumstances. Third, to the extent that there is any precariousness in Big Rivers' current financial situation, this precariousness will be resolved if the Commission grants Big Rivers' proposed rates.

Q. Are there other examples of the Opposing Intervenors' claims that should be disregarded for lack of support?

A. Yes, additional unsupported claims are discussed in the Rebuttal Testimony of Daniel M. Walker and Ralph R. Mabey.

VII. KIUC'S RECOMMENDATIONS SHOULD BE REJECTED

Q. Please summarize KIUC's recommendations in this case.

A. KIUC admits it is proposing essentially the same rate plan it proposed, and which the Commission rejected, in the previous rate case, Case No. 2012-00535. (Kollen Testimony, p. 10:4-7 ("the Commission should adopt the KIUC Rate Plan proposed in the Century rate case and that I propose again in this case, modified only to include" certain "reasonable increase[s]").) Its recommendations include awarding dramatically less than the base rate increase requested by Big Rivers, repurposing the Rural Economic Reserve fund to benefit Large Industrial customers on the backs of the Rural Class, repurposing both Reserve Funds to support Big Rivers' TIER, attempting to force Big Rivers' creditors into a "negotiated solution" before the reserve funds are depleted, and forcing Big Rivers to "pursue options" including asset sales, liquidation, or restructuring. (*Id.* at p. 10:8-20.)

Q. What is the rate relief that KIUC recommends?

A. KIUC's proposal includes the approval of a mere $8.559 million in rate relief. (Kollen Testimony, pp. 16-17.) A rate adjustment of $8.559 million does not prevent the adverse financial consequences outlined in Big Rivers' rebuttal testimony.

Q. Do you believe the KIUC's proposal is reasonable?

A. No.

Q. Why does KIUC's recommendation not prevent adverse financial consequences?

A. KIUC's proposal is unworkable. KIUC's proposed rates are grossly insufficient to maintain Big Rivers' operations and are likely to force Big Rivers into bankruptcy. Even according to Mr. Kollen's calculations (which Big Rivers disputes), and after repurposing all of Big Rivers' Reserve Funds, KIUC's proposal would result in Big Rivers having insufficient rates by December 2014 or January 2015. (Kollen Testimony, pp. 10:22-11:2; KIUC's Response to Big Rivers' Data Request Item No. 25.) As explained in the Rebuttal Testimony of Ralph R. Mabey, Big Rivers' creditors will not be willing to grant additional concessions to Big Rivers. So, Big Rivers would need additional revenues at that time, but would have no realistic means of doing so unless, as a precautionary measure, Big Rivers filed yet another rate case immediately after the conclusion of this proceeding. To do that, Big Rivers would need to begin preparing the case very soon.

KIUC's proposed rate plan is unreasonable and would likely lead to Big Rivers experiencing negative margins beginning in 2015, failing to meet its required MFIR, spending additional funds to prepare to prosecute another rate case, and ultimately entering bankruptcy (which, as discussed in the Rebuttal Testimony of Ralph R. Mabey, is not a rational or acceptable option). It would leave Big Rivers with only unrealistic and unworkable options, such as seeking creditors' forgiveness of a significant portion of the outstanding secured long-term debt or at a minimum, deferring approximately $44 million in interest expense for the year ending December 31, 2015.

Q. Are there other flaws with KIUC's rate plan and its calculations?

A. Yes. Big Rivers is proposing in this instant case to utilize any transmission revenue from Century to replenish the Economic Reserve. As Mr. Berry has testified, it would be inappropriate to reduce Big Rivers' revenue requirement by the potential transmission revenues Big Rivers could receive. There remains much uncertainty with respect to when or how long Big Rivers will receive transmission revenue, and if the Commission determines that transmission revenues should be included in the determination of Big Rivers' revenue requirement, and those transmission revenues do not come to pass, Big Rivers will be at risk of default of its loan covenants. Therefore, Mr. Kollen's proposal to reduce the requested increase by this potential amount of $12.781 million is not reasonable and is very risky to Big Rivers and its Members.

Mr. Kollen's proposal also includes the reduction of $1.333 million in the revenue deficiency for the allocation of ACES fees paid by Century for both the Hawesville and Sebree smelters. However, it would be inappropriate to exclude the portion of ACES fees allocated to the Sebree smelter unless the contracts allowing that smelter to remain in operation are approved by the Commission in Case No. 2013-00413. This issue is addressed in the Rebuttal Testimony of Mr. John Wolfram.

Mr. Kollen's proposal includes the removal of MATS 2014 Capital Expenditures for Wilson and Coleman in the amount of $694,000. Environmental capital expenditures, all costs of which are passed through Big Rivers' Environmental Surcharge tariff and are removed from the revenue requirement in this case, do not impact the revenue deficiency, and therefore, Mr. Kollen's proposal is in error by $694,000.

Lastly, Mr. Kollen's proposal includes a reduction of $1.6 million for non-recurring lay-up costs for Coleman. Please see the Direct Testimony of Mr. John Wolfram, Exhibit Wolfram-2, Reference Schedule 1.13. Any non-recurring lay-up costs for Coleman have already been properly removed from the revenue deficiency in this instant case via a pro-forma entry. Mr. Kollen is in error.

Q. Does KIUC set forth a realistic plan to resolve the revenue deficiency caused by its rate plan?

A. No. KIUC suggests that the imminent financial shortfall created by its proposed rate plan should be resolved by somehow forcing Big Rivers' creditors to make significant concessions, thus splitting the revenue deficiency between Big Rivers' Members and its creditors. (Kollen Testimony, pp. 11, 36-42.) However, this proposal is unrealistic. As I discuss above, and as discussed in Mr. Mabey's and Mr. Walker's rebuttal testimonies, Big Rivers' creditors would not react as KIUC suggests, nor would they agree to abandon debt principal. Instead, they would rationally act to protect their interests; for example, RUS would likely implement the lock box to capture Big Rivers' revenues, including those from the Reserve Funds. Additionally, it is very unlikely that any lender would agree to loan Big Rivers additional monies if Big Rivers seeks to have its current lenders share in operational costs to reduce a rate increase. As Mr. Mabey testifies, lenders would ask for a meaningful *quid pro quo* to compensate for such concessions, and this is not something Big Rivers can offer the lenders. KIUC's plan is unworkable.

Q. What is your recommendation regarding KIUC's recommended course of action?

A. The KIUC recommendation has very serious flaws, is not supported by any studies or analyses, and would result in very adverse financial consequences for Big Rivers and its Members. The Commission should reject it.

VIII. THE ATTORNEY GENERAL'S RECOMMENDATIONS SHOULD BE REJECTED

Q. Please summarize the Attorney General's recommendations in this case.

A. The Attorney General proposes removing the entire revenue deficiency calculated by Big Rivers and authorizing a 1.10 TIER. (Ostrander Testimony, pp. 7:4-9:15.)

Q. Why is the Attorney General's recommendation flawed?

A. As I have discussed above, without the proposed adjustment to its rates, Big Rivers' ongoing financial viability would be undermined, and it would likely be forced to file for bankruptcy. As discussed in more detail in the Rebuttal Testimony of Ralph R. Mabey, bankruptcy is not a viable solution. The Attorney General's recommendation turns a blind eye to the economic reality that Big Rivers presently faces. The Attorney General's witnesses provide broad commentary about their concerns, but they do not provide a constructive recommendation or any evidence to support their speculation. Moreover, the Attorney General's recommendations in this case are almost identical to those already rejected by the Commission in the previous rate case, Case No. 2012-00535.

Q. Why is the Attorney General's use of the 1.10 MFIR inappropriate in this case?

A. As I discuss above, the Commission rejected the Attorney General's proposal of a 1.10 MFIR in the previous rate case, Case No. 2012-00535, in part because it found that the use of a 1.10 MFIR "will not provide any 'cushion' in the event of either an unexpected decline in revenues or unavoidable increase in expenses." (Century Order at pp. 41-42.) That remains true, and the Attorney General has again failed to provide any reasonable basis for basing rates on the minimum annual MFIR Big Rivers must actually achieve. Consequently, the Commission should reject this portion of the Attorney General's proposal. This issue is discussed further in the Rebuttal Testimony of Mr. Daniel M. Walker.

Q. Is the Attorney General's proposed treatment of the potential sale of the Wilson Station or Coleman Station appropriate?

A. No, the Attorney General's proposed "policy and practices" in the event of a possible future sale of a power plant is premature. Because any sale of generation assets must be approved by the Commission, the Commission will have the opportunity to review the terms of any sale when it arises. Any discussion of specific "policy and practices" before then is based on nothing more than the Attorney General's speculation and conjecture, and it is consequently wasteful of the parties' and the Commission's resources.

Q. What is your recommendation regarding the Attorney General's recommended course of action?

A. The Attorney General's recommendation has very serious flaws, is not supported by studies or analyses, and the Commission should reject it.

IX. THE SIERRA CLUB'S RECOMMENDATIONS SHOULD BE REJECTED

Q. Please summarize the Sierra Club's recommendations in this case.

A. Sierra Club recommends that the Commission only grant Big Rivers "short-term rate increases," thereby forcing Big Rivers to sell or retire the Coleman Station and the Wilson Station. (Ackerman Testimony, pp. 5:16-6:6.) In addition, Sierra Club recommends that Big Rivers should recover only the "minimum necessary to pay its outstanding debts . . . ." (*Id.* at p. 6:6-8.)

Q. Why is Sierra Club's recommendation flawed?

A. The recommendation takes an unreasonably narrow and short-term view. First, the rejection of the requested rate increase in favor of "exploring" is unrealistic. Big Rivers has serious service and financial obligations and credit issues to manage in a time-sensitive manner, and this kind of academic suggestion is misplaced in a serious rate proceeding that could mean the difference between bankruptcy and continued financial viability. Second, the rejection of Big Rivers' proposed rate adjustment will undermine Big Rivers' ongoing financial viability and is likely to force it into bankruptcy, despite Sierra Club's avowals to the contrary.

Sierra Club's proposal, purportedly designed to barely keep Big Rivers "afloat" while it sheds assets, is no better than KIUC's or the Attorney General's recommendations. Sierra Club provides no reason to think Big Rivers' creditors would agree to allow Big Rivers to retire Wilson or Coleman, or to sell those plants below book value, either of which would reduce the collateral available to the creditors. This is especially true if rates are designed to be minimal and offer no chance at improving Big Rivers' credit position.

Sierra Club's approach would dramatically extend the regulatory uncertainty surrounding Big Rivers' financial future, which would likely scare off potential load replacement customers and suppress regional economic development to the detriment of Big Rivers' Mitigation Plan. It would likewise scare off potential lenders that Big Rivers will need in the future to continue operations. As discussed above, Moody's has already identified the Commission's ongoing support of Big Rivers as a major positive sign for Big Rivers' financial future. Sierra Club's proposal would reverse that in favor of forcing Big Rivers toward likely bankruptcy, despite the fact that Mr. Ackerman has performed no analysis showing that bankruptcy would lead to lower rates.

Q. Are there other problems with Sierra Club's recommendation?

A. Yes. Sierra Club proposes that the Commission force Big Rivers to sell the Wilson Station and Coleman Station for less than net book value or, failing that, retire both plants. (Ackerman Testimony, pp. 23:18-25:2.) This position is consistent with Sierra Club's political opposition to fossil fuel-fired power plants. However, as Big Rivers demonstrated in Case No. 2012-00063, Big Rivers cannot retire generating capacity or sell it for less than book value because it would trigger a loss in the amount of the book value of the units and would reduce Big Rivers' Members' equity in the same amount. It is vitally important for Big Rivers to maintain its Members' equity, especially now that all three of its credit ratings are below investment grade.

Big Rivers' Members' equity is one of the few remaining positives in the eyes of the credit rating agencies, and its Members' equity is critical to its ability to borrow in the future and improve its credit ratings. Without the ability to borrow, Big Rivers would likely be forced into bankruptcy. In addition, there is no evidence to suggest that Big Rivers' creditors would approve the kind of sales or retirements proposed by Sierra Club. In light of the significant negative consequences of Sierra Club's recommendations, I believe it is extremely unlikely that Big Rivers would receive such approval.

Mr. Ackerman offers no expertise, studies, or analyses to support his assertions about selling or retiring plants, nor does he explain—aside from his affiliation with the Sierra Club[2]—why he believes it is in ratepayers' rational interests to force sales or retirements at rock bottom prices.

Q. Are there other problems with Sierra Club's recommendation?

A. Yes. Sierra Club proposes that the Commission should "allow rates that cover scheduled debt payments after the departure of Wilson and Coleman: there should be no additional markups, adders, or rate of return allowed on such payments." (Ackerman Testimony, p. 29:5-10.) This proposal is unrealistic and, I believe, contrary to basic regulatory principles.

As I discuss above, although Sierra Club asserts that its proposal is designed to keep Big Rivers temporarily "afloat," it would have functionally the same effects as the KIUC and Attorney General recommendations because creditors and vendors would no

[2] Sierra Club makes no secret that it is primarily motivated by its desire to force Big Rivers to reduce its use of coal generation. For example, Sierra Club has been soliciting Kentucky residents to oppose Big Rivers' rate adjustment on the grounds that "Big Rivers should look for opportunities to transition or close these dirty coal burning plants . . . ." (*See* Sierra Club's Solicitation for Public Comment, attached hereto as Exhibit Richert Rebuttal-2 (retrieved December 11, 2013).

longer view Big Rivers as a financially viable operation. This would restrict Big Rivers' ability to borrow (or lead to significantly higher borrowing costs) and seriously risk causing a default of Big Rivers' MFIR covenants. Unlike Mr. Mabey and Mr. Walker, Mr. Ackerman is not an expert when it comes to dealing with creditors. His unfounded speculation on this issue should be disregarded.

Finally, although I am not a lawyer, I find it hard to believe that the Sierra Club's proposal would be appropriate for a regulator to adopt. Speaking from a financial perspective as CFO, I believe it would be incredibly damaging for the Commission to deny Big Rivers any rate of return whatsoever. The rate of return is a foundational part of any utility's finance, and it cannot simply be dismissed in a misguided attempt to force third parties to negotiate. My understanding has always been that the rate of return is a basic regulatory protection, and Mr. Ackerman has not explained why it would be appropriate or lawful to completely eliminate such a fundamental part of the rates. Similarly, depriving Big Rivers, and ultimately its Members, of any opportunity to outperform TIER would only impose costs, and would provide no practical benefit. It would also signal a lack of regulatory support that could trigger adverse and damaging reactions from creditors and rating agencies.

Q. **What is your recommendation regarding Sierra Club's recommended course of action?**

A. The Sierra Club's recommendation has very serious flaws, is not supported by studies or analyses, and the Commission should reject it.

X. CONCLUSION

Q. What is your recommendation in this case?

A. The Commission should grant Big Rivers' proposed rates. Big Rivers' proposal is very carefully designed to protect its Members and stabilize its finances without being dependent on the success of Big Rivers' mitigation efforts or increased off-system sales for its financial well-being going forward. Any success from the mitigation efforts described in the Direct Testimony of Robert W. Berry would only benefit the Members in the future.

The Commission should reject the positions of the Attorney General, KIUC, and Sierra Club, all of which are unreasonable, unsupported, and likely to force Big Rivers into bankruptcy. If the Commission approves any of the Opposing Intervenors' proposals, Big Rivers would incur enormous cost, confront a great deal of negative disruption, and face a counterproductive and uncertain environment, likely for many years. This route is likely to lead to bankruptcy, the risks of which are enormous.

Big Rivers proposes a rate adjustment that will restore its financial stability so that it can demonstrate that it has regulatory support from the Commission and it can focus its resources still more intensely on realizing the benefits of the remaining aspects of its Mitigation Plan.

Q. Does this conclude your testimony?

A. Yes.

Big Rivers Electric Corporation
Case N[redacted]3-00199
Exhibit R[redacted]Rebuttal-1
No Rate Increase (TIER and Cash Impact) - (Millions)

	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014
Margins Without Rate Increase and No Access to Reserves	$ 3.36	$ (6.00)	$ (7.77)	$ (9.98)	$ (7.87)	$ (5.07)	$ (2.72)	$ (3.72)	$ (4.36)	$ (7.53)	$ (4.93)	$ (3.61)	$ (60.21)
Cash Balance	$ 77.79	$ 80.42	$ 85.49	$ 70.79	$ 48.88	$ 52.17	$ 48.59	$ 43.42	$ 41.42	$ 39.95	$ 33.66	$ 25.13	$ 25.13
TIER													(0.38)

	2015 January	2015 February	2015 March	2015 April	2015 May	2015 June	2015 July	2015 August	2015 September	2015 October	2015 November	2015 December	2015	2016	2017
Margins Without Rate Increase and No Access to Reserves	$ (2.67)	$ (3.47)	$ (7.00)	$ (11.08)	$ (6.97)	$ (5.41)	$ (2.37)	$ (3.22)	$ (4.01)	$ (7.50)	$ (5.21)	$ (3.92)	$ (62.85)	$ (64.79)	$ (64.31)
Cash Balance	$ 24.72	$ 22.94	$ 20.34	$ 6.32	$ (8.67)	$ (14.74)	$ (18.09)	$ (22.93)	$ (24.06)	$ (24.04)	$ (30.70)	$ (40.04)	$ (40.04)	$ (97.41)	$ (154.79)
TIER													(0.44)	(0.49)	(0.49)

Tell the Kentucky PSC to say no to Big Rivers' rate increase

Big Rivers Electric Corporation is trying to raise your rates. Again. And the culprit is dirty coal, as Big Rivers tries to make up for the loss of their biggest customers to two of their coal plants instead of investing in clean energy.

The Public Service Commission (PSC) of Kentucky has denied their previous attempts to raise rates drastically. If we speak with one voice, the PSC may deny them again. Big Rivers should look for opportunities to transition or close these dirty coal burning plants, not pass their losses onto Kentucky families and communities.

Send a message to the PSC and tell them to deny Big Rivers' latest attempt to force unnecessary costs onto consumers instead of investing in energy efficiency.

1. Complete the form below with your information.
2. Personalize your message if you wish.
3. Click the Send Your Message button to send your message to:

    Kentucky Public Service Commission

Send Your Message

Enter Your Information:

Required fields

Title:

First Name:

Last Name:

Your Email:

Address 1:

Address 2:

City:

State / Province:
Choose a State

ZIP / Postal Code:

Phone Number:

Join Sierra Club's Mobile Action Network! Enter your mobile number below to receive timely actions on your phone a few times a month. Reply "STOP" to unsubscribe at anytime.

Enter your mobile number below:

☑ Yes, I would like to receive periodic updates and communications from Sierra Club.

Personalize Your Message:

No Rate Increase for Big Rivers Electric Corporation and Dirty Coal

Dear Commissioner,

Personalize your message

Big Rivers Electric Corporation should not be trying again to raise rates to pay for the loss of its biggest customers, the aluminum smelters.

Even though more and more consumers of electricity move away from coal, the Big Rivers Electric Corporation has refused to change their business model. They have proposed idling two of their plants and raising rates on rate payers to make up for lost revenue.

As a consumer and a Kentucky resident, I oppose this. It is time for Big Rivers to invest in energy efficiency and renewable, clean energy and transition away from coal.

It is not fair for Big Rivers to force rate payers to shoulder the burden of their failing business model. The PSC needs to tell Big Rivers to invest in energy efficiency and renewable energy and not allow them to pass the increased costs of doing business onto consumers.

Sincerely,
[Your Name]
[Your Address]
[City, State ZIP]

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Exhibit Richert Rebuttal-2
Page 1 of 2

Send Your Message

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	) Case No. 2013-00199

REBUTTAL TESTIMONY

OF

TED J. KELLY
PRINCIPAL, BURNS & McDONNELL

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: December 17, 2013

REBUTTAL TESTIMONY
OF
TED J. KELLY

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REBUTTAL TESTIMONY
OF
TED J. KELLY

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ted J. Kelly, and my business address is 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 continuously employed by the firm since July 1998. Prior to that, I was employed with another major engineering 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 education background?

A. I am a graduate of the Missouri University of Science & Technology (formerly, 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 Master's Degree in Business Administration with emphasis 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, rate design, pricing, financial feasibility, cost of capital, and other utility 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 4,300 employee-owners includes engineers, architects, construction managers, developers, estimators, accountants, economists, technicians, and financial analysts 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 testified before the Kentucky Public Service Commission (the "Commission") in two previous Big Rivers rate cases, Case Nos. 2011-00036 and 2012-00535, and 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. In its order dated October 29, 2013, in Case No. 2012-00535, the Commission denied the depreciation rates proposed by Big Rivers in that case due to the temporary nature of the awarded rates. The proposed depreciation rates were based on the Report on the Comprehensive Depreciation Rate Study ("the 2012 Depreciation Study") prepared by Burns & McDonnell for Big Rivers. Big Rivers had Burns & McDonnell prepare the 2012 Depreciation Study because, in its order dated November 17, 2011, in Case No. 2011-00036, the Commission required Big Rivers to file a new depreciation study as part of its next rate case. That next rate case was Case No. 2012-00535.

In denying the proposed depreciation rates in Case No. 2012-00535, the Commission stated:

> In light of the temporary nature of the rates awarded herein, the Commission will reflect an adjustment to reduce Big Rivers' test-year O&M expenses by $1,778,761 and require it to continue using the depreciation rates that are currently in use and that were authorized by the Commission in Case No. 2011-00036. Big Rivers' new depreciation study has already been filed in its new rate case, Case No. 2013-00199, and will be considered in that case.[1]

As a result of the Commission's decision to consider the depreciation rates from the 2012 Depreciation Study in this case, I am filing testimony to support that study. My testimony on this issue incorporates my direct testimony filed in Case No. 2012-00535, except that certain citations have been changed to reflect that the study is not an exhibit to my testimony.

A true and accurate copy of the 2012 Depreciation Study was filed in this proceeding as an attachment to Big Rivers' response to Item 55 of the Commission Staff's First Request for Information. The 2012 Depreciation Study was performed for all of Big Rivers' facilities accounted for in accordance with Rural Utilities Service ("RUS") Bulletin 1767B-1, Uniform System of Accounts. The 2012 Depreciation Study is based on historical plant records of Big Rivers as of July 31, 2012.

My testimony also addresses claims made by Kentucky Industrial Utility Customers, Inc. ("KIUC") that depreciation expense on the Big Rivers Wilson and Coleman generating stations should cease while those plants are idled.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibit:

1. Exhibit Kelly Rebuttal-1 – Burns & McDonnell Letter dated November 28, 2012.

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[1] Order dated October 29, 2013, in *In the Matter of: Application of Big Rivers Electric Corporation for an Adjustment of Rates,* Case No. 2012-00535, at pp. 39-40 (footnote omitted).

III. 2012 DEPRECIATION STUDY

Q. Did you prepare the 2012 Depreciation Study?

A. Yes. I personally prepared portions of the 2012 Depreciation Study and the entire 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 publicly-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 2010 and filed with the RUS in February of 2011 (the "2010 Depreciation Study") in connection with Big Rivers' previous rate case, Case No. 2011-00036.

Q. What is depreciation?

A. The FERC and RUS Uniform System of Accounts define 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 to be given consideration 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 2012 Depreciation Study?

A. The 2012 Depreciation 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 on page ES-6 of the Study. These depreciation rates will result in an increase in annual depreciation expense of approximately $1.6 million per year (3.7 percent) as shown in Table ES-1 of the 2012 Depreciation Study. (*See* 2012 Depreciation Study, p. ES-6.)

C. Study Approach

Q. What was Burns & McDonnell's overall approach to meeting the requirements of the 2012 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. Burns & McDonnell relied substantially on the performance of previously completed physical site observations of the generation and transmission facilities by experienced power plant design engineers and transmission system engineers, respectively, performed in connection with the 2010 Depreciation Study. I personally participated in the site inspections and staff interviews in 2010 and in a conference call pertaining to the current condition of Big Rivers' generation and transmission facilities conducted in the completion of the 2012 Depreciation Study. Generally, the previously completed site visits included observation of the equipment and facilities and discussion with Big Rivers' staff and included the following activities:

1. Observation of Big Rivers' generating and transmission plant equipment and facilities;
2. Evaluation of the physical condition of the equipment and facilities;
3. Interviews of Big Rivers' generation and transmission operating and maintenance staff;
4. Review of each facility's organization structure, procedures, and staffing levels;

5. Evaluation of Big Rivers' generation and transmission operating and maintenance practices;
6. Assessment of Big Rivers' generation and transmission operating and maintenance reports;
7. Collection of pertinent cost and operating data records;
8. Collection of environmental data; and
9. Development of facilities descriptions.

The previously completed site visits were conducted at each of Big Rivers' production facilities, representative transmission substations, representative transmission lines, and the headquarters offices in Henderson, Kentucky. Key production, transmission, and accounting staff were interviewed and the condition of the facilities was assessed during these site visits. The site observations of the system facilities did not include any internal inspections or examinations, environmental testing, or completion of any performance tests on the equipment and facilities. No system, structural, pipe stress, or other mathematical modeling analysis was included in the scope of the facilities observations.

The conference calls completed in connection with the 2012 Depreciation Study were held to discuss the current condition of Big Rivers' generation and transmission facilities and to review operations and maintenance of said facilities since the completion of the 2010 Depreciation Study.

After completing the inspections and interviews, Burns & McDonnell engineers applied their experience and engineering judgment in developing an Engineering Assessment for each of Big Rivers' generating facilities and approximating the remaining lives of each asset. (*See* 2012 Depreciation Study, Part II – Engineering Assessment.)

Q. How did you develop the depreciation rates?

A. The projected remaining useful 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 2012 Depreciation Study included analysis of the service life characteristics, projected net salvage values, 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 ES-1 of the 2012 Depreciation Study. (*See* 2012 Depreciation Study, p. ES-6.)

Q. In preparing the 2012 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 2012 Depreciation Study report?

A. Part I, Introduction, discusses Big Rivers, the purpose of the 2012 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 July 31, 2012. 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 an engineering assessment of Big Rivers' generation and transmission plant assets in service as of July 31, 2012. The following activities were conducted to examine Big Rivers' generation and transmission plant assets from an engineering perspective:

1. A discussion of each production facility's basic design and equipment;
2. Previously completed on-site reviews and analyses of each production facility's current operating condition;
3. Conference call pertaining to the current condition of Big Rivers' generation and transmission facilities;
4. An analysis of each production facility's historical performance;
5. A discussion of the operating and maintenance procedures for each production facility;
6. An analysis of external factors that may impact each facility's useful life;
7. An opinion, based on the study's findings, regarding the remaining life of each facility;
8. A discussion of the composition of the transmission system; and
9. An opinion, based on the study's findings, regarding remaining life of each substation.

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 component that is considered in the calculation of depreciation rates. One important component of determining the remaining life of Big Rivers' facilities involves an evaluation of the maintenance activities performed by Big Rivers, operating statistics, and the resultant condition of the facilities.

Q. Did RUS comment on Big Rivers maintenance practices mentioned in the Depreciation Study Report?

A. Yes. RUS indicated that Big Rivers needs to resume its normal schedule of major inspections and maintenance practices. RUS may have misunderstood what we were indicating in the report. As a result of prevailing resource constraints, Big Rivers selectively deferred some major maintenance while continuing routine maintenance. Inspections performed by Burns & McDonnell and a review of operating results over the last several years indicated no adverse conditions as a result of these short term deferrals. Burns & McDonnell did review Big Rivers' plans, developed in May 2012, to reschedule the maintenance activities that are described by Bob Berry in his testimony. In light of the favorable operating results and assuming timely rescheduling of the deferred maintenance, in our opinion Big Rivers showed good judgment in the use of available resources, and its facilities are being reasonably and prudently operated.

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 the Engineering Assessment of the 2012 Depreciation Study. (*See* 2012 Depreciation Study, Tables II-1 through II-8, pp. II-2 through II-6.)

i. Robert D. Green Plant

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"). The Green Plant includes two units that are each significantly larger than the units at either the Reid Plant or the 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 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. The 2011 adjusted net heat rate was

11,270 Btu per kWh and 11,193 Btu per kWh for Green Plant Units One and Two, respectively, 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 has a seven year average Equivalent Forced Outage Rate ("EFOR") of 2.1 percent, while Green Plant Unit 2 has a seven year average EFOR of 1.5 percent.

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 Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that this facility cannot remain in service another 20 to 27 years based on the data available at the time of the analysis (depending on its operation). 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 very good. The HEP and hanger review addresses the concern over creep damage with an aging plant. This type of review program is critical and is currently being performed on all Big Rivers' units.

ii. HMP&L Station Two

Q. Describe the HMP&L 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 (the "City") through its municipal utility, Henderson Municipal

Power & Light. Big Rivers operates HMP&L Station Two on behalf of the City. HMP&L Station Two includes two units similar in size to the three units at the Big Rivers Kenneth C. Coleman Plant. HMP&L Unit 1 is rated for net continuous capacity of 153 MW, and HMP&L Unit 2 has a rated net capacity of 159 MW. HMP&L Unit 1 began commercial operations in 1973, and HMP&L Unit 2 began commercial operations in 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. HMP&L Unit 1 is equipped with a General Electric turbine-generator with nameplate rating for the turbine of 175,984 kW. HMP&L 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 HMP&L Station Two's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the level of reliability necessary to meet Big Rivers' electric production requirements. Both HMP&L Station Two units have been performing well. The 2011 adjusted net heat rate was 11,035 Btu per kWh and 11,286 Btu per kWh for HMP&L Units One and Two, respectively, which is competitive with other coal fired plants in the region. HMP&L Unit 1 has a seven year average EFOR of 7.7 percent, while HMP&L Unit 2 has a seven year average EFOR of 5.1 percent.

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 Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that HMP&L Station Two cannot remain in service another 16 to 21 years based on the data available at the time of the analysis (depending on its operation). 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 HEP and hangers. A consistent program like this for monitoring status and identifying areas to address in future budgets is very good. The HEP and hanger review addresses the concern over creep damage with an aging plant. This type of review program is critical and is currently being performed on all Big Rivers' units.

iii. Robert A. Reid Plant

Q. Describe the Robert A. Reid Plant.

A. The Robert A. Reid Plant (the "Reid Plant")is also located on the plant site near Sebree, Kentucky. The Reid Plant steam turbine generating 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 began commercial operation in 1966 and is currently rated at 65 MW.

Q. How has the Reid Plant been operated?

A. Burns & McDonnell reviewed the Reid Plant's historical operating performance to verify that the generating unit has competitive heat rates and is capable of providing the level of reliability necessary to meet Big Rivers' electric production requirements. The Reid Plant has performed commendably over the years. However, the unit had one of the highest heat rates on Big Rivers' system. The 2011 adjusted net heat rate for the unit was reported to be 15,027 Btu per kWh. This is relatively high for coal fired power plants in that region of the country, which is why the unit is primarily used for capacity and dispatched mostly as a peaking unit and for market sales. In addition, the seven year average EFOR of 21.2 percent is considered high when compared to other coal fired power plants in the region.

Q. What is the estimated remaining useful life for the 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. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that the Reid Plant cannot remain in service another 12 years or longer based on the data available at the time of the analysis (depending on its operation). 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 HEP and hangers. A consistent program like this for monitoring status and identifying areas to address in future budgets is very good. The HEP and hanger review addresses the concern over creep damage with an aging plant. This type of review program is critical and is currently being performed on all Big Rivers' units.

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; therefore, the Wilson Plant facilities (such as coal handling, water supply, ash handling, and sludge disposal) all have more than adequate capacity for the current operating requirements.

Q. How has the Wilson Plant been operated?

A. Burns & McDonnell reviewed the Wilson Plant's historical operating performance to verify that the generating unit has a competitive heat rate and is capable of providing the level of reliability necessary to meet Big Rivers' electric production requirements. The Wilson Plant has been performing well. The 2011 adjusted net heat rate was only 10,752 Btu per kWh, which is competitive with other coal fired power plants in the region. The seven year average EFOR was 4.6 percent.

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

A. The details provided for the Wilson Plant are the most comprehensive and complete of any of the Big Rivers facilities. The Wilson Plant is in very good condition for its age and service requirements. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that the Wilson Plant cannot remain in service another 29 to 38 years based on the data available at the time of the analysis (depending on its operation). 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 HEP and hangers. A consistent program like this for monitoring status and identifying areas to address in future budgets is very good. The HEP and hanger review addresses the concern over creep damage with an aging plant. This type of review program is critical and is currently being performed on all Big Rivers' units.

v. Kenneth C. Coleman Plant

Q. Describe the Kenneth C. Coleman Plant.

A. The Kenneth C. Coleman Plant (the "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 land to the south is occupied by Century Aluminum and is the site of an aluminum reduction plant, a primary customer of power from the Coleman 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.

Coleman Plant 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. Coleman Plant 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. Coleman Plant 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 Coleman Plant been operated?

A. Burns & McDonnell reviewed the Coleman Plant's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the level of reliability necessary to meet Big Rivers' electric production requirements. All three Coleman units have been performing well. Coleman Units 1, 2, and 3 had 2011 adjusted net heat rates of 10,656; 11,537; and 10,609 Btu per kWh, respectively. The availability of the units has also been good. Coleman Unit 1 had a seven year average EFOR of 4.8 percent, Coleman Unit 2 had a seven year average EFOR of 2.7 percent, and Coleman Unit 3 had a seven year average EFOR of 5.9 percent.

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

A. Coleman Plant Units 1, 2, and 3 are in good condition for their age and type. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that the Coleman Plant cannot remain in service another 11 to 21 years based on the data available at the time of the analysis (depending on its operation). 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 HEP and hangers. A consistent program like this for monitoring status and identifying areas to address in future budgets is very good. The HEP and hanger review addresses the concern over creep damage with an aging plant. This type of review program is critical and is currently being performed on all Big Rivers' units.

vi. Robert A. Reid Combustion Turbine

Q. Describe the Robert A. Reid combustion turbine.

A. The Robert A. Reid Combustion Turbine (the "Reid CT") is a General Electric Frame 7 combustion turbine 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 Plant, this unit is also located at the Sebree, Kentucky site with the HMP&L Station 2 and the Green Plant.

Q. How has the Reid CT been operated?

A. The Reid CT has been operated less than 1,000 hours over the last three years combined.

Q. What is the estimated remaining useful life for the Reid CT?

A. The relatively low number of operating hours for the Reid CT indicates that it should provide reasonably available capacity for a number of years into the future provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations.

F. Transmission Assets

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

A. Yes. The following efforts were conducted to examine Big Rivers' major electric substation assets in service from an engineering perspective:

1. Review of Big Rivers' retirement records and history;
2. Analysis of current operating and maintenance programs as well as each facility's current operating conditions;
3. Analysis of the external or environmental factors that may impact the depreciation rates; and
4. 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. Estimated remaining useful lives for Big Rivers' transmission assets were based primarily on the transmission engineer's professional judgment based on experience and national industry standards regarding the expected useful life of major electric substation equipment.

- The Reid EHV substation is approximately 30 years old. Assuming a continued level of maintenance on the substation, the Reid EHV substation as a whole can be expected to function properly for an additional 27 to 28 years based on the data available at the time of the analysis.
- The Coleman EHV substation is approximately 25 years old. Assuming a continued level of maintenance on the substation, the Coleman EHV substation as a whole can be expected to function properly for an additional 32 to 33 years based on the data available at the time of the analysis.
- The Wilson EHV substation is approximately 30 years old. Assuming a continued level of maintenance on the substation, the Wilson EHV substation as

a whole can be expected to function properly for an additional 27 to 28 years based on the data available at the time of the analysis.

- The Hancock substation is approximately 42 years old. Typically, substation transformers and circuit breakers are replaced 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 continued level of maintenance on the substation, the Hancock substation appears to be in good working order and should continue to function properly for an additional 17 to 18 years based on the data available at the time of the analysis.
- The Hardinsburg substation is 44 years old. Typically, substation transformers and circuit breakers are replaced any time after 40 years of useful life. However, given regular and proper maintenance, this equipment can last between 50 and 60 years. Assuming a continued level of maintenance on the substation, the Hardinsburg substation appears to be in good working order and should continue to function properly for an additional 17 to 18 years based on the data available at the time of the analysis.

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. The life of these individual units can vary based on a number of factors including but not limited to operating hours and maintenance. The Green, HMP&L Station Two and Coleman facilities have multiple units, but are forecasted to retire in the same year. This is reasonable for three reasons. First, the units were installed within two to three years of each other. Second, most plant accounts are assigned to the entire generating station, not to individual units of the facility. 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 are shown in Account 312 A-K. This is primarily due to the caustic nature of scrubber operations. As such, scrubber equipment dealing with sulfur dioxide removal and related piping will be expected to have a shorter life than that expected for the vast majority of the production plant. That life expectancy is directly related to the design, wear and tear from variable amounts of daily operation, and the levels of removal based on the particular coal mix being burned.

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.

The Wilson Plant is significantly newer than the other facilities. As such, its plant balance is significantly larger in comparison to the other facilities. If the remaining service life of each facility is weighted by the plant balances in Account 311 – Structures, Account 312 – Boiler Plant, and Account 314 – Turbine, the weighted average remaining service life is approximately 26 to 28 years based on the data available at the time of the analysis. As such, the remaining service life for Account 311 – Structures was assumed to be 28 years and the remaining service life for Account 312 – Boiler Plant and Account 314 – Turbine was assumed to be 26 years based on the data available at the time of the analysis.

Insufficient plant additions prior to retirement activity prevented a reliable actuarial analysis of Account 316 – Miscellaneous Equipment. As a result, other publicly available industry information, the Engineer's Assessment in Section II and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

G. Depreciation Analysis and Methods

Q. Describe the depreciation analysis.

A. The depreciation rate analysis was performed based on the electric generation, transmission, and general plant historical accounting records of Big Rivers as of July 31, 2012. The methodologies and basis for calculating the proposed depreciation rates and completing the 2012 Depreciation Study are similar to the process utilized in completing the 2010 Depreciation 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 key differences between the 2010 Depreciation Study and the 2012 Depreciation Study.

A. Big Rivers' 2012 Depreciation Study reflects production plant, transmission, and general plant account balances and reserve balances as of July 31, 2012. The 2010 Depreciation Study included production plant, transmission, and general plant account balances and reserve balances as of April 30, 2010. (*See* Letter from Burns & McDonnell to Billie Richert, Nov. 28, 2012, attached hereto as Exhibit Kelly Rebuttal-1, comparing the preparation of the 2012 Depreciation Study and the 2010 Depreciation Study.)

The existing depreciation rates in the 2012 Depreciation Study are the same depreciation rates that were proposed and approved in the 2010 Depreciation Study. (*See* 2012 Depreciation Study, pp. ES-6, III-6, that contains tables comparing existing and proposed depreciation rates.)

The remaining service lives in the 2012 Depreciation Study reflect the passage of time between the two studies. The average service lives are the same in both studies for all accounts.

As I discuss later in this testimony, Big Rivers' management decided that due to the short period of time since the 2010 Depreciation Study was completed and approved and the expedited timeframe required for this report it would be appropriate to use net salvage factors that are consistent with the 2010 Depreciation Study. The analysis required to incorporate the 2010 and 2011 removal costs in Big Rivers proposed depreciation rates has been deferred and will be addressed in a future depreciation study.

Q. Describe the depreciation rate study methods you employed.

A. Two primary methods have been used to calculate depreciation accruals: 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. The Whole Life method uses the 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. Typical property falling into this category includes 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 where retirement activity was insufficient to conduct actuarial analysis, or when the results of such an analysis were inconclusive, other publicly available industry information and the professional 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. Typical property falling into this category includes 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. 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. As the information was readily available, interim retirement life tables were developed separately for each of the accounts under the Life Span method.

Although detailed interim retirement records are maintained for each building and production facility, interim retirements for most locations are relatively few and little applicable life knowledge would be derived from attempting an analysis on such a thin available data set. Therefore, to improve the validity of the interim retirement rate analysis, an interim retirement rate calculation was performed for each account as a whole, rather than by account and then by location.

Engineers 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 2012 Depreciation 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. This AYFR and the aforementioned interim retirement rates are inputs to the remaining life (RL) calculation for each account.

The RL 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 2012 Depreciation Study (July 31, 2012). The net salvage parameter in the RL rate equation is the future net salvage rate (FS). The RL depreciation rate is expressed mathematically as:

$$(1 - FS - RR) / RL$$

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 actuarial analyses. For accounts where retirement activity was insufficient to conduct actuarial analysis, or for when 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. Three engineering publications that provide electric industry information were also considered as a resource for making certain assumptions or for the evaluation of lifespan and salvage value parameters:

1. "Depreciation Statistics from 100 Large United Electric Utilities – FERC Jurisdiction", Society of Depreciation Professionals Journal, Mougin, Clarence, 1992.
2. "A Survey of Depreciation Statistics", Edison Electric Institute, Robinson, Earl, 1995.
3. "Power Plant Removal Costs Revisited", Society of Depreciation Professionals Journal, Ferguson, John, 1997.

Q. How did you perform the net salvage analysis and calculate removal costs?

A. For the 2012 Depreciation Study, Big Rivers provided salvage values and removal costs for 2010 and 2011. Including the very large removal costs incurred by Big Rivers in 2010 and 2011 resulted in unrealistic net salvage factors. Therefore, the net salvage factors for each production, transmission, and general plant account were taken directly from the net salvage analysis performed in the 2010 Depreciation Study. The net salvage factors provided in the 2010 Depreciation Study are calculated as an average of the available historical data by system account from 1965 to 1998 and estimated values from 1998 to 2010. The net salvage figures used in the depreciation rate formulas in the 2010 Depreciation Study 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.

The removal costs incurred by Big Rivers total $6.7 million in 2010 and $1.8 million in 2011. For perspective, Big Rivers' removal costs for the entire period from 1965 to 2010 were only $6.4 million. The large removal costs incurred by Big Rivers in 2010 and 2011 were actually incurred and do not appear unreasonable given the refurbishment retirements incurred at the Wilson Plant. However, Big Rivers' management decided that due to the short period of time since the 2010 Depreciation Study was completed and approved and the expedited timeframe required for this report, it would be appropriate to use net salvage factors that are consistent with the 2010 Depreciation Study. The analysis required to incorporate the 2010 and 2011 removal costs in Big Rivers' proposed depreciation rates has been deferred and will be addressed in a future depreciation study.

Q. What effect would including the removal costs for 2010 and 2011 have had on depreciation expense?

A. Big Rivers' annual depreciation expense would have increased significantly (approximately $17.7 million).

H. Study Results

Q. What are the results of your study?

A. The proposed depreciation rates have been developed for all of Big Rivers' generation, transmission, and general plant in service 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 previously completed on-site observations of the Big Rivers generation and transmission facilities, Burns & McDonnell has formulated estimates of the remaining useful service lives for each plant account based on the data available at the time of the analysis.

Table ES-1 in the 2012 Depreciation Study 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 July 31, 2012. (*See* 2012 Depreciation Study, p. ES-6.) This table also provides a comparison calculation of Big Rivers' annual depreciation expense, calculated using the existing and proposed depreciation rates. This comparison shows that the proposed depreciation rates, if implemented by Big Rivers, would result in an estimated increase in depreciation expense of approximately $1.6 million per year (3.7 percent) based on July 31, 2012 account balances.

I. Recommendation

Q. What is your recommendation?

A. I recommend that the Kentucky Public Service Commission approve the proposed depreciation rates set forth in Table ES-1 of the 2012 Depreciation Study for prospective application by Big Rivers. (*See* 2012 Depreciation Study, p. ES-6.)

IV. DEPRECIATION EXPENSE SHOULD CONTINUE ON IDLED PLANT

Q. On pages 45-60 of his direct testimony, KIUC witness Lane Kollen argues that "[t]he Commission should set the depreciation rate to 0% for the Wilson and Coleman plants for *ratemaking* purposes while they are shut down. This *ratemaking* is consistent with the *accounting* requirements set forth in U.S. GAAP and the RUS [Uniform System of Accounts ("USOA")]."[2] Do you agree with Mr. Kollen?

A. No, I do not agree with Mr. Kollen's argument. I believe that depreciation expense should not be reduced on the Wilson and Coleman generating stations while they are idled for the reasons stated in Big Rivers' response to Item 89 of the Attorney General's Second Request for Information ("AG 2-89"). That response incorporates Big Rivers' response to Item 4 of the post-hearing requests for information in Case No. 2012-00535, which I co-sponsored and helped prepare.

Q. Do you have other comments on Mr. Kollen's testimony?

A. Yes. Mr. Kollen claims that "the RUS Uniform System of Accounts requires that [Big Rivers] cease depreciation expense on the plants after they are shutdown."[3] Even assuming that the temporary idling of a plant is a "shutdown," , Mr. Kollen provides

[2] Direct Testimony of Lane Kollen at p. 60, l. 5-8 (emphasis in original).

[3] *Id.* at p. 45, l. 13-15.

little support for this position other than his own incorrect interpretation of definitions from the RUS USOA.

He goes on to criticize Big Rivers for relying on relevant interpretations of those same concepts from the International Accounting Standards Boards ("IASB"), the Internal Revenue Service ("IRS"), and the RUS. Mr. Kollen explains why those interpretations are not binding accounting requirements on Big Rivers, but he fails to provide a reason for why his own biased interpretation should outweigh the interpretations from Big Rivers, the IASB, the IRS, and the RUS.

The only authority Mr. Kollen cites in support of his interpretation of the RUS USOA definitions is a National Association of Regulatory Utility Commissioners (NARUC) depreciation manual. However, his quotation of this manual is a general statement that expenses should be allocated to periods where the related assets provide benefits; it does not purport to address the situation of idled plant, unlike the IASB and IRS pronouncements cited by Big Rivers, which specifically state that depreciation expense should continue on idled property. Mr. Kollen also ignores the fact that the idled plants continue to provide benefits to Big Rivers, as explained in the Rebuttal Testimony of Ms. Billie J. Richert.

Mr. Kollen claims on page 50, lines 15-16 of his direct testimony that Big Rivers "cited no provision of the RUS USOA that either requires or allows it to continue depreciation during the shutdown period." This statement is clearly false. In its response to AG 2-89, Big Rivers cites provisions of the RUS USOA (as codified in the Code of Federal Regulations (CFR)), in addition to guidance from the Financial Accounting Standards Board ("FASB"), the IASB, the IRS, and the RUS, that Big

Rivers and myself relied upon in reaching, and that are consistent with, our conclusion that depreciation expense should continue on the Wilson and Coleman generating stations while they are idled. Mr. Kollen simply disagrees with the cited interpretations from the CFR, FASB, IASB, IRS, and RUS, and instead prefers his own interpretation.

I would also like to point out that on page 50, line 4 of his direct testimony, Mr. Kollen alleges that I agree with his premise. My statement is correct, but his quotation of my testimony is taken out of context and does not even support his position.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

November 28, 2012

Ms. Billie Richert
VP Accounting & Interim CFO
Big Rivers Electric Corporation
201 Third Street
Henderson, KY 42420

Re: Updates Completed for Big Rivers Electric Corporation's Comprehensive Depreciation Study Dated November 2012

Dear Ms. Richert:

Burns & McDonnell respectfully submits this letter pertaining to updates completed in the preparation of the 2012 Comprehensive Depreciation Rate Study (2012 Study) compared to the prior Comprehensive Depreciation Rate Study (2010 Study) prepared for Big Rivers.

The Rural Utilities Service (RUS) previously approved the depreciation rates in the 2010 Study on February 28, 2011. The purpose of this letter is to provide the RUS with a list of items in the 2012 Study that have been updated since the 2010 Study.

Item 1: Plant Account Balances and Reserve Balances are Updated to July 31, 2012
Big Rivers' 2012 Study reflects production plant, transmission, and general plant account balances and reserve balances as of July 31, 2012. The 2010 Study included production plant, transmission, and general plant account balances and reserve balances as of April 30, 2010.

Item 2: Existing Depreciation Rates
The existing depreciation rates in the 2012 Study, contained in the tables on page ES-6 and III-6 (for comparison to the proposed depreciation rates) are the same depreciation rates that were proposed and approved in the 2010 Study.

Item 3 Remaining Service Lives
The remaining service lives in the 2012 Study reflect the passage of time between the two studies. The average service lives are the same in both studies for all accounts.

Item 4 Removal Costs
For the 2012 Study, Big Rivers provided salvage values and removal costs for 2010 and 2011. The removal costs incurred by Big Rivers total $6.7 million in 2010 and $1.8 million in 2011. For perspective, Big Rivers' removal costs for the entire period from 1965 to 2010 were only $6.4 million.

9400 Ward Parkway • Kansas City, MO 64114-3319
Tel: 816 333-9400 • Fax: 816 333-3690 • www.burnsmcd.com

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Including very large removal costs incurred by Big Rivers in 2010 and 2011 resulted in unrealistic net salvage factors. Therefore, the net salvage factors for each production, transmission, and general plant account were taken directly from the net salvage analysis performed in the 2010 Study.

The large removal costs incurred by Big Rivers in 2010 and 2011were actually incurred, and do not appear unreasonable given the refurbishment retirements incurred at Wilson. However, Big Rivers' management decided that due to the short period of time since the 2010 Study was completed and approved and the expedited timeframe required for this report it would be appropriate to use net salvage factors that are consistent with the 2010 Study. The analysis required to incorporate the 2010 and 2011 removal costs in Big Rivers proposed depreciation rates has been deferred and will be addressed in a future depreciation study.

Burns & McDonnell greatly appreciates the opportunity to provide this summary of updates completed in the preparation of the 2012 Comprehensive Depreciation Rate Study for Big Rivers. If you have any additional questions or would like to discuss this information please contact me at 816-822-4354 or Ted Kelly at 816-822-3208.

Sincerely,

Burns & McDonnell

Jon Summerville
Project Manager
Business & Technology Services

Ted J. Kelly
Principal and Project Director
Business & Technology Services

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

APPLICATION OF BIG RIVERS	**)**
ELECTRIC CORPORATION FOR A	**) Case No. 2013-00199**
GENERAL ADJUSTMENT IN RATES	**)**

REBUTTAL TESTIMONY

OF

RALPH R. MABEY
SENIOR OF COUNSEL, STUTMAN, TREISTER & GLATT

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: **December 17, 2013**

REBUTTAL TESTIMONY
OF
RALPH R. MABEY

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REBUTTAL TESTIMONY
OF
RALPH R. MABEY

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Ralph R. Mabey. I practice law at Stutman, Treister & Glatt ("Stutman") as Senior Of Counsel. My business address is 50 East South Temple, Suite 318, Salt Lake City, UT 84111.

Q. Have you previously testified before the Kentucky Public Service Commission (the "Commission")?

A. No.

Q. Summarize your work experience and educational background.

A. I graduated *cum laude* with a Bachelor of Arts degree in English Literature from the University of Utah in 1968 and obtained my Juris Doctor from Columbia University in 1972, where I was a Harlan Fiske Stone Scholar and served on the Board of Editors of the *Columbia Law Review*. I also served as an International Fellow of Columbia University.

Q. Describe your work experience.

A. Upon completion of law school and the conclusion of a federal court clerkship with the United States District Court for the District of Utah, I co-founded a law firm in Salt Lake City where I practiced for over five years. In 1979, I was appointed as United States Bankruptcy Judge for the District of Utah and served in that capacity until 1983. Subsequently, I retired from the bench and founded the international bankruptcy practice of the long-established New York law firm LeBouef, Lamb, Greene & MacRae

("LeBouef"). I led the bankruptcy practice there for approximately 22 years as a LeBouef partner. During my tenure at LeBouef, I represented various parties-in-interest in complex out-of-court restructurings and chapter 11 cases throughout the United States. Following a hiatus after I departed LeBouef, I joined Stutman, where I continue my practice as a restructuring lawyer. I am a member in good standing of the New York and Utah bars.

I also currently serve as a Professor of Law at the S.J. Quinney College of Law at the University of Utah where I teach various courses, including Business Organizations, Business Reorganizations under the Bankruptcy Code, and International Bankruptcy. Previously, from 1983-2006, I served as a Senior Lecturer at the J. Reuben Clark Law School at Brigham Young University.

Q. Do you belong to any professional or honorary organizations?

A. I belong to several professional organizations devoted to the study and development of bankruptcy law. I am past president and past chair of the American College of Bankruptcy and previously served as an appointee of the late Chief Justice William H. Rehnquist to the U.S. Judicial Conference's Advisory Committee on the Bankruptcy Rules. I am a member of the National Bankruptcy Conference, the American Law Institute, and a founding member of the International Insolvency Institute. In 2009, I was awarded the Lifetime Distinguished Service Award by the American College of Bankruptcy.

Q. Have you published any professional articles?

A. I am a contributing author to *Collier on Bankruptcy 15th Edition*, a leading treatise on bankruptcy law. I previously served as a contributing author for the *Collier Bankruptcy*

Manual, as managing editor for the *Norton Bankruptcy Law Adviser*, and on the Editorial Advisory Board for the *American Bankruptcy Law Journal.* I have published scholarly articles and lectured on topics related to bankruptcy law throughout my career.

Q. Describe some of your work experience as a bankruptcy lawyer.

A. During my career as a bankruptcy lawyer, I have represented clients or served in other roles in several significant chapter 11 cases. Some of my more notable representations include:

Trustee
Cajun Electric Power Cooperative (Chapter 11 Trustee)

Examiner
Extended Stay
A.H. Robins Company

Committee Representations
Columbia Gas System (Equity Committee)
MicroAge (Creditors Committee)
Federated Department Stores (Pre-Merger Bondholders Committee)

Mediator
Lehman Brothers Holdings
Caldor Corporation
MarkAir
William Herbert Hunt Trust Estate
Sea Launch

Expert Witness/Consultant
AT&T (Expert Litigation Consultant)
Boston Chicken (Expert Witness)
Grupo Mexico, parent of ASARCO (Expert Witness)

Significant Creditor/Party-In-Interest Representations
Trans World Airlines (Counsel for the pilots)
Dow Corning (Counsel for certain bondholders)
London Insurance Market/Lloyd's (Counsel respecting asbestos liability in bankruptcy cases)

Q. Do you have any experience with bankruptcies filed by electric power generation companies or by companies in other regulated industries?

A. As noted above, I served as chapter 11 Trustee for Cajun Electric Power Cooperative ("Cajun Electric") in its multi-billion dollar bankruptcy case, filed on December 21, 1994. In this capacity, I addressed many of the same issues that Big Rivers would likely encounter should it be forced into a bankruptcy filing. In addition, I previously represented the Equity Committee of Columbia Gas System in the chapter 11 case, and Public Service Company of Colorado in its purchase of the assets of Colorado-Ute Electric Association, a rural electric generating association owned by its cooperative members. I have also published articles regarding bankruptcy issues, including (with Patrick S. Malone) *Chapter 11 Reorganization of Utility Companies*, 22 ENERGY LAW JOURNAL 277 (2001). From 1991 to 2012 I was appointed by the mayor and served on my home town's Power Commission that supervised the Bountiful City Light and Power Company, a municipal owned power company.

Q. What is the purpose of your testimony?

A. Big Rivers Electric Corporation ("Big Rivers") has asked me to address the subjects of debt restructuring and potential bankruptcy that are raised by the testimony of certain of the intervenors in this rate case (the "Opposing Intervenors"). Certain of the Opposing Intervenors' witnesses have proposed that the Kentucky Public Service Commission (the "KPSC" or the "Commission") should deny a significant portion of Big Rivers' proposed rate adjustment, suggesting that the burden of Big Rivers' excess capacity be "shared" between the retail customers on the Big Rivers system and Big Rivers' creditors. I have considered Big Rivers' financial position and debt structure, among other materials, and determined that any attempt at a consensual out-of-court restructuring of Big Rivers' secured debt will likely fail. Rather, if the KPSC adopts any of the Opposing Intervenors' positions, Big Rivers will likely be forced to file for protection under chapter 11 of the United States Bankruptcy Code (the "Bankruptcy Code"). A chapter 11 filing will create problems and risks for Big Rivers that would undermine its stability, threaten its viability, and possibly result in the cessation of Big Rivers' operations and liquidation of its assets. Because Big Rivers has the prospect of resolving its financial issues through a rate adjustment in the interim and successful implementation of its proposed Load Concentration Analysis and Mitigation Plan (the "Mitigation Plan"), it is my belief that bankruptcy should be a last resort for Big Rivers.

II. <u>AN OUT-OF-COURT WORKOUT IS UNLIKELY; BANKRUPTCY IS PROBABLE IF ANY OF THE OPPOSING INTERVENORS' POSITIONS ARE ACCEPTED BY THE COMMISSION.</u>

Q. Summarize your view of the likelihood that Big Rivers' Lenders will agree to large principal debt reductions outside of a bankruptcy proceeding.

A. The position of the Kentucky Industrial Utilities Customers, Inc. ("KIUC") and the Attorney General that the Commission's denial of all, or substantially all, of the requested rate relief (*see, e.g.,* Direct Testimony and Exhibits of Lane Kollen) will result in an out-of-court restructuring of Big Rivers' secured debt, rather than a bankruptcy, is incorrect.

KIUC, through Mr. Kollen, states that denial of the requested relief would be the foundation for a "workout" process between Big Rivers and its four major lenders: the Rural Utilities Service of the United States Department of Agriculture ("RUS"), CoBank, the Cooperative Finance Corporation ("CFC"), and the holders of the Ohio County, Kentucky Pollution Control Bonds ("Ohio County Bondholders", and together with RUS, CoBank, and CFC, the "Lenders"), which would result in a negotiated consensual reduction of a substantial amount of Big Rivers' indebtedness to the Lenders.[1] Based upon my experience, granting the Opposing Intervenors' requested relief will not result in a successful consensual reduction of Big Rivers' secured debt. In my judgment, if any of the Opposing Intervenors' positions are accepted, the consensual workout path will fail and a bankruptcy filing will be a highly probable result for at least the following reasons:

- The magnitude of the principal debt reduction that will be required, without a rate adjustment, to allow Big Rivers to pay its obligations.
- The need for concessions from multiple creditors, and the complexity of the internal financing and approval process of the Lenders.
- The concerns that are inherent in the approval process of governmental entities—such as RUS.
- The probability that none of the Lenders will be willing to make debt concessions unless all of the Lenders, and potentially other stakeholders (e.g., fuel suppliers, organized labor), agree to make corresponding economic concessions.
- The signal that a rate adjustment denial will give to Big Rivers' stakeholders that rate support is unreliable, that they should prepare for the worst, withhold concessions, and withdraw normal credit terms, which could precipitate an accelerated depletion of Big Rivers' cash and its Economic Reserve and Rural Economic Reserve (the "Reserves").
- The inability of Big Rivers to offer any meaningful *quid pro quo* or upside participation to the Lenders in exchange for principal debt concessions.

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[1] Mr. Kollen testifies that the Commission should "[d]irect Big Rivers to work with all stakeholders to achieve a reasonable negotiated solution to the Company's excess capacity and related fixed costs prior to the depletion of the reserve funds." Direct Testimony and Exhibits of Lane Kollen, Page 10, Lines 18-20.

For purposes of this testimony, I note here at the outset, that the value, revenue, and debt capacity for a rate-regulated utility are almost exclusively a function of the rates that the utility can charge its customers.

Q. In order to avoid bankruptcy and successfully effectuate an out-of-court workout, would the Lenders have to consent to large principal debt reductions?

A. I am informed that, as of September 30, 2013, the stated amount of Big Rivers total outstanding long-term debt principal was $965.9[2] million in the following principal amounts: RUS: $326.0 million; CoBank: $225.9 million; the CFC: $330.7 million; the Ohio County Bondholders: $83.3 million. As Ms. Richert, Big Rivers' Chief Financial Officer has testified, Big Rivers proposes to draw down on the Reserves in order to prevent passing on additional rate adjustments to its Members' retail customers until absolutely necessary. However, if either the Attorney General's or KIUC's proposal is accepted, the only way that Big Rivers would be able to continue to operate and to avoid defaults under its secured loans after the Reserves are exhausted is through a forgiveness of a significant portion of its outstanding secured long-term debt. For the reasons stated below, I believe that such reductions are unlikely to occur outside of a bankruptcy proceeding.

Q. How likely is it that Big Rivers will get all of the Lenders to consent to principal debt reductions in amounts required for a successful out-of-court workout?

[2] On a GAAP basis, Big Rivers' total outstanding long-term debt, as of September 30, 2013, was $856.9. In accordance with GAAP, for financial reporting purposes, the RUS Series B Note, with no stated interest rate and with a stated outstanding principal amount of $245.5 million due December 2023, is recorded at an imputed interest rate of 5.80%, and the RUS Series A Note, with a stated outstanding principal amount of $80.5 million and quarterly principal payments becoming due October 2019, is recorded at an effective interest rate of 5.84%.

A. One of the axioms of any workout process is that all similarly situated creditors make comparable concessions to the borrower. In my experience, getting any of the Lenders, let alone all of them, to agree to the magnitude of principal haircuts required if either the Attorney General's or KIUC's proposal is adopted is a highly doubtful, if not impossible, proposition. Getting all of the comparably situated secured creditors to agree to make these proportionate concessions in a timely fashion would be difficult to achieve because, among other things, each Lender has its own internal financial forecasting models, decision-making structure and protocols, and political considerations.

A further complicating factor in this case is the fact that CFC and CoBank refinanced $442 million of Big Rivers' debt only 18 months ago (in July 2012), which resulted in extended maturities, lower interest rates, and covenants more favorable to Big Rivers. The refinancing also resulted in millions of dollars in total actual savings for Big Rivers and its three cooperative members: Jackson Purchase Energy Corporation, Kenergy Corp and Meade County Rural Electric Cooperative Corporation (collectively referred to herein as the "Members"). Having just agreed to these significant concessions, it is highly doubtful that CFC or CoBank would consent to any further restructuring outside of a bankruptcy court, where even further concessions would inevitably be sought. From the Lenders' perspective, any agreement to further concessions outside of a bankruptcy court would be an unwise exposure to a triple-dip by Big Rivers (i.e., first, the concessions already agreed to under the 2012 refinancing; second, the concessions the Lenders would be asked to agree to during an out-of-court workout; third, the additional concessions the Lenders would be asked or required to agree to if Big Rivers later files for bankruptcy). If I were advising the Lenders, I would warn them of this risk and recommend that they not agree to additional concessions. The risk to Lenders of repeated concessions is much greater because Big Rivers' debt service capability is to some extent beyond its control—it is controlled largely by the Commission, which, if it sustains any of the Opposing Intervenors' rate proposals in this case, will demonstrate its willingness to undermine debt service requirements.

Ms. Richert has testified that the July 2012 refinancing with CFC and CoBank took many months. Even if the Lenders agreed to discuss a workout, the fact that one of the largest Lenders—RUS—is a governmental agency will significantly slow down the pace of any such discussions. The rationale and priorities of governmental units differ from those of private lenders, and the governmental decision-making process may be slower and more bureaucratic than it is in the private sector. The three private Lenders—Ohio County Bondholders, CoBank and CFC—would be asked to take write downs directly to their bottom lines—an unpalatable proposition for private lenders, and therefore an unlikely outcome.[3] Indeed, as Ms. Richert has testified, the July 2012 refinancing with CFC and CoBank did not result in *any* principal loan reductions (other than paying down RUS debt from the CFC and CoBank loan proceeds).

[3] I have generally reviewed the credit documents governing Big Rivers' indebtedness to Ohio County Bondholders, CoBank, and CFC. On this basis, I have concluded that both the Indenture Trustee for the Ohio County Bondholders and CoBank would likely face difficulties in obtaining approvals from all required holders for any material loan modifications. I am informed that the CoBank loan is held by five (5) separate lending institutions, each of whom would have to formally consent to the principal reduction. I also understand, based on my review of publicly available information, that the Ohio County Bondholders are held by several institutions, and the Indenture Trustee is not authorized to consent to a principal reduction of that debt without the unanimous consent of the bondholders. The Indenture Trustee, CoBank, and CFC will have to overcome these internal hurdles before the issue of obtaining consent from all four Lenders can even be addressed.

For these reasons, I believe that all of the Lenders will reject Big Rivers' request for a voluntary principal debt reduction of the magnitude required. Instead, I believe that the Lenders will determine that a bankruptcy court will be the best forum to address these issues. Indeed, in many respects, it is easier for a lender's decision-makers to justify concessions to their governing boards made in the context of a bankruptcy proceeding (i.e., to blame it on the judge) than to voluntarily write down a substantial asset. Without unanimity, there probably cannot be a successful workout in this case, and the only way to overcome the unanimity hurdle would be a chapter 11 bankruptcy.

Q. Would it be difficult to obtain concessions from other creditor groups, to the extent that the Lenders demand such concessions?

A. Even if the hurdles with the Lenders could be overcome and if they agreed to make concessions, I believe that they would do so only if other major stakeholders agreed to make corresponding economic concessions and "share the pain" of the workout. The Lenders would look to organized labor, fuel suppliers, and other major vendors to grant corresponding economic concessions to Big Rivers—or to prove that they could not—as a condition to agreeing to principal forgiveness as contemplated by the Opposing Intervenors.

Indeed, the parties do not need to look far to find evidence of the difficulty of getting all of a debtor's constituent groups to consent to an out-of-court workout. Based on my discussions with counsel and review of the first-day declaration filed in support of Big Rivers' chapter 11 filing in 1996, the lack of constituent consent is part of what ultimately landed Big Rivers in bankruptcy then. I am informed that, prior to that chapter

11 filing, Big Rivers initiated and engaged in extensive negotiations over a period of many months with the RUS, its other lenders at the time, the Members (i.e., the distribution cooperatives), and the two aluminum smelters that were on the Big Rivers system, among others. In the end, it was Big Rivers' view that a comprehensive agreement could not be achieved primarily because the banks that issued letters of credit backing Big Rivers' unsecured pollution control bonds refused to agree to a sufficient material compromise regarding the obligations they were owed, even though the RUS was amenable to making certain modifications. However, *the RUS did not agree to any principal reduction* during the pre-bankruptcy discussions, and no such reduction resulted under the Big Rivers chapter 11 plan—only the interest rate and term of the RUS loan were modified.

Q. Without a rate adjustment, will Big Rivers deplete its Cash Reserves while attempting to negotiate an out-of-court workout and ultimately end up having to file for bankruptcy?

A. Opposing Intervenor witness Mr. Kollen suggests that access to cash and the Reserves would provide Big Rivers with sufficient liquidity to pay operating expenses and contractual debt service and to maintain its minimum margins for interest ratio (MFIR) for about a year, during which a negotiated debt restructuring could be completed. As I have explained above, I do not believe that any amount of time will be enough to extract the kinds of concessions from the Lenders that Big Rivers will need in order to avoid a bankruptcy. If any of the Opposing Intervenors' positions are adopted by the

Commission, Big Rivers will run out of money trying to effectuate an out-of-court workout.

Based on my experience, I think that it would take at least six to eight weeks just to complete an internal assessment of the myriad of issues related to a workout. At a minimum, in order to prepare for a serious restructuring, Big Rivers would need to do a preliminary valuation of its assets, analyze and test its historic and projected cash flows, analyze alternative capital structures, prepare a business plan assessment, and prepare a model of different debt capacities. Only then could constructive negotiations begin, and the negotiations would be complicated by the issues I discussed earlier.

While these discussions continued, without a rate adjustment, Big Rivers' normal credit terms would likely become constricted for different reasons. Ms. Richert has testified, for example, that even after idling the Wilson and Coleman stations, fuel suppliers that presently represent approximately $11 million in monthly purchases on credit terms could begin to demand cash deposits to cover deliveries.[4] I would also expect normal trade credit terms to evaporate or be substantially cut back, which would also diminish the amount of liquidity that would remain available to Big Rivers. Most significantly, as Ms. Richert testified, without the requested rate adjustment, even if nothing else changes, if Big Rivers is granted access to the Reserves to supplement its margin shortfall and to help with meeting TIER, it would likely experience negative margins beginning in 2015, fail to meet its required MFIR, be forced to spend additional funds to prosecute another rate case, and ultimately file for bankruptcy.

[4] For example, as Ms. Richert has testified, the Midcontinent Independent System Operator has *already* asked for a $7.5 million deposit and has terminated Big Rivers' unsecured credit support.

For these reasons, it is my firm belief that, without sufficient rate relief, Big Rivers would run through all of its liquidity if it attempted an out-of-court work out, would not reach a consensual resolution, and would ultimately end up in bankruptcy.

Q. Would Big Rivers' status as a not-for-profit cooperative complicate its ability to negotiate an out-of-court workout?

A. Often, when a lender is asked to make concessions on the principal of its debt, the borrower/debtor is asked to make a meaningful *quid pro quo* to compensate the lenders for such concessions. In the for-profit context, that *quid pro quo* may consist of granting the lenders an equity stake in the company, to give them an opportunity to share in the "upside" of the company's success that may be realized as a result of the implementation of the proposed debt relief. Unfortunately, this is not something that Big Rivers can offer the Lenders. As a member-owned cooperative and a not-for-profit entity, Big Rivers is not in a position to offer equity to its stakeholders in the way of a *quid pro quo* for any debt concessions. The only "benefit" that Big Rivers could offer in exchange for an out-of-court workout is the avoidance of a disorderly liquidation. In my judgment, the Lenders will opt to allow Big Rivers to look to the bankruptcy court for any further relief.

Q. What impact will the Commission's denial of rate relief have upon Big Rivers' execution of its Mitigation Plan?

A. As Mr. Berry has testified, Big Rivers is proposing to address its financial challenges in two steps. First, Big Rivers is seeking a rate adjustment to address its needs. The Reserves will be used to offset rate adjustments to retail customers until they are depleted over the course of approximately one year.[5] Second, Big Rivers has outlined a Mitigation Plan, which focuses on off-system and other open-market sales of energy, as well as potential asset dispositions.

Mr. Berry has testified that Big Rivers is well positioned to implement and begin reaping the benefits of its Mitigation Plan in the reasonably near term. The rate relief will provide immediate financial stability, which will serve as the foundation for the early-stage success of the Mitigation Plan. However, without a rate adjustment, the Mitigation Plan will probably not succeed. In my judgment, adoption of the Opposing Intervenors' positions that little or no rate relief should be granted would signal to current and potential lenders and creditors that Big Rivers has lost its critical regulatory support and, therefore, doing business with Big Rivers is an unmanageable risk. Under such circumstances, it is highly unlikely that any third parties will be willing to enter into power purchase agreements, asset purchase agreements, or other agreements that are key elements of the Mitigation Plan. Moreover, reluctance to do business with Big Rivers would last until parties were convinced that Big Rivers had regained adequate regulatory support.

In sum, it is unlikely that any third parties would take the risk of dealing with Big Rivers when Big Rivers' financial stability is in question. If the period of uncertainty is allowed to continue long enough, while some aspects of the Mitigation Plan, such as the sale of certain assets, may not be materially delayed, I believe that the financial instability

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5 Mr. Bailey testified that if Big Rivers' requested proposals for a rate adjustment and use of Reserves is approved, the Economic Reserve is expected to be depleted in July 2014, and the Rural Economic Reserve is expected to last until April 2015—ratepayers will not feel the impact of the requested rate adjustment until the Reserves are depleted. Direct Testimony of Mark A. Bailey, Page 7, Lines 13-18.

and threat of a Big Rivers bankruptcy would undermine implementation of the smelter load replacement aspects of the Mitigation Plan. I believe that, if this happens, Big Rivers would be left with no choice but to file for bankruptcy, which would put the company's future onto an uncertain course that would not be controlled by management or the Commission, as discussed below.

III. A BANKRUPTCY FILING IS A LAST RESORT

Q. What are the costs of a bankruptcy, and what other impact might a chapter 11 bankruptcy filing have on Big Rivers, its Members, and its Members' retail customers?

A. The suggestions by the Opposing Intervenor witnesses that a chapter 11 case is an easy way to make a substantial portion of Big Rivers' secured debt disappear are misleading and potentially dangerous. To the contrary, as is evidenced by chapter 11 cases of other energy-generating utilities, the process is unpredictable, burdensome, and expensive—in terms of both cash and human capital.

During a chapter 11 case, Big Rivers' significant business decisions would be subject to objection by creditors and other parties-in-interest, many of whom would promote their own agendas over the interests of Big Rivers and its Members. Creditors may limit Big Rivers' access to capital for ongoing operations and attempt to prevent the use of the Reserves for their current purposes or to sustain operations and make prudent capital expenditures, as proposed by two of the Opposing Intervenors. Vendor and market reaction could be equally damaging by creating additional liquidity issues. The uncertainty resulting from a bankruptcy proceeding may render Big Rivers unable to compete effectively for lucrative power supply contracts or to be able to sell its available energy capacity at optimal prices.

In addition to the fallout from creditor and contract counter-party reactions, a bankruptcy case would most likely involve jurisdictional disputes to sort out the overlapping authority of the bankruptcy court, the federal district court, Kentucky state courts, the Commission, and the Federal Energy Regulatory Commission. These jurisdictional disputes would potentially substantially limit the Commission's authority to regulate Big Rivers' operations and other activities while the bankruptcy case is pending and thereafter. The bankruptcy court would likely appoint either a chapter 11 trustee or an examiner (with expanded duties) to manage or oversee Big Rivers' operations, which would significantly disempower the existing management. If a trustee was appointed, Big Rivers would also lose the exclusivity period in which only the debtor could propose and solicit acceptances to a plan of reorganization. This would probably result in a drawn out and highly contested plan confirmation process, similar to what happened in the Cajun Electric case, where the plan confirmation process alone lasted over three years.

After toiling for several years to formulate a confirmable bankruptcy plan of reorganization and spending tens of millions of dollars on professional fees and related expenses, Big Rivers could nevertheless fail to reorganize. Such failure could result in further rate instability and possibly the liquidation of all of Big Rivers' assets.

In sum, even under the best of circumstances, chapter 11 would be a traumatic event for Big Rivers and its constituents. Chapter 11 would also inevitably cause the accumulation of millions of dollars of expenses that are unavoidable in a bankruptcy case of this size. Big Rivers' Members and their retail customers may be forced to bear some or most of these high costs of chapter 11. Also, should reorganization efforts ultimately fail, the Members and their retail customers could be forced to source their energy from other providers, at unknown costs. For these and other reasons, in my opinion, the millions of dollars that would be spent on a chapter 11 case can be spent more effectively by implementing programs that will inure to the medium and longer-term benefit of Big Rivers' Members and their retail customers.

Q. What additional challenges would the Lenders present to Big Rivers' reorganization efforts in the event of a chapter 11 bankruptcy?

A. The primary purpose of Big Rivers' filing for chapter 11 would be to significantly reduce the principal amount of its $965.9 million of secured obligations to the Lenders. With debt reduction being the primary objective, I believe that these sophisticated institutions would adopt an adversarial approach to Big Rivers and the Commission on many of the significant issues that would arise in the bankruptcy case. Some of the consequences of the tension between Big Rivers, the Commission, and the Lenders—as a result of the bankruptcy—could include: (i) the reluctance, outright refusal, or inability of the Lenders to provide critical financing for Big Rivers' continued operations and environmental compliance costs; (ii) an even further negative effect on the rating agencies' view of Big Rivers' debt obligations; (iii) a chilling effect on Big Rivers' ability to convince future financing sources of its stability, without which it would not be able to continue to operate; and (iv) controversy about who can and should control power generation and delivery going forward.

One of the major issues that would need to be addressed immediately in a chapter 11 case is whether Big Rivers would be allowed to use the cash and the money it collects from ratepayers to pay its expenses and, if so, on what terms (e.g. how much cash can be used, for what purposes it can be used, and if such use should be subject to other restrictions). If Big Rivers filed for bankruptcy, the Lenders would aggressively assert that all of Big Rivers' cash on hand and cash held in the Reserves were subject to their lien rights. The Bankruptcy Code prevents a debtor's use of cash receipts that are the collateral of a creditor (referred to in bankruptcy as "cash collateral"), absent consent of the creditor or order of the bankruptcy court. On this basis, the Lenders would take the position that Big Rivers could not use any of its cash to fund its operations unless the Lenders consented or the bankruptcy court entered an order allowing Big Rivers to use such cash.

Without the Lenders' consent, Big Rivers would be faced with the task of convincing the bankruptcy court to grant it permission to use the Lenders' cash collateral to fund day-to-day operations during the case. Such permission would be contingent on Big Rivers either: (i) convincing the bankruptcy court that the Lenders do not have valid liens on the cash, or that such liens are avoidable; or (ii) agreeing (or being ordered) to make "adequate protection" payments to the Lenders throughout the case, or provide other protection, to ensure that no diminution of the value of the Lenders' collateral occurs through the effective date of a reorganization plan.

A debtor's request to use a secured lender's cash collateral over the lender's objection, or the objection of any creditor for that matter, can result in major litigation. As a consequence, even if Big Rivers were successful in obtaining permission to use the Lenders' cash collateral, it would likely be ordered to adhere to a strict budget that would leave little room for error and severely curtail the independent judgment of Big Rivers' management about operations.

Much of the controversy in a Big Rivers chapter 11 case could focus on the value of Big Rivers' assets because such valuation would have a direct bearing on the Lenders' security, including whether the Lenders' collateral is being adequately protected from diminution resulting from Big Rivers' use of the cash. Valuation litigation is expensive, complex, and unpredictable, and often involves the participation of numerous parties-in-interest, each arguing for a valuation of Big River' assets that fits its parochial self-interest. Opinions of value could vary widely based upon assumptions about rates that might be approved by the Commission and assumptions about future electricity and natural gas prices. To add further uncertainty, all of these issues would be tried in the bankruptcy court before a judge that may have little or no experience with the power generation industry.

Q. If Big Rivers files for chapter 11 protection, how long do you estimate the bankruptcy case would last and why?

A. A bankruptcy process deliberately exposes strategic decisions to the public domain. In large chapter 11 cases, courts often have regularly scheduled hearings to address and approve a variety of administrative and legal compliance matters, as required by the

Bankruptcy Code. The Bankruptcy Code generally prohibits chapter 11 debtors from entering into transactions outside of the ordinary course of a debtor's business, absent court approval. Transactions outside of the ordinary course of Big Rivers' business could include, for example, obtaining financing, incurring significant capital expenditures, selling assets, entering into new power supply contracts, modifying coal supply agreements, and actions that would impact Big Rivers' all-requirements contracts.

Generally, a bankruptcy court issues its orders after the debtor, creditors, and other parties-in-interest have been notified of the relief being requested by the moving party, have had the opportunity to file objections, and have been given a chance to be heard. In large cases there are multiple competing constituent interests and the motivations of many parties are often inconsistent with the interests of the debtor, its Members, or in a case like Big Rivers', its Members' retail customers. As a result, one or more parties (e.g., the secured lenders, the official committee of unsecured creditors, a regulatory agency) often take very aggressive positions. In bankruptcy court, this means that they may file objections to almost every motion and take discovery on proposed transactions or administrative motions the debtor is required to file.[6] Some participants respond or object to motions because they believe that advocating any position, even a losing one, is better than waiving a potential right by not responding at all. This is because filing a response of any kind generally preserves a party's right to later appeal the order or otherwise participate in litigation of the matter at issue. For example, the

[6] For instance, the Cajun Electric case spawned over 300 related lawsuits (referred to in bankruptcy as "adversary proceedings"), appeals, and administrative proceedings, and approximately 400 depositions were taken over the course of the case. As trustee, I received numerous requests for production of documents, and I estimate that my staff reviewed over 100,000 documents in response to those requests.

sale of any significant asset by a chapter 11 debtor outside of the ordinary course of its business can only occur after the bankruptcy court affords "notice and an opportunity for a hearing" to all major parties-in-interest, including creditors with liens on the asset being sold. A debtor's request to sell an asset outside of its ordinary course of business is often perceived as an invitation for each secured creditor's attorney and financial advisor to weigh in on the proposed process, object to the process, appear at the hearing to consider the process, participate in the actual sale/auction, and thereafter to appear at the hearing to approve the sale and weigh in on the form of order—often all at the debtor's expense (as I explain below).

Together, this process can result in thousands of filings and many days in court,[7] during which all major constituents are often represented. Based on my experience in the Cajun Electric case, and my familiarity with similar cases, a Big Rivers chapter 11 case would likely last a minimum of two years, and likely longer, until a plan is confirmed and several more years before the case is closed and the associated costs cease.[8] Before a plan becomes effective, the costs, diminution in the Commission's oversight, disruption and distraction of Big Rivers' management, and the constraints and limitation on business innovation would continue. After a plan became effective, Big Rivers would continue to accrue legal expenses and United States Trustee (the "U.S. Trustee") fees while all of the

[7] The Cajun Electric Case Docket had over 6,200 entries, which does not include the related adversary proceedings, appellate proceedings that took place in other federal courts, or any other proceedings before the Louisiana Public Service Commission, etc. Throughout the span of the Cajun Electric case, there were over 125 total hearing days in Bankruptcy Court, plus many more in other venues.

[8] From petition date to the effective date of a plan of reorganization, Public Service Company of New Hampshire took 39 months, El Paso Electric Company (filed January 8, 1992) took 49 months, Pacific Gas & Electric took 36 months, Mirant Corporation (filed July 14, 2003) took 30 months, and Cajun Electric took 63 months.

claims that were filed against it were determined and/or litigated, and numerous other matters were completed before the case could be closed.[9]

Q. What is your opinion about the impact that a bankruptcy filing could have on the Commission's regulatory authority over Big Rivers' finances and operations?

A. In bankruptcies of power-generating companies, the authority of state and federal agencies to regulate the activities of the debtor is often limited. These limitations are generally based on the premise that federal bankruptcy law, rather than state law, controls most aspects of a utility's operations during a chapter 11 case. While some courts have held that the state agencies continue to assert control over rate regulation, they have allotted little authority to the state agencies over other operational issues, including the assumption and rejection of contracts with suppliers and retail customers, changes in corporate structure, transfers of assets, form and content of debt documents, and other terms that may be incorporated into a chapter 11 plan. If Big Rivers is forced to file for bankruptcy, I believe that the Commission would likely be allowed to be heard and participate in the bankruptcy process. However, the Commission's actual authority to approve or disapprove a particular plan may not extend beyond post-confirmation rate setting. All other aspects of Big Rivers' reorganization plan could be placed in the hands of the trustee or examiner, creditors, and other parties-in-interest who may not be motivated by the retail customers' best interests. In short, bankruptcy could result in the

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9 A chapter 11 case is not closed until all of the various matters in the case are determined and finalized and the plan is substantially consummated, which can be years after the plan becomes effective. For example, the Cajun Electric case closed sixteen (16) years after its bankruptcy petition date, but certain administrative matters such as tax returns are still being finalized. In addition, although Cajun Electric confirmed its plan of reorganization in 1999, the company continued to pay significant quarterly fees to the U.S. Trustee until

loss of existing protections for the retail customers on the Big Rivers system, which could result in further cost increases.

Public Service Company of New Hampshire. For instance, in the chapter 11 case of the Public Service Company of New Hampshire, which was filed on January 28, 1988, the debtor and its creditors challenged the right of the New Hampshire Commission to participate in the bankruptcy case at all. While the New Hampshire Commission was ultimately permitted to participate in the case, the bankruptcy court: (i) enjoined the New Hampshire Commission from commencing an involuntary rate case during the bankruptcy; and (ii) found that the Bankruptcy Code preempted all of the New Hampshire Commission's authority over the provisions contained in the plan of reorganization other than authority over rates. This ruling prevented the New Hampshire Commission from exercising authority over asset transfers, mortgages, securities issuance, and contracts with affiliates that were all included in the debtor's plan of reorganization.

Cajun Electric. I was appointed trustee of Cajun Electric on the motion of the RUS. My experience in the Cajun Electric chapter 11 case was that the Louisiana Public Service Commission (the "LPSC") objected to most of the things I attempted to accomplish. This is because Cajun Electric was insolvent, and the trustee therefore owed a duty to maximize values for the benefit of creditors, while the LPSC sought to lower rates at the expense of creditors or otherwise. The case involved several heavily contested issues relating to the LPSC's authority to approve or disapprove the actions

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approximately 2008. After much negotiation, the U.S. Trustee finally allowed the reorganized company to stop paying the quarterly fees.

taken during Cajun Electric's bankruptcy proceeding. For instance, at the onset of the case, the LPSC moved to lower rates, arguing that Cajun Electric was presumably insolvent and would likely not be required to pay postpetition interest on its prepetition debt. Cajun Electric obtained an injunction to prevent the rate decrease, and after much litigation, the injunction was ultimately reversed by the Fifth Circuit. Another regulatory issue was that during the pendency of the bankruptcy case, the LPSC sought an open administrative docket to determine whether I, as the Cajun Electric trustee, acted prudently by initially failing to reject the company's fuel supply and transportation contracts. The bankruptcy court ruled that the LPSC was enjoined from making such an inquiry and that the decision was not subject to state regulatory approval, thereby limiting the LPSC's authority during the case. The plan of reorganization that was ultimately confirmed required the approval of the LPSC; however, state law may have been preempted in the bankruptcy case but for the fact that the applicable federal law required state regulatory approval under certain of the circumstances of that case.

Pacific Gas and Electric Company ("PG&E"). PG&E challenged the California Commission's ability to control rates during PG&E's bankruptcy case that was filed on April 6, 2001. While the California Commission was ultimately permitted to set rates during the case, an appellate court ruled that section 1123(a) of the Bankruptcy Code preempted non-bankruptcy law on issues related to plan confirmation (except regarding post-confirmation rates). This ruling permitted PG&E to take several actions and enter into transactions contemplated in its plan of reorganization without the California Commission's approval.

Jurisdictional challenges, like those prosecuted in the Public Service Company of New Hampshire, Cajun Electric, and PG&E bankruptcy cases, usually result in extensive and expensive litigation for both the debtor and the regulatory agencies seeking to establish their authority. In Big Rivers' situation, litigation regarding the scope of the Commission's authority over various actions that Big Rivers may seek during, and as part of the exit from, a bankruptcy case could potentially extend the duration of the case by months, if not years. The high stakes of the decisions reached during such litigation would likely lead to appeals by the unsuccessful litigants.

Q. How much do you think that a Big Rivers chapter 11 case would cost and who would be responsible for paying those expenses?

A. The costs of a chapter 11 case of a debtor the size of Big Rivers seeking to restructure are indisputably high—generally in the many millions of dollars. Filing a large chapter 11 case such as Big Rivers' would be akin to engaging in multiple complex, multi-party litigations that touch upon virtually every aspect of the debtor-company's business. Therefore, Big Rivers would need to employ both its existing professionals (e.g., outside utility counsel, auditors and tax consultants, tax and general legal counsel, and general litigation counsel), as well as an array of additional professionals (e.g., bankruptcy counsel, tax and financial consultants, and investment bankers). Given the size of its case, Big Rivers might also require the services of bankruptcy-specific service firms including service and claims agents to provide notice of the proceedings to creditors, ratepayers, and other parties-in-interest. Big Rivers would also be responsible for paying quarterly fees to the U.S. Trustee, among other expenses, until its case was closed, which could be years after a chapter 11 plan became effective, as was the case in Cajun Electric.

In addition to its own professional fees, Big Rivers would be responsible for paying all of the fees and expenses of the professionals that would be retained by the official committee of unsecured creditors, as well as those of any other committees that the U.S. Trustee may appoint to ensure that the various interests in the case are properly represented. Based on my review of the Indenture and the relevant portions of the respective loan agreements with the Lenders, Big Rivers would also be responsible for paying the professional fees for the Lenders and the Indenture Trustee. Also, as I indicate below, I believe that there is a strong probability that the bankruptcy court would appoint a chapter 11 trustee or examiner, who would also charge the estate for his professionals' fees.

When these fees and expenses are considered in the context of a complex chapter 11 case that typically continues for a number of years, these cumulative costs add up quickly and can be very high. Based on my experience, the professional fees in chapter 11 cases continue to reach unprecedented heights. It is difficult to quantify with certainty the total amount of chapter 11 professional fees that Big Rivers would be required to pay since professional fees are driven, in large part, by the length of the case and the nature of the disputes between and among the debtor and its creditors. Nonetheless, by examining professional fee costs in other large electric generation and transmission company bankruptcy cases, I have projected a range of professional fees that I believe Big Rivers is likely to incur if it files for chapter 11.

I would estimate the professional fees incurred by Big Rivers alone (i.e., not counting the secured creditors' or other entities' professional fees which Big Rivers may be obligated to pay) could be between $20 million and $40 million, which is approximately 1.3% to 2.7% of Big Rivers' $1.48 billion book value of assets. By way of comparison: (i) in the Mirant Corporation chapter 11 case, the company had a $19.4 billion book value of assets at the time of its filing in 2003, and the professional fees for the debtor totaled approximately $390 million, which was approximately 2% of the book value of its assets; (ii) in the El Paso Electric chapter 11 case, the debtor's professional fees were approximately $120 million, which was 6% of its $2.0 billion book value of assets at the time of its filing in 1992; and (iii) in the Cajun Electric chapter 11 case, the debtor's professional fees were approximately $32 million, which was approximately 1.5% of the $2.1 billion book value of the company's assets at the time of its filing in 1994.

Q. Is there a risk that Big Rivers' management may be replaced if there is a bankruptcy filing?

A. One of the many risks inherent in any chapter 11 case is the possible loss of control by the debtor's management. This could occur if the bankruptcy court appointed a chapter 11 trustee pursuant to Bankruptcy Code section 1104(a). Control would also be diminished, to some extent, if the Bankruptcy Court appointed a bankruptcy examiner pursuant to Bankruptcy Code section 1104(c) and provided the examiner with expanded powers. Based on my experience, such an appointment would be a distinct possibility in a case such as Big Rivers' due to the conflicting fiduciary duties owed by Big Rivers'

Members to their constituents and to Big Rivers' creditors. While certain observers might label the appointment of a trustee or examiner as a positive development for Big Rivers, handing control of a complex business to a stranger (i.e., a trustee) or allowing review and second guessing of potentially every business decision by a third party (i.e., an examiner) would complicate Big Rivers' operations and could complicate its ability to exit from chapter 11. Further, as described above, the addition of another player in the case and resultant professional fees would further diminish Big Rivers' cash position. Also, when a trustee is appointed, the Bankruptcy Code permits creditors to submit their own plans of reorganization immediately, as occurred in Cajun Electric. These competing plans potentially add yet additional layers of litigation to a chapter 11 case.

Q. What effect would administering a chapter 11 bankruptcy case have on the time and focus of Big Rivers' senior management?

A. A large chapter 11 case demands that the debtor's management devote many hours to the reorganization process. Even when a trustee is appointed, the trustee may turn to management for many tasks. Indeed, upon a filing, certain members of Big Rivers' management—particularly the finance and accounting teams—would likely be asked to devote nearly 100% of their time to bankruptcy-related issues both in preparation of the filing and throughout the case. Human resources, risk management and contract management personnel must also devote substantial time and energy to Big Rivers' reorganization effort.

As I explained earlier, upon a chapter 11 filing, Big Rivers would become involved in prosecuting or objecting to dozens of motions and participating in multiple litigation matters and adversary proceedings that would be brought before the bankruptcy court. Each matter would require attention by the company's management and employees in addition to their regular jobs. Their time would initially be spent on everything from preparing lists of all creditors and amounts they are owed, to identifying all of Big Rivers' contracts and summarizing contract terms and parties, to providing summaries of all payments made in the year prior to the filing. Financial historical data and projections would also need to be provided. Thereafter, as I described above, the need for bankruptcy court approval for all non-ordinary course transactions, as well as other general motion practice throughout a bankruptcy case relating to administrative, procedural, and compliance matters, would require Big Rivers' management to provide evidence in support of motions and oppositions by way of declarations or depositions, and to attend many of the hearings. As a result, management would be in a continual state of preparation for upcoming bankruptcy court hearings for the duration of the case.

In addition, management would need to devote substantial time towards the ultimate goal of the chapter 11 case: devising, obtaining court approval of, and implementing a plan of reorganization. Big Rivers' management would need to expend many days constructing, negotiating and possibly litigating a plan of reorganization. The task of devising a plan of reorganization that could be confirmed over the objection of Big Rivers' Lenders would be daunting, particularly in light of the significant principal debt concession that the Opposing Invervenors' respective proposals would require Big Rivers to seek from the Lenders if the requested rate adjustment is not approved. For all of these reasons, a chapter 11 filing would substantially disrupt Big Rivers' business operations throughout the case, which could span years.

Q. How might a chapter 11 filing impact Big Rivers' ability to retain its key personnel?

A. Critical employees often believe that a bankruptcy filing would eventually result in a change of ownership or a change of management, or both, which in turn would result in their termination. Such employees sometimes preemptively resign in favor of opportunities that they believe pose less long-term risk. This sometimes causes material disruption, as new employees must be identified, retained, and then trained, all during a time when the debtor's resources are already severely strained by the bankruptcy. Recognizing this risk, historically, companies in chapter 11 have sought to incentivize critical employees to stay during the duration of the chapter 11 case by creating appropriate retention bonus programs. Congress restricted this practice when it amended the Bankruptcy Code in 2005 by placing severe limitations on postpetition employee incentive programs—especially for management personnel—making it difficult to incentivize these employees to stay. Based on past experience, I believe that some personnel who would be key players in Big Rivers' recovery would terminate their employment during a chapter 11 proceeding, thus delaying and complicating Big Rivers' prospects for restructuring.

Q. What impact might a chapter 11 filing have on Big Rivers' relationships with its vendors and on its liquidity?

A. While the focus of a Big Rivers chapter 11 filing would initially be restructuring its long-term debt, the impact of the filing could impair various day-to-day relations with Big

Rivers' creditors and business partners and result in other far-reaching consequences as mentioned earlier. Vendors may refuse to do business with Big Rivers altogether upon a bankruptcy filing, or they may insist on payment of all outstanding prepetition amounts before agreeing to supply goods or services to Big Rivers. Big Rivers' vendors could also materially change payment terms, insisting on cash in advance or cash on delivery of goods and services. Each of these measures could create a serious strain on short-term liquidity throughout a chapter 11 case.

Q. Could a bankruptcy filing negatively impact Big Rivers' ability to compete for new business?

A. Businesses are frequently reluctant to engage in transactions with companies in chapter 11 because of the (often valid) perception of instability and increased risk. This reluctance could undermine Big Rivers' progress in implementing its Mitigation Plan by restricting its ability to enter into long-term power sales contracts. Mr. Berry discusses the Mitigation Plan in detail in his rebuttal testimony. He explained that Big Rivers is well positioned to reap benefits from the Mitigation Plan over the next several years. However, I believe that a pending chapter 11 filing would discourage potential contract counterparties from entering into transactions with Big Rivers. Moreover, even those counterparties that would be willing to accept the risk of nonperformance by Big Rivers would demand compensation (i.e., lower prices) for such risk, resulting in higher rates and smaller returns to Members.

Q. Big Rivers filed bankruptcy in 1996 and was able to reorganize, so why is it your opinion that bankruptcy is a last resort now?

A. Based on my very limited review of the facts of Big Rivers' first bankruptcy filing, I understand that Big Rivers made every effort to avoid bankruptcy in the mid 1990's. However, as I explained above, the refusal by certain lenders to consent to the terms of a viable restructuring necessitated the filing. In 1996, the bankruptcy filing was helpful for other purposes in addition to restructuring the company's debt obligations. At that time, Big Rivers also filed for bankruptcy in order to: (i) reject or restructure highly burdensome long-term coal supply contracts, (ii) resolve its outstanding litigation with various parties (e.g., the smelters and coal providers), and (iii) receive judicial approval for consummating a long-term lease transaction with PacifiCorp Kentucky Energy Company ("PKEC"), pursuant to which PKEC would lease and operate Big Rivers' generation assets (a deal which ultimately was not approved by the bankruptcy court).

In 2013, Big Rivers' situation is entirely different than it was in 1996. Among other things, I am informed that Big Rivers is not currently a party to any material unprofitable or otherwise onerous executory contracts that it wants to reject. Nor is Big Rivers embroiled in the kind or number of lawsuits that it faced in 1996. Accordingly, Big Rivers would suffer the instability, risks, and expenses of chapter 11 without obtaining meaningful benefits that it achieved by its 1996 bankruptcy filing.

Q. If Big Rivers does file for bankruptcy, is a successful reorganization a certain or a highly likely outcome?

A. The primary potential benefit to Big Rivers of a chapter 11 filing could be the ability to restructure its secured debts without the unanimous consent of the Lenders. However, there is no certainty that Big Rivers would be able to accomplish this task in a bankruptcy proceeding. Big Rivers may not succeed in cramming down a chapter 11 plan over the objections of the Lenders.

Also, in the 1996 bankruptcy, Big Rivers did *not* obtain *any* principal debt reduction. Instead, the company was only able to negotiate an interest rate reduction (from approximately 8% to 5% per annum) and to extend its repayment period. Today, especially given the very recent refinancing with CFC and CoBank, under which Big Rivers is paying historically low all-in effective interest rate of 4.11%, and Big Rivers' below investment grade ratings, there is little room for a meaningful interest rate reduction. Accordingly, unless a plan that includes principal debt reductions can be confirmed over some or all of the Lenders' objections, Big Rivers could face liquidation.

IV. <u>CONCLUSION</u>

Q. Can you summarize your conclusions as to what would be the impact if the Commission denies Big Rivers' request for rate relief and what is your ultimate recommendation to the Commission?

A. Failure to grant the requested rate adjustment will result in Big Rivers' bankruptcy rather than an out-of-court restructuring, and the path through chapter 11 is expensive and unpredictable. Therefore, a Big Rivers bankruptcy filing is not the optimal solution for the company, its stakeholders, or its Members' retail customers—it is a last resort. A chapter 11 case will cost millions of dollars, delay or make impossible the implementation of Big Rivers' Mitigation Plan, impair Big Rivers' ability to access capital markets for anticipated and necessary capital projects, and place in doubt the control, the operations, and the future of Big Rivers, along with the sources and costs of the Members' wholesale power supplies. Big Rivers may also be liquidated piecemeal by a trustee or examiner, or the assets may be sold to a for-profit company, over which the Commission could lose regulatory control. The effect that such a sale would have on Big Rivers' Members' existing retail customers is uncertain. What is certain is that this process, regardless of how it turns out, will cost millions of dollars and put the future of the company in jeopardy. The retail customers may ultimately end up bearing the brunt of these increased costs in one form or another. It is my opinion that the requested rate adjustment is a far superior mechanism for serving the interests of Big Rivers' Members and for continuing the viability of Big Rivers as it will allow the company to implement its Mitigation Plan for the benefit of the company, its creditors, the Members, and the Members' retail customers.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	) Case No. 2013-00199

REBUTTAL TESTIMONY

OF

DANIEL M. WALKER

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: December 17, 2013

REBUTTAL TESTIMONY
OF
DANIEL M. WALKER

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REBUTTAL TESTIMONY
OF
DANIEL M. WALKER

I. INTRODUCTION

Q. Please state your name and address.

A. My name is Daniel M. Walker. I am an advisor on cooperative finance. My business address is 7106 University Drive, Richmond, Virginia 23229.

Q. Are you the same Daniel M. Walker that submitted direct testimony in this case?

A. Yes.

Q. What is the purpose of your testimony?

A. I have been asked by Big Rivers Electric Corporation ("Big Rivers") to comment on certain parts of the Direct Testimony filed by Bion C. Ostrander on behalf of the Kentucky Attorney General's Office and on the rate plan proposed by Kentucky Industrial Utility Customers, Inc. ("KIUC") as set forth in the Direct Testimony of Lane Kollen (the "KIUC Rate Plan").

Q. Please summarize your rebuttal testimony.

A. Mr. Ostrander's recommendation of an authorized TIER of 1.10x for Big Rivers is inappropriate and much too low to be a creditable recommendation for the Kentucky Public Service Commission ("Commission") to consider. In addition, the KIUC Rate Plan is not realistic and would have serious negative consequences.

II. COMMENTS ON THE DIRECT TESTIMONY OF BION C. OSTRANDER

Q. Would you explain your concern about Mr. Ostrander's recommendation to set the Big Rivers' authorized TIER at the 1.10x level?

A. An authorized TIER of 1.10x would greatly harm Big Rivers' ability to repair its below investment grade debt rating and would be a significant impediment to improving its financial position.

Q. Would you explain why Mr. Ostrander has reached the wrong conclusion in his testimony?

A. Yes. There are a number of reasons why the Commission should disregard Mr. Ostrander's recommendation.

Q. Please explain.

A. For one, Mr. Ostrander clearly misunderstands the difference between the indenture TIER/MFI requirement of 1.10x and the level of interest coverage necessary to achieve sufficient ratings in order to attract capital. Mr. Ostrander states on page 10, line 3 of his testimony his reasoning to recommend a TIER of 1.10x: "I am proposing a 1.10 TIER, and this is the **only** interest coverage ratio that is contractually required of BREC at this time per existing loan agreements and BREC agrees with this conclusion." (Emphasis in original.) The indenture requirement of 1.10x is considered the default level of financial performance. In other words, if Big Rivers earns less than 1.10x, Big Rivers could no longer borrow additional funds under the indenture. This would be an extremely detrimental occurrence for any generation and transmission ("G&T") cooperative.

An authorized TIER at the 1.10x level would invite significant problems for Big Rivers even if simple margin attrition occurs. Mr. Ostrander implicitly recognizes this possibility on page 11 of his testimony when he discusses the difference between "earned" TIERs and Commission "authorized" TIERs. Mr. Ostrander states further on page 11, line 22, "The Company merely has the opportunity to earn that TIER." That is one of the reasons that the rating agencies, bondholders, and bankers expect a cooperative to "earn" a "cushion for compliance with financial covenants." An authorized coverage at the 1.10x level would not provide the cushion required by the financial community. I know of no G&T cooperative that is rated and has also issued debt in the capital markets which has only earned an interest coverage at the 1.10x level. As shown in the attached exhibit of the debt rated G&T's, Exhibit Walker Rebuttal-1, these G&Ts have earned a TIER/MFI within a range from 1.14 to 3.17x (each has an indenture MFI requirement similar to that of Big Rivers).

The only G&T that comes close to the 1.10x level is Oglethorpe Power in Tucker, Georgia. Over the last two years, Oglethorpe has earned a TIER/MFI at the 1.14x level. Oglethorpe can earn at this level and also achieve reasonable ratings and financings because it has the ability to adjust its rates every month if necessary. In other words, to support its credit profile, Oglethorpe can very quickly adjust its rates to remove the risks of under recovery, and thus, it is not likely to experience margin attrition. This is not possible in a state rate regulated environment.

Q. Are there other reasons why Mr. Ostrander reached the wrong conclusion in his testimony?

A. Yes. Mr. Ostrander's recommendation of 1.10x TIER defies the wishes of the Commission as stated in its October 29, 2013 order in Big Rivers' Case No. 2012-00535 (the "Order"). The Commission found in the Order: "The Commission finds that a TIER of 1.20x is reasonable and appropriate at this time." (Order at p. 43.) The Order was a "breath of fresh air" to the rating agencies and banks that have a stake in Big Rivers' credit profile. Moody's on November 1, 2013 stated in response to the Order:

> Even though the approved rate increase is about 20% less than the full amount included in the filing after certain revisions were made, the rate increase is credit positive for BREC because it is still a sizable amount which will support financial performance, ensure a degree of cushion for compliance with financial covenants, including its minimum required margins for interest ratio of 1.1 times in its debt documents, and buys additional time for BREC to pursue other strategies to mitigate significant

loss of electric load due to the termination of contracts with two aluminum smelters.

A copy of Moody's response[1] is attached as Exhibit Walker Rebuttal-2. As discussed by Moody's, the Commission's action in Case No. 2012-00535 is a credit positive. Some key words in Moody's statement include:

- "the rate increase is a credit positive"
- "ensure a degree of cushion for compliance with financial covenants"

In spite of the Commission order and the positive comments of Moody's, Mr. Ostrander wants to take the Commission down a darker path that would jeopardize Big Rivers' financial position.

Q. Are there other reasons why Mr. Ostrander reached the wrong conclusion in his testimony?

A. Yes. Another reason why Mr. Ostrander reached the wrong conclusion is that he does not understand the significance of financial performance in the rating process and the ability to attract capital. Mr. Ostrander stated on page 11, line 11 of his testimony, "a higher TIER is a relatively small contributor to improving BREC's financial health."

Q. Is this statement true?

A. No. Stronger financial performance is the key to Big Rivers' financial health.

Q. Would you explain?

A. Yes. As I explained in my direct testimony, each utility has a "basket of risk" which includes either credit positives or credit negatives. The credit evaluation process weighs the credit positives against a utility's credit negatives. In other words, a stronger credit positive like "financial performance" helps to mitigate a credit negative, such as the loss of significant load in Big Rivers' case. Of the five general rating categories found in Moody's

[1] Moody's Investor Service, "Issuer Comment: Kentucky PSC order to increase wholesale rates charged by Big Rivers, a credit positive," November 1, 2013.

"U.S. Electric G&T Cooperative Methodology Factor Grid," financial performance by itself accounts for 40% of the total rating process. For Big Rivers, in Kentucky, TIER is the focal point for financial performance because that financial indicator is used to set rates. For an investor-owned utility, it could be rate of return or return on equity. In fact, each one of the five rating categories in Moody's analysis has either a direct or indirect impact on the ability of Big Rivers to earn sufficient TIER and adequate cash flow:

1. **Wholesale power contract and regulatory status (20%):** Big Rivers' wholesale power contracts establish the structure to collect revenue to produce TIER/MFI.
2. **Rate Flexibility (10%):** This category illustrates the board's involvement and rate adjustment mechanisms in setting rates and recovering costs, which impacts financial performance such as TIER/MFI.
3. **Member/Owner Profile (10%):** Percentage of residential sales and member capitalization, which indicates the stability of cash flows to the G&T to protect TIER/MFI performance.
4. **Average G&T Financial Metrics (40%):** Moody's looks at TIER, DSC, funds from operation, interest, debt and equity, and total capitalization. Each of these indicators is linked. For example, rates set to produce a strong TIER/MFI will also produce stronger financial performance in other areas.
5. **G&T Size (10%):** The size of the G&T is an indication of its ability to spread its fixed cost over a larger number of sales units. The greater the number of sales units, the less likely a single event would have a detrimental impact on TIER/MFI.

Q. Do you agree with the concern expressed on page 11, line 28 of Mr. Ostrander's testimony that Ms. Richert and you only used one or two years of financial data from other utilities in your TIER comparison?

A. No. It is true that the rating agencies and potential bondholders look at multiple years of data in their analyses. However, as shown on Exhibit Walker Rebuttal-3, the collective TIER/MFI for the G&T peer group has a tendency to be similar from year to year. The average TIER of the "A" range was 1.73x for 2010, 1.65x for 2011, and 1.62x for 2012. This analysis results in the same conclusion as that found in my direct testimony: Big Rivers' request of a 1.24x TIER is extremely reasonable and well below the average of other G&Ts' earned TIER/MFI.

Q. Do you agree with the concern expressed on page 12, line 4 of Mr. Ostrander's testimony that Big Rivers had not shown how other G&Ts used in the TIER comparison were "Financially and Operationally Comparable" to Big Rivers.

A. No. First of all, G&Ts are a relatively small group when compared to investor-owned utilities for credit analysis and capital attraction. In most cases, the first credit analysis "cut" is to put all the G&Ts in one basket and review how they compare financially to each other. The second "cut" is to separate generation G&Ts from transmission G&Ts (which just provide either distribution or transmission services). The third "cut" analysis, which is the primary way Big Rivers is evaluated by the credit agencies and bondholders, is to look at generation G&Ts by their credit ratings. This is the analysis I have used in my exhibits. After this point, an analyst may use any number of "cuts" depending on the specific objective. For example, an analyst may want to see how the financial performance of state-regulated G&Ts compare to each other over the past three years. Such a comparison follows:

G&T	Average Financial Performance (2010-2012)	Current Rating
Arkansas	2.08x	(AA)
Chugach	1.36x	(A-)
East Kentucky	1.40x	(BBB+)
Big Rivers	1.17x	(BB-)

If an analyst performed this analysis, he or she would likely conclude that Big Rivers' financial performance for this three-year period was below other state-regulated G&Ts with ratings.

Q. Did Mr. Ostrander do any comparison to determine whether his proposed TIER was reasonable?

A. No.

Q. Do you have any other comments on Mr. Ostrander's recommended level of TIER/MFI?

A. Yes. Mr. Ostrander provided no evidence in his testimony that his recommended TIER of 1.10x was sufficient to even sustain, much less improve, Big Rivers' financial performance or allow Big Rivers to attract capital. As I stated in my direct testimony, Big Rivers' TIER recommendation of 1.24x is not, on its own, a long-term solution, but it will allow Big Rivers the ability to start the recovery process to achieve stable margins and better financial performance. Also, with regard to Mr. Ostrander's belief that "a higher TIER is a relatively small contributor to improving BREC's financial health," I believe the Commission's decision in this case to adopt Big Rivers' TIER/MFI recommendation of 1.24x would send a positive signal to the rating agencies. Even though the difference between that TIER and the TIER authorized in Case No. 2012-00535 is only 4 basis points, a slightly higher authorized TIER/MFI is certainly reasonable in comparison to other rated G&Ts, and it would indicate a reasonable degree of regulatory support for Big Rivers' efforts to improve its financial position for the benefit of its Members.

III. COMMENTS ON THE KIUC RATE PLAN

Q. Do you have any comments about KIUC's recommendation that Big Rivers' revenue requirement should be split between ratepayers and creditors?

A. Yes. Mr. Kollen states on page 36, line 4, "I recommend that the Commission balance the cost burden associated with Big Rivers' excess capacity, which no longer is used and useful, by equitably sharing that burden between the Company's customers and its creditors." It is unclear how specifically Mr. Kollen expects the Commission to achieve this "equitable sharing" between Big Rivers' customers and its creditors, but it is clear that this proposal is not realistic and would have serious negative consequences.

Q. Would you explain?

A. Yes. Mr. Kollen is suggesting the Commission direct Big Rivers to somehow force its lenders to write off a portion of Big Rivers' debt by intentionally undermining Big Rivers' financial integrity. This action would seriously impede or even destroy Big Rivers' ability to attract capital in the future.

Banks and bondholders enter into financial transactions with the full expectation that their principal will be returned on an amortizing schedule or at debt maturity. I am not aware of a single cooperative financial institution that would agree to advance funds if it felt it would have to take a "hair cut" or experience a loss of principal. The National Rural

Utilities Cooperative Finance Corporation ("CFC"), for example, which is a non-profit cooperative owned by cooperatives across the country, would resist efforts to force a write down of principal in order to protect its other members, as well as its own debt ratings.. CFC, along with other financial institutions, would not accept this risk and would instead simply divert their lending capital to other utilities in more supportive regulatory environments.

One of Big Rivers' principal objectives is to continue restoring its credit and financial condition so that it can protect its existing member equity and continue providing service to its members. In order to accomplish this, Big Rivers will, in the future, need to expand its financial resources for both short and long term capital. This will require both improved ratings and additional lenders. A Commission order requiring—either explicitly or implicitly—Big Rivers to demand its lenders take a "hair cut" would create credit uncertainties about the Commission's willingness to support debt obligations. This would severely weaken Big Rivers' ability to attract capital.

This has happened before. One concrete example is the reaction of the Rural Electrification Administration ("REA") (now the Rural Utilities Service or RUS) to the Commission's decision in Case No. 9613, which Mr. Kollen relies on in support of his recommendation. It is my understanding that in that case, the Commission denied the rate relief Big Rivers was seeking and ordered Big Rivers to work with stakeholders to develop a revised workout plan. Simultaneously, the Commission instituted a related case, Case No. 9885, to monitor and review the revised workout plan, saying that, among other things, the revised workout plan needed to insure "an equitable sharing of the risk by the creditors" and that "provisions . . . which are not contingent upon an immediate rate increase and guaranteed full repayment of debt are desirable."[2] In response, REA sent the Commission a letter stating that REA and the Rural Telephone Bank "will suspend all loan and loan guarantee approvals and advances on loans and loan guarantees already approved to all electric and telephone borrowers in Kentucky." A copy of this letter is attached as Exhibit Walker Rebuttal-4.

Thus, in the past, the same action advocated by Mr. Kollen in this proceeding resulted not only in the tightening of available credit to Big Rivers, but to all REA and RTB cooperative borrowers in Kentucky. A similar action today could affect not only cooperative utilities, but it could also damage the ability of even investor-owned utilities in Kentucky to attract future capital because the same bondholders that buy cooperative debt in the capital markets also buy investor-owned utilities' debt.

Q. How would the rating agencies respond to a Commission order adopting the KIUC Rate Plan?

A. The rating agencies would also have a very negative reaction to Mr. Kollen's proposal. The rating agencies judge the ability of a regulated utility to pay its debt service. Any proposal that would interfere with Big Rivers' debt service obligations has the potential to be a credit negative and would further impair Big Rivers' credit position. Both Moody's and S&P have recently made positive statements about the Kentucky Commission's support of the credit profile of Kentucky cooperatives. I don't believe the Commission should reverse its current positive support of the cooperative credit profile by adopting the KIUC Rate Plan.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

[2] Order dated March 17, 1987, in *In the Matter of: An Investigation of Big Rivers Electric Corporation's Rates for Wholesale Electric Service*, Case No. 9885, at pp. 1, 3.

Big Rivers Electric Corporation

G&T TIER and MFI ANALYSIS FOR 2011

	Moodys	Fitch	S&P	Tier or *MFI*
A+/AA Rated:				
Arkansas	A1 (Stable)	A+	AA (Stable)	2.37
Associated	A1 (Stable)	AA	AA (Stable)	1.51
Basin	A1 (Stable)	A+	A (Stable)	*1.26*
Central-SC	NR	NR	AA- (Stable)	*1.40*
Average				**1.64**
A Rated:				
Brazos	NR	A	A- (Positive)	1.95
Buckeye	A2 (Stable)	A	A- (Stable)	1.50
Central Iowa	NR	A	A (Stable)	2.13
Dairyland	A3 (Stable)	NR	A (Stable)	1.45
Golden Spread	A3 (Stable)	A	A (Stable)	3.17
Hoosier	A3 (Stable)	NR	A (Stable)	*1.83*
Oglethorpe	Baa1 (Stable)	A	A (Stable)	*1.14*
Old Dominion	A3 (Positive)	A	A (Stable)	1.20
Average				**1.80**
A- Rated:				
Chugach	NR	A-	A- (Stable)	1.58
Corn Belt	NR	A-	A- (Stable)	1.88
Great River	Baa1 (Stable)	A-	A- (Stable)	*1.22*
Minnkota	Baa2 (Stable)	NR	A- (Stable)	1.55
North Carolina	NR	A-	A- (Stable)	1.29
Power South	A3 (Stable)	A-	A- (Stable)	1.44
San Miguel	NR	A-	A- (Stable)	1.57
Seminole	A3 (Stable)	NR	A- (Stable)	1.41
South Miss.	A3 (Stable)	A-	A- (Stable)	1.72
South Texas	NR	A-	A- (Stable)	1.70
Wabash Valley	NR	NR	A- (Stable)	1.47
Western Farmers	NR	A-	BBB+ (Positive)	*1.29*
Average				**1.51**
BBB Rated:				
East Kentucky	NR	BBB	BBB (Positive)	**1.48**
Big Rivers	**Ba1 (Negative)**	**BB (Negative)**	**BB- (Negative)**	**1.12**

NR: No Rating

Sources: G&T Accounting & Finance Association Annual Directory June 2012; Fitch U.S. Public Power Peer Study, June 2012; S&P Industry Report Card: Expect U.S. Electric Cooperatives Utilities To Maintain A Stable Course in 2013 April, 2013; Moody's Rating Methodology: U.S. Electric Generation & Transmission Cooperatives, April 2013

Moody's
INVESTORS SERVICE

Issuer Comment: Kentucky PSC order to increase wholesale rates charged by Big Rivers, a credit positive

Global Credit Research - 01 Nov 2013

On 29 October, the Kentucky Public Service Commission (KPSC) approved a wholesale power rate increase of $54.2 million (retroactive to 20 August) for Big Rivers Electric Corporation (BREC; pollution control revenue bonds (cusip number 677288AG7) Ba2; negative), a credit positive for BREC.

Even though the approved rate increase is about 20% less than the full amount included in the filing after certain revisions were made, the rate increase is credit positive for BREC because it is still a sizable amount which will support financial performance, ensure a degree of cushion for compliance with financial covenants, including its minimum required margins for interest ratio of 1.1 times in its debt documents, and buys additional time for BREC to pursue other strategies to mitigate significant loss of electric load due to the termination of contracts with two aluminum smelters. It is not uncommon for a state public service commission to disallow certain requested amounts in rate case proceedings and often times, disallowed amounts are far more substantial compared to BREC's recent decision. Notwithstanding the fact that BREC is left with substantial excess capacity due to large customer contract termination notices, we note several supportive comments made by the KPSC in the rate order about prudent steps made by BREC, which we believe factored into the recent decision, and should bode well for BREC as it awaits another decision in a separate pending rate case expected in the early part of 2014.

BREC's contracts with its largest customer, Century Aluminum of Kentucky (a subsidiary of Century Aluminum Company), which owns the Hawesville smelter and the Sebree smelter have historically made up roughly two-thirds of BREC's annual energy sales and accounted for just under 60% of its system demand and in excess of 60% of annual revenues. Revenues which BREC has been receiving from base energy charges paid by the smelters ended on 20 August 2013 in the case of the Hawesville smelter and will end on 31 January 2014 in the case of the Sebree smelter.

The substantial majority of the rate increase requested in the case decided on 29 October was seeking replacement revenues to offset loss of the Hawesville smelter load and to also cover declining margins on off system sales other operating cost pressures. BREC is among the few electric generation and transmission cooperatives subject to rate regulation, which we view as a negative rating consideration among G&T cooperatives because it can sometimes pose challenges in implementing timely and sufficient rate increases. In this instance, however, the timing and amount of the rate increase ended up as a reasonable outcome, in our view, which we had already incorporated into the most recent rating action of 11 July. Among the more significant items contributing to the lower than requested rate increase approved in the October decision were deferral of costs related to depreciation of a generation plant that will be in excess of BREC's needs at least in the near term, as well as several other reductions to costs of service that will reduce BREC's operating margins, and to some extent, its cash flow.

Because regulatory laws in Kentucky permit implementation of requested rates after a six month period from the effective date requested, BREC had been charging its customers the full amount of its original request ($74.5 million) since 20 August, subject to refund. Based on the 29 October rate order, BREC will provide a refund to customers with interest within 60 days of the rate order to address the excess billed amounts between 20 August and 30 September.

On June 28, 2013, BREC filed another rate case proceeding, seeking KPSC approval for its rate strategy to address load loss when the Sebree smelter notice of termination period expires on January 31, 2014. Included in the $70.4 million rate increase is the Sebree smelter's $23.7 million share of the $68.6 million rate increase requested after revisions in the rate case filing decided on 29 October. Importantly and a key rating consideration are the plans to accelerate use of the economic reserve and rural economic reserve accounts in the amount of $70.4 million to offset this second rate increase which goes into effect on February 1, 2014. Tha accelerated use of tha reserve accounts would effectively neutralize any additional non-smelter customer rate impact from this second rate case filing until July 2014 for large industrial (non-smelter) customers and April 2015 for rural (residential) customers. Under this approach, BREC hopes to delay further non-smelter customer rate shock as it implements other load concentration mitigation strategies. The outcome of the current rate case, scheduled for early 2014, which will also address the manner in which tha economic reserves are implemented, will be an important milestone for the BREC rating.

Specifically, the load loss mitigating strategies, some of which are already being implemented, includa entering into long-tarm bilateral sales arrangaments, temporarily idling generation and reducing staff, making short-term off system sales, participating in the capacity markets, and selling or leasing generating assets. In that vein, BREC acknowledges that it would specifically consider the sale of its 417-MW D.B. Wilson and 443-MW K.C. Coleman coal-fired plants. Any steps to idle either of the two plants would only occur after ensuring that doing so would not jeopardize meeting MISO transmission system reliability standards. At the same time, BREC is responding to requests for proposals to sell power from these plants to other energy providers which could provida a alternative source of revenue and cash flow for BREC. Longer term opportunities may arise for sales of electricity, depending on economic development activity in its service territory. Should a transaction, either an outright sale or a long-term power arrangement for all capacity involving both Wilson and Coleman occur, BREC's total owned/available capacity would reduce to 584 MW from 1,444 MW. BREC also has rights to about 197 MW of coal-fired capacity from Hendarson Municipal Power and Light Station Two and about 178 MW of contracted hydro capacity from Southeastern Power administration.

Meanwhile, BREC's financial performance through September 30, 2013 has exceeded managemant's expectations given successful cost controls and better than anticipated margins from off system sales, with net margins in excess of $25 million. In terms of liquidity considerations, BREC addressed what had been its most pressing near term obligation by using a portion of its existing cash on May 31, 2013 to repay a $58.8 million tax-exempt debt maturity which was scheduled for June 1, 2013. As of September 30, 2013, BREC reported its cash balance was approximately $107 million (which included about $20 million designated for capital expenditures) and its debt maturities over the next eight quarters are largely comprised of scheduled amortizations of long-term debt to be paid at a rate of roughly $5.5 million per quarter. Following the 29 October rate case ordar, we undarstand that BREC is seeking additional external liquidity with National Rural Utilities Cooperative Finance Corp. (NRUCFC) through a senior secured loan to fund an estimated $60 million of KPSC approved environmental related capital expenditures over the next two years. This amount could be reduced by at least half if either or both of the Wilson and Coleman plants are idled. We understand that NRUCFC approval of this request for a multi-year loan is premised on NRUCFC's determination whether BREC's rate case order in its opinion is a satisfactory one and that funds would serve as a bridge to long-term senior secured financing under the U.S. Department of Agriculture's Rural Utilities Service (RUS) loan program. BREC's existing external liquidity is comprised of a recently amended and extended $50 million revolver with NRUCFC, which expires July 2017. As part of the amend and extand process, the revolver converted to a secured facility instead of unsecured, and permits access to funding despite smelter-ralated load loss. Extension of this facility is an important liquidity milestone because BREC had already terminated its $50 million CoBank facility, which was scheduled to expire in July 2017. The existing cash on hand and the $50 million revolver with NRUCFC, along with the anticipated $60 million three-year senior sacured term loan with NRUCFC for environmental capital expenditures will supplement the cooperative's internally generated cash flow going forward.

Contacts	**Phone**
Kevin G. Rose/New York	12125530389
A.J. Sabatelle/New York	12125534136
Chee Mee Hu/New York	12125533665

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Big Rivers Electric Corporation

G&T TIER and MFI ANALYSIS FOR 2010, 2011, 2012

	S&P	2010 TIER or MFI	2011 TIER or MFI	2012 TIER or MFI
A+/AA Rated:				
Arkansas	AA (Stable)	2.36	2.37	1.5
Associated	AA (Stable)	1.51	1.51	1.51
Basin	A (Stable)	1.19	*1.26*	1.28
Central-SC	AA- (Stable)	1.49	*1.40*	1.93
Average		**1.64x**	**1.64x**	**1.56x**
A Rated:				
Brazos	A- (Positive)	2.04	1.95	1.98
Buckeye	A- (Stable)	1.51	1.50	1.45
Central Iowa	A (Stable)	2.11	2.13	2.43
Dairyland	A (Stable)	1.31	1.45	1.46
Golden Spread	A (Stable)	5.06	3.17	2.75
Hoosier	A (Stable)	1.86	*1.83*	1.7
Oglethorpe	A (Stable)	1.14	*1.14*	1.14
Old Dominion	A (Stable)	1.23	1.20	1.21
Average		**2.03x**	**1.80x**	**1.77x**
A- Rated:				
Chugach	A- (Stable)	1.26	1.58	1.23
Corn Belt	A- (Stable)	1.54	1.88	2.17
Great River	A- (Stable)	1.25	*1.22*	1.31
Minnkota	A- (Stable)	1.48	1.55	1.39
North Carolina	A- (Stable)	1.25	1.29	1.28
Power South	A- (Stable)	1.43	1.44	1.45
San Miguel	A- (Stable)	1.5	1.57	1.55
Seminole	A- (Stable)	1.9	1.41	1.42
South Miss.	A- (Stable)	1.9	1.72	1.92
South Texas	A- (Stable)	1.8	1.70	1.76
Wabash Valley	A- (Stable)	1.36	1.47	1.47
Western Farmers	BBB+ (Positive)	1.66	*1.29*	1.37
Average		**1.53x**	**1.51x**	**1.53x**
"A" Range Ave.		**1.73x**	**1.65x**	**1.62x**
BBB Rated:				
East Kentucky	BBB+ (Positive)	**1.28x**	**1.48x**	**1.46x**
Big Rivers	BB- (Neg.)	**1.15x**	**1.12x**	**1.25x**

Sources: G&T Accounting & Finance Association Annual Directory 2010, 2011, 2012; Fitch U.S. Public Power Peer Study, June 2012; S&P Industry Report Card: Expect U.S. Electric Cooperatives Utilities To Maintain A Stable Course in 2013 April, 2013; Moody's Rating Methodology: U.S. Electric Generation & Transmission Cooperatives, April 2013

United States Department of Agriculture
Rural Electrification Administration
Office of the Administrator
Washington, D.C. 20250

April 9, 1987

RECEIVED
APR 10 1987
CHAIRMAN
P.S.C.

Honorable Richard D. Heman, Jr.
Chairman, Commonwealth of Kentucky
Public Service Commission
730 Schenkel Lane
Frankfort, Kentucky 40602

Dear Chairman Heman:

I have carefully reviewed the March 17, 1987 Order of the Public Service Commission of the Commonwealth of Kentucky in Case No. 9885 which denied a modest rate increase for Big Rivers Electric Corporation. I have discussed this Order with the Secretary of Agriculture, the General Counsel of the Department, and officials of the Department of Justice. Frankly, we are all surprised and disappointed at this action of the Commission and the rationale on which the Order is based.

The Order raises profound and disturbing questions about the future feasibility and security of loans made or guaranteed by the Rural Electrification Administration (REA) and the Rural Telephone Bank (RTB) for use in the Commonwealth of Kentucky. It appears that the Commission wants to reserve to itself the final authority to determine when and if loans will be repaid and the manner in which REA will exercise its jurisdiction over power sales of its borrowers.

The Commission's Order denying rate relief to Big Rivers has compromised the ability of Big Rivers to repay its Federal loans. Because of the position taken by the Commission as expressed in this Order, REA is obligated to consider the options available to it to protect the Rural Electrification and Telephone programs and the interest of the American taxpayer. Until we are in a position to reach a final decision, REA and the RTB will suspend all loan and loan guarantee approvals and advances on loans and loan guarantees already approved to all electric and telephone borrowers in Kentucky.

It would be helpful if you and the other members of the Commission would meet with me in Washington, D. C. to discuss this matter and attempt to arrive at a satisfactory resolution assuring repayment of loans to Kentucky borrowers.

For your information, I am enclosing a copy of a letter which REA is sending to its electric and telephone borrowers in Kentucky notifying them of REA's suspension action.

Sincerely,

Harold V Hunter

HAROLD V. HUNTER
Administrator

Enclosure

United States Department of Agriculture
Rural Electrification Administration
Washington D.C. 20250

LETTER SENT TO ALL REA-FINANCED ELECTRIC AND TELEPHONE SYSTEMS IN KENTUCKY

Dear Mr./Ms.:

I was surprised and disappointed to learn of the March 17, 1987 Order of the Public Service Commission of the Commonwealth of Kentucky in Case No. 9885 denying a modest rate increase to Big Rivers Electric Corporation (Big Rivers). Big Rivers has sought the rate increase to reflect the commercialization last year of the Wilson Generating Plant, a revenue producing, state-of-the-art, coal-fired, 400 MW power plant located in Western Kentucky.

The Rural Electrification Administration (REA), with the endorsement of the Commission, extended over $700 million in Federal loans and guarantees to Big Rivers to finance most of the Wilson Plant. Big Rivers has been in default on its Government loans since 1984 and is presently more than $220 million in arrears.

A similar attempt to modestly increase rates was rejected by the Public Service Commission in 1985, some 6 months after Big Rivers had defaulted on its Government loans. This latest rejection came after years of arduous negotiations among Big Rivers, REA, and other interested parties.

Big Rivers has not had a rate increase since 1981 and currently charges its members the lowest rates of any consumer-owned generating cooperative in the country. Had the Commission granted Big Rivers' request in this case, its rates would still have been far below those projected by Big Rivers in prior Commission proceedings authorizing the construction and financing of the Wilson Plant.

The Commission has apparently undertaken to allocate economic risks to REA in a manner not contemplated in the Rural Electrification Act or assumed by REA. The Order raises profound and disturbing questions about the feasibility of loans made or guaranteed by REA and the Rural Telephone Bank (RTB) for use in the Commonwealth of Kentucky. The Commission has seemingly reserved to itself the final authority to determine when Federal loans will be repaid, if ever. The Order also suggests that the Commission will make repayment of REA loans dependent upon how REA exercises its jurisdiction over power sales of its borrowers.

The Commission's Order denying rate relief has compromised important Federal interests, including the ability of Big Rivers to repay its Federal loans. Because of the climate of uncertainty created by the Order of the Public Service Commission dated March 17, 1987, I am not able to conclude, as required by law, that the security for REA and RTB loans is reasonably adequate and that such loans will be repaid within the time agreed. Accordingly, I must ask you, pursuant to your loan contract, to provide evidence satisfactory to

REA of the continuing economic feasibility of your system taking into account the Order of the Public Service Commission. Regretfully, until I receive satisfactory assurances in this matter, I must suspend any action on requests for the advance of funds on loans made or guaranteed by REA or the RTB, and on applications for additional loans or guarantees.

For your information, a copy of my letter to the Commission Chairman is enclosed.

Sincerely,

Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	) Case No. 2013-00199

REBUTTAL TESTIMONY

OF

DEANNA M. SPEED
DIRECTOR RATES AND BUDGETS

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: December 17, 2013

REBUTTAL TESTIMONY
OF
DEANNA M. SPEED

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REBUTTAL TESTIMONY
OF
DEANNA M. SPEED

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is DeAnna M. Speed. My business address is 201 Third Street, Henderson, Kentucky 42420.

Q. Are you the same DeAnna M. Speed who provided direct testimony in this proceeding?

A. Yes.

II. PURPOSE OF TESTIMONY

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

A. I am testifying on behalf of Big Rivers Electric Corporation ("Big Rivers") in order to address certain issues and matters raised in intervenor testimony filed on behalf of the Office of the Attorney General of Kentucky ("Attorney General") on October 28, 2013.[1] I will explain that Big Rivers' outside professional expenses are reasonable and have been prudently incurred. Additionally, I will explain how the Commission should reject the Attorney General's proposed Adjustment OAG-6-BCO because Big Rivers' rate case expenses are reasonable and well-supported. Throughout, I will address Mr. Bion Ostrander's numerous allegations and arguments concerning Big Rivers' rate case expenses and explain why the Commission should disregard these baseless accusations.

[1] Direct Testimony of Bion C. Ostrander on Behalf of Kentucky Office of Attorney General (the "Ostrander Testimony").

III. <u>THE ATTORNEY GENERAL'S PROPOSAL TO ADJUST BIG RIVERS' ESTIMATED RATE CASE EXPENSES SHOULD BE REJECTED.</u>

Q. Are Big Rivers' proposed rates intended to be fair, just, and reasonable?

A. Yes. Because Big Rivers is a not-for-profit member-owned cooperative (as opposed to an investor-owned utility), there is no profit motivation for Big Rivers to impose unfair rates on its Members or their retail member-owners or to incur unreasonable or imprudent expenses. This is further addressed in the Rebuttal Testimony of Mark A. Bailey, the Rebuttal Testimony of Billie J. Richert, and the Rebuttal Testimony of Robert W. Berry.

Q. What rate case expenses does Big Rivers seek to recover through its proposed rates?

A. Big Rivers seeks to recover legal and consultant fees related only to ratemaking as part of its rate case expenses. Big Rivers understands its obligations to its Members and the Commission, and it is not seeking recovery of legal or consulting fees unrelated to the rate case as part of rate case expenses.

All of these expenses are reasonable and were prudently incurred. In this proceeding, Big Rivers used the same basic processes and most of the same counsel and consultants it used in its previous rate case, Case No. 2012-00535, where the Commission found that Big Rivers had "provided adequate support for, and documentation of, its actual rate case expenses, and it has made improvements in both areas since its last rate case." (*Application of Big Rivers Electric Corporation for a General Adjustment in Rates*, Order, P.S.C. Case No. 2012-00535, p. 29 (Oct. 29, 2013) (the "October 29 Order"), *petition for rehearing filed* (Nov. 20, 2013)).

Q. Should the Commission adopt the Attorney General's recommendation to make no changes in rates or to limit Big Rivers' requested recovery?

A. No. Adopting the Attorney General's recommendation would have unfavorable consequences for the reasons further discussed in the Rebuttal Testimonies of Mark A. Bailey, Billie J. Richert, Robert W. Berry, Daniel M. Walker, and Ralph R. Mabey. Specifically regarding rate case expenses, the Attorney General's recommendation has no basis in fact or Commission precedent because Big Rivers' rate case expenses are reasonable, well-supported, and appropriately documented.

Q. Please summarize the Attorney General's proposed Adjustment OAG-6-BCO.

A. The Attorney General seeks to disallow certain rate case expenses included in Big Rivers' application on the grounds that they are allegedly "duplicative." It also seeks to disallow certain rate case expenses on the grounds that they have not yet been spent, despite the facts that the parties to this proceeding are still drafting testimony, the Commission has not yet held its evidentiary hearing, and the parties have not yet drafted post-hearing briefs. It also seeks to disallow certain rate case expenses on the grounds that they are allegedly speculative, excessive, or not reasonably documented.

Q. Should the Commission adopt the Attorney General's proposed Adjustment OAG-6-BCO to adjust Big Rivers' estimated rate case expenses?

A. Absolutely not. Any adjustment, including the removal of reasonable rate case expenses, could have unfavorable consequences for Big Rivers' ongoing financial integrity. As discussed in the Rebuttal Testimonies of Mark A. Bailey and Billie J. Richert, Big Rivers has requested the bare minimum to meet its debt service, continue funding an appropriately reduced scale of operations, and still have access to reasonable rates in the credit markets.

Big Rivers' rate case expenses are reasonable and well-supported. The Attorney General's attempts to justify a reduction in the recovery of Big Rivers' rate case expenses are unfounded and should be rejected.

Q. Has Big Rivers complied with the Commission's January 29, 2013 Order in Case No. 2011-00036 (the "Rehearing Order")[2] as it pertains to rate case expenses?

A. Yes. Since the issuance of the Rehearing Order, Big Rivers has provided and will continue to provide unredacted invoices as required by the Rehearing Order. Big Rivers will also satisfy, in my testimony that follows, the Rehearing Order's requirement to show that "use of highly compensated counsel was essential for the particular tasks being performed." (Rehearing Order, p. 6.) Big Rivers will provide the same kind of support for, and documentation of, its rate case expenses as it did in the previous rate case, Case No. 2012-00535, in which the Commission found that Big Rivers' support was adequate and approved Big Rivers' recovery of rate case expenses. (October 29 Order at p. 29.)

Q. Was it appropriate for Big Rivers to employ the use of outside professionals for this rate case?

A. Yes. Big Rivers has an extremely limited number of internal regulatory staff and no internal legal department. The Commission previously noted this in its October 29 Order in the prior rate case. (October 29 Order at pp. 29-30.) There, the Commission allowed full recovery of Big Rivers' actual rate case expenses, which were budgeted and incurred in the same manner as Big Rivers' rate case expenses in this proceeding.

[2] *In the Matter of Application of Big Rivers Elec. Cop. for a General Adjustment in Rates,* Ky. P.S.C. Case No. 2011-00036 (Jan. 29, 2013).

Mr. Ostrander argues that the rate case expenses should have been used for Big Rivers to "[hire] its own specialized employees for a certain contractual time frame" to perform the legal and regulatory work associated with this rate case. (Ostrander Testimony, p. 41:5-10.) This suggestion is misguided for a number of reasons. First, Mr. Ostrander's plan for how Big Rivers should staff this case is economically and functionally no different from Big Rivers' practice of engaging outside legal and consulting professionals. Surprisingly, Mr. Ostrander's calculations violate his own claims (whether or not true) that Big Rivers should realize efficiency savings in this second case. For example, the calculations he performs on Page 41 Lines 12-18 of his testimony, show Big Rivers incurring the exact same expense for both rate cases.

Second, Mr. Ostrander's plan would be implemented at the expense of the institutional experiences and memory developed by Big Rivers' current legal and consulting team which they have obtained through prior engagements with Big Rivers. The current team is familiar with Big Rivers and the issues involved in this case, which leads to greater efficiency and prevents precisely the kind of "duplication" that Mr. Ostrander purports to find of concern. This specific expertise would be lost under Mr. Ostrander's plan.

Third, Big Rivers' legal and consulting team has expertise and experience in numerous areas that simply could not be replicated by hiring 3-6 people full time, as Mr. Ostrander suggests. The use of outside professionals provides Big Rivers with access to dozens of consulting and legal professionals and allows for unmatched breadth and depth of expertise that simply could not be replicated using Mr. Ostrander's approach.

Fourth, if Big Rivers hired internal employees instead of using external professionals, Big Rivers would lose access to necessary tools such as legal databases used by counsel and modeling software used by consulting staff that are necessary in various phases of this proceeding. Big Rivers would have to pay additional sums beyond its labor cost in order to obtain these tools if it implemented Mr. Ostrander's ill-conceived suggestion. In addition, hiring specialized staff involves incurring expenses that may be unnecessary during periods when regulatory or legal activities ebb.

Finally, I understand that even utilities in Kentucky with relatively large internal legal and rate departments rely on outside professionals in addition to their internal staff. There are outside consultants that Big Rivers must use to conduct or support independent analysis. Preparation and support of the depreciation study is one example of such independent analysis. Thus, hiring more people would not eliminate the need for outside professionals.

Big Rivers' use of outside professionals to staff its rate cases has been found reasonable in the past and continues to be the most reasonable and prudent way for Big Rivers to engage in the regulatory process. Any notion that Big Rivers should have hired additional internal staff to perform the functions associated with this and other rate proceedings should not be taken as a serious suggestion and should be disregarded.

Q. Are Big Rivers' rate case expenses unnecessary or duplicative?

A. No. Mr. Ostrander argues that some of the rate case costs are "duplicative and lack any substantial economies of scale or savings from the prior rate case 2012-00535." (Ostrander Testimony, p. 41:25-26.) He argues that duplicity occurs because many of the issues, testimony, and data requests are the same in both cases. (*Id.*, p. 41:29-31.) He then proceeds to grossly mischaracterize Big Rivers' response to Item 258 of the Attorney General's initial data requests where he claims that the company admits that "it does not even budget for these efficiencies in this case." (*Id.*, p. 41:32-33.)

Mr. Ostrander provides no specific factual support for his allegations regarding duplicity of the work required for this case. Without providing any documentary evidence, he merely suggests that "adjustments, schedules, and formatting [had] already been performed and this did not require significant effort to update." He also claims that the Attorney General issued many of the same discovery requests in this case as in the prior rate case, and that the responses to many of those "should not have required much additional work." However, he does not point to any specific alleged overlap of effort, most likely because he grossly overstates the overlap between the two cases.

First, there was a greater number of data requests (counting subparts) in this case than in the prior case. The volume of the work was thus higher, and the vast majority of the responses could not be merely duplicated. Second, even in many of the questions that were asked in both cases, the Attorney General employed wording changes and shuffled the order of its prior data requests that it reused, making it difficult to rely on electronic searching or other more efficient methods of comparison. As a result, simply identifying the areas of potential overlap required significant time, and even once that was done most requests still required some kind of additional, new, or updated response. Third, any responses to duplicative requests between Case No. 2012-00535 and Case No. 2013-00199 in the application or in discovery had to be recreated and updated since each case was based on different test periods and each case had different base periods. Finally, schedules and adjustments could not merely be reused with minor updates. Again, because each case had different test periods and base periods, schedules had to be redone in order to accurately reflect Big Rivers' revenue requirement in this proceeding.

In budgeting for this case, it was impossible for Big Rivers to know the full extent of potential overlap between the two cases or the volume of data requests because Big Rivers was preparing this case at the same time it was prosecuting the previous case. Big Rivers did have a general expectation of efficiencies, as evidenced by the fact that the budgeted rate case costs as presented in Big Rivers' response to Item 258 of the Attorney General's initial data requests are 13% lower in this proceeding than in the prior one. Mr. Ostrander's allegations are vague, and he seems to suggest that Big Rivers should be able to provide an itemization that shows how costs will be reduced at various points throughout the proceeding. However, a more specific breakdown by phase of the proceeding is not possible as the process does not lend itself to that kind of evaluation.

Lastly, Mr. Ostrander still fails to recognize that only <u>actual</u> costs are recoverable. Big Rivers cannot provide invoices for work not yet performed; these will be provided as costs are incurred. All rate case costs that Big Rivers seeks to recover will be reviewed for reasonableness and prudence, and the proper documentation will be provided to the Commission. To put it more simply, Mr. Ostrander's suggestion that no additional expenses beyond those presently invoiced can be recovered is premature; it is irrelevant, given Big Rivers' intent to recover only actual costs; and it is not in keeping with Commission practice that has been established in numerous cases, including Big Rivers' previous rate case.

Q. How does Big Rivers ensure the accuracy and reasonableness of rate case expenses?

A. Big Rivers reviews monthly invoices from all outside professionals for accuracy and reasonableness. Before these invoices are filed with the Commission, they are reviewed by Big Rivers' staff to ensure that the charges bear a reasonable relation to deliverables that were obtained, and to ensure that the work performed was in furtherance of this rate case.

Mr. Ostrander argues that Big Rivers manages the accuracy of rate case expense invoices but not their reasonableness, and that costs are excessive. (Ostrander Testimony, pp. 41:35-42:8.) As I have already mentioned, Big Rivers is using the same staffing strategy and review process in this case as in the prior rate case. Big Rivers' expenses and its methods of verifying their reasonableness were approved by the Commission in the October 29 Order. Additionally, expenses to date in this case continue to be lower than those in the prior case, which the Commission found to be reasonable and prudently incurred. Mr. Ostrander's allegations are not remotely based in fact; on the contrary, these aspersions are a mere rehash of contentions he made in his testimony in the prior rate case that the Commission rejected. (Ostrander Testimony, p. 49:13-18 (admitting that he "ha[s] used a similar approach" to reducing rate case expenses as he did in the previous rate case).)

Finally, Big Rivers proactively monitors and manages the workload of all of its outside professionals. Big Rivers works closely with outside professionals to promote effective communication and timely completion of tasks. Internal staff develops and manages timelines in order to more efficiently produce deliverables required in this case. Internal staff also monitors the staff levels of outside professionals, ensuring appropriate personnel reductions are made as workload for a specific deliverable tapers. Also, as the

Commission noted, Big Rivers changed its use of outside counsel after the 2011 rate case in order to reduce costs.

Q. How has the Attorney General misunderstood or otherwise misapplied Commission precedent?

A. Mr. Ostrander ignores Commission precedent where he seeks disallowance of recovery for certain unspent legal fees associated with this rate case. (*See* Ostrander Testimony, p. 41:20-23). This criticism is unfounded, especially since the issue of the recovery of unspent rate case expenses was litigated in the prior rate case (in which the Attorney General also intervened and in which Mr. Ostrander also offered testimony). To quote the Commission in the October 29 Order, "[i]t should come as no surprise that a significant portion of the rate case expenses a utility has estimated at the time it files its application will not have been spent by the time intervenor testimony is filed." (October 29 Order at *29.) The Commission should decline to revisit this issue, particularly where the Attorney General does not present any new relevant arguments. Furthermore, it is settled Commission practice to allow recovery of reasonable expenses actually incurred <u>through the month of the hearing</u>. (*Id.* at p. 30.) Accordingly, this allegation is without any merit whatsoever.

IV. <u>BIG RIVERS' RATE CASE LEGAL COSTS ARE REASONABLE AND WERE PRUDENTLY INCURRED.</u>

Q. Has Big Rivers been attentive to the issue of rate case legal and professional costs?

A. Yes, Big Rivers has been attentive to the issue of rate case costs, as well as all other costs. Big Rivers addressed rate case costs from the outset in planning for this rate adjustment filing.

The Commission should recognize that a rate case based on a fully forecasted test year is more factually complicated, and potentially more voluminous, than a rate case based on a historical test year, and that the suspension period is one month longer. For these reasons, Big Rivers planned for more time from attorneys and consultants than it would have in a rate case presenting a historical test year. In addition, Big Rivers anticipated there would be several highly-active intervenors, as in the previous rate case, and this expectation has come to pass.

The volume of work required of Big Rivers in this proceeding cannot be overstated. Because of the tremendous scope of this proceeding and the number of intervenors, Big Rivers continues to vigilantly monitor rate case expenses to ensure that they remain reasonable.

Q. What steps has Big Rivers taken to ensure that its legal costs for this proceeding are reasonable?

A. As in the prior rate case, Big Rivers has taken a common sense approach to the division of labor that has allowed it to efficiently perform all necessary work and provide all requested information on the timeline established by the Commission.

Internally, Big Rivers employs a Regulatory Affairs Manager with significant experience in ratemaking proceedings. This employee is, in part, responsible for helping to control rate case fees by performing tasks such as ensuring filing compliance and facilitating document production in-house to avoid the heavy fees associated with outsourced document production. Additionally, Big Rivers' staff is responsible for document reproduction in order to keep those costs down and avoid the need to outsource that part of the process.

Externally, Big Rivers has relied heavily on regional counsel for the vast majority of the work in this proceeding. The use of multiple law firms, each playing a different role, has allowed Big Rivers to prosecute this case as efficiently as possible and keep costs reasonable.

Big Rivers relies on Sullivan, Mountjoy, Stainback & Miller PSC ("SMSM") for primary legal support for this proceeding. To provide support for SMSM in what we knew would be a complex case with extraordinary demands, Big Rivers retained Dinsmore & Shohl ("Dinsmore"), a regional law firm with offices in Louisville, Frankfort, Lexington, and elsewhere throughout the region. Dinsmore's attorneys have experience with regulatory proceedings before the Commission (including the prior rate case), charge hourly rates that are comparable to other firms in Kentucky, and are located in close proximity to both Big Rivers and the Commission, all of which allow Big Rivers to control its costs for legal counsel and travel while maintaining the necessary high level of legal expertise.

These two firms performed the vast majority of the legal work in the prior rate case and are intimately familiar with the parties and issues in the present case. Over half of forecasted rate case expenses (56%) are budgeted for these two firms. (*See* Big Rivers' Response to Item 258 of the Attorney General's initial set of data requests.)

Also, as was done in the last case, Big Rivers has retained Haynes and Boone, LLP ("Haynes Boone") for the limited purpose of advising it on the highly specialized issues related to restructuring and bankruptcy that have been raised by the intervenors in this case, and Big Rivers retained Orrick, Herrington & Sutcliffe ("Orrick") for the limited purposes of providing assistance based on Orrick's intimate knowledge with respect to Big Rivers' existing loans and bonds. I will address Haynes Boone's and Orrick's fees in further detail later. Unlike in the prior rate case, it has not been necessary for Big Rivers to retain international firm Hunton & Williams LLP for representation or counsel pertaining to this rate case.

Q. Are Haynes Boone's legal fees in this proceeding reasonable and justified?

A. Yes. Haynes Boone is uniquely qualified to advise in the area of utility restructuring and bankruptcy. Haynes Boone became familiar with Big Rivers and the issues in the present proceeding during the course of its engagement with Big Rivers in the prior rate case. Haynes Boone's insight and advice could not have been offered by any other legal counsel as efficiently and timely, given Haynes Boone's expertise and previous engagement with Big Rivers. Its expert assistance has been necessary in allowing Big Rivers to economically and thoroughly understand, analyze, and respond to the serious issues and suggested courses of action raised by the intervenors regarding restructuring and bankruptcy. In other words, Haynes Boone is only used when it is "essential for the particular tasks being performed" related to this case as required by the Rehearing Order. (Rehearing Order, p. 6.) While SMSM and Dinsmore are used for primary support, Haynes Boone plays a highly limited role in this case. As Mr. Ostrander's own testimony reflects, Haynes Boone's limited role in this proceeding is corroborated by the unredacted invoices Big Rivers has provided to the Commission. (Ostrander Testimony p. 45:14-15.)

Q. Are Orrick's legal fees in the proceeding reasonable and justified?

A. Yes. Orrick has performed extensive, highly-specialized work for Big Rivers in the past on matters that either relate directly to this case or that have been raised in this case by intervenors in data requests. Big Rivers has called on Orrick for insight and advice that could not have been offered by any other legal counsel as efficiently or as timely. Orrick was only used when it was "essential for the particular tasks being performed," as required by the Rehearing Order. (Rehearing Order, p. 6.) Orrick's limited role in this proceeding is corroborated by the invoices Big Rivers has provided to the Commission.

Q. Were Big Rivers' legal charges for this proceeding prudently incurred?

A. Yes. As previously discussed, this case is critical to Big Rivers' ongoing financial viability. In addition, because it is a fully forecasted test year rate case involving multiple intervenors, the costs of the case are unavoidably higher than would be expected in an historical test year rate case. Consequently, Big Rivers has required the services of the law firms discussed above in order to meet regulatory requirements and handle the volume of work product that must be timely produced and reviewed by Big Rivers.

Despite the high volume of critically necessary legal work during the prosecution of this case, Big Rivers has engaged in ongoing efforts to ensure that its legal costs remain reasonable. Big Rivers thoroughly reviews invoices from legal counsel to ensure that only costs related to the rate case are included and that costs are not excessive.

In short, to the extent that Mr. Ostrander accuses the attorneys of overbilling or providing imprudent or unnecessary services, those allegations are false. Because Mr. Ostrander's accusations regarding the alleged unreasonableness of legal fees are unfounded, the Commission should disregard his testimony on these matters.

V. BIG RIVERS' OTHER PROFESSIONAL CHARGES FOR THIS RATE CASE ARE REASONABLE AND WERE PRUDENTLY INCURRED.

Q. Were Big Rivers' other professional costs for this rate case prudently incurred?

A. Yes. As was the situation in the previous rate case, Big Rivers retained Catalyst to provide various expert ratemaking services. The intervenors have not alleged in this proceeding that hourly rates for Big Rivers' outside consultants are unreasonable. As in previous cases, Big Rivers' use of Catalyst is reasonable. Big Rivers relied on the expertise of its consultants to efficiently and properly prepare its rate adjustment request. Big Rivers' overall estimates for Catalyst's expenses are reasonable in light of the fully forecasted test year used in this case and the heavy workload anticipated as a result of the actions of the intervenors.

Big Rivers has also retained Mr. Ralph R. Mabey, a restructuring expert, and Mr. Daniel M. Walker, a cooperative finance expert, for consultation and to offer testimony on behalf of Big Rivers. They provide specialized expertise in areas that Big Rivers does not have and cannot obtain from its other outside professionals. Mr. Mabey was retained to address restructuring issues that Big Rivers anticipated the intervenors would raise, and did raise, in this case. Mr. Walker was retained to advise Big Rivers on an appropriate Times Interest Earned Ratio ("TIER") for ratemaking given the termination of the smelter contracts that essentially capped Big Rivers' TIER in the two previous rate cases. As for all of Big Rivers' other outside professionals, Big Rivers has provided, and will continue to provide, unredacted invoices to the Commission for charges as they accrue. These charges are reasonable, prudently incurred, and properly documented for the Commission and for the public.

Finally, ACES Power Marketing and Burns & McDonnell continue to play a role in Big Rivers' ratemaking proceedings. As is seen in Big Rivers' response to Item 258 of the Attorney General's initial request for information, the budgeted expenses for these two organizations also dropped over 50% from the prior rate case to the present rate case.

Q. Please explain the increase in the amount of budgeted but unallocated professional services expenses.

A. The budget for outside professional services for this rate case includes a category of budgeted but unallocated expenses. The amount in this category increased from the prior rate case as a direct result of Big Rivers' experience in the prior rate case.

In the prior rate case, Big Rivers was required to retain additional professionals to respond to proposals by the intervenors' witnesses. The injection of the issue of bankruptcy into the proceeding required Big Rivers to seek a legal services provider and expert witness that had the relevant expertise in this area. Based on this experience from the prior rate case, it was reasonable to budget for additional professionals to respond to issues that the intervenors may raise. Additionally, at the time that the budget for this rate case was prepared, the extent of the need for restructuring counsel and an expert witness on the subject was unclear. Finally, I would point out once again that Big Rivers will only seek to recover actual costs that are reasonable, prudently incurred, and appropriately documented for the Commission, and the public. Big Rivers will not seek recovery of budgeted but unspent amounts.

VI. CONCLUSION

Q. Do you have any final comments?

A. Yes. Big Rivers' requested rates are fully supported by data and include only reasonable rate case expenses properly included in the rate. They are fair, just, and reasonable under the totality of circumstances. The Attorney General's proposed adjustment OAG-6-BCO is unsupported by the facts, contradicts Commission precedent, and should be disregarded. The Commission should grant the rate adjustments Big Rivers seeks in this matter.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	) Case No. 2013-00199)

REBUTTAL TESTIMONY

OF

ROBERT W. BERRY
CHIEF OPERATING OFFICER

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: December 17, 2013

REBUTTAL TESTIMONY
OF
ROBERT W. BERRY

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REBUTTAL TESTIMONY
OF
ROBERT W. BERRY

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert W. Berry. My business address is 201 Third Street, Henderson, Kentucky 42420.

Q. Are you the same Robert W. Berry who provided direct testimony in this proceeding?

A. Yes.

II. PURPOSE OF TESTIMONY

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

A. I am testifying on behalf of Big Rivers Electric Corporation ("Big Rivers") to address certain issues and matters raised in the testimonies filed on October 28, 2013, on behalf of the Office of the Attorney General of Kentucky (the "Attorney General"), Kentucky Industrial Utility Customers, Inc. ("KIUC"), and Ben Taylor and Sierra Club ("Sierra Club") (collectively, the "Opposing Intervenors").

III. THE OPPOSING INTERVENORS' CRITICISMS OF BIG RIVERS' MITIGATION PLAN ARE UNSUBSTANTIATED AND SHOULD BE DISREGARDED

Q. Have you reviewed the Opposing Intervenors' testimony regarding Big Rivers' Load Concentration Analysis & Mitigation Plan (the "Mitigation Plan")?

A. Yes.

Q. Do the Opposing Intervenors raise valid concerns about the wisdom or viability of the Mitigation Plan?

A. No. As an initial matter, the Opposing Intervenors mischaracterize the goal and purpose of the Mitigation Plan. First, contrary to the Opposing Intervenors' suggestions, Big Rivers is not staking its long-term viability on the success of any element of the Mitigation Plan except this rate case. The goal of the Mitigation Plan is to provide a plan for Big Rivers to follow to mitigate the adverse financial impact of the contract terminations by the Century Hawesville and Century Sebree aluminum smelters. Big Rivers' long-term viability is dependent upon achieving in this case the rate relief it needs. Successful sales of power and/or generation under the Mitigation Plan will simply be an added benefit to Big Rivers' Members in the future by allowing Big Rivers to reduce the rate increase needed due to the smelter contract terminations.

Second, the Opposing Intervenors' attempts to paint the Mitigation Plan as a definite determination to restart Big Rivers' Wilson and Coleman generating stations are equally misleading. The Mitigation Plan is not and is not intended to be a cost-benefit analysis of when the plants should be restarted. The Mitigation Plan is simply a plan to reduce, to the extent possible, the rate increase needed due to the smelter contract terminations as well as a plan to replace the load which was previously utilized by the smelters. Big Rivers has not made the determination of when to restart the plants, and in fact, those plants have not yet even been idled. Big Rivers has performed Production Cost Modeling to evaluate the cost-benefit of idling the plants versus running the plants and selling the power into the wholesale market. As I have previously testified, at the current market prices, it is more cost effective to idle the plants until such time the market strengthens or we replace the load previously utilized by the smelters. Additional analyses will be performed in the future when circumstances appear to justify bringing the plants back online; that decision will be based on an analysis of the circumstances at the time.

Third, despite the Opposing Intervenors' claims to the contrary, Big Rivers' decision not to retire the Wilson and Coleman generating stations or try to sell them at rock bottom prices is not entirely based on the anticipated success of the Mitigation Plan. Big Rivers firmly believes the units are valuable assets that should be maintained to provide future benefits to the Big Rivers' Members. As stated time and again, Big Rivers' Members have invested in these assets over many years, and a knee-jerk reaction to the smelter contract termination should not strip the Members of their opportunity to receive benefit from these units in the future. Furthermore, the financial ramifications of retiring the plants or selling them at fire sale prices are described more fully in the Rebuttal Testimony of Ms. Billie J. Richert and the Rebuttal Testimony of Mr. Ralph A. Mabey. As those witnesses explain, taking those actions would be the equivalent of throwing in the towel on Big Rivers; it offers little likelihood for Big Rivers of anything except bankruptcy and potentially liquidation; both of which are huge gambles for Big Rivers' Members. It just does not make sense to throw in the towel on Big Rivers, whose Members have significant equity, just because two very significant loads terminated their contracts, rather than allowing Big Rivers to use the resources it has to mitigate the adverse consequences of those contract terminations.

In its order dated October 29, 2013, in Case No. 2012-00535, the Commission held: "[W]e find it reasonable to afford Big Rivers the time to pursue its mitigation strategies, including operational changes to reduce costs, seeking to acquire replacement load, increasing off-system sales, and attempting to sell or lease its generating facilities."[1] It would be arbitrary for the Commission to say in October that it was giving Big Rivers time to pursue its mitigation plan, only to turn around a few short months later and force Big Rivers into bankruptcy.

The rate increase sought in this case is intended to address Big Rivers' immediate financial needs that must be met to allow Big Rivers the opportunity to further pursue the Mitigation Plan. I believe the Commission should once again reject the Opposing Intervenors' attempts to torpedo reasonable efforts under the Mitigation Plan to mitigate the smelter contract terminations and to risk everything on bankruptcy. Later in this testimony, I address the Opposing Intervenors' specific areas of criticism of the Mitigation Plan and other modeling supplied by Big Rivers in this proceeding.

Q. The Opposing Intervenors assert that the Mitigation Plan is unlikely to succeed. Do you agree?

A. No. The Mitigation Plan addresses a number of possible scenarios going forward, particularly with respect to the strength of various markets, which allows Big Rivers to have the flexibly to respond to changing conditions. In addition, the Mitigation Plan does not assume the success of any one element; rather, it outlines multiple mitigation strategies simultaneously, including the rate increase requested in this proceeding, increased marketing of power (both on short-term and long-term bases), marketing of generation assets, economic development, and reduction of generation-related costs.

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[1] Order dated October 29, 2013, in *In the Matter of: Application of Big Rivers Electric Corporation for an Adjustment of Rates*, Case No. 2012-00535, at p. 19.

Big Rivers has said that it is unsure of the timing and amounts of load recovery; however, Big Rivers is confident the question is "when," not "if" as the Opposing Intervenors assert. Big Rivers continues to focus on a multi-pronged approach because Big Rivers believes a diversified solution is in the best interest of its Members. However, if Big Rivers is unsuccessful in finding replacement load, as the Opposing Intervenors claim it will be, Big Rivers still can add Member value just by taking advantage of the Midcontinent Independent System Operator, Inc. ("MISO") market, to which it has ready access.

The Opposing Intervenors' criticisms in this case focus on the replacement load assumptions contained in some of the long-term modeling Big Rivers filed in this case in response to requests for information. I address those criticisms later in this testimony, but it is important to note that Big Rivers' budget and financial plan, and the rate relief Big Rivers is seeking in this proceeding, do not include the longer-term replacement load assumptions, nor is Big Rivers' long-term financial integrity dependent upon obtaining the replacement load projections.

One of the flaws in the Opposing Intervenors' analysis is that, by focusing on replacement load, they largely ignore the possibility of increased off-system sales and revenues from future capacity auctions in the MISO market. The Opposing Intervenors appear to believe that if Big Rivers does not achieve the replacement load assumed in some long-term modeling, Big Rivers will have no additional revenues. For example, Attorney General witness Larry W. Holloway's net present value analysis includes no revenues from future MISO capacity auctions.[2] In my rebuttal testimony in Case No. 2012-00535, I supplied projected MISO capacity values from two reputable energy consulting firms: Wood Mackenzie and IHS Global. I also provide those projections in Exhibit Berry Rebuttal-1 in this case. By excluding all revenues from capacity auctions, Mr. Holloway's analysis is seriously flawed.

The Opposing Intervenors also largely ignore the possibility of increased off-system sales. The Opposing Intervenors offer criticisms of Big Rivers' projected energy prices, which I address later in this testimony, but those criticisms are red herrings. Big Rivers' generating stations currently clear the market about 90% of the time, even in this era of low-priced natural gas and a depressed economy. Although power market prices are currently very depressed, Big Rivers is a low-cost generator and makes margins on the power it sells into the market. The only reason Big Rivers anticipates idling its Wilson and Coleman generating plants is because the fixed cost savings of idling the plants exceeds the margins currently made on off-system sales from those plants. However, even a small increase in power prices could reverse that equation. At current prices, the margins on generation from Big Rivers' Wilson station are very close to equaling the fixed cost savings from idling the plant. The Opposing Intervenors, however, place no weight on the additional future off-system revenues that Big Rivers would receive even if it does not achieve the projected level of replacement load.

[2] *See* Attorney General's response to Item 28 of Big Rivers' First Request for Information to the Attorney General (when asked "whether Mr. Holloway's analysis incorporates any revenues from Big Rivers participating in future MISO capacity auctions," the Attorney General confirmed that "[t]he analysis does not include capacity auction revenues").

IV. THE OPPOSING INTERVENORS' CRITICISMS OF BIG RIVERS' ENERGY PRICE FORECAST SHOULD BE DISREGARDED

Q. On pages 10-12 of his direct testimony, Sierra Club witness Frank Ackerman criticizes the energy price forecast included in Big Rivers' modeling. Do you agree with Mr. Ackerman's criticisms?

A. No. To begin, the energy prices used in the development of the budget and financial plan that form the basis of the revenue requirement in this case involved actual broker values provided to Big Rivers by ACES. These broker values are actual market transactions and are not forecasts, and thus, Mr. Ackerman's criticisms of the ACES energy price forecast used in the long-term modeling Big Rivers filed in this case are irrelevant. Big Rivers believes the long-term power price forecasts are reasonable.

Q. Did Mr. Ackerman offer an energy price forecast that was lower than Big Rivers' forecast?

A. No. Mr. Ackerman provided no energy price forecast at all. He did not provide a forecast to compare Big Rivers' forecast to, nor did he provide a forecast that he says is more reasonable than Big Rivers' forecast.

Q. Why would energy prices increase between the broker values from ACES to the forecasted prices in the long-term forecast?

A. ACES updates the broker value energy prices on a daily basis, while the long-term forecasts from Wood Mackenzie are updated twice per year (Fall and Spring). The daily broker values are influenced by current weather forecasts, natural gas pricing, generation outages, etc., while the long-term Wood Mackenzie forecast assumes normal weather patterns and normal loads. For example, if there was a very hot summer forecasted, the broker values would reflect that forecast. The long-term forecasts being updated semiannually and assuming normal conditions can cause a mismatch with the daily updated broker values. The broker values represent what a buyer is willing to pay for the energy today while the long-term forecasts represent the future market value.

Q. Why are the forecasted prices in this case lower than the forecasted prices filed in the last case?

A. The forecasted prices between the two cases are different because the forecasts were obtained at different times. The forecasted prices in this case utilize the April 2013 ACES broker values and the spring 2013 Wood Mackenzie energy price forecast. The forecasted prices in the previous case, Case No. 2012-000535, utilized the fall 2012 ACES broker values and the fall 2012 Wood Mackenzie energy price forecast. The forecasted prices for this case are actually higher for the years 2014-2015, and then lower for the remaining years (2016 forward) when compared to the previous rate case. It is quite reasonable that forecasted prices vary over time even when forecasted by industry experts such as Wood Mackenzie.

V. THE OPPOSING INTERVENORS' CRITICISMS OF BIG RIVERS' CAPACITY PRICE FORECAST ARE UNSUBSTANTIATED AND SHOULD BE DISREGARDED

Q. On pages 12-15 of his direct testimony, Sierra Club witness Frank Ackerman criticizes the capacity price forecast included in Big Rivers' modeling. Do you agree with Mr. Ackerman's criticisms?

A. No. I would again note that the long-term modeling provided by Big Rivers in this case, including the capacity price forecasts, does not affect the test period or Big Rivers' revenue requirement. Additionally, however, Exhibit Berry Rebuttal-1 demonstrates that there is significant value associated with the available generating capacity owned by Big Rivers' Members. The capacity price forecasts provided by Wood Mackenzie, as well as IHS Global, are reasonable forecasts that were prepared by these entities for the marketplace as a whole, not just for Big Rivers. These forecasts are relied upon by numerous other utilities throughout the country for planning purposes. Mr. Ackerman states that the Wood Mackenzie forecasts are "strangely high." We believe the forecast provided by Wood Mackenzie is strikingly similar to the forecasts provided by IHS Global, a competing provider. It seems unlikely that Mr. Ackerman's opinion on future capacity prices would be more astute than those of two highly reputable entities who have specialized in forecasting market prices for decades. As such, these forecasts are reasonable to rely upon to substantiate the value for Big Rivers' Members of the potential sale of capacity and energy from their existing generating assets.

As I stated during the hearing in Case No. 2012-00535, there is no value in arguing over long-term energy and capacity prices because Big Rivers will only return the units to service if the energy or capacity prices at the time support the economics to do so.

Q. Did Mr. Ackerman offer a MISO capacity forecast that was lower than Big Rivers' forecast?

A. No. Although Mr. Ackerman purported to compare the Big Rivers MISO capacity forecast to the cost of new entry and to PJM capacity prices, he did not provide any MISO capacity forecast.

Q. Mr. Ackerman criticizes the Big Rivers MISO capacity forecast because it reflects capacity prices increasing in 2016. Why would MISO capacity prices increase in 2016?

A. MISO is predicting that it will experience a deficit in capacity beginning in 2016 due to multiple plant retirements driven by the new MATS regulations. Mr. Ackerman himself explained in his testimony that the MISO "capacity surplus may shrink or disappear in 2016, when some coal plants will retire to avoid the costs of MATS compliance."[3] While some regulated utilities have chosen to build combined cycle gas generation to replace those generating units, most merchant companies will likely decommission their coal plants and not replace that supply. This decline in supply should place upward pressure on wholesale market prices. Also, a national economic turnaround will likely drive up demand, and in turn, lead to higher prices.

Q. Do you agree that MISO capacity prices would exceed the cost of new entry as Mr. Ackerman claims?

A. MISO costs could exceed the cost of new entry ("CONE"), especially in the short run. As Mr. Ackerman noted in his testimony, CONE is typically defined as the cost per MW of a combustion turbine, the cheapest form of capacity to build. It is unreasonable to assume that companies would choose to build new generation at a "break even" price, thus the market would have to climb higher than the cost of new entry to incent the building of new generation. If high prices continue over a period of time, it is possible that entities would build generation to sell into the market.

Q. Why would MISO capacity prices exceed PJM capacity prices in the future?

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[3] Direct Testimony of Frank Ackerman ("Ackerman Testimony") at p. 12:17-19.

A. Capacity prices are a direct result of the volume of available capacity versus load demand in that specific market. Currently, MISO has a higher level of available capacity than PJM, which is why PJM's current capacity prices are higher than the MISO capacity prices; however, this situation is expected to change significantly in the 2016-2017 timeframe. Many MISO generators have committed capacity in the PJM Forward Capacity Auctions over the last several years. In the 2016/2017 PJM Capacity Auction that occurred in May 2013, 4,723.1 MW of MISO Capacity was offered and cleared in the PJM Auction. This means that in 2016 and 2017, those MWs will not be available to satisfy resource adequacy requirements in the MISO footprint, even though those assets are located in MISO. The inability of those MWs to be utilized to satisfy resource adequacy in MISO will help provide significant upward pressure on MISO capacity prices. Similarly, in the 2015/2016 PJM Auction, imports into PJM were 4,335.2MW. Given the significant amount of MISO capacity that has already been committed, price differences should be expected.

Q. Do you agree that there is no risk of capacity shortfall in MISO as Mr. Ackerman claims?

A. No. I expect a tightening of available capacity in MISO. Evidence of this was presented by Commissioner Breathitt at the hearing in Case No. 2013-00221. A copy of the document presented by Commissioner Breathitt is attached as Exhibit Berry Rebuttal-2.

VI. <u>THE OPPOSING INTERVENORS' CRITICISMS OF BIG RIVERS' PROJECTED REPLACEMENT LOAD SHOULD BE DISREGARDED</u>

Q. Do you agree with the Opposing Intervenors' criticisms of the replacement load Big Rivers projected?

A. No. I would first note that the projected replacement load in Big Rivers' long-term forecast does not affect the test period or the revenue requirement in this case. In addition, the very nature of replacement load makes it unreasonable to expect Big Rivers to identify the specific loads it will be able to attract in the future. The replacement load included in the long-term forecast Big Rivers filed in this case is just one possibility; but, so long as Big Rivers receives the rate relief it needs in this case, its financial integrity is not dependent on achieving the projected levels of replacement load.

Q. Does Big Rivers have a reasonable opportunity to achieve significant amounts of replacement load?

A. Absolutely. As I discuss above, Big Rivers is a low-cost generator, and it would be unreasonable to think its current ability to sell its generation output into the market in competition with other generators, including natural gas-fired generators, would not translate into opportunities for replacement load. Big Rivers utilizes Navigant Consulting to benchmark its generating units to determine the competitiveness of its generating units compared to other utilities. Exhibit Berry Rebuttal-3 reflects the competitiveness of the Wilson facility compared to natural gas combined cycle units. The following three time periods were evaluated: five years (2008 Q2 thru 2013 Q1), three years (2010 Q2 thru 2013 Q1), and 1 year (2012 Q2 thru 2013 Q1). In the 5 year data set and the 3 year data set, the total operating cost of the Wilson unit was in the best quartile compared to natural gas combined cycle units. In the 1 year data set evaluated, the Wilson unit was better than the median compared to natural gas combined cycle units, which confirms that the Wilson unit is very competitive in all supply portfolios. The Opposing Intervenors' criticisms are also misleading because they compare the projected replacement load to native load growth for Big Rivers' Members and for other utilities across the state and country.[4] But the situation Big Rivers finds itself in is very different from normal native load growth. The Mitigation Plan involves not only seeking internal economic development opportunities, but it also involves seeking bilateral contracts with other entities, such as other utilities and municipalities beyond its own border and even beyond the MISO footprint. For example, Big Rivers is in negotiations with a Nebraska consortium for 50 to 100 MW of power and capacity. A copy of a newspaper article about the potential sale is attached as Exhibit Berry Rebuttal-4. Additionally, the fact that numerous Kentucky utilities—including East Kentucky Power Cooperative, Duke Energy, Louisville Gas & Electric, Kentucky Utilities Company, and American Electric Power Company (Kentucky Power)—have issued requests for proposal for this type of power arrangement in recent months substantiates that Big Rivers' plan is reasonable and viable.

Q. The Opposing Intervenors claim that Big Rivers will not be able to attract customers away from the Tennessee Valley Authority ("TVA"). Do you agree?

A. No. The Opposing Intervenors' claim that Big Rivers cannot attract customers away from TVA is based on nothing more than their opinion as to what TVA might be willing to offer. The fact is that customers currently served by TVA have approached Big Rivers because TVA's rates are projected to exceed the rates that Big Rivers can provide. Big Rivers continues to pursue those opportunities.

Q. The Opposing Intervenors point to the fact that Big Rivers has only attracted 25 MW of load in over a year since the Century Hawesville smelter terminated its

[4] *See* Direct Testimony of Philip Hayet ("Hayet Testimony") at pp. 14-16 and 19-24; Ackerman Testimony at pp. 7-10.

contract as evidence that the Mitigation Plan will not succeed. Do you agree with this criticism?

A. No. Although the Century Hawesville smelter terminated its power contract on August 20, 2012, there was much uncertainty about the smelter situation for a long time after that. After the contract termination, there were proposals in the Kentucky General Assembly that would have required Big Rivers to provide power to the smelters, and up until the contract termination became effective on August 20, 2013, there was some uncertainty about whether the Century Hawesville smelter would actually leave the Big Rivers system.

Moreover, uncertainty surrounding Big Rivers' financial and regulatory situation has made obtaining replacement load more difficult, especially given that the Attorney General and other intervenors in the Big Rivers rate cases have taken positions that would lead to Big Rivers' bankruptcy. If the Commission grants Big Rivers the rate relief it needs in this case, this uncertainty will be removed. Big Rivers has repeatedly stated that load replacement will not occur overnight. To assume that 850 MW of load replacement could occur overnight is unreasonable and short-sighted. However, Big Rivers' Mitigation Plan is reasonable and will result in replacement loads, and Big Rivers continues to see positive signs that the Mitigation Plan will reap future benefits for Big Rivers' Members.

Q. The Opposing Intervenors criticize the assumptions in the long-term forecasts that the replacement load will have a 75% load factor.[5] Do you agree with this criticism?

[5] *See, e.g.,* Hayet Testimony at p. 17.

A. No. As I have repeatedly testified, the Opposing Intervenors have continuously tried to distract from the important issues in this case. This case is not based on long-term forecasts; however, I will address this criticism even though it is not paramount to this case. Big Rivers was required to make assumptions in its long-term forecasts regarding replacement load. Big Rivers considered all information available at the time and determined that replacement load would likely take many forms. Big Rivers assumed some of the replacement load would likely take the form of market agreements for energy, which would likely have a 100% load factor, while other replacement load would primarily consist of residential load, which would likely have a 60-65% load factor. Big Rivers also assumed some of the load would likely be placed as new economic development load, which often has load factors in excess of 90%. When determining how to forecast replacement load, Big Rivers felt 75% would be a reasonable number to approximate the average replacement load it would achieve.

Based on our current discussions, it appears the 75% load factor was on target, as the Nebraska loads that Big Rivers is in negotiations with have an average load factor of 72%. As such, the Opposing Intervenors' criticism is unfounded and should be disregarded.

Q. The Opposing Intervenors claim that this rate increase will prevent success under the Mitigation Plan. Do you agree?

A. No. Big Rivers has no choice but to seek rate relief in this proceeding as the first step in mitigating the smelter contract terminations. Big Rivers expects to attract internal load by offering economic development rates. Rates such as economic development rates are subject to Commission approval, but Big Rivers believes the circumstances justify such rates, because as long as the replacement load is contributing to Big Rivers' fixed costs, other Members will benefit. This is also supported by the data provided in Exhibit Wolfram-8, comparing the proposed Big Rivers rates and Kentucky rates to other utilities and other states, respectively. No party in this proceeding has controverted the data provided in Exhibit Wolfram-8. The comparative rate data provided in that exhibit, particularly for the industrial rate class, supports my contention that Big Rivers can successfully attract load.

VII. OTHER CRITICISMS OF THE MITIGATION PLAN

Q. Are there other criticisms from the Opposing Intervenors of the Mitigation Plan that you wish to address?

A. Yes. The Opposing Intervenors criticize Big Rivers' Mitigation Plan by asserting that Big Rivers' modeling does not include the impacts of possible CO2 regulation or other potential environmental regulations such as NAAQS, CSAPR, Section 316(b) of the Clean Water Act, and coal combustion residue (CCR).[6] I would note, as I have earlier in this testimony, that the long-term forecast filed in this case was simply a forecast. It is not being used to justify the revenue requirement in this case, nor is it being used to justify returning the Wilson and Coleman stations to service. To clarify any misconceptions, the Wilson unit is fully compliant with all current and proposed environmental regulations except some potential CO2 regulations. However, I also think it is important to point out that throwing in the towel on Big Rivers, throwing away the equity the Members have built, and forcing Big Rivers into bankruptcy based on the

[6] *See, e.g.*, Hayet Testimony at pp. 27-35, 38.

possible effects of selected potential environmental regulations is, to me, a ridiculous notion.

VIII. THE OPPOSING INTERVENORS' RECOMMENDATION TO REDUCE BIG RIVERS' REVENUE REQUIREMENT TO EXCLUDE THE FIXED COSTS OF THE WILSON AND COLEMAN GENERATING STATIONS SHOULD BE REJECTED

Q. Do you agree with the Opposing Intervenors' recommendations that Big Rivers should not be permitted to recover the fixed costs of the Wilson and Coleman generating stations?

A. No. The Wilson and Coleman generating stations were prudent investments, have provided service and other benefits to Big Rivers' Members for many years, and will remain used and useful to Big Rivers and its Members even if they are idled. The fact that MISO has identified Coleman as a System Support Resource ("SSR") resource confirms the value from the system reliability it provides. In the Wilson Y2 report, MISO suggested Wilson may also be needed in a few years for reliability purposes. Therefore, it is fair and reasonable for the rates to include the fixed costs (interest expense, depreciation, property tax and property insurance) of the Wilson and Coleman generating stations if they are idled.

One of the benefits the Wilson and Coleman generating stations continue to provide, in addition to system reliability, is the opportunity to mitigate the smelter contract terminations. Without these plants, Big Rivers would have no opportunity to seek replacement load or increase additional off-system sales revenues to mitigate the rate impact of the smelter terminations. These plants will continue to provide the opportunity for economic development and an opportunity for Big Rivers to diversify its load concentration. The Coleman and Wilson plants can also afford Big Rivers the ability to comply with potential CO_2 regulations, if and when they become effective. Thus, Wilson and Coleman remain valuable assets that Big Rivers is actively marketing for the benefit of its Members. As I discussed above, Big Rivers' Mitigation Plan is reasonable, and we fully expect that it will benefit Big Rivers' Members in the future.

Even if idled, Wilson and Coleman serve as a kind of insurance policy for Big Rivers' Members against inevitable fluctuations in the energy markets. Maintaining the plants' generation capacity, even if temporarily idled, ensures that Big Rivers' Members will continue to benefit from an energy independence that protects them against spikes in electric market rates, energy shortages, and similar or unforeseen circumstances. This flexibility may prove to be especially important in light of the unpredictability of the smelters and their uncertain future in the region, as well as in light of the unpredictability of gas supply and pricing.

Finally, Big Rivers' ongoing financial viability depends on access to the capital markets. Big Rivers' continued ownership of the Wilson and Coleman generating stations—and their generation capacity—is necessary to allow Big Rivers reasonable access to these markets, as explained in the rebuttal testimonies of Billie J. Richert.

IX. THE OPPOSING INTERVENORS' RECOMMENDATIONS THAT BIG RIVERS' REVENUE REQUIREMENT SHOULD BE REDUCED BY THE AMOUNT OF TRANSMISSION REVENUES BIG RIVERS COULD RECEIVE FROM CENTURY HAWESVILLE AND CENTURY SEBREE SHOULD BE REJECTED

Q. Do you agree with the Opposing Intervenors' recommendations that Big Rivers' revenue requirement should be reduced based on the potential transmission revenues Big Rivers could receive from Century Hawesville and Century Sebree?

A. No. Big Rivers expects that Century will install the necessary equipment to allow Century Hawesville to operate with Coleman Station idled on or before May 31, 2014. If this occurs, Big Rivers will receive transmission revenues from Century Hawesville as long as Century Hawesville continues to operate.

Big Rivers also anticipates that the Commission will approve the agreements that were recently filed that will enable Century Sebree to continue to operate after January 31, 2014, the effective date of its contract termination. Big Rivers expects that MISO will not require the Wilson Station to run as an SSR, and if both of those contingencies come to pass, Big Rivers will receive transmission revenues from Century Sebree as long as Century Sebree continues to operate.

Nevertheless, it would be inappropriate to reduce Big Rivers' revenue requirement by the potential transmission revenues Big Rivers could receive. With regard to Century Hawesville, it is unknown when or whether Century will install the necessary equipment to allow it to operate with the Coleman plant idled. Even if Century does install the necessary equipment, MISO has determined that there will be times that Century will be required to curtail load, thus reducing the potential transmission revenue received by Big Rivers.

With regard to the Century Sebree facility, there is not yet an approved power contract allowing that facility to continue beyond January 31, 2014. Based on comments from KIUC in this case, there may be more opposition to the Century Sebree contracts than there was to the Century Hawesville contracts. And MISO has not yet issued a final determination that the Century Sebree facility will be able to operate with Wilson idled.

Thus, with respect to both facilities, there remains uncertainty with respect to when Big Rivers will receive transmission revenues. Currently, Big Rivers does not receive any such revenues that are not offset by SSR costs. If the Commission determines that transmission revenues should be included in the determination of Big Rivers' revenue requirement, and those transmission revenues do not come to pass, Big Rivers will be at risk of default in its financial obligations.

To address this risk while ensuring the Members benefit if the transmission revenues do materialize, Big Rivers proposes to direct any transmission revenue received from the smelters to replenish the Economic Reserve. This will allow Big Rivers the opportunity to pass the revenue on to its Members by offsetting a portion of the rate increase as long as it continues to receive the transmission revenue. This would also mitigate the need for Big Rivers to file an emergency rate case if the transmission revenue ceased abruptly. If the Commission reduces the base rate increase to reflect the transmission revenue, then Big Rivers would not have adequate time to get a rate case filed and processed in time to recover the lost revenue. Please see Exhibit Berry Rebuttal-5 for a calculation of the transmission revenue Big Rivers could receive from the Century Hawesville and Sebree smelters. It is important to recognize that Big Rivers will not begin receiving the transmission revenue associated with the Hawesville smelter until the Coleman SSR contract is terminated.

X. COMMENTS ON THE OPPOSING INTERVENORS' RECOMMENDATIONS THAT BIG RIVERS' REVENUE REQUIRMENT SHOULD BE REDUCED FOR ACES FEES THAT MAY BE REIMBURSED BY THE SMELTERS

Q. Do you agree with the Opposing Intervenors' recommendations that Big Rivers' revenue requirement should be reduced for the ACES fees that may be reimbursed by the smelters?

A. Yes. Century Hawesville and Century Sebree will reimburse Big Rivers for a portion of the fees that Big Rivers pays ACES. This will continue as long as the two smelter facilities' loads remain in the calculation of fees by ACES. There are similar fees that Big Rivers pays to the North American Electric Reliability Corporation ("NERC"), to the National Renewables Cooperative ("NRCO"), to the Kentucky State Treasurer (for the PSC Assessment), and to the SERC Reliability Corporation ("SERC"), a portion of which will also be reimbursed by Century for the Hawesville and Sebree smelters' share of these costs. Big Rivers will also realize a reduction in taxes and insurance while the Coleman and Wilson units are idled. If the Commission approves the Century Sebree transaction documents in Case No. 2013-00413, then it would be appropriate to reduce the revenue requirement by approximately $2,324,624. Please see Exhibit Berry Rebuttal-6 for a complete list of the aforementioned fees. These adjustments are addressed in the Rebuttal Testimony of Mr. John Wolfram.

Q. Is any adjustment to Big Rivers' revenue requirement required as a result of the SSR agreement that was recently filed with the Federal Energy Regulatory Commission ("FERC") by MISO?

A. No. I would note that in its order dated December 10, 2013, in Case No. 2012-00535, the Commission granted a rehearing "on the issue of the SSR revenues included in the SSR agreement filed with FERC by MISO" in response to the Opposing Intervenors' allegation that "the agreement provides for Big Rivers to receive $40.974 million annually from MISO for fixed and capital-cost recovery related to operation of Coleman as an SSR, or $12.313 million greater than the amount estimated by Big Rivers and accepted by the Commission in setting Big Rivers' revenue requirement in this case." However, the Opposing Intervenors' inference that Big Rivers will receive $40.974 in total net revenues and $12.313 million in net revenues more than was in the revenue requirement in Case No. 2012-00535 is simply incorrect. Under the SSR agreement, Big Rivers is reimbursed for the actual costs required to operate the Coleman generating station. Thus, any revenues Big Rivers receives under the SSR agreement are offset by actual costs to operate the units. Big Rivers will not make a profit on the operation of Coleman as an SSR resource. The Coleman SSR contract includes a true-up mechanism such that Big Rivers will only recover the actual operating cost of the facility. Thus, the SSR agreement does not change the revenue requirement in Case No. 2012-00535 or this case.

Q. Are there any other items in the SSR budget that Big Rivers is getting reimbursed for that impact the revenue requirement in the test year?

A Per the SSR budget, Big Rivers is being reimbursed for the time value of money (carrying cost) for, fuel inventory, reagent inventory and the incremental Material and Supply (M&S) inventory. This is an incremental expense of approximately $715,643 that Big Rivers will incur only during the SSR period at Coleman Station and it is not included in the revenue requirement in this case or Case No. 2012-00535. Therefore, the revenue requirement should not be adjusted to remove the recovery of this incremental SSR expense. As stated earlier, Century has intervened in the SSR filing with FERC, contesting the SSR budget, specifically the 7.85% time value of money mentioned above.

Q When did MISO and Big Rivers reach agreement on the SSR budget for Coleman?

A. After multiple iterations, Big Rivers and MISO finally reached an agreement on the SSR budget on October 31, 2013. The original SSR budget was submitted to MISO and the Independent Market Monitor ("IMM") on September 16, 2013. On September 26, 2013, during a conference call between MISO and Big Rivers, the IMM requested several changes to the SSR budget. Subsequently on September 30, Century requested that Big Rivers and MISO accept a two-unit (Units 2 and 3) SSR for Coleman Station rather than the originally planned three units to avoid the costs associated with the scheduled maintenance outage on Coleman unit 1. MISO agreed to a two-unit SSR, providing Century would agree to curtail load on a pre-contingent basis if needed to avoid a potential reliability event. Century agreed, and a two-unit budget was submitted to MISO on October 2, 2013. On October 24, Century changed its position and requested that the budget be revised again to reflect three Coleman units in the SSR, and that request required revising the budget to reflect a different budgeting period. The final, revised three-unit budget was sent to MISO on October 29. MISO's and the IMM's agreement on the Coleman SSR budget, including most of Big Rivers' proposals, was given verbally at the end of a conference call with MISO on October 31, 2013. MISO then filed the SSR Agreement, based upon that budget, with FERC on November 1, 2013. It is important to recognize that Century has intervened in the FERC SSR filing and has protested certain items in the SSR budget, which may result in additional changes. Regardless of what changes may occur, Big Rivers will not profit from the final approved SSR agreement. A timeline of the Coleman SSR Budget process is attached as Exhibit Berry Rebuttal-7.

XI. THE KIUC RECOMMENDATION TO REDUCE REVENUE REQUIREMENT BY $1.6 MILLION TO REFLECT AMORTIZATION OF COLEMAN LAYUP EXPENSES SHOULD BE REJECTED

Q. Do you agree with KIUC's recommendation that Big Rivers' revenue requirement should be reduced to reflect the amortization of Coleman layup expenses?

A. No. Expenses associated with ongoing maintenance at Coleman while it is idled are properly included in the revenue requirement. Non-recurring expenses associated with the initial cost to layup Coleman were removed from the test period through a pro forma adjustment. No further adjustment is required or appropriate.

XII. THE KIUC RECOMMENDATION TO REDUCE REVENUE REQUIREMENT BY $0.682 MILLION TO REMOVE INTEREST EXPENSE, TIER, DEPRECIATION, PROPERTY TAX, AND PROPERTY INSURANCE ON MATS CAPITAL EXPENDITURES SHOULD BE REJECTED

Q. Do you agree with KIUC's recommendation to reduce Big Rivers' revenue requirement to remove interest expense, TIER, depreciation, property tax, and property insurance on MATS capital expenditures?

A. No. Interest expense, TIER, depreciation, property tax, and property insurance on MATS capital expenditures are charged to Members through Big Rivers' environmental surcharge tariff. Those items are not included in base rates. So if those costs are not incurred, they cannot be charged to the Members. Therefore, this proposed adjustment is inappropriate.

XIII. <u>THE KIUC PROPOSAL TO GIVE LARGE INDUSTRIAL CUSTOMERS MARKET-BASED PRICING FOR UP TO 25% OF THEIR LOAD SHOULD BE REJECTED</u>

Q. Do you agree with KIUC's proposal to allow Large Industrial customers market-based pricing for up to 25% of their load, at the option of the customer?

A. No. Big Rivers' three Members have all-requirements contracts that do not allow access to market-based power. Furthermore, KIUC's proposal to allow Large Industrial customers to have access to market-based pricing for up to 25% of their load would only require a greater rate increase for other Members and would require those other Members (the Rurals) to subsidize the Large Industrials. Additionally, if the Commission allowed this rate treatment, there would be no end to customers seeking market-based pricing for all of their load, leaving no customers to pay for a utility's fixed costs when market prices are low but then forcing the utility to have the capacity available to serve all the customers in its territory when market prices are high. This would be unreasonable and unworkable.

Q. Do you agree with Mr. Baron that it is unreasonably discriminatory to allow the smelters market-based pricing while denying market-based pricing to the Large Industrials?

A. No. The smelters are unique, and have been treated as a unique class since they located in the Big Rivers territory. There are only two of them, and it is unlikely, in my view, that there will ever be another aluminum smelter located in the Big Rivers wholesale service area. They have an extraordinarily high load factor of approximately 98%. Their combined loads of 850 MW are substantially greater than the combined loads of all the remaining customers of Big Rivers' Members. My understanding is that the smelters were carved out of the Big Rivers all-requirements contracts with its Members in 1998 when LG&E/WKE entered into the 25 year lease agreement with Big Rivers. So the smelter load is not part of Big Rivers' all-requirements obligation to its Members. Big Rivers and Kenergy are allowing the smelters to be served with market-based pricing as an alternative to the smelters closing and adding that adverse economic impact on top of the rate increases Big Rivers is seeking.

XIV. <u>SIERRA CLUB'S RECOMMENDATION THAT BIG RIVERS SHOULD BE REQUIRED TO DROP THE ASKING PRICE OF THE WILSON AND COLEMAN PLANTS SHOULD BE REJECTED</u>

Q. Do you agree with Sierra Club's recommendation that Big Rivers should be required to immediately drop the asking price of the Wilson and Coleman plants?

A. No. It is unreasonable to force Big Rivers to try to sell its generating stations at rock bottom prices. Doing so would reduce Members' equity and the collateral that those plants provide, preventing Big Rivers from having access to capital markets in the future, which would provide little hope of a future for Big Rivers other than bankruptcy and potentially liquidation. Likewise, these assets are valuable assets that have and will continue to bring value to Big Rivers' Members in the future. Choosing to unnecessarily liquidate assets at fire sale prices would be unwise regardless of the business in which you operate. This issue is discussed further in the Rebuttal Testimony of Ms. Billie J. Richert.

XV. CONCLUSION

Q. Do you have any closing comments?

A. Yes. In her rebuttal testimony, Ms. Richert states that for the nine months ended September 30, 2013, Big Rivers' maintenance expense has been favorable by $7.1 million, a significant portion of which was due to the deferral of the Coleman outage. The Coleman outage that was originally scheduled for the Spring of 2013 was deferred as a result of the anticipated idling of that generating station.

Q. Please summarize your recommendations.

A. Big Rivers' Mitigation Plan is reasonable, and the Commission should grant Big Rivers the rate relief required to give Big Rivers time to implement the plan. The Opposing Intervenors offer shockingly, little support or analyses in their quest for rates that would give Big Rivers little possibility for anything but bankruptcy and would prevent Big Rivers from mitigating the smelter contract terminations.

For the reasons stated above and in the testimonies of the other Big Rivers witnesses, Big Rivers' proposed rates are fully supported by reliable data, and they are just, fair, and reasonable. The Commission should adopt those rates.

Q. Does this conclude your testimony?

A. Yes.

Big Rivers Electric Corporation
Case No. 2013-00199
Exhibit Berry Rebuttal-1
Future Projected Value of MISO Market Capacity*

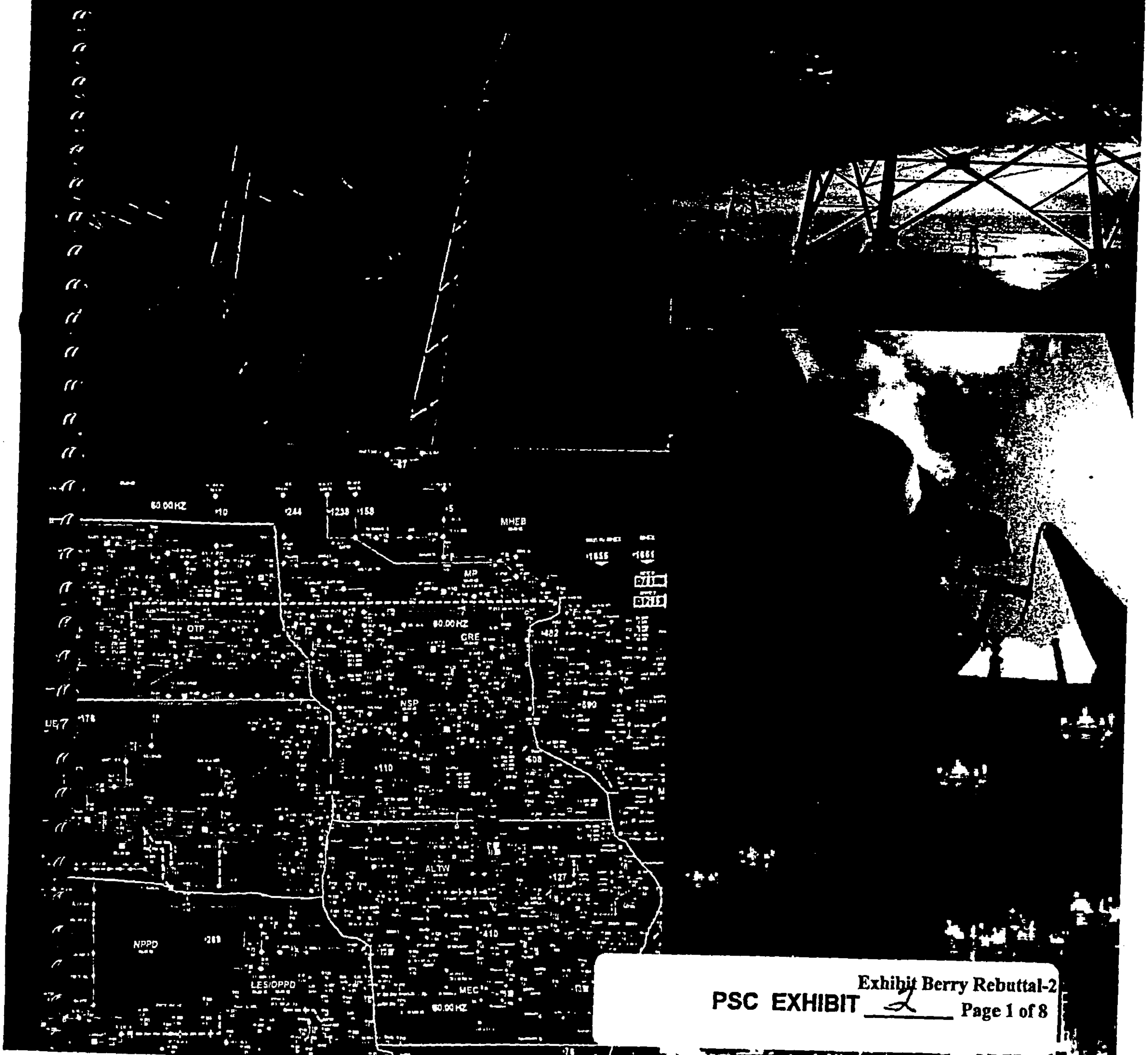
	Wood-Mackenzie Projection MISO Capacity Value		IHS Global Projection MISO Capacity Value	
Year	$/kW-Month	482 MW Value	$/kW-Month	482 MW Value
2014	[redacted]			
2015				
2016				
2017				
2018				
2019				
2020				
2021				
2022				
2023				

*Note: These projections include only values for capacity. Energy values are not included in these projections.

MISO

At-a-Glance

July 2013



Welcome

rom John R. Bear, President and CEO of MISO

ear Friends of MISO:

s you know, there are several complex challenges which are converging. Economic ecovery signals, environmental compliance uncertainty and risks to resource dequacy are some of the critical matters facing our industry. Taking a focused pproach to strengthen our core business functions while balancing several of these ey strategic initiatives has resulted in better stakeholder coordination, greater rice transparency for regulators and improved reliability for members. Against this ackdrop, we thank you for your continued support in working with us.

egional Reliability - 2013 and Beyond

efining our processes and improving our core services reflect a broader regional iew that provides added value for our membership. Our focus for the remainder f 2013 and beyond will mitigate the impact of changes in the following critical reas:

- Energy Policy: We continue to analyze the impact of key policy changes associated with environmental regulations, transmission planning, increased compliance focus, and renewable mandates.

- Environmental Compliance: Shortfalls between 6-9 GW are expected in 2016 based on current analysis due environmental compliance and routine outage scheduling, particularly during off-peak or shoulder periods. eater transparency from utilities on generation and transmission outage plans will greatly aid MISO's regional tuational awareness and ability to mitigate outages in non-shoulder periods.

- Portfolio Shift: MISO continues its outreach with generation owners, gas industry experts and policy makers to help reliably facilitate compliance with new Mercury and Air Toxics Standards (MATS). We continue to survey our members quarterly on their plans, and study and coordinate gas-electric interdependency analysis and the transition to gas-fired generation.

- South Region Integration: In the South Region, MISO is on target for full system integration in December 2013. We now provide our reliability coordination services for the region, and last month received unanimous approval to expand our balancing authority upon integration. This expanded and geographically diverse footprint will bring economic benefits to consumers with improved system reliability and generation diversity for all MISO members.

- Order 1000: MISO remains fully engaged with our neighbors to achieve the most efficient use of the transmission system through improved seams coordination and Order 1000 compliance. This month's Interregional Order 1000 compliance filings reflect improved coordination, and the opportunities that still remain to address differing approaches to regional cost allocation.

look forward to continued collaboration with regulators and stakeholders as we respond to the challenges ahead nsuring continued focus on the lowest-cost delivered energy for all consumers throughout MISO.

incerely,

. Bear
ent and CEO
idcontinent Independent System Operator, Inc.

Exhibit Berry Rebuttal-2

able of Contents

M O Overview

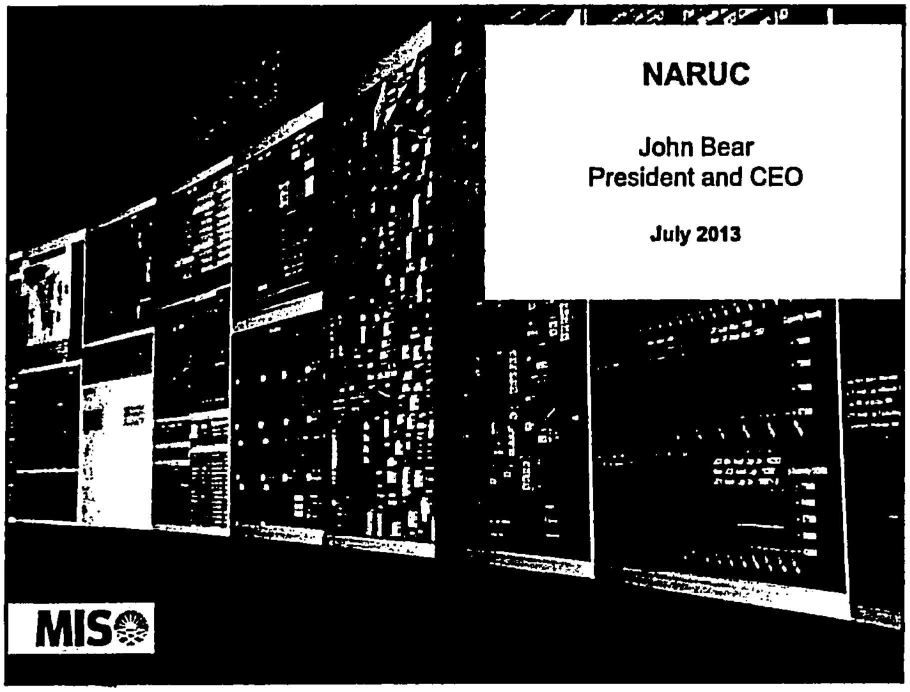
esource Adequacy

ransmission Planning

outh Region Integration

ISO Innovation

MIS



MISO region must work collaboratively, transparently and quickly to address resource adequacy risks

- MISO's generation fleet's composition and utilization is evolving rapidly
- Resource adequacy risks will persist for foreseeable future
  - Outage coordination period – Mercury and Air Toxic Standards (MATS) upgrades
  - Retirement Phase I – MATS compliance
  - Retirement Phase II – Proposed water/carbon regulations
- Forward transparency of plans is critical to mitigate risks.
- Load shedding is a shared risk in our "Mutual Insurance Pool" model

MISO 1

Many factors are influencing the evolution of the region's generation fleet

- Significant unit retirements, driven by:
  - Age
  - Environmental regulations
  - Economics
- Fuel costs, particularly natural gas prices
- Current and proposed future environmental regulations
  - MATS
  - Water
  - Carbon

These changes will result in reserve margin erosion and increased reliance on gas transport infrastructure designed for a different purpose.

MISO 2

The generation fleet's evolution increases resource adequacy risks in three distinct periods

	Environmental Compliance Phase Now - 2015	Retirement Phase I 2016 - 2017	Retirement Phase II 2018 and beyond
Nature of Risks	• 40 GW of coal units will require outages to implement *upgrades* • Increase reliance on gas fired generation and underlying gas infrastructure	• Significant generation retirements • Insufficient reserve margins • Risk of load shedding • Increased reliance on natural gas	• Proposed water/carbon regulations drive additional capacity retirements
Mitigation Efforts	• Collaboration with Asset Owners to reliably sequence outages • Collaboration with adjacent RTOs and others on outage management and seams operations • Collaboration with gas industry to improve reliability of integrated operation	• Improve transparency of Load Serving Entity (LSE) and state plans - Specific unit reliance - Forward view • Increased collaboration - State regulators - LSEs - Asset Owners - Natural Gas Industry • Drill emergency procedures, including load shed processes	• Increased transparency of plans and impacts

MISO 3

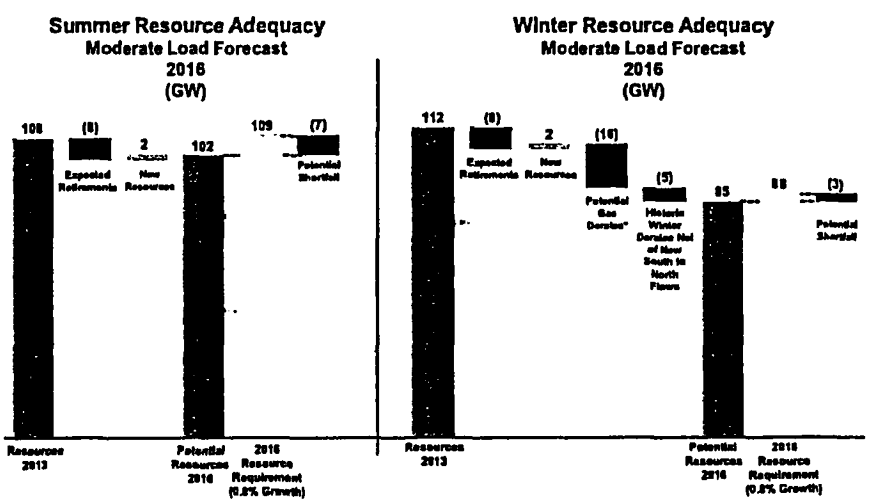
MISO is collaborating with various parties to maximize preparedness for the coming challenges

- MISO surveying Load Serving Entities quarterly regarding their plans to comply with environmental regulations.
- MISO partnering with state regulators to perform resource assessment for the near-term period.
- MISO collaborating with the natural gas industry and stakeholder communities to explore improvements in gas-electric coordination.
- MISO remains focused on interregional deliverability to maximize flexibility and improve reliability.

The outlook derived from these efforts contains uncertainty, but is currently the best information we have to plan from...

MISO 4

Forecast 2016 resource adequacy is very tight under a moderate (50/50) load forecast scenario



*Units without firm gas transport or distillate backup

MISO 5

Limited options remain to mitigate the potential 2016 shortfall

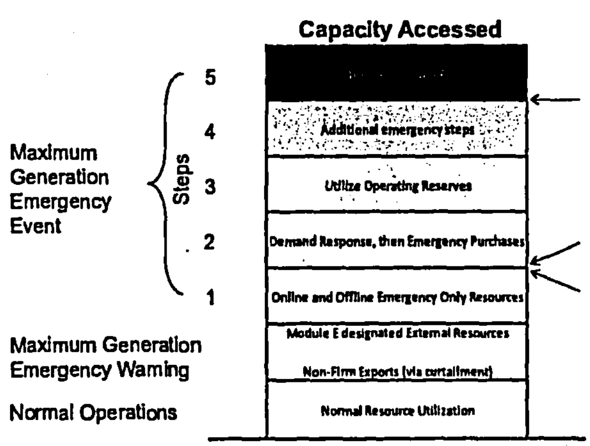
- Planning Horizon
  - Window narrowing for new capacity additions - likely limited to current site expansion
- Operating Horizon
  - Heavy reliance on demand side resources
  - Emergency purchases from neighboring entities where available
  - Load shed as a last resort

The lack of a complete supply picture in the immediate future puts longer-lead solutions at risk

MISO

6

Tight or inadequate supply in real-time requires MISO to initiate it's Capacity Emergency Procedure to gain access to certain resources



MISO

7

More engagement is needed to improve regional visibility and achieve clarity

- Improved transparency into Load Serving Entities plans would allow for a complete assessment of reliability risk.
  - Partial or non-responses are limiting clarity in terms of retirement levels and outage timing.
- State agreement on regional roles is necessary to allow these challenges, including prevention of overbuilding, to be addressed in a timely and effective manner.
- Continued collaboration between the electric and natural gas industries is critical to fully understand and minimize fuel supply risk for gas-fired resources.

MISO

8

MISO region must work collaboratively, transparently and quickly to address resource adequacy risks

- MISO's generation fleet's composition and utilization is evolving rapidly
- Resource adequacy risks will persist for foreseeable future
  - Outage coordination period – Mercury and Air Toxic Standards (MATS) upgrades
  - Retirement Phase I – MATS compliance
  - Retirement Phase II – Proposed water/carbon regulations
- Forward transparency of plans is critical to resolution
- Load shedding is a shared risk in our "Mutual Insurance Pool" model

MISO

9

5 Year Benchmarking, Wilson Station vs. Combined Cycle (130-600 MW) - 2008 Q2 thru 2013 Q1

Wilson Station vs. Combined Cycle (130-600 MW) - 2008 Q2 thru 2013 Q1

	EAF, %	EFOR, %	NCF, %	Oper. w/o Fuel	Maint.	Fuel	Non-Fuel O&M $	O&M $ inc. Fuel
Big Rivers Wilson Station	89.96	3.99	86.52	$ 4.02	$ 9.00	$ 18.49	$ 13.02	$ 31.52
CC (130-600 MW) Median	87.65	2.21	61.71	$ 1.19	$ 4.55	$ 45.81	$ 6.07	$ 55.64
CC (130-600 MW) Upper Quartile	90.72	7.36	70.32	$ 3.03	$ 7.33	$ 53.75	$ 10.20	$ 60.77
CC (130-600 MW) Lower Quartile	84.48	1.59	47.17	$ 0.89	$ 3.83	$ 39.27	$ 4.97	$ 46.01

Best Quartile	XX.XX
Worse than Median	XX.XX

Combined Cycle (CC) Benchmarking includes **26 units** representing **11,900 MW** of capacity

BIG RIVERS ELECTRIC CORPORATION

3 Year Benchmarking, Wilson Station vs. Combined Cycle (130-600 MW) - 2010 Q2 thru 2013 Q1

Wilson Station vs. Combined Cycle (130-600 MW) - 2010 Q2 thru 2013 Q1	EAF, %	EFOR, %	NCF, %	Oper. w/o Fuel	Maint.	Fuel	Non-Fuel O&M $	O&M $ inc. Fuel
Big Rivers Wilson Station	93.33	3.96	89.29	$ 4.02	$ 6.91	$ 19.28	$ 10.93	$ 30.21
CC (130-600 MW) Median	89.52	2.20	56.64	$ 1.63	$ 3.92	$ 33.82	$ 6.23	$ 41.46
CC (130-600 MW) Upper Quartile	94.32	3.70	72.61	$ 3.88	$ 6.51	$ 45.26	$ 8.98	$ 51.64
CC (130-600 MW) Lower Quartile	86.24	1.06	39.30	$ 0.95	$ 2.59	$ 25.96	$ 4.57	$ 31.09

Best Quartile	XX.XX
Worse than Median	XX.XX

Combined Cycle (CC) Benchmarking includes **41 units** representing **15,600 MW** of capacity

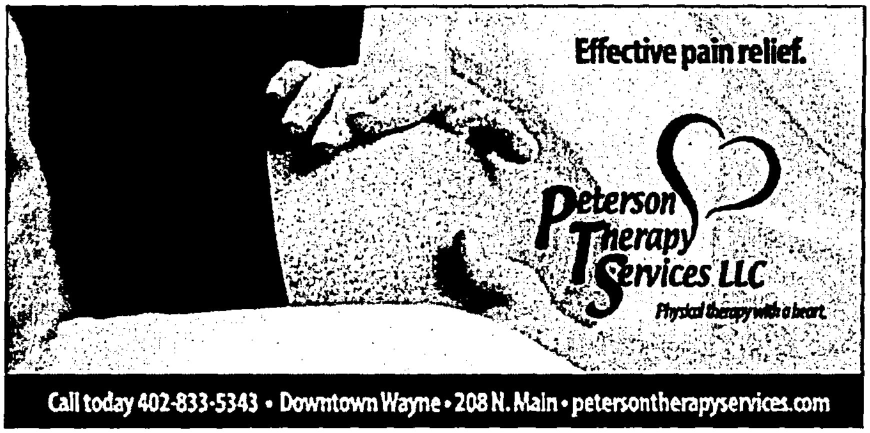
BIG RIVERS ELECTRIC CORPORATION

1 Year Benchmarking, Wilson Station vs. Combined Cycle (130-600 MW) - 2012 Q2 thru 2013 Q1

Wilson Station vs. Combined Cycle (130-600 MW) - 2012 Q2 thru 2013 Q1								
	EAF, %	EFOR, %	NCF, %	Oper. w/o Fuel	Maint.	Fuel	Non-Fuel O&M $	O&M $ inc. Fuel
Big Rivers Wilson Station	95.76	4.01	88.55	$ 3.64	$ 5.35	$ 22.50	$ 9.00	$ 31.50
CC (130-600 MW) Median	92.10	1.92	59.76	$ 1.15	$ 4.22	$ 25.05	$ 6.43	$ 33.45
CC (130-600 MW) Upper Quartile	94.83	3.45	75.00	$ 3.55	$ 7.80	$ 35.81	$ 9.88	$ 42.75
CC (130-600 MW) Lower Quartile	87.55	0.69	43.45	$ 0.86	$ 2.48	$ 22.78	$ 4.21	$ 27.30

Best Quartile	XX.XX
Worse than Median	XX.XX

Combined Cycle (CC) Benchmarking includes 50 units representing 18,300 MW of capacity



Big Rivers Electric Corporation Extends Energy Offer To City Council

Posted: 20 November, 2013

WAYNE (KTCH/KCTY) - Lindsay Barron of Big Rivers Electric Corporation in Henderson, Kentucky spoke at the Wayne City Council meeting Tuesday night to present Big Rivers' proposal of public power services to the City of Wayne..

The city is in the process of re-evaluating its contract with its current power supplier, Nebraska Public Power District (NPPD), after being asked by NPPD to sign a new 20-year contract by Dec. 31, 2013. The city's current 20-year wholesale power total purchase contract with the NPPD contains a reduction option that allows the City of Wayne to give NPPD official notice to reduce purchases from them after a 3-year wait and begin buying power from another supplier. However, the contract contains unclear terms for this reduction.

Attorneys for Wayne and NPPD have been in contact with NPPD to clarify the conflicting language in the contract, but NPPD has declined to clarify at this time. This gives the City of Wayne the possible option to reduce purchases from NPPD by 30% beginning January 2017 and by 10% each following year, or to give notice to reduce 90% beginning January 2019.

Big Rivers offers a discount from the City of Wayne's current rate, paying 90% of what NPPD's current rate is in 2020, Barron said. Big Rivers also offers a 10-year term, presenting more opportunities to adjust or re-evaluate, as opposed to a 20-year term.

In the event that the city wants to purchase renewable energy, Barron said, the City of Wayne will have the right to take 15% of its annual energy as renewable in substitute of Big Rivers' energy. Big Rivers will purchase the available capacity rights from any owned generation at a rate of $1.50/kW-month for qualifying capacity credits as defined by the Southwest Power Pool Electric Energy Network (SPP).

Todd Hegwer, an energy consultant for the City of Wayne and other local communities, recommended to the council to give NPPD notice to Limit and Reduce, due to the potential savings. The notice must be delivered prior to Dec. 31, 2013. Hegwer said his recommendation is to finalize the Big Rivers Electric Corporation contract and come back for approval in December.

The developing consensus is to go with an offer from Big Rivers that guarantees a rate for 10 years, beginning in 2017 that will be 10% below NPPD's rate. Other options include: 1) Giving the required notice to reduce to NPPD and begin buying open market energy only as the city reduces in the years after 2017 or 2019; or 2) Riding out the current NPPD contract until 2022, then buying only through the Municipal *Energy*Agency of Nebraska (MEAN) as Neligh does, or on the market by using the value of the city power plant to avoid paying demand charges to any generator.

Decisions on accepting the offer from Big Rivers or pursuing alternative options will be made next month.

Case No. 2013-00199
Exhibit Berry Rebuttal-4
Page 1 of 1

BIG RIVERS ELECTRIC CORPORATION
ESTIMATED SMELTER TRANSMISSION AND ANCILLARY SERVICE REVENUE

	Century Hawesville	Century Sebree	Total
Realized Annual Revenue Estimate for Century			
Total Schedule 1 Revenue to BREC	$ 1,027,651	$ 783,943	$ 1,811,594
Total Schedule 2 Revenue to BREC*	261,192	199,250	460,442
Total Schedule 9 Revenue to BREC**	7,519,098	5,735,942	13,255,040
Total Realized Transmission and Ancillary Service Revenue	$ 8,807,941	$ 6,719,135	$ 15,527,076

*Assumed we will only receive 48% of potential revenues due to unit shutdowns.
**Century Hawesville revenues will be offset against Coleman SSR costs.

BIG RIVERS ELECTRIC CORPORATION
REVENUE REQUIREMENT ADJUSTMENT

Line	Adjustment to Revenue Requirement*		Century Hawesville		Century Sebree		Total
7	ACES Power Marketing	$	783,724	$	531,184	$	1,314,908
8	NERC		47,400		38,060		85,460
9	National Renewables Cooperative (NRCO)		24,900		26,100		51,000
10	PSC Assessment (paid to Ky State Treasurer)		193,773		243,081		436,854
11	SERC		58,350		46,840		105,190
12	Property Taxes and Insurance		113,328		217,884		331,212
13							
14	**Total**	$	1,221,475	$	1,103,149	$	2,324,624

*The Rebuttal Testimony of Mr. John Wolfram adjusts only the Century Hawesville amount out of the revenue requirement. The Century Sebree amount should also be removed if the PSC approves the Century Sebree documents in Case Number 2013-00413.

In preparing this exhibit, Big Rivers realized that a similar table contained in the Direct Testimony of Robert W. Berry filed in Case No. 2013-00413 contained incorrect amounts. Big Rivers will be providing a revised table in that proceeding.

Coleman SSR Budget (Agreements) Timeline

Date	Event
9/16/2013	Coleman SSR budget (3 units) was sent to MISO/IMM for review
9/26/2013	Conference call with MISO/IMM about Coleman SSR budget - five revisions were requested (listed below):
	- Capital costs should be moved to be included in fixed costs
	- G&A labor should only include going forward costs
	- Property tax and insurance should only include the difference between running and idled
	- Plant labor and non-labor expenses should be reduced by the idled expenses
	- On inventories, only the difference in inventories between running and idled states should be charged in the value of money
9/30/2013	Century requests a 2-unit SSR budget (without Coleman 1)
10/3/2013	Sent MISO/IMM Coleman SSR budget (2-unit) with the revisions from 9/26/13 call incorporated
10/9/2013	Sent MISO/IMM a revised Coleman SSR budget (2-unit) - updated gypsum and ash hauling contracts (expenses)
10/24/2013	Century requests a 3-unit SSR budget
10/29/2013	Sent MISO/IMM the Coleman SSR budget (3-unit)
10/31/2013	Conference call with MISO/IMM about the Coleman SSR budget - MISO/IMM verbally approves budget
11/1/2013	Final copy of the Coleman SSR agreement sent to MISO
11/1/2013	MISO files the Coleman SSR agreement with FERC - comment period ends 11/22/13

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES	)) Case No. 2013-00199)

REBUTTAL TESTIMONY

OF

LINDSAY N. BARRON
VICE PRESIDENT, ENERGY SERVICES

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: December 17, 2013

REBUTTAL TESTIMONY
OF
LINDSAY N. BARRON

Table of Contents

REBUTTAL TESTIMONY
OF
LINDSAY N. BARRON

I. INTRODUCTION

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

A. My name is Lindsay N. Barron. I am employed by Big Rivers Electric Corporation ("Big Rivers"), 201 Third Street, Henderson, Kentucky 42420, as Vice President, Energy Services.

Q. Are you the same Lindsay N. Barron who provided direct testimony in this proceeding?

A. Yes.

II. PURPOSE OF TESTIMONY

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

A. This testimony rebuts testimony submitted by witnesses for the Office of the Attorney General of Kentucky ("Attorney General"), Kentucky Industrial Utility Customers, Inc. ("KIUC"), and Sierra Club (collectively, the "Opposing Intervenors"). Specifically, I will explain Big Rivers' position on price elasticity and its impact on the load forecast. I will further explain why Big Rivers' elasticity assumptions factored into load forecast data for the forecasted test period are reasonable and appropriate for use in setting rates and should be relied upon by the Commission for this proceeding.

III. THE IMPACT OF PRICE ELASTICITY ON BIG RIVERS' RURAL LOAD FORECAST

Q. Attorney General witness Mr. David Brevitz asserts on pages 30 and 31 of his direct testimony that Big Rivers' response to KIUC 1-33 confirmed that a 1,300kWh/month customer will reduce usage by 15.12% due to price elasticity. Is that accurate?

A. No. In the response to KIUC 1-33, Big Rivers merely acknowledged that the calculations proposed in the question were performed correctly and do not consider changes in factors that have a positive impact on consumption. Big Rivers did not, and does not, agree that the proposed reductions in consumption will occur.

Q. Mr. Brevitz predicts that Big Rivers' estimate of price elasticity for Rurals is understated because it is a short-term estimate based on historical prices that did not contain significant price increases. How do you respond?

A. Big Rivers' estimate of price elasticity for the Rurals is appropriate in this case for the very reason Mr. Brevitz points out – that is, because it is a short-term estimate. The forecasted test period in this case includes the twelve months immediately following the effective date of the contract termination of the Sebree smelter. The price elasticity coefficient used in the load forecast in this case was developed in accordance with standard industry practices by GDS Associates, Inc. ("GDS"), a qualified and reputable company. In addition, the price elasticity coefficient was based on historical data to reflect an elasticity specifically for Rural customers located in Big Rivers' Members' service areas.

While the historical data does not reflect any annual price increases equal to that predicted by Big Rivers during the projected test year, use of the derived elasticity is appropriate. The price increase projected at the retail level for Rural customers is expected to result in a final rate lower than the national average for 2012 and comparable to the East South Central census region.[1] Based on all the information available to it, Big Rivers has concluded that the impact of the proposed rate increase on energy consumption is reasonable. Although Mr. Brevitz apparently disagrees, he has provided no Big Rivers specific analysis to support his assumption that the price impact is significantly understated.

Q. Mr. Ackerman criticizes the price elasticity used in Big Rivers' forecast and asserts that the adopted "price elasticities for Rurals are at the low end of published estimates, and may represent short-run" elasticities. (Ackerman Testimony, p. 4.) Do you agree with Mr. Ackerman's criticism?

A. No. As I stated previously, the use of short-run price elasticity values is appropriate in this filing as they correspond to the forecasted test year and reflect customer reaction (lower energy consumption) to the price increase over the near term. Interestingly, Mr. Ackerman agrees that the short-run elasticity is appropriate for use in a rate case. He states, "In the year of a rate increase, a utility should use the short-run estimate." (*Id.* at p 16.)

Instead of agreeing that Big Rivers' short-run elasticity was appropriate for this case, however, Mr. Ackerman compares that short-run elasticity to long-run elasticities from two studies (the published estimates to which he refers). These two publications are the same studies that Big Rivers used as a comparison for its elasticity. (*Id.* at p.

[1] Energy Information Administration, EIA-861- schedules 4A-D, EIA-861S and EIA-861U.

16.) Mr Ackerman explains, "Both of those studies distinguish between short-run and long-run elasticities . . . Big Rivers' estimates are similar to some of the short-run estimates in both sources, but distinctly smaller than the long-run estimates." (*Id.*). Thus, Mr. Ackerman's criticism is flawed because he compares Big Rivers' short-run elasticity (which he acknowledges is consistent with published estimates of short-run elasticities and which he acknowledges should be used "[i]n the year of a rate increase) to estimates of long-run estimates.

This flaw is further seen when Mr. Ackerman compares Big Rivers' short-run elasticity to rates in 2017-2018. (*Id.* at p. 19). However, Big Rivers did not use the short-run elasticity in the longer term forecasts. Big Rivers uses the short-run elasticity to determine rates for the forecasted test period, but for its long-term load forecast, Big Rivers incorporates long-run elasticities. Thus, comparing the short-run elasticity Big Rivers used to determine rates in the near term to long-term rates is inappropriate and is not consistent with what Big Rivers did.

Mr. Ackerman suggests that Big Rivers should have blended short-run and long-run elasticities. (*Id.* at p. 21.) But this suggestion does not make sense. The short-run elasticity is appropriate for setting rates in the short term, as Mr. Ackerman acknowledges. Blending short-run and long-run elasticities arbitrarily and incorrectly would only serve to inflate the price elasticity coefficients and result in Big Rivers requesting too much in this proceeding. .

Q. **On pages 26 through 28 of his testimony, Mr. Brevitz criticizes Big Rivers for not reflecting in its load forecast potential lost sales to employees/subcontractors**

displaced by the USEC plant closure. Should Big Rivers have included an impact for the loss of USEC personnel in its load forecast?

A. No, and it is important to clarify this situation. The USEC plant was not served by Big Rivers, nor was it served by Jackson Purchase, Big Rivers' Member. Consequently, potential lost sales include only lost sales due to the possible relocation of employees who had previously worked at the plant and who lived in Jackson Purchase's service territory or to the indirect, secondary impacts of the USEC closure. Many uncertainties remain with the USEC plant closure, and forecasting the "trickle down" electricity consumption effect of losing USEC jobs is a difficult task due to the speculative nature of predicting the impact on Jackson Purchase customers. There may be significant cleanup efforts at the site, and it is possible that the creation of jobs to cleanup the facility could significantly offset any job loss in the area. Moreover, the impacts of the USEC closure on Big Rivers' native load are not likely to occur in the short-term, thus no change to the forecasted test period sales volumes is warranted.

Q. Have any of the Opposing Intervenors performed detailed studies or analyses on their own or acquired any applicable studies from reputable outside sources to support their claims regarding the Big Rivers Rural elasticity assumptions in this case?

A. No, the Opposing Intervenors have not performed or acquired detailed studies or analyses that are applicable to Big Rivers' specific situation. In fact, except for published estimates referenced by Mr. Ackerman (which contain short-run elasticities that are consistent with Big Rivers' short-run elasticities), the Opposing Intervenors do not even reference any studies or analyses to support their claims.

Q. Did Big Rivers perform reliable analyses and studies in the process of developing elasticity assumptions and related load forecasts for Rural customers?

A. Yes. As I described in my direct testimony, Big Rivers retained GDS to develop the load forecast, the scope of which included a price elasticity analysis. Results of the analysis were compared to industry norms and to the results of price elasticity studies performed by the Energy Information Administration and by the National Renewable Energy Laboratory, which is operated for the Department of Energy.

IV. <u>THE IMPACT OF PRICE ELASTICITY ON BIG RIVERS' INDUSTRIAL LOAD FORECAST</u>

Q. Mr. Ackerman states on page 18 of his direct testimony that zero price elasticity for Large Industrials is unreasonable. Mr. Brevitz makes a similar statement on pages 29 and 30 of his direct testimony. How do you respond?

A. I disagree with Mr. Ackerman's and Mr. Brevitz' statements. Big Rivers' assumption that Large Industrial customers will not reduce their demand in the short run is reasonable. Large Industrial loads have generally already invested in cost effective energy efficiency measures, and they generally maintain low technological obsolescence. This is consistent with statement made by the Large Industrial customers represented by KIUC in this proceeding. For example, Kelly Thomas of Aleris testified that "Aleris already undertakes significant energy efficiency efforts to protect our bottom line and will continue to do so," and she further argues that "Aleris will not be able to reduce its load requirements anywhere near the total amount needed to offset a significant portion of the rate increase." (Thomas Testimony, p. 7:18-22.) Similarly, Bill Cummings of Kimberly-Clark Corporation testified that Kimberly-Clark has identified 40 energy efficiency projects that "will reduce energy consumption by only 4%." (Cummings Testimony, p. 6:13-15.)

For Large Industrial customers, reaction to increased electric energy cost should be driven by changes in production, fuel switching or energy efficiency measures currently not cost-effective. It is unreasonable to assume that Large Industrial customers have a significant opportunity for load reduction based on increasing efficiency.

Q. Mr. Ackerman presented two studies in his direct testimony. Do you feel these studies are applicable to Big Rivers' current situation?

No. Mr. Ackerman relies upon two studies that deal with demand response (day ahead real-time-pricing and limited customer analysis of hourly price elasticity, peak period elasticity and substitution elasticity). It is imperative to note that customer response to price in real-time pricing and time of use rate scenarios is not applicable to Big Rivers' current situation.

Q. Mr. Ackerman states on page 17 of his testimony that it is "simply implausible" to assume that industrial customers are unaffected by price increases. Do you agree?

A. No. It is not implausible for industrial customers to maintain or even increase their consumption during periods of rising prices.

Q. Are you aware of any counterexamples to Mr. Ackerman's position, or examples that are consistent with Big Rivers' position that its Large Industrial customers will not reduce their energy usage in response to the proposed increase?

A. Yes. Vectren Corporation ("Vectren") is a utility adjacent to Big Rivers based in Evansville, Indiana. Vectren's service territory shares a number of characteristics with

Big Rivers' territory, including transportation infrastructure, employee market, cost of living, energy and natural resource availability and climate. In the last twelve years, Vectren has experienced significant increases in electricity costs. From 2001 to 2006, large power customers of Vectren witnessed costs per megawatt climb from $35.9 per MWh to $53.6 per MWh, a 49.3% increase. During that same period, the average energy consumption per customer did not decline; it rose by 9%. In 2007, Vectren reclassified its large power customers resulting in an increase in the number of large power customers from 69 to 105. From 2007 to 2012, the average cost per megawatt for its large power customers continued to increase from $59.2 per MWh to $75.5 per MWh (down from 2011 cost of $81.6 per MWh), an additional 27.5% increase. Once again, the average energy consumption per customer increased, this time by 6.4%, while the number of customers in the large power rate class rose from 105 to 112.

This is not theory or conjecture, but the actual experience of a utility that is situated close to and shares significant regional characteristics with Big Rivers and its Members. This counterexample demonstrates that Mr. Ackerman's position is not universally applicable. Although Big Rivers would not expect to see consistent growth in the average annual consumption per customer over time resulting from increased electricity prices, it is reasonable to assume that electricity consumption is likely to remain level, during the test period, for existing large power facilities.

Q. Do you see any weaknesses with the Opposing Intervenors' claims that national or regional coefficients of elasticity for industrial users are more accurate than the coefficient utilized by Big Rivers?

A. Yes. Big Rivers' rate increases will not be related to critical peak pricing, day ahead real time pricing, elasticity of substitution or similar circumstances described in the studies relied on by Mr. Ackerman. Even after exhaustion of the reserve accounts, Big Rivers' Large Industrial rates will be on par with those of our neighboring utility, Vectren. And as is evidenced by the actual statistics shared above, Vectren's industrial customer base has not contracted in customer count or average use per customer as a result of average rates more than doubling from $35.9 to $75.5 per MWh. I also note that the anticipated successes of Big Rivers' Mitigation Plan (as addressed in the testimony of Robert W. Berry) will help to alleviate any more generalized concerns about the longer term price elasticity of demand in this class.

Q. Mr. Cummings states on pages 7 and 8 of his direct testimony that Kimberly-Clark might evaluate the possibility of installing a cogeneration system at its plant served by Big Rivers if the proposed rate adjustment is granted, and that this action would further reduce Big Rivers' load. How do you respond?

A. First, I think it is important to note that it is not definite that this will occur and if it were to occur, it would not occur quickly enough to impact the forecasted test period in this case. Mr. Cummings states only that "Kimberly-Clark will certainly evaluate installing a . . . cogeneration system," he does not testify that the installation of a cogeneration system is guaranteed or even likely, nor does he suggest when such a system would be installed. Setting that clarification aside, the possibility of a large customer installing cogeneration exists regardless of the rate case—indeed, Domtar has had a cogeneration system for many years prior to Big Rivers' recent rate cases. Additionally, Big Rivers has been supportive of Combined Heat and Power (CHP) projects in the past and will continue to be a proponent for this type of facility. Even so, the possibility that Kimberly-Clark might evaluate a CHP project does not mean that the load forecast assumed in the test period that begins February 2014 or that Big Rivers' price elasticity coefficient is somehow flawed.

Q. **Mr. Cummings suggests on page 8 of his testimony that Big Rivers' proposed rates could cause the closure of industrial and commercial employers, which could threaten Big Rivers' long-term viability. Do you agree with Mr. Cummings' assessment of the rate adjustment and his suggestion that the proposed rates jeopardize Big Rivers' long-term viability?**

A. No. As stated in the testimonies of Mark Bailey and Billie Richert, the proposed rates will stabilize Big Rivers financially. They are necessary for Big Rivers' long-term financial viability; they certainly will not threaten it.

While Mr. Cummings suggests that Big Rivers' proposed rates could cause the closure of industrial and commercial employers, none of the three Large Industrial customers testifying in this case claim that their company will face closure as a result of the proposed rate adjustment. Mr. Cummings speculates without any stated factual basis that it might cause other facilities to do so. Based on the considered judgment of Big Rivers' management team and the actual data from Vectren, Big Rivers believes that such closures, as a result of increased electricity costs, are unlikely.

Q. **KIUC witness Mr. Philip Hayet states that an October 2012 study produced by the Kentucky Energy and Environmental Cabinet indicated that electric price increases "may force businesses to seek ways to reduce costs, or close, causing substantial job losses in Kentucky's electricity-intensive manufacturing sector,**

and slowing overall long-term job creation in other sectors." (Hayet Testimony, pp. 26-27.) Does Mr. Hayet demonstrate how this study relates to Big Rivers' current situation or into a projection of price elasticity for Big Rivers?

A. No. The study quoted provides high-level information about the state as a whole and is not applicable to Big Rivers' unique situation. Furthermore, the study discusses the general impact of price increases but does not address the impact of denying a necessary rate adjustment. In this case, as discussed in the rebuttal testimonies of Ralph R. Mabey and Billie J. Richert, Big Rivers would likely face bankruptcy if its proposed rates are denied, leading to serious negative consequences for Big Rivers' Members and their retail customers throughout western Kentucky.

Q. KIUC witness Mr. Lane Kollen states on page 8 of his direct testimony that he believes there will be additional base rate adjustments due to the loss of existing customers and other reductions in load due to conservation as customers respond to the rate adjustments proposed in this case. How do you respond?

A. I disagree with Mr. Kollen's assertion. I discussed earlier why Big Rivers has reliably forecasted reductions in consumption. Furthermore, in looking at commercial customers in the Vectren service territory, in the years between 2001 and 2006, the number of commercial customers grew from 16,821 to 21,406 during the period in which the cost of electricity for the commercial customer rose from $54.1 per MWh to $70.5 per MWh. In 2007, there was a reclassification of commercial customers and from 2007 to 2012, the number of commercial customers remained relatively constant, ranging from 18,419 to 18,295, even during a severe economic downturn, while average commercial customer electricity prices rose from $83.3 per MWh to $115.1 per MWh.

Q. Mr. Brevitz asserts on pages 24 and 25 of his testimony that Big Rivers incorrectly assumes that existing Large Industrial customers will simply pay the higher rates for the same level of consumption. Do you agree that this is a "material flaw" in Big Rivers' strategy?

A. No. Mr. Brevitz cites only a couple of articles regarding companies becoming energy self-sufficient and removing themselves from the grid, but he does not even attempt to show that those articles form a basis for determining that the 20 Large Industrials on Big Rivers' system will reduce load. Similarly, he relies on Kimberly-Clark's witness's testimony about cogeneration; however, as I discuss above, that testimony indicates only that Kimberly-Clark might "evaluate" cogeneration, and certainly does not prove that any particular Large Industrial customer plans to adjust its load as a result of Big Rivers' proposed rates. The capital costs associated with cogeneration are significant and will be difficult to justify without waiting until Big Rivers has an opportunity to execute its Mitigation Plan to help to bring rates down for its Members.

Q. Does the test period load forecast include any replacement load?

A. No. The load forecast for the test period in this case does not include any assumptions for replacement load. As further discussed in the Direct Testimony of Robert W. Berry, load replacement will take a few years to come to fruition, but Big Rivers will ensure that its Members and their retail customers benefit when it does.

Q. Have any of the Opposing Intervenors performed detailed studies or analyses on their own or acquired any studies from reputable outside sources to support their claims regarding the Big Rivers Large Industrial elasticity assumptions?

A. No, the Opposing Intervenors have not performed or acquired detailed studies or analyses specific to Big Rivers' situation. Except for the anecdotal observations discussed earlier, which are inapplicable to the elasticity of the 20 Large Industrial customers on the Big Rivers system, the Opposing Intervenors appear to have performed no studies or analyses to support their claims.

V. CONCLUSION

Q. What would be the effect of adopting the Opposing Intervenors' proposed elasticity values?

A. Higher elasticity would result in a request for higher rates. Building in elasticity without sufficient evidence that it will take place, as the Opposing Intervenors propose, would imprudently and unnecessarily drive up Member rates.

Q. What are your conclusions and recommendations regarding the Opposing Intervenors' concerns regarding price elasticity and Big Rivers' load forecast?

A. The Attorney General's, KIUC's, and Sierra Club's concerns regarding Big Rivers' price elasticity assumptions and related load forecast are unsubstantiated and should be disregarded. The Opposing Intervenors did not perform detailed, specific analyses, and the examples provided in their collective testimony are not relevant to Big Rivers' situation.

In contrast, Big Rivers hired a reputable company, GDS, to develop the load forecast, which incorporated the impact of the proposed rates specifically on Big Rivers' Members and their residential, commercial, and most industrial customers. GDS has developed load forecasts and performed price elasticity studies for numerous utilities across the country. GDS' analysis of the Rural customer class consumption was rigorous, and it is a reasonable forecast on which to rely.

With regard to the 20 Large Industrial customers, they are sophisticated energy users and have already taken steps to be energy efficient, as confirmed by the testimonies filed by KIUC in this proceeding. Comparable data from the electric utility nearest to Big Rivers confirms Big Rivers' business judgment that Large Industrial customers will be generally inelastic to the proposed rate increase.

To reiterate, assuming that the price elasticity of demand of our customers will be greater than we have assumed would result in increased rates that are currently unwarranted. The price elasticity assumptions and related load forecast information utilized in Big Rivers' forecasted test period are reasonable and appropriate for setting rates that will become effective on February 1, 2014, and should be accepted.

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. 2013-00199**

REBUTTAL TESTIMONY

OF

THOMAS W. DAVIS
VICE PRESIDENT ADMINISTRATIVE SERVICES

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: December 17, 2013

REBUTTAL TESTIMONY
OF
THOMAS W. DAVIS

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REBUTTAL TESTIMONY
OF
THOMAS W. DAVIS

I. INTRODUCTION

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

A. My name is Thomas W. Davis. I am employed by Big Rivers Electric Corporation ("Big Rivers"), 201 Third Street, Henderson, Kentucky 42420, as Vice President Administrative Services.

Q. Are you the same Thomas W. Davis that adopted the Direct Testimony of James V. Haner in this proceeding?

A. Yes.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my rebuttal testimony is to respond to the testimony of Mr. Bion C. Ostrander filed on behalf of the Office of the Attorney General of Kentucky ("Attorney General"). In particular, I will (i) address Mr. Ostrander's criticisms regarding Big Rivers' employee compensation; (ii) explain why the Commission should reject Adjustment OAG-4-BCO to adjust the forecasted test period payroll expense; and (iii) explain why the Commission should reject Adjustment OAG-5-BCO to remove general pay increases for bargaining unit employees.

III. EMPLOYEE COMPENSATION

Q. In his direct testimony on pages 31 through 38, Mr. Ostrander repeatedly asserts

that Big Rivers has been unwilling or unable to provide data, reconciliations, supporting calculations, justifications, etc. How do you respond?

A. Big Rivers has provided the information requested to the extent it was available and relevant to the revenue requirement set out in the forecasted test period. In its information requests to the Attorney General, Big Rivers requested a listing of information Mr. Ostrander claims Big Rivers failed to provide. Some of those items are addressed later in this testimony; the remaining items are addressed in the Rebuttal Testimony of John Wolfram. Except for the information that was not available, which I explain below, Big Rivers did not fail to provide information that was requested.

Q. In proposed adjustment OAG-4-BCO, Mr. Ostrander proposes reducing the forecasted test period payroll expense (labor and benefits) because he alleges that Big Rivers has understated this payroll adjustment in its forecasts. Does Big Rivers agree with this adjustment?

A. No. Big Rivers has not understated the payroll adjustment in its forecasts. Mr. Ostrander's calculations are incorrect.

First, the test period labor/benefits amount that Mr. Ostrander used in his calculation fails to account for the pro forma adjustment removing non-recurring labor/labor overheads from the revenue requirement. (*See* Exhibit BCO-2, Schedule A-5, at Line 23; Direct Testimony of John Wolfram, Exhibit Wolfram-2, p. 11, at Line 14.)

Second, as recognized in Mr. Ostrander's schedule, Big Rivers is capitalizing less labor expense in the forecasted test period than in the base period. (Exhibit BCO-2, Schedule A-5, at Lines 11 and 23.) As a result, the labor cost reduction from the revenue requirement in the forecasted test period is not understated—it is in fact smaller when compared to the higher amount of labor costs capitalized in the base period. Big Rivers' forecast that fewer labor dollars will be capitalized in the test period is reasonable because two facilities will be idled during that time period.

Finally, I will point out that Big Rivers has a thorough budget process for labor. We look at pay rates for each position. We confirm the number of off-duty hours with payroll (comparing to the previous year). Each manager reviews expected overtime percentages. Headcount is approved by human resources and senior management, as are any pay raises. Overheads are examined by the human resource department and are sent to budgeting during the budget process. Any positions that are expected to be open are discussed with human resources in an effort to reflect lower labor costs. Additionally, we have removed non-recurring costs associated with the idling of Coleman using pro forma adjustments to the revenue requirement in this case. (See Exhibit-2 Wolfram.)

Big Rivers' payroll expenses provided in this rate case have been diligently calculated, are reasonable and appropriate, and should be relied upon by the Commission. Mr. Ostrander's proposed adjustment is inappropriate and should be disregarded.

Q. **Does Mr. Ostrander provide any examples of what he claims to be inaccuracy in Big Rivers' payroll calculations?**

A. Yes. Mr. Ostrander asserts that the first six months of Big Rivers' base period included fewer straight time hours (521,931) due to positions being vacated and unfilled, and that these hours increased to 651,382 in the second six months of the base period.

(Ostrander Testimony, p. 32:10-15.)

Q. How do you respond to that example of alleged inaccuracy?

A. In its August 29, 2013, update of Tab 50 of its Application, Big Rivers corrected the hours worked during the base period and provided an explanation for the correction. The historical portion of the base period did not include paid time off, so it was not comparable to the other periods on the schedule. The revised historical base period reflects 617,737 hours, not the 521,931 hours stated by Mr. Ostrander.

Q. Mr. Ostrander also asserts that he does not understand why straight time hours increased between the first 6 months of the base period and the second 6 months of the base period. Can you explain?

A. Yes. The apparent discrepancy is because these two numbers are measuring slightly different things.

First, the straight time hours for the second 6 months of the base period are projections based on headcount being fully-staffed. My understanding, however, is that, in practice, headcount is not fully-staffed due to vacancies that occur as people leave and are later replaced, and so not all of the budgeted hours are actually worked. Big Rivers does not budget the hours reduction; it only budgets the reduction of the dollars associated with open positions. Consequently, these projected hours will be slightly higher than the actual hours (as discussed later, Big Rivers has adjusted for this in its revenue requirement). In this part of the base period, 16 positions are assumed to not be filled at any point in time. If these open positions were removed from the "hours" line, it would reduce the 651,382 hours significantly.

Second, the straight time hours for the first 6 months of the base period are historical data, and they reflect the actual hours worked in that time period. Therefore, these hours do not include the time associated with any open positions. Because Big Rivers had open positions in that time period, the hours worked were lower than they would have been if headcount had been fully-staffed.

Q. Mr. Ostrander professes to be confused about how the hours set forth in Big Rivers' base period translate to labor dollars. Can you clarify?

A. Certainly. For the second 6 months of the base period as well as the forecasted test period, Big Rivers has labor dollars identified by account number for the positions projected to be open. While total labor hours, discussed earlier, show labor hours gross of those projected open positions, the labor dollars are adjusted down by the amount of savings expected. Importantly, this means that Big Rivers did not include in the revenue requirement the cost of labor hours projected but not being worked. During the forecasted test period, open positions are assumed at 7 for this rate case.

Q. Does Big Rivers address straight time or overtime hours for the forecasted test period?

A. Big Rivers budgets straight-time hours, but not overtime hours. Overtime is budgeted as a percent of straight-time hours. As James V. Haner previously testified, overtime factor estimates are provided by the department managers based on historical data, planned workloads and schedules, or other considerations applicable to specific departments.

Q. On pages 33 and 34 of his testimony, Mr. Ostrander asserts that Big Rivers did not provide the information requested by AG 2-71. Is this accurate?

A. No. Mr. Ostrander's claims that Big Rivers failed to provide requested information are incorrect and misleading. Big Rivers either provided the information requested or explained why the requested information was not available.

In subparts (a) and (b) of AG 2-71, the Attorney General claimed that Big Rivers did not provide certain payroll information allegedly requested in AG 1-239. However, contrary to the Attorney General's assertion, AG 1-239 only sought information about officer payroll, and Big Rivers provided the requested information with respect to each individual identified as an officer in Big Rivers' bylaws or explained why the information was not available. Big Rivers accurately and appropriately explained this in response to AG 2-71(d), in which the Attorney General asked why Big Rivers did not provide additional information in response to AG 1-239.

The only new information requested in AG 2-71 was sought in subpart (c). Big Rivers' response to that subpart provided the information that was available.

For these reasons, Mr. Ostrander's allegations that Big Rivers' responses to data requests were somehow incomplete are incorrect and misleading and should be disregarded.

Q. Mr. Ostrander asserts that Big Rivers has admitted that some of the current rate case witnesses are performing duties of unfilled and vacated Officer positions. (Ostrander Testimony, p. 34:3-5.) Is Mr. Ostrander's assertion correct?

A. No. It is correct that certain Big Rivers employees are performing duties that were previously performed by employees who have left the company. However, there are no unfilled and vacated officer positions. Big Rivers has two executive officer positions in its bylaws, CEO and COO, both of which are filled.

Q. Mr. Ostrander expresses "significant concern" that Big Rivers budgets payroll costs by using average rates by department rather than by individual employee. (Ostrander Testimony, p. 35:1-9.) Please address this practice.

A. It is a common practice to utilize average payroll cost per employee multiplied by the number of employees to determine labor costs for budgeting purposes. The reason for this is that a utility cannot predict with certainty which specific employees will perform specific work, which specific employees will work overtime, which specific employees will depart, and which employees will be hired, and at what rate.

Q. Please describe Mr. Ostrander's proposed adjustment OAG-5-BCO.

A. Mr. Ostrander proposes adjustment OAG-5-BCO to remove general pay increases. This adjustment is intended to remove the estimated expense portion of Big Rivers' forecasted test period pay increases, which Mr. Ostrander divides into three categories: (a) the Non-bargaining pay increase effective January 2, 2015; (b) the Bargaining-Generation wage increase effective September 15, 2014; and (c) the Bargaining-Transmission wage increase effective October 15, 2014. (Ostrander Testimony, p. 37:8-13.)

Q. What is Mr. Ostrander's reason for proposing this adjustment?

A. Mr. Ostrander claims that the forecasted test period pay increases for late 2014 and early 2015 are "not known and measurable in terms of the percent and amount to be awarded." (Ostrander Testimony, p. 37:13-15.)

Q. Please respond to the validity of Mr. Ostrander's proposed adjustment to the non-bargaining pay increase effective January 2, 2015.

A. First, Mr. Wolfram explains in his Rebuttal Testimony that Mr. Ostrander's reference to a "known and measurable" standard is inappropriate in a forecasted rate case.

Second, the issue is moot. In its October 29, 2013 order in Case No. 2012-00535, the Commission denied Big Rivers rate recovery for this anticipated increase. In his Rebuttal Testimony, Mr. Wolfram adjusts the revenue requirement to remove this previously-anticipated increase.

Even so, I would note that no employee at Big Rivers, including management, determines his or her own pay or pay increases. Those are either set by the Board of Directors or by the CEO. I would also note that Big Rivers' financial health does not set the market price for employee compensation. Big Rivers competes with other entities in the region and across the country for qualified employees, and Big Rivers must maintain competitive wages to retain and attract qualified employees.

Q. Please respond to Mr. Ostrander's proposed adjustment to the Bargaining-Generation wage increase effective September 15, 2014.

A. Budgeted increases for bargaining unit employees are determined by the collective bargaining agreement Big Rivers has with the union. This agreement expires in September of 2015, at which time it will be renegotiated. These wage increases should be included in the revenue requirement for this reason.

Q. Please respond to Mr. Ostrander's proposed adjustment to the Bargaining-Transmission wage increase effective October 15, 2014.

A. Again, budgeted increases for bargaining unit employees are determined by the collective bargaining agreement Big Rivers has with the union. This agreement expires in October of 2016, at which time it will be renegotiated. These wage increases should be included in the revenue requirement for this reason.

Q. Mr. Ostrander asserts that Big Rivers "is unable or perhaps unwilling" to determine the expense impact of labor costs on its revenue requirement, and further alleges that Big Rivers has not explained the allocation of its labor costs between expenses and capital. (Ostrander Testimony, p. 37:16-17.) Please address these accusations.

A. I believe Mr. Ostrander is confused on this issue. It is simply not accurate to suggest that Big Rivers has not or cannot determine the expense impact of its labor costs on its revenue requirement, nor is it correct to suggest that Big Rivers refuses to explain its determination. In fact, Big Rivers set forth the expense impact of labor costs on its revenue requirement in its response to AG 1-237.

As Big Rivers explained in its response to AG 1-237(d), the allocation of labor costs between expenses and capital depends on the need for internal labor for capital projects in a given year. In order to determine the revenue requirement impact of labor costs allocated to expenses in the forecasted test period, Big Rivers relied on its years of experience to project a typical allocation of labor costs between expense and capital. Based on the information available to it, Big Rivers projected that approximately 98-99% of its labor costs will be allocated to expense rather than capital (as is typical). Big Rivers provided these calculations in the attachment to its response to AG 1-237(a). Because of the nature of labor cost allocation, the additional calculations Mr. Ostrander seeks simply do not exist. Big Rivers has appropriately determined, explained, and supported its determination of the expense impact of labor costs on its revenue requirement. Mr. Ostrander's assertions are misguided, and should be disregarded.

Q. Mr. Ostrander continues with the theme from his testimony in Case No. 2012-00535 that Big Rivers places a priority on pay increases over maintenance. (Ostrander Testimony, p. 37:20-21.) How do you respond?

A. Mr. Ostrander attempts to correlate a pay number he has devised with a number he believes the Commission allowed Big Rivers, in its 2011 rate case, to use for deferred maintenance. As explained by Mr. Haner in Case No. 2012-00535, there is no such correlation. Mr. Ostrander's claims are unfounded. A utility can both perform necessary maintenance and maintain an appropriately competitive compensation program. Both maintenance and employee compensation are costs of doing business that must be covered by sufficient revenues if a business is to continue. A business may be able to defer one or both of these costs in the short-term, but it cannot do so in the long-term. Furthermore, as I stated earlier in my testimony, I am not aware of any employee who, singly or as part of a group, has set his or her own pay. No officer, manager, or other employee has chosen to award himself or herself a pay raise to the detriment of performing maintenance.

IV. <u>CONCLUSION</u>

Q. What is your recommendation regarding OAG-4-BCO where the Attorney General proposes payroll reduction adjustments totaling $5,594,280 to reflect the impact of headcount reductions?

A. For the reasons stated earlier, the Attorney General's recommendation to adopt Adjustment OAG-4-BCO should be rejected.

Q. What is your recommendation regarding OAG-5-BCO where the Attorney General proposes payroll reduction adjustments totaling $748,616 to reflect non-bargaining unit and bargaining unit general pay increases?

A. For the reasons stated earlier, no reduction should be made to remove any portion of the wage increase for bargaining unit employees. As noted earlier, the Rebuttal Testimony of John Wolfram addresses the removal of the previously-budgeted increase for non-bargaining unit employees.

Q. Do you have any other recommendations?

A. Yes. For the reasons stated earlier and in the Direct Testimony of James V. Haner, the Commission should approve the forecasted compensation expense included in the revenue requirement in this case, as adjusted in the Rebuttal Testimony of John Wolfram.

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. 2013-00199)

REBUTTAL TESTIMONY

OF

JOHN WOLFRAM
PRINCIPAL
CATALYST CONSULTING LLC

ON BEHALF OF

BIG RIVERS ELECTRIC CORPORATION

FILED: December 17, 2013

REBUTTAL TESTIMONY
OF
JOHN WOLFRAM

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REBUTTAL TESTIMONY
OF
JOHN WOLFRAM

I. INTRODUCTION

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

A. My name is John Wolfram. I am the Principal of Catalyst Consulting LLC. My business address is 3308 Haddon Road, Louisville, Kentucky, 40241.

Q. On whose behalf are you testifying?

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

Q. Are you the same John Wolfram that provided direct testimony in this proceeding?

A. Yes.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to respond to testimony submitted by witnesses for the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("Attorney General"), the Kentucky Industrial Utility Customers, Inc. ("KIUC"), and the Sierra Club ("Sierra Club") (collectively, the "Opposing Intervenors"). Specifically, I will explain that the Opposing Intervenors have inappropriately attempted to redefine this rate filing and transform it into a long term resource assessment. This case is about rates that are fair, just, and reasonable based on the base period and the forecasted test period, and while consideration of Big Rivers' Load Concentration Analysis and Mitigation Plan ("Mitigation Plan") provides some context for justifying Big Rivers' proposed rates, that fact should not divert attention from the primary focus on evaluating the base period and forecasted test period revenues and expenses for ratemaking purposes.

The Opposing Intervenors' criticisms of the Mitigation Plan are unfounded, mischaracterize the Mitigation Plan, and should be disregarded. In particular, the analyses sponsored by Attorney General witness Mr. Larry Holloway ("Holloway Study") and by KIUC witness Mr. Philip Hayet ("Hayet Analysis") are flawed. I will explain how the KIUC mischaracterizes Big Rivers' proposed rate adjustment in this case. I will describe why the forecasted test period used in this case is consistent with applicable regulations and is appropriate for setting rates, and why the Attorney General's assertions to the contrary are erroneous. I will explain why the KIUC suggestion that the smelter surcredit revenues should be deferred and amortized in the revenue requirement should be denied. I will describe why the Opposing Intervenor claims regarding rate discounts for new load should be rejected. I will rebut the overall recommendation of the Attorney General and will explain why the adjustments proposed by Attorney General witness Mr. Bion C. Ostrander should be denied. Finally, I will provide revised exhibits for the cost of service study and proposed rates that properly reflect the information in the record in this case, consistent with 807 KAR 5:001(16)(11)(d).

III. <u>THE RATE CASE TEST PERIOD IS NOT COMPRISED OF THE LONG TERM PLANNING HORIZON</u>

Q. Mr. Brevitz indicates that Big Rivers' proposed rates "are not fair, just and reasonable" (Brevitz Testimony, p. 22:13-14). Do you agree?

A. No. Big Rivers is proposing rates in this case that are fair, just, and reasonable, based on the forecasted test period. As noted in its application, Big Rivers filed this rate case pursuant to KRS 278.180, .190, .192, and related sections, and 807 KAR 5:001, 807 KAR 5:011, and related sections. Big Rivers elected to file the case using a fully forecasted test period, and it filed the requisite information for both the base period and the test period. This information should be assessed to determine whether the proposed rates are fair, just and reasonable. For the most part, however, the Opposing Intervenors did not focus on the specific data provided for the base period and the test period, and instead focused their attention almost exclusively on the long term planning horizon in the 2016-2027 timeframe. That long-term planning horizon does not directly affect Big Rivers' revenue requirement in this case.

Q. What time period comprises Big Rivers' test period in this rate filing?

A. Big Rivers' fully forecasted test period spans from February 1, 2014 to January 31, 2015. It does not extend to the years 2016-2027, which is the timeframe that the Opposing Intervenors emphasize in their testimonies.

Q. Did Big Rivers properly prepare the forecasted test period in this case?

A. Yes. Big Rivers met the requirements associated with the use of a fully forecasted test period for setting rates, adequately supported the forecast, and performed all required analyses. Big Rivers relied upon reasonable projections of market prices, fuel costs, headcount, and other factors that were available or could otherwise be developed for its forecast in the short time period between January 31, 2013 and June 28, 2013.

The rate adjustment proposed by Big Rivers in this case is needed by February 1, 2014, when the Sebree smelter contract terminates, under any reasonable set of circumstances. The Big Rivers forecast for the test period properly reflects this simple fact. The Attorney General and KIUC witnesses, on the other hand, focus on 2016-2027 to request rates that are insufficient to meet the test period revenue requirement.

Q. **Are you suggesting that the Commission should examine only the base period and forecasted test period in this case?**

A. No. The Commission clearly has broad discretion to consider many issues that could affect the reasonableness of Big Rivers' rates, including the reasonableness of the Mitigation Plan beyond the end of the test period. Even so, the Commission has already done so, as reflected at page 19 of its October 29, 2013, order in Case No. 2012-00535 (the "Century Order"), which found it "reasonable to afford Big Rivers the time to pursue its mitigation strategies." None of the resource planning issues raised by the Opposing Intervenors alter the Commission's finding on this issue, at least in the near term. Accordingly, the focus in this case—even more so than in Case No. 2012-00535—should be primarily upon an examination of the base period and forecasted test periods.

Q. **Does the Commission have to fully resolve in this case whether or not Big Rivers will be able to secure replacement load and return the Wilson and Coleman units to service in the 2018-2020 period?**

A. No. This case is a rate application. The Commission should consider whether the forecasted test period provides a sound basis for rates that are fair, just and reasonable, and it should set rates accordingly. To do so, the Commission should assess whether the forecasted test period reasonably represents the conditions that will exist at the time the rates are placed into effect. Again, this does not require that the Commission try to fully evaluate in this case the conditions that will exist several years from now on a least cost planning basis.

Q. Why isn't it necessary for the Commission to fully evaluate the long term planning horizon in this case?

A. First, none of the replacement load projected in Big Rivers' long term production cost modeling occurs in the test period or is factored into the revenue requirement. Thus, the long term planning horizon is not relevant to the proceeding.

Second, it would be arbitrary for the Commission to rule at the end of October 2013 that it was going to allow Big Rivers time to pursue the Mitigation Plan, only to reverse course a few short months later based on the Opposing Intervenors' opinions – which remain the same as in Case No. 2012-00535 – about what might occur in 2016-2022. In its Century Order, the Commission stated on page 19 that

> "Further, we find it reasonable to afford Big Rivers the time to pursue its mitigation strategies, including operational changes to reduce costs, seeking to acquire replacement load, increasing off-system sales, and attempting to sell or lease its generating facilities."

The Commission further stated on page 20 that Big Rivers will "be able to implement its mitigation plan, and possibly attract new load." Big Rivers made it clear in Case No. 2012-00535 that it may take three to four years for the Mitigation Plan to come to full fruition. The Century Order supports Big Rivers' continued implementation and pursuit of the Mitigation Plan, and the assumptions regarding that implementation are incorporated into the forecasted test period in this case. The Opposing Intervenors' positions will prevent Big Rivers from having any opportunity to pursue mitigation, which is in direct conflict with the Commission's findings in the Century Order that it was going to give Big Rivers time to pursue the Mitigation Plan.

Third, granting the rate relief Big Rivers needs in the case in order to be able to continue pursuing the Mitigation Plan does not mean the Commission is forever barred from evaluating and monitoring Big Rivers' resource needs in the future. The Commission has continuing jurisdiction over Big Rivers under KRS 278. Additionally, the statutes and regulations governing the filing of Integrated Resource Plans ("IRPs"), Certificates of Public Convenience and Necessity ("CPCNs"), Environmental Compliance Plans ("ECPs"), and transfers of control provide the Commission the necessary authority to continue to monitor and evaluate Big Rivers' progress on an ongoing basis.

Q. Please elaborate on the Commission's continuing jurisdiction over elements of Big Rivers' long-term planning.

A. Big Rivers is required to prepare and file an IRP every three years. The next IRP filing is due in May of 2014, with subsequent IRP filings due in 2017 and 2020. Although it is ordinarily resolved via a Commission Staff Report rather than a Commission Order, the IRP process provides a forum in which Big Rivers conducts a thorough assessment of its future load forecasts, demand side alternatives, and supply side alternatives over a fifteen-year planning horizon. The process is transparent, provides for intervenor review and comment, and is performed with a periodicity of three years. For these reasons, the IRP process ensures that Big Rivers will review and update its load forecast and resource plans as it is implementing its Mitigation Plan, between now and the timeframe discussed by the Opposing Intervenors in their testimony.

Furthermore, it is expected that before Big Rivers restarts the Coleman units, Big Rivers will file ECP and CPCN cases. At present, these filings are anticipated in the 2017-2018 timeframe.

Alternatively, if Big Rivers is successful in its efforts to sell or lease the Wilson and/or Coleman plant(s), Big Rivers would file an application with the Commission seeking authority to transfer control of those assets pursuant to KRS 278.218. In that filing, Big Rivers would include the studies that demonstrate that such a transaction is for a proper purpose and is consistent with the public interest.

Additionally, as discussed by Mr. Berry in his rebuttal testimony, Big Rivers will only return the Wilson and Coleman plants to service if the economics at the time justify it. Big Rivers will perform additional analyses prior to returning the plants to service, based on the circumstances existing at that time.

All of these filings will provide the Commission with an opportunity to monitor and evaluate Big Rivers' long-term plans for Wilson and Coleman.

Q. **Do these points address the particular claims made by the Opposing Intervenors that Big Rivers did not perform sufficient studies and that Big Rivers' forecasts are deficient or erroneous?**

A. Yes. I address the specific claims in the questions that follow.

Q. **Mr. Ackerman claims that Big Rivers' "analysis and forecasts appear deficient in several respects...The Commission should direct them to develop revised and improved analyses, as a basis for more careful resource planning." (Ackerman Testimony, p. 5: 24-27) How do you respond?**

A. This criticism is misplaced. This is a rate case, not a resource planning case. Big Rivers is not seeking permission to construct new generating facilities. Big Rivers already owns the Wilson and Coleman stations following the granting by the Commission of CPCNs to construct those facilities and approval to include the costs of the facilities in Big Rivers' revenue requirement. After the Sebree smelter contract termination becomes effective on January 31, 2014, Big Rivers will continue to be subject to the plant fixed costs that cannot be avoided by idling the plants. Those fixed costs will not change based on additional analyses, and additional analyses will not impact Big Rivers' revenues and expenses in the forecasted test period used in this filing.

Q. Mr. Ackerman claims that a "re-examination of the basis of Wood Mackenzie forecasts, and an explanation of alternatives, should be a priority for future [Big Rivers] planning efforts." (Ackerman Testimony, p. 15: 12-14) How do you respond?

A. Mr. Ackerman takes issue with the "blending" of the ACES broker prices and the Wood Mackenzie forecast. The ACES broker prices cover the first seven years of the planning period, and they are then "blended" with the Wood Mackenzie forecasts between years seven and ten, after which the Wood Mackenzie forecast is used. However, both the blending and the Wood Mackenzie forecast with which Mr. Ackerman takes issue pertain only to the long term planning horizon -- not the forecasted test period used to determine the revenue requirement in this case -- and thus do not directly affect the proposed rates. The prices in the forecasted test period are the ACES broker prices, which are actual market prices and not forecasted prices.

Q. Mr. Brevitz implies that Big Rivers should have performed a Net Present Value ("NPV") analysis in this case, and that two of Big Rivers' Members have previously included NPV analyses in Commission filings. (Brevitz Testimony, p. 37: 1-10.) How do you respond?

A. Big Rivers understands NPV analyses and in fact included its own NPV analysis in the ECP / CPCN filing last year in Case No. 2012-00063. The NPV analysis is ordinarily used to identify a least-cost option among several alternatives. In this case, the Attorney General has not identified the specific alternatives for which an NPV comparison would be appropriate. Furthermore, none of the cases cited by the Attorney General were rate cases. The cited cases were least-cost assessments that pertained to planning horizons that extended beyond the time period applicable to test periods in rate case filings pursuant to 807 KAR 5:001.

Q. Mr. Kollen recommends that "the Commission direct the Company to retain professional advisers and counsel to identify and pursue options that will benefit customers, including, but not limited to, asset sales, corporate restructuring, corporate liquidation, and creditor concessions." (Kollen Testimony, p. 11:2-5) Similarly, Mr. Hayet claims that the "Commission should direct the Company to re-evaluate other business options to right-size the Company." (Hayet p. 44: 19-20) How do you respond?

A. Big Rivers responds to the broad impacts of these particular recommendations in the Rebuttal Testimony of Mark A. Bailey. The financial and practical implications of these suggestions are further addressed in the Rebuttal Testimony of Daniel M. Walker, Billie J. Richert, and Ralph R. Mabey. My response is limited to the more narrowlydefined context of setting rates. Even if we ignored the substantive flaws of the KIUC's recommendation, the time required for such activities would likely prohibit the resultant outcomes from being reflected in the test period results. The same is true for Mr. Hayet's recommendation. In other words, the proposed options would take time – at least months and perhaps years – and thus would prevent Big Rivers from meeting its financial obligations beginning February 1, 2014.

Q. Mr. Hayet claims that the "Company's Load Mitigation Plan is premised on unrealistic or clearly erroneous assumptions" (Hayet p. 4:9-10) and that the "Company has supplied few studies, no written analyses, and little evidence supporting its assumptions regarding replacement load" (Hayet p. 5:10-13). How do you respond?

A. The Commission has already found that Big Rivers should be given time to implement its Mitigation Plan, and so the first claim is moot. The claims regarding replacement load do not affect the proposed rates because the replacement load is projected to commence in 2016, not during the test period relied upon for establishing the proposed rates. I address the Mitigation plan further in section IV of my testimony and Mr. Robert W. Berry addresses the Mitigation Plan in detail in his rebuttal testimony.

Q. Mr. Hayet claims that "no reliable evaluation based on updated assumptions has been performed, and I believe the Company should be required to perform such a study to determine what the proper disposition of the Coleman and Wilson plants should be." (Hayet Testimony, p. 8: 21-p. 9:1) How do you respond?

A. The IRP process, along with the ECP, CPCN, and transfer of control filing processes, sufficiently satisfies this claim. Moreover, Big Rivers continues to evaluate options in its Mitigation Plan for their feasibility.

Q. Mr. Hayet claims that "[a]nother factor that I believe should be considered as part of that study is Kentucky's state policy related to carbon emissions" (Hayet Testimony, p. 2-3). Mr. Hayet further claims that "Big Rivers should have at least performed a sensitivity study as part of its Load Mitigation Plan analysis in this proceeding to evaluate the impacts of CO2" (Hayet p. 28:19- p. 29:1). How do you respond?

A. Carbon emissions regulations, and/or carbon emission prices, are not expected to be in place during the forecasted test period. No Opposing Intervenor witness contravenes this point. Thus, these issues will not affect Big Rivers' proposed rate adjustment in this matter, and can instead be addressed in the IRP and/or ECP/CPCN processes. They do not need not to be resolved in this rate filing.

Q. What do the anticipated IRP, ECP and CPCN filings mean for the Commission in this rate proceeding?

A. The IRP, ECP and CPCN filings discussed above permit the Commission to decide this rate filing as it would any other – by reviewing the base period and test period revenues and expenses for reasonableness – without transforming this rate proceeding into a least cost resource analysis over the long term planning horizon. Presumably, that is one reason the law established those different proceedings for those issues in the first place. In this case, Big Rivers proposed rates that are based on a fully forecasted test period that reasonably represents the conditions that will exist at the time the rates take effect.

The IRP filings in 2014, 2017 and 2020, in conjunction with ECP and CPCN filings that are expected to precede the restart of the Coleman and Wilson units in the 2017-2018 timeframe, give the Commission the necessary assurances that Big Rivers will continue to perform the appropriate resource studies on a routine basis. These studies will be conducted in conjunction with the continuing implementation of the Mitigation Plan that the Commission has already given Big Rivers time to pursue. These studies will also provide Big Rivers, the intervenors, and the Commission with additional and on-going insight into the reasonableness of Big Rivers' resource plans – and thus its rates – over the next three to five years and beyond.

IV. <u>CRITICISMS OF THE MITIGATION PLAN ARE FLAWED</u>

Q. The Opposing Intervenors criticize the Mitigation Plan. Are these criticisms valid?

A. No. Big Rivers responds to most of the criticisms of the Mitigation Plan in the Rebuttal Testimony of Mr. Robert W. Berry. I will address a few additional points here.

Q. Do any of the Opposing Intervenors compare Big Rivers' rates to those of other utilities in Kentucky as a basis for their criticisms of the Mitigation Plan?

A. No. Big Rivers compared its rates to those of other utilities in Kentucky, and Kentucky's resultant rates to those of other states. This was provided in Exhibit Wolfram-8. None of the Opposing Intervenors contravened that data. In fact, none of the Opposing Intervenors mentioned the data in Exhibit Wolfram-8 whatsoever. Instead, the Opposing Intervenors emphasize the proposed increase in Big Rivers' rates – comparing the proposed rates to the current rates – and imply that this increase will be fatal to attracting new load. In reality, the comparison of Big Rivers' proposed rates to the rates of *other utilities* is the meaningful comparison. As the data in Exhibit Wolfram-8 shows, this comparison does not corroborate the dire circumstances portrayed by the Opposing Intervenors, particularly for the industrial customer segment. The comparison supports the position outlined by Mr. Berry in his rebuttal testimony.

A. THE HOLLOWAY STUDY IS FLAWED

Q. Mr. Holloway for the Attorney General provides a "Member Benefit Analysis for Rate Treatment of Coleman and Wilson Costs" ("Holloway Study"). In this study, Mr. Holloway purports to analyze the member benefits of the costs of owning and operating the Wilson and Coleman plants. Is this analysis valid?

A. No. First of all, a study of this nature addresses the long term planning horizon, not the rate case test period, as I discussed before. Thus, it does not invalidate the test period financials. In other words, test period values do not include discounted revenue and expense streams related to future time periods, and thus the Holloway Study does not alter the proposed rates in this case. That point aside, the analysis has other flaws and is not meaningful.

Q. In what ways is the Holloway Study flawed?

A. In general, an NPV analysis as performed in the Holloway Study is of questionable value in this situation, because there is no realistic alternative to Big Rivers' proposal that does not undermine Big Rivers' financial integrity. At the very least, the Attorney

General has not put forth such a scenario, let alone quantified a comparative NPV for such a scenario.

More specifically, the Holloway Study is not meaningful because it does not address the question of idling and keeping the plants versus the real consequences of the Attorney General's proposal, i.e. putting Big Rivers at risk for bankruptcy, as described in the rebuttal testimony of Billie J. Richert.

Mr. Holloway states that "Utilizing Big Rivers' own data, I performed the analysis to determine if any future benefits of utilizing these units to sell off-system to either replacement load or the short term market, provides a reasonable off-set to costs that will be incurred by Big Rivers' Members if Wilson and Coleman costs continue to be included in member rates." (Holloway Testimony, p. 14: 7-10) However, the Holloway Study does not perform comparisons to other alternatives, including those that would stem from the Attorney General's own recommendations. It does not consider any of the potential costs related to the Opposing Intervenors' recommendations, including the higher interest rates associated with restructuring or bankruptcy, or the significant costs associated with restructuring or bankruptcy, or the impacts of selling the plants below book value. It is inconsistent and ultimately invalid for the Holloway Study to include the costs Big Rivers proposes to recover in its application but to ignore the costs that would exist if the Commission were to adopt the Attorney General's recommendations.

Q. Are there other problems with the Holloway Study?

A. Yes. The Attorney General claims that "the analysis contained in Exhibit Holloway-3 compares the Members' net present value of the costs and benefits of owning and operating Wilson and Coleman to a new gas-fired combined cycle unit installed at the same time that Big Rivers' long-term forecast anticipates returning Wilson to service." (Holloway Testimony, p. 17:10-13) This comparison is meaningless, however, if the Commission adopts the Opposing Intervenors' recommendations, because Big Rivers will not be able to finance a new gas-fired combined cycle unit.

Finally, the NPV analysis does not rely upon proper and complete input data. To properly compare the NPVRR of idling plants to that of obtaining another resource, a full production cost modeling analysis over the life of the plants would be necessary. This was not included in the Holloway Study.

Q. Are there other problems with the Holloway Study?

A. Yes. The study uses two different values to discount future revenues in the NPV analysis. Specifically, the analysis uses a 5% discount rate for the costs of Wilson and Coleman plants which Big Rivers proposes to include in rates, but a 10% discount rate for the revenues from off-system sales and replacement load. Mr. Brevitz claims that the revenues from off-system sales and replacement load are "more distant" and "subject to significant uncertainty" but the revenues from proposed increased rates are "more certain." (Brevitz Testimony, pp. 43:14–44:3.) This is flawed. The 10% discount rate itself is arbitrary and unsupported. The fact that the off-system sales and replacement load revenue is "more distant" is properly accounted for by the application of a discount rate in the first place, when all future cash streams are "brought back" to present value terms. The difference between the two proposed discount rates is not supported by any evidence or data. The use of a higher discount rate for the revenues from off-system sales and replacement load understates the impact of those revenues.

Any differences in risk should be accounted for in the revenue values themselves and not in the discount rate applied to those values in order to determine the NPV.

Q. Are there problems with the sensitivity analysis in the Holloway Study?

A. Yes. Broadly speaking, the analysis only includes one scenario, so it hardly qualifies as a true sensitivity study; a meaningful sensitivity analysis would ordinarily consist of numerous scenarios that cover a range of both positive and negative adjustments to key variables in the base case. Such a range of consideration is absent here.

Furthermore, the single scenario assumes that Big Rivers "achieves only 50% of its forecasted replacement load, and that it occurs one year later than in Big Rivers' forecast" but then also assumes that "Wilson and Coleman are returned to service in the years they are currently forecasted to return to service." (Holloway Testimony, p. 11: 14-17) This premise is flawed because, all else being equal, if the replacement load were delayed, Big Rivers would similarly delay the return of the plants to service. This flawed assumption compounds the risks associated with obtaining replacement load. Also, the Holloway Study already accounts for the alleged "higher risk" of replacement load by employing the arbitrarily-higher 10% discount rate. This too overstates the risks of the Mitigation Plan.

Q. Are there problems with the analysis of asking prices for Wilson and Coleman?

A. Yes. The study purports to determine the minimum price that could be asked for Wilson and Coleman if it were possible to sell the units immediately (Holloway Testimony, p. 16:16-19). However, this premise is flawed. Even if one ignores the substantive flaws of the concept of minimized asking prices, it simply is not possible for Big Rivers to sell the plants immediately; it takes time to find a buyer, negotiate terms and conditions of sale, prepare a filing with the Commission seeking authority to transfer control of those assets pursuant to KRS 278.218, and execute the necessary agreements. For this reason, the Holloway Study should at least have included the costs of the plants for a period of time instead of assuming an immediate sale. This is in addition to the conceptual and financial problems with the "fire sale" approach that are described by other witnesses for Big Rivers.

B. THE HAYET ANALYSIS IS FLAWED

Q. Mr. Hayet for the KIUC states that he conducted an analysis of the impact that CO2 costs could have on Big Rivers ("Hayet Analysis"). In this study, Mr. Hayet purports to analyze the effects of CO2 pricing on Big Rivers' operations and planning decisions. Is this analysis applicable to this rate filing?

A. No. Like the Holloway Study, the Hayet Study addresses the long term planning horizon, not the rate case test period, as I discussed before. In the Hayet Analysis, Mr. Hayet assumes that CO2 impacts would begin in 2020 (Hayet Testimony, p. 30:17-20). This means that CO2 impacts are excluded from the test period, both in Big Rivers' forecast and in the Hayet Analysis. Thus, the Hayet Analysis does not alter the proposed rates in this case.

Q. Are there other problems with the Hayet Analysis?

A. Yes. The appropriate way to assess the impacts of CO2 on Big Rivers' operations is to include the appropriate costs as inputs to a production cost model. The Hayet Analysis did not include production cost runs and instead relied upon "a simplifying assumption that Big Rivers generation output would not change" (Hayet Testimony, p. 30:3-4).

The studies that Big Rivers expects to prepare in the IRP and ECP / CPCN proceedings that I described earlier are superior to the Hayet Analysis in this regard. The Commission should rely upon Big Rivers' IRP and ECP/CPCN studies, and not upon the Hayet Analysis, for assessing Big Rivers' resource planning for 2020 and beyond.

V. <u>THE KIUC MISCHARACTERIZES THE PROPOSED RATE ADJUSTMENT IN THIS CASE</u>

Q. How does the KIUC characterize the rate adjustment proposed by Big Rivers in this case?

A. Mr. Kollen does not characterize the rate adjustment proposed by Big Rivers in this case. Instead, Mr. Kollen combines the all-in effects of the rate adjustments proposed in this case with the rate adjustments proposed by Big Rivers in Case No. 2012-00535 (Kollen Testimony, p. 13) and discusses the combined effects of these two cases – along with the expiration of the credits from the contracts and tariffs approved in Unwind in Case No. 2007-00455 -- noting that his values "include all of the increases across all tariff components in the test year" (Kollen Testimony, pp. 13-14.) However, Mr. Kollen's values are not limited to the test year; they include all of the increases in all rate components from May 1, 2012 to February 1, 2014 (i.e. the beginning of the base period in the previous rate case to the end of the test period in this case). This characterization is inappropriate for several reasons.

First, as noted above, Mr. Kollen inappropriately includes the effects of the previous rate case, which exaggerates the percentage increase proposed in this case by Big Rivers.

Second, Mr. Kollen eliminates the effects of the MRSM / Economic Reserve in the revenue calculations for the "Alcan Test Year" (Kollen Testimony, p. 13). This is consistent with the labeling of Mr. Kollen's tables as "After Reserves Are Depleted," but this is misleading because the reserves will not be depleted for the "Alcan Test Year" that the middle columns of the table seem to represent.

Third, while Mr. Kollen correctly attributes the effects of the FAC and Environmental Surcharge ("ES") mechanisms to the smelter contract terminations, he then goes on to rely upon these effects to support the KIUC position opposing the proposed rates. This is improper because the FAC and ES charges are projected to increase in the fully forecasted test period with or without the proposed rate adjustment.

Finally, Mr. Kollen includes both the base period amounts and the test period amounts in his comparisons. The proper way to quantify the rate increase proposed by Big Rivers is to calculate the total Member billings by class <u>at the forecasted test period consumption levels</u> using the present rates and using the proposed rates, and to determine the difference. Mr. Kollen's method of calculating the rate impact overstates the impact of the proposed base rate increases for the fully forecasted test period.

VI. <u>THE PROPOSED FORECASTED TEST PERIOD IS REASONABLE</u>

Q. Throughout his testimony, Attorney General witness Mr. Ostrander indicates that the fully forecasted test period used by Big Rivers in this case is inaccurate or should otherwise cause the Commission concern. Do you agree?

A. No. The fully forecasted test period relied upon by Big Rivers is appropriate for setting rates in this case and should not cause the Commission concern.

Q. Why is the forecasted test period appropriate for setting rates in this case?

A. Big Rivers' use of the fully forecasted test period is consistent with applicable regulations. When Big Rivers developed the forecast for this filing, the forecast included all information that was known and available to Big Rivers at that time. Other information became available after Big Rivers filed this case, but the regulation specifies the conditions under which the applicant can revise the forecasted test period. Specifically, 807 KAR 5:001(16)(11)(d) states in part as follows:

> After an application based on a forecasted test period is filed, there shall be no revisions to the forecast, except for the correction of mathematical errors, unless the revisions reflect statutory or regulatory enactments that could not, with reasonable diligence, have been included in the forecast on the date it was filed.

Big Rivers adhered to the requirements of this regulation and to the filing requirements related to the use of the fully forecasted test period.

Q. Did the Commission find Big Rivers' use of a forecasted test period appropriate for setting rates in Case No. 2012-00535?

A. Yes. On page 6 of the Century Order, the Commission found "Big Rivers' use of the proposed forecasted test period to be reasonable."

Q. Does Big Rivers' use of a forecasted test period in this case differ from its use of a forecasted test period in Case No. 2012-00535?

A. No. Not only is Big Rivers' methodology the same, but the reason for using a forecasted test period—the unilateral termination of a smelter service contract—is the same.

Q. Mr. Ostrander claims that Big Rivers' filing has "unique and substantive flaws" which he implies are related to Big Rivers' utilization of a fully forecasted test

period. (Ostrander Testimony, p. 15.) Do you agree with his characterization of the use of the forecast test year in Big Rivers' filing?

A. No. I disagree with these statements. I will address the particular reasons for my disagreement in response to Mr. Ostrander's specific comments.

Q. **Mr. Ostrander argues that Big Rivers' rate case filing should be "less speculative, more transparent" (Ostrander Testimony, p. 13:7.) Do you agree?**

A. No. Big Rivers' filing is not unduly speculative, lacking in transparency, or inconsistent with the applicable ratemaking principles.

First, Kentucky law allows the applicant to file a rate case using either a historical test period or a fully forecasted test period, and the regulations set forth the requirements of each. By definition, the fully forecasted test period may serve as the basis for the determination of fair, just and reasonable rates. As I explain above, Big Rivers met both the statutory and regulatory requirements attendant to the use of a fully forecasted test period.

Second, Big Rivers provided a thorough description of its budget development process in the Direct Testimony of Jeffrey R. Williams. Big Rivers supported that description with further detail on many components of the budget development process described in the testimony and exhibits of its other witnesses, including Mr. Berry, Mr. Crockett, Ms. Barron, Mr. Haner, Mr. Warren and Mr. Wolfram. Information about the base period, test period, or other supporting data was provided with the Application in Tabs 11, 22-24, 26-28, 32-39, 42, 44-54, 56, and 57. Big Rivers also provided a significant amount of information in the discovery phase of this case (the majority of which was provided in response to numerous data requests from the Attorney General) in order to support Big Rivers' application, its proposed rates, and its fully forecasted test period. For example, Big Rivers' responses and the accompanying attachments to AG-1 Items 19, 23-25, 49, 51, 61-64, 68, 70, 73, 76, 84, 86-88, 90, 92-95, 97, 98, 100, 102, 105, 106, 109, 110, 112-115, 124, 126, 127, 132-144, 146, 147, 150, 152, 154-157, 162-165, 172, 174, 187, 194-196, 198-202, 204, 205, 208, 216, 217, 225-227, 231, 237-244, 246-247, 251, 254-257, 259, 261-265, 267, 269, 270, 272-276, 280-290, 292 and to AG-2 Items 1, 5, 7-9, 27-29, 34, 38, 48, 52, 54, 56, 58, 59, 62, 65, 67, 70, 72, 77, 78, and 83, in addition to the responses to data requests from the Commission Staff, KIUC, and Sierra Club, are more than sufficient to aid the Commission and Opposing Intervenors in evaluating the Financial Model. For these reasons it is simply not accurate to allege, as Mr. Ostrander does, that the forecasted test period lacks transparency.

Third, Mr. Ostrander seeks to apply the same "known and measurable" standard that is applicable to a historical test period to a fully forecasted test period. (Ostrander Testimony, p. 28:1; p. 29:11-12) When the entire test period is based on a forecast, the values are not, and cannot be, "known and measurable" in the same way or to the same extent that would be applicable to a historical test period. This was discussed in Case No. 2012-00535, and the same concepts apply in this case.

Q. Mr. Ostrander quotes a research paper by the National Regulatory Research Institute ("NRRI") on future test years.[1] Mr. Ostrander states that there are "many other relevant concerns regarding a forecasted test period that are

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[1] *Future Test Years: Challenges Posed for State Utility Commissions*, author Ken Costello Principal Researcher, Energy and Environment, National Regulatory Research Institute, Briefing Paper No. 13-08, dated July 2013.

addressed in this document and which I believe would be useful for the Commission's consideration in this case." (Ostrander Testimony, p. 19:1-4) Are there other relevant points in this paper for the Commission to consider?

A. Yes. The paper notes that the factors which might drive whether or not a forecasted test year ("FTY") would best produce "just and reasonable" rates include:

> *A dynamic environment in which the future is unlike the past and might deviate substantially from the past in terms of utility cost, operating and demand conditions.* [2]

Big Rivers is experiencing just such a dynamic situation at present. The future will be unlike the past and will deviate substantially from the past because of the smelter contract terminations. In the test period, Big Rivers will have idled a significant percentage of its available capacity, will collect hundreds of millions of dollars less in revenues, and will have hundreds of millions of dollars less in expenses than it had this year. This factor wholly supports Big Rivers' use of the forecasted test period in this case. The paper further notes that

> Consumer groups often concentrate on the negatives of FTYs while slighting their benefits. They tend to unequivocally reject FTYs in principle, while actual conditions may sometimes justify them.[3]

Thus, it is not surprising that the Attorney General is unjustifiably critical of the use of the fully forecasted test period in this case.

Q. Mr. Ostrander claims that he believes that Big Rivers "has used the forecasted test period to its advantage in this regard as it relates to its estimated cost impact of the loss of smelters" (Ostrander Testimony, p. 18:24-25). How do you respond?

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[2] *Id.*, p. 14.
[3] *Id.*, p. 11.

A. Mr. Ostrander implies that Big Rivers determined its revenue requirement based on the calculated revenue impact of the smelter contract termination. This is not the case. The revenue requirement is based on test period revenues and expenses, in total for Big Rivers, and not on an estimate of the revenue impact of the smelter contract termination. As Mr. Bailey explains in his rebuttal testimony, Big Rivers is not looking to 'pass the buck' from the smelter terminations by making up the loss of those revenues from the remaining customers.

Q. Mr. Ostrander indicates that Big Rivers did not determine the "actual impacts" of the smelter departure from "historical financial data" and thus if "the impact of the Sebree smelter in this rate case is not 'accurate' then it must be inaccurate or at least something less than accurate." (Ostrander Testimony, p. 28:12-14.) How do you respond?

A. Mr. Ostrander is mischaracterizing Big Rivers' response to AG 1-84. Also, the type of information that the Attorney General requested is simply not available. Big Rivers explained this in Case No. 2012-00535 in response to AG 1-51 and AG 2-17, and the same response applies here. It is just not possible to provide the "actual" "historical financial data" of Big Rivers' operations without the Sebree smelter on the system because there is no applicable historical period without the Sebree smelter on the system. The historical period includes the Sebree smelter load and does not include the effects of any Big Rivers actions taken in response to the Sebree smelter contract termination. One can only project the impact of the Sebree smelter contract termination, and Big Rivers did so by determining the revenue deficiency in the period immediately following the effective date of that contract termination. Mr. Ostrander claims that because Big Rivers used the revenue deficiency as the estimate of the impact of the contract termination that the revenue deficiency is therefore an estimate. But this is not the case. Big Rivers' revenue deficiency was not estimated; it was determined using test period revenues and expenses. Thus, the historical "actual" information requested by the Attorney General does not exist, and Mr. Ostrander's claim that the revenue deficiency is an estimate is incorrect.

Q. Mr. Ostrander also claims that Big Rivers' Financial Model "does not have a formal User's Manual, so it is not possible to test [Big Rivers'] projected amounts against some objective formal written underlying procedures" and that this constitutes a "unique problem" with the fully forecasted test period. (Ostrander Testimony, p. 15:5; 16:8-10.) How do you respond?

A. I disagree with the assertion that if Big Rivers' Financial Model does not include a "Manual," the model or its results must have a problem. First it must be noted that Big Rivers did produce documentation for the Financial Model in response to AG 1-155. This nine-page document includes a description of the function of each worksheet in the model, the inputs to and outputs of the Financial Model, and the checks to ensure its accuracy. It is unclear why this document does not seem to address the Attorney General's concerns about formal written procedures. Big Rivers also provided a significant amount of information in Case No. 2012-00535 in response to PSC 1-57, PSC 2-13, AG 1-7, AG 1-17, AG 1-97, AG 1-131, AG 1-190, AG 1-236, AG 1-239, AG 1-240, AG 1-241, AG 1-242, and AG 1-267 to explain how particular elements of the model work. That information about the use of the model still applies. Specific information was provided in this case in response to PSC 2-14; AG 1-98 and 2-28;

KIUC 1-18, 1-34, 1-64, 2-20, 2-21, 2-24, 2-27, 2-28; and SC 1-13 and 1-14. Again, it is unclear why the Attorney General does not give any weight to this significant volume of documentation and explanation.

Second, the Attorney General alleges that the lack of a formal manual—apparently above and beyond the significant amount of documentation and information already provided by Big Rivers—gives Big Rivers an opportunity to "manipulate" the assumptions underlying the Financial Model. However, the Attorney General offers no evidence to support the implication that Big Rivers "manipulated" any underlying assumptions. Big Rivers has not manipulated its Financial Model in this proceeding.

Third, the Attorney General's witnesses contradict one another on the need for a user's manual. In its First Request for Information, Question No. 31, Big Rivers asked Mr. Holloway to provide a user's manual for his "Member Benefit Analysis for Rate Treatment of Coleman and Wilson." In his response, Mr. Holloway noted that "Spreadsheets are provided with formulas intact. No manual is necessary." Big Rivers similarly provided its Financial Model in spreadsheet form with formulas intact, so it is unclear why the Attorney General does not maintain a consistent position with respect to the need for a users' manual, or whether Mr. Ostrander believes that Mr. Holloway's analysis is also subject to "unique problems" in this regard.

For these reasons, Mr. Ostrander's claim should be disregarded by the Commission.

VII. THE KIUC SUGGESTION THAT THE SMELTER SURCREDIT REVENUES SHOULD BE DEFERRED AND AMORTIZED IN THE REVENUE REQUIREMENT SHOULD BE REJECTED.

Q. Mr. Kollen claims that Big Rivers "simply removed the Smelter surcredit revenues in the test year, thereby increasing the revenue requirement, even though it too is nonrecurring" (Kollen Testimony, p. 68:15-16). How do you respond?

A. I disagree. The smelter surcredit revenues differ from the other items noted by Mr. Kollen. The surcredit revenues are not a nonrecurring, one-time event. They are recurring revenues that Big Rivers has received since the unwind transaction that are coming to an end. Since the unwind, they have been coupled with the smelter surcharges, which are also coming to an end. They have also already been included in the determination of Big Rivers' rates. The nonrecurring expenses which Big Rivers proposes to amortize in the revenue requirement are one-time events that do not recur and which have not yet been recognized in rates.

Also, as explained in responses to PSC 2-24 and PSC 3-4, for the smelter surcharge, the proposed rate treatment is aimed at addressing regulatory lag and the matching principle. Recall that the surcredit simply provides to the Rurals and Large Industrials funds that were collected from the smelters. In the forecasted test period in this case, the smelter service contracts are no longer effective, and the smelters no longer pay the surcharge. After the regulatory lag, the pass-through of those funds to the Rurals and Large Industrials will also cease. Thus, because both will be eliminated as a result of the smelter contract terminations, and in order to satisfy the matching principle, neither the surcharge amounts nor the surcredit amounts should remain in the test period revenue requirement. For accounting purposes, all of the funds collected from the smelters will be returned to the Rurals and Large Industrials through the surcredit mechanism, but for ratemaking purposes, the surcredit amounts should be removed from the revenue requirement. The amortization proposed by Mr. Kollen is therefore inappropriate.

VIII. THE INTERVENOR CLAIMS REGARDING RATE DISCOUNTS FOR NEW CUSTOMERS ARE MISPLACED.

Q. Mr. Henry expresses the view that it is unreasonable for Big Rivers to provide discounts to new customers while increasing the rates of its existing customers. (Henry Testimony, p. 11:10-15) How do you respond?

A. While I understand the general sentiment expressed by Mr. Henry, the merits of a discounted rate offering are not at issue in this proceeding. That being said, I think it is reasonable for Big Rivers to contemplate discounted rates under the present circumstances. Such an offering could attract new load, and as long as the rates produce a contribution towards Big Rivers' fixed costs, as they should, current ratepayers will benefit. These discounted rates, whether through an economic development tariff or incorporated into a special contract, would be subject to Commission review and approval in a future proceeding; they are not before the Commission in this matter.

Q. Mr. Kollen claims that Big Rivers refused to serve the Century Sebree smelter at a price that would have provided some contribution to fixed costs, but is now willing to sell to other potential and unknown loads for the same price that it previously rejected. (Kollen Testimony, p. 34:3-9) How do you respond?

A. This comment is not relevant, and it is misplaced. Big Rivers' negotiations with the smelter(s) are not at issue in this proceeding, nor are any proposed special contracts incorporating an economic development rate.

IX. THE ATTORNEY GENERAL'S RECOMMENDATIONS SHOULD BE REJECTED

Q. The Attorney General recommends that the Commission make no changes to Big Rivers' rates, under either one of two options. How do you respond?

A. The recommendation is flawed. The assertion that Big Rivers will experience no revenue deficiency after the Century Sebree service contract termination is not credible.

Under Option 1, Mr. Brevitz is sponsoring the only adjustment (Adjustment OAG-1-DB), which increases operating income and net margins by an amount of $70.4 million related to the net revenue loss from Century Sebree. This is flawed because, as discussed further in the Rebuttal Testimony of Billie J. Richert, the revenue requirement is based on Big Rivers' total test period revenues and expenses – analyzed from the bottom up -- not on an estimate of the revenue impact of the smelter contract termination, from the top down. This is also flawed for additional reasons described in the Rebuttal Testimony of Billie J. Richert.

Under Option 2, Mr. Brevitz sponsors one adjustment (Adjustment OAG-2-DB), which is related to removing certain expenses of idling both the Wilson and Coleman plants. This is addressed in the Rebuttal Testimonies of Ms. Billie J. Richert and Mr. Robert W. Berry. Mr. Holloway sponsors one adjustment (Adjustment OAG-3-LH), related to transmission revenues, which is addressed in Mr. Berry's rebuttal testimony. Mr. Ostrander sponsors the remaining adjustments. These include OAG-4-

BCO and OAG-5-BCO, which are addressed in the Rebuttal Testimony of Mr. Thomas W. Davis, and OAG-6-BCO, which is address in the Rebuttal Testimony of Ms. DeAnna M. Speed. Finally, Mr. Ostrander sponsors Adjustment OAG-7-BCO, regarding ACES fees, which is consistent with Big Rivers' response to PSC 3-10. I address this in the next section of my testimony.

Thus, for the reasons outlined herein and in the rebuttal testimony of other Big Rivers witnesses, the Commission should reject the Attorney General's recommendation to leave Big Rivers' rates unchanged. All of the proposed adjustments except for OAG-7-BCO should be denied.

X. UPDATES TO COST OF SERVICE STUDY AND PROPOSED RATES

Q. Did Big Rivers provide updates to its exhibits in this case to reflect the findings in the Century Order?

A. Yes. Big Rivers provided an update to its exhibits in response to PSC 3-1 to address the effects of the Century Order. That update included the following changes.

1. Update "Present Rates" to match those ordered by the Commission. *See* Century Order Appendix.
2. Remove depreciation expenses associated with Coleman Station ($6,466,191). *See* Century Order, page 33. The value used differs slightly from that in the Century Order because the test period in this case differs from that in Case No. 2012-00535.
3. Remove labor expenses associated with 2014 pay increases for non-bargaining employees ($450,000). *See* Century Order, page 23. The value here differs

slightly from that in the Century Order because the test period in this case differs from that in Case No. 2012-00535.

Q. Does Big Rivers have additional revisions to incorporate at this time?

A. Yes. There are additional items not yet accounted for in the PSC 3-1 exhibits that are reflected in the record in this case. The first item stems from the Century Order, and the remaining items are identified in the Rebuttal Testimony of Mr. Robert W. Berry.

1. Add the difference between the Case No. 2012-00535 rate case costs approved by the Commission in the Century Order ($1,634,971 or $544,990 per year for three years) and the amount Big Rivers originally included in the test period in this filing ($1,585,977 or $528,659 per year for three years). This adds $16,331 to the test period expenses than were included in the rate case amortization in the Big Rivers Financial Model as originally filed. Note this only relates to the on-going amortization of the Case No. 2012-00535 rate case costs; no changes are required for the proposed amortization of the rate case costs related to the instant proceeding.

2. Remove the portion of ACES expenses to be paid by Century ($783,724), consistent with Big Rivers' response to PSC 3-10.

3. Remove the portion of NERC dues, National Renewables Cooperative ("NRCO") dues, Commission Assessment, SERC dues, and property taxes and insurance that will either (a) be paid by Century as long as the Century Hawesville load remains on the system or (b) be avoided by Big Rivers after that point in time, consistent with Exhibit Berry Rebuttal-6.

These items are all included in the revised Big Rivers Financial Model that is input to the cost of service study. These items combine for a total reduction in the revenue requirement of $1,221,475.

Q. Is Big Rivers removing similar items that relate to the Century Sebree smelter?

A. No, not at this time. The Commission has not yet approved the agreements proposed in Case No. 2013-00413. As such, the amounts do not yet qualify as a correction due to a "regulatory enactment" pursuant to 807 KAR 5:001(16)(11)(d). However, if the Commission does approve the agreements filed in Case No. 2013-00413, it will be appropriate to remove an additional $1,103,149, as noted in Exhibit Berry Rebuttal-6, from the revenue requirement in this case.

Q. Is Big Rivers providing updated exhibits to reflect these additional corrections?

A. Yes. The following exhibits are provided as a result of the changes I just described. (The naming convention includes the ".2" suffix to distinguish the revised exhibit from the earlier versions of these exhibits filed in this case.)

1) Exhibit Speed-2.2 - Summary of Proposed Changes to Tariff Rates
2) Exhibit Warren-2.2- Big Rivers Financial Model
3) Exhibit Warren-3.2 - Financial Results With and Without Rate Increase
4) Exhibit Wolfram-2.2 - Revenue Requirements Analysis
5) Exhibit Wolfram-3.2 - Cost of Service Study: Functional Assignment and Classification
6) Exhibit Wolfram-4.2 - Cost of Service Study: Allocation to Rate Classes
7) Exhibit Wolfram-5.2 - Billing Determinants: Present & Proposed Rates
8) Exhibit, Wolfram-6.2 - Summary of Proposed Increase

9) Exhibit Wolfram-7.2 - Estimate of Retail Rate Increase

The revised exhibits Warren-2.2, Warren-3.2, Wolfram-3.2, and Wolfram-4.2 are provided under a petition for confidential treatment. Exhibits Wolfram-3.2 through Wolfram-7.2 are provided in electronic format, in a single "COSS" file, on the CONFIDENTIAL electronic media accompanying this testimony, and are provided with a motion for deviation.

Q. Do the additional corrections result in a revision to the data provided in response to PSC 3-7 regarding Environmental Surcharge ("ES") revenues?

A. Yes. The table provided in response to PSC 3-7 is reproduced here to include the corrected amounts. Recall that the total ECP costs are "jurisdictionalized" or split between the native load sales and off-system sales, on the basis of total adjusted revenues. The increase to base rates affects the split, as shown in the table below. This data is drawn directly from the Big Rivers Financial Model.

Table 1. Total Test Period ES Revenues ($)

Rate Class (1)	Without Base Rate Adjustment (2)	With Base Rate Adjustment (3)	Variance (4)
Rurals	13,241,248	14,086,285	845,037
Large Industrials	4,468,442	4,603,463	135,021
Smelter	0	0	0
Total Jurisdictional	17,709,690	18,689,748	980,058
Off System Sales	4,853,058	3,873,000	(980,058)
Total	**22,562,748**	**22,562,748**	**0**

The values in Columns (2) and (3) are based on the revised exhibits provided and incorporate the corrections noted herein.

Q. **What is the total effect of these revisions on the revenue deficiency as originally filed in this case?**

A. The revisions increase the as-filed revenue deficiency by $830,163, from $70.4 million to $71.2 million.

Q. **What is the total effect of these revisions on the proposed rate adjustment in this case?**

A. First, it is important to recall that Big Rivers is proposing to modify the Member Rate Stability Mechanism ("MRSM") and Rural Economic Reserve ("RER") mechanism so that the Economic Reserve and Rural Economic Reserve funds offset the base rate increases proposed in this filing. This revision does not change that proposal. With this revision, the amount of the offsets would also be revised, such that the proposed adjustment remains fully offset by the reserve funds.

Putting that fact aside for a moment, the revisions alter the originally-proposed rate adjustment as indicated in the table below. The table also includes the values as first updated in response to PSC 3-1 on November 12, 2013.

Table 2. Revisions to Proposed Rates

Item (1)		Application Jun. 28, 2013 (2)	PSC 3-1 Nov. 12, 2013 (3)	Rebuttal Dec. 17, 2013 (4)	Variance (5 = 4 - 2)
Revenue Deficiency		$70,396,884	$72,433,271	$71,227,047	$830,163
Rates					
RDS	Demand	24.742	23.694	23.511	(1.231)
	Energy	0.035000	0.035000	0.035000	0
LIC	Demand	17.979	17.147	17.000	(0.979)
	Energy	0.035000	0.035000	0.035000	0
Incremental Revenues					
Rurals		$54,864,141	$56,147,011	$55,195,990	$331,849
		30.5%	32.5%	31.9%	1.4%
Large Industrial		$15,532,735	$16,285,586	$16,027,040	$494,305
		25.8%	28.1%	27.6%	1.8%
Total		$70,396,876	$72,432,598	$71,223,030	$826,154
		29.4%	31.4%	30.8%	1.4%

XI. CONCLUSION

Q. Do you have any closing comments?

A. Yes. This case is about rates that are fair, just, and reasonable based on the base period and the forecasted test period, not on the long term planning horizon. In the Century Order, the Commission found that it was reasonable to allow Big Rivers time to pursue its Mitigation Plan. Approving the rates Big Rivers seeks in this proceeding will provide the regulatory support necessary for Big Rivers to effectively do just that.

The Opposing Intervenors' positions, however, will prevent Big Rivers from having any opportunity to pursue that mitigation. The IRP process and the ECP / CPCN filing requirements ensure that Big Rivers will review and update its load forecast and resource plans on an on-going basis as it implements and pursues its Mitigation Plan. The planning issues raised by the Opposing Intervenors should be addressed in those proceedings. Those issues do not affect the test period or Big Rivers' proposed rate adjustment in this matter, and the Commission does not need to resolve those issues in this rate filing.

Q. What is your recommendation to the Commission in this case?

A. For the reasons outlined herein and in the rebuttal testimony of other Big Rivers witnesses, the Commission should reject the Attorney General's recommendation to leave Big Rivers' rates unchanged. The Commission should also reject all of the Attorney General's proposed adjustments except for OAG-7-BCO regarding ACES fees. The Commission should not rely upon the Holloway Study or the Hayet Analysis. The Commission should reject the KIUC's recommendations and the KIUC

Rate Plan. The Commission should reject the recommendations of the Sierra Club. The Commission should accept the revenue deficiency calculation provided in Exhibit Wolfram 2.2. The rates proposed in Exhibits Speed 2.2 and Wolfram 5.2 are fair, just, and reasonable, and the Commission should approve them.

Q. Does this conclude your testimony?

A. Yes.

Big Rivers Electric Corporation
Case No. 2013-00199
Summary of Proposed Changes to Tariff Rates

Standard Rate Schedule	Rate	Sheet Number(s)	Current Rate [1]	Proposed Rate [2]	Incr. (Decr.) [2]
RDS	Demand	1	$12.914 per kW	$23.511 per kW	$10.597 per kW
	Energy	1	$0.035000 per kWh	$0.035000 per kWh	$0.000000 per kWh
LIC	Demand	26	$10.715 per kW	$17.000 per kW	$6.285 per kW
	Energy	26	$0.030000 per kWh	$0.035000 per kWh	$0.005000 per kWh
QFS	*On-Peak Maintenance Service*				
	Demand per Week	44	$3.010 per kW	$5.486 per kW	$2.476 per kW
	Energy	44	$0.035000 per kWh	$0.035000 per kWh	$0.000000 per kWh
	Off-Peak Maintenance Service				
	Demand per Week	44	3.010 per kW	$5.486 per kW	$2.476 per kW

[1] Per the Commission Order dated October 29, 2013 in Case No. 2012-00535.
[2] Please see the Rebuttal Testimony of Mr. John Wolfram for analysis supporting these proposed rates.

	Big Rivers Financial Model	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
1	I. Sales													
2														
3	Energy (TWH)													
4	Rural	0.23	0.20	0.18	0.15	0.16	0.20	0.23	0.23	0.17	0.16	0.16	0.23	2.31
5	Large Industrial	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.08	0.08	0.08	0.08	0.98
6	Century	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
7	Alcan	[redacted]												
8	Market													
9	Total Energy Sales	0.73	0.42	0.39	0.41	0.41	0.41	0.44	0.43	0.41	0.47	0.44	0.46	5.41
10														
11	Demand (MW)													
12	Rural	495.40	437.90	386.40	325.20	379.40	470.20	509.20	492.50	446.20	328.60	398.10	459.70	5,128.80
13	Large Industrial	139.90	140.90	139.50	144.50	144.30	146.00	150.30	151.70	146.80	146.00	145.80	147.70	1,743.40
14														
15	II. Rates, Accrual Based ($ / MWH)													
16														
17	Rural													
18	Load Factor (%)	62.95%	67.06%	63.09%	63.87%	57.45%	58.14%	60.82%	61.47%	54.02%	64.62%	61.83%	66.32%	61.71%
19	Demand ($/ KW-mo.)	12.91	23.51	23.51	23.51	23.51	23.51	23.51	23.51	23.51	23.51	23.51	23.51	22.45
20	Energy ($/ MWH)	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
21	Base Rate ($/ MWH)	62.57	87.17	85.09	86.12	90.00	91.16	86.95	86.41	95.44	83.90	87.81	82.64	84.91
22														
23	Non-Smelter Non-FAC PPA	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	0.05	0.05	0.05	0.05	(0.43)
24	FAC	4.87	5.24	5.50	5.63	5.89	6.46	5.98	6.38	6.45	5.83	5.95	6.00	5.84
25	Environmental Surcharge	3.66	5.22	5.07	5.69	5.72	5.62	5.07	6.27	8.15	7.50	6.86	6.04	5.82
26	Surcredit	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)
27	Total	8.39	10.31	10.42	11.17	11.46	11.93	10.90	12.50	14.48	13.19	12.66	11.90	11.52
28	Economic Reserve	(11.60)	(37.43)	(37.54)	(38.29)	(38.59)	(39.06)	(27.87)	0.00	0.00	0.00	0.00	0.00	(18.60)
29	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	(8.16)	(37.62)	(39.58)	(38.31)	(37.78)	(37.02)	(16.61)
30	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	Effective Rate ($/ MWH)	58.71	59.39	57.31	58.35	62.23	63.39	61.18	60.63	70.37	58.83	62.74	57.57	60.80
32														
33	Large Industrial													
34	Load Factor (%)	75.34%	80.85%	78.17%	77.86%	78.62%	76.75%	78.07%	79.04%	76.17%	77.56%	75.68%	73.75%	77.14%
35	Demand ($/ KW-mo.)	10.72	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	18.50
36	Energy ($/ MWH)	30.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	34.60
37	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	0.00
38	Base Rate ($/ MWH)	49.12	66.29	64.23	65.33	64.82	65.77	64.27	63.91	66.00	64.46	66.20	65.98	63.89
39														
40	Non-Smelter Non-FAC PPA	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	0.05	0.05	0.05	0.05	(0.42)
41	FAC	4.87	5.24	5.50	5.63	5.89	6.46	5.98	6.38	6.45	5.83	5.95	8.00	5.86
42	Environmental Surcharge	2.93	4.04	3.90	4.40	4.22	4.16	3.83	4.75	5.80	5.88	5.28	4.91	4.51
43	Surcredit	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)
44	Total	7.66	9.13	9.25	9.88	9.96	10.47	9.66	10.98	12.10	11.56	11.08	10.76	10.22
45	Economic Reserve	(10.87)	(28.65)	(28.77)	(29.40)	(29.48)	(29.98)	(27.87)	0.00	0.00	0.00	0.00	0.00	(15.32)
46	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	Effective Rate ($/ MWH)	45.25	46.12	44.06	45.16	44.66	45.60	45.41	74.23	78.15	76.07	77.33	78.80	58.38
48														

#	Big Rivers Financial Model	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
49	**Non-Smelter Member Blend**													
50	Base Rate ($/ MWH)	59.17	81.33	78.64	78.82	81.53	83.78	80.72	80.02	86.11	77.14	81.12	78.26	78.65
51														
52	Non-Smelter Non-FAC PPA	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	0.05	0.05	0.05	0.05	(0.43)
53	FAC	4.87	5.24	5.50	5.63	5.89	6.46	5.98	6.38	6.45	5.83	5.95	6.00	5.85
54	Environmental Surcharge	3.48	4.89	4.71	5.24	5.21	5.20	4.73	5.84	7.41	6.94	8.37	5.75	5.43
55	Surcredit	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)
56	Total	8.20	9.98	10.06	10.72	10.96	11.51	10.56	12.07	13.71	12.62	12.17	11.60	11.13
57	Economic Reserve	(11.41)	(34.98)	(34.83)	(35.17)	(35.52)	(36.42)	(27.87)	0.00	0.00	0.00	0.00	0.00	(17.62)
58	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	(5.92)	(26.95)	(27.04)	(24.98)	(26.09)	(27.28)	(11.65)
59	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	Effective Rate ($/ MWH)	55.31	55.68	53.22	53.72	56.31	58.22	56.85	64.49	72.84	64.83	67.26	62.63	60.08
61														
62	**Smelters**													
63	Base Rate	45.23	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	45.23
64	TIER Adjustment	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95
65	Total	48.18	61.96	61.96	61.96	61.96	61.96	61.96	61.96	61.96	61.96	61.96	61.96	48.18
66	Non-FAC PPA	(0.39)	0.14	0.18	0.33	0.26	0.12	(0.00)	0.01	0.22	0.27	0.20	0.03	(0.39)
67	FAC	4.87	5.24	5.50	5.63	5.89	6.46	5.98	6.38	6.45	5.83	5.95	6.00	4.87
68	Environmental Surcharge	2.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.69
69	Surcharge	1.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.88
70	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
71	Effective Rate ($/ MWH)	57.23	67.34	67.64	67.92	68.11	68.55	67.94	68.34	68.63	68.06	68.12	67.99	57.23
72														
73	Market	[redacted]												
74														
75	**III. Statement of Operations (Millions of $)**													
76														
77	Electric Energy Revenues	[redacted]												
78	Income From Leased Property Net													
79	Other Operating Revenue and Income	0.31	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	3.65
80	TOTAL OPER. REVENUES & PAT. CAPITAL	[redacted]												
81														
82	Operating Expense-Production-Excluding Fuel	[redacted]												
83	Operating Expense-Production-Fuel													
84	Operating Expense-Other Power Supply													
85	Operating Expense-Transmission													
86	Operating Expense-RTO/ISO													
87	Operating Expense-Distribution													
88	Operating Expense-Customer Accounts													
89	Operating Expense-Customer Service and Information													
90	Operating Expense-Sales													
91	Operating Expense-Administrative and General													
92	TOTAL OPERATION EXPENSE													
93														
94	Maintenance Expense-Production	[redacted]												
95	Maintenance Expense-Transmission													
96	Maintenance Expense-Distribution													
97	Maintenance Expense-General Plant													
98	TOTAL MAINTENANCE EXPENSE													

	Big Rivers Financial Model	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
99														
100	Depreciation and Amortization Expense	3.21	3.21	3.21	3.22	3.23	3.24	3.25	3.25	3.32	3.32	3.33	3.33	39.11
101	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	0.00
102	Interest on Long-Term Debt	3.67	3.37	3.66	3.60	3.70	3.59	3.73	3.73	3.62	3.72	3.62	3.71	43.72
103	Interest Charged to Construction - Credit	(0.17)	(0.19)	(0.22)	(0.27)	(0.31)	(0.35)	(0.36)	(0.01)	(0.01)	(0.02)	(0.01)	(0.01)	(1.93)
104	Other Interest Expense	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
105	Asset Retirement Obligation													
106	Other Deductions	0.05	0.05	0.05	0.05	0.05	0.07	0.05	0.05	0.05	0.06	0.06	0.08	0.66
107														
108	TOTAL COST OF ELECTRIC SERVICE	[redacted]												
109														
110	OPERATING MARGINS	[redacted]												
111														
112	Interest Income	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.83
113	Allowance For Funds Used During Construction													
114	Income (Loss) From Equity Investments													
115	Other Non-Operating Income (Net)													
116	Generation and Transmission Capital Credits													
117	Other Capital Credits and Patronage Dividends	0.00	0.00	1.69	0.03	0.00	0.00	0.00	0.01	1.02	0.00	0.00	0.00	2.74
118	Extraordinary Items													
119	NET PATRONAGE CAPITAL OR MARGIN	[redacted]												
120														
121														
122	IV. Balance Sheet (Millions of $)													
123	Total Utility Plant in Service	2,046.07	2,046.54	2,049.58	2,054.35	2,060.31	2,061.57	2,062.67	2,124.81	2,126.49	2,128.53	2,128.70	2,128.81	2,128.81
124	Construction Work in Progress	76.97	82.16	87.43	92.73	98.06	100.81	101.10	40.00	40.00	40.00	40.00	40.00	40.00
125	Total Utility Plant	2,123.03	2,128.69	2,137.01	2,147.09	2,158.37	2,162.38	2,163.77	2,164.81	2,166.49	2,168.53	2,168.70	2,168.81	2,168.81
126	Accum. Provision for Depreciation and Amort.	999.00	1,002.34	1,004.87	1,006.87	1,008.51	1,011.67	1,014.88	1,018.10	1,021.18	1,024.15	1,027.72	1,031.31	1,031.31
127	NET UTILITY PLANT	1,124.03	1,126.35	1,132.14	1,140.22	1,149.86	1,150.71	1,148.89	1,146.71	1,145.31	1,144.37	1,140.98	1,137.50	1,137.50
128														
129	Non-Utility Property (Net)													
130	Invest. in Assoc. Org - Patronage Capital	4.15	4.15	3.80	3.81	3.81	3.81	3.81	3.81	4.32	4.32	4.32	4.32	4.32
131	Invest. in Assoc. - Other - General Funds	42.87	42.54	42.54	42.54	42.20	42.20	42.20	41.86	41.86	41.86	41.51	41.51	41.51
132	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	0.02
133	Special Funds	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13
134	Special Funds (Transition 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
135	Special Funds (Economic Reserve)	54.36	44.81	35.70	27.61	18.94	8.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00
136	Special Funds (Rural Economic Reserve)	65.68	65.78	65.88	65.98	66.08	66.16	64.40	56.03	49.25	43.27	36.64	28.30	28.30
137	TOTAL OTHER PROP. AND INVESTMENTS	168.21	158.42	149.06	141.08	132.18	122.19	111.56	102.85	96.57	90.60	83.62	75.28	75.28
138														
139	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	0.01
140	Cash - Construction Funds - Trustee													
141	Special Deposits	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
142	Temporary Investments	77.78	80.42	91.46	82.20	65.13	73.84	76.62	78.30	82.99	87.68	86.34	83.44	83.44
143	Accounts Receivable - Sales of Energy (Net)	41.32	29.61	27.13	26.05	27.56	30.01	32.93	32.50	30.21	28.55	29.53	32.50	32.50
144	Accounts Receivable - Other (Net)	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.38	0.36
145	Fuel Stock	18.55	18.87	19.12	19.25	19.27	19.34	19.38	19.41	19.43	19.45	19.47	19.48	19.48
146	Materials and Supplies - Other	26.23	26.29	26.34	26.39	26.45	26.50	26.55	26.61	26.66	26.71	26.77	26.82	26.82
147	Prepayments	3.58	3.26	2.95	2.63	2.31	2.00	1.68	1.37	1.05	0.74	0.42	4.19	4.19
148	Other Current and Accrued Assets	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
149	TOTAL CURRENT AND ACCRUED ASSETS	169.13	160.12	168.68	158.20	142.39	153.36	158.84	159.86	162.01	164.81	164.20	168.11	168.11

Big Rivers Financial Model	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
Unamortized Debt Discount & Extraor. Prop. Losses	3.95	3.92	3.89	3.85	3.82	3.78	4.24	4.20	4.16	4.11	4.07	4.03	4.03
Regulatory Assets	11.16	10.91	10.67	10.42	10.18	9.94	9.86	9.82	9.62	9.43	9.22	8.97	8.97
Other Deferred Debits	3.85	3.84	3.83	3.82	3.81	3.80	4.04	4.03	4.02	4.02	4.01	4.00	4.00
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	0.00
TOTAL ASSETS AND OTHER DEBITS	1,480.33	1,463.56	1,468.26	1,457.60	1,442.24	1,443.78	1,437.44	1,427.47	1,421.70	1,417.34	1,406.10	1,397.89	1,397.89
TOTAL MARGINS & EQUITY	414.62	414.61	412.27	407.13	404.67	405.97	410.09	413.05	414.85	412.27	412.98	415.66	415.66
Long-Term Debt - RUS	218.14	218.14	220.11	220.12	220.12	222.15	222.16	222.16	224.24	224.25	224.25	226.36	226.36
Long-Term Debt - Other	665.76	662.70	675.86	675.86	672.78	683.43	683.43	680.33	678.37	678.37	675.25	673.27	673.27
TOTAL LONG-TERM DEBT	883.90	880.84	895.97	895.98	892.90	905.58	905.59	902.49	902.61	902.62	899.50	899.63	899.63
Notes 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	0.00
Accounts Payable	22.78	18.68	20.36	20.18	18.78	17.35	17.08	17.49	17.50	18.74	16.83	15.52	15.52
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	0.00
Taxes Accrued	1.26	1.61	1.96	2.32	2.67	3.02	3.37	1.44	1.79	2.14	1.85	1.65	1.65
Interest Accrued	5.52	5.19	4.24	6.70	6.66	5.48	5.54	5.55	4.23	6.77	6.74	5.50	5.50
Other Current and Accrued Liabilities	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30
TOTAL CURRENT AND ACCRUED LIAB.	36.86	32.78	33.87	36.50	35.41	33.14	33.29	31.78	30.82	34.95	32.72	29.97	29.97
Deferred Credits	1.14	0.92	0.70	0.48	0.26	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Credits (Economic Reserve)	54.36	44.81	35.70	27.61	18.94	8.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Credits (Rural Economic Reserve)	65.68	65.78	65.88	65.98	66.08	66.18	64.40	56.03	49.25	43.27	36.64	28.30	28.30
Accumulated Operating Provisions	23.77	23.82	23.87	23.92	23.97	24.02	24.07	24.12	24.17	24.22	24.27	24.32	24.32
Obligation under Capital Leases - Noncurrent													
TOTAL LIABILITIES AND OTHER CREDITS	1,480.33	1,463.56	1,468.26	1,457.60	1,442.24	1,443.78	1,437.44	1,427.47	1,421.70	1,417.34	1,406.10	1,397.89	1,397.89
V. Cash Flow Statement (Millions of $)													
Operating Receipts													
Rural	13.62	11.72	10.39	8.73	10.09	12.48	14.10	13.66	12.21	9.29	11.12	13.06	140.47
Large Industrial	3.55	3.53	3.58	3.66	3.67	3.68	3.96	6.62	6.29	6.41	6.14	6.22	57.32
Smelters	14.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.86
Offsystem	[redacted]												
Lease Income													
Other Operating Revenues	0.31	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	3.65
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
Other	0.00	0.00	1.69	0.03	0.00	0.00	0.00	0.01	1.02	0.00	0.00	0.00	2.74
Interest Earnings	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.83
Total Receipts	[redacted]												
Operating Disbursements													
PPA													
Fuel Costs	[redacted]												
Fuel Costs (Labor & Exp)													
Power Supply (P Power, APM, Cogen, & TVA Tran)													
Production O&M													
Transmission O&M													
A&G	2.01	2.24	3.04	2.31	2.67	2.93	2.21	2.37	2.29	2.37	2.06	2.57	29.07
Working Capital	(3.11)	(8.60)	(5.18)	(1.55)	1.90	3.23	2.52	0.45	(2.46)	(3.56)	2.52	8.28	(5.59)
Other	3.57	(0.24)	(0.24)	(0.24)	(0.24)	(0.22)	(0.24)	(0.24)	(0.24)	(0.24)	(0.24)	(0.24)	0.96
Total Disbursements	[redacted]												
Operating Receipts less Disbursements	[redacted]												

	Big Rivers Financial Model	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
210	Capital Expenditures													
211	Generation	[redacted]												
212	Transmission													
213	A&G	0.00	0.21	0.10	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.55
214	Other / IT	0.00	0.05	0.10	0.31	0.11	0.26	0.22	0.32	0.23	0.04	0.01	0.00	1.64
215	Total Capital Expenditures	[redacted]												
216														
217	Income Taxes from Operations	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
218														
219	Net Pre-Finance Cash Flow	(1.38)	(0.20)	(8.62)	(16.24)	(18.93)	(9.29)	(3.54)	0.02	2.63	(0.19)	(1.25)	(6.46)	(63.45)
220														
221	Financing													
222	Principal	0.00	3.05	(13.16)	0.00	3.08	(10.65)	0.00	3.10	1.95	0.00	3.13	1.98	(7.51)
223	Interest	3.68	3.70	2.64	1.13	3.74	2.76	3.65	3.71	2.86	1.17	3.65	2.84	35.53
224	Debt Issuance Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00	0.00	0.00	0.02	0.52
225	Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.00	0.00	0.00	0.00	0.00	0.25
226	Aggregate Debt Service (incl. Line of Credit)	3.68	6.75	(10.52)	1.13	6.82	(7.89)	4.40	6.82	4.81	1.17	6.78	4.84	28.78
227														
228	Post-Finance Cash Flow	(5.05)	(6.95)	1.90	(17.37)	(25.75)	(1.40)	(7.95)	(6.80)	(2.18)	(1.36)	(8.04)	(11.30)	(92.24)
229														
230	Unwind Transaction													
231	Cash Proceeds													
232	Debt Reduction													
233	Misc. Transaction													
234	Net Before Member Reserves													
235	Station Two O&M Fund													
236	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	1.88	8.47	6.87	6.05	6.70	8.40	38.37
237	Economic Reserve	3.54	9.58	9.14	8.11	8.68	10.11	8.85	0.00	0.00	0.00	0.00	0.00	58.02
238	Net Before Transition Reserve	3.54	9.58	9.14	8.11	8.68	10.11	10.73	8.47	8.87	6.05	6.70	8.40	96.38
239														
240	Ending Cash Balances (Incl. Transition Reserve)	77.79	80.42	91.47	82.20	65.14	73.84	76.63	78.30	82.99	87.69	86.35	83.45	83.45
241	Ending Cash Balances excl. Transition Reserve)	77.79	80.42	91.47	82.20	65.14	73.84	76.63	78.30	82.99	87.69	86.35	83.45	83.45
242	Change in Working Capital													
243	Other Property	0.00	(0.33)	(0.35)	0.01	(0.34)	0.00	0.00	(0.34)	0.51	0.00	(0.35)	0.00	(1.18)
244	Accounts Receivable	(0.29)	(11.71)	(2.48)	(1.09)	1.51	2.46	2.91	(0.42)	(2.30)	(1.66)	0.98	2.97	(9.11)
245	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
246	Prepayments	(0.45)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	3.77	0.16
247	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
248	Accounts Payable	(2.02)	4.10	(1.68)	0.19	1.40	1.43	0.27	(0.41)	(0.01)	(1.24)	1.91	1.30	5.24
249	Taxes Accrued	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	1.93	(0.35)	(0.35)	0.29	0.21	(0.74)
250	Other Accruals	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.60)
251	Total	(3.11)	(8.60)	(5.18)	(1.55)	1.90	3.23	2.52	0.45	(2.46)	(3.56)	2.52	8.26	(5.59)
252														
253														

	Big Rivers Financial Model	2014 January	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2014 Total
254	VI. Cash Flow Statement - Indirect (Millions of $)													
255														
256	**Cash Flows From Operating Activities:**													
257	Net Margin	[redacted]												
258	Adjustments to reconcile net margin to net cash													
259	provided by operating activities:													
260	Depreciation and amortization	3.48	3.49	3.49	3.49	3.51	3.53	3.54	3.54	3.61	3.61	3.62	3.62	42.53
261	Interest compounded - RUS Series A Note	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.05
262	Interest compounded - RUS Series B Note	0.00	0.00	1.97	0.00	0.00	2.02	0.00	0.00	2.08	0.00	0.00	2.11	8.18
263	Noncash member rate mitigation revenue	(7.18)	(9.55)	(9.12)	(8.09)	(8.66)	(10.08)	(10.70)	(8.44)	(6.67)	(5.86)	(8.49)	(8.15)	(98.98)
264	Changes in certain assets and liabilities:													
265	Other property	0.00	0.33	0.35	(0.01)	0.34	0.00	0.00	0.34	(0.51)	0.00	0.35	0.00	1.18
266	Accounts receivable	0.29	11.71	2.48	1.09	(1.51)	(2.46)	(2.91)	0.42	2.30	1.66	(0.98)	(2.97)	9.11
267	Inventories	(1.13)	(0.37)	(0.31)	(0.18)	(0.07)	(0.12)	(0.10)	(0.08)	(0.08)	(0.08)	(0.07)	(0.06)	(2.65)
268	Prepayments	0.45	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	(3.77)	(0.16)
269	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
270	Accounts payable	2.02	(4.10)	1.68	(0.19)	(1.40)	(1.43)	(0.27)	0.41	0.01	1.24	(1.91)	(1.30)	(5.24)
271	Taxes accrued	0.35	0.35	0.35	0.35	0.35	0.35	0.35	(1.93)	0.35	0.35	(0.29)	(0.21)	0.74
272	Other accruals	(0.09)	(0.42)	(1.08)	2.28	(0.26)	(1.44)	(0.20)	0.11	(1.23)	2.63	0.06	(1.12)	(0.78)
273	Net cash provided by operating activities	[redacted]												
274														
275	**Cash Flows From Investing Activities:**													
276	Capital expenditures	[redacted]												
277	Net proceeds from restricted investments	3.54	9.58	9.14	8.11	8.68	10.11	10.73	8.47	6.87	6.05	6.70	8.40	96.38
278	Net cash provided by (used in) inv. activities	[redacted]												
279														
280	**Cash Flows From Financing Activities:**													
281	Net principal payments on debt obligations	0.00	(3.05)	13.16	0.00	(3.08)	10.65	0.00	(3.10)	(1.95)	0.00	(3.13)	(1.98)	7.51
282	Debt issuance cost	0.00	0.00	0.00	0.00	0.00	0.00	(0.50)	0.00	0.00	0.00	0.00	(0.02)	(0.52)
283	Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	0.00	(0.25)	0.00	0.00	0.00	0.00	0.00	(0.25)
284	Net cash provided by (used in) fin. activities	0.00	(3.05)	13.16	0.00	(3.08)	10.65	(0.75)	(3.10)	(1.95)	0.00	(3.13)	(2.00)	6.74
285														
286	Net increase (decrease) in cash	(1.51)	2.63	11.05	(9.26)	(17.07)	8.71	2.79	1.68	4.69	4.70	(1.34)	(2.90)	4.15
287														
288	**Cash and Cash Equivalents - Beg. of Period**													79.30
289	**Cash and Cash Equivalents - End of Period**													83.45

	Big Rivers Financial Model	2015 January	2015 February	2015 March	2015 April	2015 May	2015 June	2015 July	2015 August	2015 September	2015 October	2015 November	2015 December	2015 Total
1	<u>I. Sales</u>													
2														
3	**Energy (TWH)**													
4	Rural	0.23	0.19	0.18	0.15	0.16	0.19	0.23	0.22	0.17	0.15	0.17	0.22	2.28
5	Large Industrial	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.08	0.08	0.08	0.08	0.99
6	Century	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
7	Alcan	[redacted]												
8	Market													
9	Total Energy Sales	0.44	0.40	0.44	0.34	0.37	0.42	0.46	0.46	0.42	0.44	0.42	0.43	5.05
10														
11	**Demand (MW)**													
12	Rural	495.50	438.00	386.50	325.30	379.50	470.40	509.30	492.60	446.40	328.70	398.20	459.80	5,130.20
13	Large Industrial	142.90	143.90	142.50	144.50	144.30	146.00	150.30	151.70	146.80	148.00	145.80	147.70	1,752.40
14														
15	<u>II. Rates, Accrual Based ($ / MWH)</u>													
16														
17	**Rural**													
18	Load Factor (%)	62.39%	66.24%	62.16%	62.53%	56.30%	57.15%	59.98%	60.60%	52.98%	63.32%	60.82%	65.64%	60.78%
19	Demand ($/ KW-mo.)	23.51	23.51	23.51	23.51	23.51	23.51	23.51	23.51	23.51	23.51	23.51	23.51	23.51
20	Energy ($/ MWH)	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
21	Base Rate ($/ MWH)	85.65	87.82	85.84	87.22	91.13	92.13	87.68	87.15	96.63	84.91	88.69	83.14	87.99
22														
23	Non-Smelter Non-FAC PPA	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	1.82	1.82	1.82	1.82	0.61
24	FAC	5.94	6.45	7.21	7.32	7.26	6.73	5.31	5.62	7.08	7.64	7.22	7.10	6.65
25	Environmental Surcharge	6.45	6.75	7.34	7.60	7.87	7.41	6.54	7.02	8.85	8.47	7.72	6.76	7.31
26	Surcredit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	Total	12.39	13.20	14.55	14.91	15.13	14.15	11.85	12.64	15.93	16.11	14.94	13.86	13.96
28	Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	Rural Economic Reserve	(37.51)	(38.32)	(39.67)	(35.58)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(12.48)
30	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	Effective Rate ($/ MWH)	60.58	62.75	60.77	66.60	106.30	106.33	99.59	99.84	114.38	102.83	105.45	98.82	90.09
32														
33	**Large Industrial**													
34	Load Factor (%)	75.06%	80.46%	77.83%	77.86%	76.62%	76.75%	78.07%	79.04%	76.17%	77.56%	75.68%	73.75%	77.06%
35	Demand ($/ KW-mo.)	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
36	Energy ($/ MWH)	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
37	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	0.00
38	Base Rate ($/ MWH)	65.44	66.44	64.36	65.33	64.82	65.77	64.27	63.91	68.00	64.46	66.20	65.98	65.22
39														
40	Non-Smelter Non-FAC PPA	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	1.82	1.82	1.82	1.82	0.63
41	FAC	5.94	6.45	7.21	7.32	7.26	6.73	5.31	5.62	7.08	7.64	7.22	7.10	6.73
42	Environmental Surcharge	5.03	5.22	5.64	5.84	5.76	5.44	4.90	5.26	6.28	6.63	5.94	5.50	5.62
43	Surcredit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	Total	10.97	11.67	12.86	13.16	13.02	12.17	10.20	10.88	13.36	14.27	13.17	12.60	12.34
45	Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	Effective Rate ($/ MWH)	76.46	78.16	77.26	78.53	77.89	77.99	74.52	74.84	81.17	80.55	81.18	80.40	78.20
48														

	Big Rivers Financial Model	2015 January	2015 February	2015 March	2015 April	2015 May	2015 June	2015 July	2015 August	2015 September	2015 October	2015 November	2015 December	2015 Total
49	**Non-Smelter Member Blend**													
50	Base Rate ($/ MWH)	80.44	81.72	79.05	79.42	82.18	84.38	81.19	80.49	86.80	77.70	81.65	78.59	81.11
51														
52	Non-Smelter Non-FAC PPA	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	1.82	1.82	1.82	1.82	0.62
53	FAC	5.94	6.45	7.21	7.32	7.26	6.73	5.31	5.62	7.08	7.64	7.22	7.10	6.67
54	Environmental Surcharge	6.08	6.31	6.80	8.97	7.15	6.83	6.09	6.51	8.02	7.82	7.16	6.43	6.60
55	Surcredit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56	Total	12.02	12.77	14.02	14.29	14.41	13.56	11.40	12.13	15.10	15.46	14.39	13.52	13.47
57	Economic Reserve	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	Rural Economic Reserve	(27.65)	(27.39)	(27.14)	(22.91)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(8.71)
59	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	Effective Rate ($/ MWH)	64.67	67.15	65.98	70.85	96.61	97.99	92.63	92.67	103.72	94.98	97.85	93.93	86.49
61														
62	**Smelters**													
63	Base Rate	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	0.00
64	TIER 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	0.00
65	Total	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	0.00
66	Non-FAC PPA	2.47	2.92	3.09	3.68	3.42	2.90	2.42	2.45	3.25	3.46	3.20	2.51	0.00
67	FAC	5.94	6.45	7.21	7.32	7.26	6.73	5.31	5.62	7.08	7.64	7.22	7.10	0.00
68	Environmental Surcharge	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
69	Surcharge	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
70	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
71	Effective Rate ($/ MWH)	67.42	68.39	69.32	70.01	69.69	68.65	66.74	67.08	69.34	70.11	69.44	68.62	0.00
72														
73	Market	[redacted]												
74														
75	**III. Statement of Operations (Millions of $)**													
76														
77	Electric Energy Revenues	[redacted]												
78	Income From Leased Property Net													
79	Other Operating Revenue and Income	0.31	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	3.64
80	TOTAL OPER. REVENUES & PAT. CAPITAL	[redacted]												
81														
82	Operating Expense-Production-Excluding Fuel	[redacted]												
83	Operating Expense-Production-Fuel													
84	Operating Expense-Other Power Supply													
85	Operating Expense-Transmission													
86	Operating Expense-RTO/ISO													
87	Operating Expense-Distribution													
88	Operating Expense-Customer Accounts													
89	Operating Expense-Customer Service and Information													
90	Operating Expense-Sales													
91	Operating Expense-Administrative and General													
92	TOTAL OPERATION EXPENSE													
93														
94	Maintenance Expense-Production	[redacted]												
95	Maintenance Expense-Transmission													
96	Maintenance Expense-Distribution													
97	Maintenance Expense-General Plant													
98	TOTAL MAINTENANCE EXPENSE													

	Big Rivers Financial Model	2015 January	2015 February	2015 March	2015 April	2015 May	2015 June	2015 July	2015 August	2015 September	2015 October	2015 November	2015 December	2015 Total
99														
100	Depreciation and Amortization Expense	3.33	3.33	3.33	3.34	3.35	3.36	3.36	3.37	3.37	3.38	3.38	3.38	40.28
101	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	0.00
102	Interest on Long-Term Debt	3.72	3.41	3.71	3.61	3.71	3.60	3.70	3.70	3.59	3.70	3.60	3.69	43.74
103	Interest Charged to Construction - Credit	(0.00)	(0.00)	(0.01)	(0.05)	(0.07)	(0.08)	(0.08)	(0.00)	(0.01)	(0.01)	(0.01)	(0.01)	(0.33)
104	Other Interest Expense	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
105	Asset Retirement Obligation													
106	Other Deductions	0.06	0.05	0.06	0.06	0.06	0.08	0.05	0.05	0.05	0.06	0.06	0.08	0.72
107														
108	TOTAL COST OF ELECTRIC SERVICE	[redacted]												
109														
110	OPERATING MARGINS	[redacted]												
111														
112	Interest Income	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.78
113	Allowance For Funds Used During Construction													
114	Income (Loss) From Equity Investments													
115	Other Non-Operating Income (Net)													
116	Generation and Transmission Capital Credits													
117	Other Capital Credits and Patronage Dividends	0.00	0.00	1.63	0.00	0.00	0.00	0.00	0.00	0.99	0.00	0.00	0.00	2.62
118	Extraordinary Items													
119	NET PATRONAGE CAPITAL OR MARGIN	[redacted]												
120														
121														
122	IV. Balance Sheet (Millions of $)													
123	Total Utility Plant in Service	2,129.85	2,130.18	2,132.89	2,142.79	2,146.16	2,147.15	2,148.09	2,149.03	2,150.30	2,151.30	2,151.58	2,151.69	2,151.69
124	Construction Work in Progress	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00
125	Total Utility Plant	2,169.85	2,170.18	2,172.89	2,182.79	2,186.16	2,187.15	2,188.09	2,189.03	2,190.30	2,191.30	2,191.58	2,191.69	2,191.69
126	Accum. Provision for Depreciation and Amort.	1,034.60	1,038.12	1,040.89	1,041.41	1,044.02	1,047.39	1,050.78	1,054.15	1,057.42	1,060.79	1,064.39	1,068.04	1,068.04
127	NET UTILITY PLANT	1,135.25	1,132.07	1,131.99	1,141.38	1,142.14	1,139.76	1,137.31	1,134.88	1,132.88	1,130.52	1,127.20	1,123.65	1,123.65
128														
129	Non-Utility Property (Net)													
130	Invest. In Assoc. Org - Patronage Capital	4.32	4.32	3.23	3.23	3.23	3.23	3.23	3.23	3.72	3.72	3.72	3.72	3.72
131	Invest. In Assoc. - Other - Generel Funds	41.51	41.16	41.16	41.16	40.81	40.81	40.81	40.45	40.45	40.45	40.08	40.08	40.08
132	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	0.02
133	Special Funds	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13
134	Special Funds (Trensition 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
135	Special Funds (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
136	Special Funds (Rural Economic Reserve)	19.72	12.27	5.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
137	TOTAL OTHER PROP. AND INVESTMENTS	66.70	58.91	50.74	45.54	45.18	45.18	45.18	44.82	45.32	45.32	44.95	44.95	44.95
138														
139	Cash - Generel 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	0.01
140	Cash - Construction Funds - Trustee													
141	Special Deposits	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
142	Temporary Investments	89.33	94.19	97.62	89.12	78.97	78.33	81.39	83.44	89.04	95.25	93.53	89.84	89.84
143	Accounts Receivable - Sales of Energy (Net)	33.53	30.53	30.17	24.86	27.48	31.71	34.95	34.27	31.40	28.84	30.27	33.04	33.04
144	Accounts Receivable - Other (Net)	0.36	0.36	0.38	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
145	Fuel Stock	19.95	20.23	20.44	20.62	20.59	20.65	20.69	20.72	20.74	20.76	20.78	20.78	20.78
146	Materials and Supplies - Other	26.88	26.93	26.99	27.04	27.10	27.15	27.21	27.26	27.32	27.38	27.43	27.49	27.49
147	Prepayments	3.86	3.52	3.18	2.83	2.49	2.15	1.81	1.47	1.13	0.79	0.45	4.41	4.41
148	Other Current and Accrued Assets	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
149	TOTAL CURRENT AND ACCRUED ASSETS	175.22	177.09	180.08	166.16	158.30	161.67	167.73	168.83	171.30	174.69	174.13	177.23	177.23

Row	Big Rivers Financial Model	2015 January	2015 February	2015 March	2015 April	2015 May	2015 June	2015 July	2015 August	2015 September	2015 October	2015 November	2015 December	2015 Total
150														
151	Unamortized Debt Discount & Extraor. Prop. Losses	3.99	3.94	3.90	3.86	3.81	3.77	3.73	3.69	3.64	3.60	3.56	3.51	3.51
152	Regulatory Assets	9.48	10.01	10.56	11.15	11.71	12.25	12.75	13.25	13.37	13.54	13.67	13.66	13.66
153	Other Deferred Debits	3.99	3.98	3.98	3.97	3.96	3.95	4.19	4.18	4.18	4.17	4.16	4.15	4.15
154	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	0.00
155														
156	TOTAL ASSETS AND OTHER DEBITS	1,394.62	1,386.00	1,381.25	1,372.05	1,365.11	1,366.58	1,370.89	1,369.66	1,370.69	1,371.83	1,367.67	1,367.15	1,367.15
157														
158														
159	TOTAL MARGINS & EQUITY	419.64	422.19	420.71	414.46	412.93	413.92	418.44	421.95	424.12	421.57	422.00	424.37	424.37
160														
161	Long-Term Debt - RUS	226.37	226.37	228.46	228.47	228.47	230.62	230.63	230.63	232.83	232.84	232.84	235.07	235.07
162	Long-Term Debt - Other	673.27	670.12	668.12	668.12	664.94	662.92	662.92	659.71	657.67	657.67	654.44	652.37	652.37
163	TOTAL LONG-TERM DEBT	899.64	896.49	896.58	896.59	893.41	893.53	893.54	890.34	890.50	890.51	887.28	887.44	887.44
164														
165	Notes 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	0.00
166	Accounts Payable	17.15	16.33	20.76	20.11	17.39	18.63	17.95	18.28	17.95	18.69	17.54	16.03	16.03
167	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	0.00
168	Taxes Accrued	1.28	1.65	2.02	2.39	2.76	3.13	3.50	1.48	1.85	2.22	1.90	1.61	1.61
169	Interest Accrued	5.53	5.35	4.21	6.68	6.75	5.44	5.48	5.57	4.19	6.71	6.76	5.47	5.47
170	Other Current and Accrued Liabilities	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30
171														
172	TOTAL CURRENT AND ACCRUED LIAB.	31.28	30.63	34.29	36.47	34.19	34.50	34.23	32.63	31.29	34.92	33.50	30.40	30.40
173														
174	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	0.00
175	Deferred Credits (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
176	Deferred Credits (Rural Economic Reserve)	19.72	12.27	5.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
177	Accumulated Operating Provisions	24.37	24.42	24.47	24.53	24.58	24.63	24.68	24.73	24.78	24.83	24.89	24.94	24.94
178	Obligation under Capital Leases - Noncurrent													
179														
180	TOTAL LIABILITIES AND OTHER CREDITS	1,394.62	1,386.00	1,381.25	1,372.05	1,365.11	1,366.58	1,370.89	1,369.66	1,370.69	1,371.83	1,367.67	1,367.15	1,367.15
181														
182														
183	V. Cash Flow Statement (Millions of $)													
184	Operating Receipts													
185	Rural	13.93	12.23	10.86	9.75	16.90	20.58	22.63	22.17	19.48	15.92	18.39	22.19	205.04
186	Large Industrial	6.10	6.08	6.38	6.36	6.41	6.29	6.51	6.68	8.54	6.79	6.45	6.52	77.09
187	Smelters	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
188	Offsystem	[redacted]												
189	Lease Income													
190	Other Operating Revenues	0.31	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	3.64
191	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
192	Other	0.00	0.00	1.63	0.00	0.00	0.00	0.00	0.00	0.99	0.00	0.00	0.00	2.62
193	Interest Earnings	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.78
194	Total Receipts	[redacted]												
195														
196	Operating Disbursements													
197	PPA													
198	Fuel Costs	[redacted]												
199	Fuel Costs (Labor & Exp)													
200	Power Supply (P Power, APM, Cogen, & TVA Tran)													
201	Production O&M													
202	Transmission O&M													
203	A&G	2.31	2.25	3.05	2.28	2.73	3.22	2.26	2.41	2.35	2.39	2.08	2.62	29.96
204	Working Capital	(0.56)	(3.23)	(6.59)	(5.36)	4.27	2.28	3.22	0.31	(2.75)	(4.00)	2.19	8.54	(1.69)
205	Other	(0.23)	(0.24)	(0.24)	(0.24)	(0.24)	(0.22)	(0.24)	(0.24)	(0.24)	(0.22)	(0.22)	(0.22)	(2.78)
206	Total Disbursements	[redacted]												
207														
208	Operating Receipts less Disbursements	[redacted]												
209														

	Big Rivers Financial Model	2015 January	2015 February	2015 March	2015 April	2015 May	2015 June	2015 July	2015 August	2015 September	2015 October	2015 November	2015 December	2015 Total
210	Capital Expenditures													
211	Generation	[redacted]												
212	Transmission													
213	A&G	0.00	0.09	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.24
214	Other / IT	0.08	0.10	0.21	0.30	0.24	0.39	0.32	0.30	0.07	0.05	0.01	0.00	2.04
215	Total Capital Expenditures	[redacted]												
216														
217	Income Taxes from Operations	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
218														
219	Net Pre-Finance Cash Flow	0.94	4.14	1.09	(12.59)	(3.33)	4.15	6.96	8.86	10.42	7.37	5.06	1.15	34.23
220														
221	Financing													
222	Principal	0.00	3.15	2.00	0.00	3.18	2.02	0.00	3.20	2.05	0.00	3.23	2.07	20.90
223	Interest	3.68	3.59	2.76	1.13	3.64	2.77	3.65	3.61	2.77	1.17	3.55	2.75	35.06
224	Debt Issuance Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02
225	Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.00	0.00	0.00	0.00	0.00	0.25
226	Aggregate Debt Service (incl. Line of Credit)	3.68	6.75	4.76	1.13	6.82	4.79	3.90	6.81	4.82	1.17	6.78	4.84	56.23
227														
228	Post-Finance Cash Flow	(2.74)	(2.61)	(3.66)	(13.71)	(10.15)	(0.64)	3.05	2.05	5.60	6.21	(1.72)	(3.70)	(22.00)
229														
230	Unwind Transaction													
231	Cash Proceeds													
232	Debt Reduction													
233	Misc. Transaction													
234	Net Before Member Reserves													
235	Station Two O&M Fund													
236	Rural Economic Reserve	8.63	7.47	7.09	5.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26.40
237	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
238	Net Before Transition Reserve	8.63	7.47	7.09	5.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.40
239														
240	Ending Cash Balances (Incl. Transition Reserve)	89.34	94.20	97.63	89.13	78.98	78.34	81.39	83.44	89.05	95.25	93.54	89.84	89.84
241	Ending Cash Balances excl. Transition Reserve)	89.34	94.20	97.63	89.13	78.98	78.34	81.39	83.44	89.05	95.25	93.54	89.84	89.84
242	Change in Working Capital													
243	Other Property	0.00	(0.35)	(1.09)	0.00	(0.36)	0.00	0.00	(0.36)	0.50	0.00	(0.36)	0.00	(2.03)
244	Accounts Receivable	1.03	(2.99)	(0.36)	(5.31)	2.61	4.23	3.24	(0.68)	(2.87)	(2.55)	1.43	2.77	0.54
245	Materials, Supplies & Other	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.66
246	Prepayments	(0.33)	(0.34)	(0.34)	(0.34)	(0.34)	(0.34)	(0.34)	(0.34)	(0.34)	(0.34)	(0.34)	3.96	0.21
247	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
248	Accounts Payable	(1.63)	0.82	(4.43)	0.66	2.72	(1.25)	0.68	(0.33)	0.33	(0.74)	1.15	1.51	(0.50)
249	Taxes Accrued	0.37	(0.37)	(0.37)	(0.37)	(0.37)	(0.37)	(0.37)	2.02	(0.37)	(0.37)	0.32	0.30	0.04
250	Other Accruals	(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)
251	Total	(0.56)	(3.23)	(6.59)	(5.36)	4.27	2.28	3.22	0.31	(2.75)	(4.00)	2.19	8.54	(1.69)
252														
253														

	Big Rivers Financial Model	2015 January	2015 February	2015 March	2015 April	2015 May	2015 June	2015 July	2015 August	2015 September	2015 October	2015 November	2015 December	2015 Total
254	VI. Cash Flow Statement - Indirect (Millions of $)													
255														
256	**Cash Flows From Operating Activities:**													
257	Net Margin	[redacted]												
258	Adjustments to reconcile net margin to net cash													
259	provided by operating activities:													
260	Depreciation and amortization	3.62	3.62	3.62	3.63	3.65	3.66	3.66	3.67	3.67	3.68	3.68	3.69	43.85
261	Interest compounded - RUS Series A Note	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.05
262	Interest compounded - RUS Series B Note	0.00	0.00	2.09	0.00	0.00	2.14	0.00	0.00	2.20	0.00	0.00	2.23	8.67
263	Noncash member rate mitigation revenue	(9.13)	(8.01)	(7.64)	(5.79)	(0.57)	(0.54)	(0.50)	(0.50)	(0.12)	(0.17)	(0.13)	0.01	(33.09)
264	Changes in certain assets and liabilities:													
265	Other property	0.00	0.35	1.09	0.00	0.36	0.00	0.00	0.36	(0.50)	0.00	0.36	0.00	2.03
266	Accounts receivable	(1.03)	2.99	0.36	5.31	(2.61)	(4.23)	(3.24)	0.68	2.87	2.55	(1.43)	(2.77)	(0.54)
267	Inventories	(0.53)	(0.34)	(0.26)	(0.24)	(0.02)	(0.12)	(0.10)	(0.08)	(0.08)	(0.08)	(0.07)	(0.06)	(1.97)
268	Prepayments	0.33	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	(3.96)	(0.21)
269	Dther 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
270	Accounts payable	1.63	(0.82)	4.43	(0.66)	(2.72)	1.25	(0.68)	0.33	(0.33)	0.74	(1.15)	(1.51)	0.50
271	Taxes accrued	(0.37)	0.37	0.37	0.37	0.37	0.37	0.37	(2.02)	0.37	0.37	(0.32)	(0.30)	(0.04)
272	Dther accruals	0.13	(0.08)	(1.05)	2.52	0.11	(1.29)	0.06	0.19	(1.29)	2.61	0.15	(1.18)	0.88
273	Net cash provided by operating activities	[redacted]												
274														
275	**Cash Flows From Investing Activities:**													
276	Capital expenditures	[redacted]												
277	Net proceeds from restricted investments	8.63	7.47	7.09	5.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.40
278	Net cash provided by (used in) inv. activities	[redacted]												
279														
280	**Cash Flows From Financing Activities:**													
281	Net principal payments on debt obligations	0.00	(3.15)	(2.00)	0.00	(3.18)	(2.02)	0.00	(3.20)	(2.05)	0.00	(3.23)	(2.07)	(20.90)
282	Debt issuance cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.02)	(0.02)
283	Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	0.00	(0.25)	0.00	0.00	0.00	0.00	0.00	(0.25)
284	Net cash provided by (used in) fin. activities	0.00	(3.15)	(2.00)	0.00	(3.18)	(2.02)	(0.25)	(3.20)	(2.05)	0.00	(3.23)	(2.09)	(21.17)
285														
286	Net increase (decrease) in cash	5.89	4.86	3.43	(8.50)	(10.15)	(0.64)	3.05	2.05	5.60	8.21	(1.72)	(3.70)	8.40
287														
288	**Cash and Cash Equivalents - Beg. of Period**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	83.45
289	**Cash and Cash Equivalents - End of Period**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	89.84

	Big Rivers Financial Model	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2015 January	Test Period Total
1	**I. Sales**													
2														
3	**Energy (TWH)**													
4	Rural	0.20	0.18	0.15	0.16	0.20	0.23	0.23	0.17	0.16	0.18	0.23	0.23	2.31
5	Large Industrial	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.98
6	Century	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
7	Alcan	[redacted]												
8	Market													
9	Total Energy Sales	0.42	0.39	0.41	0.41	0.41	0.44	0.43	0.41	0.47	0.44	0.46	0.44	5.12
10														
11	**Demand (MW)**													
12	Rural	437.90	386.40	325.20	379.40	470.20	509.20	492.50	446.20	328.60	398.10	459.70	495.50	5,128.90
13	Large Industrial	140.90	139.50	144.50	144.30	146.00	150.30	151.70	146.80	146.00	145.80	147.70	142.90	1,748.40
14														
15	**II. Rates, Accrual Based ($ / MWH)**													
16														
17	**Rural**													
18	Load Factor (%)	67.06%	63.09%	63.87%	57.45%	58.14%	60.82%	61.47%	54.02%	64.62%	61.83%	66.32%	62.39%	61.85%
19	Demand ($/ KW-mo.)	23.51	23.51	23.51	23.51	23.51	23.51	23.51	23.51	23.51	23.51	23.51	23.51	23.51
20	Energy ($/ MWH)	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
21	Base Rate ($/ MWH)	87.17	85.09	86.12	90.00	91.16	86.95	86.41	95.44	83.90	87.81	82.64	85.65	87.23
22														
23	Non-Smelter Non-FAC PPA	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	0.05	0.05	0.05	0.05	0.05	(0.36)
24	FAC	5.24	5.50	5.63	5.89	6.46	5.98	6.38	6.45	5.83	5.95	6.00	5.94	5.95
25	Environmental Surcharge	5.22	5.07	5.69	5.72	5.62	5.07	6.27	8.15	7.50	6.86	6.04	8.45	6.10
26	Surcredit	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	0.00	(0.13)
27	Total	10.31	10.42	11.17	11.46	11.93	10.90	12.50	14.46	13.19	12.66	11.90	12.39	11.92
28	Economic Reserve	(37.43)	(37.54)	(38.29)	(38.59)	(39.06)	(27.87)	0.00	0.00	0.00	0.00	0.00	0.00	(17.45)
29	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	(8.16)	(37.62)	(39.58)	(38.31)	(37.78)	(37.02)	(37.51)	(20.36)
30	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	Effective Rate ($/ MWH)	59.39	57.31	58.35	62.23	63.39	61.18	60.63	70.37	58.83	62.74	57.57	60.58	60.98
32														
33	**Large Industrial**													
34	Load Factor (%)	80.85%	78.17%	77.86%	76.62%	76.75%	78.07%	79.04%	76.17%	77.56%	75.68%	73.75%	75.06%	77.14%
35	Demand ($/ KW-mo.)	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00	17.00
36	Energy ($/ MWH)	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
37	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	0.00
38	Base Rate ($/ MWH)	66.29	64.23	65.33	64.82	65.77	64.27	63.91	66.00	64.46	66.20	65.98	65.44	65.20
39														
40	Non-Smelter Non-FAC PPA	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	0.05	0.05	0.05	0.05	0.05	(0.36)
41	FAC	5.24	5.50	5.63	5.89	6.46	5.98	6.38	8.45	5.83	5.95	6.00	5.94	5.94
42	Environmental Surcharge	4.04	3.90	4.40	4.22	4.16	3.83	4.75	5.80	5.88	5.28	4.91	5.03	4.68
43	Surcredit	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	0.00	(0.14)
44	Total	9.13	9.25	9.88	9.96	10.47	9.66	10.98	12.10	11.56	11.08	10.76	10.97	10.49
45	Economic Reserve	(28.65)	(28.77)	(29.40)	(29.48)	(29.98)	(27.87)	0.00	0.00	0.00	0.00	0.00	0.00	(14.43)
46	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	Effective Rate ($/ MWH)	46.12	44.06	45.16	44.66	45.60	45.41	74.23	78.15	76.07	77.33	76.80	76.46	60.90
48														

	Big Rivers Financial Model	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2015 January	Test Period Total
49	**Non-Smelter Member Blend**													
50	Base Rate ($/ MWH)	81.33	78.64	78.82	81.53	83.78	80.72	80.02	86.11	77.14	81.12	78.26	80.44	80.65
51														
52	Non-Smelter Non-FAC PPA	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	(0.65)	0.05	0.05	0.05	0.05	0.05	(0.36)
53	FAC	5.24	5.50	5.63	5.89	6.46	5.98	6.38	6.45	5.83	5.95	6.00	5.94	5.95
54	Environmental Surcharge	4.89	4.71	5.24	5.21	5.20	4.73	5.84	7.41	6.94	6.37	5.75	6.08	5.68
55	Surcredit	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)	0.00	(0.13)
56	Total	9.98	10.06	10.72	10.96	11.51	10.56	12.07	13.71	12.62	12.17	11.60	12.02	11.49
57	Economic Reserve	(34.98)	(34.83)	(35.17)	(35.52)	(36.42)	(27.87)	0.00	0.00	0.00	0.00	0.00	0.00	(16.55)
58	Rural Economic Reserve	0.00	0.00	0.00	0.00	0.00	(5.92)	(26.95)	(27.04)	(24.98)	(26.09)	(27.28)	(27.85)	(14.28)
59	TIER Related Rebate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	Effective Rate ($/ MWH)	55.68	53.22	53.72	56.31	58.22	56.85	64.49	72.84	64.83	67.26	62.63	64.67	60.96
61														
62	**Smelters**													
63	Base Rate	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	59.01	0.00
64	TIER Adjustment	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	2.95	0.00	0.00
65	Total	61.96	61.96	61.96	61.96	61.96	61.96	61.96	61.96	61.96	61.96	61.96	59.01	0.00
66	Non-FAC PPA	0.14	0.18	0.33	0.26	0.12	(0.00)	0.01	0.22	0.27	0.20	0.03	2.47	0.00
67	FAC	5.24	5.50	5.63	5.89	6.48	5.98	6.38	6.45	5.63	5.95	8.00	5.94	0.00
68	Environmental Surcharge	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
69	Surcharge	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
70	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
71	Effective Rate ($/ MWH)	67.34	67.64	67.92	68.11	68.55	67.94	68.34	68.63	68.06	68.12	67.99	67.42	0.00
72														
73	Market	[redacted]												
74														
75	III. Statement of Operations (Millions of $)													
76														
77	Electric Energy Revenues	[redacted]												
78	Income From Leased Property Net													
79	Other Operating Revenue and Income	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.31	3.65
80	TOTAL OPER. REVENUES & PAT. CAPITAL	[redacted]												
81														
82	Operating Expense-Production-Excluding Fuel	[redacted]												
83	Operating Expense-Production-Fuel													
84	Operating Expense-Other Power Supply													
85	Operating Expense-Transmission													
86	Operating Expense-RTO/ISO													
87	Operating Expense-Distribution													
88	Operating Expense-Customer Accounts													
89	Operating Expense-Customer Service and Information													
90	Operating Expense-Sales													
91	Operating Expense-Administrative and General													
92	TOTAL OPERATION EXPENSE													
93														
94	Maintenance Expense-Production	[redacted]												
95	Maintenance Expense-Transmission													
96	Maintenance Expense-Distribution													
97	Maintenance Expense-General Plant													
98	TOTAL MAINTENANCE EXPENSE													

	Big Rivers Financial Model	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2015 January	Test Period Total
99														
100	Depreciation and Amortization Expense	3.21	3.21	3.22	3.23	3.24	3.25	3.25	3.32	3.32	3.33	3.33	3.33	39.23
101	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	0.00
102	Interest on Long-Term Debt	3.37	3.66	3.60	3.70	3.59	3.73	3.73	3.62	3.72	3.62	3.71	3.72	43.77
103	Interest Charged to Construction - Credit	(0.19)	(0.22)	(0.27)	(0.31)	(0.35)	(0.36)	(0.01)	(0.01)	(0.02)	(0.01)	(0.01)	(0.00)	(1.77)
104	Other Interest Expense	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
105	Asset Retirement Obligation													
106	Other Deductions	0.05	0.05	0.05	0.05	0.07	0.05	0.05	0.05	0.06	0.06	0.08	0.06	0.67
107														
108	TOTAL COST OF ELECTRIC SERVICE	[redacted]												
109														
110	OPERATING MARGINS	[redacted]												
111														
112	Interest Income	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.83
113	Allowance For Funds Used During Construction													
114	Income (Loss) From Equity Investments													
115	Other Non-Operating Income (Net)													
116	Generation and Transmission Capital Credits													
117	Other Capital Credits and Patronage Dividends	0.00	1.69	0.03	0.00	0.00	0.00	0.01	1.02	0.00	0.00	0.00	0.00	2.74
118	Extraordinary Items													
119	NET PATRONAGE CAPITAL OR MARGIN	[redacted]												
120														
121														
122	**IV. Balance Sheet (Millions of $)**													
123	Total Utility Plant in Service	2,046.54	2,049.58	2,054.35	2,060.31	2,061.57	2,062.67	2,124.81	2,126.49	2,128.53	2,128.70	2,128.81	2,129.85	2,129.85
124	Construction Work in Progress	82.18	87.43	92.73	98.06	100.81	101.10	40.00	40.00	40.00	40.00	40.00	40.00	40.00
125	Total Utility Plant	2,128.69	2,137.01	2,147.09	2,158.37	2,162.38	2,163.77	2,164.81	2,166.49	2,168.53	2,168.70	2,168.81	2,169.85	2,169.85
126	Accum. Provision for Depreciation and Amort.	1,002.34	1,004.87	1,006.87	1,008.51	1,011.67	1,014.88	1,018.10	1,021.18	1,024.15	1,027.72	1,031.31	1,034.60	1,034.60
127	NET UTILITY PLANT	1,126.35	1,132.14	1,140.22	1,149.86	1,150.71	1,148.89	1,146.71	1,145.31	1,144.37	1,140.98	1,137.50	1,135.25	1,135.25
128														
129	Non-Utility Property (Net)													
130	Invest. In Assoc. Org - Patronage Capital	4.15	3.80	3.81	3.81	3.81	3.81	3.81	4.32	4.32	4.32	4.32	4.32	4.32
131	Invest. In Assoc. - Other - General Funds	42.54	42.54	42.54	42.20	42.20	42.20	41.86	41.86	41.86	41.51	41.51	41.51	41.51
132	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	0.02
133	Special Funds	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13	1.13
134	Special Funds (Transition 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
135	Special Funds (Economic Reserve)	44.81	35.70	27.61	18.94	8.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
136	Special Funds (Rural Economic Reserve)	65.78	65.88	65.98	66.08	66.18	64.40	56.03	49.25	43.27	36.64	28.30	19.72	19.72
137	TOTAL OTHER PROP. AND INVESTMENTS	158.42	149.06	141.08	132.18	122.19	111.56	102.85	96.57	90.60	83.62	75.28	66.70	66.70
138														
139	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	0.01
140	Cash - Construction Funds - Trustee													
141	Special Deposits	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
142	Temporary Investments	80.42	91.46	82.20	65.13	73.84	76.62	78.30	82.99	87.68	86.34	83.44	89.33	89.33
143	Accounts Receivable - Sales of Energy (Net)	29.61	27.13	26.05	27.56	30.01	32.93	32.50	30.21	28.55	29.53	32.50	33.53	33.53
144	Accounts Receivable - Other (Net)	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
145	Fuel Stock	18.87	19.12	19.25	19.27	19.34	19.36	19.41	19.43	19.45	19.47	19.48	19.95	19.95
146	Materials and Supplies - Other	26.29	26.34	26.39	26.45	26.50	26.55	26.61	26.66	26.71	26.77	26.82	26.88	26.88
147	Prepayments	3.26	2.95	2.63	2.31	2.00	1.68	1.37	1.05	0.74	0.42	4.19	3.86	3.86
148	Other Current and Accrued Assets	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
149	TOTAL CURRENT AND ACCRUED ASSETS	160.12	168.66	158.20	142.39	153.36	158.84	159.86	162.01	164.81	164.20	168.11	175.22	175.22

	Big Rivers Financial Model	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2015 January	Test Period Total
150														
151	Unamortized Debt Discount & Extraor. Prop. Losses	3.92	3.89	3.85	3.82	3.78	4.24	4.20	4.16	4.11	4.07	4.03	3.99	3.99
152	Regulatory Assets	10.91	10.67	10.42	10.18	9.94	9.86	9.82	9.62	9.43	9.22	8.97	9.48	9.48
153	Other Deferred Debits	3.84	3.83	3.82	3.81	3.80	4.04	4.03	4.02	4.02	4.01	4.00	3.99	3.99
154	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	0.00
155														
156	TOTAL ASSETS AND OTHER DEBITS	1,463.56	1,468.26	1,457.60	1,442.24	1,443.78	1,437.44	1,427.47	1,421.70	1,417.34	1,406.10	1,397.89	1,394.62	1,394.62
157														
158														
159	TOTAL MARGINS & EQUITY	414.61	412.27	407.13	404.67	405.97	410.09	413.05	414.85	412.27	412.98	415.66	419.64	419.64
160														
161	Long-Term Debt - RUS	218.14	220.11	220.12	220.12	222.15	222.16	222.16	224.24	224.25	224.25	226.36	226.37	226.37
162	Long-Term Debt - Other	662.70	675.86	675.86	672.78	683.43	683.43	680.33	678.37	678.37	675.25	673.27	673.27	673.27
163	TOTAL LONG-TERM DEBT	680.84	895.97	695.96	892.90	905.58	905.59	902.49	902.61	902.62	699.50	899.63	899.64	899.64
164														
165	Notes 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	0.00
166	Accounts Payable	18.68	20.36	20.18	18.78	17.35	17.08	17.49	17.50	18.74	16.63	15.52	17.15	17.15
167	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	0.00
168	Taxes Accrued	1.61	1.96	2.32	2.67	3.02	3.37	1.44	1.79	2.14	1.65	1.65	1.28	1.28
169	Interest Accrued	5.19	4.24	6.70	6.66	5.48	5.54	5.55	4.23	6.77	6.74	5.50	5.53	5.53
170	Other Current and Accrued Liabilities	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30	7.30
171														
172	TOTAL CURRENT AND ACCRUED LIAB.	32.78	33.87	36.50	35.41	33.14	33.29	31.78	30.82	34.95	32.72	29.97	31.26	31.26
173														
174	Deferred Credits	0.92	0.70	0.48	0.26	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
175	Deferred Credits (Economic Reserve)	44.81	35.70	27.61	18.94	8.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
176	Deferred Credits (Rural Economic Reserve)	65.78	65.88	65.98	66.08	66.18	64.40	56.03	49.25	43.27	36.64	28.30	19.72	19.72
177	Accumulated Operating Provisions	23.82	23.87	23.92	23.97	24.02	24.07	24.12	24.17	24.22	24.27	24.32	24.37	24.37
178	Obligation under Capital Leases - Noncurrent													
179														
180	TOTAL LIABILITIES AND OTHER CREDITS	1,463.56	1,468.26	1,457.60	1,442.24	1,443.78	1,437.44	1,427.47	1,421.70	1,417.34	1,406.10	1,397.89	1,394.62	1,394.62
181														
182														
183	V. Cash Flow Statement (Millions of $)													
184	Operating Receipts													
165	Rural	11.72	10.39	8.73	10.09	12.48	14.10	13.66	12.21	9.29	11.12	13.06	13.93	140.78
186	Large Industrial	3.53	3.58	3.66	3.67	3.68	3.96	6.62	6.29	6.41	6.14	6.22	6.10	59.87
187	Smelters	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
188	Offsystem	[redacted]												
189	Lease Income													
190	Other Operating Revenues	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.31	3.65
191	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
192	Other	0.00	1.69	0.03	0.00	0.00	0.00	0.01	1.02	0.00	0.00	0.00	0.00	2.74
193	Interest Earnings	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	1.63
194	Total Receipts	[redacted]												
195														
196	Operating Disbursements													
197	PPA													
196	Fuel Costs	[redacted]												
199	Fuel Costs (Labor & Exp)													
200	Power Supply (P Power, APM, Cogen, & TVA Tran)													
201	Production O&M													
202	Transmission O&M													
203	A&G	2.24	3.04	2.31	2.67	2.93	2.21	2.37	2.29	2.37	2.06	2.57	2.31	29.37
204	Working Capital	(8.60)	(5.18)	(1.55)	1.90	3.23	2.52	0.45	(2.46)	(3.56)	2.52	8.26	(0.56)	(3.04)
205	Dther	(0.24)	(0.24)	(0.24)	(0.24)	(0.22)	(0.24)	(0.24)	(0.24)	(0.24)	(0.24)	(0.24)	(0.23)	(2.84)
206	Total Disbursements	[redacted]												
207														
208	Operating Receipts less Disbursements	[redacted]												
209														

Big Rivers Financial Model

	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2015 January	Test Period Total
Capital Expenditures													
Generation	[redacted]												
Transmission													
A&G	0.21	0.10	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.55
Other / IT	0.05	0.10	0.31	0.11	0.26	0.22	0.32	0.23	0.04	0.01	0.00	0.08	1.72
Total Capital Expenditures	[redacted]												
Income Taxes from Operations	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
Net Pre-Finance Cash Flow	(0.20)	(8.62)	(18.24)	(18.93)	(9.29)	(3.54)	0.02	2.63	(0.19)	(1.25)	(6.46)	0.94	(61.14)
Financing													
Principal	3.05	(13.16)	0.00	3.08	(10.65)	0.00	3.10	1.95	0.00	3.13	1.98	0.00	(7.51)
Interest	3.70	2.64	1.13	3.74	2.76	3.65	3.71	2.86	1.17	3.65	2.84	3.68	35.53
Debt Issuance Cost	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00	0.00	0.00	0.02	0.00	0.52
Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.25
Aggregate Debt Service (Incl. Line of Credit)	6.75	(10.52)	1.13	6.82	(7.89)	4.40	6.82	4.81	1.17	6.78	4.84	3.68	28.78
Post-Finance Cash Flow	(6.95)	1.90	(17.37)	(25.75)	(1.40)	(7.95)	(6.60)	(2.18)	(1.36)	(8.04)	(11.30)	(2.74)	(89.92)
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	1.88	8.47	6.87	6.05	6.70	8.40	8.63	46.99
Economic Reserve	9.58	9.14	8.11	8.68	10.11	8.85	0.00	0.00	0.00	0.00	0.00	0.00	54.47
Net Before Transition Reserve	9.58	9.14	8.11	8.68	10.11	10.73	8.47	6.87	6.05	6.70	8.40	8.63	101.47
Ending Cash Balances (Incl. Transition Reserve)	60.42	91.47	82.20	65.14	73.84	76.63	78.30	82.99	87.69	86.35	83.45	89.34	89.34
Ending Cash Balances excl. Transition Reserve)	60.42	91.47	82.20	65.14	73.84	76.63	76.30	82.99	87.69	86.35	83.45	89.34	69.34
Change in Working Capital													
Other Property	(0.33)	(0.35)	0.01	(0.34)	0.00	0.00	(0.34)	0.51	0.00	(0.35)	0.00	0.00	(1.16)
Accounts Receivable	(11.71)	(2.48)	(1.09)	1.51	2.46	2.91	(0.42)	(2.30)	(1.66)	0.98	2.97	1.03	(7.79)
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	0.65
Prepayments	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	(0.32)	3.77	(0.33)	0.28
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	4.10	(1.68)	0.19	1.40	1.43	0.27	(0.41)	(0.01)	(1.24)	1.91	1.30	(1.63)	5.63
Taxes Accrued	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	(0.35)	1.93	(0.35)	(0.35)	0.29	0.21	0.37	(0.02)
Other Accruals	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.60)
Total	(8.60)	(5.18)	(1.55)	1.90	3.23	2.52	0.45	(2.46)	(3.56)	2.52	8.26	(0.56)	(3.04)

Big Rivers Financial Model	2014 February	2014 March	2014 April	2014 May	2014 June	2014 July	2014 August	2014 September	2014 October	2014 November	2014 December	2015 January	Test Period Total
VI. Cash Flow Statement - Indirect (Millions of $)													
Cash Flows From Operating Activities:													
Net Margin	[redacted]												
Adjustments to reconcile net margin to net cash provided by operating activities:													
Depreciation and amortization	3.49	3.49	3.49	3.51	3.53	3.54	3.54	3.61	3.61	3.62	3.62	3.62	42.67
Interest compounded - RUS Series A Note	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.01	0.05
Interest compounded - RUS Series B Note	0.00	1.97	0.00	0.00	2.02	0.00	0.00	2.08	0.00	0.00	2.11	0.00	8.18
Noncash member rate mitigation revenue	(9.55)	(9.12)	(8.09)	(8.66)	(10.08)	(10.70)	(8.44)	(6.67)	(5.86)	(6.49)	(8.15)	(9.13)	(100.93)
Changes in certain assets and liabilities:													
Other property	0.33	0.35	(0.01)	0.34	0.00	0.00	0.34	(0.51)	0.00	0.35	0.00	0.00	1.18
Accounts receivable	11.71	2.48	1.09	(1.51)	(2.46)	(2.91)	0.42	2.30	1.66	(0.98)	(2.97)	(1.03)	7.79
Inventories	(0.37)	(0.31)	(0.18)	(0.07)	(0.12)	(0.10)	(0.08)	(0.08)	(0.08)	(0.07)	(0.06)	(0.53)	(2.05)
Prepayments	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	(3.77)	0.33	(0.28)
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	(4.10)	1.68	(0.19)	(1.40)	(1.43)	(0.27)	0.41	0.01	1.24	(1.91)	(1.30)	1.63	(5.63)
Taxes accrued	0.35	0.35	0.35	0.35	0.35	0.35	(1.93)	0.35	0.35	(0.29)	(0.21)	(0.37)	0.02
Other accruals	(0.42)	(1.08)	2.28	(0.26)	(1.44)	(0.20)	0.11	(1.23)	2.63	0.06	(1.12)	0.13	(0.56)
Net cash provided by operating activities	[redacted]												
Cash Flows From Investing Activities:													
Capital expenditures	[redacted]												
Net proceeds from restricted investments	9.58	9.14	8.11	8.68	10.11	10.73	8.47	6.87	6.05	6.70	8.40	8.63	101.47
Net cash provided by (used in) inv. activities	[redacted]												
Cash Flows From Financing Activities:													
Net principal payments on debt obligations	(3.05)	13.16	0.00	(3.08)	10.65	0.00	(3.10)	(1.95)	0.00	(3.13)	(1.98)	0.00	7.51
Debt issuance cost	0.00	0.00	0.00	0.00	0.00	(0.50)	0.00	0.00	0.00	0.00	(0.02)	0.00	(0.52)
Line of Credit (Upfront Fee)	0.00	0.00	0.00	0.00	0.00	(0.25)	0.00	0.00	0.00	0.00	0.00	0.00	(0.25)
Net cash provided by (used in) fin. activities	(3.05)	13.16	0.00	(3.08)	10.65	(0.75)	(3.10)	(1.95)	0.00	(3.13)	(2.00)	0.00	8.74
Net increase (decrease) in cash	2.63	11.05	(9.26)	(17.07)	8.71	2.79	1.68	4.69	4.70	(1.34)	(2.90)	5.89	11.55
Cash and Cash Equivalents - Beg. of Period													89.34
Cash and Cash Equivalents - End of Period													100.88

Big Rivers Electric Corporation
Case No. 2013-00199
Statement of Operations (With and Without Proposed Rate Increase)
Fully Forecasted Test Period (February 2014 to January 2015)

		With Proposed Rate Increase	Without Proposed Rate Increase
1	Electric Energy Revenues	[redacted]	
2	Income From Leased Property Net	0	0
3	Other Operating Revenue and Income	3,646,941	3,646,941
4	**TOTAL OPER. REVENUES & PATRONAGE CAPITAL**	[redacted]	
5			
6	Operating Expense-Production-Excluding Fuel	[redacted]	
7	Operating Expense-Production-Fuel		
8	Operating Expense-Other Power Supply		
9	Operating Expense-Transmission		
10	Operating Expense-RTO/ISO		
11	Operating Expense-Distribution		
12	Operating Expense-Customer Accounts		
13	Operating Expense-Customer Service and Information		
14	Operating Expense-Sales		
15	Operating Expense-Administrative and General		
16	**TOTAL OPERATION EXPENSE**		
17			
18	Maintenance Expense-Production	[redacted]	
19	Maintenance Expense-Transmission		
20	Maintenance Expense-Distribution		
21	Maintenance Expense-General Plant		
22	**TOTAL MAINTENANCE EXPENSE**		
23			
24	Depreciation and Amortization Expense	39,232,311	39,232,311
25	Taxes	885	885
26	Interest on Long-Term Debt	43,765,994	43,765,994
27	Interest Charged to Construction - Credit	(1,768,401)	(1,768,401)
28	Other Interest Expense	0	0
29	Asset Retirement Obligation	0	0
30	Other Deductions	668,273	668,273
31			
32	**TOTAL COST OF ELECTRIC SERVICE**	[redacted]	
33			
34	**OPERATING MARGINS**	[redacted]	
35			
36	Interest Income	1,829,006	1,797,086
37	Allowance For Funds Used During Construction	0	0
38	Income (Loss) From Equity Investments	0	0
39	Other Non-Operating Income (Net)	0	0
40	Generation and Transmission Capital Credits	0	0
41	Other Capital Credits and Patronage Dividends	2,739,448	2,739,448
42	Extraordinary Items	0	0
43	**NET PATRONAGE CAPITAL OR MARGIN**	[redacted]	

BIG RIVERS ELECTRIC CORPORATION
Calculation of Revenue Requirement
Based on Fully Forecasted Test Period
For the 12 Months Ended January 31, 2015

Line	Description	Ref Sched	Alcan Rate Case Amount
1	**Total Oper Rev & Patronage Capital Without Proposed Rate Increase**	Exh Warren-3.2	$ 292,538,389
2			
3	**Adjustments to Revenue**		
4	To Remove Fuel Adjustment Clause Revenue	1.01	$ (19,581,659)
5	To Remove Environmental Surcharge Revenue	1.02	$ (17,709,690)
6	To Remove Non-FAC PPA Revenue	1.03	$ 1,183,384
7	To Remove Surcredit Revenue (Crediting of Smelter Surcharge)	1.09	$ 442,329
8	Subtotal	Lines 4-7	$ (35,665,636)
9			
10	Adjusted Revenue	Line 1 + Line 8	$ 256,872,753
11			
12	**Total Cost of Service**	Exh Warren-3.2	$ 363,313,759
13			
14	**Adjustments to Cost of Service**		
15	To Remove Fuel Expense Recoverable through the FAC	1.01	$ (19,581,659)
16	To Remove Expenses Recoverable through the ES	1.02	$ (17,709,690)
17	To Remove Expenses Recoverable through the Non-FAC PPA	1.03	$ 1,183,384
18	To Remove Promotional Advertising	1.04	$ (55,756)
19	To Remove Lobbying Expenses	1.05	$ (71,023)
20	To Remove Economic Development Expenses	1.06	$ (144,568)
21	To Remove Donations Expenses	1.07	$ (63,328)
22	To Remove Touchstone Energy dues	1.08	$ (132,766)
23	To Remove Non-recurring Labor related to Plant Layup	1.10	$ (2,831,632)
24	To Normalize Certain Outside Professional Services	1.11	$ 73,593
25	To Normalize Demand Side Management Expenses	1.12	$ (96,000)
26	To Normalize Non-Labor Expenses related to Plant Layup	1.13	$ (1,343,377)
27	To Normalized MISO Capacity charge related to Plant Layup	1.14	$ (408,442)
28	Subtotal	Lines 15-27	$ (41,181,264)
29			
30	Adjusted Cost of Service	Line 12 + Line 28	$ 322,132,495
31			
32	Adjusted Operating Margins	Line 10 - Line 30	$ (65,259,743)
33			
34	**Non-Operating Items**		
35	Interest Income	Exh Warren-3.2	$ 1,797,086
36	Other Capital Credits / Patronage Dividends	Exh Warren-3.2	$ 2,739,448
37	Total Non-Operating Items	Lines 35-36	$ 4,536,534
38			
39	**Calculation of Revenue Deficiency**		
40	Adjusted Net Margin (Deficit)	Line 32 + 37	$ (60,723,209)
41			
42	Target TIER		1.24
43			
44	Interest on Long-Term Debt	Exh Warren-3.2	$ 43,765,994
45			
46	Margins Required for Target TIER	Line 44*(Line 42-1)	$ 10,503,839
47			
48	**Revenue Deficiency for Target TIER**	Line 40 - 46	$ (71,227,047)

Reference Schedule: 1.01

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended January 31, 2015

Fuel Adjustment Clause Revenues and Expenses

Line #	Year (1)	Month (2)	Revenue (3)	Expense (4)
1	2014	Feb	$ 1,436,318	$ 1,436,318
2	2014	Mar	$ 1,443,603	$ 1,443,603
3	2014	Apr	$ 1,297,979	$ 1,297,979
4	2014	May	$ 1,440,545	$ 1,440,545
5	2014	Jun	$ 1,792,443	$ 1,792,443
6	2014	Jul	$ 1,899,073	$ 1,899,073
7	2014	Aug	$ 2,004,681	$ 2,004,681
8	2014	Sep	$ 1,639,354	$ 1,639,354
9	2014	Oct	$ 1,412,533	$ 1,412,533
10	2014	Nov	$ 1,526,698	$ 1,526,698
11	2014	Dec	$ 1,848,751	$ 1,848,751
12	2015	Jan	$ 1,839,684	$ 1,839,684
13		TOTAL	$ 19,581,659	$ 19,581,659
14				
15	Test Year Cost		$ 19,581,659	$ 19,581,659
16				
17	Pro Forma Year Cost		$ -	$ -
18				
19	Adjustment		$ (19,581,659)	$ (19,581,659)

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended January 31, 2015

Environmental Surcharge Revenues and Expenses

Line #	Year (1)	Month (2)		Revenue (3)		Expense (4)
1	2014	Feb	$	1,267,801	$	1,267,801
2	2014	Mar	$	1,177,661	$	1,177,661
3	2014	Apr	$	1,126,875	$	1,126,875
4	2014	May	$	1,197,638	$	1,197,638
5	2014	Jun	$	1,381,806	$	1,381,806
6	2014	Jul	$	1,442,424	$	1,442,424
7	2014	Aug	$	1,767,420	$	1,767,420
8	2014	Sep	$	1,776,502	$	1,776,502
9	2014	Oct	$	1,556,489	$	1,556,489
10	2014	Nov	$	1,534,012	$	1,534,012
11	2014	Dec	$	1,685,812	$	1,685,812
12	2015	Jan	$	1,795,250	$	1,795,250
13		TOTAL	$	17,709,690	$	17,709,690
14						
15	Test Year Cost		$	17,709,690	$	17,709,690
16						
17	Pro Forma Year Cost		$	-	$	-
18						
19	Adjustment		$	(17,709,690)	$	(17,709,690)

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended January 31, 2015

Non-FAC PPA Revenues and Expenses

Line #	Year (1)	Month (2)		Revenue (3)		Expense (4)
1	2014	Feb	$	(178,583)	$	(178,583)
2	2014	Mar	$	(171,151)	$	(171,151)
3	2014	Apr	$	(150,320)	$	(150,320)
4	2014	May	$	(159,373)	$	(159,373)
5	2014	Jun	$	(180,933)	$	(180,933)
6	2014	Jul	$	(207,159)	$	(207,159)
7	2014	Aug	$	(205,024)	$	(205,024)
8	2014	Sep	$	12,819	$	12,819
9	2014	Oct	$	12,222	$	12,222
10	2014	Nov	$	12,950	$	12,950
11	2014	Dec	$	15,535	$	15,535
12	2015	Jan	$	15,632	$	15,632
13		TOTAL	$	(1,183,384)	$	(1,183,384)
14						
15	Test Year Cost		$	(1,183,384)	$	(1,183,384)
16						
17	Pro Forma Year Cost		$	-	$	-
18						
19	Adjustment		$	1,183,384	$	1,183,384

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended January 31, 2015

Promotional Advertising

Line #	Year (1)	Month (2)	Amount (3)
1	2014	Feb	$ 5,000
2	2014	Mar	$ 5,500
3	2014	Apr	$ 4,966
4	2014	May	$ 4,000
5	2014	Jun	$ 4,500
6	2014	Jul	$ 4,000
7	2014	Aug	$ 4,000
8	2014	Sep	$ 4,500
9	2014	Oct	$ 4,000
10	2014	Nov	$ 4,500
11	2014	Dec	$ 5,290
12	2015	Jan	$ 5,500
13		TOTAL	$ 55,756
14			
15	Test Year Cost		$ 55,756
16			
17	Pro Forma Year Cost		$ -
18			
19	Adjustment		$ (55,756)

Reference Schedule: 1.05

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended January 31, 2015

Lobbying Expenses

Line #	Year (1)	Month (2)	Amount (3)
1	2014	Feb	$ 1,520
2	2014	Mar	$ 2,270
3	2014	Apr	$ 1,486
4	2014	May	$ 54,137
5	2014	Jun	$ 1,870
6	2014	Jul	$ 1,120
7	2014	Aug	$ 1,120
8	2014	Sep	$ 1,870
9	2014	Oct	$ 1,120
10	2014	Nov	$ 1,120
11	2014	Dec	$ 1,870
12	2015	Jan	$ 1,520
13		TOTAL	$ 71,023
14			
15	Test Year Cost		$ 71,023
16			
17	Pro Forma Year Cost		$ -
18			
19	Adjustment		$ (71,023)

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended January 31, 2015

Economic Development Expenses

Line #	Year (1)	Month (2)	Amount (3)	
1	2014	Feb	$	-
2	2014	Mar	$	-
3	2014	Apr	$	-
4	2014	May	$	-
5	2014	Jun	$	-
6	2014	Jul	$	-
7	2014	Aug	$	-
8	2014	Sep	$	144,568
9	2014	Oct	$	-
10	2014	Nov	$	-
11	2014	Dec	$	-
12	2015	Jan	$	-
13		TOTAL	$	144,568
14				
15	Test Year Cost		$	144,568
16				
17	Pro Forma Year Cost		$	-
18				
19	Adjustment		$	(144,568)

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended January 31, 2015

Donations Expenses

Line #	Year (1)	Month (2)		Amount (3)
1	2014	Feb	$	2,060
2	2014	Mar	$	2,575
3	2014	Apr	$	21,000
4	2014	May	$	1,000
5	2014	Jun	$	1,000
6	2014	Jul	$	1,000
7	2014	Aug	$	1,000
8	2014	Sep	$	1,000
9	2014	Oct	$	1,000
10	2014	Nov	$	1,000
11	2014	Dec	$	4,643
12	2015	Jan	$	26,050
13		TOTAL	$	63,328
14				
15	Test Year Cost		$	63,328
16				
17	Pro Forma Year Cost		$	-
18				
19	Adjustment		$	(63,328)

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended January 31, 2015

Touchstone Energy Dues Expenses

Line #	Year (1)	Month (2)	Amount (3)
1	2014	Feb	$ -
2	2014	Mar	$ 132,766
3	2014	Apr	$ -
4	2014	May	$ -
5	2014	Jun	$ -
6	2014	Jul	$ -
7	2014	Aug	$ -
8	2014	Sep	$ -
9	2014	Oct	$ -
10	2014	Nov	$ -
11	2014	Dec	$ -
12	2015	Jan	$ -
13		TOTAL	$ 132,766
14			
15	Test Year Cost		$ 132,766
16			
17	Pro Forma Year Cost		$ -
18			
19	Adjustment		$ (132,766)

Reference Schedule: 1.09

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended January 31, 2015

Smelter Surcredit

Line #	Year (1)	Month (2)		Revenue (3)		Expense (4)
1	2014	Feb	$	(40,630)	$	-
2	2014	Mar	$	(38,939)	$	-
3	2014	Apr	$	(34,199)	$	-
4	2014	May	$	(36,259)	$	-
5	2014	Jun	$	(41,164)	$	-
6	2014	Jul	$	(47,131)	$	-
7	2014	Aug	$	(46,645)	$	-
8	2014	Sep	$	(37,687)	$	-
9	2014	Oct	$	(35,932)	$	-
10	2014	Nov	$	(38,073)	$	-
11	2014	Dec	$	(45,671)	$	-
12	2015	Jan	$	-	$	-
13		TOTAL	$	(442,329)	$	-
14						
15	Test Year Cost		$	(442,329)	$	-
16						
17	Pro Forma Year Cost		$	-	$	-
18						
19	Adjustment		$	442,329	$	-

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended January 31, 2015

Non-Recurring Labor Related to Plant Layup (Coleman)

Line #	Year (1)	Month (2)		Plant (3)		IT (4)		Safety (5)		Supply Chain (6)		TOTAL (7)
1	2014	Feb	$	973,074	$	21,884	$	10,279	$	103,208	$	1,108,445
2	2014	Mar	$	1,048,002	$	23,556	$	11,065	$	111,092	$	1,193,714
3	2014	Apr	$	1,100,936	$	22,492	$	10,565	$	106,075	$	1,240,068
4		TOTAL	$	3,122,012	$	67,931	$	31,909	$	320,375	$	3,542,227
5												
6	Test Year Cost		$	3,122,012	$	67,931	$	31,909	$	320,375	$	3,542,227
7												
8	Headcount - Budget			104		2		1		16		123
9	Headcount - Pro Forma			15		0		0		13		28
10	Ratio			0.144		-		-		0.813		n/a
11												
12	Pro Forma Year Cost		$	450,290	$	-	$	-	$	260,305	$	710,595
13												
14	Adjustment		$	(2,671,722)	$	(67,931)	$	(31,909)	$	(60,070)	$	(2,831,632)

Reference Schedule: 1.11

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended January 31, 2015

Normalization of Certain Outside Professional Services

Line #	Year (1)	Month (2)	Integrated Resource Plan (3)	Load Forecast (4)	Transient Stability Study (5)	TOTAL (6)
1	2014	Feb	$ 20,000	$ -	$ -	$ 35,250
2	2014	Mar	$ 20,000	$ -	$ 30,000	$ 35,250
3	2014	Apr	$ 20,000	$ -	$ -	$ -
4	2014	May	$ -	$ -	$ -	$ -
5	2014	Jun	$ -	$ -	$ -	$ 20,600
6	2014	Jul	$ -	$ -	$ -	$ 20,000
7	2014	Aug	$ -	$ -	$ -	$ 50,000
8	2014	Sep	$ -	$ -	$ -	$ 20,000
9	2014	Oct	$ -	$ -	$ -	$ -
10	2014	Nov	$ -	$ -	$ -	$ -
11	2014	Dec	$ -	$ -	$ -	$ -
12	2015	Jan	$ -	$ 17,240	$ -	$ -
13		TOTAL	$ 60,000	$ 17,240	$ 30,000	$ 107,240
14						
15	Periodicity (Years)		3	2	2	n/a
16						
17	Test Year Cost		$ 445,000	$ 65,000	$ 30,000	$ 540,000
18						
19	Normalized Annual Cost		$ 148,333	$ 32,500	$ -	$ 180,833
20						
21	Adjustment		$ 88,333	$ 15,260	$ (30,000)	$ 73,593

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended January 31, 2015

Demand Side Management Expenses

Line #	Year (1)	Month (2)		Amount (3)
1	2014	Feb	$	44,124
2	2014	Mar	$	52,868
3	2014	Apr	$	44,124
4	2014	May	$	44,124
5	2014	Jun	$	311,608
6	2014	Jul	$	44,124
7	2014	Aug	$	44,124
8	2014	Sep	$	49,588
9	2014	Oct	$	62,701
10	2014	Nov	$	44,124
11	2014	Dec	$	299,544
12	2015	Jan	$	54,947
13		TOTAL	$	1,096,000
14				
15	Test Year Cost		$	1,096,000
16				
17	Pro Forma Year Cost		$	1,000,000
18				
19	Adjustment		$	(96,000)

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended January 31, 2015

Non-Labor Expenses Related to Plant Layup

Line #	Year (1)	Month (2)		Amount (3)
1	2014	Feb	$	1,773,641
2	2014	Mar	$	53,049
3	2014	Apr	$	58,591
4	2014	May	$	65,601
5	2014	Jun	$	220,054
6	2014	Jul	$	79,317
7	2014	Aug	$	71,554
8	2014	Sep	$	68,811
9	2014	Oct	$	72,274
10	2014	Nov	$	83,253
11	2014	Dec	$	231,753
12	2015	Jan	$	131,628
13		TOTAL	$	2,909,526
14				
15	Test Year Cost		$	2,909,526
16				
17	Pro Forma Year Cost		$	1,230,305
18				
19	Total Adjustment		$	(1,679,221)
20				
21	Amortization Period (Yrs)			5
22	Amort of Total Adjustment		$	(335,844)
23				
24	Adjustment		$	(1,343,377)

BIG RIVERS ELECTRIC CORPORATION
Based on the Fully Forecast Test Period
For the 12 Months Ended January 31, 2015

MISO Capacity Charge

Line #	Year (1)	Month (2)		Amount (3)
1	2014	Feb	$	119,129
2	2014	Mar	$	131,893
3	2014	Apr	$	127,638
4	2014	May	$	131,893
5	2014	Jun	$	-
6	2014	Jul	$	-
7	2014	Aug	$	-
8	2014	Sep	$	-
9	2014	Oct	$	-
10	2014	Nov	$	-
11	2014	Dec	$	-
12	2015	Jan	$	-
13		TOTAL	$	510,552
14				
15	Test Year Cost		$	510,552
16				
17	Amortization Period (Yrs)			5
18				
19	Pro Forma Year Cost		$	102,110
20				
21	Adjustment		$	(408,442)

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Functional Assignment and Classification

12 Months Ended
January 31, 2015

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Plant In Service						
Intangible Plant	INTPLT	PT&D	$ 66,895	58,434	-	8,461
Production Plant	PPROD	F001	$ 1,791,416,938	1,791,416,938	-	-
Transmission Plant	PTRAN	F002	$ 259,386,456	-	-	259,386,456
Distribution Plant	PDIST	F003	$ -	-	-	-
Total Production & Transmission Plant	PT&D		2,050,803,394	1,791,416,938	-	259,386,456
General Plant	PGP	PT&D	$ 37,457,964	32,720,265	-	4,737,699
Total Plant In Service	TPIS		$ 2,088,328,253	$ 1,824,195,637	$ -	$ 264,132,616
Construction Work In Progress (CWIP)						
CWIP Production	CWIP1	PPROD	$ 50,631,351	50,631,351	-	-
CWIP Transmission	CWIP2	PTRAN	$ 16,550,853	-	-	16,550,853
CWIP Distribution Plant	CWIP3	PDIST	$ -	-	-	-
CWIP General Plant	CWIP4	PT&D	$ 453,666	396,286	-	57,380
Total Construction Work In Progress	TCWIP		$ 67,635,870	$ 51,027,637	$ -	$ 16,608,233
Total Utility Plant			$ 2,155,964,123	$ 1,875,223,275	$ -	$ 280,740,848

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
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12 Months Ended
January 31, 2015

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Rate Base						
Total Utility Plant	TUP		$ 2,155,964,123	$ 1,875,223,275	$ -	$ 280,740,848
Less: Acummulated Provision for Depreciation						
Production	ADEPREPA	PPROD	$ 884,962,475	884,962,475	-	-
Transmission	ADEPRTP	PTRAN	$ 124,011,687	-	-	124,011,687
Distribution	ADEPRD11	PDIST	$ -	-	-	-
General & Common Plant	ADEPRD12	PT&D	$ 10,475,196	9,150,289	-	1,324,907
Intangible, Misc, and Other Plant	ADEPRGP	PT&D	$ -	-	-	-
Retirement Work In Progress	ADEPRRT	PT&D	$ -	-	-	-
Total Accumulated Depreciation	TADEPR		$ 1,019,449,358	$ 894,112,764	$ -	$ 125,336,594
Net Utility Plant	NTPLANT		$ 1,136,514,765	$ 981,110,511	$ -	$ 155,404,254
Working Capital						
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 22,556,130	9,490,006	10,529,654	2,536,469
Materials and Supplies	M&S	TPIS	$ 26,553,805	23,195,269	-	3,358,536
Prepayments	PREPAY	TPIS	$ 2,309,891	2,017,735	-	292,156
Fuel Stock	FS	TPIS	$ 19,304,614	16,862,959	-	2,441,656
Total Working Capital	TWC		$ 70,724,441	$ 51,565,969	$ 10,529,654	$ 8,628,817
Net Rate Base	RB		$ 1,207,239,206	$ 1,032,676,480	$ 10,529,654	$ 164,033,071

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

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January 31, 2015

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

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Cost of Service Study
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12 Months Ended
January 31, 2015

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Operation and Maintenance Expenses (Continued)						
Other Power Supply Expenses						
555 PURCHASED POWER Energy	OM555	OMPP	[redacted]			-
555 PURCHASED POWER Demand	OMD555	OMPPD	[redacted]			-
555 PURCHASED POWER BREC Share of HMP&L Station Two	OMH555	OMPPH	[redacted]			-
555 PURCHASED POWER OPTIONS	OMO555	OMPP	[redacted]			-
555 BROKERAGE FEES	OMB555	OMPP	[redacted]			-
555 MISO TRANSMISSION EXPENSES	OMM555	OMPP	[redacted]			-
556 SYSTEM CONTROL AND LOAD DISPATCH	OM556	PROFIX	[redacted]			-
557 OTHER EXPENSES	OM557	PROFIX	[redacted]			-
558 DUPLICATE CHARGES	OM558	Energy	[redacted]			-
Total Other Power Supply Expenses	TPP		[redacted]			$ -
Total Electric Power Generation Expenses			[redacted]			$ -
Transmission Expenses						
560 OPERATION SUPERVISION AND ENG	OM560	LBTRAN	$ 949,606	-	-	949,606
561 LOAD DISPATCHING	OM561	LBTRAN	$ 2,064,338	-	-	2,064,338
562 STATION EXPENSES	OM562	PTRAN	$ 738,595	-	-	738,595
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	$ 1,289,642	-	-	1,289,642
565 TRANSMISSION OF ELECTRICITY BY OTHERS	OM565	PTRAN	$ 2,698,514	-	-	2,698,514
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	$ 620,525	-	-	620,525
567 RENTS	OM567	PTRAN	$ 60,242	-	-	60,242
568 MAINTENACE SUPERVISION AND ENG	OM568	LBTRAN	$ 532,091	-	-	532,091
569 STRUCTURES	OM569	PTRAN	$ (80,241)	-	-	(80,241)
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	$ 1,748,250	-	-	1,748,250
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	$ 2,439,053	-	-	2,439,053
572 UNDERGROUND LINES	OM572	PTRAN	$ -	-	-	-
573 MISC PLANT	OM573	PTRAN	$ 813,708	-	-	813,708
573 MARKET FACILITATION MONITORING MISO	OM575	PTRAN	$ 961,746	-	-	961,746
Total Transmission Expenses			$ 14,836,071	$ -	$ -	$ 14,836,071

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January 31, 2015

Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Operation and Maintenance Expenses (Continued)						
Total Distribution Maintenance Expense	OMDM		$ -	$ -	$ -	$ -
Total Distribution Operation and Maintenance Expenses			-	-	-	-
Transmission and Distribution Expenses			14,836,071	-	-	14,836,071
Production, Transmission and Distribution Expenses	OMSUB		[redacted]			$ 14,836,071
Customer Accounts Expense						
901 SUPERVISION/CUSTOMER ACCTS	OM901	F025	$ -	-	-	-
902 METER READING EXPENSES	OM902	F025	$ -	-	-	-
903 RECORDS AND COLLECTION	OM903	F025	$ -	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F025	$ -	-	-	-
905 MISC CUST ACCOUNTS	OM903	F025	$ -	-	-	-
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -
Customer Service Expense						
907 SUPERVISION	OM907	TUP	$ -	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	TUP	$ 1,293,291	1,124,884	-	168,407
908 CUSTOMER ASSISTANCE EXP-INCENTIVES	OM908x	TUP	$ -	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	TUP	$ 31,897	27,744	-	4,154
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	$ 143,537	124,846	-	18,691
915 MDSE-JOBBING-CONTRACT	OM915	TUP	$ -	-	-	-
916 MISC SALES EXPENSE	OM916	TUP	$ -	-	-	-
Total Customer Service Expense	OMCS		$ 1,468,725	$ 1,277,474	$ -	$ 191,251
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service	OMSUB2		253,495,067	62,797,878	175,669,866	15,027,323

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Operation and Maintenance Expenses (Continued)						
Administrative and General Expense						
920 ADMIN. & GEN. SALARIES-	OM920	LBSUB9	$ 12,994,105	6,065,590	4,471,988	2,456,527
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB9	$ 8,876,103	4,143,325	3,054,756	1,678,021
922 ADMINISTRATIVE EXPENSES TRANSFERRED	OM922	LBSUB9	$ -	-	-	-
923 OUTSIDE SERVICES EMPLOYED	OM923	LBSUB9	$ 3,904,506	1,822,606	1,343,756	738,144
924 PROPERTY INSURANCE	OM924	TUP	$ -	-	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB9	$ -	-	-	-
926 EMPLOYEE BENEFITS	OM926	LBSUB9	$ 398,481	186,009	137,139	75,333
927 FRANCHISE REQUIREMENTS	OM927	TUP	$ -	-	-	-
928 REGULATORY COMMISSION FEES	OM928	TUP	$ -	-	-	-
929 DUPLICATE CHARGES-CR	OM929	LBSUB9	$ -	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	LBSUB9	$ 1,526,596	712,608	525,386	288,602
931 RENTS AND LEASES	OM931	PGP	$ 1,933	1,689	-	244
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	$ 217,906	190,345	-	27,561
Total Administrative and General Expense	OMAG		$ 27,919,629	$ 13,122,173	$ 9,533,025	$ 5,264,432
Total Operation and Maintenance Expenses	TOM		[redacted]			$ 20,291,755
Operation and Maintenance Expenses Less Purchased Power	OMLPP		[redacted]			

BIG RIVERS ELECTRIC CORPORATION
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12 Months Ended
January 31, 2015

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Transmission Demand
Labor Expenses										
Steam Power Generation Operation Expenses										
500 OPERATION SUPERVISION & ENGINEERING	LB500	PROFIX	$	3,007,988		3,007,988		-		-
501 FUEL	LB501	Energy	$	1,445,181		-		1,445,181		-
502 STEAM EXPENSES	LB502	PROFIX	$	4,041,398		4,041,398		-		-
505 ELECTRIC EXPENSES	LB505	PROFIX	$	4,266,944		4,266,944		-		-
506 MISC. STEAM POWER EXPENSES	LB506	PROFIX	$	986,533		986,533		-		-
507 RENTS	LB507	PROFIX	$	-		-		-		-
509 ALLOWANCES	LB509	Energy	$	-		-		-		-
Total Steam Power Operation Expenses	LBSUB1		$	13,748,044	$	12,302,863	$	1,445,181	$	-
Steam Power Generation Maintenance Expenses										
510 MAINTENANCE SUPERVISION & ENGINEERING	LB510	Energy	$	2,763,175		-		2,763,175		-
511 MAINTENANCE OF STRUCTURES	LB511	PROFIX	$	564,433		564,433		-		-
512 MAINTENANCE OF BOILER PLANT	LB512	Energy	$	5,067,466		-		5,067,466		-
513 MAINTENANCE OF ELECTRIC PLANT	LB513	Energy	$	799,627		-		799,627		-
514 MAINTENANCE OF MISC STEAM PLANT	LB514	PROFIX	$	630,832		630,832		-		-
Total Steam Power Generation Maintenance Expense	LBSUB2		$	9,825,534	$	1,195,266	$	8,630,268	$	-
Total Steam Power Generation Expense			$	23,573,578	$	13,498,129	$	10,075,449	$	-

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12 Months Ended
January 31, 2015

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		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	$	-		-		-		-
554 MAINTENANCE OF MISC OTHER POWER GEN PLT	LB554	PROFIX	$	-		-		-		-
Total Other Power Generation Maintenance Expense	LBSUB8		$	-	$	-	$	-	$	-
Total Other Power Generation Expense			$	-	$	-	$	-	$	-
Total Production Expense	LPREX		$	23,573,578	$	13,498,129	$	10,075,449	$	-

BIG RIVERS ELECTRIC CORPORATION
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Functional Assignment and Classification

12 Months Ended
January 31, 2015

Description	Name	Functional Vector		Total System		Production Demand		Production Energy		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	$	766,580		-		-		766,580
561 LOAD DISPATCHING	LB561	PTRAN	$	1,107,540		-		-		1,107,540
562 STATION EXPENSES	LB562	PTRAN	$	199,449		-		-		199,449
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	$	72,290		-		-		72,290
565 TRANSMISSION OF ELECTRICITY BY OTHERS	LB565	PTRAN	$	-		-		-		-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	$	394,136		-		-		394,136
567 RENTS	LB567	PTRAN	$	-		-		-		-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	$	250,243		-		-		250,243
569 MAINTENACE OF STRUCTURES	LB569	PTRAN	$	-		-		-		-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	$	1,359,620		-		-		1,359,620
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	$	1,106,606		-		-		1,106,606
573 MAINT OF MISC. TRANSMISSION PLANT	LB573	PTRAN	$	253,014		-		-		253,014
Total Transmission Labor Expenses	LBTRAN		$	5,509,477	$	-	$	-	$	5,509,477

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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Transmission Demand
Labor Expenses (Continued)										
Total Distribution Operation and Maintenance Labor Expenses		PDIST		-		-		-		-
Transmission and Distribution Labor Expenses				5,509,477		-		-		5,509,477
Production, Transmission and Distribution Labor Expenses	LBSUB		$	29,083,055	$	13,498,129	$	10,075,449	$	5,509,477
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	$	192,839		167,729		-		25,111
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		$	192,839	$	167,729	$	-	$	25,111
Sub-Total Labor Exp	LBSUB9			29,275,895		13,665,858		10,075,449		5,534,588

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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Transmission Demand
Labor Expenses (Continued)										
Administrative and General Expense										
920 ADMIN. & GEN. SALARIES-	LB920	LBSUB9	$	12,994,105		6,065,590		4,471,988		2,456,527
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB9	$	-		-		-		-
922 ADMIN. EXPENSES TRANSFERRED - CREDIT	LB922	LBSUB9	$	-		-		-		-
923 OUTSIDE SERVICES EMPLOYED	LB923	LBSUB9	$	-		-		-		-
924 PROPERTY INSURANCE	LB924	TUP	$	-		-		-		-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB9	$	-		-		-		-
926 EMPLOYEE BENEFITS	LB926	LBSUB9	$	304,550		142,163		104,812		57,575
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	$	108,435		94,720		-		13,715
Total Administrative and General Expense	LBAG		$	13,407,089	$	6,302,473	$	4,576,800	$	2,527,817
Total Operation and Maintenance Expenses	TLB		$	42,682,984	$	19,968,330	$	14,652,249	$	8,062,405
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$	42,682,984	$	19,968,330	$	14,652,249	$	8,062,405

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Description	Name	Functional Vector		Total System		Production Demand		Production Energy		Transmission Demand
Other Expenses										
Depreciation Expenses										
Production	DEPRDP2	PPROD	$	30,085,499		30,085,499		-		-
Transmission	DEPRDP3	PTRAN	$	5,225,407		-		-		5,225,407
Transmission	DEPRDP4	PTRAN	$	-		-		-		-
Distribution	DEPRDP5	PDIST	$	-		-		-		-
General & Common Plant	DEPRDP6	PGP	$	3,921,408		3,425,427		-		495,981
Other Plant	DEPROTH	TPIS	$	-		-		-		-
Total Depreciation Expense	TDEPR		$	39,232,314		33,510,926		-		5,721,389
Property Taxes & Other	PTAX	TUP	$	885		770		-		115
Amortization of Investment Tax Credit	OTAX	TUP	$	-		-		-		-
Other Interest Expenses	OT	TUP	$	-		-		-		-
Interest on Long Term Debt	INTLTD	TUP	$	43,765,994		38,066,965		-		5,699,029
Interest Charged to Construction - CR		TUP	$	(1,768,401)		(1,538,127)		-		(230,274)
Other Deductions	DEDUCT	TUP	$	668,273		581,253		-		87,020
Total Other Expenses	TOE		$	81,899,065	$	70,621,786	$	-	$	11,277,279
Total Cost of Service (O&M + Other Expenses)			[redacted]						$	31,569,033

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Description	Name	Functional Vector	Total System	Production Demand	Production Energy	Transmission Demand
Functional Vectors						
Production Plant	F001		1.000000	1.000000	0.000000	0.000000
Transmission Plant	F002		1.000000	0.000000	0.000000	1.000000
Distribution Plant	F003		1.000000	0.000000	0.000000	1.000000
Production Plant	F017		1.000000	0.000000	1.000000	0.000000
Production Variable Cost	PROVAR		1.000000	0.000000	1.000000	0.000000
Production Fixed Cost	PROFIX		1.000000	1.000000	0.000000	0.000000
Distribution Operation Labor	F023		-	-	-	-
Distribution Maintenance Labor	F024		-	-	-	-
Customer Accounts Expense	F025		1.000000	0.000000	0.000000	1.000000
Customer Service Expense	F026		1.000000	0.000000	0.000000	1.000000
Purchased Power Energy	OMPP		1.000000	0.000000	1.000000	0.000000
Purchased Power Demand	OMPPD		1.000000	1.000000	0.000000	0.000000
Purchased Power BREC Share of HMP&L Station Two	OMPPH		[redacted]			0.000000
				-	-	0.000000
Production Energy	Energy		1.000000	0.000000	1.000000	0.000000
Internally Generated Functional Vectors						
Total Prod, Trans, and Dist Plant		PT&D	1.000000	0.873520	-	0.126480
Total Transmission Plant		PTRAN	1.000000	-	-	1.000000
Operation and Maintenance Expenses Less Purchased Power		OMLPP	1.000000	0.420728	0.466820	0.112451
Total Plant in Service		TPIS	1.000000	0.873520	-	0.126480
Total Operation and Maintenance Expenses (Labor)		TLB	1.000000	0.467829	0.343281	0.188890
Sub-Total Prod, Trans, Dist, Cust Acct and Cust Service		OMSUB2	1.000000	0.247728	0.692991	0.059281
Total Steam Power Operation Expenses (Labor)		LBSUB1	1.000000	0.894881	0.105119	-
Total Steam Power Generation Maintenance Expense (Labor)		LBSUB2	1.000000	0.121649	0.878351	-
Total Transmission Labor Expenses		LBTRAN	1.000000	-	-	1.0000000
Sub-Total Labor Exp		LBSUB7	1.000000	0.466796	0.344155	0.189049
Total General Plant		PGP	1.000000	0.873520	-	0.126480
Total Production Plant		PPROD	1.000000	1.000000	-	-
Total Intangible Plant		INTPLT	1.000000	0.873520	-	0.126480

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
January 31, 2015

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Total System
Plant In Service									
Power Production Plant									
Production Demand	TPIS	PLPDMD	12CP	$	1,444,681,705	$	379,513,932	$	1,824,195,637
Production Energy	TPIS	PLPENG	PENG	$	-	$	-	$	-
Production - Steam Direct	TPIS	PLPSTM	STMD	$	-	$	-	$	-
Total Power Production Plant		PLPT		$	1,444,681,705	$	379,513,932	$	1,824,195,637
Transmission Plant	TPIS	PLTRN	12CP	$	209,181,269	$	54,951,347	$	264,132,616
Distribution Substation	TPIS	PLDST	SUBA	$	-	$	-	$	-
Distribution Other	TPIS	PLDMC	Cust05	$	-	$	-	$	-
Total		PLT		$	1,653,862,974	$	434,465,279	$	2,088,328,253

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
January 31, 2015

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Total System
Net Utility Plant									
Power Production Plant									
Production Demand	NTPLANT	NTPDMD	12CP	$	776,995,831	$	204,114,679	$	981,110,511
Production Energy	NTPLANT	NTPENG	PENG	$	-	$	-	$	-
Production - Steam Direct	NTPLANT	NTPSTM	STMD	$	-	$	-	$	-
Total Power Production Plant		NTPT		$	776,995,831	$	204,114,679	$	981,110,511
Transmission Plant	NTPLANT	NTTRN	12CP	$	123,073,249	$	32,331,006	$	155,404,254
Distribution Substation	NTPLANT	NTDST	SUBA	$	-	$	-	$	-
Distribution Other	NTPLANT	NTDMC	Cust05	$	-	$	-	$	-
Total		NTPLT		$	900,069,080	$	236,445,685	$	1,136,514,765

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
January 31, 2015

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Total System
Net Cost Rate Base									
Power Production Plant									
Production Demand	RB	RBPDMD	12CP	$	817,833,782	$	214,842,697	$	1,032,676,480
Production Energy	RB	RBPENG	PENG	$	7,384,642	$	3,145,012	$	10,529,654
Production - Steam Direct	RB	RBPSTM	STMD	$	-	$	-	$	-
Total Power Production Plant		RBPT		$	825,218,424	$	217,987,710	$	1,043,206,134
Transmission Plant	RB	RBTRN	12CP	$	129,906,887	$	34,126,184	$	164,033,071
Distribution Substation	RB	RBDST	SUBA	$	-	$	-	$	-
Distribution Other	RB	RBDMC	Cust05	$	-	$	-	$	-
Total		RBPLT		$	955,125,312	$	252,113,894	$	1,207,239,206

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
January 31, 2015

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Total System
Operation and Maintenance Expenses									
Power Production Plant									
Production Demand	TOM	OMPDMD	12CP	[redacted]					
Production Demand Reallocation of Purchased Power									
Production Energy	TOM	OMPENG	PENG						
Production - Steam Direct	TOM	OMPSTM	STMD						
Total Power Production Plant		OMPT							
Transmission Plant	TOM	OMTRN	12CP	$	16,070,166	$	4,221,589	$	20,291,755
Distribution Substation	TOM	OMDST	SUBA	$	-	$	-	$	-
Distribution Other	TOM	OMDMC	Cust05	$	-	$	-	$	-
Total		OMPLT		[redacted]					

Case No. 2013-00199
Exhibit Wolfram-4.2

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
January 31, 2015

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Total System
Labor Expenses									
Power Production Plant									
Production Demand	TLB	LBPDMD	12CP	$	15,814,028	$	4,154,302	$	19,968,330
Production Energy	TLB	LBPENG	PENG	$	10,275,894	$	4,376,355	$	14,652,249
Production - Steam Direct	TLB	LBPSTM	STMD	$	-	$	-	$	-
Total Power Production Plant		LBPT		$	26,089,922	$	8,530,657	$	34,620,579
Transmission Plant	TLB	LBTRN	12CP	$	6,385,065	$	1,677,339	$	8,062,405
Distribution Substation	TLB	LBDST	SUBA	$	-	$	-	$	-
Distribution Other	TLB	LBDMC	Cust05	$	-	$	-	$	-
Total		LBPLT		$	32,474,988	$	10,207,996	$	42,682,984

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
January 31, 2015

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Total System
Depreciation Expenses									
Power Production Plant									
Production Demand	TDEPR	DPPDMD	12CP	$	26,539,161	$	6,971,765	$	33,510,926
Production Energy	TDEPR	DPPENG	PENG	$	-	$	-	$	-
Production - Steam Direct	TDEPR	DPPSTM	STMD	$	-	$	-	$	-
Total Power Production Plant		DPPT		$	26,539,161	$	6,971,765	$	33,510,926
Transmission Plant	TDEPR	DPTRN	12CP	$	4,531,085	$	1,190,304	$	5,721,389
Distribution Substation	TDEPR	DPDST	SUBA	$	-	$	-	$	-
Distribution Other	TDEPR	DPDMC	Cust05	$	-	$	-	$	-
Total		DPPLT		$	31,070,246	$	8,162,069	$	39,232,314

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
January 31, 2015

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Total System
Property and Other Taxes									
Power Production Plant									
Production Demand	PTAX	PRPDMD	12CP	$	610	$	160	$	770
Production Energy	PTAX	PRPENG	PENG	$	-	$	-	$	-
Production - Steam Direct	PTAX	PRPSTM	STMD	$	-	$	-	$	-
Total Power Production Plant		PRPT		$	610	$	160	$	770
Transmission Plant	PTAX	PRTRN	12CP	$	91	$	24	$	115
Distribution Substation	PTAX	PRDST	SUBA	$	-	$	-	$	-
Distribution Other	PTAX	PRDMC	Cust05	$	-	$	-	$	-
Total		PRPLT		$	701	$	184	$	885

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
January 31, 2015

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Total System
Interest Expenses									
Power Production Plant									
Production Demand	INTLTD	INPDMD	12CP	$	30,147,341	$	7,919,624	$	38,066,965
Production Energy	INTLTD	INPENG	PENG	$	-	$	-	$	-
Production - Steam Direct	INTLTD	INPSTM	STMD	$	-	$	-	$	-
Total Power Production Plant		INPT		$	30,147,341	$	7,919,624	$	38,066,965
Transmission Plant	INTLTD	INTRN	12CP	$	4,513,377	$	1,185,652	$	5,699,029
Distribution Substation	INTLTD	INDST	SUBA	$	-	$	-	$	-
Distribution Other	INTLTD	INDMC	Cust05	$	-	$	-	$	-
Total		INPLT		$	34,660,718	$	9,105,276	$	43,765,994

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
January 31, 2015

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Total System
Cost of Service Summary -- Unadjusted						
Operating Revenues						
Sales to Members		REVUC	R01	[redacted]		
Off System Sales Revenue			OSS			
Income from Leased Property Net		OTHREV	RBPLT			
Other Operating Revenue & Income		OTHREV	RBPLT			
Total Operating Revenues		TOR		$ 216,428,233	$ 76,110,156	$ 292,538,389
Operating Expenses						
Operation and Maintenance Expenses				[redacted]		
Depreciation and Amortization Expenses				$ 31,070,246	$ 8,162,069	$ 39,232,314
Property and Other Taxes			NPT	$ 701	$ 184	$ 885
Total Operating Expenses		TOE		[redacted]		
Utility Operating Margin				[redacted]		
Non-Operating Items						
Interest Income			RBPLT	$ 1,421,791	$ 375,295	$ 1,797,086
Other Non-Operating Income			RBPLT	$ -	$ -	$ -
Other Capital Credits & Patronage Dividends			RBPLT	$ 2,167,355	$ 572,093	$ 2,739,448
Total Non-Operating Items				$ 3,589,146	$ 947,387	$ 4,536,533
Net Utility Operating Margin		TOM		[redacted]		
Net Cost Rate Base				[redacted]		
Rate of Return on Rate Base (Unadjusted)				-1.79%	-2.55%	-1.95%

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
January 31, 2015

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Total System
Cost of Service Summary -- Pro-Forma (Before Proposed Rate Increase)									
Operating Revenues									
Total Operating Revenue				$	216,428,233	$	76,110,156	$	292,538,389
Pro-Forma Adjustments:									
To Remove Fuel Adjustment Clause Revenue		1.01		$	(13,737,782)	$	(5,843,877)	$	(19,581,659)
To Remove Environmental Surcharge Revenue		1.02		$	(13,241,248)	$	(4,468,442)	$	(17,709,690)
To Remove Non-FAC PPA Revenue		1.03		$	826,876	$	356,508	$	1,183,384
To Remove Surcredit Revenue		1.09		$	308,324	$	134,005	$	442,329
Total Revenue Adjustments				$	(25,843,830)	$	(9,821,806)	$	(35,665,636)
Total Pro-Forma Operating Revenue				$	190,584,403	$	66,288,350	$	256,872,753

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
January 31, 2015

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Total System
Cost of Service Summary -- Pro-Forma (Before Proposed Rate Increase) (cont.)						
Operating Expenses						
Operation and Maintenance Expenses				[redacted]		
Depreciation and Amortization Expenses				$ 31,070,246	$ 8,162,069	$ 39,232,314
Property and Other Taxes			NPT	$ 701	$ 184	$ 885
Adjustments to Operating Expenses:						
To Remove Fuel Expense Recoverable through the FAC		1.01		$ (13,737,782)	$ (5,843,877)	$ (19,581,659)
To Remove Expenses Recoverable through the ES		1.02		$ (13,241,248)	$ (4,468,442)	$ (17,709,690)
To Remove NFPPA		1.03		$ 828,876	$ 356,508	$ 1,183,384
To Remove Promotional Advertising		1.04	R01	$ (41,744)	$ (14,012)	$ (55,756)
To Remove Lobbying Expenses		1.05	R01	$ (53,174)	$ (17,849)	$ (71,023)
To Remove Economic Development Expenses		1.06	R01	$ (108,236)	$ (36,332)	$ (144,568)
To Remove Donations Expenses		1.07	R01	$ (47,413)	$ (15,915)	$ (63,328)
To Remove Touchstone Energy dues		1.08	R01	$ (99,400)	$ (33,366)	$ (132,766)
To Remove Non-Recurring Labor related to Plant Layup		1.10	LBPLT	$ (2,154,423)	$ (677,209)	$ (2,831,632)
To Normalize Certain Outside Professional Services		1.11	EnergyNS	$ 51,515	$ 22,078	$ 73,593
To Remove Forecast DSM Expenses		1.12	12CP	$ (867,983)	$ (228,017)	$ (1,096,000)
To Allocate Annual DSM Solely to Rural Rate Class		1.12	EnergyR	$ 1,000,000	$ -	$ 1,000,000
To Normalize Non-Labor Expenses Related to Plant Layup		1.13	RBPLT	$ (1,062,833)	$ (280,544)	$ (1,343,377)
To Normalize MISO Capacity charge related to Plant Layup		1.14	12CP	$ (323,468)	$ (84,974)	$ (408,442)
Total Expense Adjustments				$ (29,859,314)	$ (11,321,950)	$ (41,181,264)
Total Operating Expenses		TOE		[redacted]		
Utility Operating Margins -- Pro-Forma				[redacted]		
Non-Operating Items				$ -	$ -	$ -
Sum of Non-Operating Items				$ 3,589,146	$ 947,387	$ 4,536,533
Adjustments to Non-Operating Items			12CP	$ -	$ -	$ -
Total Non-Operating Items				$ 3,589,146	$ 947,387	$ 4,538,533
Net Utility Operating Margin				[redacted]		
Net Cost Rate Base				[redacted]		
Rate of Return on Rate Base -- Pro Forma (Before Proposed Rate Increase)				-1.37%	-1.96%	-1.50%

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
January 31, 2015

Description	Ref	Name	Allocation Vector		Rurals		Large Industrials		Total System
Cost of Service Summary -- Pro-Forma (After Proposed Rate Increase)									
Operating Revenues									
Total Operating Revenue				$	190,584,403	$	66,288,350	$	256,872,753
Pro-Forma Adjustments:									
To Reflect Proposed Increase				$	55,200,007	$	16,027,040	$	71,227,047
Total Pro-Forma Operating Revenue				$	245,784,410	$	82,315,390	$	328,099,800
Operating Expenses									
Total Operating Expenses				[redacted]					
Utility Operating Margins -- Pro-Formed for Increase				[redacted]					
Net Cost Rate Base				[redacted]					
Rate of Return -- Pro Forma (After Proposed Rate Increase)					4.03%		4.02%		4.03%

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
January 31, 2015

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Total System
Allocation Factors						
Energy Allocation Factors						
Energy Usage by Class		E01	Energy	0.701319	0.298681	1.000000
Customer Allocation Factors						
Rev		R01		172,877,765	58,029,852	230,907,617
Energy		Energy		2,308,552,000	983,179,000	3,291,731,000
FAC Revenue Allocator		FACA		2,308,552,000	983,179,000	3,291,731,000
Base Fuel Revenue Allocator		BSFL		2,308,552,000	983,179,000	3,291,731,000
Fuel Expense Applicable to FAC Allocator		FACEX		2,308,552,000	983,179,000	3,291,731,000
Energy - NonSmelter		EnergyNS		0.7000	0.3000	1.0000
Energy - Rurals only		EnergyR		1.0000	-	1.0000
Customers (Metering Points)		Cust05		3	1	4
Demand Allocators						
Steam - Direct Assignment		STMD		-	-	-
Substation Allocator		SUBA		-	-	-
Coincident Peak Demand CP		12CP		5,128,900	1,347,348	6,476,248

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
January 31, 2015

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Total System
Production Energy Allocation						
Production Energy Residual Allocator		PENGA		2,308,552,000	983,179,000	3,291,731,000
Production Energy Costs				-	-	-
Member Specific Assignment				-	-	-
Production Energy Residual			PENGA	129,886,222	55,316,669	185,202,891
Production Energy Total		PENGT		129,886,222	55,316,669	185,202,891
Production Energy Total Allocator		PENG	PENGT	0.701319	0.298681	1.000000
FAC Expense Residual Allocator		FACALL		2,308,552,000	983,179,000	3,291,731,000
FAC Expense Cost				-	-	-
Member Specific Assignment				-	-	-
FAC Expense Residual			FACALL	-	-	-
FAC Expense Total		FACT		-	-	-
FAC Expense Allocator		FACAL	12CP	0.701319	0.298681	1.000000
OSS Allocated Amount		OSSA		[redacted]		
Off-System Sales Allocator						
Off-System Sales Revenue			OSSA	[redacted]		
Specific Assignment						
Total OSS Assignments		OSS				
				-	-	-

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
January 31, 2015

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Total System
Operating Expenses						
Expenses before Adjustments						
Production Demand				[redacted]		
Production Energy						
Transmission Demand				$ 20,601,342	$ 5,411,916	$ 26,013,258
Total				[redacted]		
Expenses After Revenue Offsets						
Production Demand				[redacted]		
Production Energy						
Transmission Demand				$ 20,601,342	$ 5,411,916	$ 26,013,258
Total				[redacted]		
Rate Base						
Production Demand				[redacted]		
Production Energy						
Transmission Demand				$ 129,906,887	$ 34,126,184	$ 164,033,071
Total				[redacted]		
Operating Expenses-Unit Costs						
Production Demand ($/kW)				[redacted]		
Production Energy ($/kWh)						
Transmission Demand ($/kW)				4.02	4.02	4.02
Rate Base-Unit Costs						
Production Demand ($/kW)				[redacted]		
Production Energy ($/kWh)						
Transmission Demand ($/kW)				25.33	25.33	25.33

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Rate Schedule Allocation

12 Months Ended
January 31, 2015

Description	Ref	Name	Allocation Vector	Rurals	Large Industrials	Total System
Revenue Requirement Assuming a Rate of Return of	4.03%					
Production Demand				[redacted]		
Production Energy						
Transmission Demand				25,834,591	6,786,676	32,621,268
Total Revenue Requirement				[redacted]		
Unit Revenue Requirement						
Production Demand						
Production Demand (Per kW)				[redacted]		
Production Demand Margin (Per kW)						
Total Production Demand (Per kW)						
Production Energy						
Production Energy - (Per kWh)				[redacted]		
Production Energy Margin - (Per kWh)						
Total Production Energy (Per kWh)						
Transmission Demand						
Transmission Demand (per kW)				4.02	4.02	4.02
Tranmission Margin (Per kW)				0.04	0.04	0.04
Total Transmission Demand (per kW)				4.05	4.05	4.05

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Billing Determinants - Present and Proposed Rates

12 Months Ended
January 31, 2015

Rate		Billing Determinants	Current Rate Charge	Current Rate Billings	Proposed Rate Charge	Proposed Rate Billings	Variance Billings
Rural Delivery Point Service							
Demand Charge	CP	5,128,900 kW-Mo	12.914 /kW-Mo	$ 66,234,615	23.511 /kW-Mo	$ 120,585,568	$ 54,350,953
Energy Charge		2,308,552,000 kWh	0.035000 /kWh	80,799,320	0.035000 /kWh	80,799,320	-
Total Demand and Energy Charges			0.063691	$ 147,033,935	0.087234	$ 201,384,888	$ 54,350,953
Non-Smelter Non-FAC PPA			(0.000358)	(826,876)	(0.000358)	(826,876)	-
FAC			0.005951	13,737,782	0.005951	13,737,782	-
Environmental Surcharge			0.005736	13,241,248	0.006102	14,086,285	845,037
Surcredit			(0.000134)	(308,324)	(0.000134)	(308,324)	-
Total		2,308,552,000 kWh	0.074886	$ 172,877,765	0.098795	$ 228,073,755	$ 55,195,990
Increase	$ Wholesale				0.023909	$ 55,195,990	
Increase	% Wholesale					31.9%	
Increase	% Retail (est.)					22.2%	
Large Industrial Customer Delivery Point Service							
Demand Charge	NCP	1,746,400 kW-Mo	10.715 /kW-Mo	$ 18,712,676	17.000 /kW-Mo	$ 29,688,800	$ 10,976,124
Energy Charge		983,179,000 kWh	0.030000 /kWh	29,495,370	0.035000 /kWh	$ 34,411,265	$ 4,915,895
Total Demand and Energy Charges			0.049033	$ 48,208,046	0.065196739	$ 64,100,065	$ 15,892,019
Non-Smelter Non-FAC PPA			(0.000363)	(356,508)	(0.000363)	(356,508)	-
FAC			0.005944	5,843,877	0.005944	5,843,877	-
Environmental Surcharge			0.004545	4,468,442	0.004682	4,603,463	135,021
Surcredit			(0.000136)	(134,005)	(0.000136)	(134,005)	-
Total		983,179,000 kWh	0.059023	$ 58,029,852	0.075324	$ 74,056,892	$ 16,027,040
Increase	$ Wholesale				0.016301	$ 16,027,040	
Increase	% Wholesale					27.6%	
Increase	% Retail (est.)					26.7%	
TOTAL Rural & Large Industrial Services							
Total		3,291,731,000	0.070148	$ 230,907,617	0.091785	$ 302,130,647	$ 71,223,030
INCREASE					0.021637	$ 71,223,030	
						30.8%	

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Summary of Proposed Increase

12 Months Ended
January 31, 2015

Class	Total Revenue at Current Rates ($)	Total Revenue at Proposed Rates ($)	Wholesale Increase ($)	Wholesale Increase (%)
Rural	172,877,765	228,073,755	55,195,990	31.9%
Large Industrial	58,029,852	74,056,892	16,027,040	27.6%
Total	230,907,617	302,130,647	71,223,030	30.8%

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Estimate of Retail Rate Increase

12 Months Ended
January 31, 2015

Rural Delivery Service

		Current	Proposed	Increase	Increase
Estimated Retail Rate ($/kWh)					
All-In Wholesale Rate		0.074886	0.098795	0.023909	31.9%
Estimated Retail Distr Cost Adder		0.033000	0.033000		
Total Retail Rate Estimate		0.107886	0.131795	0.023909	22.2%
Estimated Billings ($/Month)					
Monthly Usage	100 kWh	$ 10.79	$ 13.18	$ 2.39	22.2%
	200	$ 21.58	$ 26.36	$ 4.78	22.2%
	300	$ 32.37	$ 39.54	$ 7.17	22.2%
	400	$ 43.15	$ 52.72	$ 9.57	22.2%
	500	$ 53.94	$ 65.90	$ 11.96	22.2%
	600	$ 64.73	$ 79.08	$ 14.35	22.2%
	700	$ 75.52	$ 92.26	$ 16.74	22.2%
	800	$ 86.31	$ 105.44	$ 19.13	22.2%
	900	$ 97.10	$ 118.62	$ 21.52	22.2%
	1000	$ 107.89	$ 131.80	$ 23.91	22.2%
	1100	$ 118.67	$ 144.97	$ 26.30	22.2%
	1200	$ 129.46	$ 158.15	$ 28.69	22.2%
	1300	$ 140.25	$ 171.33	$ 31.08	22.2%
	1400	$ 151.04	$ 184.51	$ 33.47	22.2%
	1500	$ 161.83	$ 197.69	$ 35.86	22.2%

Large Industrial Customer Service

		Current	Proposed	Increase	Increase
Estimated Retail Rate ($/kWh)					
All-In Wholesale Rate		0.059023	0.075324	0.016301	27.6%
Estimated Retail Distribution Cost Adder		0.002000	0.002000		
Total Retail Rate Estimate		0.061023	0.077324	0.016301	26.7%
Estimated Billings ($/Month)					
Monthly Usage	500 kWh	$ 30.51	$ 38.66	$ 8.15	26.7%
	600	$ 36.61	$ 46.39	$ 9.78	26.7%
	700	$ 42.72	$ 54.13	$ 11.41	26.7%
	800	$ 48.82	$ 61.86	$ 13.04	26.7%
	900	$ 54.92	$ 69.59	$ 14.67	26.7%
	1000	$ 61.02	$ 77.32	$ 16.30	26.7%
	1100	$ 67.12	$ 85.06	$ 17.93	26.7%
	1200	$ 73.23	$ 92.79	$ 19.56	26.7%
	1300	$ 79.33	$ 100.52	$ 21.19	26.7%
	1400	$ 85.43	$ 108.25	$ 22.82	26.7%
	1500	$ 91.53	$ 115.99	$ 24.45	26.7%
	1600	$ 97.64	$ 123.72	$ 26.08	26.7%
	1700	$ 103.74	$ 131.45	$ 27.71	26.7%
	1800	$ 109.84	$ 139.18	$ 29.34	26.7%
	1900	$ 115.94	$ 146.92	$ 30.97	26.7%
	2000	$ 122.05	$ 154.65	$ 32.60	26.7%