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COMMISSION

COMMONWEALTH OF KENTUCKY
OFFICE OF THE ATTORNEY GENERAL

JACK CONWAY
ATTORNEY GENERAL

1024 CAPITAL CENTER DRIVE
SUITE 200
FRANKFORT, KENTUCKY 40601

October 29, 2013

Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Blvd.
Frankfort, KY 40601

RE: *In Re* Application of Big Rivers Electric Corporation, Inc.
for an Adjustment of Rates; Case No. 2013-00199

Dear Mr. Derouen:

On this date, Tuesday, October 29, 2013, the Attorney General is filing his pre-filed written direct testimony in the above-styled matter. The Attorney General's testimony includes certain items for which the petitioner, Big Rivers Electric Corp. ["Big Rivers"], has sought confidential protection. As you may be aware, the Attorney General entered into a confidentiality agreement with Big Rivers in which the Attorney General, among other things, agreed to protect the confidentiality of information which Big Rivers deems confidential, and for which it seeks confidential protection from the Public Service Commission. Big Rivers has filed with the Commission petitions for confidential treatment, dated July 1, 2013; July 15, 2013; September 2, 2013; and October 22, 2013. To date, it appears that the Commission has yet to rule on any of these petitions.

In accordance with Commission procedures, the Attorney General has separately printed each page containing any information for which Big Rivers has sought confidential protection, and is placing these pages in a sealed envelope marked "Confidential."

Please advise if you should have any questions, or require any further information.

Yours truly,

Lawrence W. Cook
ASSISTANT ATTORNEY
GENERAL

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION, INC. FOR AN ADJUSTMENT OF RATES	)))	Case No. 2013-00199

ATTORNEY GENERAL'S PRE-FILED TESTIMONY
PUBLIC REDACTED VERSION

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and files the following testimony in the above-styled matter with the reservation of the right to file supplemental testimony as noted below.

The Attorney General notes that, due to the fact that the rates which Big Rivers Electric Corporation, Inc. ["Big Rivers"] filed in Case No. 2012-00535 are currently in effect subject to refund, and further because the Commission has not issued its Final Order in that proceeding, that Order is certain to affect Big Rivers' financial status and consequently is likely to alter the company's fully forecasted test year utilized in the instant matter. Finally, the Commission's Final Order in Case No. 2012-00535 is likely to be issued on or before November 15, 2013 which will likely occur *after* the filing of the instant round of intervenor testimony, but *before* Big Rivers files its rebuttal testimony. This would give the company the right to address the implications and ramifications of the

Commission's Final Order in Case No. 2012-00535, but would deny the intervenors the same right. To address this potential deprivation of due process rights and which would deprive the Attorney General of meaningful participation in the instant case, the Attorney General reserves his right to file supplemental testimony in in the instant matter to fully clarify his position(s).

Respectfully submitted,
JACK CONWAY
ATTORNEY GENERAL

JENNIFER BLACK HANS
DENNIS G. HOWARD, II
LAWRENCE W. COOK
ASSISTANT ATTORNEYS GENERAL
1024 CAPITAL CENTER DRIVE
SUITE 200
FRANKFORT KY 40601-8204
(502) 696-5453
FAX: (502) 573-8315
Jennifer.Hans@ag.ky.gov
Dennis.Howard@ag.ky.gov
Larry.Cook@ag.ky.gov

Certificate of Service and Filing

Counsel certifies that an original and ten photocopies of the foregoing were served and filed by hand delivery to Jeff Derouen, Executive Director, Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40601; counsel further states that true and accurate copies of the foregoing were mailed via First Class U.S. Mail, postage pre-paid, to:

Mark A. Bailey
President and CEO
Big Rivers Electric Corporation
201 Third St.
Henderson, KY 42420

Hon. James M. Miller
Sullivan, Mountjoy, Stainback & Miller, PSC
P.O. Box 727
Owensboro, KY 42302-0727

Hon. Michael L. Kurtz
Boehm, Kurtz & Lowry
36 E. 7th St.
Ste. 1510
Cincinnati, OH 45202

Gregory Starheim
President and CEO
Kenergy Corp.
P. O. Box 18
Henderson, KY 42419-0018

Hon. J. Christopher Hopgood
Kristin Henry
Ruben Mojica
Staff Attorneys
Sierra Club
85 Second Street
San Francisco, CA 94105

Dorsey, King, Gray, Norment & Hopgood
318 Second St.
Henderson, KY 42420

Burns Mercer
Meade County RECC
P.O. Box 489
Brandenburg, KY 40108

Hon. Thomas C. Brite
Brite and Hopkins PLLC
P.O. Box 309
Hardinsburg, KY 40143

Kelly Nuckols
President & CEO
Jackson Purchase Energy Corp.
PO Box 3188
Paducah, KY 42002-3188

Hon. Melissa Yates
P.O. Box 929
Paducah, KY 42002-0929

Thomas J. Cmar
5042 N. Leavitt Street, Ste. 1
Chicago, IL 60625

Shannon Fisk
Earthjustice
1617 JFK Blvd. Suite 1675
Philadelphia, PA 19103

this 24th day of Oct., 2013

Assistant Attorney General

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

DIRECT TESTIMONY

OF

DAVID BREVITZ, C.F.A.

ON BEHALF OF

KENTUCKY OFFICE OF ATTORNEY GENERAL

PUBLIC REDACTED VERSION

FILED: October 28, 2013

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BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY
CASE NO. 2013-00199
DIRECT TESTIMONY OF
DAVID BREVITZ

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David Brevitz. My business address is 3623 SW Woodvalley Terrace, Topeka, Kansas.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am an independent consultant serving state regulatory commissions, Attorney General's Offices, and consumer organizations. I am testifying on behalf of the Kentucky Office of the Attorney General, in conjunction with Mr. Larry Holloway and Mr. Bion Ostrander.

Q. DO YOU HAVE SPECIFIC EXPERIENCE, EXPERTISE AND DIRECT KNOWLEDGE REGARDING THE SUBJECTS WHICH ARE CONTAINED IN YOUR TESTIMONY?

A. Yes. Over the course of decades of experience in economic regulation of public utilities at the state commission level, I have developed expertise in the public utility concept, economic characteristics of public utilities, the rate case process and determination of revenue requirements, public utility cost of service principles, and public utility financing and reorganization transactions. I have conducted several detailed and extensive analyses of proposed utility financial transactions and related utility regulatory policies, under the relevant laws in those states. On behalf of the Attorney General, I have addressed two such transactions in Kentucky:

- The proposed spin-off of Alltel's wireline telephone division ("Windstream"), and subsequent merger with Valor Communications in a reverse Morris Trust transaction on a tax-free basis, which included incurrence of substantial new debt by Windstream, and payments and other transactions including special dividends to Alltel.

- The "Unwind" transaction between Big Rivers Electric Corporation ("Big Rivers" or "BREC" or "the company") and E.ON. The "Unwind" engagement was limited to assessing whether BREC would be financially viable on a going forward basis following any approval of the transaction, based on review of the financial projections of BREC. The financial projections included a scenario if both aluminum smelters left the system. My review included the nature and extent of the BREC organization, both current and proposed; statements and rationale offered by Joint Applicants as to why the proposed transactions were in the public interest; internal managerial analyses, presentations and reports of E.ON, BREC and its member cooperatives, and the smelters; and, the proposed agreements among BREC, Kenergy and the aluminum smelters, including provisions for termination of the agreements.

My training and experience in public utility regulation began while studying at the Institute of Public Utilities in the Economics Department at Michigan State University. This program covered principles of public utility regulation, and addressed development and application of state commission utility regulatory practices in detail for electric, gas and telephone utilities. While at Michigan State, I earned an undergraduate degree in Justice, Morality and Constitutional Democracy from James Madison College (a residential college at MSU) and an MBA in Finance (1980). Since that time, I have worked on numerous matters for state utility commissions, consumer advocates, Attorneys General, and international regulatory bodies. Further description of my background and experience is provided on Exhibit DB-1.

Q. **DID YOU FILE TESTIMONY ON BEHALF OF THE KENTUCKY OFFICE OF THE ATTORNEY GENERAL IN THE MOST RECENT APPLICATION (CASE NO. 2012-00535, THE CENTURY HAWESVILLE CASE) FOR A RATE INCREASE BY BIG RIVERS?**

A. Yes. I provided testimony in that matter regarding BREC's "precarious financial position," the Unwind Transaction and the related Smelter Agreements,[1] BREC's Corrective Plan and Mitigation Plan, debt leverage, financial projections and market price projections included in the financial projections, BREC's mission, and BREC's excess capacity due to termination of the Smelter Agreements between and among Century Aluminum, Kenergy, and BREC. That testimony and the testimony of Mr. Bion Ostrander and Mr. Larry Holloway supported a recommendation that the Commission not grant any of the requested increase, due to the fact that it would result in rates which were not just and reasonable due to the inclusion of "excess capacity" costs. Although BREC has chosen a strategy of filing different cases to address the loss of the two smelter loads, my testimony filed under Case No. 2012-00535 remains highly relevant to this current case, so I encourage the Commission and Staff to consider the testimony presented by the OAG and the issues identified in that proceeding, as well as this current testimony. There is a very significant commonality of issues between the two cases, especially in light of the fact that as of the time of the filing of my testimony in this current

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[1] *Applications of Big Rivers Electric Corporation for: (1) Approval of Wholesale Tariff Additions for Big Rivers Electric Corporation, (2) Approval of Transactions, (3) Approval to Issue Evidences of Indebtedness, and (4) Approval of Amendments to Contracts; and of E.ON U.S., LLC, Western Kentucky Energy Corp. and LG&E Energy Marketing, Inc. for Approval of Transactions,* Case No. 2007-00455.*Corporation, (2) Approval of Transactions, (3) Approval to Issue Evidences of Indebtedness, and (4) Approval of Amendments to Contracts; and of E.ON U.S., LLC, Western Kentucky Energy Corp. and LG&E Energy Marketing, Inc. for Approval of Transactions,* Case No. 2007-00455.

case, the Commission has not yet issued a Final Order in Case No. 2012-00535 . It is my understanding that the rates filed in Case No. 2012-00535 are currently in effect subject to refund, pending the Commission's final Order, which I understand is due on or before November 15, 2013. Regarding the Commission's final determination in that proceeding, I reserve the option to file supplemental testimony to clarify the OAG's position.

Q. DO YOU HAVE OTHER RELEVANT QUALIFICATIONS?

A. Yes. In 1984 I was designated as a Chartered Financial Analyst by the Institute of Chartered Financial Analysts ("ICFA"), which later became the CFA Institute. The CFA Institute is the organization which has defined and organized a body of knowledge important for all investment professionals. The general areas of knowledge are ethical and professional standards, accounting, statistics and analysis, economics, fixed income securities, equity securities, and portfolio management.

Additionally, I have been designated as a Senior Fellow by the Public Utilities Research Center at the University of Florida ("PURC"). This designation is reserved for knowledgeable and experienced professionals who foster strong ties to academia, industry, and government, who embody PURC's values of respect, integrity, effectiveness and expertise, and who support PURC's mission to contribute to the development and availability of efficient utility services through research, education, and service.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS MATTER?

A. The purpose of my testimony is to address BREC's being "in the midst of a difficult transition period"[2] in light of BREC's mission; BREC's Mitigation Strategy and the extent to which it is supported by appropriate financial and Net Present Value analysis; financial model assumptions as presented in this case, including BRECs' demand estimates including price elasticity; excess plant capacity left by the termination of the Smelter Agreements; and, recommendations to the Commission regarding application of the "fair, just and reasonable rates" and "used or useful" standards associated with public utility ratemaking.

BREC's "Difficult Transition Period"

Q. WHAT IS YOUR UNDERSTANDING OF THE "DIFFICULT TRANSITION" BREC STATES IT "IS IN THE MIDST OF"?

A. BREC has been in a "difficult transition period" or "precarious financial position"[3] since the Unwind Transaction. In each year following the Unwind, BREC has been

[2] Direct Testimony of Mark A. Bailey on behalf of Big Rivers Electric Corporation, Case No. 2013-00199, at page 4, line 21 [hereafter cited as "Bailey Century Sebree Case Direct Testimony"].
[3] Direct Testimony of Mark Bailey, Case No. 2012-00535, at page 7, line 18 [hereafter, "Bailey Century Hawesville Case Direct Testimony"].

deferring maintenance outages "because that was the only option for BREC to meet the minimum margins for interest ratio ("MFIR") required by its loan agreements."[4] The apparent cause of this was "depressed off system sales revenues," where BREC "derives almost all of its margins."[5] BREC's "difficult transition" has been dealt another very material blow by the departures of Century Aluminum of Kentucky ("Century") and Alcan Primary Products Corporation ("Alcan," and together "the smelters") from BREC's system.[6] Century was the source of approximately 36% of BREC's wholesale revenues, and Alcan has been the source of approximately 28% of wholesale revenues, for a total of 64%.[7] BREC filed the prior Century Hawesville case "principally to cover revenues lost from Century's termination and a decline in the off-system sales market."[8] The current Century Sebree case "is designed to address the termination of the Alcan power contract,"[9] and recover "both an amount needed to recover Alcan's contribution to Big Rivers' costs (approximately $46.7 million) and an amount needed to recover the portion of Century revenues allocated to Alcan in the Century Rate Case

[4] Direct Testimony of Robert W. Berry on behalf of Big Rivers Electric Corporation, Case No. 2012-00535, at page 8, line 12 [hereafter "Berry Century Hawesville Case Direct Testimony"].
[5] Bailey Century Hawesville Case Direct Testimony, at page 8, lines 1-2.
[6] Century acquired the Sebree smelter from Rio Tinto Alcan in June 2013. Both smelters are now owned and operated by Century. Therefore in this testimony the smelters will be referred to as either "Century Sebree" or "Century Hawesville" as appropriate. Case No. 2013-00199 will be referred to as the "Century Sebree Case," and Case No. 2012-00535 will be referred to as the "Century Hawesville Case.".
[7] Corrective Plan to Achieve Two Credit Ratings of Investment Grade; Big Rivers response to PSC 3-9, Attachment 1, at page 2.
[8] *Id.* at page 9, line 9.
[9] Bailey Century Sebree Case Direct Testimony, at page 5, lines 14-15.

(approximately \$23.7 million)."[10] As a result of the smelter departures, BREC began implementation of a "Mitigation Plan"[11] under which it will idle or reduce generating capacity to cut costs.[12] Big Rivers intends to idle its Coleman and Wilson plants under the Mitigation Plan, for purposes of the financial forecast which underlies this case. The plants will remain in idled status "until Big Rivers' mitigation efforts produce sufficient replacement load or there is a sufficient increase in wholesale market prices."[13] Also, under the Mitigation Plan, Big Rivers will seek to bring new load to its system. Big Rivers states "attracting load or entering into bilateral sales contracts will require three or four years to come to full fruition."[14]

As described in more detail below, the Mitigation Plan offered by BREC has not been analyzed from a consumer perspective that considers the time value of money and risk, and are subject to a great deal of uncertainty. Subsequent to the Mitigation Plan, BREC stated in the Corrective Plan it submitted to U.S. Rural Utilities Service ("RUS") that it "believes completion of the entire process will most

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[10] Bailey Century Sebree Case Direct Testimony, at page 5, line 22, to page 6, line 2.
[11] The Mitigation Plan is described at pages 10-11 of the Berry Century Sebree Case Direct Testimony. The Mitigation Plan document was provided in response to AG 1-89 in the Century Hawesville Case. See also, Big Rivers' Response to AG 1-49 in this case.
[12] In this case Big Rivers uses the terms "idle" and "lay up" interchangeably in its testimony. See for example, Bailey Direct Testimony at page 5 ("lay up") and Berry Direct Testimony at pages 14-16 ("idle"). "Laying up" and "idling" generating plant are also used interchangeably in Big Rivers' response to PSC Staff 2-21e in the Century Hawesville Case.
[13] Bailey Century Sebree Case Direct Testimony, at page 5, lines 18-19.
[14] Berry Century Sebree Case Direct Testimony, at page 13, line 1.

likely take three to four years,"[15] where the "entire process" refers to "rate relief," "successful implementation of its Load Concentration Mitigation Plan" and pay down of the $58.8 million Pollution Control Bond issue due June 1, 2013. Of these three elements, the anticipated results from the Mitigation Plan are most uncertain, and will take years for potential development of any material results—while the proposed rate increases are certain if imposed by the Commission and are proposed to take effect immediately. The direct impact of BREC's Mitigation Plan is to push all the risks of the Mitigation Plan failing to work out on a timely basis, or at all, to consumers.

For some time BREC has been repurposing funds that had been earmarked for specific uses. For example, since the Unwind, BREC has deferred maintenance to make the margins required by debt covenants, and has used funds borrowed for the ordinary course of business to redeem bonds. Also, the BREC response to PSC 3-3 in the Century Hawesville case shows an increasing inability to fund budgeted capital projects, as follows:

Construction Budget versus Actual

Years	Actual	Budget	Variance
2012	$ 39.8	$ 83.3	$ 43.5
2011	$ 38.4	$ 53.0	$ 14.6
2010	$ 44.5	$ 45.6	$ 1.1

[15] Big Rivers Response to AG 2-37 in the Century Hawesville case, Attachment 1, at page 7.

Q. DOES BREC HAVE A SYMBIOTIC RELATIONSHIP WITH THE SMELTERS?

A. Yes, in the sense that BREC's financial health has been inextricably tied to the smelters. The smelters represented over 60% of BREC's load. BREC has constructed its system and invested hundreds of millions of dollars in order to serve the smelter load, and the Unwind Transaction assumed BREC would continue to serve the smelter load over the long term. The smelter departure removes revenues supporting the capital and operating costs of the BREC system, which leaves BREC in a very precarious financial position, facing a difficult and risky transition period.

Debt Leverage

Q. DOES BREC'S DEBT LEVERAGE CONTRIBUTE TO ITS "DIFFICULT TRANSITION PERIOD"?

A. Yes. BREC operates with a significant amount of debt as compared to equity. Higher debt leverage is associated with higher risk and higher reward. The risk component derives from the fact that higher debt levels require higher levels of fixed debt service (payment of principal and interest) such that there is an increasing risk that earnings (cash) will be insufficient to meet those fixed debt service obligations including debt covenants, all other things equal. BREC's ability to benefit from the reward component was capped after the Unwind due to the rebate provision in the smelter agreements for all margins over the 1.24 "Contract TIER" level. The Contract TIER rebate provision obviated any opportunity for BREC to secure its financial position in good times by accumulating margins, and left it with only the prospect of a marginal existence in the narrow band between 1.1 MFIR and 1.24 TIER.

A debt ratio may be calculated using end-of-year 2012 data from the preliminary RUS Financial and Operating Report[16]:

Total Margins and Equities	$	402,881	
Total Long Term Debt	$	845,317	67.7%
Total Capitalization	$	1,248,198	

BREC has relatively high levels of debt as compared to equity, with associated fixed debt service obligations.

Furthermore, high debt leverage increases BREC's exposure to interest rate risk which is caused by rising interest rates. BREC faces the risk of higher interest expense where variable interest rates apply and in connection with future financing.

The reduction in revenues from the departure of the smelters has triggered significant negotiations among BREC and its lenders. Continued liquidity is a

[16] Big Rivers' Response to AG 1-162, Century Hawesville case.

concern being addressed, but BREC's options are narrowing over time. An example of these narrowing options include the fact that BREC was obliged to use CoBank funds originally approved by the Commission for use in the normal course of business to instead repay maturing Pollution Control Bonds (as approved in Case No. 2012-00492). Then, BREC used the $35 million Transition Fund balance to partially replace the CoBank funds, intended for later use for capital expenditures.[17]

A further example of narrowing options is the renegotiated CFC Line of Credit presented to the Commission for approval in Case No. 2013-00125. BREC was required to renegotiate this Line of Credit agreement since the departure of the smelters would constitute an Event of Default, allowing CFC (at its discretion) to accelerate all unpaid principal and interest on obligations between BREC and CFC. These obligations include the Line of Credit, first mortgage notes in the amount of $302 million, and a promissory note in the amount of $43 million.[18]

The renegotiated terms of the CFC Amended and Restated Line of Credit include more restrictive terms such as limiting advances under the CFC Revolver to times when BREC's available cash is less than $35 million, and requiring repayment on

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[17] *In the Matter of the Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness,* Case No. 2012-00492, Order (March 26, 2013) at page 4.
[18] CFC Amended and Restated Line of Credit Application at pages 4-5.

Line of Credit balances when available cash balances exceed $35 million.[19] This serves to create a narrow band for use of the Line of Credit, and also would tend to keep such use more temporary—eliminating BREC's management discretion to retain the funds for a longer period. Also, the renegotiated terms provide CFC the remedy of pursuing damages from BREC in the event of default.[20] Further the renegotiated terms prohibit BREC from using an advance from the Line of Credit "to pay any portion of the principle amount of the $58,800,000 County of Ohio, Kentucky, Pollution Control Floating Rate Demand Bonds."[21] Finally, the renegotiated terms limit BREC's financial flexibility by requiring BREC to maintain a minimum member equity balance, and each year to add 75% of positive net margins for the particular fiscal year to that minimum member equity balance.[22] The renegotiated terms also change the Line of Credit from being unsecured, to secured under BREC's Indenture. Following Commission approval, this amended and updated agreement for the CFC Revolving Line of Credit was executed on August 20, 2013.

BREC is in a poor position to handle any further negative results from its operating position. BREC faces various exigencies, including exposure to requests for credit

[19] CFC Amended and Restated Line of Credit Application, at page 7. *See also*, Exhibit 4 to that application, which is a redline version of the Amended and Restated Line of Credit Agreement.
[20] CFC Amended and Restated Line of Credit Application, Exhibit 4, page 17.
[21] *Id.*, at page 7.
[22] *Id.*, Exhibit 4, page 14.

enhancements from suppliers,[23] as well as uncertain consumer demand and response to price increases. Its options for dealing with these are narrowing over time.

BREC's Corrective Plan, Mitigation Plan and Financial Projections

Q. IS BREC IN THE PROCESS OF IMPLEMENTING A "CORRECTIVE PLAN" UNDER THE SUPERVISION OF THE RURAL UTILITIES SERVICE (RUS)?

A. Yes. The Loan Agreement between BREC and RUS requires that BREC maintain at least two investment grade credit ratings, and to notify RUS within 5 days of a failure to maintain such credit ratings. Following Alcan's Notice of Termination, Standard and Poor's downgraded BREC's credit rating below investment grade (to BB-) on February 4, 2013, and Fitch Rating downgraded to BB on February 6, 2013. BREC properly notified RUS of these downgrades below investment grade. Subsequent to that notification the Loan Agreement requires BREC to provide a "written plan satisfactory to the RUS setting forth the actions that shall be taken

[23] Big Rivers responses to KIUC 1-61 and 2-27 in the Century Hawesville case. Also, Big Rivers' response to KIUC 1-60 in that case states "The recent credit rating downgrades resulted in Big Rivers being required to post an additional $3 million letter of credit with MISO." Big Rivers' Response to AG 1-9 states "Additionally, in June 2013 Big Rivers was required to post $2.5 million in cash collateral with MISO, in addition to its existing letter of credit, to meet MISO's required level of financial assurances."

that are reasonably expected to achieve two Credit Ratings of Investment Grade."[24] The Corrective Plan provided to RUS is dated March 7, 2013.

Q. WHAT DOES THE CORRECTIVE PLAN WHICH BREC PROVIDED TO RUS ADDRESS?

A. The Corrective Plan addresses items that, according to BREC, are the focus for the credit ratings agencies. These items identified by BREC are as follows: "access to and maintenance of liquidity"; "replacement load for BREC's two largest customers who have given notice of termination"; and, "increased BREC's activity in off-system sales market."[25] These three items are further discussed below based on discussion contained in the Corrective Plan itself, information from various Commission proceedings, including information provided by Big Rivers in response to data requests:

- Access to and maintenance of liquidity:
  - Lines of Credit: BREC completed negotiations with CFC for "major modifications" to the terms associated with its $50 million line of credit for which modifications were required due to the termination notices, and following Commission approval executed the amended and

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[24] Big Rivers Response to AG 2-37 in the Century Hawesville case, Attachment 1, page 2.
[25] *Id.*, at page 4.

updated agreement with CFC on August 20, 2013.[26] BREC made the necessary application to the Commission to issue new evidences of indebtedness to implement the major modifications to the CFC line of credit, [27] the day after it received the Commission's order on its prior financing application in Case No. 2012-00492. BREC terminated its CoBank $50 million line of credit on May 24, 2013 due to the Century termination notice.[28] The original CFC and CoBank lines of credit were approved in connection with the Unwind Transaction. BREC stated it would "restart negotiations" with CoBank to attempt to restructure the line of credit later in March, 2013.[29]

- Environmental Compliance Plan financing: BREC is still facing the necessity of financing $60 million in costs of its Mercury and Air Toxics Standards (MATS) compliance plan as approved by the Commission. "Big Rivers expects initially to finance these expenditures with a new short-term loan from the National Rural Utilities Cooperative Finance Corporation ("CFC"), and then convert that short-term borrowing to

[26] Big Rivers' Response to AG 1-27, in the Century Sebree case.
[27] *In the Matter of the Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness*, Case No. 2013-00125, Application dated March 27, 2013.
[28] *Id.*
[29] *Id.*, at page 5.

long-term financing with the Rural Utilities Service ("RUS")."[30] Big Rivers has since stated "Subsequently, and as a result of the contract terminations by Century and Alcan, Big Rivers' management determined it would be prudent to defer MATS expenditures at the Coleman and Wilson plants until closer to their return to service."[31]

- Century Hawesville Rate Case: BREC stated in the Corrective Plan it sought $74 million in increased revenues from the Commission.
- Alcan (Century Sebree) Rate Case: BREC stated in the Corrective Plan it "plans to file another general rate case in late June 2013 to address the annual revenue deficiency resulting from Alcan's contract termination." This case was filed in late June 2013.
- Pollution Control Bond Refinancing: BREC redeemed $58.8 million in bonds which mature in June 2013. BREC originally sought approval to redeem these bonds with proceeds from issuance of a like amount of bonds. However, this plan became uncertain and therefore impractical given BREC's changed financial picture due to the smelter terminations—it became uncertain whether investors would in fact

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[30] Direct Testimony of Billie J. Richert on behalf of Big Rivers Electric Corporation, Case No. 2013-00199, at page 6, line 19 [hereafter cited as "Richert Century Sebree Case Direct Testimony"].
[31] Big Rivers' Response to Sierra Club 2-11.

purchase the new bonds, and what interest rate would be required by the investors for an appropriate risk adjusted return. BREC therefore proposed to use remaining proceeds from its CoBank secured loan—that was approved by the Commission for capital expenditures—to redeem the bonds at or before maturity. BREC also asked for Commission approval to use the $35 million transition reserve fund to partially replenish the CoBank funds. The Commission granted the approvals sought by BREC in its amended application.[32]

- "Replacement Load and Addressing Reliance on Off-System Sales" is addressed in the Corrective Plan by also providing to RUS the BREC Mitigation Plan.

Q. PLEASE OUTLINE BREC'S "MITIGATION PLAN."

A. Mr. Berry describes the mitigation steps being taken by BREC to address the Century contract termination, via implementation of BREC's Load Concentration Mitigation Plan, in his testimony at pages 9-18. The Mitigation Plan itself is provided under protection of confidentiality, but Mr. Berry addresses the Plan in a

[32] *In the Matter of Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness*, Case No. 2012-00492, Order (March 26, 2013).

general way in his public testimony. The Mitigation Plan is comprised of four elements:

- "Petition the Commission for a rate increase";
- "market all excess power";
- "idle or reduce generation"; and,
- "execute forward bilateral sales with counterparties, enter into wholesale power agreements, and/or participate in capacity markets."[33]

While this rate case proceeding will occur under statutory timelines, the remaining three elements of the Mitigation Plan are all uncertain, longer term, and therefore risky. BREC is **shifting this risk** of the Mitigation Plan to remaining rural and large industrial consumers through its request for increased rates in this matter.

- Marketing of excess power "is not expected to be an effective mitigation method for the next few years," since "off-system sales margins will remain depressed."[34] When and the extent to which this will occur is uncertain and therefore is risky.

[33] Berry Direct Testimony in the Century Sebree Case, at pages 10-11.
[34] *Id.*, at page 10.

- Idling or reducing generation shifts the carrying costs of that unused plant to remaining rural and large industrial consumers for an indefinite time period, under BREC's approach of increasing rates to make up for lost load and margins during that indefinite time period.

- For a variety of reasons, efforts to find load replacement "take time."[35] "Attracting load or entering into bilateral sales contracts will require three or four years to come to full fruition."[36] BREC has not suggested in this case it believes the time period for load replacement is any shorter than indicated by its previous testimony in the Century Hawesville case.

The steps in BREC's Mitigation Plan that lead to reducing the scale of BREC operations to appropriate size for its remaining load take BREC in the right direction, but are still very uncertain. Remaining rural and large industrial consumers should not be required to pay rates which are not fair, just and reasonable for the indeterminate period of time—three or four years, or more—before the Mitigation Plan (assuming it works as BREC anticipates), is able to properly align BREC's system load with its generating resources—without significant excess capacity. BREC's Mitigation Plan recognizes this where it states (at page 3) **[BEGIN CONFIDENTIAL]** [redacted]

[35] *Id.*, at page 11.
[36] *Id.*, at page 13, line 1.

[redacted] [END CONFIDENTIAL] This is equally applicable to assigning cost responsibility for the excess capacity created by the departure of the smelters to remaining customers, who cannot economically support such cost assignment.

Q. IS THE MITIGATION PLAN IN DIRECT CONFLICT WITH BREC'S REQUEST TO INCREASE RATES IN THIS CASE?

A. Yes. BREC's request to increase rates for large industrial consumers in this case and prospective further increases to those rates is in direct conflict with BREC's efforts under the Mitigation Plan to attract new large industrial load. Prospective large industrial consumers will be dis-incented by BREC's "precarious financial position" or "difficult transition period" and BREC's continuing dependence on rate increases during this transition period. All other things being equal, this conflict serves to both defer the point at which replacement load becomes an effective mitigation to BREC's current "precarious financial position" or "difficult transition period," and to extend the period of time that remaining rural and large industrial consumers are being asked by BREC to pay rates which are not fair, just and reasonable. Big Rivers' Mitigation Plan in essence requires consumers to pay the carrying costs of four or more unneeded generating plants (3 Coleman units and 1 Wilson unit), while 800 MW of new load is sought which, in the current environment for coal plant operation is challenging, at best.

A further material flaw in Big Rivers' strategy is that it assumes existing large industrial customers will simply pay the higher rates for the same level of power consumption. One needs look no further than the front page of the *Wall Street Journal* to see how unrealistic this assumption is:

> From big-box retailers to high-tech manufacturers, more companies across the country are producing their own power. Since 2006, the number of electricity-generation units at commercial and industrial sites has more than quadrupled to roughly 40,000 from about 10,000, according to federal statistics. Experts say the trend is gaining momentum, spurred by falling prices for solar panels and natural gas, as well as a fear that power outages caused by major storms will become more common. The growing number of companies that are at least partly energy self-sufficient is sending a shudder through the utility industry, threatening its revenues and growth prospects, according to a report earlier this year by the Edison Electric Institute, a trade association for investor-owned electric companies. State and federal regulators say they are worried that utilities could end up with fewer customers to pay for costly transmission lines and power plants.[37]

In the Century Hawesville case, Kimberly Clark Corporation stated:

> The Company has gone to great capital expense in some instances to address uncompetitive power costs and/or unreliable power supply. Kimberly-Clark has installed gas-fired combined heat and power cogeneration in facilities in California, Connecticut and Italy, and another

[37] "Power Play: Companies Unplug From Grid, Delivering a Jolt to Utilities"; *The Wall Street Journal*, page 1, September 18, 2013. *See also* the following article which discusses Wal-Mart's plans to be 100% energy self-sufficient and to essentially remove its stores from the electric grid: http://www.smartgridnews.com/artman/publish/News_Commentary/Utilities-What-Walmart-s-power-plans-say-about-your-future-it-s-scary-5694.html#.Uma5-VLD_Ws

will start up at our tissue mill in Australia. Should rate hikes for Owensboro Mill be approved, Kimberly-Clark will certainly evaluate installing a similar combined heat and power cogeneration system for Owensboro to keep the mill competitive on overall cost of manufacture.[38]

Q. ARE THERE OTHER ISSUES OR INCONSISTENCIES WITHIN THE MITIGATION STRATEGY AND ITS ASSUMPTIONS?

A. Yes. There are a number of other inconsistencies, problematic assumptions with the Mitigation Strategy or other developments which will directly affect it:

1. It will be very difficult at best to attract new large industrial customers, who will see the prospect of continued Big Rivers' rate increases to support excess capacity in a coal-based generation fleet (under its proposed Mitigation Plan), subject to uncertainty over expected more stringent pollution control regulations.

2. Big Rivers' Mitigation Strategy is based in significant part on pursuing current [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] industrial or other customers. Beyond the fact that these customers tend to have term commitments, it is questionable whether [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] will let these customers go without meeting any offer from competitors including Big Rivers. The existing

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[38] Direct Testimony of Bill Cummings on behalf of Kimberly-Clark Corporation and KIUC, Century Hawesville case, page 6, line 7.

[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] customers that are Big Rivers' targets will tend to use Big Rivers' interest to obtain more favorable pricing from [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

3. TVA is also losing industrial customers, which will sharpen its interest in ensuring no further defections of industrial customers. TVA's largest industrial customer at 2000 MW, United States Enrichment Corporation Inc.'s ("USEC") Paducah Gaseous Diffusion Plant, is shutting down over the next year, and terminating 1,200 employees as well as numerous subcontractors, who are highly paid.[39] TVA has suffered a "'staggering loss' in power sales ..., down $1.5 billion in the past five years."[40] This will spark an effort by TVA to set rates at competitive levels in order to attract and retain large industrial customers.

4. USEC, Inc.'s Paducah Gaseous Diffusion Plant is directly adjacent to Jackson Purchase's service territory. It has "a large, highly paid workforce"[41] which is subject to layoff with the plant closing. No doubt some USEC employees and subcontractors live in Jackson Purchase territory, so Jackson Purchase sales to consumers and small businesses will be reduced as the impact of reduced

[39] The "average salary for plant workers, include benefits, was $125,000." "Paducah Plant Closure Disrupts Workers' Lives," *The Paducah Sun*, August 19, 2013.
[40] "TVA Chief Works to Slim Down Agency," *Chattanooga Times Free Press*, October 11, 2013.
[41] "The Effects of Losing USEC"; *The Paducah Sun*, September 15, 2013.

employment ripples through the economy in the area. There is both a direct and indirect effect of reduced employment from plant closure that will affect Jackson Purchase sales. "It's not just the roughly 1,200 USEC workers losing their jobs who take the hit, but also another 2,770 people whose jobs are created in part by having such a large, highly paid work force in the county."[42] This is recognized in load forecast correspondence, but ultimately is not addressed in Big Rivers' load forecast. Jackson Purchase expressed significant concern, as follows:

> Kelly has the greatest concern and he is far more familiar with the timing and effects of USEC closing. ... There are 1,200 direct jobs with many more indirect ones affected. My informal survey of friends who work for them tells me that most are actively looking for work outside this community. Most of the jobs are highly specialized and all the employees have security clearances. They will likely be able to find jobs elsewhere and will leave this area when they do. A large percentage do not have roots here and will be especially susceptible to moving. Kelly is also more familiar (although Lindsay may know) the amount and timing of the rate increases. If nothing else changes I have heard that with the unwind funds depleted we will be looking at an increase from present rates of 80+ percent by June '15. That will surely also have an effect on consumption.[43]

[42] *Id.*

[43] Big Rivers' Response to KIUC 1-92, Attachment, page 133, email from Chuck Williamson of Jackson Purchase to John Hutts of GDS Associates, copying Michael Mattox and Lindsay Barron.

Big Rivers ultimately did not reflect the USEC closure in its load forecast for this case, despite this perception of its importance and significance by one of its members.[44]

5. The revenue projections underlying the Mitigation Strategy are based on faulty assumptions regarding rural consumer and large industrial customer response to price increases—price elasticity of demand. In particular, large industrial customers are assumed to make no response to increased prices—which is demonstrably not likely. This is illustrated by testimony before the Commission in the Century Hawesville case:

    a. "in a competitive global marketplace we cannot afford to pay for 100% of the costs incurred to serve other customers while Big Rivers' creditors recoup 100% of their investments;"[45]

    b. "to succeed, we require cost competitive and predictable electricity rates that reflect the true cost of service." "We cannot pay for excess capacity that is not providing service to us." "If prices are not competitive or lack predictability, it severely impedes our ability to justify the capital

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[44] *Id.*, at page 132, email reply of Lindsay Barron.
[45] Direct Testimony of Steve Henry on behalf of Domtar Paper and KIUC, Century Hawesville case, page 8, line 9.

improvements that are required for our facility to remain both technologically and commercially competitive.";[46] and,

c. "Big Rivers' large industrial rate payers will consider both [the Century Hawesville and Century Sebree] cases when making decisions regarding capital investment in their facilities." "It is possible that capital investment could bypass the Owensboro mill in favor of Kimberly Clark's other US tissue plants."[47]

6. Price elasticity of demand is a quantification and estimate of consumers' response to price change—whether price reduction or increase. Increased prices are expected to reduce the quantity purchased by consumers, all other things equal. Big Rivers did not provide any estimation of the reduced quantity of power purchased by its rural and large industrial customers due to the proposed rate increases in the Century Hawesville case. However, Big Rivers does address price elasticity of demand in this Century Sebree case in its updated load forecasting. Nonetheless, this price elasticity estimation is faulty in its application for a number of reasons:

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[46] Direct Testimony of Kelly Thomas on behalf of Aleris International and KIUC, Century Hawesville case, page 3, lines 9, 12, and 13.

[47] Direct Testimony of Bill Cummings on behalf of Kimberly Clark Corporation and KIUC, Century Hawesville case, page 4, line 21, and page 5, line 21.

- Big Rivers assumes no response to price increases by large industrial customers. "Big Rivers believes it is inappropriate to assume that large industrial customers will reduce their consumption without first having seen such a demonstration of such reduction."[48] Big Rivers states that "rather than developing a regression based forecasting model, projections of large industrial energy and demand requirements are based on consumption and peak demand from the previous year and are adjusted to reflect known changes in operations, thus price elasticity for the large industrial class was not directly incorporated into the forecast."[49] This contention verges on the incredible, especially given the KIUC testimony in the Century Hawesville case, the history of smelter drive for lower rates, and industry developments as exemplified in the *Wall Street Journal* article cited above.

- Big Rivers' response to KIUC 1-33 confirms that a customer using 1300 kWh/month will reduce usage by 15.12%, based on the price elasticity study presented in this case and as included in Big Rivers' load forecasting. However, this estimate of price elasticity is most likely significantly understated since it: a) is a short-term (1 year) estimate,

[48] Big Rivers Response to PSC 2-20.
[49] *Id.*

rather than a longer-term estimate where consumers have more ability to adapt to the price increases; and b) is based on historical prices that did not contain or include significant price increases.[50]

7. As discussed in Mr. Holloway's testimony, Big Rivers' "forecast" of replacement load is a key assumption, and crucial to the company's purported "demonstration" of the member benefit of retaining the Wilson and Coleman units. This key assumption has no quantitative support.

8. Neither the Mitigation Plan nor the Financial Projections provided in response to PSC 1-57 and PSC 2-14 contain any specific provision for economic development rates. Big Rivers' response to KIUC 2-36 indicates it is using economic development rates "in a number of its proposals." That response states this economic development rate "includes a fixed demand component of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] with energy charges and riders charged at [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] The financial projections do not reflect this economic development rate in calculating revenues from "replacement load." Instead, those revenues are calculated using a different and higher rate. This will lead to *lower* revenues than included in the financial projections, with

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[50] Big Rivers Response to KIUC 2-45.

all the consequences that logically follow such as deferral of projected rate decreases, deferral of plant restart, etc.

This rate is also [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] the demand rate for Large Industrial prior to the Century Hawesville case:

	Existing	Century Hawesville	Century Sebree
Rural	$ 9.500	$ 16.454	$24.742
	$ 0.029736	$ 0.030	$ 0.035
Large Industrial	$ 10.500	$ 11.960	$17.979
	$ 0.024505	$ 0.030	$ 0.035
Source: Exhibit Wolfram 5			

9. Big Rivers' offers to sell its plants are indicative of the reality of the situation. If it truly believed in ultimate consumer benefit, it would not be trying to sell plants. "Sensitivity analysis which factors in the value of capacity revenues to Big Rivers' Members, as projected by Wood Mackenzie, demonstrates significant future benefits provided by the plants to Big Rivers' Members."[51] Again, if Big Rivers truly believed in this benefit to consumers, it would not be trying to sell plants.

[51] Big Rivers' Response to KIUC 2-33.

Member Benefit and Net Present Value Analysis

Q. BIG RIVERS AT VARIOUS PLACES IN ITS TESTIMONIES AND RESPONSES TO DATA REQUESTS STATES THAT ITS STRATEGY WILL ULTIMATELY BENEFIT ITS MEMBERS AND MEMBER OWNERS. PLEASE PROVIDE EXAMPLES OF THESE VARIOUS STATEMENTS.

A. There are many examples of this statement, including:

1. "As ... mitigation efforts are successful, Big Rivers' members will benefit."[52]
2. "Big Rivers' Mitigation Plan will provide an opportunity to benefit its members ...."[53]
3. "As Big Rivers is successful in mitigating the adverse impacts of the Smelter contract terminations, Big Rivers' members will benefit..."[54]
4. "It just does not make sense for Big Rivers to retire these plants and deprive Members of the future benefits these plants will provide."[55]

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[52] Bailey Direct Testimony, Century Sebree case, at page 8, line 3.
[53] Berry Direct Testimony, Century Sebree case, at page 12, line 18.
[54] *Id.*, at page 18, line 16.
[55] Big Rivers' Response to KIUC 1-51.

5. "It just does not make sense for Big Rivers to prematurely retire these plants without taking the time for the assets to make additional contributions for the Members' benefit."[56]

BREC's response to AG 1-82 states that since BREC "has invested significant time and energy into researching the market and developing its off-system sales plan," "Big Rivers reasonably anticipates that increased off-system sales will benefit its Members and their member-owners when wholesale electricity prices have recovered from their current slump, currently expected to occur around 2019."[57] Similarly, Big Rivers states "for the continued benefit of its Members, and consistent with the Commission's expectations set forth as part of the Unwind Transaction, Big Rivers has approached this question of available generation capacity resulting from the termination of the smelter contracts as a unique opportunity to benefit its Members."[58] BREC makes many statements through its testimonies and data request responses echoing this theme.

The clear implication of these statements is that BREC claims ultimately its members will benefit financially from the Mitigation Plan, in that dollars paid in

[56] Big Rivers' Response to SC 1-16.
[57] Big Rivers Response to AG 1-82, page 2, line 16.
[58] Big Rivers' Response to AG 1-82, page 1, line 14.

up front to carry the costs of unneeded facilities will be more than returned to members in subsequent years.

Q. DOES BIG RIVERS PROVIDE QUANTITATIVE INFORMATION THAT SUPPORTS ITS CLAIM THAT "MEMBERS BENEFIT" FROM ITS MITIGATION PLAN, AND THAT CASH PROVIDED BY CONSUMERS THROUGH INCREASED RATES UP FRONT WILL BE MORE THAN RETURNED IN SUBSEQUENT YEARS?

A. Big Rivers presents a spreadsheet containing its long term Financial Forecast in response to PSC 2-14.[59] The purported "member benefit" is entirely a product of material assumptions inserted into the spreadsheet. These material assumptions include very substantial new replacement load from mitigation plan efforts, as well as increased off system sales. These assumptions drive apparent substantial new revenues mathematically via formula. The assumed revenues are very large in relation to revenues from remaining members, and those assumed large revenues permit assumed substantial rate decreases for those remaining Rural and Large Industrial customers.

Big Rivers states "there have been a number of production cost models and financial models presented in this case that demonstrate that these plants will add

[59] "Financial Forecast (2014 - 2027) 5-16-2013.xlsx" (Confidential) provided in response to PSC 2-14.

value to Big Rivers' Members in the future."[60] Big Rivers also states "sensitivities were performed to quantify the financial benefit to Big Rivers' Members of projected MISO capacity prices."[61] While Big Rivers points to certain modeling to support its claim of "member benefit" from its mitigation plan, no quantification on a cost/benefit basis is provided to specifically show this anticipated "member benefit" on a basis that accounts for the time value of money or for the risks that the assumptions are inaccurate. Since Big Rivers performed no analysis, Member Benefit analysis that addresses the time value of money and the risks associated with the material assumptions in Big Rivers' Financial Forecast. This Member Benefit analysis is sponsored by Mr. Holloway, and attached to his testimony.

Q. SHOULD BIG RIVERS' CLAIMS OF BENEFITS BE SUPPORTED BY NET PRESENT VALUE ANALYSIS, WHICH ACCOUNTS FOR THE TIME VALUE OF MONEY, AND RISKS?

A. Yes. Basic management and managerial finance practices would require these statements to be supported by Net Present Value analysis, especially since this is an exceptional watershed moment for Big Rivers and its assets/operations, over a long time horizon.

[60] Big Rivers' Response to KIUC 2-33.
[61] Big Rivers' Response to KIUC 2-13.

Net present value analysis is employed by corporate management for decisions regarding assets, capital investment and strategic decisions. Clearly, Big Rivers' proposed Mitigation Strategy regards its corporate future and very large assets—Wilson and Coleman generating stations. Public utility status does not absolve Big Rivers of the need to perform NPV analysis for a decision as fundamental as it faces with the departure of the smelters and substantial excess capacity. In fact, as an example the Commission has had to consider and ultimately perform its own NPV analysis for a water company, to assess important decisions regarding the future course and plan of a public utility.[62] Additionally, two of Big Rivers' own members have submitted cases which involved NPV analysis.[63]

Q. WHAT IS NET PRESENT VALUE ANALYSIS, AND ITS APPLICATION TO BIG RIVERS' CURRENT CIRCUMSTANCES?

A. Net present value analysis determines the value in today's dollars of the expected net cash flows over time of a decision—positive and negative, discounted at the appropriate discount rate/cost of capital. To illustrate the present value concept,

[62] *In the Matter of: The Application of Kentucky-American Water Company for a Certificate of Public Convenience and Necessity Authorizing the Construction of Kentucky River Station I, Associated Facilities and Transmission Main*; Case No. 2007-00134, Order dated April 25, 2008, beginning at p. 51.

[63] *In the Matter of: Application of Kenergy Corp. for Authorization to Borrow $6,428,795 From Cobank and Execute Necessary Note and to Prepay Rural Utilities Services 5% Notes Of Same Amount*; Case No. 2003-00328, Order dated Sept. 2, 2003 (2003 WL 22701657 (Ky.P.S.C.), beginning at p. 1; *In The Matter Of: Application of Meade County Rural Electric Cooperative Corporation for an Order and Certificate of Public Convenience and Necessity Authorizing Applicant to Execute a "Secured Promissory Note" Not to Exceed $14,726,249.25 Pursuant to KRS 278.300 and 807 KAR 5:001, Sec. 11 And Related Sections*, Case No. 2003-00310, Order dated Aug. 18, 2003 (2003 WL 22299940 (Ky.P.S.C.) beginning at p. 2.

the table below shows the present value of a dollar 7 years from now, in 2020, at the indicated interest rates:

6%	$ 0.67
7%	$ 0.62
8%	$ 0.58
9%	$ 0.55
10%	$ 0.51

If the Net Present Value is not positive (indicating it does not provide adequate net cash inflows as discounted for the time value of money and risk), the proposed project or decision should not be approved. Assuming that to be the case, alternative scenarios such as: a) the sale of plants (which could produce either a gain or a loss, and could result in BREC proposing to recover any loss through amortization or immediate recovery from customers); or b) the write off of the net book value of plants and other related costs—should be analyzed on a net present value basis. Big Rivers' responses to data requests indicate *it has done none of this* *type of analysis,*[64] but instead has pre-determined its Mitigation Strategy approach *based on assertion of benefits, with no other analysis.*

The Net Present Value analysis framework, as applied to BREC's Mitigation Strategy on a conceptual basis, would discount the increased rates to be paid by consumers now and in the future, to cover the costs of carrying unused plant (in total, the "outflow") for the distant and uncertain "payback" of post-2019 net revenues from new load and better prices for off-system sales (in total, the "inflow"). If the net present value of those discounted cash flows is less than 1.0, the decision should not be approved. The member benefit analysis attached to Mr. Holloway's testimony shows that the net present value is indeed negative, such that the present value of those distant dollars does not outweigh the dollars Big Rivers seeks to charge consumers today.

Reserve Funds

Q. DOES BIG RIVERS PROPOSE TO USE AND DISSIPATE ITS RESERVE FUNDS IN THIS CASE?

A. Yes. Under Big Rivers' proposal, the Economic Reserve will be used and depleted in July 2014[65] — at which time the Large Industrial class will see the full impact of

[64] Big Rivers' Response to AG 2-59; Big Rivers' Response to KIUC 2-33.
[65] Richert Century Sebree Case Direct Testimony, at page 14, line 6.

the proposed rate increases. Similarly, the Rural Economic Reserve would be depleted in April 2015,[66] and the rural customer class will see the impact of proposed rate increases at that point. The Commission should not approve the dissipation of reserve funds in this fashion, for purposes of pursuing a Mitigation Plan that is inconsistent and unlikely to benefit consumers. Reserve funds should be used only in the interim while Big Rivers is working with its creditors on a plan to reduce its excess scale of operations. Reserve funds should not be dissipated pursuing a mitigation strategy unlikely to succeed and with demonstrable lack of benefit to consumers.

Q. DID PSC STAFF ASK BREC TO IDENTIFY AND DISCUSS PLANS TO BENEFIT BIG RIVERS' MEMBERS ASSUMING BREC's MITIGATION EFFORTS ARE SUCCESSFUL, AND IF SO WERE SUCH PLANS AND BENEFITS PROVIDED?

A. In PSC 2-8, PSC staff asked BREC to identify and describe the specific plan to benefit Big Rivers' members if mitigation efforts are successful, and for specific plan information regarding benefit to Big Rivers' members. Big Rivers provided no information about specific plans or benefits in its response. Furthermore, Big Rivers' response to KIUC 2-16 states "Wilson and Coleman are idled, and then

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[66] *Id.*, at line 7.

profitably back in service in [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] in the 'Financial Forecast (2014 - 2027) 5-16-2013.xlsx' run attached to PSC 2-14. The units were brought back in service to serve the projected load for the system. A series of rate decreases for the members are also forecasted after 2019 due to the additional margins received from operating these units." These are the assumed rate decreases referred to above.

Q. WHAT IS THE BASIS FOR BIG RIVERS' ASSUMPTION ON REPLACEMENT LOAD FOR INCLUSION IN ITS LONG-TERM FINANCIAL FORECAST?

A. In response to KIUC 2-32, Big Rivers states that "the replacement load forecasted in Big Rivers' long-term load forecast was determined based on informed judgment. ... The replacement load was not meant to be specific, but rather represented what Big Rivers' management believed was a reasonable expectation for load replacement given all of the information available to it at the time." Big Rivers was asked for but was not able to provide any further information regarding underlying assumptions, composition and sources of the additional load, pricing discounts necessary to entice and obtain each of the new loads, and whether each of the loads is a new load associated with a new facility or load transferred from and presently served by another utility or supplier. The replacement load figures are large round numbers without any supporting details or basis, and therefore more closely resemble "plug" numbers necessary to make the projections "work."[67]

Q. IF BIG RIVERS CONTINUES TO AVER THAT THERE ARE BENEFITS TO ITS PROPOSED MITIGATION PLAN, SHOULD CONSUMERS PAY HIGHER RATES TO FACILITATE BIG RIVERS' PURSUIT OF THAT PLAN?

A. No. The purported benefits are merely assumptions in Big Rivers' financial projections, which have not been adjusted for risk or the time value of money. There is no valid "member benefit" argument in favor of saddling consumers with higher rates to pay for the mitigation plan. In essence, Big Rivers is asking the Commission to increase rates on consumers to pay for a merchant generation operation. If Big Rivers truly believes there are future benefits from the mitigation plan based on merchant generation, these benefits should be made evident to Big Rivers' lenders, and the lenders should support the mitigation plan via deferring principal and interest payments during the period Big Rivers is working its mitigation plan, as opposed to ratepayers carrying the gamble that a merchant generation play will work out. Consumers are being asked to pay for, and assume the risk of Big Rivers' merchant generation line of business with a vague and extremely uncertain promise of later benefit, which is not even estimated or

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[67] New load projections "sketched out on the white board," with the nature of the projected load "unknown". Big Rivers Response to KIUC 1-92, Attachment at page 54. *See also*, pages 9 and 51.

validated with standard Net Present Value analysis. Consumers should not fund Big Rivers' Mitigation Strategy through significantly increased rates including plant which is not "used or useful"— for the ultimate benefit of a merchant generation operation. Creditors which knowingly extended credit to Big Rivers should carry Big Rivers' transition through temporary forgiveness of debt principal and interest payments—especially given Big Rivers' expressed confidence that it will work out beneficially.

Q. HAS A MEMBER BENEFIT ANALYSIS BEEN PERFORMED TO ASSESS WHETHER THE INCREASED RATES PROPOSED TO BE PAID IMMEDIATELY BY RATEPAYERS ARE OFFSET BY LATER BENEFITS ON A RISK-ADJUSTED BASIS THAT CONSIDERS THE TIME VALUE OF MONEY?

A. Yes. That member benefit analysis was performed by OAG Witness Mr. Larry Holloway, is attached to his testimony, and described therein. The member benefit analysis appropriately considers the time value of money and risk. That member benefit analysis uses a 5% discount factor for the excess capacity costs of Wilson and Coleman plants which Big Rivers proposes to include in rates, since there is some certainty that increased revenues will be generated from increased rates. However, a 10% discount factor is used to discount the assumed revenues from off system sales and replacement load, since these assumed revenues are more distant and subject to significant uncertainty. The higher discount factor used here appropriately recognizes the difference in risk and uncertainty associated with these assumed revenues, versus the lower discount factor for the more certain revenues proposed to be collected from ratepayers via proposed increased rates.

Excess Capacity and Fair, Just and Reasonable Rates

Q. BREC STATES THIS RATE CASE IS DESIGNED TO RECOVER THE LOST MARGINS DUE TO THE ALCAN (CENTURY SEBREE) CONTRACT TERMINATION, WHICH BREC CALCULATES TO BE $70.4 MILLION.[68] SHOULD THE COMMISSION ALLOW BREC TO INCREASE RATES CHARGED TO THE RURAL AND LARGE INDUSTRIAL CLASSES TO RECOVER LOST MARGINS FROM THE CENTURY SEBREE DEPARTURE?

A. No. The Unwind Transaction was a bargained-for exchange, including the Smelter Agreements. The smelters and BREC had a Commission-approved bargained-for exchange regarding the terms, conditions and rates under which BREC would provide power to the smelters. The Commission should not allow BREC to now transfer lost margins from the smelters to remaining rural and large industrial consumers. These lost margins from the Century Sebree departure cover costs which are not appropriately assigned to other rural and large industrial consumers and which stem at least in part from plant which is no longer "used or useful" in

[68]Berry Century Sebree Case Direct Testimony, at page 18, line 9.

providing public utility service. The rates proposed to be charged to remaining large industrial and rural consumers are not fair, just and reasonable since they include BREC's proposal to make these consumers responsible for paying costs of another customer--lost margins due to Century's departure. The Commission should not require remaining large industrial and rural consumers to be responsible for all costs on a residual basis, including the costs of excess capacity that result from consequences of the bargained-for agreement between BREC, Kenergy and the smelters—and a party which is no longer present - E.ON.

Q. DO YOU PROPOSE AN ADJUSTMENT TO THE REVENUE REQUIREMENTS PRESENTED BY BREC IN THIS CASE, TO ADDRESS THIS?

A. Yes, I recommend that the Commission remove the impact of "lost margins" from the departure of Century that is reflected in Mr. Ostrander's schedules as adjustment OAG-1-DB, which reverses BREC's proposed adjustment of $70.4 million.

Q. ARE THE WILSON AND COLEMAN PLANTS "USED OR USEFUL" IN PROVIDING PUBLIC UTILITY SERVICE TO REMAINING RURAL AND LARGE INDUSTRIAL CONSUMERS?

A. No. BREC has demonstrated by its own actions in "laying up" the Wilson and Coleman plants in response to the departure of the two Century smelter departures that neither plant is "used or useful" in the provision of utility service. Offering the plants for sale also demonstrates that they are not "used or useful" in the provision of utility service. The Commission should not burden ratepayers with the cost of plant and operations which are not used or useful. BREC has removed some of the costs of the Wilson and Coleman plants via expense adjustments to recognize its planned "lay-up", but [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] million remains in proposed revenue requirements,[69] as follows:

Cost	Wilson	Coleman	Total
Depreciation expense	$20,177,366	$6,466,202	$26,643,568
Property tax expense	$1,097,354	$476,341	$1,573,695
Property insurance expense	$1,252,681	$732,472	$1,985,153
Interest expense	$20,981,499	$6,786,049	$27,767,548
Confidential - Fixed department expense	[redacted]	[redacted]	[redacted]
Confidential - Labor/labor overhead	[redacted]	[redacted]	[redacted]
Confidential Total Wilson & Coleman Idled Costs	[redacted]	[redacted]	[redacted]

Q. IS IT REASONABLE TO INCLUDE THESE COSTS OF THE IDLED WILSON AND COLEMAN PLANTS IN REVENUE REQUIREMENTS IN THIS CASE?

A. No. The Commission should exclude these costs from ratemaking in this matter. The Commission may elect to exclude these costs either directly via an adjustment

[69] Big Rivers' Response to KIUC 1-21 (revised).

in this amount, or via inclusion in the higher level adjustment of $70.4 million to reverse BREC proposed "lost margins" adjustment to account for Century Sebree's departure from the system. Century's departure leaves BREC with considerable excess generating capacity, and BREC plans to address this excess capacity issue by laying up the Wilson and Coleman plants or by selling one or both of those plants. BREC states in response to PSC Staff 2-14 "in the financial model the Wilson Station returns to service in [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]... and Coleman Station in [BEGIN CONFIDENTIAL] [redacted]." [END CONFIDENTIAL] The generating plant lay-ups place the plants in a state where they are "unavailable for service" and it would take "weeks or months" to bring the units back into service.[70] Neither plant is "used or useful" in utility service in its state of lay-up, and both are unavailable for utility service in its state of lay-up. The Commission should not include the costs of plant which are not used and useful in providing public utility service in revenue requirements. Therefore, the Commission should exclude costs of the idled Wilson and Coleman plants from revenue requirements in this proceeding as being excess capacity – plant which is not used or useful in the provision of public utility service. This is necessary to achieve fair, just and reasonable rates.

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[70] Big Rivers' Response to PSC 2-21(e) in the Century Hawesville case, at page 6. Note also Big Rivers Response to AG 1-111 in the Century Hawesville case which states it will take 43 days to "restore [Wilson] from an idled status."

Q. DOES THE PUBLIC QUESTION WHY ITS RATES MUST INCREASE TO RECOVER COSTS OF PLANT WHICH IS NOT USED OR USEFUL (OR EXCESS CAPACITY), SUCH AS THE COSTS OF THE WILSON PLANT?

A. Yes. One member of the public has directly questioned the recovery of the shortfall caused by Century's departure from all other ratepayers instead of reducing capacity, as follows:

> "Why would BREC need to maintain its facilities at or near the same capacity as they have now?"[71]

> "It seems, logically, that BREC should be able to reduce operating costs by scaling back operations related to the Century power-generating, and that that reduction of operating costs would offset the vast majority of the 'lost revenue' from Century's business."[72]

This observation from the public is accurate, is just as relevant to the instant case as it was in Case No. 2013-00535, and is addressed by the removal of costs related to the idled Wilson plant as proposed in my testimony.

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[71] Attachment to Big Rivers Response in the Century Hawesville case to KIUC 2-43, page 11.
[72] *Id.*, page 4.

BREC's Mission

Q. WHAT IS THE MISSION OF BREC?

A. According to its website, "the mission of BREC is to safely deliver low cost, reliable wholesale power and cost-effective shared services desired by the members."[73] BREC states in its Application at pages 2-3 that it "exists for the principal purpose of providing the wholesale electricity requirements of its three distribution cooperative member-owners . . ."

Q. IS MAINTAINING EXCESS CAPACITY IN REVENUE REQUIREMENTS AND INCREASING RATES TO REMAINING CONSUMERS TO COVER THOSE COSTS CONSISTENT WITH BREC'S MISSION AS A COOPERATIVE?

A. No. BREC operates on a non-profit basis to serve its retail members. Maintaining excess capacity on the scale created by the departure of the smelters would cause BREC to more closely resemble a *merchant* generator rather than a *cooperative* serving its members. BREC's proposed lay-up of the Wilson and Coleman plants demonstrates that BREC has significant capacity in excess of what it needs for its "principal purpose of providing the wholesale electricity requirements of its three

[73] http://www.bigrivers.com/default.aspx

distribution cooperative member-owners."[74] As stated by Mr. Berry at pages 4-5, and Mr. Holloway at Table 1, BREC has net capacity availability of 1,819 MW.

Even after its proposed idling of Wilson and Coleman units, BREC will have "959 MW of generating capacity to serve 650 MW of peak load, or a reserve margin of approximately 48%."[75] BREC proposes to require consumers to pay the costs of maintaining excess capacity in the form of idled generating plants and high reserve margin created by the departure of the smelters while it searches for replacement load in a depressed off system sales market. The Commission should not allow BREC to place its members or their customers in the position of paying for excess capacity for an indeterminate time period with uncertain results.

Q. IS BREC CHARGING ITS MEMBERS ONLY FOR THE COSTS OF POWER RECEIVED UNDER THE MEMBERS' "ALL REQUIREMENTS" CONTRACTS?

A. No. BREC is proposing to charge its members for the costs of excess capacity which is not necessary for the provision of power to the members. In this application, BREC is inverting its stated role of providing the members with "all *power* requirements" and instead is requiring its members to pay "all *costs*" of

[74] Similarly, the fact that Big Rivers has offered the Wilson plant for sale demonstrates significant capacity in excess of what is needed to serve member requirements.
[75] Direct Testimony of Larry Holloway, P.E., Century Sebree case, at page 7, line 15.

BREC. The "all requirements" concept should not be expanded to flow through all costs of BREC's excess capacity to its members.

Q. **SHOULD REMAINING RURAL AND LARGE INDUSTRIAL CONSUMERS BE REQUIRED TO BEAR THE COSTS AND RESULTS OF BREC'S DECISION TO PROCEED WITH THE UNWIND TRANSACTION (IN THE FORM OF THE COSTS OF EXCESS CAPACITY)?**

A. No. This is a primary question for the Commission to consider – who should bear the risk of BREC's decision to pursue, negotiate and agree to the Unwind transaction? "BREC viewed this proposal [E.ON's proposal for BREC to take back operational responsibility] as an opportunity to improve its financial position for the benefit of itself and its members, as a means to obtain financing on more favorable terms, and as a way to better manage its long-term power supply."[76] However, this view of BREC turned out rather quickly to have been very wrong. The Commission should not burden remaining consumers with the excess capacity costs caused by the smelters' departure based on BREC's decision to pursue, negotiate and agree to the Unwind transaction. In the Unwind transaction, BREC re-acquired substantial long-term and fixed obligations in plant assets and debt in part to serve a substantial but intermediate-term load of the smelters. This

[76] Case No. 2007-00455, "Unwind Case" Final Order, page 7.

mismatch between BREC fixed assets and obligations versus remaining customer load should not be addressed by burdening remaining ratepayers with the carrying costs of the excess fixed assets. It should be addressed by reducing the scale of BREC's operations.

Q. DOES THE SMELTERS' TERMINATION OF THE SMELTER AGREEMENTS PROVIDE BREC WITH AN OPPORTUNITY TO REDUCE THE SCALE OF ITS OPERATIONS?

A. Yes, termination of the smelter agreements provides BREC with both the opportunity and the necessity of reducing the scale of its operations. BREC is at a major fork in the road. It has chosen to file rate cases to burden remaining consumers with the costs of excess capacity caused by termination of the Smelter Agreements. The other path is to work directly on reducing the excess scale of operations that is causing the excess capacity costs. It is very likely (given the large size of the smelter load) that the rate increase path will end up at the excess scale reduction path, only at a later date. BREC should not dissipate reserve funds during pursuit of rate increases and replacement load when such an approach cannot generate materially beneficial results for at least 3-4 years. Reserve funds would be best and most appropriately used at this juncture to support a transition while BREC is taking concrete steps to reduce its scale of operations.

Disallowance of Costs of Excess Capacity

Q. ARE YOU AWARE OF OTHER CASES IN WHICH A STATE UTILITY COMMISSION HAS NOT INCLUDED GENERATING PLANT COSTS OR EXPENSES IN A G&T COOPERATIVE'S REVENUE REQUIREMENTS DUE TO EXCESS CAPACITY, CONCERNS REGARDING EXCESSIVE RATES, AND "USED OR USEFUL" REGULATORY POLICY?

A. Yes, I am aware of two instances. First, as I discussed in my testimony in Case No. 2012-00535, the Kansas Corporation Commission found it necessary to disallow a portion of the generation plant for Sunflower Electric Cooperative due to these concerns. Sunflower sought to include a generating station financed by REA (predecessor to RUS) in rates to be charged to its eight retail members in Western Kansas, and the KCC disallowed a substantial portion of that generating plant for ratemaking purposes. Sunflower had negotiated a Deferral Plan with REA under which the Holcomb Unit would be phased in to rate base. Sunflower and REA's Deferral Plan "contemplated 50% of Holcomb in rate base the first year, and an additional 10% of Holcomb each succeeding year until the entire plant was in rate base after the sixth year."[77] Sunflower filed a rate case in 1984 to request 60% of

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[77] *In the Matter of the Application of Sunflower Electric Cooperative, Inc., for approval of the State Corporation Commission to make certain changes in its charges for sale of electricity to its member cooperatives;* Docket No. 143,069-U, Order (April 2, 1985) at page 6. Hereafter referred to as the "Sunflower Rate Case Order." A full copy of this Order is included as an exhibit to my testimony filed in Case No. 2012-00535.

Holcomb be placed into rate base. The Commission stated it would "evaluate each rate case on its own merits and allow such further portion of the Holcomb Unit to be placed into rate base as can be justified on the basis of usage, economics, rate impact, price elasticity, off system sales, peak requirements, carrying costs and load growth."[78] Facing circumstances very similar to those faced currently by this Commission, the Kansas Corporation Commission determined "the appropriate percentage of the Holcomb Unit to include in rate base, ... evaluat[ing] Sunflower's total generating capacity, firm purchase and sales, reserve requirements, system demand and performance criteria."[79] The KCC allowed 57% of the Holcomb Unit into rate base and disallowed the remainder based on the excess capacity not being "currently used and required to be used" and concerns that excessive rates to residential and industrial customers would result.[80]

Second, the Kentucky Public Service Commission in Case No. 9613 refused to allow recovery of Wilson-related debt expenses. [81] I am familiar with that case only by reference and review of the Order dated March 17, 1987. However, it appears from the Commission's 9613 Order that issues similar to those being considered in

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[78] Sunflower Rate Case Order, page 6, emphasis added.
[79] *Id.*, page 7.
[80] *Id.*, page 13-14.
[81] *In the matter of Big Rivers Electric Corp.'s Notice of Changes in Rates and Tariffs for Wholesale Electric Service and of a Financial Workout Plan,* Case No. 9613, Order (March 17, 1987). A full copy of this Order is included as an exhibit attached to my testimony filed in Case No. 2012-00535. See also Case No. 9887, Order dated Aug. 10, 1987.

this matter -- including but not limited to the issues of off-system sales, Big Rivers' precarious financial position and debt leverage, excess capacity and the used and useful nature of the Wilson plant, and the allocation of risk between Big Rivers' creditors and ratepayers – were considered by the Commission. Also considered in the Commission's 9613 Order was the similarity of Big Rivers' circumstances to those of Sunflower Electric Cooperative.[82] Otherwise, the record will speak for itself.

Q. WHAT IS THE IMPORTANCE OF COMMISSION ACTION AS RECOMMENDED BY THE TESTIMONY ON BEHALF OF THE ATTORNEY GENERAL IN THIS MATTER?

A. Unless the Commission acts as recommended by our testimonies, the Commission can expect more of the same in the future with a repeat of history. The Commission can expect continued rate increase requests from BREC as the preferred means of dealing with its "difficult transition period" or "precarious financial position." At this time there is no end in sight to what promises to be multiple rate cases and financing applications in the future, for the reasons expressed in this testimony, especially due to the extended time period and uncertainty associated with replacing the smelter load under BREC's proposed

[82] *Id.*, at p. 17.

Mitigation Plan approach. The lost smelter load is simply too big to replace, and BREC therefore must take material and concrete steps to reduce the scale of its operations. BREC operations include excess capacity given the departure of the smelter load, and the Commission should require BREC to deal with this circumstance directly rather than subject remaining consumers to paying rates which are not fair, just and reasonable for an extended and uncertain time period to support what in essence is a merchant generation operation in a depressed market for power. This will require that BREC work with its lenders, the Commission and potential buyers to reduce the scale of its operations.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

EXHIBIT DB-1

DAVID BREVITZ, C.F.A.

David Brevitz, C.F.A.
Brevitz Consulting Services
3623 SW Woodvalley Terrace
Topeka, Kansas 66614

General

Mr. Brevitz is an independent regulatory consultant, a Chartered Financial Analyst and has more than thirty years of experience in state regulation of public utilities, regulatory policy at the state commission level, determination of revenue requirements in state regulatory proceedings, various telecommunications matters including telecommunications cost allocations and revenue requirements, and telecommunications regulation/de-regulation. Mr. Brevitz's consulting practice focuses on technical assistance to state utility commissions, consumer advocate offices and organizations, state attorneys general offices, and international telecommunications regulatory bodies.

Professional Designation and Community Service

Mr. Brevitz has achieved designation as Chartered Financial Analyst from the CFA Institute (formerly the Institute of Chartered Financial Analysts) in 1984. The CFA Institute is the organization which has defined and organized a body of knowledge important for all investment professionals. The general areas of knowledge are ethical and professional standards, accounting, statistics and analysis, economics, fixed income securities, equity securities, and portfolio management.

Mr. Brevitz is current President and previous Treasurer (2007 to 2010) of the Kiwanis Club of Topeka. He has served numerous terms on the Board of Directors of the Club, has been recognized by Kiwanis International as a George F. Hixson Fellow, and has his name inscribed on the Kiwanis International Foundation Tablet of Honor.

Recent Relevant Experience

- **March 2012 to Current, Kansas Statewide Broadband Initiatives, Department of Commerce**: Mr. Brevitz is assisting the Kansas Department of Commerce's Kansas Statewide Broadband Initiative's Broadband Mapping effort under NTIA auspices. Mr. Brevitz is working with the University of Kansas's Data Access and Support Center, and providing expertise and assistance in the areas of broadband research and analysis, service provider relations, data collection, data validation and verification, best practices, and overcoming challenges and barriers.

- **March 2012 to November 2012, Rural Local Exchange Company Revenue Requirement Issues, Utah Office of Consumer Services**: Mr. Brevitz is assisting the OCS in examination of RLEC revenue requirement issues to ensure prudent use of Utah Universal Service Funds, and that by extension the UUSF statewide assessment is appropriate and cost based. Mr. Brevitz is reviewing and analyzing issues such as employee and officer compensation issues; allocations between regulated and non-regulated operations; affiliate and related party transactions; implications and impacts of the FCC's Mega-Order on intercarrier compensation and the Federal Universal Service Fund; and appropriate treatment of expenditures for Fiber to the Home programs.

- **August 2011 to Current, Utilities Division Staff, Kansas Corporation Commission**: Mr. Brevitz is assisting KCC staff and the Commission in assessing policy and financial impacts on Kansas rural Local Exchange Carriers, larger Price Cap carriers and Kansas consumers of the FCC's actions regarding the Federal Universal Service Fund and Intercarrier Compensation, which culminated in the FCC's November 18, 2011 Report and Order. Mr. Brevitz is also evaluating revenue requirement and policy issues pertaining to rural Local Exchange Carriers of management compensation, use of RUS loan funds for Fiber to the Home, how Kansas Universal Service Funds are expended, and questions regarding RLEC affiliates and subsidiary relationships. Mr. Brevitz is also analyzing broadband deployment in Kansas through the FCC Form 477 data filed by each service provider in the state twice a year.

- **October 2011 to December 2011, Vermont E911 Board**: Mr. Brevitz performed an analysis of Vermont rural local exchange carrier and FairPoint Communications tariffs and charges for E911 service elements to the Vermont E911 Board, as compared to tariffs and charges for the same elements in the remaining 49 states. The analysis was provided in a Report which identified "best practices" in E911 tariffing and charges, and estimated the cost savings to the Vermont E911 Board and Vermont citizens from adopting these best practices.

- **July 2010 to February 2011, Project Leader, Florida Statewide Strategic Broadband Planning**: Mr. Brevitz led the Public Utility Research Center project team to study government use of broadband capabilities, study assets and services used by government in Florida for broadband capability, and recommend options for the State of Florida to optimize use of government fiber optic and other assets, from a State of Florida enterprise perspective, for current and future broadband capabilities needed by governmental entities. The project culminated in the report on "Strategic Planning for Florida Governmental Broadband Capabilities" containing analysis and options provided to Florida policymakers, available at:

  http://bear.warrington.ufl.edu/centers/purc/docs/papers/1111_Brevitz_Strategic_Planning_for.pdf

- **July 2009 to Current, PURC Senior Fellow**: Mr. Brevitz has been designated as a Senior Fellow by the Public Utility Research Center at the University of Florida. This designation is reserved for knowledgeable and experienced professionals who foster strong ties to academia, industry, and government, who embody PURC's values of respect, integrity, effectiveness and expertise, and who support PURC's mission to contribute to the development and availability of efficient utility services through research, education, and service.

- **February 2010 to Current, Statewide Toll Free Calling Plan Proposal**: Mr. Brevitz is assisting AARP in review of the proposed Statewide Toll Free Calling Plan rules before the Oklahoma Corporation Commission to draft and provide comments on the proposed rules on behalf of AARP. The proposed rules would significantly change intrastate intercarrier compensation (including elimination of access charges), eliminate long distance charges on consumers' bills (including Wide Area Calling Plans), revise facilities and signaling arrangements, and implement a telephone number based assessment methodology.

- March, 2008 to Current, FairPoint Communications Financial Monitoring docket: Mr. Brevitz is assisting the Maine Office of Public Advocate before the Maine Public Utilities Commission in Docket No. 2008-108 in monitoring compliance by FairPoint with financial and other commitments required by the PUC's conditional approval of the Verizon/FairPoint transaction. Mr. Brevitz is also assisting OPA in other matters that arise from time to time pertaining to FairPoint, such as request for waiver of provisions of FairPoint's Performance Assurance Plan, and particularly operational and service quality problems caused by lack of proper performance of FairPoint's new Operational Support Systems (OSS), other back office systems and supporting business practices.

- September 2006 to Current, Nevada Office of Attorney General, Bureau of Consumer Protection, Various Telecommunications Regulatory and Cost Recovery Plans: Mr. Brevitz is providing assistance to the Bureau of Consumer Protection regarding telecommunications matters generally, which include legislative proposals, merger and acquisition proposals, requests to increase rates for basic services, performance measurement and incentive plans, proposals to reclassify individual services as discretionary or competitive, proposals to introduce new services, requests to be designated as an Eligible Telecommunications Carrier (ETC), and other matters.

- October 2009 to January 2011, FairPoint Communications Bankruptcy Proceeding: Mr. Brevitz assisted the Maine Office of Public Advocate regarding the bankruptcy filing by FairPoint Communications in the US Bankruptcy Court (NY, NY). Mr. Brevitz reviewed filings by the company and parties to the proceeding, as well as financial and operational information pertaining to FairPoint's proposed reorganization.

- 1999-Current, Kansas Corporation Commission Advisory Staff: Mr. Brevitz is serving as advisor to the Commissioners on a variety of telecommunications technical and policy matters. Mr. Brevitz also served as advisor on electric industry matters, including cases involving structure/restructure of Westar Energy and Aquila.

- March 2009 to June 2009, Nevada Office of Attorney General, Bureau of Consumer Protection: Mr. Brevitz assisted the BCP in its review and assessment of AT&T Nevada's Performance Measurement Plan and related Performance Incentives Plan, and changes proposed by AT&T to the Plans. The Plans are designed by the Commission to be self-executing and to encourage competition and discourage discriminatory conduct.

- February 2009 to June 2009, USAID Capacity Assessment and Development for the Department of Public Services Regulatory Commission of Armenia: Mr. Brevitz was team leader for the project to conduct a telecom sector strategic analysis, legal and regulatory assessment, and human and institutional capacity assessment for the PSRC in Armenia, under the auspices of USAID and the Academy for Educational Development. The team consisted of three experts from the US, and local experts in Armenia. The team delivered a comprehensive Final Report to AED and USAID on May 31, 2009, which addressed government's plan for IT sector development, market structure and technological potential, the current telecommunications law and regulatory environment, current regulatory performance and priorities, overlapping responsibilities, performance gaps, and human and institutional capacity assessment regarding areas including independence, accountability, transparency, institutional characteristics, organizational structure, and financing and budget.

- **February 2009, Presentation to 36th PURC Annual Conference**: Mr. Brevitz presented on the subject of "Telecommunications Competition: Where is it and Where is it Going?" The presentation at the Public Utility Research Center, University of Florida, assessed market structure and the competitiveness of telecommunications markets from a consumer perspective.

- **December 2008 to June 2009, Kansas Corporation Commission Staff:** Mr. Brevitz assisted the Kansas Corporation Commission Utilities Division staff in Docket No. 08-GIMT-1023-GIT in its assessment of Sprint Nextel's petition to the Commission to bring Embarq's intrastate switched access charges into parity with interstate rates. Mr. Brevitz filed testimony to assess Embarq's cost study in support of its intrastate switched access charges.

- **December 2008 to February 2010, Public Utilities Regulatory Authority of The Gambia:** Mr. Brevitz assisted the Public Utilities Regulatory Authority in The Gambia, under the auspices of the ITU, in the review of international wholesale and retail tariffs charged by the incumbent telecommunications company (GAMTEL) to mobile operators and retail customers to ensure that proposed rates are set at levels that are fair and not anticompetitive. Extensive individual consultations were held with stakeholders that culminated in further industry-wide consultations. In the course of this review, cost information for international wholesale and retail tariffs was reviewed and considered, retail rate benchmarking information was considered, the arrangement between GAMTEL and its affiliated mobile operator (GAMCEL) was reviewed vis-à-vis comparable arrangements with other mobile operators, and the results were provided in a consultative reports to PURA. Policy considerations based on enactment of the Information and Communications Act of 2008 were also addressed, especially including cost accounting and liberalization of the international gateway.

- **November 2008 to March 2009, Nevada Office of Attorney General, Bureau of Consumer Protection, Merger Application of Embarq and CenturyTel :** Mr. Brevitz provided assistance and testimony to the Bureau of Consumer Protection in the Embarq/CenturyTel merger case, addressing in filed testimony the subjects of financial viability, financial projections, debt leverage, synergies and customer benefits asserted to be associated with the proposed transaction. This case was resolved by stipulation among the parties.

- **November 2008, Presentation to NASUCA 2008 Annual Meeting**: Mr. Brevitz presented "Deregulation and Price Increases: the Hallmarks of a Competitive Market?" at the Annual Meeting in New Orleans, Louisiana, which addressed telecommunications market structure and the pattern of price increases following service deregulation.

- **May 2008 to September 2008, Unitil Corporation Acquisition of Northern Utilities**: Mr. Brevitz is working on behalf of the Maine Office of Public Advocate to address the financial, structural and transactional aspects of Unitil Corporation's proposed acquisition of NiSource's Northern Utilities gas distribution operations in Maine and New Hampshire, and also the Granite State Pipeline operation. Mr. Brevitz filed direct testimony containing recommendations and conditions designed to bring the proposed transaction to a level which would meet the "no net harm" standard for Commission approval of such transactions.

- <u>April – November, 2008, Maryland Office of People's Counsel, Verizon Alternative Regulation Plan</u>: Mr. Brevitz addressed the subjects of measurement and evaluation of telecommunications competition, how the level of competition has changed over the term of Verizon-Maryland's previous Alternative Regulation Plan, and the extent to which competition acts as an effective regulator in three rounds of prefiled expert testimony on behalf of the Maryland OPC in Case No. 9133 before the Maryland Public Service Commission. Mr. Brevitz used Verizon – MD data to construct a Herfindahl-Hirschman Index (HHI) which showed a highly concentrated duopolistic market structure, and an absence of effective competition. Mr. Brevitz evaluated the structure and impact on competition of Verizon's "Wholesale Advantage" program pertaining to CLECs subsequent to the demise of Unbundled Network Elements. Mr. Brevitz addressed many competition related subjects such as substitutability of services including VoIP, wireless and cable services; ILEC migration strategies; marketplace behavior under duopoly in contrast to "perfect competition" constructs; and ILEC claims regarding line losses and competition.

- <u>January, 2008 to January, 2009, Big Rivers Electric Corporation "Unwind" Transaction:</u> Mr. Brevitz worked for the Kentucky Attorney General (Office of Rate Intervention) to assess the Big Rivers and E.ON joint application to "unwind" a previous lease transaction. The 1998 transactions were part of Big Rivers' implementation of its bankruptcy reorganization, and included leasing Big Rivers' generating facilities to E.ON's predecessor for it to manage, operate and maintain; transferring responsibility to manage, operate and maintain two additional generating units owned by the City of Henderson (through Henderson Municipal Power & Light, or "HMPL"); purchasing by Big Rivers of a set amount of power at substantially fixed prices through a Power Purchase Agreement that it uses to serve the loads of its three member retail cooperatives; payment by LG&E Energy Marketing ("LEM") to the US Rural Utilities Service ("RUS") of monthly margin payments; and, providing a portion of two aluminum Smelters' power needs at substantially fixed rates through power supply contracts between LEM and predecessors of Kenergy. Various other proposed agreements and approvals are also to be addressed in this matter. Direct testimony was filed in this matter on behalf of the Attorney General of Kentucky's Office of Rate Intervention.

- <u>September 2007 - February 2008, Cable & Wireless/Barbados Price Caps</u>: Mr. Brevitz assisted the Fair Trading Commission and its staff in assessing the results of the first price cap plan for Cable & Wireless/Barbados, and in assessing the desirability of continuing a price cap for Cable & Wireless/Barbados, and related structural changes to better fit the revised price cap plan to current policies and conditions in Barbados. The assessment included consideration of actual financial results and future expected financial results and competitive conditions.

- <u>2007 to March, 2008, FairPoint/Verizon Merger/Acquisition of New England State Operations:</u> Mr. Brevitz worked on behalf of the Maine Office of Public Advocate to assess the proposed spin-off of Verizon operations in Maine, New Hampshire and Vermont and subsequent merger with and into FairPoint Communications, in a reverse Morris trust transaction. The assessment included evaluating financial projections of the company in support of financial viability of the proposed transaction; financial analyses associated with the proposed transaction performed by the company and investment advisors; and implications of resulting debt leverage and structure of the company as "high debt/high dividend". The testimony also included assessment of risk factors associated with the proposed transaction and FairPoint's operational execution risks. The Hearing Examiner's Report and the Commission's Final Order adopted Mr. Brevitz's financial recommendations including substantial debt and dividend reduction.

- <u>2007 to March, 2008, FairPoint/Verizon Merger/Acquisition of New England State Operations:</u> Mr. Brevitz worked on behalf of the New Hampshire Office of Consumer Advocate to assess the proposed spin-off of Verizon operations in Maine, New Hampshire and Vermont and subsequent merger with and into FairPoint Communications, in a reverse Morris trust transaction. The assessment included evaluating financial projections of the company in support of financial viability of the proposed transaction; financial analyses associated with the proposed transaction performed by the company and investment advisors; and implications of resulting debt leverage and structure of the company as "high debt/high dividend". The testimony also included assessment of risk factors associated with the proposed transaction and FairPoint's operational execution risks. The Commission made preliminary determinations in favor of Mr. Brevitz's financial recommendations, which were then reflected in the Commission's Final Order.

- <u>April 2007, PURC Advanced Training Course on Regulatory Economics and Process: Interconnection, Pricing and Competition:</u> Mr. Brevitz developed and presented three courses to members of the National Telecommunications Commission from Thailand. The courses covered accounting separation, case study on a rate proposal, and principles and practices for rate rebalancing.

- <u>January, 2007, 21st International Training Program on Utility Regulation:</u> Mr. Brevitz developed and presented training sessions on accounting separation, rate rebalancing (case study), and universal service obligations to the semi-annual training program for regulatory agency staff and commissioners worldwide. The training program is provided by the Public Utilities Research Center at the University of Florida in Gainesville.

- <u>2006-2008, Telecommunications Training for Regulatory Agency for Telecommunications (RATEL) in Serbia:</u> Mr. Brevitz assisted RATEL in implementation of new policies designed to open telecommunications markets in Serbia to competition. Issues being addressed include cost orientation of prices (rate rebalancing), universal service funds, interconnection, administrative procedures, internet telephony, and spectrum management.

- <u>2006-2007, Embarq UNE Loop Pricing Application:</u> Mr. Brevitz assisted the Bureau of Consumer Protection in the Nevada Attorney General's office in its assessment of Embarq's proposal to increase rates for the unbundled loop. This work included assessment of Embarq's proposed UNE loop cost model and its inputs, FCC orders which speak to TELRIC costing and UNE pricing, and use of the mapping program to support Embarq's proposed cost model.

- "Assessing Pricing Behavior Under Deregulation": Presentation at the NASUCA Mid-Year Meeting, June 14, 2006, Memphis Tennessee.

- 2006 Spin-off of Windstream from Alltel: On behalf of the Kentucky Attorney General (Office of Rate Intervention), Mr. Brevitz formulated discovery, and analyzed and addressed information relevant to the proposed spin-off of the local telecommunications operations from Alltel Corporation and subsequent merger with Valor Communications. Prefiled testimony was provided before the Kentucky PSC addressing the excessive debt burden placed on "SpinCo" by Alltel; conflicting company claims regarding merger synergies; lack of basis for claimed increased buying power; and non-arms-length nature of decisions and transactions in the proposed spin-off.

- 2005 Rate and Revenue Requirement Review of Saco River and Pine Tree Telephone Companies: On behalf of the Maine Public Advocate's Office, Mr. Brevitz addressed revenue requirement levels for both companies, including detailed review of expense levels and trends, expanded calling plan criteria and data, and detailed review of holding company organization and charges between affiliates.

- 2005 Price Deregulation of Basic Local Exchange Service: On behalf of AARP, Mr. Brevitz provided comments before the Public Utilities Commission of Ohio regarding final rules to implement procedures for addressing price deregulation applications. The comments addressed the need for effective competition to be demonstrated before approving price deregulation of BLES; market segmentation between stand-alone BLES and service bundles; barriers to entry; current competitive market conditions and whether "many sellers" exist; functionally equivalent and substitute services; and other related matters.

- 2005 Spin off of "LTD Holding Company" from Sprint Nextel: On behalf of the Nevada Bureau of Consumer Protection, Mr. Brevitz led a team to analyze the proposed spin-off from a technical and public interest perspective under Nevada statutes. Issues addressed included: asset transfers to LTD Holding Co.; levels of debt to be placed on LTD Holding Co.; "normal" levels of debt for Sprint's Local Telecommunications Division; financial and cost of capital implications of the spin off; impact on LTD's ability to compete and other competitive trends; and accounting issues such as division of pension assets and pension liabilities.

- "Telecommunications Convergence: On Duopoly?": Presentation at the NASUCA Mid-Year Meeting, June 15, 2005, New Orleans, Louisiana.

- 2005 Intrastate Deregulation Proposal of SBC Oklahoma: On behalf of AARP, Mr. Brevitz filed testimony addressing SBC Oklahoma's proposal to deregulate pricing of almost all intrastate services (E911 and access services were excepted). The testimony responded to SBC Oklahoma assertions regarding significant retail competition on a widespread basis, openness of markets, barriers to entry and exit, reasonable interchangeability of use of cellular and VoIP services for basic residential services, market share analysis, and competitive trends including CLEC responses to the elimination of UNE-P, access line losses. The testimony further analyzed the actions, opportunities, and competitive responses of SBC Oklahoma and its corporate affiliates, observed public safety deficiencies of cellular and VoIP services, and market trends converging on duopoly.

- <u>2004 to 2005: Alternative Regulation Plan Filing by Verizon Vermont:</u> Mr. Brevitz assisted the Vermont Department of Public Service in assessing matters included in the Vermont Public Service Board's assessment of proposed changes to the Alternative Regulation Plan applicable to Verizon Vermont. Prefiled testimony addresses matters including assessment of competition and modes of competition, VoIP/wireless substitution, continuation of direct assignment practices under the FCC's separations freeze, jurisdictional cost allocations, rate flexibility, and UNE availability and commercial agreements with CLECs.

- <u>2005 UNE Loop Cost Proceeding</u>: On behalf of the Arkansas Public Service Commission General Staff, Mr. Brevitz filed testimony which analyzed SBC Arkansas' proposed increased UNE loop rates, and UNE loop model and shared and common cost model inputs and outputs, including fill factors, defective pairs, IDLC, DSL expenses, and retail related costs.

- <u>2004 Mass Market Switching Reviews under the FCC Triennial Review Order</u>: Separately for the Arkansas Public Service Commission staff, and the New Mexico Attorney General's office, Mr. Brevitz provided analysis and two-step evaluation under the FCC's Triennial Review Order ("TRO") of impairment in access to local circuit switching for mass market customers. The evaluations were done on a granular, market-specific basis. The evaluations determined whether unbundled local circuit switching (and by extension, the UNE-Platform) must continue to be provided as an Unbundled Network Element by incumbent local exchange companies.

- <u>2004 OSIPTEL/Peru</u>: Worked with OSIPTEL (telecom regulator in Peru) to analyze barriers to competition in Peru. Presented workshop and training materials regarding the Economic Aspects of Competition Regulation for Public Utilities, which addressed concepts of market power, dominance, cross subsidies, essential facilities, ex ante versus ex post regulation, asymmetric regulation.

- <u>2003 to 2005: Cable & Wireless Rate Adjustment/Barbados Fair Trading Commission</u>: Mr. Brevitz advised the FTC and its staff regarding the application of C&W Barbados to increase domestic revenues and institute local measured service, and providing related analyses. The Company's filing was in part designed to enable Price Cap regulation, and opening the market to competitors. As such, Price Cap and competitive issues were necessarily considered along with revenue requirements and tariff/pricing issues.

- <u>2003 CenturyTel Rate Case/Arkansas PSC:</u> Mr. Brevitz led a team providing analysis and testimony on behalf of PSC staff in the CenturyTel of Northwest Arkansas rate case, in which the Company sought to treble local rates. Mr. Brevitz provided an analysis of CenturyTel of Northwest Arkansas' ("CNA") modernization programs and provision of DSL services from the perspective of basic local service ratepayers, and also addressed the local competition claims of the Company.

- <u>2002 Maryland Office of People's Counsel:</u> Maryland PSC's Case No. 8918 is to review Verizon's Price Cap regulatory plan, after Verizon had operated five or more years under it. Topics addressed included the proper productivity factor to use in the price Cap formula, and any necessary amendments to the structure of the price cap plan. Mr. Brevitz provided expert testimony on the proper formulation and terms for the price cap formula, competition, and other matters related to the extension of price cap regulation.

- **2001 Maine Office of Public Advocate–Verizon Maine 271 Review:** Review of Verizon's Section 271 filing before the Maine Public Service Commission, and Declaration filed on behalf of the Public Advocate which addresses Checklist Item #13 (Reciprocal Compensation), and Verizon's proposed performance measurement metrics and proposed Performance Assurance Plan.

- **2001 Vermont Department of Public Service–Verizon Vermont 271 Review:** Review of Verizon's Section 271 filing assertions of compliance with the "14 Point" competitive checklist and non-discrimination obligations of the Telecommunications Act of 1996, before the Vermont Public Service Board. Mr. Brevitz filed a Declaration on behalf of the DPS which addresses Checklist Item #13 (Reciprocal Compensation), and Verizon's proposed performance measurement metrics and proposed Performance Assurance Plan. Mr. Brevitz's work continued on behalf of the Department in Docket No. 6255, which worked through a series of workshops to evaluate appropriate carrier-to-carrier standards for use in Verizon-Vermont's territory, resulting in a stipulation approved by the Public Service Board.

- **2001 Public Utility Research Center (PURC)/University of Florida:** Presentation of two seminar modules and an interconnection case study as staff training for the Panamanian telecommunications regulatory body, ERSP. Mr. Brevitz developed course content and presentation materials for the seminar, under the auspices of PURC, on the topics of the "US Experience in Telecom Competition" and "Consumer Issues in Telecom Competition". These topics were presented by Mr. Brevitz in the seminar at Panama City, Panama on March 29-30, 2001.

- **2001-2002 Michigan Attorney General's Office–Federal District Court Litigation Support**: Mr. Brevitz supported the Attorney General's office in its defense of lawsuits by Ameritech and Verizon against the PSC and the Governor regarding recently passed state legislation. The state legislation eliminated the intrastate EUCL being charged by both companies, expanded local calling areas, and froze the application of the Price Cap Index for a period of time.

- **1999-2000 Delaware Public Service Commission Staff–Evaluation of Bell Atlantic-Delaware's Collocation Tariff Filing:** On behalf of the Staff, Mr. Brevitz reviewed BA-Delaware's Collocation tariff filing, and prefiled testimony on behalf of Delaware PSC staff. Issues addressed include non-discriminatory provisioning of collocation; collocation intervals; utilization of "best practices" for terms, conditions and pricing; and costing.

- **1999-2000 Vermont Department of Public Service–Evaluation of Carrier to Carrier Wholesale Quality of Service:** On behalf of the Vermont DPS, Mr. Brevitz was engaged in the review of quality of service standards related to Verizon's wholesale activities of provisioning Unbundled Network Elements and resold services. The work effort was conducted within a workshop of the parties, and was drawn on the similar activity for BA-NY and a number of other states including Massachusetts and Virginia. Measures, standards and benchmarks were to be determined, along with an appropriate remedy plan in the event those items are not met by the incumbent carrier. This matter was resolved in the context of Verizon's Section 271 case.

- **1999-2000 Vermont Department of Public Service–Investigation of Geographically Deaveraged Unbundled Network Prices:** On behalf of the Vermont DPS, Mr. Brevitz testified before the Vermont Public Service Board regarding the appropriateness and extent of geographic deaveraging of rates for Unbundled Network Elements (UNEs) in Vermont. In formulating these positions, it was necessary to consider FCC Orders, competitive policy implications, and related issues such as distribution of federal high cost support. The FCC had spotlighted the linkages between high cost support and geographic deaveraging determinations. Consequently the testimony also considered federal high cost support distribution implications and local rate impacts stemming from geographic deaveraging determinations to be made by the Board.

- **1999 Vermont Department of Public Service–Evaluation of Bell Atlantic Proposed Alternative Regulation Plan, Wholesale Quality of Service Standards, and Cost of Service:** Mr. Brevitz served as project manager and lead consultant in the DPS review of Bell Atlantic's proposed Price Point Plan and proposed appropriate modifications. Those modifications included moving rate reductions forward to the inception of the plan, and aligning the plan more closely to the status of competition in Vermont by allowing streamlined regulation only for truly new services, not bundles of existing services. Mr. Brevitz also supported the immediate implementation of detailed wholesale quality of service standards along with a remedies structure. Mr. Brevitz addressed the cost of service issues of reciprocal compensation and local number portability, and proposed rate design changes to effect the return of $16 million in excess revenues.

- **1998-99 Delaware Public Service Commission Geographic Deaveraging of Bell Atlantic UNE Loop Rates:** Mr. Brevitz worked for PSC staff to analyze cost and policy issues associated with geographic deaveraging of UNE loop rates. Methodology and policy to determine geographic zones was reviewed for BA-Del, and compared to all other Bell Atlantic states. BA-Del cost data was reviewed to assess closeness of fit between BA-Del's proposed population of zones with existing exchanges to the loop costs of those exchanges. After review of comments of interested parties, Mr. Brevitz prepared and submitted a report and recommendation to the PSC regarding modification of BA-Del's proposal to implement geographically deaveraged UNE loop rates. The PSC adopted the report and recommendation in its Order in the matter.

- **1998 Vermont Department of Public Service- Evaluation of Proposed Special Contracts for Toll and Centrex Services for Compliance with Imputation Requirements:** Mr. Brevitz worked for the DPS in this matter, which was an evaluation of four individual customer toll contracts, and two individual customer Centrex contracts, under the Vermont Public Service Board's price floor and imputation requirements. This evaluation included analysis of whether Bell Atlantic had appropriately followed the Board's imputation requirements; whether the imputed costs had been appropriately calculated and included all relevant costs; and, whether undue price discrimination would result from approval of Bell Atlantic's proposed prices. Mr. Brevitz analyzed the Company's filed testimony and costing information provided in support of the contract pricing; drafted staff discovery and analyzed responses of other parties in the matter; and, supported pre-filed rebuttal and surrebuttal testimony before the Board under cross examination. Hearings in this matter were held in November and December of 1998 and January 1999.

- <u>1998 Delaware Public Service Commission- Re-classification of Residential ISDN as "Competitive"</u>: Mr. Brevitz worked for Delaware Public Service Commission staff in this case (Docket 98-005T), which was a filing by Bell Atlantic to move Residential ISDN ("R-ISDN") from the basic service classification to the competitive service classification, pursuant to the Telecommunications Technology Investment Act and related Commission rules to implement the Act. Bell Atlantic filed an application before the PSC stating that R-ISDN met the statutory and rule conditions for moving the service to the competitive class of services, along with market information in support of that statement. Mr. Brevitz analyzed the company's filing and the comments of other parties in the matter from an economic and public policy perspective, analyzed the Company's compliance with applicable provisions of the TTIA and Commission rules, drafted staff discovery and analyzed discovery responses of other parties, and presented testimony under cross examination before the Commission. The hearing in this matter was held July 9, 1998.

- <u>1997 Delaware Public Service Commission - Costing and Pricing of Residential ISDN Service</u>: Mr. Brevitz assisted the Delaware PSC staff in this case (Docket 96-009T) by reviewing the prefiled testimony of all parties; reviewing the cost studies supporting Bell Atlantic's proposed R-ISDN pricing; comparing those costs to Bell Atlantic's UNE rates and costs; reviewing Bell Atlantic's contribution analyses and demand forecasts for the R-ISDN service; reviewing and comparing two Bell Atlantic local usage studies (the second of which more than tripled the costs of the earlier study); providing an analytic report on the usage cost studies to PSC staff and rate counsel; assisting in the preparation and conduct of cross-examination; and assisting staff rate counsel in preparation of the brief in this matter. The hearing in this matter concluded in January 1998.

- <u>1997 Georgia Public Service Commission - Unbundled Network Elements Cost Study Review</u>: Mr. Brevitz was a lead consultant in this engagement. The GPSC opened a cost study docket to determine the cost basis for BellSouth UNE rates, following arbitration hearings involving BellSouth and several competitors. Introduced for the first time by BellSouth, and considered in the hearing was BellSouth's "TELRIC Calculator". Also considered in the hearing, as sponsored by AT&T/MCI was Hatfield Model Versions 3 and 4. Mr. Brevitz prepared and provided to GPSC staff an "Issues Matrix" which listed the issues, party positions on the issues, and a suggested staff position. Also on behalf of GPSC staff, Mr. Brevitz analyzed cost inputs and outputs pertaining to both models. No testimony was provided in this matter as GPSC staff did not testify in the hearing. Hearings on the matter concluded in September 1997.

- <u>1995, 1996 and 1997 Wyoming Public Service Commission - Competition Rules</u>: Mr. Brevitz was the Project Manager and a lead consultant for this engagement. Mr. Brevitz is actively involved in writing and implementing comprehensive competition rules in Wyoming which consider the new 1995 Telecommunications Act in Wyoming and the 1996 Federal Telecommunications Act. These rules address interconnection/unbundling, universal service, service quality, price caps/alternative regulation, privacy, resale, intraLATA dialing parity, TSLRIC/cost study methods; access charge rate design; number portability, reciprocal compensation, rights-of-way and other matters.

- **1995 and 1996 Wyoming Public Service Commission - U S WEST Pricing Plan:** Mr. Brevitz was the Project Manager and a lead consultant for this engagement. Mr. Brevitz has evaluated and filed testimony regarding U S WEST's pricing plan, competition issues, universal service and U S WEST cost study issues.

- **1996 Oklahoma Corporation Commission - Seminar on 1996 Federal Telecom Act:** Mr. Brevitz presented a seminar on the 1996 Federal Telecom Act to the Oklahoma Corporation Commission Staff.

- **1995 and 1996 Georgia Public Service Commission - Local Number Portability and Competition Policy:** Mr. Brevitz was the Project Manager and a lead consultant for this engagement. Mr. Brevitz assisted the GPSC in implementing rules related to the new 1995 Telecommunications Act in Georgia and the 1996 Federal Telecom Act. Mr. Brevitz was primarily involved in initiating and coordinating the Number Portability Task Force and guiding the industry workshop on permanent number portability. The PSC has accepted the industry workshop recommendation. As a result, Georgia will be one of the first states to implement full number portability. Assistance was also provided on other competition issues.

- **1996 California Public Service Commission - Pricing of Unbundled Elements and Resale services:** Mr. Brevitz assisted Sprint in the pricing (second) phase of the California Commission's OANAD proceeding. Testimony was presented regarding proper pricing of unbundled network elements, given previous a PUC decision on UNE costs. The cost (first) phase involved the development of cost study principles, performance of TSLRIC cost studies of unbundled network elements by Pacific Bell and GTEC, and performance of avoided cost studies for retail services for resale.

- **1995 to 1996 Kansas Telecommunications Strategic Planning Committee - Kansas Corporation Commission:** Mr. Brevitz served as the Kansas Corporation Commission representative on this legislative committee, which was organized in mid-1994 to research and recommend any needed changes to the telecommunications statutes and state policies. The TSPC issued its final report to the Governor and the legislature in January 1996. Mr. Brevitz drafted the NTIA grant application for the Committee and worked with Legislative Research staff to draft the TSPC's Report to the Kansas Legislature. Mr. Brevitz also drafted subsequent reports to the Kansas Legislature regarding telecommunications on behalf of the KCC.

- **1995 Chairperson of Kansas Corporation Commission Working Groups:** Mr. Brevitz was appointed to the Cost Studies and Universal Service Working Groups for the KCC's general competition investigation, subsequent to the KCC's May 1995 Phase I competition order. He was also active in other Task Forces including Unbundling, Number Portability and Local Resale.

- **Kansas Corporation Commission - Infrastructure/Competition Report**: Produced a special report on Kansas telecommunications infrastructure/competition issues which was provided to the 1995 Kansas legislature.

- **1994 Kansas Corporation Commission - Alternative Regulation Legislation:** In 1994 the Kansas Legislature passed House Bill 3039, which extended SWBT's "TeleKansas" alternative regulation plan for two years. Mr. Brevitz provided substantial assistance in negotiating the detailed provisions for the KCC's implementation of the bill.

- **Kansas Corporation Commission - Southwestern Bell Telephone Infrastructure Analysis:** Investigated SWBT's infrastructure/modernization budget and addressed construction requirements, tariffs, rates, terms and conditions for SWBT's provision of interactive television ("ITV") to all Kansas schools at deep discount prices for the benefit of the Kansas infrastructure and schools.

Work History

Independent Telecommunications Consultant

Following a significant engagement with the Kansas Corporation Commission, extensive professional services have been provided to state public utility commissions, as indicated above under "Recent Relevant Experience".

A variety of duties and tasks have been performed for the Kansas Corporation Commission, including providing staff support for Statewide Strategic Telecommunications Planning Committee, composed of 17 members (legislators, state agency heads, private enterprise); assisting in KCC implementation of House Bill 3039 ("TeleKansas II", extension of alternative regulatory plan for Southwestern Bell Telephone); and providing analysis and testimony for communications general investigations into competition in the local exchange and other markets. Those general investigations included General Competition, Competitive Access Providers, Network Modernization, Universal Service, Quality of Service, and Access Charges.

Kansas Consolidated Professional Resources - Director of Regulatory Affairs

Duties included monitoring of and participating in state regulatory affairs on behalf of twenty independent local exchange companies in Kansas that compose the partnership of KCPR. Active participation in statewide industry committees in the areas of access charges, optional calling plans/EAS, educational interactive video, dual party relay systems and private line/special access merger.

Kansas Corporation Commission - Chief of Telecommunications

Duties included supervising the formulation of staff testimony and policy recommendations on matters such as long distance competition, access charges, telephone company rate cases, and deregulation of CPE and Inside Wiring; analyzing Federal Communications Commission and

Divestiture court decisions; supervising and performing tariff analysis; and testifying before the Commission as necessary. SWBT's $120 million "Divestiture rate case" was completed in this time period, as were several other large rate cases. Active member of the National Association of Regulatory Utility Commissioners (NARUC) Staff Committee on Communications.

Arizona Corporation Commission - Chief Rate Analyst - Telecommunications

Duties included supervision of staff and formulation of policy recommendations on telecommunications cases, along with production of analyses and testimony as required.

Kansas Corporation Commission - Economist - Research and Energy Analysis Division

Duties included research, analysis and production of casework and testimony regarding gas/electric and telecommunications matters. Matters addressed included revision of jurisdictional separations, deregulation of CPE and inside wire, Wolf Creek Nuclear Generating Plant Task Force, and divestiture of the Bell Operating Companies from AT&T.

Education

Michigan State University - Graduate School of Business
East Lansing, Michigan
Master's Degree in Business Administration-Finance.

Michigan State University/James Madison College
East Lansing, Michigan
Bachelor of Arts Degree in Justice, Morality and Constitutional Democracy.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION, INC. FOR AN ADJUSTMENT OF RATES	)))	Case No. 2013-00199

AFFIDAVIT OF DAVID BREVITZ

State of Kansas)
)
)

David Brevitz, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

David Brevitz
David Brevitz

SUBSCRIBED AND SWORN to before me this 22nd day of October, 2013.

Ashley N Roberts
NOTARY PUBLIC

My Commission Expires: 08/08/15

ASHLEY N. ROBERTS
Notary Public - Notary Seal
State of Missouri
County of Boone
My Commission Expires August 8, 2015
Commission #11224246

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

DIRECT TESTIMONY

OF

LARRY W. HOLLOWAY, P.E.

ON BEHALF OF

KENTUCKY OFFICE OF ATTORNEY GENERAL

REDACTED

FILED: October 28, 2013

DIRECT TESTIMONY
OF
LARRY W. HOLLOWAY, P.E.

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BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2013-00199

DIRECT TESTIMONY OF

LARRY W. HOLLOWAY, P.E.

INTRODUCTION

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

A. My name is Larry W. Holloway. My business address is 830 Romine Ridge, Osage City, Kansas. I am an independent consultant testifying on behalf of the Kentucky Office of the Attorney General ("OAG").

Q. Briefly describe your education and work experience.

A. I am a registered professional engineer and have worked over 30 years in all aspects of the electric industry; including generation construction, startup, and operations; regulatory oversight, ratemaking and public policy; and utility resource procurement and management.

My professional experience began outside of the electric industry and includes one year as a field engineer for a natural gas utility and two years as a project engineer for an inorganic chemical plant. Since 1981, the majority of my professional experience has been in the electric industry. I have twelve years of construction, design, startup and operations engineering experience with power plants, primarily nuclear. In 1993, I started work at the Kansas Corporation Commission (KCC) as Chief of Electric

Operations, Rates and Services. In 1998, I was promoted to Chief of Energy Operations. In March of 2009, I accepted the position of Operations Manager with Kansas Power Pool (KPP), a Kansas municipal energy agency. I continue to work at the KPP and do consulting on a part time basis, provided there is no conflict with the responsibilities of my KPP position and I can arrange the necessary time away from my KPP position.

A short summary of my experience and education is attached as Exhibit Holloway-1.

Q. Have you previously filed testimony before this Commission, the Federal Energy Regulatory Commission, or any other state regulatory commissions?

A. I have previously filed testimony before this Commission regarding the 2012 application by Big Rivers Electric Corporation ("Big Rivers" or "the company") for a rate increase, Case No. 2012-00535._I have filed analyses for settlement purposes at the Federal Energy Regulatory Commission ("FERC"), and I filed testimony in numerous cases before the Kansas Corporation Commission ("KCC") both as a member of KCC Staff and on behalf of KPP. Testimony I have filed before the KCC includes analysis, review and policy recommendations on utility ratemaking; generation reliability, resource acquisition, planning, dispatch, siting, and fuel and operating costs; utility merger proposal savings and benefits; transmission siting, policy, classification, cost recovery and regionalization; energy cost adjustment mechanisms; and disposition of gain on sale of utility assets. For a full listing of these dockets see Exhibit Holloway-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by the OAG to review the application, testimony, and data responses in this matter, with particular attention to any potential issues in the areas of excess generation capacity, load forecasts, transmission pricing, depreciation costs, and forecasted member costs and benefits. My comments and recommendations are included in this testimony and cover the topics of excess generation capacity, replacement load forecasts, analysis of member benefits from Coleman and Wilson, transmission costs, and Coleman and Wilson depreciation costs.

It is my understanding that the rates filed in Case No. 2012-00535 are currently in effect subject to refund, pending the Commission's final Order, which I understand is due on or before November 15, 2013. Regarding the Commission's final determination in that proceeding, I reserve the option to file supplemental testimony to clarify the OAG's position.

Q. Are you sponsoring any exhibits?

A. Yes, I have prepared the following exhibits:

1. Holloway-1 – Qualifications of Larry W. Holloway, P.E.
2. Holloway-2 – Load and Generation Analysis
3. Holloway-3 – Member Benefit Analysis for Rate Treatment of Coleman and Wilson Costs

EXCESS GENERATING CAPACITY

Q. Have you reviewed Big Rivers' load forecasts?

A. Yes. This filing is the first Big Rivers rate application that reflects loss of all load from the two smelters, Century Hawesville and Century Sebree.[1] Case No. 2012-00535 (the "Century Hawesville Case") addressed Big Rivers' revenue shortfall from the loss of Century Hawesville, while this case (the "Century Sebree Case") addresses the additional revenue shortfall from the loss of load from Century Sebree.[2]

As described by Big Rivers, a new load forecast was prepared to develop this application:

> "Personnel under my direction worked with GDS in the preparation of the 2013 Load Forecast that was used in the development of Big Rivers' budgets and the development of this application."[3]

Further, Big Rivers explains that the load forecast utilized eliminates all smelter load:

> "As a result of the Alcan contract termination, beginning on January 31, 2014, Big Rivers reduced its peak demand forecast by 368 MW and its energy forecast by 3,159 GWh/year. The demand reduction represents Alcan's full contract demand specified in the smelter agreement, and the energy reduction represents the full contract demand at 98% load factor, consistent with the terms and conditions for billing as specified in the smelter agreement. These reductions result in the elimination of one hundred percent of the Alcan load from the Big Rivers load forecast. This is in addition to the full elimination of the Century load from the Big Rivers load forecast effective August 20, 2013, as described in Case No. 2012-00535."[4]

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[1] Century acquired the Sebree smelter from Rio Tinto Alcan in June 2013. Both smelters are now owned and operated by Century. Therefore in this testimony the smelters will be referred to as either "Century Sebree" or "Century Hawesville" as appropriate. Case No. 2013-00199 will be referred to as the "Century Sebree Case," and Case No. 2012-00535 will be referred to as the "Century Hawesville Case."

[2] While Big Rivers maintained that there were a few other minor revenue deficiencies, depreciation expenses, etc., by far the majority of the requested rate increase is due to the loss of the smelter load in both cases.

[3] See P.6, L12-14 of the Direct Testimony of Lindsay N. Barron filed June 28, 2013 in this proceeding.

[4] Ibid, p.7, l.24 to p.8, l.

The amount of load removed from Big Rivers' load forecast related to both smelters is roughly 850 MW.[5] In fact, Big Rivers estimates that the member peak demand after the smelters exit will be approximately 650 MW.[6]

Q. How does Big Rivers' generation capacity compare to remaining member peak load of 650 MW?

A. Counting the full 178 MW of capacity available from the Southeastern Power Administration ("SEPA") contract,[7] Big Rivers has a total net generating capacity of 1,819 MW. This is roughly 2.8 times the amount of member load that will remain after the smelter load is removed. If Big Rivers maintained all of the 1,819 MW of generation capacity it would have a reserve margin of approximately 180% to serve the remaining 650 MW of load.

Q. How does Big Rivers propose to address the excess generation capacity after the smelter load departs?

A. To address this problem Big Rivers plans to idle both the Wilson and Coleman generation stations.[8] Big Rivers anticipates even with these plants idled it will still have 959 MW of generating capacity to serve 650 MW of peak load, or a reserve margin of approximately 48%.

[5] See p. 11, l.3-5 of the Direct Testimony of Robert W. Berry filed June 28, 2013 in this proceeding.
[6] Ibid, p.15, l.10-11.
[7] Ibid, p.4, l.20 to p.5, l.9. SEPA contract capacity is currently not available but expected to return to full amount January 2015.
[8] Ibid, p.15, l.1-20.

Table 1 - Current Big Rivers Generating Capacity with Wilson and Coleman Idle

Plant or Contract	Generating Capacity	Reference
Kenneth W. Coleman	443	Berry Direct P.4, l.21 to p.5, l.9
Robert A. Reid	130	Berry Direct P.4, l.21 to p.5, l.9
Robert D. Green	454	Berry Direct P.4, l.21 to p.5, l.9
D.B. Wilson	417	Berry Direct P.4, l.21 to p.5, l.9
HMP&L Station 2 (current rights)	197	Berry Direct P.4, l.21 to p.5, l.9
SEPA	178	Berry Direct P.4, l.21 to p.5, l.9
Subtotal	1819	
w/o Coleman & Wilson	959	

Q. Does Big Rivers anticipate any changes to the remaining 959 MW of generating capacity in the future?

A. Yes. Henderson Municipal Power and Light ("HMP&L") has notified Big Rivers that it will increase its HMP&L Station 2 reservation by 5 MW after May 2014 and by an additional 5 MW after May 2015. The net result is that after May 2015, and after idling Wilson and Coleman, Big Rivers will have 949 MW of available generation capacity.[9]

[redacted] **MWs of generation capacity?**

A. No, at least not for a very long time. Even with that reduction in generating capacity, Big Rivers' own current load forecasts show that the company's "Native Load," i.e., the load associated with the members' Rural and Industrial customers, will only grow to approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] by [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] and even at that future date

[9] Ibid, p.5, l.11-16.

the 949 MW of generating capacity will still represent a reserve margin of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].[10]

REPLACEMENT LOAD

Q. How does Big Rivers propose to deal with the impact of the loss of 850 MW of smelter load and the resulting excess generating capacity?

A. Big Rivers' Mitigation Plan consists of several steps. The first step listed, of course, is to apply for a rate increase to offset the revenue shortfall from the loss of smelter load.[11] The second step is to market all excess power when the market price is greater than marginal generation cost.[12] The third step is to idle generating plants when the market price does not support the cost of generating.[13] The fourth step, and indeed a key assumption in Big Rivers' long-term financial forecast, is to find load replacement for the 850 MW previously used by the smelters.[14]

Q. In what time frame does Big Rivers anticipate finding this replacement load?

A. Big Rivers' long-term financial forecast assumes that replacement load will be obtained in the amounts of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].[15]

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[10] See Exhibit Holloway-2.
[11] See p. 10, l.7-11 of the Direct Testimony of Robert W. Berry filed June 28, 2013 in this proceeding.
[12] Ibid, p.10, l.12-16.
[13] Ibid, p.10, l.17-20.
[14] Ibid, p.11, l.1-16.
[15] See Exhibit Holloway-2, page 2.

Q. When does Big Rivers anticipate returning Coleman and Wilson to service?

A. If Big Rivers is not able to find replacement load, or to sell or lease the units, it anticipates that off-system market prices will recover sufficiently to support operation of these units in 2019.[16] This is different from the long-term forecasts that Big Rivers has provided with its replacement load assumptions. Under the scenarios where Big Rivers achieves its anticipated levels of replacement load, Wilson is returned to service in [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] and Coleman is returned to service in [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].[17]

Q. How do the forecasted dates when Wilson and Coleman will return to service compare to the assumed dates that Big Rivers will pick up replacement load in the long-term financial forecasts?

A. According to Big Rivers' long-term financial forecasts, Big Rivers will be serving [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of replacement load in [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] before Wilson returns to service.[18]

Q. Is there a level of replacement load that Big Rivers can serve even before Wilson and Coleman are forecast to return to service?

A. Yes. Since there is a level of replacement load that Big Rivers can serve without returning Wilson and Coleman to service, it should be assumed that this level of replacement load

[16] See p. 13, l.19-22 of the Direct Testimony of Robert W. Berry filed June 28, 2013 in this proceeding.
[17] See Annual Resource Report PSC 2-14 PCM Run 4-22-2013 (2013-2027).
[18] See Exhibit Holloway-2, page 2.

and the associated energy ***does not require Wilson and Coleman to be returned to service.*** This is further illustrated on page 3 of Exhibit Holloway-2.

Q. Has Big Rivers provided justification for its assumed levels of replacement load?

A. Yes, but Big Rivers failed to provide any quantitative evidence to support its assumed levels of replacement load. Instead, when asked this question in KIUC 2-32, Big Rivers merely responded that "...Big Rivers states that the replacement load forecasted in Big Rivers' long-term load forecast was determined based on informed judgment."

Q. How critical are Big Rivers' assumptions regarding replacement load?

A. As previously discussed, Wilson and Coleman are not needed or necessary to serve the members' native load Rural and Industrial customers in the foreseeable future. If Big Rivers is unable to obtain replacement load, then the only benefit Wilson and Coleman would provide members would be from any potential of off-system sales into the market.

Q. How do changes in the forecast of replacement load affect Big Rivers' excess generation capacity?

A. In preparing my testimony, I performed a sensitivity analysis assuming that Big Rivers achieves only 50% of its forecasted replacement load, and that it occurs one year later than in Big Rivers' forecast. Additionally, this analysis assumes that Wilson and Coleman are returned to service in the years they are currently forecasted to return to service. While Big Rivers' long-term forecasts assume that Wilson and Coleman return to service primarily due to increased market prices, decreasing the amount and timing of the replacement load changes the time when Wilson and Coleman are required as capacity to serve replacement load. The purpose of these sensitivity analysis assumptions is to attempt to quantify just how sensitive Big Rivers' forecasts are to changes in their "assumptions" regarding the amount and timing of any replacement load.

The results are shown on page 4 of Exhibit Holloway-2 and the resulting reserve margins are illustrated on page 5 of Exhibit Holloway-2. As shown, the reduced replacement load forecast would not require Wilson or Coleman to return to service until [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] to serve the replacement load, and would result in a reserve margin of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL], the end of the long-term forecast period.

Q. Setting aside the uncertain replacement load forecast, is there a point in the long-term forecast when Wilson and Coleman will be needed or necessary to provide service to the members' native load Rural and Industrial customers?

A. No. There is no anticipated need or necessity for either of these generating plants to serve the full requirements members' native load in the near or long-term future.

Q. Do the members receive any benefit from these units?

A. If the Commission approves the rate increases for Big Rivers to recover all of the costs for owning and operating Wilson and Coleman, the members' retail customers will bear certainly the burden of a large rate increase immediately. Nonetheless, even though these units will not be needed or necessary to serve the native load customers, eventually, years from now, the members may receive some benefits of an unknown amount. But the benefits occur only if these units are used to sell power off-system to either replacement load or directly into the market (assuming, of course, that the off-system sales of these units into the market becomes profitable again). This is, in essence Big Rivers' current plan if it cannot sell the facilities.[19] However, from the perspective of the members' Native Load Rural and Industrial customers these units are not needed now or in the future. Furthermore, any uncertain future benefits will only serve to mitigate the unnecessary burden imposed by years of rate increases to pay for the certain and known costs of owning, maintaining and operating these units today.

ANALYSIS OF MEMBER BENEFITS

Q. Has Big Rivers provided any cost benefit analysis regarding ownership of Wilson and Coleman?

A. No. The OAG asked for Big Rivers to provide a cost versus benefits analysis justifying the reported asking price for Coleman and Wilson from a customer perspective, as well as scenarios related to timing of the sale of Coleman and Wilson.[20] Big River's provided the following response:

> "The timing and price for any sale of the plant(s) will affect the total revenue requirement impact, the balance sheet impact, and the operating income statement impact. Because the plants have not been sold, the timing and sale price(s) are not known. Consequently, the requested information is not available."

Q. Has any party in this proceeding provided a member benefit analysis of the costs of owning and operating Wilson and Coleman?

[19] From Big Rivers' perspective the actions taken to try to achieve some level of benefits from Wilson and Coleman to offset the costs of owning and operating these units, while recovering all of these costs in members rates, coincides with their perceived primary objective and obligation to serve their debt to creditors.
[20] See AG 2-35 and AG 2-36.

A. Yes. On behalf of the OAG, I am sponsoring a Member Benefit Analysis for Rate Treatment of Coleman and Wilson Costs in Exhibit Holloway-3.

Q. What is the purpose of this analysis?

A. After reviewing Big Rivers' native load forecasts and generating capacity it has become clear to me that Wilson and Coleman are not needed or necessary to serve Big Rivers' members' Native Load Rural and Industrial customers, in *either* the near-tem *or* long-term future. 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.

A cost benefit analysis is a systematic process for calculating and comparing the benefits and costs of a project, investment, decision or policy. In a cost-benefit analysis, benefits and costs are adjusted for the time value of money and are evaluated based on their net present value. The analysis performed here determines the net present value of Wilson and Coleman ownership to the members.

This analysis uses the values and timing of the costs and benefits provided in Big Rivers' long-term forecasts. For the time value of money, the analysis uses the interest rate which Big Rivers utilized in their latest Integrated Resource Planning filing for the anticipated Wilson and Coleman ownership costs. As discussed in the Direct Testimony of David Brevitz, an investment level cost of money of 10% was used to evaluate the off-system sales benefits, as these benefits are far more uncertain than the costs and the related interest rate should reflect these uncertainties. Additional assumptions, inputs and results are fully discussed in Exhibit Holloway-3. The policy implications and ratemaking recommendations from this analysis will be addressed in the Direct Testimony of Mr. David Brevitz.

Q. What did this analysis show?

A. As described, the Member Benefit Analysis for Rate Treatment of Coleman and Wilson Costs provides several results and conclusions. First, this analysis determines the net present value of Wilson and Coleman costs and benefits from a member perspective. As a result of that analysis the Commission can, if it chooses, select an annual adjustment to Big Rivers' revenue requirements to make sure that the overall costs of Coleman and Wilson equal the anticipated benefits they may eventually achieve. Second, this analysis provides an amount that approximates the immediate value for liquidating Coleman and Wilson to prevent addition of the cost of owning and operating these units from being added to Big Rivers' revenue requirements. Third, this analysis attempts to answer the question of how Wilson and Coleman compare to investing in a new gas-fired combined cycle plant to meet the forecasted replacement load and related market sales benefits. Finally, a sensitivity analysis was performed to determine how the results of this analysis are affected if the forecasted replacement load fails to materialize for one year, and then occurs at only 50% of anticipated values.

Q. What can be concluded from the Member Benefit Analysis for Rate Treatment of Coleman and Wilson Costs shown in Exhibit Holloway-3?

A. While the overall policy and ratemaking recommendations will be discussed by Mr. David Brevitz, as the analysis contained in Exhibit Holloway-3 indicates, from the perspective of the members, the Commission could simply offset the shortfall of benefits to cover the costs of Wilson and Coleman ownership by adjusting Big Rivers revenue requirements by [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] to bring the current negative net present values of Wilson and Coleman respectively of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] to zero.[21] In other words, this adjustment reasonably assures that the costs of owning and operating Wilson and Coleman equal the benefits related to this ownership for Big Rivers' members.

Another conclusion regards Big Rivers' asking price to sell Wilson and Coleman. Big Rivers estimates it may be possible to complete a sale of Wilson and Coleman within 3 years. [22] To that end, Big Rivers has indicated that it is currently asking [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] for Wilson and [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] for Coleman.[23] However, in the meantime, Big Rivers' members will continue to pay all the costs of owning and operating Wilson and Coleman. To that end the analysis presented in Exhibit Holloway-3 determines the minimum price that could be asked for Wilson and Coleman if it were possible to sell the units immediately to prevent burdening the ratepayers with the ongoing costs. [BEGIN CONFIDENTIAL] [redacted] [END

[21] See Exhibit Holloway-3 Attachment B
[22] See p. 13, l.15-18 of the Direct Testimony of Robert W. Berry filed June 28, 2013 in this proceeding.
[23] See response to PSC 2-15.

CONFIDENTIAL],[24] assuming the proceedings were used to retire debt, would assure that Big Rivers' members are immediately made whole and would prevent Wilson and Coleman cost recovery in rates.

Because Wilson and Coleman are neither needed nor necessary to serve the members' native load, the only benefit they provide members is from any potential profits of off-system sales to either replacement load or market sales. *Therefore, from the perspective of the members' Native Load Rural and Industrial customers, costs related to owning and operating these units into the future is no different than that of investing in a merchant generating facility.*

The analysis contained in Exhibit Holloway-3[25] 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 service. The results of this analysis show that a new combined cycle unit installed in [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].[26]

Finally, as discussed, I performed a sensitivity analysis assuming that the replacement load occurs at a rate of 50% of the current forecast and 1 year later in the forecast period. In other words, if the forecast assumed that 2 MW of replacement load

[24] See Exhibit Holloway-3
[25] See Exhibit Holloway-3 Attachment C
[26] Ibid. Also see Exhibit Holloway-3 Appendix

would occur in 2017, the sensitivity analysis assumes that only 1 MW of this replacement load would occur and not until 2018. In this case the negative NPV of Coleman, Wilson and the combined cycle alternative all increase respectively to [BEGIN CONFIDENTIAL] [redacted] for Wilson [END CONFIDENTIAL].[27] As demonstrated the member benefits are highly dependent on the level and timing of replacement load.

Q. Does the Member Benefit Analysis for Rate Treatment of Coleman and Wilson Costs in Exhibit Holloway-3 imply that Coleman and Wilson have no value?

A. No. First, this analysis is from the perspective of the members' Native Load Rural and Industrial customers, who do not need any of the generating capacity from Wilson and Coleman now or in the future. In fact, even though Wilson and Coleman are not needed or necessary for the members' Native Load Rural and Industrial customers, these customers would still receive an overall benefit if the amount of costs included in their rates were greatly reduced from the actual costs incurred. As shown on Exhibit Holloway-3 Attachment B, if the nominal annual costs were added to the calculated annual adjustment for 2014 for Wilson and Coleman, for example, these retail customers could still pay a small portion of costs and eventually recover those costs from future benefits.[28] Specifically, for 2014 the nominal annual costs for [BEGIN CONFIDENTIAL] [redacted]

[27] Ibid.

[28] Assuming, of course, that Big Rivers' forecast of replacement load, market costs, etc., all come to fruition.

[redacted] [END CONFIDENTIAL].[29]

Second, if Coleman and Wilson have some value for the members' Native Load Rural and Industrial customers, who do not need the generation capacity, these units would obviously have a much greater value for customers who need the generation capacity.

TRANSMISSION REVENUE

Q. Has Big Rivers included any adjustments in its revenue requirements for MISO transmission revenues it will receive after the smelters depart?

A. No, Big Rivers failed to include any adjustments for MISO transmission revenues. Big Rivers justifies this omission by stating that:

> "... At this time, the contracts among Big Rivers, Kenergy, and Century have been filed with the Commission, but they have not been approved or executed. Until the contracts are approved and executed, it would be speculative and inappropriate to include revenues that could arise under the contracts in the forecast."[30]

Q. Have the contracts among Big Rivers, Kenergy, and Century been approved?

A. Yes. On August 14, 2013, in Case Number 2013-00221, the Commission approved the contracts.[31]

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[29] See Exhibit Holloway-3 Attachment B.

[30] See p. 17, l.4-7 of the Direct Testimony of Robert W. Berry filed June 28, 2013 in this proceeding.

[31] Referred to here as the "Century Hawesville Agreements."

Q. Has Big Rivers filed an application for a similar agreement to serve the Century Sebree smelter?

A. Not yet. However, it is my understanding that the Century Sebree smelter has lower operating costs per unit of production and is more efficient than the Century Hawesville smelter. Given that Century now owns both smelters, it would appear very likely that such an application will be filed before the Commission issues an order in this case. Assuming this will be a similar agreement to that approved in Case Number 2013-00221, the Commission should recognize that approving a similar contract for Century Sebree likely implies the Commission should also approve an adjustment to the transmission revenues Big Rivers will receive. In any case, the Commission will know before it issues an order in this proceeding whether or not these assumptions are valid.

Q. Does Big Rivers currently receive any MISO transmission revenue for Century Hawesville operation?

A. No. Under the Century Hawesville Agreements transmission revenue received by Big Rivers from MISO for the Century Hawesville load is used to off-set the Coleman operating costs under the System Support Resource (SSR) agreement. However, Century Hawesville is currently in the process of installing capacitors and protective relays to allow the smelter to withstand some level of power interruption. Century Hawesville has only agreed to pay the SSR costs through May 30, 2014. After May 30, 2014, it would be expected that Big Rivers would receive the MISO transmission revenue related to Century Hawesville without returning this revenue to Century Hawesville.[32]

Q. Has MISO determined the level of base load that the Century Hawesville smelter can operate at with Coleman idled?

A. Yes. In response to this question by Staff, Big Rivers has indicated that "MISO has established a Base Load of 338 MW providing Century installs the adequate capacitor additions. Century may be allowed to operate above the Base Load if it agrees to curtail load during transmission constraints/contingencies."[33] Additionally, when Big Rivers was asked by the OAG to provide the forecasted Century Hawesville payments for transmission service through 2016,[34] Big Rivers referred to its response to a similar question asked by the Sierra Club:

> "... Utilizing rates published by MISO effective July 1, 2013 for Schedule 9 of $15,586.7989/MW-yr and Century monthly peak loads of 482 MW, Big Rivers would expect to receive about $7,512,837/yr in transmission revenues. ... Utilizing the same rates and Century monthly peak loads equal to the base load level determined by MISO of 338 MW, Big Rivers would expect to receive about $5,268,338/yr in transmission revenues."[35]

On page 10 of its August 14, 2013 Order in Case Number 2013-00221 when evaluating the Century Hawesville smelter load the Commission observed that "Due to the nature of Century Kentucky's smelting operations, it is essential to its economic viability to operate at a firm load of 482 MW."

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[32] See page 9 through page 11 of the Commission's August 14, 2013 Order in Case Number 2013-00221.
[33] See response to PSC 2-17.
[34] See AG 1-149.
[35] See SC 1-12.

In conclusion, it is reasonable to expect Big Rivers to receive the $7,512,837/yr in transmission revenues from Century Hawesville associated with the firm load of 482 MW.

Q. Assuming Big Rivers reaches a similar agreement with Century Sebree in the near future, how much transmission revenue would Big Rivers receive from Century Sebree?

A. In a response to that question Big Rivers agreed that the annual transmission revenue from Century Sebree would be $5,735,942/yr.[36] In summary, Big Rivers would expect the following amount of transmission revenue from the smelters on an annual basis starting at the end of May 30, 2014:[37]

Table 2 - Adjustment for Smelter Transmission Revenue

	Annual Transmission Revenue
Century Hawesville	$7,512,837
Century Sebree	$5,735,942
Total Adjustment	$13,248,779

Q. Do you have any other observations regarding adjustment of Big Rivers' revenue requirements to recognize this transmission revenue?

A. Yes. First, the Commission stated that approving the crediting of transmission revenues for SSR costs did not create any incremental costs to retail customers when it approved the Century Hawesville Agreements.[38] While this assumption was likely based on the rates under consideration in Case Number 2012-00535, under the circumstances of this

[36] See AG 2-80.
[37] Ibid.
[38] See p.11 of the Commission's August 14, 2013 Order in Case Number 2013-00221.

case, ratemaking principles dictate that this adjustment should be made. To do otherwise would result in rates that are not fair just and reasonable and would create incremental costs for retail customers.

Second, there is a large discrepancy between the amount of revenues Big Rivers receives for use of its transmission system from MISO and the amount of revenue that Big Rivers allocates to its members for the same transmission service. For example Big Rivers has determined that transmission costs to be allocated to its members' Rural and Industrial customers equal $32,762,202 in the forecasted test period. This information and the associated demand allocators are shown in the following table:[39]

Table 3 - Big Rivers' Allocation of Transmission Costs to Its Members

	Source	Rurals	Industrials	Total
Transmission Revenue Requirement	PSC 2-33	$25,946,205	$6,815,997	$32,762,202
Transmission Revenue Demand Allocators (12CP) in kW-mo	Wolfram-4 page 13 of 14	5,128,900	1,347,348	6,476,248

While this does not account, as it should, for the $13,248,779 in transmission revenue from the smelters, shown in Table 2 above, even if adjusted to account for the smelter transmission revenue, the amount identified above would be inadequate to account for a fair and equitable sharing of transmission costs among all Big Rivers' transmission users. The table below illustrates how Big Rivers' transmission costs should be recovered, if all transmission users paid the same amount for the service:

[39] Information in Table 3 and Table 4 was verified in Big Rivers' response to AG 2-81.

Table 4 - Allocation of Transmission Costs Equally Among all Big Rivers' Transmission Users						
	Source	Century Hawesville	Century Sebree	Rurals	Industrials	Total
Transmission Revenue Requirement	PSC 2-33	$11,363,262	$8,675,686	$10,076,251	$2,647,004	$32,762,202
Transmission Revenue Demand Allocators (12CP) in kW-mo	Wolfram-4 page 13 of 14, 2012-00535 AG 1-234, and SC 1-12	5,784,000	4,416,000	5,128,900	1,347,348	16,676,248

As shown above, if the smelters were allocated transmission costs similar to Big Rivers' members, they would pay a much larger share of these costs. In fact, the difference between the same allocation of transmission costs and the amount paid under the MISO tariffs is summarized below:

Table 5 - Revenue Shortfall from Smelters for Transmission Service			
	Annual Transmission Revenue from MISO	Allocation of Big Rivers' Transmission Revenue Requirements for the Forecasted Test Period	Revenue Shortfall
Century Hawesville	$7,512,837	$11,363,262	($3,850,425)
Century Sebree	$5,735,942	$8,675,686	($2,939,744)
Total Adjustment	$13,248,779	$20,038,948	($6,790,169)

Q. **Are you proposing that the smelter transmission revenue adjustment should be $20,038,948 instead of $13,248,779?**

A. No. The amount of $13,248,779 represents the amount of revenue that Big Rivers will receive from MISO for the smelters use of the system. However, this leads to a couple of interesting observations.

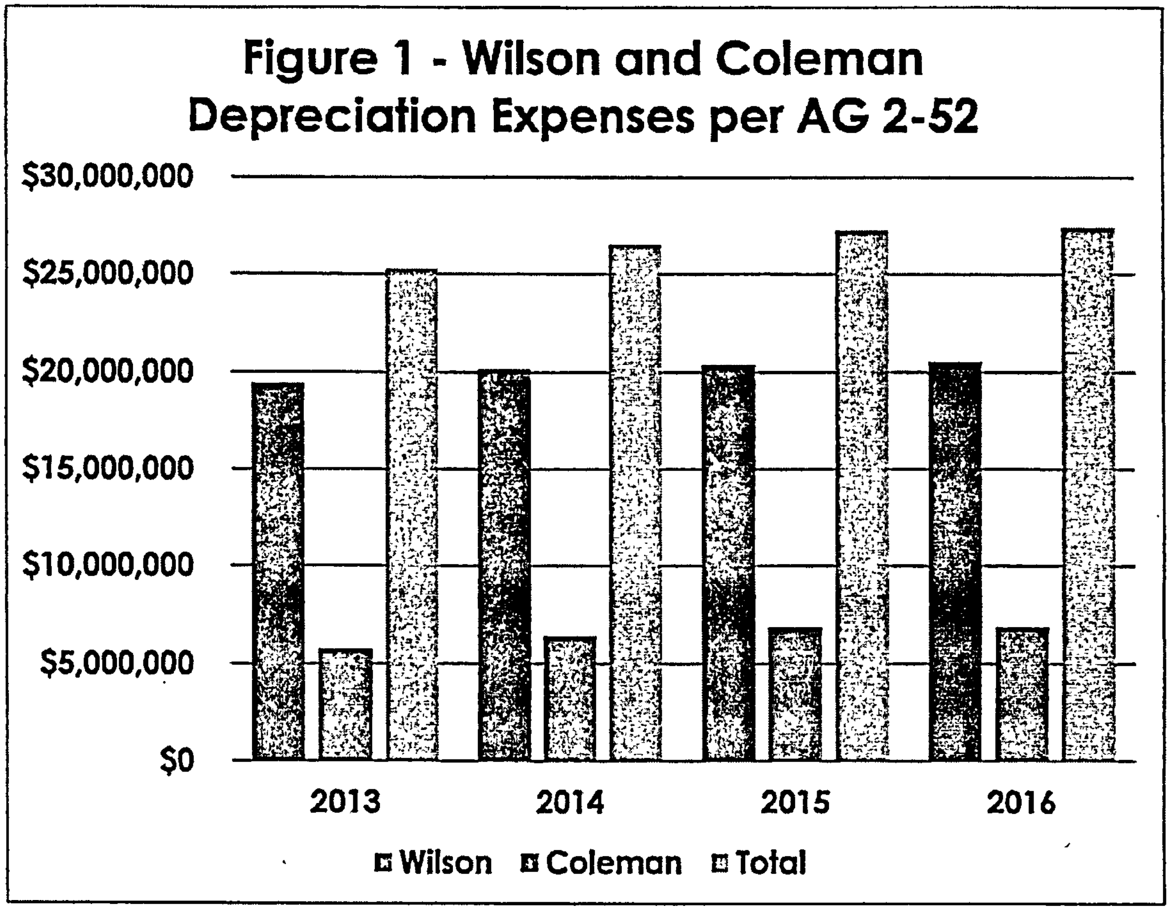
First, while Big Rivers is exploring sale of some of its generating facilities, members might also benefit from a sale of its transmission system. If the transmission system was independently operated the costs would be allocated equitably among all users, and the members' Rural and Industrial customers would not be asked to shoulder an inappropriate portion of that burden.

Second, and perhaps more important given any potential restructuring discussion in Kentucky, the revenue shortfall in Table 5 can be seen as a proxy for the types of stranded costs that can occur when existing load and customers leave the traditional regulatory framework for electric service. In this case the remaining customers are being asked to pick up an additional $6,790,169 of costs annually as a direct result of the smelters move to market energy and away from direct service from Big Rivers.

DEPRECIATION

Q. Does Big Rivers include depreciation costs for idled units in its revenue requirements?

A. Yes. In addition to including the costs to layup and maintain Coleman and Wilson while these units are idled, Big Rivers has included depreciation expenses for each unit. In fact, depreciation costs for Wilson and Coleman continue to increase annually even though the plants are to be idled:



As shown above, Big Rivers' members native load customers are being asked to pay almost $27 million a year for depreciation costs associated with units that are not needed or necessary to provide their electric service and will, in fact, be idled and unavailable. Furthermore, while these units are in lay-up or in mothballed status, however one chooses to describe it, there is little reason to believe that they will experience normal wear and tear associated with operation. Given the circumstances it would not be unreasonable for the Commission to remove depreciation costs from Big Rivers' revenue requirements while the units are in lay-up.

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, INC.) Case No. 2013-00199
FOR AN ADJUSTMENT OF RATES)

AFFIDAVIT OF LARRY HOLLOWAY

)
State of Kansas)
)

Larry Holloway, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Larry Holloway

SUBSCRIBED AND SWORN to before me this 2nd day of October, 2013.

NOTARY PUBLIC

My Commission Expires: LINDA L. MEYER Notary Public - State of Kansas My Appt. Expires 9-29-15

TAB 1

EXHIBIT HOLLOWAY-1

CASE NO. 2013-00199

Qualifications of Larry W. Holloway, P.E.

General

Electric industry professional with broad experience in public utility regulation, power plant operations, maintenance and performance testing, transmission service, resource planning, procurement and scheduling, utility load forecasting and planning, project management, and electric utility ratemaking.

Work History and Recent Relevant Experience

Kansas Power Pool (KPP) March 2009 - Present
Operations Manager

Preparation of annual budget, including load forecasts, purchase power and fuel costs, generation capacity costs, and pool wide rate design for a wholesale not for profit municipal energy agency that provides 34 municipal utilities with generation supplies and transmission service.

Responsible for securing generation resources and transmission service for KPP members. Oversight of administration of service contracts for transmission scheduling, Information technology, and metering services. Coordinating of regulatory services and responsible for expert testimony on transmission policy and services.

Kansas Corporation Commission (KCC) July 1993 to March 2009
Chief of Energy Operations

Provided electric utility industry expert testimony before the KCC as member of KCC Staff.in over 40 dockets, including dockets involving generating costs and performance,

Acted as Commission liaison before many groups including legislative committees, industrial groups, NARUC, environmental groups, civic organizations, utility groups, federal agencies, regional reliability councils, transmission organizations and state social agencies.

Provided presentations, courses and speeches on a variety of KCC and industry issues to many groups including legislative committees, regional transmission organizations, industry conferences and international regulatory bodies.

Wolf Creek Nuclear Plant -WCNOC — June 1989 to July 1993
BOP System Engineering Supervisor

Browns Ferry Nuclear Plant- TVA — August 1987 to June 1989
Senior System Engineer

Trojan Nuclear Plant - Portland General Electric — October 1984 to August 1987
System Engineer III

Wolf Creek Nuclear Plant - Matsco — April 1983 to October 1984
Contract Startup Engineer

Burns & Roe - WNP 2 — September 1982 to April 1983
Nuclear Design Engineer

Ebasco Inc - Waterford Nuclear Plant — June 1981 to September 1982
Construction Engineer

FMC Inc - Inorganic Chemical Plant — June 1979 to June 1981
Project Engineer

Kansas Power & Light - Natural Gas Division — June 1978 to June 1979
Field Engineer

Education

Univerity of Kansas, Kansas
Bachelor of Science Civil Engineering, December 1977
Bachelor of Science Mechanical Engineering, May 1978
Master of Science Mechanical Engineering, May 1997

Washington State University, Washington
Master of Engineering Management, May 1988

Professional Registration

Registered Professional Mechanical and Civil Engineer, State of Oregon, PE license No. 12989

Expert Witness Testimony

FERC Provided analysis and affidavit in FERC Docket ER01-1305 for the KCC, which led to a negotiated settlement in an affiliate purchase power agreement between Westar Energy and Westar Generating Inc., and affiliate.

KCC KCC Staff testimony in Docket Nos. 95-EPDE-043-COM, 96-KG&E-100-RTS, 96-WSRE-101-DRS, 96-SEPE-680-CON, 97-WSRE-676-MER, 98-KGSG-822-TAR, 99-WSRE-381-EGF, 99-WSRE-034-COM, 99-WPEE-818-RTS, 00-WCNE-154-GIE, 00-UCUE-677-MER, 01-WSRE-436-RTS, 01-WPEE-473-RTS, 01-KEPE-1106-RTS, 02-SEPE-247-RTS, 02-EPDE-488-RTS, 02-MDWG-922-RTS, 03-MDWE-001-RTS, 03-WCNE-178-GIE, 03-MDWE-421-ACQ, 03-KGSG-602-RTS, 04-AQLE-1065-RTS, 04-KCPE-1025-GIE, 05-EPDE-980-RTS, 05-WSEE-981-RTS, 06-WCNE-204-GIE, 06-SPPE-202-COC, 06-WSEE-203-GIE, 06-KCPE-828-RTS, 06-KGSG-1209-RTS, 06-MKEE-524-ACQ, 07-WSEE-616-PRE, 07-KCPE-905-RTS, 08-WSEE-309-PRE, 08-KMOE-028-COC, 08-WSEE-609-MIS, 08-MDWE-594-RTS, 08-WSEE-1041-RTS, 08-ITCE-936-COC, 09-KCPE-246-RTS, and 08-PWTE-1022-COC.

Testimony on behalf of KPP in Docket Nos. 09-MKEE-969-RTS, 11-GIME-497-GIE, and 12-KPPE-630-MIS.

KYPSC Testimony on behalf of the Kentucky Office of Attorney General in Case Number 2012-00535 before the Kentucky Public Service Commission.

TAB 2

EXHIBIT HOLLOWAY-2

CASE NO. 2013-00199

Load and Generation Analysis

No New Load Scenario w/o Coleman & Wilson

Year	BREC Generation Capacity (kW)[1]	BREC CP Load Forecast (kW)[2]	Reserve Margin
2014	959,000	[redacted]	
2015	954,000		
2016	949,000		
2017	949,000		
2018	949,000		
2019	949,000		
2020	949,000		
2021	949,000		
2022	949,000		
2023	949,000		
2024	949,000		
2025	949,000		
2026	949,000		
2027	949,000		

1 Generation Capacity w/o Coleman & Wilson per Berry Direct, p. 4 and p. 5

2 AG 1-139 Model Tables Response CP Native System

Load and Generation Analysis

Big Rivers' New Load Scenario w/ Coleman and Wilson

Year	Generation Capacity (kW)[1]	CP Load Forecast (kW)[2]	New Load Demand (kW)[3]	Total Load Demand (kW)	Reserve Margin
2014	[redacted]				
2015					
2016					
2017					
2018					
2019					
2020					
2021					
2022					
2023					
2024					
2025					
2026					
2027					

1 Generation Capacity w/o Coleman & Wilson per Berry Direct, p. 4 and p. 5, Wilson restored in 2018, Coleman restored in 2019 per response to PSC 2-14

2 AG 1-139 Model Tables Response Native System Coincident Peak

3 AG 1-139 Model Tables Response New Load Non-Coincident Peak

Load and Generation Analysis

Big Rivers' New Load Scenario w/ Coleman and Wilson

Year	New Load Demand (kW)[1]	New Load Energy (MWH)[2]	New Load Energy From Wilson & Coleman (MWh)[3]
2014	[redacted]		
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			

1 AG 1-139 Model Tables Response New Load Non-Coincident Peak
2 AG 1-139 Model Tables Response New Load Energy
3 Assume that 2017 amount is amount supplied w/o Coleman and Wilson

Load and Generation Analysis

Big Rivers' New Load Scenario w/ Coleman and Wilson - Sensitivity Analysis
New Load is 50% of Assumptions and Occurs 1 Year Later

Year	New Load Demand (kW)[1]	New Load Energy (MWH)[2]	New Load Energy From Wilson & Coleman (MWh)[3]
2014	[redacted]		
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			

1 AG 1-139 Model Tables Response New Load Non-Coincident Peak adusted to lag 1 year and 50% of assumed amount

2 Energy Sales associated with new load demand consistent with AG 1-139 Model Tables Response New Load Energy

3 Assume that 200,000 kW and associated energy is supplied w/o Coleman and Wilson

Load and Generation Analysis

Big Rivers' New Load Scenario w/ Coleman and Wilson - Sensitivity Analysis New Load is 50% of Assumptions and Occurs 1 Year Later

Year	Generation Capacity (kW)[1]	CP Load Forecast (kW)[2]	New Load (kW)[3]	Total Load (kW)	Reserve Margin
2014	[redacted]				
2015					
2016					
2017					
2018					
2019					
2020					
2021					
2022					
2023					
2024					
2025					
2026					
2027					

1 Generation Capacity w/o Coleman & Wilson per Berry Direct, p. 4 and p. 5, Wilson restored in 2018, Coleman restored in 2019 per response to PSC 2-14

2 AG 1-139 Model Tables Response Native System Coincident Peak

3 AG 1-139 Model Tables Response New Load Non-Coincident Peak (1/2 forecast and 1 year later)

TAB 3

EXHIBIT HOLLOWAY-3

CASE NO. 2013-00199

Member Benefit Analysis for Rate Treatment of Coleman and Wilson Costs

Exhibit Holloway-3

Case Number 2013-00199

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Calculations and References

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Attachment D

Appendix

Redacted

Executive Summary

Due to the loss of the load of both smelters, Big Rivers does not need Wilson or Coleman generating facilities to serve its existing load. While Big Rivers has plans to attempt to replace the departed smelter load by sale or lease of the facilities, sale of power into the market, or various other ideas regarding how to utilize these facilities, no analysis has been provided to determine what value, if any, these facilities have for the remaining member load.[1]

Analysis using Big Rivers' own projections shows that continued ownership of these facilities costs Big Rivers' members far more than any future benefits. In fact, the only way to assure that the members are not harmed would be to implement the following adjustment to Big Rivers' annual revenue requirements:[2]

Annual Revenue Requirement Adjustment Needed for the Net Present Value of Costs to Equal Benefits (2014 - 2027)	
Annual Wilson Adjustment	[redacted]
Annual Coleman Adjustment	

In response to discovery[3], Big Rivers has provided its analysis of the sales price it expects to recover if it was to eventually sell Wilson and Coleman. However, my analysis reveals that even if Big Rivers' members had to accept a lower sale price sooner in time as opposed to receiving a higher price later in time, the members would likely achieve greater savings. That way, the members could avoid paying for the additional costs of maintaining, operating and ongoing financing of these units. In fact, from the members' perspective, rather than pay the ongoing costs of owning these units for an indeterminate amount of time, immediate sale of these units for the following amounts, or more, would provide the members with immediate benefits:[4]

[1] See AG 2-35 and AG 2-36 responses.
[2] See Attachment B.
[3] See PSC 2-15, AG 2-32, SC 2-29 and SC 2-30 responses.
[4] Derived by dividing the 2014 interest costs by the interest rate.

Minimum Wilson and Coleman Sales Price Today to Avoid 2014 Cost Recovery in Rates

	2014 Interest Costs	Interest	Related Long-Term Debt (Today's Members' Sale Price)
Wilson	[redacted]	4.96%	[redacted]
Coleman	[redacted]	4.96%	[redacted]

Finally, continued member payment of all costs associated with Wilson and Coleman, given that these plants are not needed or necessary, essentially puts Big Rivers' members in the position of owning merchant generating facilities. If this is the case, the Commission should consider how Wilson and Coleman ownership compare to one of the most likely future merchant generating market entrants, a new Combined Cycle unit installed to begin operation in [redacted], the year Wilson is forecast to return to service. The results are as follows:[5]

	Size (MW)	Total NPV	NPV/MW
Wilson	417	[redacted]	
Coleman	443		
New Combined Cycle	620		

Purpose of Member Benefit Analysis

The purpose of this analysis is to estimate the net benefit that the Wilson and Coleman generating facilities provide for Big Rivers' Rural and Industrial members, as asserted by Big Rivers under its proposed Mitigation Plan. This analysis is conducted using Big Rivers' own cost and revenue projections, over the time period considered in its Financial Forecast—through 2027.

When Big Rivers notified the Commission and the public that the Century Hawesville and Century Sebree smelter loads would no longer be part of Big Rivers' generation obligation, it became clear (and has Big Rivers has conceded) that the Coleman and Wilson units are no longer needed or necessary to serve the remaining Big Rivers' Rural and Industrial members. In fact, Big Rivers estimates that after idling Wilson and Coleman generation facilities due to the departure of the smelter loads, it will still have a reserve margin of roughly [redacted]%.[6] Big Rivers maintains that Coleman and Wilson eventually will be restarted when the gross margins exceed the variable and fixed costs

[5] See Attachment C, pages 5 through 6 for the complete analysis.
[6] See response to AG 1-71 (f).

to operate the units, and at that point, provide "benefit" to its members.[7] This restart is forecast to occur in [redacted] for the Coleman units and in [redacted] for the Wilson unit. Until that time, Big Rivers proposes to defer most construction and outage activities. As a result, environmental upgrades and related MATS equipment has been deferred until approximately 1 year prior to restart of the units, while costs related to restoration from lay-up and deferred outage activities occur immediately prior to restart.

Big Rivers at various places in its testimonies and responses to data requests states that its strategy will ultimately benefit its members and member owners. For example:

1. "As ... mitigation efforts are successful, Big Rivers' members will benefit."[8]
2. "Big Rivers' Mitigation Plan will provide an opportunity to benefit its members ...."[9]
3. "As Big Rivers is successful in mitigating the adverse impacts of the Smelter contract terminations, Big Rivers' members will benefit..."[10]
4. "It just does not make sense for Big Rivers to retire these plants and deprive Members of the future benefits these plants will provide."[11]
5. "It just does not make sense for Big Rivers to prematurely retire these plants without taking the time for the assets to make additional contributions for the Members' benefit."[12]

The clear implication of these statements is that BREC's executive management believes that ultimately, BREC's ratepayers will benefit financially from BREC's mitigation plan.

This analysis, therefore, attempts to determine the estimated net benefits that Big Rivers' members would receive from the lay-up / mothballing of Wilson and Coleman, under Big Rivers' proposed Mitigation Plan using Big Rivers' own cost and revenue projections.[13] Typically, costs included to determine regulated electric members rates are those that are needed or necessary to provide electric service. Should the Commission consider including costs for Wilson and Coleman as requested by Big Rivers, even though these units are no longer needed or necessary, it should weigh whether Big Rivers' claimed "benefit" to its members from its proposed Mitigation Plan is reasonable and supported in Big Rivers' own projections.

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[7] See response to KUIC 2-14.
[8] Bailey Direct Testimony, at page 8, line 3.
[9] Berry Direct Testimony, at page 12, line 18.
[10] *Id.*, at page 18, line 16.
[11] Big Rivers' Response to KIUC 1-51.
[12] Big Rivers' Response to SC 1-16.
[13] See Big Rivers' Response to PSC 2-14 for long term forecasts, as well as AG 2-9, KIUC 2-17 and KIUC 2-15, as well as Attachments A, B and C to this Exhibit.

Data and Analysis

To perform this analysis, revenues from Big Rivers' Financial Forecast provided in response to PSC 2-14 were used, in conjunction with cost information for Wilson and Coleman provided in response to various information requests.[14] Three analyses were conducted in order to determine:

1. the amount of expense and interest costs related to Wilson and Coleman that Big Rivers' members could pay and not be harmed by bearing the remaining annual fixed costs, assuming Big Rivers' replacement load revenue projection to be accurate;
2. the amount that Big Rivers could sell Wilson and Coleman for now, from the perspective of their ratepayers, to essentially remove all costs of these units from the regulated cost of service; and
3. the current value of Wilson and Coleman as compared to an alternative type of newer generating facility. This analysis was used solely to determine how investment in these plants compares to alternatives during the 2014 to 2027 period which Big Rivers studied.

Assumptions

Fixed Operating and Maintenance (O&M) costs

Big Rivers has provided information regarding the expected annual fixed O&M costs for Wilson and Coleman in response to KIUC 2-15 and KIUC 2-17. These amounts were used in the analysis.

Capital expenditures

Capital expenditures were estimated from Big Rivers' responses to KIUC 2-17 to replicate Wilson and Coleman Capital amounts used in Big Rivers' financial forecast model related to layup, restoration, deferred maintenance and operations. Additionally, capital expenditures related to MATS environmental upgrades were provided in response to AG 2-9.

Depreciation

[14] Big Rivers' Response to AG 2-9; AG 2-52; AG 1-195; AG 1-196; AG 1-198; AG 1-201; KIUC 2-15; KIUC 1-52; KIUC 1-67; KIUC 1-21; KIUC 1-22.

Depreciation expenses provided in response to KIUC 2-15 were used for the Financial Forecast period through 2027. I assumed additional capital expenditures made incurred additional depreciation costs at associated depreciation rates. Capital expenditures are forecasted to be made to restart Coleman and Wilson. For these capital expenditure, a depreciation rate of 2.02% was used, based on the depreciation rates filed for Account 312, Boiler Plant, by Big Rivers as illustrated in Table IV-1 of ES IV-2 in the Testimony provided by Kelly in the Application in Docket 2012-00535. However, this did not include the MATS capital expenditures. In the case of MATS capital expenditures, a depreciation rate of 2.43% was used to reflect the Big Rivers'-proposed depreciation rates for account 312 A-K environmental compliance illustrated in the same reference.

Interest Expenses

Allocated interest expenses provided in response to KIUC 2-15 were used throughout the long-term Financial Forecast period. This analysis is conservative, in that it assigns no additional interest costs to either Wilson or Coleman during the time period despite additional capital expenditures.

Time Value of Money

A time value of money factor of 5% was used in this analysis for fixed costs and adjustments. This factor is based upon Big Rivers' most recent IRP filing in Docket 2010-00443 to evaluate carrying cost factors as illustrated in Table 8.7 of the November 15, 2010 filing. Additionally it should be noted that this corresponds to the overall estimated annualized cost rate of Big Rivers' outstanding long-term debt of 4.96%, as provided in response to PSC 1-25.

A time value of money factor of 10% was used to determine benefits derived from forecasted replacement load and market sales. The uncertainty of the forecasted fuel costs, market prices and level of replacement load requires this value to be higher to reflect the associated risk, as discussed in the Direct Testimony of Mr. Brevitz.

Replacement Load

Replacement load values from Big Rivers' financial forecast through 2027 were used.[15] Values before Wilson and Coleman are returned to service are assumed to be met by Big Rivers' other units, because the replacement load values begin in the year [redacted]. Sales

[15] See PSC 2-14 response spreadsheet "Financial Forecast (2014) 5-16-2013" Stmts RUS tab and load forecasts provided in response to AG 1-139 "Model Tables."

occurring in [redacted] and later are then adjusted to remove the amounts sold without the need for Wilson and Coleman. The result of these assumptions is shown below:[16]

Big Rivers' New Load Scenario w/ Coleman and Wilson

Year	New Load Demand (kW)[1]	New Load Energy (MWH)[2]	New Load Energy From Wilson & Coleman (MWh)[3]
2014	[redacted]		
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			

1 AG 1-139 Model Tables Response New Load Non-Coincident Peak
2 AG 1-139 Model Tables Response New Load Energy
3 Assume that 2017 amount is amount supplied w/o Coleman and Wilson

Results

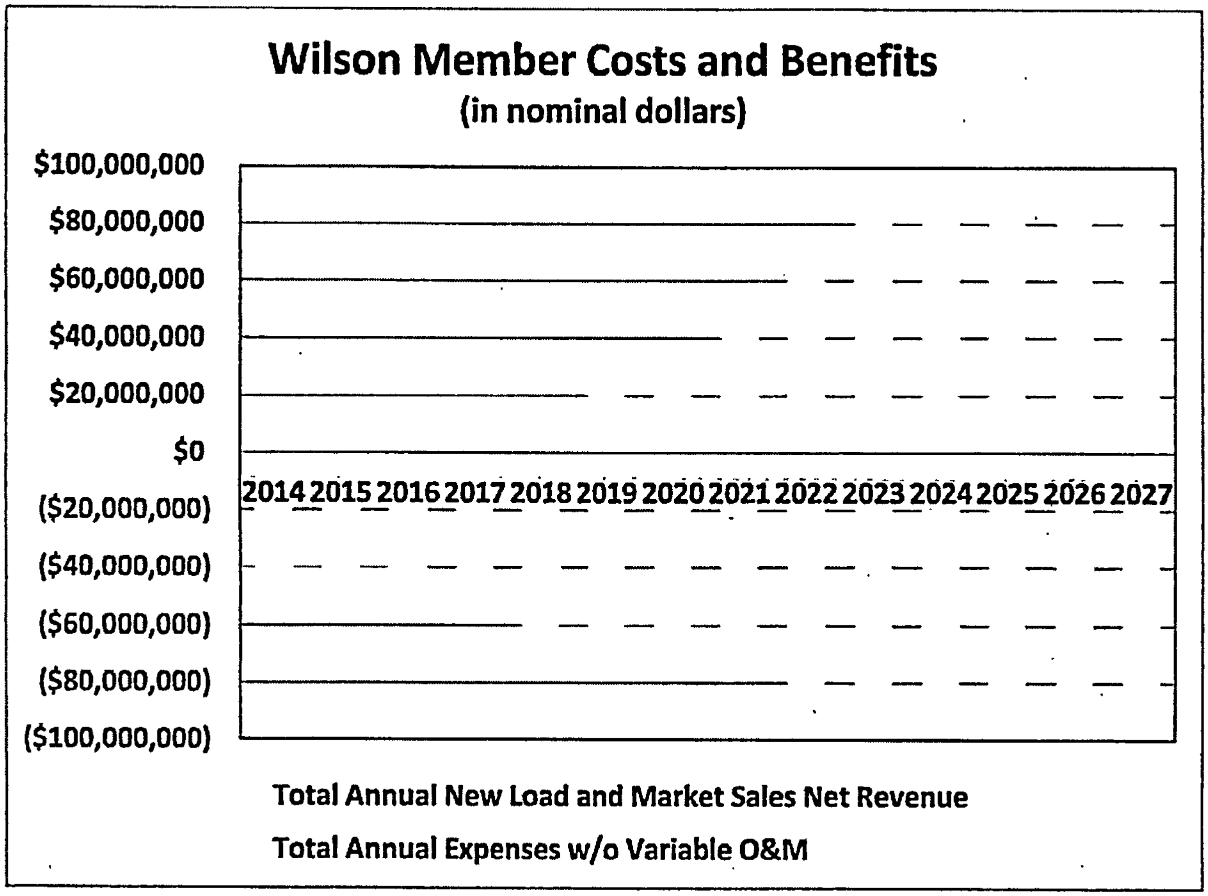
The Net Benefit of Wilson and Coleman to Members

Annual Costs

The annual costs related to Wilson and Coleman depreciation, labor, property tax, insurance, interest costs and related TIER that would be incorporated into member rates during the time period were compared to the benefits these same members are projected

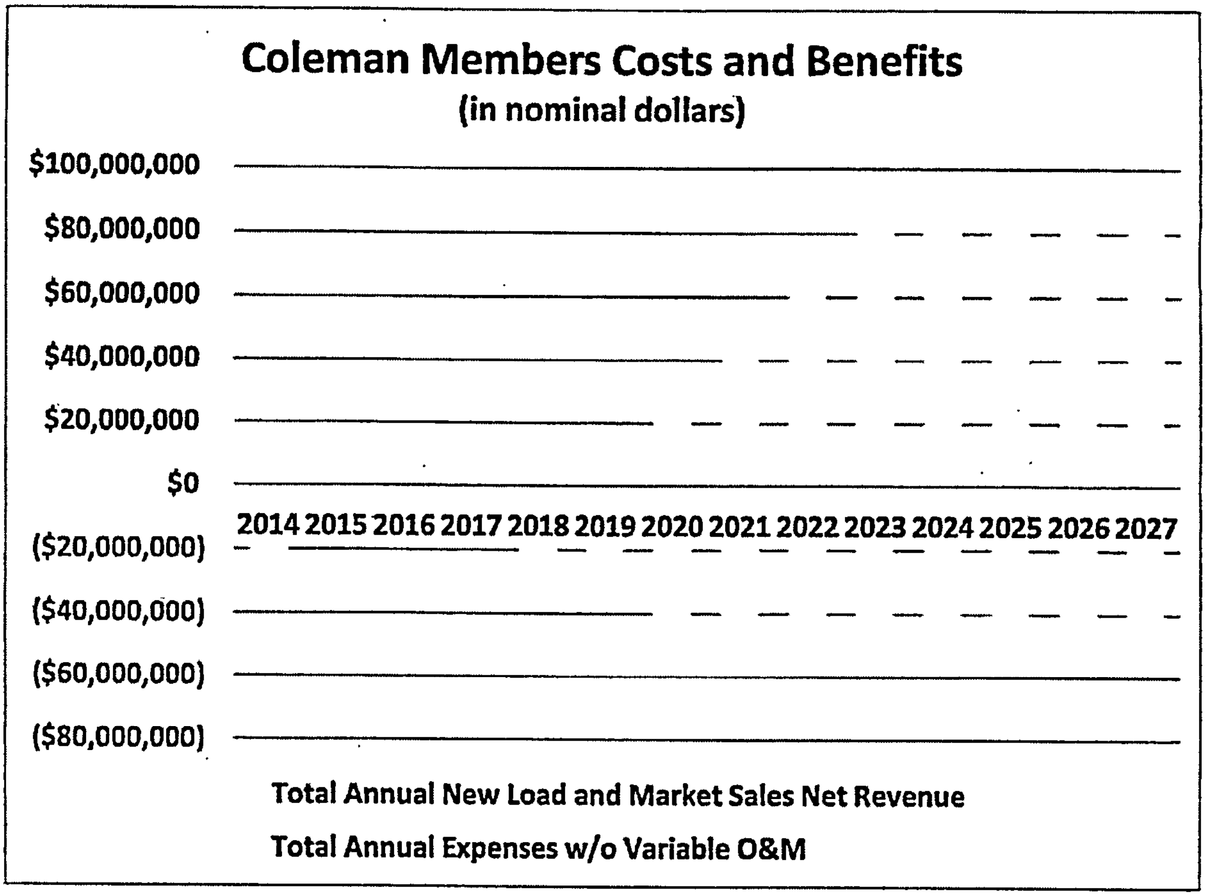
[16] See Exhibit Holloway-2, page 3 of 5.

to receive from revenues based on projected replacement load and off system sales. The results for each unit are shown below:[17]



[17] See Attachment A for the complete analysis.

Redacted



Net Benefits

When the nominal costs and benefits are brought back to the year 2014 using the time value of money, one can determine whether or not Big Rivers' members are expected to benefit from the costs these members have incurred to continue supporting the costs of Wilson and Coleman throughout the forecast period. A positive value indicates that members will receive a net benefit over the time period evaluated. A negative value indicates that members will see a net loss over the time period evaluated. The following is the 2014 Net Present Value (NPV) of these costs and benefits:[18]

	Total 2014 NPV
Wilson	[redacted]
Coleman	[redacted]

[18] See Attachment A, page 7 and 8 for the detailed analysis from the projected costs and benefits.

Revenue Adjustment to Achieve Equalization of Costs and Benefits

Expanding on the evaluation above, an analysis was performed to determine the amount of annual revenue adjustment that would be necessary to make Big Rivers' members whole for their support of Wilson and Coleman. In other words, what type of annual revenue adjustment is needed for Big Rivers' members to receive benefits equal to the costs of Wilson and Coleman ownership? Based on the same analysis to achieve an NPV approximating zero, as shown in the attached Attachment B, the following annual revenue adjustments would be needed throughout the analysis period:[19]

Annual Revenue Requirement Adjustment Needed for the Net Present Value of Costs to Equal Benefits (2014 - 2027)	
Annual Wilson Adjustment	[redacted]
Annual Coleman Adjustment	

In summary, Big Rivers' revenue requirements would need to be reduced by these amounts annually from 2014 – 2027 to assure that the NPV of the costs paid by members did not exceed the NPV of Big Rivers' projected benefits (replacement load and off-system sale revenues) that members receive.

Sale Price of Wilson and Coleman Today to Remove from Regulated Cost of Service

Big Rivers has determined the value of Wilson and Coleman, but it is important to remember that this value is derived from the fundamental assumption that members will bear all of the costs associated with owning and maintaining these units until such time as they are sold. However, it is important to understand the perspective of those who must bear the costs to own and maintain these units each year, the members' retail customers. Because Wilson and Coleman are not needed or necessary to provide the members with generation service, costs to own and maintain the units provide no benefits to these customers. Therefore the sooner these units are sold, the sooner these additional costs will be avoided.

For example, if the units were sold today the members would incur no additional costs for depreciation, labor, insurance, earnings and property tax. Furthermore, if Coleman and Wilson were sold today, the revenue could either be used to directly pay down debt

[19] See Attachment B for the detailed analysis.

Redacted

or used to pay the interest costs associated with these units. The annual costs associated with Wilson and Coleman ownership in 2014 are as follows:

Summary of Wilson and Coleman Costs and Benefits in 2014[1]

	Wilson	Coleman
Depreciation	[redacted]	
Labor Expenses		
Property Tax		
Insurance		
Interest		
Earnings		
Total Costs		
Off System Sales Benefits		

1 for 2014 detailed costs and benefits see Attachment A page 1 and page 4

Obviously if the units were sold, the members would no longer need to bear the costs [redacted] received was adequate to retire Big Rivers' debt related to the interest, then none of these costs, including the earnings related to TIER, would remain in the Cost of Service.

Big Rivers' current overall estimated annualized cost rate of outstanding long-term debt is 4.96%.[20] While Big Rivers has reached a determination of the market value of these units, it is important to recognize that from the members' perspective, selling the units immediately and retiring the associated debt would save the annual costs discussed above of approximately [redacted] million. From a debt retirement perspective, Big Rivers' members would avoid all costs associated with these units immediately if the units could be sold for the following amounts before any rate increase was implemented in 2014:[21]

Minimum Wilson and Coleman Sales Price Today to Avoid 2014 Cost Recovery in Rates

	2014 Interest Costs	Interest	Related Long-Term Debt (Today's Members' Sale Price)
Wilson	[redacted]	4.96%	[redacted]
Coleman		4.96%	

Alternative Generation Sources for Big Rivers' Members

[20] See response to PSC 1-25.

[21] Derived by dividing the 2014 interest costs by the interest rate.

As discussed, Coleman and Wilson are neither needed nor necessary to serve their members' load. From the members' perspective, continued ownership of these units to gain future uncertain (and as shown, inadequate) replacement load and off-system sales margins is no different than ownership of any other type of merchant generating facility. Of course, this is not to suggest that the Commission should support inclusion of merchant generating facilities in Big Rivers' members regulated Cost of Service. However, Big Rivers' proposal and forecasts assume that Big Rivers' members could eventually become owners of merchant generating facilities, Wilson and Coleman. Therefore, it may be instructive to compare the continued member responsibility for paying for these plants as merchant facilities as compared to ownership of a new generating plant.

Throughout the MISO region and in the State of Kentucky, many utilities are considering installing natural gas combined cycle units. While there are numerous reasons for this, one of the most understandable is the uncertain regulatory environment faced by coal generating facilities. In the past, uncertainties related to future natural gas supplies and costs often outweighed the unknown effects of future coal environmental requirements. However as natural gas reserves have dramatically increased in North America over the last 5 years, and prices (at least for now) appear to have somewhat stabilized, the lower installed costs of combined cycle gas units appear to favor these generation resources by many utilities. This in turn limits the value of Wilson and Coleman.

Nonetheless it would certainly seem that existing coal units would have a lower cost than building a new combined cycle unit. However, recent announcements seem to indicate that there appears to be an industry preference to building new combined cycle units. Given these facts, the costs of building a new natural gas combined cycle unit to begin operating in the year [redacted] should be analyzed together with the costs and benefits of laying-up / mothballing Wilson, the same year Big Rivers currently forecasts to return Wilson to operation.

Combined Cycle Cost Assumptions

Combined Cycle cost assumptions were taken directly from the Department of Energy's Energy Information Agency's (EIA) 2013 Annual Energy Outlook.[22] Using the methods outlined in the EIA reports, the costs of installing and operating an alternative 620 MW Combined Cycle unit was compared to the costs that Big Rivers' members will incur by maintaining, owning and operating Wilson and Coleman while only receiving benefits

[22] The related EIA reports and tables are attached as an Appendix to this report.

of off system sales margins.[23] The analysis assumed that the natural gas prices would be the same as in the forecasts provided by Big Rivers for Henry Hub prices and that transportation costs would be the same [redacted]/MMBTU assumed in the Big Rivers forecasts.[24]

Finally, it was assumed the Combined Cycle (CC) unit would be purchased with a 20 year loan at 5% interest with equal annual payments. A summary of the assumptions and their sources is provided below:

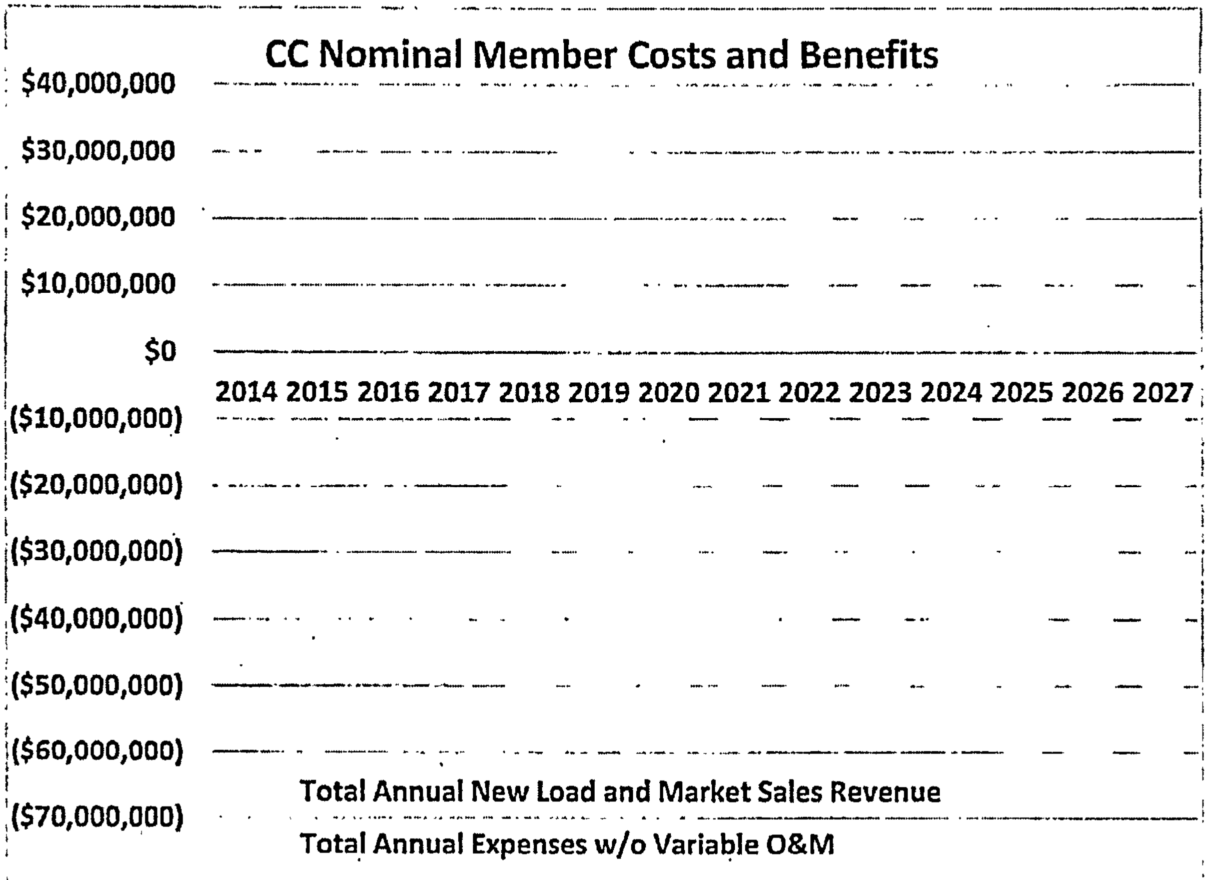
Combined Cycle Plant Costs

Items	Amount	Reference
Combined Cycle Overnight costs	$917/kW (2012 $)	EIA (see Appendix)
Size	620 MW	EIA (see Appendix)
Fixed O&M costs	$13.17/kW-yr (2012 $)	EIA (see Appendix)
Variable O&M	$3.60/MWh (2012 $)	EIA (see Appendix)
Heat Rate	7050 Btu/kWh	EIA (see Appendix)
Regional Cost Adjustment	0.93	SRCE
Capacity Adjustment negligible for Kentucky (-0.90 per table 2-4)		EIA (see Appendix)
GDP Chain-type price index annual growth 2011-2040	1.70%	EIA (see Appendix)
Gas Transportation charges per MMBTU per AG 2-6	[redacted]	
CC Capacity Factor	87%	EIA (see Appendix)
[redacted]		

[23] Any possible future value associated with capacity sales into the MISO market were not considered as these costs were assumed to be the same for any unit in the market.

[24] See response to PSC 2-14.

Applying these assumptions yield the following annual costs and benefits of the CC alternative:[25]



While the revenue from off-system sales for the CC alternative is less than would be expected from Wilson or Coleman, the lower installed costs, plus the fact that no costs are incurred until the unit is installed, affect the overall present value of these costs and benefits to members. Comparing this to Wilson and Coleman yields the following results:[26]

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[25] See Attachment C, page 1 to 4.
[26] See Attachment C for the detailed analysis.

Redacted

	Size (MW)	Total NPV	NPV/MW
Wilson	417	[redacted]	
Coleman	443		
New Combined Cycle	620		

As shown, while Coleman is a less costly alternative than future investment in a combined cycle plant, continued member cost support for Wilson would cost members more than waiting until [redacted] to install a new combined cycle unit.

Sensitivity Analysis

Much of this analysis depends on Big Rivers' forecasts and assumptions regarding replacement load. However there is little justification for this replacement load. In fact, Big Rivers states the following in response to inquiries about its replacement load estimates:

"Big Rivers includes in its budget and forecast the assumptions that it considers reasonable, reliable, made in good faith and justified for use by management."[27]Nonetheless, if these assumptions, and particularly the assumptions regarding replacement load are incorrect, the result would have major implications on the benefits, if any, Big Rivers' members would receive. For that reason this sensitivity analysis assumes that the forecasted replacement load occurs 1 year later and at 50% of the levels in the forecast. This has some dramatic effects on the forecast for several reasons:

This analysis assumed that Wilson would return to service in [redacted] and Coleman in [redacted], as well as a comparison to a new combined cycle unit in [redacted]. However, because the replacement load sales are decreased, the other Big Rivers' units are capable of meeting the reduced replacement load sales until [redacted]. The results of these assumptions for the sensitivity analysis are shown below: [28]

[27] See response to KIUC 2-7.
[28] See Exhibit Holloway-2 page 4.

Big Rivers' New Load Scenario w/ Coleman and Wilson - Sensitivity Analysis
New Load is 50% of Assumptions and Occurs 1 Year Later

Year	New Load Demand (kW)[1]	New Load Energy (MWH)[2]	New Load Energy From Wilson & Coleman (MWh)[3]
2014	[redacted]		
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			
2027			

1 AG 1-139 Model Tables Response New Load Non-Coincident Peak adusted to lag 1 year and 50% of assumed amount
2 Energy Sales associated with new load demand consistent with AG 1-139 Model Tables Response New Load Energy
3 Assume that 200,000 kW and associated energy is supplied w/o Coleman and Wilson

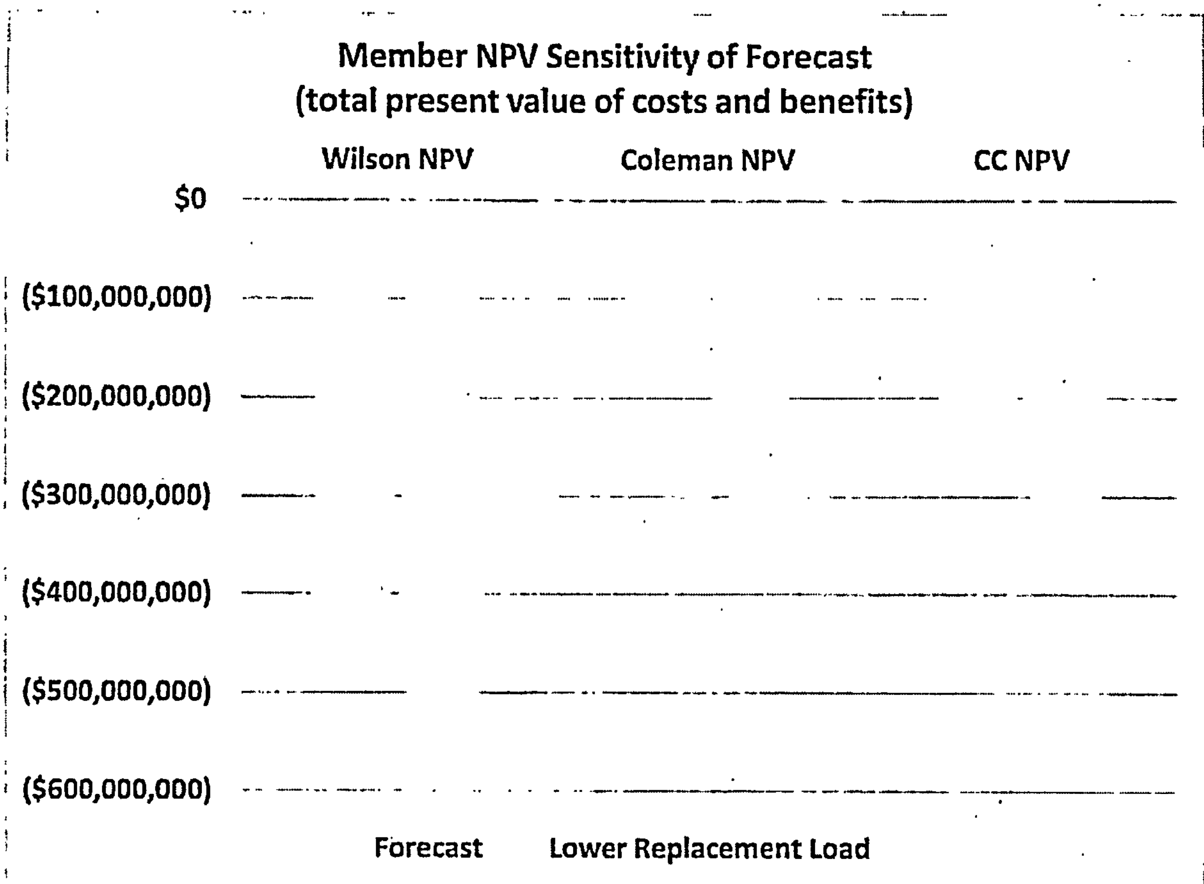
The result of this analysis is that the NPV of owning Wilson, Coleman and the combined cycle alternative all show significant costs to members, even beyond those estimated using Big Rivers' arguably optimistic forecasts:[29]

	Size (MW)	Total NPV	NPV/MW
Wilson	417	[redacted]	
Coleman	443		
New Combined Cycle	620		

The sensitivity analysis changes the amount of replacement load in the forecast that is served by Wilson and Coleman, or the alternative combined cycle unit. The assumptions

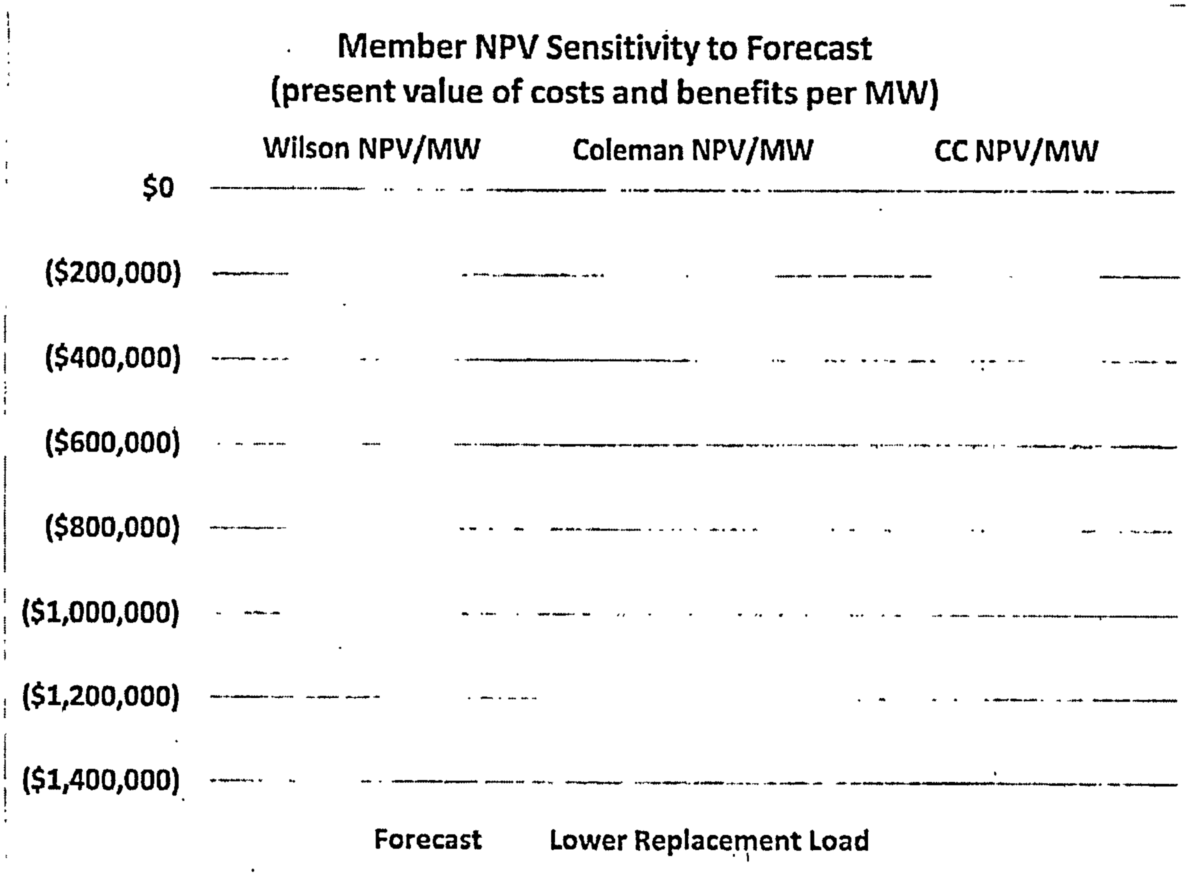
[29] See Attachment D for the Sensitivity Analysis.

and forecasts provided by Big Rivers project that sales to replacement load will be priced above the market. Therefore, as lower replacement load sales are evaluated in the sensitivity analysis, larger negative NPV's are expected. However the analysis also shows that the relative ranking of the units in NPV per MW is also unchanged. The results as compared on an overall basis are shown in the following illustration:[30]



Furthermore, the same ranking of the units is revealed on a unit (or MW) basis, as illustrated below:

[30] Ibid.



Conclusions

Big Rivers has implied that ultimately the retail ratepayers will benefit financially from the harsh rate increases that are key to Big Rivers' mitigation plan. However this analysis, based on Big Rivers' own projections and forecasts, reveals that this is not the case. Additionally, this analysis illustrates that from the financial perspective of the members, sale of these units sooner, rather than later, even at a price lower than the amount Big Rivers anticipates may be more beneficial to the members. Furthermore this analysis demonstrates that the costs of continued ownership of Wilson does not compare favorably to the costs of building a new combined cycle unit in the future.

If Big Rivers does not sell the units, its plan includes the objective of obtaining a large amount of off-system sales to uncertain future replacement load and short term market. However, from the perspective of the members' retail customers, this optimistic uncertain future will not provide overall benefits. In fact, if members are asked to pay for the costs of owning and operating Coleman and Wilson to receive these future benefits, these same customers would need to have their electric rates decreased by over [redacted] million a year.

Put another way, Big Rivers is requesting that members' retail customers pay approximately [redacted] million in 2014 for the costs of owning and maintaining Wilson and Coleman. However, unless this amount is adjusted to only [redacted] in 2014, ***and these customers get all the future benefits from these units***, these customers will be irrevocably harmed by paying for generating plants that are not needed or necessary.

Even if Big Rivers does sell these facilities in the next few years, and these same customers no longer have to bear these costs, under the current proposal they would have to pay all the associated Wilson and Coleman costs until the sale is complete. [redacted]

Wilson and Coleman are not needed to provide generating capacity for the members' retail customers. Therefore, from the perspective of these customers, continued ownership of these units for future sales to the uncertain replacement load or the market is no different than ownership of a merchant power plant. With that in mind, ownership of a new combined cycle unit in the future was compared to the costs of owning and operating Wilson and Coleman until these future costs occur. While none of these alternatives investments prove profitable, building a new combined cycle unit in the future, rather than paying the ongoing costs of Wilson, is a less costly alternative.

Finally, when the different alternatives were evaluated assuming a decreased amount of replacement load, as expected all resulted in lower benefits to offset the same costs. Nonetheless this sensitivity analysis revealed that the relative ranking of value between Coleman, Wilson and the combined cycle alternative remained unchanged.

Redacted

Wilson Annual Costs and Benefits - Attachment A

Item	Ref	2014	2015	2016	2017	2018
MATS Capital	AG 2-9	[redacted]				
Cumulative MATS Capital		[redacted]				
Idled/Restoration Capital Added	KIUC 2-17	[redacted]				
Running Capital Added	KIUC 2-17	[redacted]				
Cumulative Idled/Restoration Running Capital		[redacted]				
Idled/Restoration Operat Capital Depreciation		[redacted]				
MATS Depreciation		[redacted]				
Existing Plant Depreciation Expense		[redacted]				
Total Depreciation costs		[redacted]				
Labor Expense	KIUC 2-15	[redacted]				
Fixed Departmental Expense	KIUC 2-15	[redacted]				
Property Tax Expense Base	KIUC 2-15	[redacted]				
Property Tax Expense ECR	KIUC 2-15	[redacted]				
Property Insurance Expense Base	KIUC 2-15	[redacted]				
Property Insurance Expense ECR	KIUC 2-15	[redacted]				
Interest Expense Base	KIUC 2-15	[redacted]				
Interest Expense ECR	KIUC 2-15	[redacted]				
Tier Earnings	Calculated	[redacted]				
Total Annual Expenses w/o Variable O&M		[redacted]				
Total Annual New Load and Market Sales Net Revenue		[redacted]				
Net Annual Costs		[redacted]				

Redacted

Wilson Annual Costs and Benefits - Attachment A

Item	Ref	2019	2020	2021	2022	2023
MATS Capital	AG 2-9	[redacted]				
Cumulative MATS Capital						
Idled/Restoration Capital Added	KIUC 2-17					
Running Capital Added	KIUC 2-17					
Cumulative Idled/Restoration Running Capital						
Idled/Restoration Operat Capital Depreciation						
MATS Depreciation						
Existing Plant Depreciation Expense						
Total Depreciation costs						
Labor Expense	KIUC 2-15					
Fixed Departmental Expense	KIUC 2-15					
Property Tax Expense Base	KIUC 2-15					
Property Tax Expense ECR	KIUC 2-15					
Property Insurance Expense Base	KIUC 2-15					
Property Insurance Expense ECR	KIUC 2-15					
Interest Expense Base	KIUC 2-15					
Interest Expense ECR	KIUC 2-15					
Tier Earnings	Calculated					
Total Annual Expenses w/o Variable O&M						
Total Annual New Load and Market Sales Net Revenue						
Net Annual Costs						

Redacted

Wilson Annual Costs and Benefits - Attachment A

Item	Ref	2024	2025	2026	2027
MATS Capital	AG 2-9	[redacted]			
Cumulative MATS Capital					
Idled/Restoration Capital Added	KIUC 2-17				
Running Capital Added	KIUC 2-17				
Cumulative Idled/Restoration Running Capital					
Idled/Restoration Operat Capital Depreciation					
MATS Depreciation					
Existing Plant Depreciation Expense					
Total Depreciation costs					
Labor Expense	KIUC 2-15				
Fixed Departmental Expense	KIUC 2-15				
Property Tax Expense Base	KIUC 2-15				
Property Tax Expense ECR	KIUC 2-15				
Property Insurance Expense Base	KIUC 2-15				
Property Insurance Expense ECR	KIUC 2-15				
Interest Expense Base	KIUC 2-15				
Interest Expense ECR	KIUC 2-15				
Tier Earnings	Calculated				
Total Annual Expenses w/o Variable O&M					
Total Annual New Load and Market Sales Net Revenue					
Net Annual Costs					

Redacted

Coleman Annual Costs and Benefits - Attachment A

Item	Ref	2014	2015	2016	2017	2018
MATS Capital	AG 2-9	[redacted]				
Cumulative MATS Capital						
Idled/Restoration Capital Added	KIUC 2-17					
Running Capital Added	KIUC 2-17					
Cumulative Idled/Restoration Running Capital						
Idled/Restoration Operat Capital Depreciation						
MATS Depreciation						
Depreciation Expense						
Total Depreicatlon						
Labor Expense	KIUC 2-15					
Fixed Departmental Expense	KIUC 2-15					
Property Tax Expense Base	KIUC 2-15					
Property Tax Expense ECR	KIUC 2-15					
Property Insurance Expense Base	KIUC 2-15					
Property Insurance Expense ECR	KIUC 2-15					
Interest Expense Base	KIUC 2-15					
Interest Expense ECR	KIUC 2-15					
Tier Earnings	Calculated					
Total Annual Expenses w/o Variable O&M						
Total Annual New Load and Market Sales Net Revenue						
Net Annual Costs						

Redacted **Coleman Annual Costs and Benefits - Attachment A** Sheet 2 of 3

Item	Ref	2019	2020	2021	2022	2023
MATS Capital	AG 2-9	[redacted]				
Cumulative MATS Capital						
Idled/Restoration Capital Added	KIUC 2-17					
Running Capital Added	KIUC 2-17					
Cumulative Idled/Restoration Running Capital						
Idled/Restoration Operat Capital Depreciation						
MATS Depreciation						
Depreciation Expense						
Total Depreication						
Labor Expense	KIUC 2-15					
Fixed Departmental Expense	KIUC 2-15					
Property Tax Expense Base	KIUC 2-15					
Property Tax Expense ECR	KIUC 2-15					
Property Insurance Expense Base	KIUC 2-15					
Property Insurance Expense ECR	KIUC 2-15					
Interest Expense Base	KIUC 2-15					
Interest Expense ECR	KIUC 2-15					
Tier Earnings	Calculated					
Total Annual Expenses w/o Variable O&M						
Total Annual New Load and Market Sales Net Revenue						
Net Annual Costs						

Redacted

Coleman Annual Costs and Benefits - Attachment A

Item	Ref	2024	2025	2026	2027
MATS Capital	AG 2-9	[redacted]			
Cumulative MATS Capital					
Idled/Restoration Capital Added	KIUC 2-17				
Running Capital Added	KIUC 2-17				
Cumulative Idled/Restoration Running Capital					
Idled/Restoration Operat Capital Depreciation					
MATS Depreciation					
Depreciation Expense					
Total Depreication					
Labor Expense	KIUC 2-15				
Fixed Departmental Expense	KIUC 2-15				
Property Tax Expense Base	KIUC 2-15				
Property Tax Expense ECR	KIUC 2-15				
Property Insurance Expense Base	KIUC 2-15				
Property Insurance Expense ECR	KIUC 2-15				
Interest Expense Base	KIUC 2-15				
Interest Expense ECR	KIUC 2-15				
Tier Earnings	Calculated				
Total Annual Expenses w/o Variable O&M					
Total Annual New Load and Market Sales Net Revenue					
Net Annual Costs					

Redacted

2014 NPV of Wilson and Coleman Costs and Benefits 2014 to 2027 - Attachment A

Nominal Annual Benefits (Costs)

	2014	2015	2016	2017	2018	2019	2020	2021
Wilson Costs	[redacted]							
Wilson Generation Profits								
Coleman Costs								
Coleman Generation Profits								

2014 NPV of Annual Benefits (Costs)

	2014	2015	2016	2017	2018	2019	2020	2021
Wilson Costs	[redacted]							
Wilson Profits								
Wilson Total								
Coleman Costs								
Coleman Profits								
Coleman Total								

Assumed Interest for Costs and Adjustments	5.00%
Assumed Interest for Generation Profits	10.00%

Redacted

2014 NPV of Wilson and Coleman Costs and Benefits 2014 to 2027 - Attachment A

Nominal Annual Benefits (Costs)

	2022	2023	2024	2025	2026	2027
Wilson Costs	[redacted]					
Wilson Generation Profits						
Coleman Costs						
Coleman Generation Profits						

2014 NPV of Annual Benefits (Costs)

	2022	2023	2024	2025	2026	2027	Total 2014 NPV
Wilson Costs	[redacted]						
Wilson Profits							
Wilson Total							
Coleman Costs							
Coleman Profits							
Coleman Total							

Redacted

Annual Wilson and Coleman Rate Adjustment to Minimize Member Costs - Attachment B

Nominal Annual Benefits (Costs)

	2014	2015	2016	2017	2018	2019	2020	2021
Wilson Costs	[redacted]							
Wilson Annual Adjustment								
Wilson Generation Profits								
Coleman Costs								
Coleman Annual Adjustment								
Coleman Generation Profits								

2014 NPV of Annual Benefits (Costs)

	2014	2015	2016	2017	2018	2019	2020	2021
Wilson Costs	[redacted]							
Wilson Annual Adjustment								
Wilson Profits								
Wilson Total								
Coleman Costs								
Coleman Annual Adjustment								
Coleman Profits								
Coleman Total								

Assumed Interest for Costs and Adjustments	5.00%
Assumed Interest for Generation Profits	10.00%

Annual Wilson and Coleman Rate Adjustment to Minimize Member Costs - Attachment B

Nominal Annual Benefits (Costs)

	2022	2023	2024	2025	2026	2027
Wilson Costs	[redacted]					
Wilson Annual Adjustment						
Wilson Generation Profits						
Coleman Costs						
Coleman Annual Adjustment						
Coleman Generation Profits						

2014 NPV of Annual Benefits (Costs)

	2022	2023	2024	2025	2026	2027	Total 2014 NPV
Wilson Costs	[redacted]						
Wilson Annual Adjustment							
Wilson Profits							
Wilson Total							
Coleman Costs							
Coleman Annual Adjustment							
Coleman Profits							
Coleman Total							

Redacted

Combined Cycle Annual Costs - Attachment C

Item	Ref	2014	2015	2016	2017	2018	2019	2020
Principal and Interest (20 years)	Assumed[4]					($49,290,578.26)	($49,290,578.26)	($49,290,578.26)
Fixed O&M	EIA					($9,471,633)	($9,632,650)	($9,796,406)
Total Annual Expenses w/o Variable O&M	Calculated	$0	$0	$0	$0	($58,762,211)	($58,923,229)	($59,086,984)
Total Annual New Load and Market Sales Revenue	Calculated	[redacted]						
Net Annual Costs	Calculated	[redacted]						
Available CC Generation	Assumed[5]					4,738,090	4,725,144	4,725,144
MWH New Load	Load[3]					657,000	1,314,000	2,638,800
MWH Available for Market	Calculated					4,081,090	3,411,144	2,086,344
Market $/MWH	Forecast[2]	[redacted]						
New Load Price $/MWH	Forecast[2]	[redacted]						
CC Costs $/MWH	PCM[1]	[redacted]						
CC New Load Net Revenue	Calculated	[redacted]						
CC Market Net Revenue	Calculated	[redacted]						
CC Total Sales Net Revenue	Calculated	[redacted]						
MMBTU Fuel at 7050 heat rate	Calculated					33,403,532	33,312,265	33,312,265
Gas costs $/MMBTU	PCM[1]	[redacted]						
Transportation costs	AG 2-16	[redacted]						
Gas Delivered $/MMBTU	Calculated	[redacted]						
Total Fuel Costs	Calculated	[redacted]						
Fuel Costs/MWH	Calculated	[redacted]						
Variable Costs/MWH	EIA					$3.98	$4.05	$4.12
Total Costs/MWH	Calculated	[redacted]						

Redacted

Combined Cycle Annual Costs - Attachment C

Sheet 2 of 4

Item	2021	2022	2023	2024	2025	2026
Principal and Interest (20 years)	($49,290,578.26)	($49,290,578.26)	($49,290,578.26)	($49,290,578.26)	($49,290,578.26)	($49,290,578.26)
Fixed O&M	($9,962,944)	($10,132,314)	($10,304,564)	($10,479,741)	($10,657,897)	($10,839,081)
Total Annual Expenses w/o Variable O&M	($59,253,523)	($59,422,893)	($59,595,142)	($59,770,320)	($59,948,475)	($60,129,660)
Total Annual New Load and Market Sales Revenue	[redacted]					
Net Annual Costs						
Available CC Generation	4,725,144	4,738,090	4,725,144	4,725,144	4,725,144	4,738,090
MWH New Load	3,942,000	3,942,000	3,942,000	3,956,400	3,942,000	3,942,000
MWH Available for Market	783,144	796,090	783,144	768,744	783,144	796,090
Market $/MWH	[redacted]					
New Load Price $/MWH						
CC Costs $/MWH						
CC New Load Net Revenue						
CC Market Net Revenue						
CC Total Sales Net Revenue						
MMBTU Fuel at 7050 heat rate	33,312,265	33,403,532	33,312,265	33,312,265	33,312,265	33,403,532
Gas costs $/MMBTU	[redacted]					
Transportation costs						
Gas Delivered $/MMBTU						
Total Fuel Costs						
Fuel Costs/MWH						
Variable Costs/MWH	$4.19	$4.26	$4.33	$4.41	$4.48	$4.56
Total Costs/MWH	[redacted]					

Combined Cycle Annual Costs - Attachment C

Item	2027
Principal and Interest (20 years)	($49,290,578.26)
Fixed O&M	($11,023,346)
Total Annual Expenses w/o Variable O&M	($60,313,924)
Total Annual New Load and Market Sales Revenue	[redacted]
Net Annual Costs	
Available CC Generation	4,725,144
MWH New Load	3,942,000
MWH Available for Market	783,144
Market $/MWH	[redacted]
New Load Price $/MWH	
CC Costs $/MWH	
CC New Load Net Revenue	
CC Market Net Revenue	
CC Total Sales Net Revenue	
MMBTU Fuel at 7050 heat rate	33,312,265
Gas costs $/MMBTU	[redacted]
Transportation costs	
Gas Delivered $/MMBTU	
Total Fuel Costs	
Fuel Costs/MWH	
Variable Costs/MWH	$4.64
Total Costs/MWH	[redacted]

1 Annual Resource Report PSC 2-14 PCM Run 4-22-2013 (2013-2027)
2 Stmts RUS PSC 2-14 Financial Forecast (2014-2017) 5-16-2013
3 New Load from Response to AG 1-139 assume that New Load served before 2018 continues to be served by other BREC units
4* 620 MW unit at $917/kW (2012) escalated at 1.7% per GDP chain index to 2018, 0.93 regional adjustment per EIA, result is $944/kW (2018), 20 year, 5% interest levelized payments
5 620 MW at 87% capacity factor per EIA
EIA 2013 EIA Annual Energy Outlook Electricity Module and Background
* 2018 Installed Cost for 620 MW CC $614,269,554

Redacted

Coleman and Wilson NPV Comparison to Combined Cycle Unit - Attachment C

Nominal Annual Benefits (Costs)

	2014	2015	2016	2017	2018	2019	2020	2021
Wilson Costs	[redacted]							
Wilson Generation Profits								
Coleman Costs								
Coleman Generation Profits								
New CC Costs	$0	$0	$0	$0	($58,762,211)	($58,923,229)	($59,086,984)	($59,253,523)
New CC Generation Profits	[redacted]							

2014 NPV of Annual Benefits (Costs)

	2014	2015	2016	2017	2018	2019	2020	2021
Wilson Costs	[redacted]							
Wilson Profits								
Wilson Total								
Coleman Costs								
Coleman Profits								
Coleman Total								
New CC Costs	$0	$0	$0	$0	($48,343,816)	($46,167,892)	($44,091,617)	($42,110,372)
New CC Profits	[redacted]							
New CC Total								

Assumed Interest for Costs and Adjustments	5.00%
Assumed Interest for Generation Profits	10.00%

Redacted **Coleman and Wilson NPV Comparison to Combined Cycle Unit - Attachment C**

Nominal Annual Benefits (Costs)

	2022	2023	2024	2025	2026	2027
Wilson Costs	[redacted]					
Wilson Generation Profits						
Coleman Costs						
Coleman Generation Profits						
New CC Costs	($59,422,893)	($59,595,142)	($59,770,320)	($59,948,475)	($60,129,660)	($60,313,924)
New CC Generation Profits	[redacted]					

2014 NPV of Annual Benefits (Costs)

	2022	2023	2024	2025	2026	2027	Total 2014 NPV
Wilson Costs	[redacted]						
Wilson Profits							
Wilson Total							
Coleman Costs							
Coleman Profits							
Coleman Total							
New CC Costs	($40,219,753)	($38,415,560)	($36,693,791)	($35,050,632)	($33,482,444)	($31,985,762)	($396,561,639)
New CC Profits	[redacted]						
New CC Total							

Redacted **Coleman and Wilson NPV Comparison to Combined Cycle Unit Sensitivity Analysis - Attachment D** Sheet 1 of 2

Nominal Annual Benefits (Costs)

	2014	2015	2016	2017	2018	2019	2020	2021
Wilson Costs	[redacted]							
Wilson Generation Profits								
Coleman Costs								
Coleman Generation Profits								
New CC Costs	$0	$0	$0	$0	($58,762,211)	($58,923,229)	($59,086,984)	($59,253,523)
New CC Generation Profits	[redacted]							

2014 NPV of Annual Benefits (Costs)

	2014	2015	2016	2017	2018	2019	2020	2021
Wilson Costs	[redacted]							
Wilson Profits								
Wilson Total								
Coleman Costs								
Coleman Profits								
Coleman Total								
New CC Costs	$0	$0	$0	$0	($48,343,816)	($46,167,892)	($44,091,617)	($42,110,372)
New CC Profits	[redacted]							
New CC Total								

Assumed Interest for Costs and Adjustments	5.00%
Assumed Interest for Generation Profits	10.00%

Coleman and Wilson NPV Comparison to Combined Cycle Unit Sensitivity Analysis - Attachment D

Nominal Annual Benefits (Costs)

	2022	2023	2024	2025	2026	2027
Wilson Costs Wilson Generation Profits Coleman Costs Coleman Generation Profits	[redacted]					
New CC Costs	($59,422,893)	($59,595,142)	($59,770,320)	($59,948,475)	($60,129,660)	($60,313,924)
New CC Generation Profits	[redacted]					

2014 NPV of Annual Benefits (Costs)

	2022	2023	2024	2025	2026	2027	Total 2014 NPV
Wilson Costs Wilson Profits Wilson Total Coleman Costs Coleman Profits Coleman Total	[redacted]						
New CC Costs	($40,219,753)	($38,415,560)	($36,693,791)	($35,050,632)	($33,482,444)	($31,985,762)	($396,561,639)
New CC Profits New CC Total	[redacted]						

Electricity Market Module

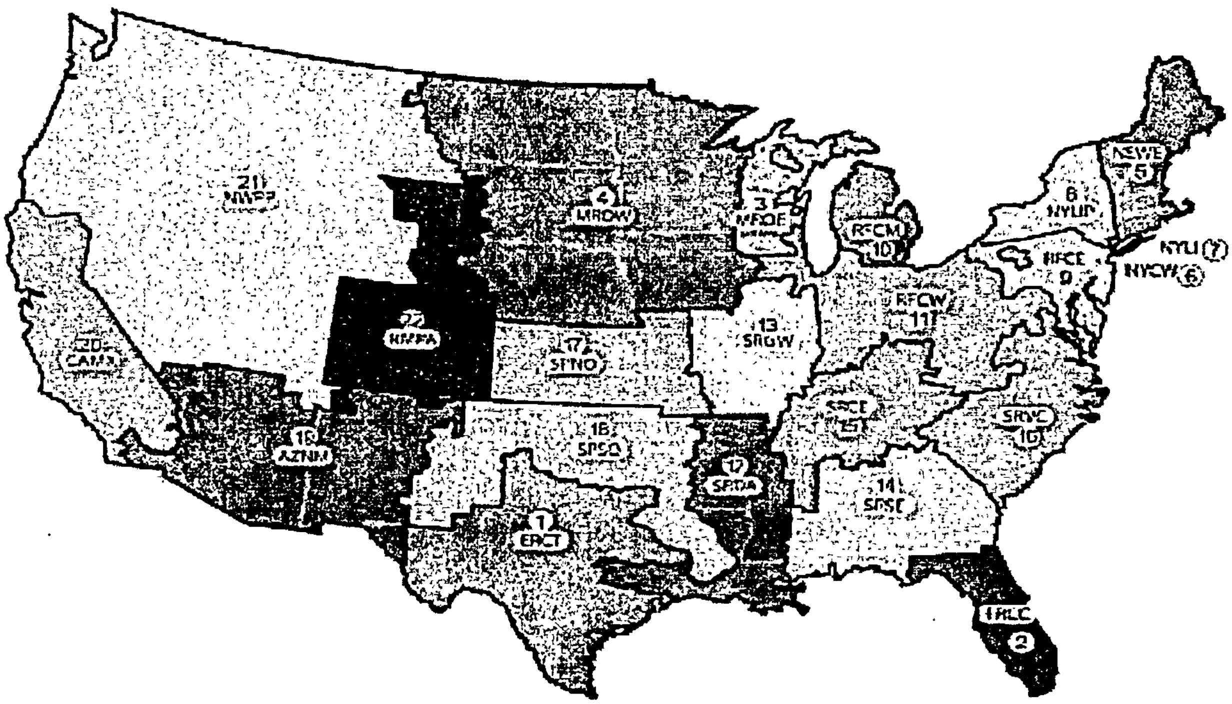
The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules—electricity capacity planning, electricity fuel dispatching, electricity load and demand, and electricity finance and pricing. It includes nonutility capacity and generation, and electricity transmission and trade. A detailed description of the EMM is provided in the EIA publication, Electricity Market Module of the National Energy Modeling System 2013, DOE/EIA-M068(2013).

Based on fuel prices and electricity demands provided by the other modules of the NEMS, the EMM determines the most economical way to supply electricity, within environmental and operational constraints. There are assumptions about the operations of the electricity sector and the costs of various options in each of the EMM submodules. This section describes the model parameters and assumptions used in EMM. It includes a discussion of legislation and regulations that are incorporated in EMM as well as information about the climate change action plan. The various electricity side cases are also described.

EMM regions

The supply regions used in EMM are based on the North American Electric Reliability Corporation regions and subregions shown in Figure 6.

Figure 6. Electricity Market Model Supply Regions



1.	ERCT	ERCOT All	12.	SRDA	SERC Delta
2.	FRCC	FRCC All	13.	SRGW	SERC Gateway
3.	MROE	MRO East	14.	SRSE	SERC Southeastern
4.	MROW	MRO West	15.	SRCE	SERC Central
5.	NEWE	NPCC New England	16.	SRVC	SERC VACAR
6.	NYCW	NPCC NYC/Westchester	17.	SPNO	SPP North
7.	NYLI	NPCC Long Island	18.	SPSO	SPP South
8.	NYUP	NPCC Upstate NY	19.	AZNM	WECC Southwest
9.	RFCE	RFC East	20.	CAMX	WECC California
10.	RFCM	RFC Michigan	21.	NWPP	WECC Northwest
11.	RFCW	RFC West	22.	RMPA	WECC Rockies

Model parameters and assumptions

Generating capacity types

The capacity types represented in the EMM are shown in Table 8.1.

Table 8.1. Generating capacity types represented in the Electricity Market Module

Capacity Type
Existing coal steam plants[1]
High Sulfur Pulverized Coal with Wet Flue Gas Desulfurization
Advanced Coal - Integrated Coal Gasification Combined Cycle
Pulverized Coal with carbon sequestration
Oil/Gas Steam - Oil/Gas Steam Turbine
Combined Cycle - Conventional Gas/Oil Combined Cycle Combustion Turbine
Advanced Combined Cycle - Advanced Gas/Oil Combined Cycle Combustion Turbine
Advanced Combined Cycle with carbon sequestration
Combustion Turbine - Conventional Combustion Turbine
Advanced Combustion Turbine - Steam Injected Gas Turbine
Molten Carbonate Fuel Cell
Conventional Nuclear
Advanced Nuclear - Advanced Light Water Reactor
Generic Distributed Generation - Baseload
Generic Distributed Generation - Peak
Conventional Hydropower - Hydraulic Turbine
Pumped Storage - Hydraulic Turbine Reversible
Geothermal
Municipal Solid Waste
Biomass - Fluidized Bed
Solar Thermal - Central Tower
Solar Photovoltaic - Fixed Tilt
Wind
Wind Offshore

[1]The EMM represents 32 different types of existing coal steam plants, based on the different possible configuration of NO_x, particulate and SO_2 emission control devices, as well as future options for controlling mercury and carbon.
Source: U.S. Energy Information Administration.

New generating plant characteristics

The cost and performance characteristics of new generating technologies are inputs to the electricity capacity planning submodule (Table 8.2). These characteristics are used in combination with fuel prices from the NEMS fuel supply modules and foresight on fuel prices, to compare options when new capacity is needed. Heat rates for new fossil-fueled technologies are assumed to decline linearly through 2025.

For the *AEO2013*, EIA commissioned an external consultant to update current cost estimates for utility-scale electric generating plants [1]. This report used a consistent methodology, similar to the one used to develop the estimates for *AEO2011* and *AEO2012*, but accounted for more recent data and experience. A cost adjustment factor, based on the producer price index for metals and metal products, allows the overnight costs to fall in the future if this index drops, or rise further if it increases.

The overnight costs shown in Table 8.2 represent the estimated cost of building a plant in a typical region of the country. Differences in plant costs due to regional distinctions are calculated by applying regional multipliers. Regional multipliers by technology are also based on regional cost estimates developed by the consultant. The regional variations account for multiple factors, such as differences in terrain, weather, population, and labor wages. The base overnight cost is multiplied by a project contingency factor and a technological optimism factor (described later in this chapter), resulting in the total construction cost for the first-of-a-kind unit used for the capacity choice decision.

Table 8.2. Cost and performance characteristics of new central station electricity generating technologies

Technology	Online Year[1]	Size (mW)	Lead time (years)	Base Overnight Cost in 2012 (2011 $/kW)	Contingency Factors: Project Contingency Factor[2]	Contingency Factors: Technological Optimism Factor[3]	Total Overnight Cost in 2012[4] (2011 $/kW)	Variable O&M[5] (2011 $/mWh)	Fixed O&M (2011$/kW)	Heatrate[6] in 2012 (Btu/kWh)	nth-of-a-kind Heatrate (Btu/kWh)
Scrubbed Coal New[7]	2016	1300	4	2,694	1.07	1.00	2,883	4.39	30.64	8,800	8,740
Integrated Coal-Gasification Comb Cycle (IGCC)[7]	2016	1200	4	3,475	1.07	1.00	3,718	7.09	50.49	8,700	7,450
Pulverized Coal with Carbon sequestion	2017	650	4	4,662	1.07	1.03	5,138	4.37	65.31	12,000	9,316
Conv Gas/Oil Comb Cycle	2015	620	3	858	1.05	1.00	901	3.54	12.94	7,050	6,800
Adv Gas/Oil Comb Cycle (CC)	2015	400	3	931	1.08	1.00	1,006	3.21	15.10	6,430	6,333
Adv CC with carbon sequestration	2017	340	3	1,833	1.08	1.04	2,059	6.66	31.23	7,525	7,493
Conv Comb Turbine[8]	2014	85	2	910	1.05	1.00	956	15.18	7.21	10,850	10,450
Adv Comb Turbine	2014	210	2	632	1.05	1.00	664	10.19	6.92	9,750	8,550
Fuel Cells	2015	10	3	6,045	1.05	1.10	6,982	0.00	357.47	9,500	6,960
Adv Nuclear	2018	2236	6	4,700	1.10	1.05	5,429	2.10	91.65	10,452	10,452
Distributed Generation - Base	2015	2	3	1,395	1.05	1.00	1,465	7.62	17.14	9,038	8,900
Distributed Generation - Peak	2015	1	2	1,675	1.05	1.00	1,759	7.62	17.14	10,042	9,880
Biomass	2016	50	4	3,685	1.07	1.02	4,041	5.17	103.79	13,500	13,500
Geothermal[7,9]	2013	50	4	2,444	1.05	1.00	2,567	0.00	110.94	9,756	9,756
MSW - Landfill Gas	2013	50	3	7,858	1.07	1.00	8,408	8.51	381.74	13,648	13,648
Conventional Hydropower[9]	2016	500	4	2,179	1.10	1.00	2,397	2.60	14.57	9,756	9,756
Wind	2013	100	3	2,032	1.07	1.00	2,175	0.00	38.86	9,756	9,756
Wind Offshore	2016	400	4	4,452	1.10	1.25	6,121	0.00	72.71	9,756	9,756
Solar Thermal[7]	2015	100	3	4,653	1.07	1.00	4,979	0.00	66.09	9,756	9,756
Photovoltaic[7,10]	2014	150	2	3,624	1.05	1.00	3,805	0.00	21.37	9,756	9,756

[1]Online year represents the first year that a new unit could be completed, given an order date of 2012. For wind, geothermal and landfill gas, the online year was moved earlier to acknowledge the significant market activity already occurring in anticipation of the expiration of the Production Tax Credit.

[2]A contingency allowance is defined by the American Association of Cost Engineers as the "specific provision for unforeseeable elements of costs within a defined project scope; particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur"

[3]The technological optimism factor is applied to the first four units of a new, unproven design, it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[4] Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2012.

[5]O&M = Operations and maintenance.

[6]For hydro, wind, solar and geothermal technologies, the heatrate shown represents the average heatrate for conventional thermal generation as of 2011. This is used for purposes of calculating primary energy consumption displaced for these resources, and does not imply an estimate of their actual energy conversion efficiency.

[7]Capital costs are shown before investment tax credits are applied.

[8]Combustion turbine units can be built by the model prior to 2014 if necessary to meet a given region's reserve margin.

[9]Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

[10]Costs and capacities are expressed in terms of net AC power available to the grid for the installed capacity.

Sources: For the *AEO2013*, EIA updated cost estimates for utility-scale electric generating plants, based on a draft report provided by external consultants. The final report can be found at www.eia.gov/forecasts/capitalcost/. Site specific costs for geothermal were provided by the National Energy Renewable Laboratory, "Updated U.S. Geothermal Supply Curve", February 2010.

Technological optimism and learning

Overnight costs for each technology are calculated as a function of regional construction parameters, project contingency, and technological optimism and learning factors.

The technological optimism factor represents the demonstrated tendency to underestimate actual costs for a first-of-a-kind, unproven technology. As experience is gained (after building 4 units) the technological optimism factor is gradually reduced to 1.0.

The learning function in NEMS is determined at a component level. Each new technology is broken into its major components, and each component is identified as revolutionary, evolutionary or mature. Different learning rates are assumed for each component, based on the level of experience with the design component (Table 8.3). Where technologies use similar components, these components learn at the same rate as these units are built. For example, it is assumed that the underlying turbine generator for a combustion turbine, combined cycle and integrated coal-gasification combined cycle unit is basically the same. Therefore construction of any of these technologies would contribute to learning reductions for the turbine component.

The learning function has the nonlinear form:

$$OC(C) = a^*C^{-b},$$

where C is the cumulative capacity for the technology component.

Table 8.3. Learning parameters for new generating technology components

Technology Component	Period 1 Learning Rate (LR1)	Period 2 Learning Rate(LR2)	Period 3 Learning Rate (LR3)	Period 1 Doublings	Period 2 Doublings	Minimum Total Learning by 2035
Pulverized Coal	-	-	1%	-	-	5%
Combustion Turbine - conventional	-	-	1%	-	-	5%
Combustion Turbine - advanced	-	10%	1%	-	5	10%
HRSG[1]	-	-	1%	-	-	5%
Gasifier	-	10%	1%	-	5	10%
Carbon Capture/Sequestration	20%	10%	1%	3	5	20%
Balance of Plant - IGCC	-	-	1%	-	-	5%
Balance of Plant - Turbine	-	-	1%	-	-	5%
Balance of Plant - Combined Cycle	-	-	1%	-	-	5%
Fuel Cell	20%	10%	1%	3	5	20%
Advanced Nuclear	5%	3%	1%	3	5	10%
Fuel prep - Biomass	-	10%	1%	-	5	10%
Distributed Generation - Base	-	5%	1%	-	5	10%
Distributed Generation - Peak	-	5%	1%	-	5	10%
Geothermal	-	8%	1%	-	5	10%
Municipal Solid Waste	-	-	1%	-	-	5%
Hydropower	-	-	1%	-	-	5%
Wind	-	-	1%	-	-	5%
Wind Offshore	20%	10%	1%	3	5	20%
Solar Thermal	20%	10%	1%	3	5	10%
Solar PV - Module	-	10%	1%	-	5	10%
Balance of Plant - Solar PV	-	10%	1%	-	5	10%

[1]HRSG = Heat Recovery Steam Generator

Note: Please see the text for a description of the methodology for learning in the Electricity Market Module.

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis.

The progress ratio (pr) is defined by speed of learning (e.g., how much costs decline for every doubling of capacity). The reduction in capital cost for every doubling of cumulative capacity (LR) is an exogenous parameter input for each component (Table 8.3). The progress ratio and LR are related by:

$pr = 2^{-b} = (1 - LR)$

The parameter "b" is calculated from the second equality above ($b = -(\ln(1-LR)/\ln(2))$). The parameter "a" is computed from initial conditions, i.e.

$a = OC(C_0)/C_0^{-b}$

where C_0 is the initial cumulative capacity. Once the rates of learning (LR) and the cumulative capacity (C_0) are known for each interval, the parameters (a and b) can be computed. Three learning steps were developed to reflect different stages of learning as a new design is introduced into the market. New designs with a significant amount of untested technology will see high rates of learning initially, while more conventional designs will not have as much learning potential. Costs of all design components are adjusted to reflect a minimal amount of learning, even if new capacity additions are not projected. This represents cost reductions due to future international development or increased research and development.

Once the learning rates by component are calculated, a weighted average learning factor is calculated for each technology. The weights are based on the share of the initial cost estimate that is attributable to each component (Table 8.4). For technologies that do not share components, this weighted average learning rate is calculated exogenously, and input as a single component.

These technologies may still have a mix of revolutionary components and more mature components, but it is not necessary to include this detail in the model unless capacity from multiple technologies would contribute to the component learning. In the case of the solar PV technology, it is assumed that the module component accounts for 50 percent of the cost, and that the balance of system components accounts for the remaining 50 percent. Because the amount of end-use PV capacity (existing and projected) is significant relative to total solar PV capacity, and because the technology of the module component is common across the end-use and electric power sectors, the calculation of the learning factor for the PV module component also takes into account capacity built in the residential and commercial sectors.

Table 8.5 shows the capacity credit toward component learning for the various technologies. It was assumed that for all combined-cycle technologies, the turbine unit contributed two-thirds of the capacity, and the steam unit one-third. Therefore, building one gigawatt of gas combined cycle would contribute 0.67 gigawatts toward turbine learning, and 0.33 gigawatts toward steam learning. Components that do not contribute to the capacity of the plant, such as the balance of plant category, receive 100 percent capacity credit for any capacity built with that component. For example, when calculating capacity for the "Balance of plant - CC" component, all combined cycle capacity would be counted 100 percent, both conventional and advanced.

Table 8.4. Component cost weights for new technologies

Technology	Pulverized Coal	Combustion Turbine-conventional	Combustion Turbine-advanced	HRSG	Gasifier	Carbon Capture/ Sequestration	Balance of Plant-IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuel Prep Biomass
Integrated Coal-Gasification Comb Cycle (IGCC)	0%	0%	15%	20%	41%	0%	24%	0%	0%	0%
Pulverized Coal with carbon sequestration	70%	0%	0%	0%	0%	30%	0%	0%	0%	0%
Conv Gas/Oil Comb Cycle	0%	30%	0%	40%	0%	0%	0%	0%	30%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	0%	30%	40%	0%	0%	0%	0%	30%	0%
Adv CC with carbon sequestration	0%	0%	20%	25%	0%	40%	0%	0%	15%	0%
Conv Comb Turbine	0%	50%	0%	0%	0%	0%	0%	50%	0%	0%
Adv Comb Turbine	0%	0%	50%	0%	0%	0%	0%	50%	0%	0%
Biomass	50%	0%	0%	0%	0%	0%	0%	0%	0%	50%

Note: All unlisted technologies have a 100 percent weight with the corresponding component. Components are not broken out for all technologies unless there is overlap with other technologies.
HRSG = Heat Recovery Steam Generator.
Source: Market-Based Advanced Coal Power Systems, May 1999, DOE/FE-0400.

Table 8.5. Component capacity weights for new technologies

Technology	Pulverized Coal	Combustion Turbine-conventional	Combustion Turbine-advanced	HRSG	Gasifier	Carbon Capture/ Sequestration	Balance of Plant-IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuel Prep Biomass
Integrated Coal-Gasification Comb Cycle (IGCC)	0%	0%	67%	33%	100%	0%	100%	0%	0%	0%
Pulverized Coal with Carbon sequestration	100%	0%	0%	0%	0%	100%	0%	0%	0%	0%
Conv Gas/Oil Comb Cycle	0%	67%	0%	33%	0%	0%	0%	0%	100%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	0%	67%	33%	0%	0%	0%	0%	100%	0%
Adv CC with carbon sequestration	0%	0%	67%	33%	0%	100%	0%	0%	100%	0%
Conv Comb Turbine	0%	100%	0%	0%	0%	0%	0%	100%	0%	0%
Adv Comb Turbine	0%	0%	100%	0%	0%	0%	0%	100%	0%	0%
Biomass	50%	0%	0%	0%	0%	0%	0%	0%	0%	100%

HRSG = Heat Recovery Steam Generator.
Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis.

Distributed generation

Distributed generation is modeled in the end-use sectors (as described in the appropriate chapters) as well as in the EMM. This section describes the representation of distributed generation in the EMM only. Two generic distributed technologies are modeled. The first technology represents peaking capacity (capacity that has relatively high operating costs and is operated when demand levels are at their highest). The second generic technology for distributed generation represents base load capacity (capacity that is operated on a continuous basis under a variety of demand levels). See Table 8.2 for costs and performance assumptions. It is assumed that these plants reduce the costs of transmission upgrades that would otherwise be needed.

Demand storage

The electricity model includes the option to build a new demand storage technology to simulate load shifting, through programs such as smart meters. This is modeled as a new technology build, but with operating characteristics similar to pumped storage. The technology is able to decrease the load in peak slices, but must generate to replace that demand in other time slices. There is an input factor that identifies the amount of replacement generation needed, where a factor of less than 1.0 can be used to represent peak shaving rather than purely shifting the load to other time periods. This plant type is limited to operating only in the peak load slices, and for *AEO2013*, it is assumed that this capacity is limited to 3.5 percent of peak demand on average in 2040, with limits varying from 2.2 percent to 6.8 percent of peak across the regions.

Representation of electricity demand

The annual electricity demand projections from the NEMS demand modules are converted into load duration curves for each of the EMM regions (based on North American Electric Reliability Corporation regions and subregions) using historical hourly load data. The load duration curve in the EMM is made up of 9 time slices. First, the load data is split into three seasons (winter - December through March, summer - June through September, and fall/spring). Within each season the load data is sorted from high to low, and three load segments are created - a peak segment representing the top 1 percent of the load, and then two off-peak segments representing the next 49 percent and 50 percent, respectively. The seasons were defined to account for seasonal variation in supply availability.

Reserve margins—the percentage of capacity required in excess of peak demand needed for unforeseeable outages—are determined within the model through an iterative approach comparing the marginal cost of capacity and the cost of unserved energy. The target reserve margin is adjusted for each model cycle until the two costs converge. The resulting reserve margins from the *AEO2013* Reference case range from 8 to 21 percent.

Fossil fuel-fired and nuclear steam plant retirement

Fossil-fired steam plant retirements and nuclear retirements are calculated endogenously within the model. Generating units are assumed to retire when it is no longer economical to continue running them. Each year, the model determines whether the market price of electricity is sufficient to support the continued operation of existing plant generators. A generating unit is assumed to retire if the expected revenues from the generator are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, operations and maintenance costs and annual capital additions, which are unit-specific and based on historical data. The average capital additions for existing plants are $8 per kilowatt (kW) for oil and gas steam plants, $17 per kW for coal plants and $22 per kW for nuclear plants (in 2011 dollars). These costs are added to the estimated costs at existing plants regardless of their age. Beyond 30 years of age an additional $7 per kW capital charge for fossil plants, and $33 per kW charge for nuclear plants is included in the retirement decision to reflect further investment to address the impacts of aging. Age-related cost increases are attributed to capital expenditures for major repairs or retrofits, decreases in plant performance, and/or increases in maintenance costs to mitigate the effects of aging.

EIA assumes all retirements reported as planned during the next ten years on the Form EIA-860 will occur. Additionally, the *AEO2013* nuclear projection assumes an additional 6.5 gigawatts of nuclear capacity retirements by 2040 based on the uncertainty related to resolving issues associated with long-term operations and aging management.

Biomass co-firing

Coal-fired power plants are assumed to co-fire with biomass fuel if it is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. This expenditure is assumed to be $280 per kW of biomass capacity. A coal-fired unit modified to allow co-firing can generate up to 15 percent of the total output using biomass fuel, assuming sufficient residue supplies are available.

Nuclear uprates

The *AEO2013* nuclear power projection assumes capacity increases at existing units. Nuclear plant operators can increase the rated capacity at plants through power uprates, which are license amendments that must be approved by the U.S. Nuclear Regulatory Commission (NRC). Uprates can vary from small (less than 2 percent) increases in capacity, which require very little capital investment or plant modification, to extended uprates of 15-20 percent, requiring significant modifications. Historically, most uprates were small, and the AEO projections accounted for them only after they were implemented and reported, but recent surveys by the NRC and EIA have indicated that more extended power uprates are expected in the near future. *AEO2013* assumes that all of those uprates reported to EIA as planned modifications on the Form EIA-860 will take place, representing 1.5 gigawatts of additional capacity. EIA also assumes an additional 6.5 gigawatts of nuclear power uprates will be completed over the projection period, based on interactions with industry stakeholders and the NRC. Table 8.6 provides a summary of projected uprate capacity additions by region.

Table 8.6. Nuclear uprates by EMM region
gigawatts

Texas Reliability Entity	0.25
Florida Reliability Coordinating Council	1.12
Midwest Reliability Council - East	0.00
Midwest Reliability Council - West	0.55
Northeast Power Coordinating Council/New England	0.25
Northeast Power Coordinating Council/NYC-Westchester	0.00
Northeast Power Coordinating Council/Long Island	0.00
Northeast Power Coordinating Council/Upstate	0.50
Reliability*First* Corporation/East	0.82
Reliability*First* Corporation/Michigan	0.25
Reliability*First* Corporation/West	0.99
SERC Reliability Corporation/Delta	0.43
SERC Reliability Corporation/Gateway	0.00
SERC Reliability Corporation/Southeastern	0.25
SERC Reliability Corporation/Central	0.75
SERC Reliability Corporation/Virginia-Carolina	1.06
Southwest Power Pool/North	0.00
Southwest Power Pool/South	0.00
Western Electricity Coordinating Council/Southwest	0.25
Western Electricity Coordinating Council/California	0.55
Western Electricity Coordinating Council/Northwest Power Pool Area	0.00
Western Electricity Coordinating Council/Rockies	0.00
Total	8.02

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis, based on Nuclear Regulatory Commission survey www.nrc.gov/reactors/operating/licensing/power-updates.html.

Interregional electricity trade

Both firm and economy electricity transactions among utilities in different regions are represented within the EMM. In general, firm power transactions involve the trading of capacity and energy to help another region satisfy its reserve margin requirement, while economy transactions involve energy transactions motivated by the marginal generation costs of different regions. The flow of power from region to region is constrained by the existing and planned capacity limits as reported in the North American Electric Reliability Corporation and Western Electricity Coordinating Council Summer and Winter Assessment of Reliability of Bulk Electricity Supply in North America. Known firm power contracts are obtained from NERC's Electricity Supply and Demand Database 2007 and information provided in the 2012 Summer and Winter Assessments. They are locked in for the term of the contract. Contracts that are scheduled to expire by 2016 are assumed not to be renewed. Because there is no information available about expiration dates for contracts that go beyond 2016, they are assumed to be phased out by 2025. The EMM includes an option to add interregional transmission capacity. In some cases it may be more economic to build generating capacity in a neighboring region, but additional costs to expand the transmission grid will be incurred as well. Explicitly expanding the interregional transmission capacity may also make the transmission line available for additional economy trade.

Economy transactions are determined in the dispatching submodule by comparing the marginal generating costs of adjacent regions in each time slice. If one region has less expensive generating resources available in a given time period (adjusting for transmission losses and transmission capacity limits) than another region, the regions are assumed to exchange power.

International electricity trade

Two components of international firm power trade are represented in the EMM—existing and planned transactions, and unplanned transactions. Data on existing and planned transactions are obtained from the North American Electric Reliability Corporation's Electricity Supply and Demand Database 2007. Unplanned firm power trade is represented by competing Canadian supply with U.S. domestic supply options. Canadian supply is represented via supply curves using cost data from the Department of Energy report, "Northern Lights: The Economic and Practical Potential of Imported Power from Canada," (DOE/PE-0079). International economy trade is determined endogenously based on surplus energy expected to be available from Canada by region in each time slice. Canadian surplus energy is determined using Canadian electricity supply and demand projections from the MAPLE-C model developed for Natural Resources Canada.

Electricity pricing

Electricity pricing is projected for 22 electricity market regions in *AEO2013* for fully competitive, partially competitive and fully regulated supply regions. The price of electricity to the consumer comprises the price of generation, transmission, and distribution, including applicable taxes. Transmission and distribution are considered to remain regulated in the AEO; that is, the price of transmission and distribution is based on the average cost to build, operate and maintain these systems. In competitive regions, an algorithm allows customers to compete for better rates among rate classes as long as the overall average cost is met. The price of electricity in the regulated regions consists of the average cost of generation, transmission, and distribution for each customer class. In the competitive regions, the generation component of price is based on marginal cost, which is defined as the cost of the last (or most expensive) unit dispatched. The competitive generation price includes the marginal cost (fuel and variable operations and maintenance costs), taxes, and a reliability price adjustment, which represents what customers are willing to pay for added capacity to avoid outages in periods of high demand. For the *AEO2013*, the difference between EIA's reliability costs and the historical Independent System Operator capacity, ancillary service, and uplift charges was added to the competitive generation price. The price of electricity in the regions with a competitive generation market consists of the competitive cost of generation summed with the average costs of transmission and distribution. The price for mixed regions reflects a load-weighted average of the competitive price and the regulated price, based on the percent of electricity load in the region subject to deregulation. In competitively supplied regions, a transition period is assumed to occur (usually over a ten-year period) from the effective date of restructuring, with a gradual shift to marginal cost pricing.

The Reference case assumes a transition to full competitive pricing in the three New York regions and in the Reliability*First* Corporation/ East region, and a 97-percent transition to competitive pricing in New England (Vermont being the only fully-regulated state in that region). Six regions fully regulate their electricity supply, including the Florida Reliability Coordinating Council, three of the SERC Reliability Corporation subregions - Southeastern (SRSE), Central (SRCE) and Virginia-Carolina (SRVC) - Southwest Power Pool Regional Entity/North (SPNO), and the Western Electricity Coordinating Council / Rockies (RMPA). The Texas Reliability Entity, which in the past was considered fully competitive by 2010, is now only 88-percent competitive, since many cooperatives have declined to become competitive or allow competitive energy to be sold to their customers. California returned to almost fully regulated pricing in 2002, after beginning a transition to competition in 1998, with only 7 percent competitive supply sold currently in the Western Electricity Coordinating Council (WECC)/ California region. All other regions reflect a mix of both competitive and regulated prices.

There have been ongoing changes to pricing structures for ratepayers in competitive states since the inception of retail competition. The AEO has incorporated these changes as they have been incorporated into utility tariffs. These have included transition period rate reductions and freezes instituted by various states, and surcharges in California relating to the 2000-2001 energy crisis in the state. Since price freezes for most customers have ended or will end in the next year or two, a large survey of utility tariffs found that many costs related to the transition to competition were now explicitly added to the distribution portion, and sometimes the transmission portion of the customer bill, regardless of whether or not the customer bought generation service from a competitive or regulated supplier. There are some unexpected costs relating to unforeseen events. For instance, as a result of volatile fuel markets, state regulators have had a hard time enticing retail suppliers to offer competitive supply to residential and smaller commercial and industrial customers. They have often resorted to procuring the energy themselves through auction or competitive bids or have allowed distribution utilities to procure the energy on the open market for their customers for a fee.

For *AEO2013*, typical charges that all customers must pay on the distribution portion of their bill (depending on where they reside) include: transition charges (including persistent stranded costs), public benefits charges (usually for efficiency and renewable energy programs), administrative costs of energy procurement, and nuclear decommissioning costs. Costs added to the transmission portion of the bill include the Federally Mandated Congestion Charges (FMCC), a bill pass-through associated with the Federal Energy Regulatory Commission passage of Standard Market Design (SMD) to enhance reliability of the transmission grid and control congestion. Additional costs not included in historical data sets have been added in adjustment factors to the transmission and distribution operations and maintenance costs, which impact the cost of both competitive and regulated electricity supply. Since most of these costs, such as transition costs, are temporary in nature, they are gradually phased out throughout the projection. Regions found to have these added costs include the Northeast Power Coordinating Council/ New England and New York regions, the Reliability*First* Corporation/ East and West regions, and the WECC/ California region.

Fuel price expectations

Capacity planning decisions in the EMM are based on a life cycle cost analysis over a 30-year period. This requires foresight assumptions for fuel prices. Expected prices for coal, natural gas and oil are derived using rational expectations, or 'perfect foresight.' In this approach, expectations for future years are defined by the realized solution values for these years in a prior run. The expectations for the world oil price and natural gas wellhead price are set using the resulting prices from a prior run. The markups to the delivered fuel prices are calculated based on the markups from the previous year within a NEMS run. Coal prices are determined using the same coal supply curves developed in the Coal Market Module. The supply curves produce prices at different levels of coal production, as a function of labor productivity, and costs and utilization of mines. Expectations for each supply curve are developed in the EMM based on the actual demand changes from the prior run throughout the projection horizon, resulting in updated mining utilization and different supply curves.

The perfect foresight approach generates an internally consistent scenario for which the formation of expectations is consistent with the projections realized in the model. The NEMS model involves iterative cycling of runs until the expected values and realized values for variables converge between cycles.

Nuclear fuel prices

Nuclear fuel prices are calculated through an offline analysis which determines the delivered price to generators in mills per kilowatthour. To produce reactor grade uranium, the uranium (U_3O_8) must first be mined, and then sent through a conversion process to prepare for enrichment. The enrichment process takes the fuel to a given purity of U-235, typically 3-5 percent for commercial reactors in the United States. Finally, the fabrication process prepares the enriched uranium for use in a specific type of reactor core. The price of each of the processes is determined, and the prices are summed to get the final price of the delivered fuel. The one mill per kilowatthour charge that is assessed on nuclear generation to go to the DOE's Nuclear Waste Fund is also included in the final nuclear price. The analysis uses forecasts from Energy Resources International for the underlying uranium prices.

Legislation and regulations

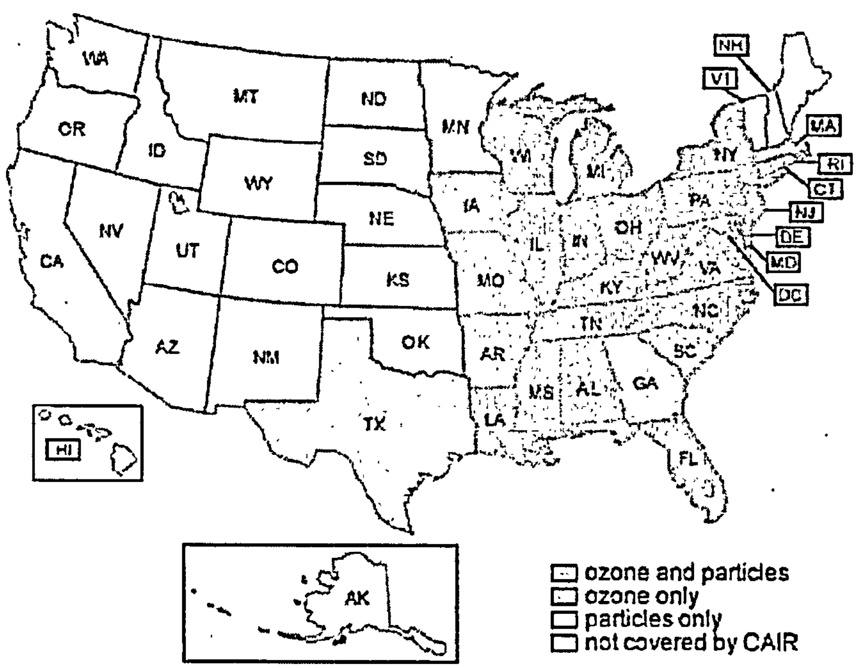
Clean Air Act Amendments of 1990 (CAAA90) and Clean Air Interstate Rule (CAIR)

Currently, regulation of SO_2 and NO_x emissions is administered under the Clean Air Interstate Rule (CAIR), and the *AEO2013* assumes that CAIR remains a binding regulation throughout the projection period. CAIR was initially promulgated in 2005, but has been challenged in court several times. The Cross-State Air Pollution Rule (CSAPR) was released by EPA in July 2011 and was intended to replace CAIR, but it was vacated by the U.S. Court of Appeals for the District of Columbia Circuit, and CAIR was reinstated.

CAIR covers all fossil fueled power plants greater than 25 megawatts in 27 states and the District of Columbia. There are annual emissions caps for SO_2 and NO_X and different states fall under each cap, as shown in the map in Figure 7, although all are in the eastern half of the United States. The caps for SO_2 and NO_X were set to allow states to achieve their National Ambient Air Quality Standards (NAAQS) for particulate matter (impacted by SO_2 levels) and ground level ozone (impacted by NO_X). Allowances can be traded amongst all participants in the CAAA90 Title IV program, not just those in CAIR states, however allowances are traded at a discount in non-CAIR states. *AEO2013* represents emissions trading in both the CAIR and non-CAIR regions, as specified by the regulation, and includes banking of allowances consistent with CAIR's provisions.

As specified in the CAAA90, EPA developed a two-phase nitrogen oxide (NOx) program, with the first set of standards for existing coal plants applied in 1996 while the second set was implemented in 2000. Dry bottom wall-fired, and tangential-fired boilers, the most common boiler types, referred to as Group 1 Boilers, were required to make significant reductions beginning in 1996 and further reductions in 2000. Relative to their uncontrolled emission rates, which range roughly between 0.6 and 1.0 pounds per million Btu, they are required to make reductions between 25 and 50 percent to meet the Phase I limits and further reductions to meet the Phase II limits. The EPA did not impose limits on existing oil and gas plants, but some states have instituted additional NOx regulations. All new fossil units are required to meet current standards. In pounds per million Btu, these limits are 0.11 for conventional coal, 0.02 for advanced coal, 0.02 for combined cycle, and 0.08 for combustion turbines. These NOx limits are incorporated in EMM.

Figure 7. States covered by the Clean Air Interstate Rule



Source: U.S. Environmental Protection Agency, Clean Air Interstate Rule—Where You Live (Washington, DC, July 31, 2012), website http://www.epa.gov/cair/where.html.

Sample costs of adding flue gas desulfurization equipment (FGD) to remove sulfur dioxide (SO2) and selective catalytic reduction (SCR) equipment to remove nitrogen oxides (NOx) are given below for 100, 300, 500, and 700-megawatt coal plants. In the EMM, plant-specific costs are calculated based on the size of the unit and other operating characteristics. FGD units are assumed to remove 95 percent of the SO_2, while SCR units are assumed to remove 90 percent of the NOx. The EMM also includes an option to install a dry sorbent injection (DSI) system, which is assumed to remove 70 percent of the SO_2. However, the DSI option is only available under the mercury and air toxics rule discussed in the next section, as its primary benefit is for reducing hydrogen chloride (HCl). The costs per megawatt of capacity decline with plant size and are shown in Table 8.7.

Table 8.7. Coal plant retrofit costs
2011 dollars

Coal Plant Size (MW)	FGD Capital Costs ($/kW)	SCR Capital Costs ($/kW)	DSI Capital Costs ($/kW)
100	695	280	128
300	538	213	58
500	454	191	41
700	395	179	32

Documentation for EPA Base Case v4.10 using the Integrated Planning Model, August 2010, EPA Contract EP-W-08-018.

Mercury regulation

The Mercury and Air Toxics Standards (MATS) were finalized in December 2011 to fulfill EPA's requirement to regulate mercury emissions from power plants. MATS also regulates other hazardous air pollutants (HAPS) such as hydrogen chloride (HCl) and fine particulate matter (PM2.5). MATS applies to coal- and oil-fired power plants with a nameplate capacity greater than 25 megawatts. The standards are scheduled to take effect in 2015, but allow for a one year waiver to comply, and require that all qualifying units achieve the maximum achievable control technology (MACT) for each of the three covered pollutants. For *AEO2013*, EIA assumes that all coal-fired generating units with a capacity greater than 25 megawatts will comply with the rule beginning in 2016, due to the large number of plants requesting the one year extension. All power plants are required to reduce their mercury emissions to 90 percent below their uncontrolled emissions levels.

Because the EMM does not explicitly model HCl or PM2.5, specific control technologies are assumed to be used to achieve compliance. In order to meet the HCl requirement, units must have either flue gas desulfurization (FGD) scrubbers or dry sorbent injection (DSI) systems in order to continue operating. A full fabric filter is also required to meet the PM2.5 limits and to improve the effectiveness of the DSI technology. When plants alter their configuration by adding equipment such as an SCR to remove NOx or an SO_2 scrubber, removal of mercury is often a resulting cobenefit. The EMM considers all combinations of controls and may choose to add NO_X or SO_2 controls purely to lower mercury if it is economic to do so. Plants can also add activated carbon injection systems specifically designed to remove mercury. Activated carbon can be injected in front of existing particulate control devices or a supplemental fabric filter can be added with activated carbon injection capability.

The equipment to inject activated carbon in front of an existing particulate control device is assumed to cost approximately $6 (2011 dollars) per kilowatt of capacity, while the cost of a supplemental fabric filter with activated carbon injection (often referred as a COPAC unit) is approximately $153 (2011 dollars) per kilowatt of capacity [2]. The amount of activated carbon required to meet a given percentage removal target is given by the following equations [3].

For a unit with a cold side electrostatic precipitator (CSE), using subbituminous coal, and simple activated carbon injection:

- Hg Removal (%) = 65 - (65.286 / (ACI + 1.026))

For a unit with a CSE, using bituminous coal, and simple activated carbon injection:

- Hg Removal (%) = 100 - (469.379 / (ACI + 7.169))

For a unit with a CSE, and a supplemental fabric filter with activated carbon injection:

- Hg Removal (%) = 100 - (28.049 / (ACI + 0.428))

For a unit with a hot side electrostatic precipitator (HSE) or other particulate control, and a supplemental fabric filter with activated carbon injection:

- Hg Removal (%) = 100 - (43.068 / (ACI + 0.421))

ACI = activated carbon injection rate in pounds per million actual cubic feet of flue gas.

Power plant mercury emissions assumptions

The EMM represents 35 coal plant configurations and assigns a mercury emissions modification factor (EMF) to each configuration. Each configuration represents different combinations of boiler types, particulate control devices, sulfur dioxide (SO_2) control devices, nitrogen oxide (NOx) control devices, and mercury control devices. An EMF represents the amount of mercury that was in the fuel that remains after passing through all the plant's systems. For example, an EMF of 0.60 means that 40 percent of the mercury that was in the fuel is removed by various parts of the plant. Table 8.8 provides the assumed EMFs for existing coal plant configurations without mercury-specific controls..

Table 8.8. Mercury emission modification factors

Configuration			EIA EMFs			EPA EMFs		
SO_2 Control	Particulate Control	NOx Control	Bit Coal	Sub Coal	Lignite Coal	Bit Coal	Sub Coal	Lignite Coal
None	BH	–	0.11	0.27	0.27	0.11	0.26	1.00
Wet	BH	None	0.05	0.27	0.27	0.03	0.27	1.00
Wet	BH	SCR	0.10	0.27	0.27	0.10	0.15	0.56
Dry	BH	–	0.05	0.75	0.75	0.50	0.75	1.00
None	CSE	–	0.64	0.97	0.97	0.64	0.97	1.00
Wet	CSE	None	0.34	0.73	0.73	0.34	0.84	0.56
Wet	CSE	SCR	0.10	0.73	0.73	0.10	0.34	0.56
Dry	CSE	–	0.64	0.65	0.65	0.64	0.65	1.00
None	HSE/Oth	–	0.90	0.94	0.94	0.90	0.94	1.00
Wet	HSE/Oth	None	0.58	0.80	0.80	0.58	0.80	1.00
Wet	HSE/Oth	SCR	0.42	0.76	0.76	0.10	0.75	1.00
Dry	HSE/Oth	–	0.60	0.85	0.85	0.60	0.85	1.00

Notes: SO_2 Controls - Wet = Wet Scrubber and Dry = Dry Scrubber, Particulate Controls, BH - fabric filter/baghouse. CSE = cold side electrostatic precipitator, HSE = hot side electrostatic precipitator, NO_x Controls, SCR = selective catalytic reduction,
— = not applicable, Bit = bituminous coal, Sub = subbituminous coal. The NO_x control system is not assumed to enhance mercury removal unless a wet scrubber is present, so it is left blank in such configurations. Sources: EPA, EMFs. www.epa.gov/clearskies/technical.html. EIA EMFs not from EPA: Lignite EMFs, Mercury Control Technologies for Coal-Fired Power Plants, presented by the Office of Fossil Energy on July 8, 2003. Bituminous coal mercury removal for a Wet/HSE/Oth/SCR configured plant, Table EMF1, Analysis of Mercury Control Cost and Performance, Office of Fossil Energy & National Energy Technology Laboratory, U.S. Department of Energy, January 2003, Washington, DC.

Planned SO_2 Scrubber and NO_x control equipment additions

EIA assumes that all planned retrofits, as reported on the Form EIA-860, will occur as currently scheduled. For *AEO2013*, this includes 17.7 gigawatts of planned SO_2 scrubbers (Table 8.9) and 9.5 gigawatts of planned selective catalytic reduction (SCR).

Carbon capture and sequestration retrofits

Although a Federal greenhouse gas program is not assumed in the *AEO2013* Reference case, the EMM includes the option of retrofitting existing coal plants for carbon capture and sequestration (CCS). This option is important when considering alternate scenarios that do constrain carbon emissions. The modeling structure for CCS retrofits within the EMM was developed by the National Energy Technology Laboratory[4] and uses a generic model of retrofit costs as a function of basic plant characteristics (such as heatrate). The costs have been adjusted to be consistent with costs of new CCS technologies. The CCS retrofits are assumed to remove 90 percent of the carbon input. The addition of the CCS equipment results in a capacity derate of around 30 percent and reduced efficiency of 43 percent at the existing coal plant. The costs depend on the size and efficiency of the plant, with the capital costs ranging from $1,250 to $1,650 per kilowatt. It was assumed that only plants greater than 500 megawatts and with heat rates below 12,000 BTU per kilowatthour would be considered for CCS retrofits.

State air emissions regulation

AEO2013 continues to model the Northeast Regional Greenhouse Gas Initiative (RGGI), which applies to fossil-fuel powered plants over 25 megawatts in the Northeastern United States. The State of New Jersey withdrew from the program at the end of 2011, leaving nine states in the accord. The rule caps CO_2 emissions from covered electricity generating facilities and requires that they account for each ton of CO_2 emitted with an allowance purchased at auction. Because the baseline and projected emissions were calculated before the economic recession that began in 2008, the actual emissions in the first years of the program have been less than the cap, leading to excess allowances and allowance prices at the floor price.

The California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006, authorized the California Air Resources Board (CARB) to set California's GHG reduction goals for 2020 and establish a comprehensive, multi-year program to reduce GHG emissions in California. As one of the major initiatives for AB 32, CARB designed a cap-and-trade program that started on January 1, 2012, with the enforceable compliance obligations beginning in 2013 for the electric power sector and industrial facilities. Fuel providers must comply starting in 2015. The AB32 cap-and-trade provisions are incorporated in *AEO2013* through an emission constraint in the EMM that also accounts for the emissions determined by the other sectors. An allowance price is calculated and added to fuel prices for the affected sectors. Limited banking and borrowing of allowances as well as an allowance reserve and offsets have been modeled, as specified in the Bill, providing some compliance flexibility and cost containment.

Table 8.9. Planned SO_2 scrubber additions by EMM region
gigawatts

Texas Reliability Entity	0.0
Florida Reliability Coordinating Council	0.0
Midwest Reliability Council - East	0.0
Midwest Reliability Council - West	1.2
Northeast Power Coordinating Council/New England	0.5
Northeast Power Coordinating Council/NYC-Westchester	0.0
Northeast Power Coordinating Council/Long Island	0.0
Northeast Power Coordinating Council/Upstate	1.0
Reliability*First* Corporation/East	0.0
Reliability*First* Corporation/Michigan	1.4
Reliability*First* Corporation/West	6.1
SERC Reliability Corporation/Delta	0.0
SERC Reliability Corporation/Gateway	3.0
SERC Reliability Corporation/Southeastern	2.5
SERC Reliability Corporation/Central	0.2
SERC Reliability Corporation/Virginia-Carolina	0.0
Southwest Power Pool/North	1.4
Southwest Power Pool/South	0.0
Western Electricity Coordinating Council/Southwest	0.4
Western Electricity Coordinating Council/California	0.0
Western Electricity Coordinating Council/Northwest Power Pool Area	0.0
Western Electricity Coordinating Council/Rockies	0.0
Total	17.7

Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Energy Policy Acts of 1992 (EPACT92) and 2005 (EPACT05)

The provisions of the EPACT92 include revised licensing procedures for nuclear plants and the creation of exempt wholesale generators (EWGs). The EPACT05 provides a 20-percent investment tax credit for Integrated Coal-Gasification Combined Cycle capacity and a 15-percent investment tax credit for other advanced coal technologies. These credits are limited to 3 gigawatts in both cases. It also contains a production tax credit (PTC) of 1.8 cents (nominal) per kilowatthour for new nuclear capacity beginning operation by 2020. This PTC is specified for the first 8 years of operation, is limited to $125 million annually, and is limited to 6 gigawatts of new capacity. However, this credit may be shared to additional units if more than 6 gigawatts are under construction by January 1, 2014. EPACT05 extended the PTC for qualifying renewable facilities by 2 years, or December 31, 2007. It also repealed the Public Utility Holding Company Act (PUHCA).

Energy Improvement and Extension Act 2008 (EIEA2008)

EIEA2008 extended the investment tax credit of 30 percent through 2016 for solar and fuel cell facilities.

American Recovery and Reinvestment Act (ARRA)

Updated tax credits for Renewables

ARRA extended the expiration date for the PTC to January 1, 2013, for wind and January 1, 2014, for all other eligible renewable resources. In addition, ARRA allows companies to choose an investment tax credit (ITC) of 30 percent in lieu of the PTC and allows for a grant in lieu of this credit to be funded by the U.S. Treasury. For some technologies, such as wind, the full PTC would appear to be more valuable than the 30 percent ITC; however, the difference can be small. Qualitative factors, such as the lack of partners with sufficient tax liability, may cause companies to favor the ITC grant option. *AEO2013* generally assumes that renewable electricity projects will claim the more favorable tax credit or grant option available to them.

Loan guarantees for renewables

ARRA provided $6 billion to pay the cost of guarantees for loans authorized by the Energy Policy Act of 2005. While most renewable projects which started construction prior to September 30, 2011 are potentially eligible for these loan guarantees, the application and approval of guarantees for specific projects is a highly discretionary process, and has thus far been limited. While *AEO2013* includes projects that have received loan guarantees under this authority, it does not assume automatic award of the loans to potentially eligible technologies.

Support for CCS

ARRA provided $3.4 billion for additional research and development on fossil energy technologies. A portion of this funding is expected to be used to fund projects under the Clean Coal Power Initiative program, focusing on projects that capture and sequester greenhouse gases. To reflect the impact of this provision, *AEO2013* Reference case assumes that an additional 1 gigawatt of coal capacity with CCS will be stimulated by 2018.

Smart grid expenditures

ARRA provides $4.5 billion for smart grid demonstration projects. While somewhat difficult to define, smart grid technologies generally include a wide array of measurement, communications, and control equipment employed throughout the transmission and distribution system that will enable real-time monitoring of the production, flow, and use of power from the generator to the consumer. Among other things, these smart grid technologies are expected to enable more efficient use of the transmission and distribution grid, lower line losses, facilitate greater use of renewables, and provide information to utilities and their customers that will lead to greater investment in energy efficiency and reduced peak load demands. The funds provided will not fund a widespread implementation of smart grid technologies, but could stimulate more rapid investment than would otherwise occur.

Several changes were made throughout the NEMS to represent the impacts of the smart grid funding provided in ARRA. In the electricity module, it was assumed that line losses would fall slightly, peak loads would fall as customers shifted their usage patterns, and customers would be more responsive to pricing signals. Historically, line losses, expressed as the percentage of electricity lost, have been falling for many years as utilities make investments to replace aging or failing equipment.

Smart grid technologies also have the potential to reduce peak demand through the increased deployment of demand response programs. In *AEO2013*, it is assumed that the Federal expenditures on smart grid technologies will stimulate efforts that reduce peak demand from what they otherwise would be, with the amount of total peak load reduction growing from 2.2 percent initially to 3.5 percent by 2040, although the shifts vary by region. Load is shifted to offpeak hours, so net energy consumed remains largely constant.

FERC Orders 888 and 889

FERC issued two related rules (Orders 888 and 889) designed to bring low-cost power to consumers through competition, ensure continued reliability in the industry, and provide for open and equitable transmission services by owners of these facilities. Specifically, Order 888 requires open access to the transmission grid currently owned and operated by utilities. The transmission owners must file nondiscriminatory tariffs that offer other suppliers the same services that the owners provide for themselves. Order 888 also allows these utilities to recover stranded costs (investments in generating assets that are unrecoverable due to consumers selecting another supplier). Order 889 requires utilities to implement standards of conduct and an Open Access Same-Time Information System (OASIS) through which utilities and non-utilities can receive information regarding the transmission system. As a result, utilities have functionally or physically unbundled their marketing functions from their transmission functions.

These orders are represented in EMM by assuming that all generators in a given region are able to satisfy load requirements anywhere within the region. Similarly, it is assumed that transactions between regions will occur if the cost differentials between them make such transactions economical.

Electricity alternative cases

Nuclear Alternative cases

For *AEO2013*, three alternate cases were run for nuclear power plants to address uncertainties about the operating lives of existing reactors, the potential for new nuclear capacity, and capacity uprates at existing plants. These scenarios are discussed in the Issues in Focus article, "Nuclear Power in *AEO2013*" in the full *AEO2013* report.

- The Low Nuclear case assumes that all existing reactors will not receive a second license renewal and are retired within 60 years of operation. The reported retirement at Oyster Creek occurs as currently planned, at the end of 2019. Kewaunee is also retired in this case, at the end of 2014, based on an announcement by Dominion Resources in late 2012. Additionally, two units that are currently out of service are assumed to be permanently shut down in the Low Nuclear case. San Onofre 2 and Crystal River 3 are not currently operating, but are assumed to be returned to service in 2015 in the Reference case. In the Low Nuclear Case both units are assumed to retire in 2013. In the Reference case, existing plants are assumed to run as long as they continue to be economic, implicitly assuming that a second 20-year license renewal will be obtained for most plants reaching 60 years of age before 2040. The Low Nuclear case was run to analyze the impact of additional nuclear retirements, which could occur if the oldest plants do not receive a second license extension. In this case, 45 gigawatts of nuclear capacity are assumed to be retired by 2040. This case assumes that no new nuclear capacity will be added throughout the projection, excluding the capacity already planned and under construction. The case also assumes that only those capacity uprates reported to EIA will be completed. In contrast, the Reference case assumes additional uprates based on Nuclear Regulatory Commission (NRC) surveys and industry reports.
- The High Nuclear case assumes that all existing nuclear units will receive a second license renewal and operate beyond 60 years (excluding one announced retirement). In the Reference case, beyond the announced retirement of Oyster Creek, an additional 6.5 gigawatts of nuclear capacity is assumed to be retired through 2040, reflecting uncertainty surrounding future aging impacts and/or costs. This case was run to provide a more optimistic outlook where all licenses are renewed and all plants are assumed to find it economic to continue operating beyond 60 years. The High Nuclear case also assumes additional planned nuclear capacity is completed based on combined license (COL) applications with the NRC. The Reference case assumes 5.5 gigawatts of planned capacity are added, while the High Nuclear case includes 13.3 gigawatts of planned capacity additions.
- The Small Modular Reactor case assumes that new advanced nuclear plants built in the forecast will be based on a smaller modular design rather than the larger AP1000 design used in the Reference case. The overnight costs are assumed to be the same as in the Reference case, but the construction lead time is reduced from six years to three years for the smaller design. The fixed operating and maintenance costs are assumed to be higher for the smaller design. To account for the necessary time for design certification, the first available online date for the small reactors is assumed to be 2025.

Notes and sources

[1] Review of Power Plant Cost and Performance Assumptions for NEMS, Science Applications International Corporation, April 2013. The costs shown Table 8.2 and used for the *AEO2013* were based on a draft report provided in September 2012 and may vary slightly from the published final report.

[2] These costs were developed using the National Energy Technology Laboratory Mercury Control Performance and Cost Model, 1998.

[3] U.S. Department of Energy, Analysis of Mercury Control Cost and Performance, Office of Fossil Energy & National Energy Technology Laboratory, January 2003.

[4] Retrofitting Coal-Fired Power Plants for Carbon Dioxide Capture and Sequestration - Exploratory Testing of NEMS for Integrated Assessments, DOE/NETL-2008/1309, P.A. Geisbrecht, January 18, 2009.

Table 4. Regional cost adjustments for technologies modeled by NEMS by Electric Market Module (EMM) region [10,11]

EMM Region	PC	IGCC	PC w/CCS	Conv. CT	Adv. CT	Conv. CC	Adv. CC	Adv. CC w/CCS	Fuel Cell	Nuclear	Biomass	MSW	On-shore Wind	Off-shore Wind	Solar Thermal	Solar PV
1 (ERCT)	0.91	0.92	0.92	0.93	0.95	0.91	0.92	0.90	0.96	0.96	0.93	0.93	0.95	0.92	0.86	0.87
2 (FRCC)	0.92	0.93	0.94	0.93	0.93	0.91	0.92	0.92	0.97	0.97	0.94	0.94	N/A	N/A	0.89	0.90
3 (MROE)	1.01	1.01	0.99	0.99	1.01	0.99	0.99	0.97	0.99	1.01	0.99	0.98	0.99	0.97	N/A	0.96
4 (MROW)	0.95	0.96	0.96	0.98	1.00	0.97	0.97	0.96	0.98	0.98	0.96	0.96	1.03	1.01	N/A	0.95
5 (NEWE)	1.10	1.09	1.05	1.16	1.20	1.16	1.15	1.08	1.01	1.05	1.04	1.02	1.06	1.03	N/A	1.03
6 (NYCW)	N/A	N/A	N/A	1.63	1.68	1.68	1.66	1.50	1.14	N/A	1.26	1.26	N/A	1.29	N/A	N/A
7 (NYLI)	N/A	N/A	N/A	1.63	1.68	1.68	1.66	1.50	1.14	N/A	1.26	1.26	1.25	1.29	N/A	1.45
8 (NYUP)	1.11	1.10	1.05	1.17	1.22	1.16	1.16	1.06	1.00	1.07	1.03	1.00	1.01	0.99	N/A	0.98
9 (RFCE)	1.15	1.14	1.09	1.21	1.25	1.21	1.21	1.12	1.02	1.08	1.07	1.03	1.05	1.03	N/A	1.05
10 (RFCM)	0.98	0.98	0.98	1.01	1.02	1.00	1.00	0.99	0.99	0.99	0.98	0.98	1.00	0.98	N/A	0.97
11 (RFCW)	1.05	1.04	1.02	1.05	1.06	1.04	1.04	1.02	1.00	1.03	1.02	1.00	1.02	1.01	N/A	1.00
12 (SRDA)	0.92	0.93	0.93	0.95	0.96	0.93	0.93	0.92	0.97	0.96	0.93	0.94	0.96	1.00	N/A	0.89
13 (SRGW)	1.07	1.06	1.05	1.05	1.05	1.06	1.05	1.04	1.02	1.03	1.03	1.03	1.04	1.00	N/A	1.05
14 (SRSE)	0.92	0.93	0.93	0.95	0.97	0.93	0.94	0.92	0.97	0.96	0.93	0.94	0.96	0.93	N/A	0.89
15 (SRCE)	0.93	0.94	0.94	0.94	0.95	0.93	0.93	0.92	0.97	0.97	0.94	0.94	0.96	1.00	N/A	0.89
16 (SRVC)	0.89	0.91	0.91	0.91	0.93	0.88	0.89	0.88	0.96	0.95	0.91	0.91	0.95	0.92	N/A	0.84
17 (SPNO)	0.98	0.99	0.98	1.00	1.01	0.99	0.99	0.98	0.99	0.99	0.98	0.98	1.02	N/A	0.97	0.97
18 (SPSO)	0.98	0.99	0.98	1.00	1.01	0.99	0.99	0.98	0.99	0.99	0.98	0.98	1.02	N/A	0.97	0.97
19 (AZNM)	1.00	1.00	0.99	1.03	1.04	1.02	1.02	1.00	0.99	1.00	1.00	0.99	1.03	1.00	0.99	0.99
20 (CAMX)	N/A	N/A	1.12	1.24	1.29	1.25	1.24	1.15	1.03	N/A	1.08	1.06	1.12	1.05	1.13	1.11
21 (NWPP)	1.01	1.01	1.00	1.02	1.03	1.01	1.01	0.99	0.99	1.01	1.00	0.98	1.05	1.02	0.99	0.99
22 (RMPA)	0.99	0.99	0.97	1.02	1.05	1.01	1.01	0.96	0.98	1.01	0.97	0.95	1.03	N/A	0.93	0.93

Note: Geothermal and Hydroelectric plants are not included in the table because EIA uses site specific cost estimates for these technologies which include regional factors.

[10] U.S. Energy Information Administration, AEO 2012 EMM Assumptions document, Figure 6.
[11] The regional tables in the report were aggregated to the appropriate Electricity Market Module region in order to represent regional cost factors in NEMS.

Table A20. Macroeconomic Indicators
(billion 2005 chain-weighted dollars, unless otherwise noted)

Indicators	Reference case							Annual growth 2011-2040 (percent)
	2010	2011	2020	2025	2030	2035	2040	
Real gross domestic product	13,063	13,299	16,859	18,986	21,356	24,095	27,277	2.5%
Components of real gross domestic product								
Real consumption	9,196	9,429	11,528	12,792	14,243	15,941	17,917	2.2%
Real investment	1,658	1,744	2,909	3,363	3,914	4,582	5,409	4.0%
Real government spending	2,606	2,524	2,446	2,529	2,659	2,803	2,980	0.6%
Real exports	1,666	1,777	3,016	4,026	5,214	6,658	8,357	5.5%
Real imports	2,085	2,185	2,927	3,515	4,311	5,308	6,518	3.8%
Energy intensity **(thousand Btu per 2005 dollar of GDP)**								
Delivered energy	5.47	5.34	4.39	3.92	3.48	3.13	2.85	-2.1%
Total energy	7.53	7.35	5.99	5.39	4.81	4.33	3.95	-2.1%
Price indices								
GDP chain-type price index (2005=1.000)	1.110	1.134	1.307	1.429	1.564	1.713	1.871	1.7%
Consumer price index (1982-4=1.00)								
All-urban	2.18	2.25	2.66	2.94	3.27	3.63	4.04	2.0%
Energy commodities and services	2.12	2.44	2.70	3.09	3.53	4.11	4.86	2.4%
Wholesale price index (1982=1.00)								
All commodities	1.85	2.01	2.22	2.40	2.59	2.82	3.10	1.5%
Fuel and power	1.86	2.16	2.48	2.91	3.38	4.02	4.90	2.9%
Metals and metal products	2.08	2.26	2.52	2.66	2.83	2.99	3.16	1.2%
Industrial commodities excluding energy	1.83	1.93	2.12	2.23	2.34	2.45	2.57	1.0%
Interest rates (percent, nominal)								
Federal funds rate	0.17	0.10	4.04	4.09	3.97	3.84	3.74	--
10-year treasury note	3.21	2.79	4.88	4.97	4.95	4.91	4.86	--
AA utility bond rate	5.23	4.78	6.91	7.10	7.21	7.35	7.39	--
Value of shipments (billion 2005 dollars)								
Service sectors	20,771	21,168	26,492	29,715	32,624	35,511	38,529	2.1%
Total industrial	5,842	6,019	7,894	8,548	9,087	9,779	10,616	2.0%
Agriculture, mining, and construction	1,585	1,582	2,211	2,295	2,375	2,494	2,644	1.8%
Manufacturing	4,257	4,438	5,683	6,253	6,712	7,285	7,972	2.0%
Energy-intensive	1,592	1,615	1,893	1,993	2,027	2,077	2,144	1.0%
Non-energy-intensive	2,665	2,823	3,790	4,261	4,685	5,208	5,828	2.5%
Total shipments	26,613	27,187	34,386	38,264	41,711	45,289	49,145	2.1%
Population and employment (millions)								
Population, with armed forces overseas	310.1	312.4	340.5	356.5	372.4	388.3	404.4	0.9%
Population, aged 16 and over	244.6	247.0	269.5	282.8	296.3	309.8	322.9	0.9%
Population, over age 65	40.6	41.6	55.4	64.5	72.7	78.1	81.8	2.4%
Employment, nonfarm	129.8	131.3	149.2	153.7	160.8	166.7	174.0	1.0%
Employment, manufacturing	11.5	11.7	12.4	12.2	11.2	10.5	9.9	-0.6%
Key labor indicators								
Labor force (millions)	153.9	153.6	164.7	169.3	174.9	182.3	190.7	0.7%
Nonfarm labor productivity (1992=1.00)	1.09	1.10	1.25	1.39	1.54	1.70	1.88	1.9%
Unemployment rate (percent)	9.62	8.95	5.49	5.27	5.32	5.33	5.24	--
Key indicators for energy demand								
Real disposable personal income	10,017	10,150	12,655	14,259	15,948	17,752	19,785	2.3%
Housing starts (millions)	0.64	0.66	1.89	1.90	1.89	1.89	1.89	3.7%
Commercial floorspace (billion square feet)	81.1	81.7	89.1	93.9	98.1	103.0	108.8	1.0%
Unit sales of light-duty vehicles (millions)	11.55	12.73	16.85	17.16	17.74	18.20	19.21	1.4%

GDP = Gross domestic product.
Btu = British thermal unit.
- - = Not applicable.
Sources: 2010 and 2011: IHS Global Insight, Global Insight Industry and Employment models, August 2012. Projections: U.S. Energy Information Administration, AEO2013 National Energy Modeling System run REF2013.D102312A.

Independent Statistics & Analysis
U.S. Energy Information Administration

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Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013

This paper presents average levelized costs for generating technologies that are brought on line in 2018[1] as represented in the National Energy Modeling System (NEMS) for the *Annual Energy Outlook 2013* (AEO2013) Early Release Reference case.[2] Both national values and the minimum and maximum values across the 22 U.S. regions of the NEMS electricity market module are presented.

Levelized cost is often cited as a convenient summary measure of the overall competiveness of different generating technologies. It represents the per-kilowatthour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle. Key inputs to calculating levelized costs include overnight capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type.[3] The importance of the factors varies among the technologies. For technologies such as solar and wind generation that have no fuel costs and relatively small O&M costs, the levelized cost changes in rough proportion to the estimated overnight capital cost of generation capacity. For technologies with significant fuel cost, both fuel cost and overnight cost estimates significantly affect the levelized cost. The availability of various incentives, including state or federal tax credits, can also impact the calculation of levelized cost. The values shown in the tables in this discussion do not incorporate any such incentives.[4] As with any projection, there is uncertainty about all of these factors and their values can vary regionally and across time as technologies evolve and fuel prices change.

It is important to note that, while levelized costs are a convenient summary measure of the overall competiveness of different generating technologies, actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve numerous other considerations. The ***projected utilization rate***, which depends on the load shape and the existing resource mix in an area where additional capacity is needed, is one such factor. The ***existing resource mix*** in a region can directly affect the economic viability of a new investment through its effect on the economics surrounding the displacement of existing resources. For example, a wind resource that would primarily displace existing natural gas

[1] 2018 is shown because the long lead time needed for some technologies means that the plant could not be brought on line prior to 2018 unless it was already under construction.
[2] The full report is available at http://www.eia.gov/forecasts/aeo/er/index.cfm.
[3] The specific assumptions for each of these factors are given in the *Assumptions to the Annual Energy Outlook*, available at http://www.eia.doe.gov/olaf/aeo/index.html.
[4] These results do not include targeted tax credits such as the production or investment tax credit available for some technologies. Costs are estimated using tax depreciation schedules consistent with current law, which vary by technology.

generation will usually have a different value than one that would displace existing coal generation.

A related factor is the ***capacity value,*** which depends on both the existing capacity mix and load characteristics in a region. Since load must be balanced on a continuous basis, units whose output can be varied to follow demand (dispatchable technologies) generally have more value to a system than less flexible units (non-dispatchable technologies) or those whose operation is tied to the availability of an intermittent resource. The levelized costs for dispatchable and nondispatchable technologies are listed separately in the tables, because caution should be used when comparing them to one another.

Since projected utilization rates, the existing resource mix, and capacity values can all vary dramatically across regions where new generation capacity may be needed, the direct comparison of the levelized cost of electricity across technologies is often problematic and can be misleading as a method to assess the economic competitiveness of various generation alternatives. Conceptually, a better assessment of economic competitiveness can be gained through consideration of avoided cost, a measure of what it would cost the grid to generate the electricity that is otherwise displaced by a new generation project, as well as its levelized cost. Avoided cost, which provides a proxy measure for the annual economic value of a candidate project, may be summed over its financial life and converted to a stream of equal annual payments, which may then be divided by average annual output of the project to develop a figure that expresses the "levelized" avoided cost of the project. This levelized avoided cost may then be compared to the levelized cost of the candidate project to provide an indication of whether or not the project's value exceeds its cost. If multiple technologies are available to meet load, comparisons of each project's levelized avoided cost to its levelized project cost may be used to determine which project provides the best net economic value. Estimating avoided costs is more complex than for simple levelized costs, because they require tools to simulate the operation of the power system with and without any project under consideration. The economic decisions regarding capacity additions in EIA's long-term projections reflect these concepts rather than simple comparisons of levelized project costs across technologies.

Policy-related factors, such as investment or production tax credits for specified generation sources, can also impact investment decisions. Finally, although levelized cost calculations are generally made using an assumed set of capital and operating costs, the inherent uncertainty about future fuel prices and future policies, may cause plant owners or investors who finance plants to place a value on ***portfolio diversification.*** While EIA considers many of these factors in its analysis of technology choice in the electricity sector, these concepts are not well represented in the context of levelized cost figures.

The levelized cost shown for each utility-scale generation technology in the tables in this discussion are calculated based on a 30-year cost recovery period, using a real after tax weighted average cost of capital (WACC) of 6.6 percent. In reality, the cost recovery period and cost of capital can vary by technology and project type. In the AEO2013 reference case a 3-percentage point increase in the cost of capital is added when evaluating investments in greenhouse gas (GHG) intensive technologies like coal-fired power and coal-to-liquids (CTL) plants without carbon control and sequestration (CCS). While the 3-percentage point adjustment is somewhat arbitrary, in levelized cost terms its impact is similar to that of an emissions fee of $15 per metric ton of carbon dioxide (CO_2) when investing in a new coal plant without CCS, similar to the costs used by utilities and regulators in their resource planning. The adjustment should not be seen as an increase in the actual cost of financing, but rather as representing the implicit hurdle being added to GHG-intensive projects to account for the possibility they may eventually have to purchase allowances or invest in other GHG emission-reducing projects that offset their emissions. As a result, the levelized capital costs of coal-fired plants without CCS are higher than would otherwise be expected.

Some technologies, notably solar photovoltaic (PV), are used in both utility-scale plants and distributed end-use residential and commercial applications. As noted above, the levelized cost calculations presented in the tables apply only to utility-scale use of those technologies.

In the tables in this discussion, the levelized cost for each technology is evaluated based on the capacity factor indicated, which generally corresponds to the high end of its likely utilization range. Simple combustion turbines (conventional or advanced technology) that are typically used for peak load duty cycles are evaluated at a 30-percent capacity factor. The duty cycle for intermittent renewable resources, wind and solar, is not operator controlled, but dependent on the weather or solar cycle (that is, sunrise/sunset) and so will not necessarily correspond to operator dispatched duty cycles. As a result, their levelized costs are not directly comparable to those for other technologies (even where the average annual capacity factor may be similar) and therefore are shown in separate sections within each of the tables. The capacity factors shown for solar, wind, and hydroelectric resources in Table 1 are simple averages of the capacity factor for the marginal site in each region. These capacity factors can vary significantly by region and can represent resources that may or may not get built in EIA capacity projections. These capacity factors should not be interpreted as representing EIA's estimate or projection of the gross generating potential of resources actually projected to be built.

As mentioned above, the costs shown in Table 1 are national averages. However, as shown in Table 2, there is significant regional variation in levelized costs based on local labor markets and the cost and availability of fuel or energy resources such as windy sites. For example, levelized wind costs for incremental capacity coming on line in 2018 range from $73.5/MWh in the region with the best available resources in 2018 to $99.8/MWh in regions where levelized costs are highest due to lower quality wind resources and/or higher capital costs at the best sites where additional wind capacity could be added. Costs shown for wind may include additional costs associated with transmission upgrades needed to access remote resources, as well as other factors that markets may or may not internalize into the market price for wind power.

Table 1. Estimated levelized cost of new generation resources, 2018

Plant type	Capacity factor (%)	U.S. average levelized costs (2011 $/megawatthour) for plants entering service in 2018 Levelized capital cost	Fixed O&M	Variable O&M (including fuel)	Transmission investment	Total system levelized cost
Dispatchable Technologies						
Conventional Coal	85	65.7	4.1	29.2	1.2	100.1
Advanced Coal	85	84.4	6.8	30.7	1.2	123.0
Advanced Coal with CCS	85	88.4	8.8	37.2	1.2	135.5
Natural Gas-fired						
Conventional Combined Cycle	87	15.8	1.7	48.4	1.2	67.1
Advanced Combined Cycle	87	17.4	2.0	45.0	1.2	65.6
Advanced CC with CCS	87	34.0	4.1	54.1	1.2	93.4
Conventional Combustion Turbine	30	44.2	2.7	80.0	3.4	130.3
Advanced Combustion Turbine	30	30.4	2.6	68.2	3.4	104.6
Advanced Nuclear	90	83.4	11.6	12.3	1.1	108.4
Geothermal	92	76.2	12.0	0.0	1.4	89.6
Biomass	83	53.2	14.3	42.3	1.2	111.0
Non-Dispatchable Technologies						
Wind	34	70.3	13.1	0.0	3.2	86.6
Wind - Offshore	37	193.4	22.4	0.0	5.7	221.5
Solar PV[1]	25	130.4	9.9	0.0	4.0	144.3
Solar Thermal	20	214.2	41.4	0.0	5.9	261.5
Hydro[2]	52	78.1	4.1	6.1	2.0	90.3

[1] Costs are expressed in terms of net AC power available to the grid for the installed capacity.
[2] As modeled, hydro is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.
Note: These results do not include targeted tax credits such as the production or investment tax credit available for some technologies, which could significantly affect the levelized cost estimate. For example,new solar thermal and PV plants are eligible to receive a 30-percent investment tax credit on capital expenditures if placed in service before the end of 2016, and 10 percent thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive either: (1) a $22 per MWh ($11 per MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30-percent investment tax credit, if placed in service before the end of 2013 (or 2012, for wind only).
Source: U.S. Energy Information Administration, Annual Energy Outlook 2013,December 2012, DOE/EIA-0383(2012)

Table 2. Regional variation in levelized cost of new generation resources, 2018

Plant type	Range for total system levelized costs (2011 $/megawatthour) for plants entering service in 2018 Minimum	Average	Maximum
Dispatchable Technologies			
Conventional Coal	89.5	100.1	118.3
Advanced Coal	112.6	123.0	137.9
Advanced Coal with CCS	123.9	135.5	152.7
Natural Gas-fired			
Conventional Combined Cycle	62.5	67.1	78.2
Advanced Combined Cycle	60.0	65.6	76.1
Advanced CC with CCS	87.4	93.4	107.5
Conventional Combustion Turbine	104.0	130.3	149.8
Advanced Combustion Turbine	90.3	104.6	119.0
Advanced Nuclear	104.4	108.4	115.3
Geothermal	81.4	89.6	100.3
Biomass	98.0	111.0	130.8
Non-Dispatchable Technologies			
Wind	73.5	86.6	99.8
Wind - Offshore	183.0	221.5	294.7
Solar PV[1]	112.5	144.3	224.4
Solar Thermal	190.2	261.5	417.6
Hydro[2]	58.4	90.3	149.2

[1] Costs are expressed in terms of net AC power available to the grid for the installed capacity.
[2] As modeled, hydro is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.
Note: The levelized costs for non-dispatchable technologies are calculated based on the capacity factor for the marginal site modeled in each region, which can vary significantly by region. The capacity factor ranges for these technologies are as follows: Wind – 30% to 39%, Wind Offshore – 33% to 42%, Solar PV- 22% to 32%, Solar Thermal – 11% to 26%, and Hydro – 30% to 65%. The levelized costs are also affected by regional variations in construction labor rates and capital costs as well as resource availability.
Source: U.S. Energy Information Administration, Annual Energy Outlook 2013, December 2012, DOE/EIA-0383(2012)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

DIRECT TESTIMONY

OF

BION C. OSTRANDER

PUBLIC REDACTED VERSION

ON BEHALF OF

KENTUCKY OFFICE OF ATTORNEY GENERAL

FILED: October 28, 2013

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BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2013-00199

DIRECT TESTIMONY OF

BION C. OSTRANDER

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1. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bion C. Ostrander. My business address is 1121 S.W. Chetopa Trail, Topeka, KS 66615-1408.

Q. WHAT IS YOUR OCCUPATION?

A. I am President of Ostrander Consulting. I am an independent regulatory consultant and a Certified Public Accountant ("CPA") with a permit to practice in Kansas.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Kentucky Office of the Attorney General ("OAG") in this rate case proceeding regarding Big Rivers Electric

Corporation ("BREC") request for substantial rate relief. I will distinguish this BREC rate case from the prior BREC rate case by referring to this rate case as either "2013-00199" or "Sebree" and the prior rate case as either "2012-00535" or "Hawesville."[1]

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGOUND.

A. Please see Exhibit BCO-1 for more information regarding my professional experience and educational background. In summary, I am an independent regulatory consultant and a practicing CPA with a specialization in regulatory issues. I have over thirty-three years of regulatory and accounting experience. I have addressed many regulatory issues in numerous state jurisdictions and on an international basis.

I started my consulting practice in 1990, Ostrander Consulting, after leaving the Kansas Corporation Commission ("KCC"). I previously served as the Chief of Telecommunications for the KCC from 1986 to 1990, and was the lead witness on most major issues. I served as Chief Auditor for the KCC from 1983 to 1986, addressing issues regarding telecom, gas,

[1] Century acquired the Sebree smelter from Rio Tinto Alcan in June 2013. Both smelters are now owned and operated by Century.

electric, and transportation. In addition, I have worked for international and regional accounting firms, including Deloitte, Haskin and Sells (now Deloitte).

I received a Bachelor of Science degree in Business Administration with a major in Accounting from the University of Kansas in 1978. I am a member of the American Institute of CPAs ("AICPA") and the Kansas Society of CPAs ("KSCPA").

Q. WHAT TYPE OF REGULATORY ISSUES HAVE YOU ADDRESSED?

A. I have addressed many regulatory issues in my career. My experience includes addressing issues related to rate cases under rate of return ("ROR") regulation and TIER requirements, alternative regulation/price cap plans, management audits, specialized accounting and regulatory issues, and other matters.

Since 2011, I have addressed twelve electric/gas utility rate cases in various jurisdictions and addressed a broad range of accounting and regulatory issues for rate base and operating expenses issues, including payroll costs, benefits expense, incentive compensation, compensation studies, rate case expenses, legal expenses, allocations of expenses from affiliates, allocation methodology, inflation factors, depreciation, software, bad debt expenses, weather normalization, income taxes/deferred income taxes, and many other issues.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION ("COMMISSION") OR ANY OTHER UTILITY REGULATORY COMMISSION?

A. Yes. I testified in the prior BREC rate case, Case No. 2012-00535. Also, I have filed direct testimony in the current Atmos Energy Corporation ("Atmos") rate case in Case No. 2013-00148, although hearings have not been held as of the filing date of this testimony.[2] I have also testified in numerous other jurisdictions and this information is provided at Exhibit BCO-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The primary purpose of my testimony is to address adjustments to BREC's rate application and sponsor the overall revenue requirement based on an interest coverage approach instead of a traditional rate-of-

[2] *In the Matter of: Application of Atmos Energy Corporation For An Adjustment Of Rates and Tariff Modifications*, Case No. 2013-00148. Direct Testimony of Bion C. Ostrander on behalf of the Kentucky Office of Attorney General, filed October 9, 2013.

return ("ROR") on rate base approach. I will also address the problems with the fully forecasted test period BREC chose in this case.

In addition, both Mr. Brevitz and Mr. Holloway will also support particular adjustments, although I will incorporate all adjustment amounts in the revenue requirement calculations at Exhibit BCO-2.

In summary, I will address the following issues:

1) Overall revenue requirement using an interest coverage approach.

2) Individual rate case adjustments.

3) The problems with using BREC's forecasted test period.

4) The proper Times Interest Earned Ratio "TIER."

Q. CAN YOU SUMMARIZE THE TYPE OF EXHIBITS THAT YOU ARE SPONSORING?

A. Yes, I am sponsoring two Exhibits:

1) Exhibit BCO-1 is my curriculum vitae.

2) Exhibit BCO-2, Schedule A-1 summarizes OAG's proposed adjustments and TIER-related revenue requirement/surplus calculation (compared to the revenue requirement of BREC), along with related supporting schedules showing the detailed adjustments as appropriate.

Q. WILL YOU SUMMARIZE YOUR TESTIMONY?

A. BREC's application shows a revenue requirement of $70.4[3] million (using a TIER of 1.24) for which BREC claims the entire amount is related to the lost revenues and margins related to the Century Sebree smelter.

The OAG is providing two adjusted revenue requirement options (both using a 1.10 TIER) for the Commission to consider, and the results of both options show that rates should remain the same without any increases:

1) Option 1 - OAG Primary Recommendation to Remove Impact of Net Revenue Loss from Century Sebree Smelter Departure - The OAG's primary recommendation removes BREC's $70.4 million estimated revenue requirement impact related to the loss of the Century Sebree smelter (Adjustment OAG-1-DB) and this produces a recommendation that rate increases are not necessary and customer rates should remain the same.

2) Option 2 - OAG's Alternative Recommendation if the Commission Does Not Accept Option 1 – If the Commission does not accept OAG's primary recommendation, then OAG would propose a second option which follows a traditional rate case approach and removes certain expenses related to idling both Wilson and Coleman plants along with other rate case adjustments. This option also produces a

[3] BREC has revised some of its underlying amounts provided in responses to various data requests, although it is not clear if BREC is going to revise its proposed revenue requirement of $70.4 million. As one example, Adjustment OAG-2-DB sponsored by Mr. Brevitz includes revised amounts from KIUC 1-22 for costs related to idling the Wilson and Colman plants. However, it is not clear if these revised amounts are intended to cause an increase in BREC's proposed revenue requirement. The OAG is not changing BREC's revenue requirement as a result of any revised data requests; we will wait to see what action BREC takes. However, Exhibit BCO-2, Schedule A-3 shows the amount of the costs related to idling the Wilson and Coleman plants prior to revised KIUC 1-22, and these amounts can be substituted for Adjustment OAG-2-DB if necessary to synchronize with BREC's proper revenue requirement amount.

recommendation that rate increases are not necessary and customer rates should remain the same.

Under OAG Option 1, the total impact of OAG recommended adjustments increases operating income and net margins by an amount of $70.4 million (the amount of BREC's proposed revenue requirement). Under OAG Option 2, the total impact of OAG recommended adjustments increases operating income and net margins by an amount of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL], and because this amount exceeds BREC's proposed revenue requirement of $70.4 million the OAG proposes to maintain existing rates and to reject all of BREC's proposed rate increases.

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, and shows that remaining ratepayers should bear no responsibility to pay for this related rate increase in this case.

Under Option 2, Mr. Brevitz sponsors one adjustment which increases operating income and net margins by an amount of [BEGIN

CONFIDENTIAL] [redacted] [END CONFIDENTIAL] and which is related to removing certain expenses specifically related to idling both the Wilson and Coleman plants. In addition, under Option 2, Mr. Holloway sponsors one adjustment which increases operating income and net margins by an amount of $13,248,779, and I will sponsor the remaining adjustments which increase operating income and net margins by an amount of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL].

KENTUCKY OFFICE OF THE ATTORNEY GENERAL SUPPORTS TIER OF 1.10

Q. DID YOU USE AN INTEREST COVERAGE APPROACH FOR CALCULATING THE REVENUE REQUIREMENT IN THIS CASE?

A. Yes. I used a times interest earned ratio ("TIER") approach (instead of a traditional ROR on rate base approach), and this is the same approach used by the Company, and as I understand the same approach which the Kentucky Public Service Commission utilizes. My exhibits will show the revenue requirement calculated using the TIER approach.

Q. WOULD YOU IDENTIFY THE TIER THAT YOU ARE RECOMMENDING, COMPARED TO THE TIER PROPOSED BY BREC?

A. I am recommending a 1.10 TIER/MFIR and BREC is proposing a 1.24 TIER.[4] For this case, there is no difference in how the TIER or MFIR are calculated, because BREC does not pay any income taxes which would normally be reflected in a MFIR calculation. Thus, it is reasonable to refer to both the OAG and BREC recommendations as a "TIER." BREC must continue to meet a minimum requirement of 1.10 TIER/MFIR under its credit agreements, and my proposal is consistent with that requirement.

TIER is a measurement of a company's ability to pay its interest expense on long-term debt with its net margins. TIER is typically calculated as:

(Net Margins + Interest Expense on Long-Term Debt)/Interest Expense on Long-Term Debt.

[4] Also, it is not necessary to refer to BREC's recommendation as a "Contract" TIER because during the test year, the second smelter (Sebree) leaves the system and it is no longer appropriate to calculate a TIER subject to the previous Smelter contracts.

Q. WHY DO YOU RECOMMEND A 1.10 TIER, INSTEAD OF BREC'S PROPOSED 1.24 TIER?

A. 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.[5] The Commission previously approved a "Contract" TIER of 1.24 for BREC, but only because this was required by BREC's agreements ("Smelter Contracts") with its two aluminum smelters, Century and Alcan, which have since departed - - and thus the "Contract" TIER of 1.24 is now not applicable.[6]

In explaining BREC's position that it should have a 1.24 TIER, Ms. Richert relies on information from a G&T Accounting and Finance Association Annual Directory ("G&T Directory") dated June 2012 (showing 2011 data for G&Ts), and the same G&T Directory dated June 2013 (showing 2012 data for G&Ts) to reach a conclusion that G&Ts with debt ratings in the "A" and "B" category[7] have an average TIER or MFIR of 1.60 for 2011[8] and a range of 1.54 MFIR to 1.60 TIER for 2012.[9] Ms. Richert and Mr.

[5] Richert Direct, p. 10, l. 14-16.
[6] See Commission Order dated November 17, 2011 in Case No. 2011-00036, p. 24.
[7] Ms. Richert's response to OAG 1-182 admits that the credit agency ratings are not included in these same G&T Directories to which she cites.
[8] Richert Direct, p. 11, l. 17-22.
[9] OAG 1-182.

Walker conclude that a higher TIER will garner better credit ratings, and the higher average TIERs from the G&T Directory can be used as a guide for establishing BREC's TIER in this proceeding - - although BREC seeks a 1.24 TIER.

I would caution the Commission with relying on Ms. Richert and Mr. Walker's conclusions based on the following:

1) <u>A Higher TIER Does Not Solve BREC's Greater Financial Problems</u> - Both Ms. Richert and Mr. Walkers' testimonies propose a higher TIER to help cure BREC's financial problems, but BREC's financial problems are more substantive and unique (given the loss of the smelters) - - a higher TIER is a relatively small contributor to improving BREC's financial health.

2) <u>The G&T TIERs Are "Earned" TIERs, not "Commission-Authorized" TIERs</u> – The higher TIERs at the G&T Directory to which Ms. Richert's testimony cites are actual "earned" TIERs by these G&Ts, and are not "Commission-authorized" TIERs. Even if the Commission should authorize a higher TIER for BREC (which means a larger rate increase for BREC), this is no guarantee that BREC will still earn an actual TIER as high as the average actual TIERs of 1.60 or 1.54 as cited from the G&T Directory. The Company merely has the opportunity to earn that TIER. The fact that BREC's actual TIERs from 2010 to 2012 have been 1.15, 1.12, and 1.25, clearly demonstrates that BREC's financial problems are more precarious and deep-seated and will not be resolved by a higher authorized TIER.

3) <u>The Comparative G&T TIER Information is Just a Snapshot in Time Without Availability of Long-Term Information</u> - BREC has relied on only one or two actual years of "earned" TIER data in the G&T Directory, but this might give the incorrect impression that these higher TIERs are consistent with long-run results for all of these G&T's. However, a mere snapshot of other G&T's "earned" TIER data

for one or two years is not indicative or a good predictor of what BREC's "authorized" TIER should be in this case.

4) <u>BREC Has Not Provided A Detailed Analysis to Show That It Is Financially and Operationally Comparable to All of the G&T's Cited in the TIER Comparison</u> – BREC has not provided a detailed analysis or comparison between its financial and operating data and those of other G&Ts to which it cites.

KENTUCKY OFFICE OF THE ATTORNEY GENERAL'S CONCERNS WITH PROJECTIONS AND FULLY FORECASTED TEST PERIOD

Q. ARE YOU USING BREC'S FULLY FORECASTED TEST PERIOD ENDING JANUARY 31, 2015 AS THE STARTING POINT FOR ADJUSTMENTS IN THIS CASE?

A. Yes. Although I don't agree with BREC's use of a fully forecasted test period, the OAG has no other reasonable alternative but to use this same forecasted data as the starting point for adjustments. It would be almost impossible, and certainly impractical, for OAG to attempt to put its own rate case together based on the most recent historical test period. To attempt to put together a completely different rate case filing based on twelve months of historical data would be extremely time consuming, costly, create further confusion and problems for the Commission, and would require that the OAG have virtually the same access as BREC has to its financial records, operational records, and all other studies and analysis that might affect issues in this case. It would be necessary to have this type of information to be on the same equal footing of BREC in preparing an alternative rate case using historical data. Clearly these conditions are not going to happen, so the OAG will use BREC's forecasted test period as the starting point for adjustments.

Q. **ARE YOUR APPROACH AND ADJUSTMENTS IN THIS RATE CASE INTENDED TO MAKE BREC'S RATE CASE FILING LESS SPECULATIVE AND MORE TRANSPARENT?**

A. Yes, from the perspective that we are removing or revising certain adjustments of BREC that are forecasted, speculative, selectively included (while other offsetting adjustments that reduce the revenue requirement are selectively excluded), and are not reasonably known and measurable from a forecasting perspective. BREC used the historic test period ending October 31, 2010, in a prior rate case in 2011-00036, and the Commission's Order recognized the "known and measurable principle" as part of that process and stated, "In using a historic test period, the Commission has given full consideration to appropriate known and measurable changes."[10]

[10] *In the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates,* Case No. 2011-00036, November 17, 2011 Order, p. 4.

Q. DID BREC ACKNOWLEDGE OR IDENTIFY AMOUNTS AND ADJUSTMENTS THAT "ARE KNOWN AND MEASURABLE" VERSUS THOSE THAT "ARE NOT KNOWN AND MEASURABLE"?

A. Unfortunately, no. As an example, OAG 1-234 asked BREC to identify all amounts and adjustments that the Company "considers to be known and measurable" and identify all amounts and adjustments that "are not known and measurable," and to provide BREC's definition of known and measurable. BREC's response stated that "known and measurable" standards are not applicable and are not meaningful for a forecasted test period, and that all adjustments are on equal footing as "projections." Thus, BREC did not define the phrase or distinguish the amounts in its filing between known and measurable and those which are not known and measurable. In response to OAG 1-234, BREC admits that it used a fully forecasted test period because it could not determine the "known and measurable" impact on revenues and expenses of removing both smelters. Because BREC's rate case depends significantly on projected and discretionary amounts that are not known or measurable, this means that the related $70.4 million revenue requirement can be very volatile and imprecise. The OAG's proposed adjustments and recommendation to reject BREC's proposed rate increases is a reflection of the problems with BREC's forecasted amounts that are not known or measurable.

Q. **A FULLY FORECASTED TEST PERIOD CAN PRESENT CHALLENGES, BUT CAN YOU EXPLAIN THE UNIQUE PROBLEMS WITH BREC'S FULLY FORECASTED FILING?**

A. The statutes allow companies in Kentucky to file a rate case using a fully forecasted test period, and I am not opposed to the statute. However, there can be substantial differences in the credibility and reasonableness of forecasts between various companies, and BREC's forecasted filing and related processes lack the necessary credibility to justify its $70.4 million proposed rate increase. I will address some of the overall problems with BREC's forecasted filing and processes in this section, but it should also be noted that every adjustment that OAG sponsors is a result of a specific problem with BREC's forecasts and related processes.[11]

A forecast or projection can be viewed as estimates, predictions, and guesses, but to have the necessary credibility it should be supported by an underlying formal User's Manual to ensure consistency, comparability,

[11] With the exception of Adjustment OAG-7-BCO which is a BREC error, or which could also be interpreted as a forecasting error.

and integrity of the processes and assumptions used in determining projected amounts. Also, a User's Manual provides a proper audit trail and can provide a third party user (such as intervenors in this rate case) the ability to objectively test compliance by measuring projected outputs against the underlying inputs, assumptions, and processes. We have all heard of the adage, "garbage in, garbage out."

Unfortunately, BREC does not have a formal User's Manual, so it is not possible to test BREC's projected amounts against some objective formal written underlying procedures in a User's Manual. Thus, BREC's underlying assumptions for its projections are subject to BREC's discretion for each issue or adjustment on a case-by-case basis, and this means that the underlying assumptions can be very volatile, subjective, subject to manipulation, and may not have a proper correlation to the amounts being projected. Of course, this assumes that there are documented "assumptions" that are being used, and in many instances in this rate case I have not been provided the underlying assumptions and calculations for BREC's projected amounts. The bottom line is that BREC's forecasting process lacks underlying documentation and the necessary credibility - -

and if it has the underlying documentation then it is not being provided to the OAG in all cases.

Of course, a company may claim that they are in the best position to forecast their own revenues and expenses because they have the related experience and familiarity with their financial operations. However, this contention is not necessarily accurate and is over-simplified. I do not believe a company can claim integrity or credibility for its forecasts if it does not have a formalized Budgeting/Forecasting User's Manual which ensures that, regardless of the person doing the specific forecasting, there will be compliance and consistency in the outcomes.

Q. ARE YOU AWARE OF A RECENT RESEARCH PAPER BY THE NATIONAL REGULATORY RESEARCH INSTITUTE ("NRRI") REGARDING THE PROBLEMS WITH FORECASTED TEST PERIOD?

A. Yes, I have reviewed this document,[12] which explains many of the problems with using a forecasted test period, and I agree with many of the paper's conclusions. I do agree that a forecasted test period can shift risk from utility shareholders (in the case of an IOU) to customers by

[12] *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. This document is copyrighted, so it cannot be attached as an exhibit.

providing increased revenue requirements if it is not necessarily justified. Further, the reliance on a forecasted test period can weaken the incentive of utility companies to manage their operations and make prudent decisions because they can attempt to resolve bad management decisions through increased and accelerated rate relief. Also, this paper points out that companies have cherry-picked regarding the forecasted test period mechanism: in times of rising costs, it favors companies to utilize a forecasted test period mechanism, although in times of declining costs a company would not necessarily do so. The paper further notes:

> The reader might ask why a commission should rely on anything other than an FTY. . . . Ratemaking, after all, is prospective, and an FTY matches the test year with the effective period of new rates. Although in theory this argument seems indisputable, **it ignores the reality that forecasts are susceptible to error and some costs and sales elements are inherently difficult to predict.** Another factor, as this paper stresses, is that **utilities would have incentives to present biased forecasts** that are not always easy for commission staff and interveners to uncover. A commission would be presumptuous to assume that forecasted costs and sales are more accurate than modified HTY [historic test year] data accounting for "known and measurable" changes. In fact, many commissions have taken this view, which seems sensible and in line with their mandate to set "just and reasonable" rates. {Emphasis added] [13]

I believe that BREC 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 which it even admits are not known and measurable and which lack

[13] Id., Executive Summary, p. iv.

substantive underlying documentation. There are many other relevant concerns regarding a forecasted test period that are addressed in this document and which I believe would be useful for the Commission's consideration in this case.

Q. HAVE YOU PROVIDED EXAMPLES OF PROBLEMS WITH BREC'S FORECASTING PROCESS THROUGHOUT YOUR TESTIMONY?

A. Yes, and I will not repeat those problems at this time. However, I could also provide numerous other examples of significant differences between BREC's original budgeted amounts and subsequent actual amounts as this relates to revenues, expenses, and plant amounts that are relevant to this rate case.

In Case No. 2012-00535, I provided some examples of problems with BREC's forecasting process. BREC tried to subsequently explain away or rationalize the reasons for these significant differences between its original budgeted amounts and its subsequent actual amounts - - but that does not matter. Of course all differences between original budgeted amounts and subsequent actual amounts have a reason for the variation, but that by itself is not a justification for an original incorrect or improper forecast amount and it does not make the original forecast to be accurate after-the-fact.

For example, BREC claims that its forecasted revenue requirement is $70.4 million. But if two years down the road BREC admits that this original forecast of $70.4 million was incorrect because BREC used a wrong assumption for the smelter departure or was subsequently able to lay-off more staff than it anticipated in the rate case, this is not going to suddenly make BREC's forecast to be accurate after-the-fact, and it certainly won't make customers feel any better about any sizeable rate increases they incurred because of those incorrect forecasts.

Q. **DO YOU BELIEVE THAT "FAIR, JUST AND REASONABLE RATES" (THAT ARE REQUIRED BY STATE STATUTE) CAN BE ACHIEVED VIA BREC'S FULLY FORECASTED REVENUE REQUIREMENT?**

A. No, I do not believe that fair, just and reasonable rates are achievable under BREC's fully forecasted revenue requirement. I will address the numerous problems with BREC's fully forecasted test period and the related revenue requirement.

<u>KENTUCKY OFFICE OF THE ATTORNEY GENERAL PROPOSED TREATMENT OF THE POTENTIAL SALE OF WILSON AND COLEMAN PLANTS</u>

Q. WILL YOU EXPLAIN HOW THE SALE OF THE WILSON AND/OR COLEMAN PLANTS SHOULD BE TREATED IN THE FUTURE?

A. Yes, OAG is recommending that the Commission adopt the following policy as part of this rate case, regarding BREC's potential sale of the Wilson and Coleman plants. If BREC does sell the Wilson and/or Coleman plants in the future, the Commission should require the following policy and practices:

1) BREC should give immediate formal notice of the sale to the Commission and explain the terms, conditions, gross sale price, net sales price, gross and net gain or loss on sale, and a copy of the accounting journal entry to be reflected on the books of BREC with the dollar impact upon all accounts. All costs or amounts that have been netted against the gross sales price (or treated as a cost of sale) should be provided to the Commission by amount and account number.

2) BREC should be required to immediately reserve amounts in a specific account that are equal to the <u>gross</u> gain on sale (if there is a gain on sale), and which will be potentially flowed through to customers as a rate reduction/credit on customer bills. Prior to any filing by BREC with the Commission, the company should reserve these funds in an account and can later contest or argue against flowing such amounts back to customers.

3) If BREC believes that some amount other than the gross gain on sale (if there is a gain on sale) should be flowed through to customers, or if BREC believes that its revenue requirements do not justify flowing such gains back to customers, then BREC should be required to file the

equivalent of a rate case based on a historical test period for the most recent 12-months ending calendar year data.

KENTUCKY OFFICE OF THE ATTORNEY GENERAL PROPOSES TWO OPTIONS FOR REVENUE REQUIREMENTS

Q. WILL YOU EXPLAIN WHY THE ATTORNEY GENERAL IS PROPOSING TWO OPTIONS FOR REVENUE REQUIREMENT IN THIS RATE CASE?

A. Yes. The OAG prefers that the Commission adopt Option 1 from a broader policy perspective. However, if the Commission chooses not to accept the OAG's primary recommendation, then OAG proposes alternative Option 2 which makes numerous "rate case adjustments" to BREC's filed case using a traditional rate case approach. Also, both Option 1 and Option 2 reach the same conclusion; BREC should not be granted a rate increase and customer rates should remain the same such that customers are not required to pay for excess capacity which is not "used or useful" as explained in Mr. Brevitz's testimony. I will now address these options in more detail.

Option 1 – Reject BREC's Filed Case Based on a Broader Fundamental Policy Perspective:

The Attorney General's primary recommendation is that the Commission adopt its proposed Option 1. Under Option 1, the OAG proposes one adjustment (OAG-1-DB) in the same amount of BREC's proposed revenue/rate increase of $70.4 million, which is the impact of net revenues that BREC will lose beginning January 31, 2014 as a result of the termination of the power contract with Century Sebree smelter.[14] Thus, this entire rate case is premised on the lost net revenues from the Century Sebree smelter. Mr. Brevitz proposes one adjustment, Adjustment OAG-1-DB, to remove the entire impact of BREC's proposed rate increase of $70.4 million.[15]

Mr. Brevitz explains that Adjustment OAG-1-DB is based on a broader fundamental policy perspective that the Unwind Transaction was a bargained-for exchange between the Century/Alcan smelters and the Commission regarding rates, terms, and conditions under which BREC would provide power to the smelters. From an important policy

[14] This is the same reason cited by Mr. Bailey for this rate case, Mr. Bailey's Direct Testimony, p. 4, l. 16-18, when he states that this case is necessary to replace net revenues that BREC will lose beginning January 31, 2014, as a result of the termination of the retail power contract of Alcan Primary Products Corporation ("Alcan").

[15] This adjustment is very similar to Mr. Brevitz' Adjustment OAG-1-DB in Case No. 2012-00535, which removed the net revenues/lost margins of $63 million related to the Century smelter.

perspective, the Commission should not allow BREC to transfer lost net revenues/margins of the smelters to remaining rural and large industrial consumers, and then also charge these remaining customers for upkeep of idled generation plant which is not "used or useful." To allow such would lead to rates that are not fair, just, and reasonable.

Option 2 - Reject BREC's Filed Case Based on Traditional Rate Case Type Adjustments:

If the Commission rejects the Attorney General's primary recommendation of Option 1, then the OAG proposes that the Commission adopt alternative Option 2. Option 2 is supported by the OAG's combined rate case adjustments to BREC's filed rate case which eliminate or offset the Company's proposed $70.4 million rate increase, and produces a consistent recommendation as Option 1 - - customer rates should not be increased. Option 2 is supported substantially by Mr. Brevitz's Adjustment OAG-2-DB which removes certain expenses related specifically to the idling of the Wilson and Coleman plants. These expenses should not be passed on to customers via rate increases during BREC's proposed idling of the Wilson and Coleman plants. This same adjustment related to the idling of the Wilson and Coleman plants is also supported in part by the "used or useful argument." In addition, Mr.

Holloway and Mr. Ostrander also propose other rate case adjustments to be adopted under Option 2.

KENTUCKY OFFICE OF THE ATTORNEY GENERAL REVENUE REQUIREMENT ADJUSTMENTS

ADJUSTMENT OAG-1-DB – REMOVE THE IMPACT OF NET REVENUES LOST TO CENTURY SEBREE'S DEPARTURE

Q. WILL YOU SUMMARIZE ADJUSTMENT OAG-1-DB (EXHIBIT BCO-2, SCHEDULE A-2)?

A. I am reflecting the impact of this $70.4 million adjustment in OAG's revenue requirement calculations at Exhibit BCO-2, Sch. A-2. Mr. Brevitz is sponsoring the policy and rationale supporting this $70.4 million adjustment which removes the impact of net revenues lost by BREC as a result of the departure of Century Sebree, and this is the same amount of BREC's proposed total rate increase.

The entire impact of BREC's proposed rate increase of $70.4 million is related to net revenues that BREC will lose due to the departure of the Century Sebree smelter. Mr. Bailey's testimony confirms and explains this when he states that the $70.4 million rate relief BREC is seeking is necessary to replace net revenues that BREC will lose beginning January 31, 2014, as a result of the termination of the retail power contract of Alcan (now known as the Century Sebree smelter).[16] In addition, this explanation is confirmed in BREC's response to OAG 1-84, in which BREC explains that the $70.4 million proposed rate increase consists of:

1) An amount of $46.7 million which is an estimate of the impact of the Sebree smelter contract termination on BREC's revenue deficiency, based on the full amount of the rate increase sought in this case less the $23.7 million attributed to the Sebree smelter's share of the increase from Case No. 2012-00535; and

2) An amount of $23.7 million which is a proportional amount of the increased revenues provided by the Sebree smelter after the increase in Case No. 2012-00535. BREC explains that the base period in this case includes a portion of revenues provided by the Sebree smelter from August 20, 2013 (the effective date of the proposed increase in Case No. 2012-00535) through September 30, 2013 (the end of the base period). Since the Sebree smelter's contract terminates prior to the forecasted test period, these increased revenues are not included in the test period.

Q. IS BREC'S ESTIMATE OF CENTURY SEBREE'S REVENUE REQUIREMENT IMPACT OF $70.4 MILLION CONSIDERED TO BE KNOWN AND MEASURABLE?

A. No, it is not known and measurable. This is BREC's *estimated* impact of the net revenue loss of $70.4 million related to Century Sebree, because most of BREC's amounts included in the forecasted test period of this case

[16] Bailey Direct, p. 4, l. 16-18. Mr. Bailey does not specifically mention the amount of $70.4 million, but this is the amount of rate relief which BREC is seeking in this rate case.

are based on estimates or also referenced as "projected or budgeted" amounts. It would appear that BREC has assembled this rate case to capture a worst case scenario, and considering the OAG's offsetting rate case adjustments, it appears that the impact on BREC's net revenues is much less than $70 million. Furthermore, if the costs of the idled Wilson and Coleman plants are removed, then there is no justified rate increase.

In the prior rate case 2012-00535, I also took issue with BREC's "estimated" $63 million impact of its lost margins related to the Century smelter departure.[17] In the prior rate case, I cited to BREC's response to OAG 2-17(c) which indicates that the Century impact of $63 million was estimated and was not known and measurable. OAG 2-17(c) asked if BREC could determine the "actual" impacts and costs of the Century smelter from historical financial data, and BREC's response indicated that this would require a great number of assumptions regarding power plant operations, outages, fuel costs, off system sales volumes, and load variations. However, what BREC failed to explain or admit to in Case No. 2012-00535, as well as in the instant case, is that its forecasted revenue requirement calculation is based *almost entirely* on assumptions and

[17] Case No. 2012-00535, Ostrander Direct, p. 21, l. 23-25, p. 22, l. 1-20, and p. 23, l. 1-7.

estimates that are not known or measurable. Thus, it is not clear why BREC selectively rejected the use of estimates for calculating the "historical" impact of the Century Hawesville smelter in 2012-00535, and the Century Sebree smelter in this case, but then proceeds to build most of its rate case based on estimates and assumptions.

Similar to OAG 2-17(b) in Case No. 2012-00535, in this rate case OAG 1-84 asked for specific supporting costs and calculations related to Century Sebree that are included in the $70.4 million total revenue requirement. BREC's response to OAG 1-84(a) states that it is not "feasible" for BREC to "accurately" reflect the effects or impacts related to the loss of the Sebree smelter in this rate case.[18] Thus, by its own admission, 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. This supports my conclusion that the Commission should question the amount of the revenue request in this case.

[18] BREC's entire response to this portion of OAG 1-84(a) states, "It is not feasible for Big Rivers to estimate the effects of the changes resulting from the contract termination - including changes to Big Rivers' load, generation dispatch, idling of power plants, staffing, etc. - and accurately reflect those in pro forma adjustments.

I understand the concept of a forecasted test period and that it is legally allowed as an option for a rate case filing, but the Commission should carefully weigh these kind of comments by BREC in its final determination of a revenue requirement. Also, the Commission should consider why BREC did not merely file a rate based on a historic actual test period, with certain selective out-of-period adjustments for the impact of the loss of the Century Sebree smelter. It is clear that a rate case based on forecasted data allows a company a much broader range and significant flexibility for determining costs. Even under a best case scenario, BREC's $70.4 million requested rate increase is a product of estimates and opinions - - and is not based substantially on known and measurable impacts or costs.

ADJUSTMENT OAG-2-DB - REMOVE THE EXPENSES RELATED TO THE IDLING OF BOTH COLEMAN AND WILSON PLANTS

Q. WILL YOU SUMMARIZE ADJUSTMENT OAG-2-DB (EXHIBIT BCO-2, SCHEDULE A-3)?

A. Regarding this adjustment, the purpose of my testimony is to reflect the impact of this adjustment on final revenue requirements. Mr. Brevitz is sponsoring the policy and rationale supporting this OAG adjustment which removes the remaining costs of idling both Wilson and Coleman plants which have not been previously removed from the revenue requirements by BREC. This results in a total decrease in expenses of [BEGIN CONFIDENTIAL] [redacted][19] [END CONFIDENTIAL] for Coleman and Wilson plants. This adjustment is necessary to remove the additional incremental expenses related to the idling of both Wilson and Coleman, which consist of depreciation expense, interest expense, property tax, property insurance, and other expenses.

ADJUSTMENT OAG-3-LH: ADJUST TRANSMISSION REVENUES

Q. WILL YOU SUMMARIZE ADJUSTMENT OAG-3-LH (EXHIBIT BCO-2, SCHEDULE A-4)?

A. Mr. Holloway's testimony supports the policy and calculation for this adjustment, which includes transmission revenues of $13,248,779 in the revenue requirement, and which causes an increase in earnings and net margins. My testimony reflects the impact of this adjustment in final revenue requirements at Exhibit BCO-2.

[19] This adjustment is based on BREC's revision to KIUC 1-22, although it is not clear if these amounts would also change BREC's requested revenue requirement. If necessary, this adjustment can be revised to the original amounts of idled expenses for Wilson and Coleman plants provided at BREC's response to OAG 1-105 and 1-106, and these amounts are also shown at Exhibit BCO-2, Schedule A-3.

ADJUSTMENT OAG-4-BCO: REVISE FORECASTED TEST PERIOD PAYROLL EXPENSE

Q. WILL YOU SUMMARIZE ADJUSTMENT OAG-4-BCO (EXHIBIT BCO-2, SCHEDULE A-5)?

A. This adjustment reduces the forecasted test period payroll expense (labor and benefits) by [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] to reflect the full annualized impact of reducing headcount from 611 full-time employees at base period end to 431 full-time employees[20] at fully forecasted test period end, because it appears that BREC has understated this payroll adjustment in its forecasts. In addition, BREC failed to provide requested supporting documentation to explain or show how it calculated, or *even if* it calculated, the specific impact of various payroll expense decreases related to: (a) the idling of the Wilson and Coleman plants; (b) employees that have left employment since the last rate case in Case No. 2015-00535; (c) an allowance for an employee turnover factor; and (d) the determination of the amount of overtime, and other impacts.

[20] These are the headcounts used by BREC and are presumed to include BREC's impact of the lay-off of employees related the idling of the Wilson and Coleman plants.

Q. WILL YOU EXPLAIN IN MORE DETAIL SOME OF THE REASONS THAT SUPPORT YOUR PAYROLL ADJUSTMENT?

A. In regard to BREC's Tab 50 included with its application, OAG 1-289 asked BREC to explain and provide supporting documentation and calculations to quantify all significant and specific reasons for the increase in payroll costs for the base period and the subsequent decrease in payroll costs for the forecasted test period. BREC's response did not provide a specific reconciliation or calculation of all relevant impacts upon changes in payroll costs from the base period to the forecasted test period. For example, BREC states that the first six months of the base period included less straight time hours of 521,931 due to positions vacated and unfilled, but then these hours increased to 651,382 in the "forecasted" six months of the base period. However, BREC did not explain why these hours increased, how the hours translate to labor dollars, and does not address straight time or overtime hours for the forecasted test period.

BREC did, however, explain that the anticipated idling of both Wilson and Coleman resulted in total reductions in payroll costs (labor and benefits) of $16,718,933, and this would appear to account for most of the total payroll cost reduction of $18,016,413 from the base period to the forecasted test period. Nonetheless, BREC did not provide any supporting calculations or cite to any workpapers to show: (a) how the $16.7 million reduction in payroll costs was calculated; (b) if the $16.7 million figure includes vacant or unfilled positions or includes unreasonable levels of overtime costs; (c) if it properly reflected an allowance for staff turnover in its payroll adjustment; (d) how it calculated overtime; (e) which positions remain vacated and unfilled and are excluded from forecasted payroll costs (and which of these positions for vacated and unfilled payroll costs are included in the forecasted payroll costs); and (f) how the amount of pay raises were reflected in the payroll calculation. Also, in response to OAG 1-289 (for which BREC's Tab 50 was the genesis for many of the payroll questions), BREC explains that it was filing a revised Tab 50 ostensibly to correct the payroll amounts in the base period and increased these costs from $69.6 million to $73.6 million (an increase of $4.0 million), but, once again, without any specific explanation or calculations for the change.

There are numerous other data requests where BREC objected, unfortunately, to providing documentation or calculations regarding payroll costs. As one example, OAG 2-71 sought payroll costs for the

Company witnesses[21] in this rate case 2013-00199 and the prior rate case 2012-00535, and all other management employees that are performing some or all duties of prior Officer positions - - because BREC has previously admitted that some of the current rate case witnesses are performing duties of unfilled and vacated Officer positions. Because of the recent turnover in Company witness positions, the intent of OAG's data request was to confirm which Officers and witness positions were included in payroll costs and which were excluded. BREC objected to providing payroll costs for Company witnesses (including those witnesses that have assumed some responsibilities of departed Officers) and stated that it would only provide this information for its Officers, which presently consist of only Mr. Bailey and Mr. Berry. BREC did state that there is one unfilled high level position, the VP of System Operations, vacated on September 6, 2013, by Mr. Crockett, whose duties are now shared by Mr. Berry, Mr. Christopher Bradley (Manager Energy Control & Compliance), Mr. Warren, and Mr. Tim Trapp (Manager Transmission Service). However, BREC failed to explain if Mr. Crockett's payroll costs were included in BREC's revenue requirements.

[21] Company witnesses included Mr. Crockett, Ms. Barron, Mr. Haner, Mr. Williams, and Ms. Speed, among others.

Furthermore, BREC's response to OAG 2-71(c) states that it budgets payroll costs by using average rates by department rather than by individual employee, and "therefore, the requested costs are not available." Based on this response, it appears that BREC may not even know which vacated or unfilled positions are included in its forecasted revenue requirement because requested cost information was not available. This is a significant concern and means that BREC's payroll costs cannot be verified and could be subject to error and including improper costs.

Q. CAN YOU EXPLAIN HOW YOU CALCULATED YOUR PAYROLL ADJUSTMENT?

A. Yes. BREC's response to OAG 1-289 explains that the ending number of employees at the end of the six-month forecasted base period is 611 and the ending number of employees in the forecasted test period is 431. To determine a reasonable annualized payroll cost reduction, I took the total 180 reduction in employees (611 employees at the base period end less 431 employees at the forecasted test period end) and multiplied this by an average payroll expense per employee (labor and benefits) for the base period of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

BREC's calculated payroll expense reduction from the base period to the forecasted test period is $18,016,413, my calculated payroll reduction is [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] is the amount of my proposed additional payroll reduction. I believe it is reasonable to calculate a payroll reduction adjustment as the difference between the two ending employee headcount levels of 611 for the base period and 431 for the forecasted base period, because it is the employee count of 431 that will be representative of payroll costs going forward. Also, my calculation is conservative because it includes a slightly higher payroll expense ratio (this means I may have overstated payroll expense to some degree) that has historically been incurred by BREC and I am not proposing to adjust for this amount. BREC has not provided any meaningful and detailed explanation, documentation, or calculations to support its proposed changes in costs (and underlying assumptions) for the period stemming from the most recent actual December 31, 2012 results, through the base period ending September 31, 2013, and through the final fully forecasted test period ending January 31, 2015. Therefore, the Commission should accept my proposed adjustment.

ADJUSTMENT OAG-5-BCO: REMOVE FORECASTED TEST PERIOD GENERAL PAY INCREASES

Q. **WILL YOU SUMMARIZE ADJUSTMENT OAG-5-BCO (EXHIBIT BCO-2, SCHEDULE A-6)?**

A. This adjustment removes the estimated expense portion of BREC's forecasted test period pay increases of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Additionally, BREC is apparently unable or perhaps unwilling to determine the expense impact on revenue requirements, and it provided no detailed calculations to support this adjustment. I believe that management pay increases have been sufficient in the past and should be put on hold given BREC's current precarious financial status (and this will help cure any pending or future deferred maintenance concerns).

Q. WHY CAN'T BREC CALCULATE THE IMPACT OF THIS PAYROLL INCREASE ADJUSTMENT ON REVENUE REQUIREMENTS?

A. Frankly, I do not know why. BREC's response to [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] but a footnote at this response states, "Information not available between capitalized and expensed." It is not clear if BREC does not *know* the amount or is *unwilling* to perform the calculation to determine the amounts expensed and capitalized. However, this is a concern if BREC does not have any underlying workpapers and calculations which show how much of these payroll increases are included in expenses, and the related allocation between expense and capital amounts. This concern is consistent with my prior stated concerns regarding BREC's forecasting and lack of underlying documentation and calculations. I have used information from other BREC data request responses to estimate the allocation of these payroll increases between expense and capital amounts for purposes of this adjustment.

ADJUSTMENT OAG-6-BCO: REVISE ESTIMATED RATE CASE EXPENSE

Q. WILL YOU SUMMARIZE ADJUSTMENT OAG-6-BCO (EXHIBIT BCO-2, SCHEDULE A-7)?

A. In the prior rate case 2012-00535, BREC proposed to include $1.6 million of estimated rate case costs with a three-year amortization expense of $.5 million per year. I proposed to remove approximately $1.0 million of the rate case costs in 2012-00535, and allowed a three-year amortization expense of about $.2 million per year. And in this rate case 2013-00199, BREC proposes to add another $1.4 million of largely duplicative rate case costs with a three-year amortization of $.5 million. I am proposing to remove approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of these rate case costs in 2013-00199, and allow a three-year amortization expense of about [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] per year. For these two combined rate cases, BREC proposes amortization expense of $1 million in this rate case 2013-00199, and I am proposing to allow an amortization of about [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] as summarized in the table below.

[BEGIN CONFIDENTIAL]

A	B	C	D	E
		2012-00535	2013-00199	
		Prior	Current	Total
Line	Rate Case Adjustment	Rate Case	Rate Case	Adjust.
1	Total BREC rate case expenses	[redacted]	[redacted]	
2	OAG Adjustment	[redacted]	[redacted]	
3	OAG Adjusted Amount	[redacted]	[redacted]	
4	Amort. 3 years	[redacted]	[redacted]	
5	OAG rate case expense allowed	[redacted]	[redacted]	[redacted]
6	BREC rate case expense amortized	[redacted]	[redacted]	[redacted]
7	Adj. OAG-6-BCO	[redacted]	[redacted]	[redacted]

[END CONFIDENTIAL]

Q. WILL YOU SUMMARIZE SOME OF THE PRIMARY REASONS FOR ADJUSTING BREC'S PROPOSED RATE CASE EXPENSES?

A. Yes. Some of the reasons for adjusting rate case expense for consultants and outside attorneys remain the same as in 2012-00535, except there is a substantive additional concern that the new estimated rate case costs *are largely duplicative* of rate case costs in 2012-00535 and do not include any meaningful economies of scale or savings from the prior case. The rate case expenses in 2013-00199 should be adjusted for a combination of the following reasons, including:

1) If BREC spends all of the rate case expense it claims for 2012-00535 and 2013-00199, it will have spent a total of **<u>$3.0 million in about one year</u>** to essentially the same group of outside consultants and attorneys (with some minor changes) for performing most of the same tasks

(spending about $1.5 m for each rate case). Just the extreme amount of rate case expense by itself is somewhat mind boggling, particularly considering BREC's precarious financial situation. This is $3.0 million that is not being spent on deferred maintenance and more critical operational issues. These rate case costs are excessive. Instead of spending $3.0 million in one year for outside rate case costs, BREC could have hired its own specialized employees for a certain contractual time frame (or at least in combination with some minimal specialized outside consulting assistance) to perform this work in some combination of the following legal/regulatory expertise:

a) Three full-time employees, each paid $200,000 per year for 5 years = $3.0 million.
b) Six full-time employees, each paid $100,000 per year for 5 years = $3.0 million.
c) Two full-time employees each paid $150,000 for 5 years, two full-time employees each paid $100,000 for 5 years, and about three full-time assistants at $50,000 per year for 3 years = $2.95 million.

2) The majority of the rate case expenses are currently unspent. Through September 2013, about 64%[22] (or $.9 million) of total forecasted rate case expenses of $1.4 million remain unspent, and these remaining estimated expenses are not known and measurable.

3) Some of the rate case costs are duplicative and lack any substantial economies of scale or savings from the prior rate case 2012-00535. The $1.4 million of estimated rate case costs in this case 2013-00199 are about 88% of the $1.6 million estimated rate case costs in 2012-00535, thus there are no substantive or meaningful economies of scale or savings and much of the costs are duplicative because many of the issues, testimony, and data requests are the same in both rate cases. In fact, the Company admits that it does not even budget for these efficiencies in this case (OAG 1-258(a)).

4) Although BREC may be managing the "accuracy" of invoices submitted by its outside consultants and attorneys, there is no documentation or analysis to show that BREC has evaluated the

[22] The 64% of estimated unspent rate case expense has been updated for BREC's October 22, 2013, update of PSC DR 1-54(a) showing invoices and additional rate case expenditures.

"reasonableness" of these charges, per the same concern expressed by the Commission in prior rate case Case No. 2011-00036.

5) Some of these rate case costs appear excessive based on my experience in numerous rate cases, considering the tasks involved (some of which are duplicated from Case No. 2012-00535), and especially considering seven months of the same time period are included in both Case No. 2012-00535 and Case No. 2013-00199.

6) The unspent amount of rate case costs are not known and measurable in terms of whether the amounts will be spent, when, by whom, and for what possible purpose besides rate case expense. Also, these amounts are not supported by actual documentation such as invoices or similar documentation.

7) Some of the hourly rates for legal services could well be considered excessive and BREC has only made general arguments that its highly compensated counsel Haynes Boone are essential for particular tasks related to restructuring and bankruptcy (and this issue was raised by the Commission in Case No. 2011-00036). Although at this time, I am not proposing any adjustments based on excessive hourly billing rates.

Q. HAS BREC PROVEN THAT ITS RATE CASE EXPENSES ARE "REASONABLE," AS OPPOSED TO ACCURATE?

A. No. In BREC's rate case in Case No. 2011-00036, the Commission criticized BREC for its significant and excessive spending on the rate case, and the Commission stated that the review process used by BREC was performed primarily to ensure the accuracy of amounts it was billed by attorneys and consultants, but "with little effort to evaluate the reasonableness of the charges."[23]

Ms. Speed's testimony states that BREC has taken steps to ensure that actual rate case costs are "reasonable," however the specific steps that she describes are primarily related to the "accuracy" of the billings, such as reviewing invoices and comparing actual costs to budgeted costs.[24] Thus, it does not appear that BREC has yet satisfied the Commission's previously stated concerns of evaluating the *reasonableness* of the rate case charges.

Also, in Case No. 2012-00535, Ms. Speed also claimed that BREC's rate case costs were reasonable and prudent,[25] but again, her basis for "reasonable and prudent" appears to be primarily based on reviewing invoices for accuracy. Furthermore, in both rate cases 2012-00535 and 2013-00199, BREC and Ms. Speed did not perform, and could not provide, any analysis that compared BREC's rate case expenses to rate case expenses incurred by other utility companies to show that the Company's

[23] *In the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates,* Case No. 2011-00036, January 29, 2013 Order, p. 5. ("Case No. 2011-00036").
[24] Speed Direct, p. 8, l. 7-23.
[25] Speed Rebuttal, p. 11, l. 2-22.

rate case expenses are reasonable, prudent, comparable to what other utilities spend in rate cases, and is not excessive.

Q. DID THE COMMISSION EXPRESS CONCERN WITH BREC'S RATE CASE EXPENSES IN A PRIOR PROCEEDING AND ESTABLISH SPECIFIC CRITERIA FOR RECOVERING FUTURE RATE CASE EXPENSES?

A. Yes. In Case No. 2011-00036 various intervenors, Commission staff and the Commissioners themselves raised concerns about the level of rate case expenses and the excessive hourly rates charged by BREC's Washington, D.C. office of attorneys Hogan Lovells US LLP ("Hogan Lovells"), which were about three times the highest hourly rates charged by BREC's Kentucky law firm.[26] The OAG brief proposed that BREC's rate case expenses be limited by applying an hourly rate more in line with those of local or regional law firms.[27] The Commission reduced Hogan Lovell's legal fees by 20% because their total fees of $897,200 significantly exceeded the original estimated fees of $174,000 included in BREC's application.[28] Most importantly, the Commission noted that BREC bears the burden of

[26] Case No. 2011-00036, Order, p. 3.
[27] *Id.*, p. 4.
[28] *Id.*, p. 6..

proof and the recovery of rate case expenses in future rate cases must meet the following criteria:

1) The rate case expenses must be supported by <u>unredacted copies of invoices</u>.

2) There must be a showing that the use of <u>highly compensated legal counsel was essential for the particular tasks being performed</u>.[29]

Q. DID YOU CONSIDER THE COMMISSION'S CONCERNS FROM CASE NO. 2011-00036 IN EVALUATING HOURLY RATES OF ATTORNEYS IN THIS RATE CASE?

A. Yes. BREC uses Haynes and Boone, LLP ("Haynes Boone") in this proceeding for addressing matters related to restructuring and bankruptcy. Through September 2013, BREC has only been billed $6,907.00 by Haynes Boone. However, unlike other attorneys, BREC has not established a specific rate case expense budget for Haynes and Boone, although there is a miscellaneous category of estimated legal expenses of $200,000 included in its rate case expense budget - - although it is not clear how much of these expenses are potentially set aside for Haynes Boone.

It appears that Ms. Speed attempts to justify the higher hourly rates of Haynes Boone in order to address the Commission's criteria in Case No. 2011-00036, because she refers to Haynes Boone as highly compensated

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[29] *Id.*, p. 6.

legal counsel that are retained to address highly specialized issues related to restructuring and bankruptcy. In addition, it appears that Haynes Boone has agreed to bill at an hourly blended rate which is less than its normal hourly rate of $695/hour that is used for several of its attorneys. As an example, Haynes Boone blended rate is reflected at $516/hour for its August 31, 2013 invoices to BREC. In this instance, the Haynes Boone blended rate of $516/hour compares to an hourly billing rate of $300/hour for Mr. Depp (the attorney with the highest hourly billing rate at Dinsmore & Shohl LLP) and a billing rate of $220/hour for Mr. Miller (the attorney with the highest hourly billing rate at Sullivan, Mountjoy, Stainback & Miller).

Q. HOW ARE YOU TREATING THE HAYNES BOONE HOURLY RATES AND CHARGES AT THIS TIME?

A. Although the example of Haynes Boone blended rate of $516/hour is more than double the hourly billing rate of Kentucky counsel Mr. Miller and is close to double the hourly rate of Kentucky counsel Mr. Depp, I am not proposing a specific adjustment to Haynes Boone's legal expenses based on the hourly rate amount. However, I have removed $175,000 of the total $200,000 amount budgeted for the non-specific category of other Consulting/Legal because BREC has not provided any supporting documentation supporting these amounts which are vague, speculative, and which are not shown as being related to a specific consultant or attorney.

Q. ARE YOU CONCERNED THAT RATE CASE COSTS FOR 2013-00199 DO NOT REFLECT ANY SIGNIFICANT OR SPECIFIC IDENTIFIABLE SAVINGS GIVEN THE DUPLICATIVE TASKS FROM 2012-00535?

A. Yes. As I previously noted, the $1.4 million of estimated rate case costs in 2013-00199 are about 88% of the $1.6 million estimated rate case costs in 2012-00535, thus there are no substantive or meaningful economies of scale or savings and much of the costs are duplicative despite the issues, testimony, and data requests being largely the same in both cases. OAG 1-258(a) asked BREC why this rate case does not reflect, or should not reflect, efficiencies and reductions in cost (especially given the seven months of overlapping time periods in both rate cases).

BREC's September 3, 2013, response to OAG 1-258(a) states that it ordinarily would expect rate case expenses to be lower, especially where the parties are the same and the two cases are close together in timing. However, BREC states that because of the large number of data requests it has received thus far, it is unclear whether any reduction in expenses will materialize, and it is premature to determine if efficiencies will materialize. BREC continues to state, "In total, however, anticipated efficiencies of counsel and consultants are not something that is specifically budgeted; they are general expectations based upon a best estimate of the work that will be required in the case." By BREC's own admission, it did not budget for anticipated efficiencies. Unfortunately, this appears to be a recurring theme to some degree in this proceeding and BREC has included various cost increases in this rate case and sometimes ignores other offsetting revenue increases or cost savings. Rate case expense would appear to be one obvious example where BREC could have cut costs and reflected these savings in this rate case.

I believe there should be substantial rate case efficiencies and savings for BREC's consultants and attorneys because of the following:

1) The OAG has issued many of the same discovery requests in this case, and BREC has referred the OAG to responses in the prior case or there has only been a minor change or no change required for many of these discovery requests. The responses to many of these questions should not have required much additional work. Moreover, BREC's consultants and attorneys could have incorporated at least some of its responses from the 2012-00535 by reference into the current case, but did not do so.

2) Many of the same adjustments, schedules, and formatting has already been performed and this did not require significant effort to update. Many of these formatted schedules are not complex anyway. In fact, in-house Staff could have likely updated much of this information the second time around instead of using outside consultants. There should be much faster ramp up time for this second rate case.

3) The primary issues and adjustments remain largely the same for this rate case; there are not a significant number of new issues or adjustments that require substantial or additional time.

Q. HAVE YOU USED A SIMILAR APPROACH TO REDUCE EXCESSIVE RATE CASE EXPENSES IN CASE NO. 2013-00199 AS YOU USED IN CASE NO. 2012-00535?

A. Yes, I have used a similar approach, although there is the new concern that BREC has not reflected any impacts of efficiencies or cost savings in this rate case. I have a supporting workpaper that more specifically explains and shows the calculation of the adjustment to rate case expenses. BREC's total budgeted rate case expense for 2013-00199 is $1,406,105, and BREC has included rate case expenses of $468,702 related to one year of amortization in this rate case (using a three-year amortization). I have reduced BREC's total rate case expense by [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

Similarly, I have carried over my rate case expense adjustment from Case No. 2012-00535 and made an adjustment for this amount.

ADJUSTMENT OAG-7-BCO: REDUCE ACES FEES

Q. WILL YOU SUMMARIZE ADJUSTMENT OAG-7-BCO (EXHIBIT BCO-2, SCHEDULE A-8)?

A. BREC's response to [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]

ACCUMULATED DEFERRED INCOME TAXES

Q. HAS BREC REFLECTED THE IMPACT OF FORECASTED ACCUMULATED DEFERRED TAXES IN ITS RATE CASE?

A. No. BREC's response to OAG 2-66 indicates it has not included or reflected the forecasted impact of accumulated deferred income taxes in this rate case. However, because rate base items are not included in the revenue requirements which are calculated using a TIER basis, this should not have any impact on this rate case. It appears that rate base items such as forecasted capital expenditures only affect the calculation of property taxes and property insurance. However, if accumulated deferred income taxes will have some impact on the revenue requirement, I am reserving the opportunity to address this.

INCOME TAXES

Q. CAN YOU EXPLAIN WHY THERE ARE NOT ANY STATE AND FEDERAL INCOME TAX EXPENSES INCLUDED BY BREC AND OAG IN THE REVENUE REQUIREMENTS CALCULATION?

A. BREC currently has a significant federal and state net operating loss carry-over ("NOLC") which it can carry-forward and use to offset against future federal and state income tax obligations. Thus, there is no federal or state income tax expense to be included in this rate case, because the Company will not incur or pay any federal or state income taxes for the foreseeable future. OAG concurs with BREC's treatment of reducing income tax expense to $0 in this rate case and not calculating taxes based on rate case determined margins.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY, AND ARE YOU RESERVING THE OPTION TO FILE SUPPLEMENTAL TESTIMONY?

A. Yes, this concludes my direct testimony. However, it is my understanding that the rates filed in Case No. 2012-00535 are currently in effect subject to refund, pending the Commission's final Order, which I understand is due on or before November 15, 2013. Regarding the Commission's final determination in that proceeding, I reserve the option to file supplemental testimony to clarify the OAG's position.

General- Ostrander

Mr. Ostrander is an independent regulatory consultant, a practicing Certified Public Accountant (CPA) and has thirty-four years of regulatory and accounting experience. Mr. Ostrander's firm, Ostrander Consulting, has been providing consulting services since 1990 and he has addressed more than 180 cases in numerous jurisdictions.

Previously, Mr. Ostrander served as the Chief of Telecommunications for the Kansas Corporation Commission (KCC - the regulatory agency for the state of Kansas) from 1986 to 1990, and served as Chief Auditor for the KCC on gas, electric, transportation, and telecom cases from 1983 to 1986. Mr. Ostrander also worked for two CPA firms, and directed audits of utility companies and other entities for the international accounting/auditing firm Deloitte, Haskins and Sells (now Deloitte).

Mr. Ostrander formed Ostrander Consulting in October 1990, after leaving employment as Chief of Telecommunications for the Kansas Corporation Commission. Ostrander Consulting has operated successfully and continuously for over 20 years through the present date and is in legal and ethical good standing in the U.S. and internationally.

Mr. Ostrander is also a licensed and practicing certified public accountant in Kansas and is required to meet strict industry ethics and practice requirements.

Mr. Ostrander's background experience started with the energy utility industry, when he performed annual audits, tax, and specialized services of Kansas Gas & Electric as a CPA employed by Deloitte. Subsequently, Mr. Ostrander became Chief Auditor at the KCC and much of his work focused on rate cases of telecommunications, gas and electric utilities. Mr. Ostrander was subsequently appointed as Chief of Telecommunication at the KCC, with a focus on telecom issues, although his expertise was periodically used in rate case audits of gas and electric utilities.

Mr. Ostrander has investigated matters related to all of the largest telecom carriers in the United States including, Verizon, AT&T, SBC/Southwestern Bell, U S WEST, Sprint, Embarq, BellSouth, MCI, numerous independent local exchange companies ("ILECs"), Relay Service Providers (provide telecom services to the speech and hearing impaired), and others. In addition, Mr. Ostrander has evaluated various other international telecom carriers, including Cable & Wireless.

Mr. Ostrander has addressed a broad range of regulatory issues including (but not limited to the following):

- ✓ Traditional Rate Cases
- ✓ Price Caps and Alternative Regulation Plans
- ✓ Specialized or Unique Accounting and Auditing Issues
- ✓ Audits of Universal Service Funds
- ✓ Virtually All Rate Case Expense Issues
- ✓ Virtually All Rate Base Issues
- ✓ Compensation Issues - Reasonableness of Base Salary, Incentives, and Perks
- ✓ Payroll Issues - Pro forma and normalized changes
- ✓ Outsourcing issues
- ✓ Affiliate Transactions
- ✓ Allocation of Costs between Regulated/Nonregulated Operations
- ✓ Depreciation Expense and Depreciation Rate Issues
- ✓ OPEB and Pension Expense Issues
- ✓ Dues and donations (EEI and AGA, etc.)
- ✓ Research and Development
- ✓ Promotions Expense
- ✓ Uncollectibles
- ✓ Rate Case Expense
- ✓ Charitable Contributions
- ✓ TIER issues
- ✓ REC Revenues
- ✓ Pipeline Assessment Costs
- ✓ Self-Insurance - Utility Company "insuring itself" for distribution/transmission losses
- ✓ Tree Trimming
- ✓ Legal costs and settlements
- ✓ Plant Held for Future Use
- ✓ Cash Working Capital (Lead/Lag Studies)
- ✓ Income Tax Issues
- ✓ Competition Issues
- ✓ Interconnection Issues
- ✓ Cost Accounting and Cost Allocation
- ✓ Access Deficit Issues in Caribbean Nations
- ✓ Universal Service Issues
- ✓ Local Loop Unbundling
- ✓ Licensing Issues
- ✓ Broadband/Internet Access and Infrastructure
- ✓ Tariff Policy and Design Issues

- ✓ Infrastructure Issues
- ✓ Facilities Sharing/Collocation Issues
- ✓ Service Quality Issues
- ✓ International Calling Prices and Competition
- ✓ Mobile/Cellular Calling Prices and Competition
- ✓ On-Net and Off-Net Pricing/Policy Issues in Caribbean Nations
- ✓ Issues Regarding Duopoly of Mobile Providers in Caribbean Nations
- ✓ Broadband Pricing and Competition Issues
- ✓ Number Portability Issues
- ✓ Purchase and Acquisitions (Debt, Finance and Regulatory Issues)
- ✓ Affiliate-Relationship Issues
- ✓ Cross-Subsidization Issues
- ✓ Parts 32, 36, 64 and 69 Issues

Work History- Ostrander

Ostrander Consulting - 1990 to Current (22 years):
Principal

Ostrander Consulting principally addresses regulatory issues on behalf of governments and regulatory agencies, including Attorney Generals and U.S. and international regulatory agencies. Services include those related to revenue requirement issues, price caps or alternative regulation plans, competition assessment, costing/pricing, interconnection/local loop unbundling, universal service, management audits and other matters.

Kansas Corporation Commission:
Chief of Telecommunications

Supervised staff and directed all telecommunications-related matters including assessment of rate cases of SWBT, United/Sprint and rural LECs. Also, directed actions regarding alternative regulation plans, establishing access charge policy, transition to intrastate competition, depreciation filings, establishment of the Kansas Relay Center, filings with the FCC, billing standards, quality of service, consumer complaints, staff training and over one hundred docketed regulatory matters per year. Mr. Ostrander was the lead witness on all major telecommunications matters.

Kansas Corporation Commission:
Chief Auditor

Directed rate cases of gas, electric and telecom companies prior to promotion to Chief of Telecommunications.

Mize, Houser, Mehlinger and Kimes (now Mize Houser & Company Professional Association):
Auditor - CPA firm

Performed auditing, tax and special projects for various industries.

Deloitte, Haskins and Sells (now Deloitte) - (International CPA/Audit Firm):
Auditor - CPA firm
Performed auditing, tax and special projects in industries such as utilities, savings and loan, manufacturing, retail, construction, real estate, insurance, banking and not-for-profit.

Education- Ostrander

University of Kansas - B.S. Business Administration with a Major in Accounting, 1978.

Professional License and Affiliations - Ostrander

- Maintains a permit to practice as a CPA in Kansas.
- Member of the American Institute of CPAs (AICPA).
- Member of the Kansas Society of CPAs (KSCPA).

Recent Experience (10 Years) - Major Cases - Bion C. Ostrander

2013 - Big Rivers Electric Corporation - Before the Public Service Commission of Kentucky - Case No. 2013-00199: Mr. Ostrander reviewed revenues, expenses, income taxes, and rate base components and proposed appropriate adjustments.

2013 - Big Rivers Electric Corporation - Before the Public Service Commission of Kentucky - Case No. 2012-00535: Mr. Ostrander reviewed revenues, expenses, income taxes, and rate base components and proposed appropriate adjustments.

2013 - Atmos Energy Corporation - Before the Public Service Commission of Kentucky - Case No. 2013-00148: Mr. Ostrander reviewed revenues, expenses, income taxes, and rate base components and proposed appropriate adjustments.

2012/2013 - Delmarva Power and Light Company - Before the Public Service Commission of Maryland - Case 9317: Mr. Ostrander reviewed revenues, expenses, income taxes, and rate base components and proposed appropriate adjustments.

2012 - Potomac Electric Power Company - Before the Public Service Commission of Maryland - Case 9311: Mr. Ostrander reviewed revenues, expenses, income taxes, and rate base components and proposed appropriate adjustments.

2013 - Bangor Gas Company - Before the Maine Public Utilities Commission - Docket No. 2012-00598: Mr. Ostrander reviewed revenues, expenses, income taxes, and rate base components and proposed appropriate adjustments.

2012 - Baltimore Gas and Electric - Before the Public Service Commission of Maryland - Case 9299: Mr. Ostrander reviewed most operating expense revenue requirement issues, including payroll, benefits/OPEB, deferred compensation, merger costs and savings, RM 43 and 44 plant and expenses, rate case expense, taxes, injuries and damages, tree trimming/vegetation management, and other expenses.

2012 - Potomac Electric Power Company - Before the Public Service Commission of Maryland - Case 9286: Mr. Ostrander reviewed most operating expense revenue requirement issues, including payroll, benefits/OPEB, deferred compensation, uncollectibles, rate case expense, taxes, injuries and damages, expenses incurred for complying with Commission's service quality directive, tree trimming/vegetation management, and other expenses.

2012 - Delmarva Power and Light Company - Before the Public Service Commission of Maryland - Case 9285: Mr. Ostrander reviewed most operating expense revenue requirement issues, including payroll, benefits/OPEB, deferred compensation, uncollectibles, rate case expense, taxes, injuries and damages, expenses incurred for complying with Commission's service quality directive, tree trimming/vegetation management, and other expenses.

2011 - Washington Gas Light - Before the Public Service Commission of Maryland - Case 9267: Mr. Ostrander reviewed all revenue requirement issues including a detailed review of the complicated outsourcing arrangement with Accenture, long-term incentives, other payroll issues, research & development, pipeline assessment costs, various rate base additions, and other issues. Mr. Ostrander pre-filed three sets of testimony and appeared as a witness for the Maryland Office of People's Counsel.

2012/2011 - PacifiCorp - Before the Washington Utilities and Transportation Commission - Docket UE-111190: Mr. Ostrander pre-filed testimony for certain revenue requirement issues including various accounting adjustments, payroll issues, "self-insurance" for transmission & distribution assets, management fees charged from Corporate to the regulated utility, and other matters for the Washington State Attorney General's Office - Public Counsel Section.

2011 - Review of the Revenue Requirements of Washington Electric Cooperative, Inc. (WEC) - Docket No. 7691 before the Vermont Public Service Board: Mr. Ostrander performed this work for the Vermont Department of Public Service, reviewing the revenue requirements, adjustments, TIER, affiliate transactions issues, and other related issues of WEC.

2012 - Docket No. 12-GIMT-170-GIT - before the Kansas Corporation Commission - Mr. Ostrander represents the Citizens' Utility Ratepayer Board of Kansas (CURB) in this proceeding to address the impacts that the FCC's Omnibus Order (issued November 2011) regarding Federal Universal Service, Connect American Fund (broadband USF and mobility fund), intercarrier compensation, lifeline, separations reform, cost models, and other related issues could have on the Kansas USF (KUSF). In addition, the KUSF is being reviewed for policy changes that could impact the fund and related annual assessments.

2011 - Docket No. 11-GIMT-420-GIT (Docket 420) - before the Kansas Corporation Commission - This docket was initiated in 2010. Mr. Ostrander represents the Citizens' Utility Ratepayer Board of Kansas (CURB) in this proceeding to address changes in policy and review of cost studies to determine cost-based Kansas Universal Service Fund support for price capped telecom carriers. This costs of universal service included in the KUSF have not been reviewed in over ten years for these carriers, and this docket will evaluate those costs and other policy issues.

2008 - 2010 - Docket No. 08-GIMT-1023-GIT (Docket 1023) - before the Kansas Corporation Commission - This docket was initiated May 2008 and essentially completed June 2010. Mr. Ostrander worked on this case from beginning to end for CURB. In this proceeding, Sprint filed a petition to reduce CenturyLink's intrastate access charges to the interstate level (mirror interstate access). There were differences of opinion regarding interpretation of language in existing Kansas statute regarding how often, and when, mirroring of interstate access charges is required for mid-sized carriers like CenturyLink (CL). CL's intrastate access rates had previously been reduced to interstate levels in 1997/1998, 2000, and 2002, and Mr. Ostrander participated in all of these proceedings. In these prior cases, part of the access charges were rebalanced to increases in basic local rates and discretionary services, and the remainder was included in the KUSF. The current proceeding rebalancing the entire difference between intrastate and interstate access rates to the KUSF, and there were no increases in any other rates of CL. There will continue to be similar proceedings in the future for periodic updates to interstate access rates.

Mr. Ostrander's responsibilities in Docket 1023 included:

- Perform analysis
- Prepare discovery and review responses to all discovery
- Prepare direct and rebuttal testimony
- Participate as a witness in hearings

- Participate in negotiations with Sprint and CenturyLink regarding the flow-through of access reductions to retail rates.

2010 - Docket No. 10-GIMT-188-GIT - (Docket 188) - before the Kansas Corporation Commission - This docket was addressed by Mr. Ostrander from June to October 2010. Mr. Ostrander reviewed Staff's testimony and calculations and no problems were identified. Hearings were not held in this proceeding because no problems or issues were identified. Kansas statute requires rural LEC access rates to update their intrastate access rates to interstate levels every 2 years, with the difference between intrastate and interstate rates included in the KUSF. Mr. Ostrander has reviewed calculations and participated in these proceedings for the past 14 years during the existence of the KUSF.

1999 to 2010 - Kansas Universal Service Fund (KUSF) Calculations and Competitive Impact - Kansas: On behalf of the Citizens' Utility Ratepayer Board of Kansas, Mr. Ostrander has addressed the calculation of KUSF assessments for each of the 14 years of the fund, including the evaluation of the projected gross revenue base, safe harbor percentages for wireless and VoIP providers, the treatment of VoIP revenues, withdrawals from the fund, statutory compliance, internal control procedures, and evaluation of competitive data and analysis submitted by carriers to ensure that assessments to consumers are reasonable and within the proper guidelines.

2009 - Review KCPL Iatan Coal Plant Charges - Docket No. 09-KCPE-246-RTS before the Kansas Corporation Commission: Mr. Ostrander represented the Citizens' Utility Ratepayer Board (CURB) in Kansas. Mr. Ostrander made numerous on-site inspections of the Iatan 2 Coal Plant of Kansas City Power & Light in order to address percent completion and in-service dates of environmental upgrades and other construction, which affects treatment in the related rate case. Errors were detected in the control budgets and allocation of common costs between Iatan units 1 and 2, KCP&L failed to comply with FERC guidelines regarding treatment of common costs, and it became necessary to analyze plant and separate the common costs between Units 1 and 2 in order to make sure such costs were not double-counted on KCP&L's books (and in rate base).

2002 to 2010 - Evaluation of the Intrastate IntraLATA/InterLATA Embedded Cost of Service of Various Alaska Rural LECs for Purposes of Establishing Annual Access Charge Rates - Alaska: For this nine year period, Mr. Ostrander evaluated the embedded costs of the intrastate jurisdiction (intrastate intraLATA/interLATA revenue requirement) of rural LECs in Alaska (using a traditional rate case approach) for purposes of establishing intrastate access charge rates in Alaska each year.

2010 - Evaluate Rural LEC Request for Increased Universal Service Fund Disbursements: On behalf of the Citizens' Utility Ratepayer Board, Mr. Ostrander determined that a rural LEC did not properly meet the filing requirements for expedited withdrawals from the Kansas Universal Service Fund (KUSF), and the company will re-file a traditional rate case in future months. Mr. Ostrander may participate in that future proceeding when it is filed.

<u>2009 to 2010 - ECTEL - Evaluate Competition and Implement Price Caps Plan:</u> On behalf of the Eastern Caribbean Telecommunications Authority (the centralized regulatory agency representing the Caribbean nations of St. Lucia, St. Vincent, Grenada, St. Kitts/Nevis, and Dominica), Mr. Ostrander completed an evaluation of competition, assessment of duopoly market, access deficit issues raised by the incumbent carrier, pricing/costing issues, imputation, impact of the initial price cap plan, retail prices for international, mobile, internet and local service, wholesale interconnection prices, financial operations of the incumbent, and infrastructure issues. Interviews were conducted with the various stakeholders and a detailed consultation process was used for gathering and assessing information from various stakeholders. All of these issues were considered in recommending the implementation of a new price cap plan for the ECTEL member nations.

<u>2009 - 2010 - Evaluate Access Costs, Rebalance to Kansas Universal Service Fund, and Related Policy for Major Carriers - Kansas:</u> On behalf of the Citizens' Utility Ratepayer Board of Kansas, Mr. Ostrander recently completed assessment of policies and evaluating costs/pricing for intrastate interconnection/access between the largest carriers in Kansas and other competitive carriers. Also, the calculation of proper amounts to be rebalanced and included in the Kansas Universal Service Fund were addressed. Mr. Ostrander also addressed universal service and the impacts of rate rebalancing proposals by Embarq, Sprint and AT&T.

<u>2010 - Evaluate Access Charges for Rural Telephone Companies - Kansas:</u> On behalf of Citizens' Utility Ratepayer Board of Kansas, Mr. Ostrander will address costing, legal, and policy issues related to interconnection/access charges for rural telephone companies in Kansas (after previously addressing this same issue for the largest carriers in Kansas). The interconnection aspects relates to the cost of the local service carrier providing access to its public switched network and facilities so that other carriers can provide competitive long distance/other services.

<u>February 2009 to June 2009, USAID Capacity Assessment and Development for the Department of Public Services Regulatory Commission of Armenia:</u> Mr. Ostrander assisted with this project to conduct a telecom sector strategic analysis, legal and regulatory assessment, and human and institutional capacity assessment for the PSRC in Armenia, under the auspices of USAID and the Academy for Educational Development. The team consisted of three experts from the US, and local experts in Armenia. The team delivered a comprehensive Final Report to AED and USAID on May 31, 2009, which addressed government's plan for IT

sector development, market structure and technological potential, the current telecommunications
law and regulatory environment, current regulatory performance and priorities, overlapping responsibilities, performance gaps, and human and institutional capacity assessment regarding areas including independence, accountability, transparency, institutional characteristics, organizational structure, and financing and budget.

<u>2008 to 2010 - Evaluate Competition/Price Caps/Tariffs - Maryland:</u> On behalf of the Maryland Office of Public Counsel (regulatory agency), Mr. Ostrander addressed competition, costing/pricing issues, tariff policy, universal service, preservation of reasonable prices for low income citizens, infrastructure issues related to fiber/DSL and other financial matters that impacted the recommendation of a new price cap plan applicable to Verizon Maryland (the dominant incumbent carrier).

<u>1999 to Current - Universal Service Fund Calculations and Competitive Impact - Kansas:</u> On behalf of the Citizens' Utility Ratepayer Board (CURB) of Kansas, Mr. Ostrander has addressed the calculation of Kansas Universal Service Fund (KUSF) assessments for each of 11 years of the operation of KUSF, including the evaluation of competitive data and analysis submitted by carriers and ensuring that assessments to consumers are reasonable and within the proper guidelines.

<u>2009/2008 - Verizon Michigan Cost Studies and Competitive Impact:</u> On behalf of the Michigan Attorney General (regulatory agency), Mr. Ostrander addressed cost studies for the retail cost of basic local service and the wholesale cost of local service (local loop unbundling), identified problems with Verizon Michigan (incumbent carrier) cost studies, and evaluated the related impacts on competition and universal service.
<u>2008/2007 - Cable & Wireless (C&W) Barbados Price Caps and Competition:</u> On behalf of the Fair Trading Commission (FTC) of Barbados (the regulatory agency in Barbados), Mr. Ostrander addressed a new price cap plan for C&W, policy related to competition, cost of regulated/deregulated services, international calling rates, cost allocation matters, tariff issues, and infrastructure matters.

<u>2008/2007 - Price Caps and Competition Impacts for AT&T and Embarq - Kansas</u>: On behalf of the Citizens' Utility Ratepayer Board of Kansas, Mr. Ostrander addressed price caps and related impacts upon competition as it relates to the carriers AT&T and Embarq in Kansas.

<u>2007 - UNE Costing Embarq Nevada:</u> On behalf of the Nevada Bureau of Consumer Protection-Attorney General, Mr. Ostrander addressed unbundled network elements (local loop unbundling).

__2007 - Legislation/Deregulation and Competitive Impacts - Embarq Nevada:__ On behalf of the Nevada Bureau of Consumer Protection-Attorney General, Mr. Ostrander addressed Legislative issues regarding competition, deregulation and pricing flexibility related to Embarq.

__2007 – Affordable Local Rates – Michigan:__ On behalf of the Michigan Attorney General, Mr. Ostrander addressed Verizon's failure to file proper tariffs to comply with Michigan law regarding affordable rates for basic local telephone service.

__2007 – RTB – Alaska:__ On behalf of GCI, Mr. Ostrander addressed the issue of the proper treatment of funds received by telephone companies related to the dissolution of the Rural Telephone Bank (RTB).

__2007 – Verizon Deregulation – Virginia:__ On behalf of the CWA, Mr. Ostrander addressed Verizon's request for deregulation and detariffing in Virginia and related competition issues.

__2007 - 2005 – Verizon Maine:__ On behalf of AARP, Mr. Ostrander addressed the revenue requirements of Verizon Maine, including issues such as Yellow Pages, affiliate transactions and DSL-related issues.

__2007 - 2008 Legislative Kansas:__ Assisted CURB in Kansas with 2007 legislative issues related to telecom, competition and other matters.

__2006/2005 – Embarq/LTD & Sprint/Nextel Change of Control – Kansas:__ On behalf of CURB of Kansas, Mr. Ostrander evaluated the separation and creation of a new local service holding company and the potential impact on customers, rates, competition, service quality and other issues.

__2006 – Embarq Sale of Exchanges to Rural Telephone – Kansas:__ On behalf of CURB of Kansas, Mr. Ostrander reviewed Embarq's sale of local exchanges to Rural Telephone Company and addressed issues such as rates, due diligence, service quality, acquisition adjustments, tariff design, competition and policy issues.

__2006/2005 – Verizon & AT&T Local Rate Rebalance – Michigan:__ On behalf of the Michigan Attorney General, Mr. Ostrander reviewed the requests of Verizon and AT&T to rebalance and increase local rates, including the necessity to preserve affordable and reasonable local rates.

__2006 – Embarq Proposal to Reduce MetroPlus Rates as a Competitive Response – Kansas:__ On behalf of CURB, Mr. Ostrander reviewed Embarq's proposal to significantly reduce its charge for MetroPlus service as a response to competition in several of its exchanges.

2006/2005 - ETC Policy in Kansas - Kansas: Mr. Ostrander assisted CURB with comments regarding the establishment of state policy and filing requirements for Eligible Telecommunication Carriers (ETCs) in Kansas, while also considering the FCC's related policy and requirements. Mr. Ostrander addressed these issues in three separate generic dockets (06-GIMT-446-GIT, 06-GIMT-082-GIT and 05-GIMT-112-GIT) before the Kansas Corporation Commission.

2006 - United Telephone (now Embarq) Sale of Exchanges to Twin Valley - Kansas: On behalf of CURB, Mr. Ostrander reviewed United Telephone's sale of local exchanges to Twin Valley Telephone Company and addressed issues such as rates, service quality, acquisition adjustments, tariff design, competition and policy issues.

2006 - Kansas Universal Service Fund (KUSF) Assessment - Kansas: On behalf of CURB, Mr. Ostrander evaluated the Kansas Universal Service Charge annual calculation and assessment.

2006/2005 - Unsubstantiated Rate Additives by CLECs - Kansas: On behalf of CURB, Mr. Ostrander has addressed issues related to excessive and unsubstantiated recurring charges Placed on telephone bills by CLECS such as Sage, CIMCO, ITC/DeltaCom, etc.

2005 - United Telephone (now Embarq) Sale of Exchanges to Blue Valley - Kansas: On behalf of CURB, Mr. Ostrander reviewed United Telephone's sale of local exchanges to Blue Valley Telephone Company and addressed issues such as rates, due diligence, service quality, acquisition adjustments, tariff design, competition and policy issues.

2005 - Saudi Arabia Communications and Information Technology Commission (CTIC): Assessed Saudi Telecom's proposed accounting separation and allocations manual on behalfof the CITC.

2005 - Embarq/LTD & Sprint/Nextel Change of Control - Nevada: On behalf of the Nevada Board of Consumer Protection, Mr. Ostrander evaluated the separation and creation of a new local service holding company and the potential impact on customers, rates, service quality and other matters.

2001 - 2003 - Kansas Gas & Electric Rate Case - Docket No. 01-WSRE-436-RTS before the Kansas Corporation Commission: Mr. Ostrander represented the Citizens' Utility Ratepayer Board (CURB) in Kansas. In this electric utility rate case, Mr. Ostrander filed testimony and appeared as a witness. Mr. Ostrander addressed issues and adjustments related to proper cost allocation policy and procedures, including the correct allocation of executive and corporate compensation, taxes, Board of Director fees, insurance, building cost, and software. In addition, he addressed the company's improper accounting treatment of restricted shares and dividend benefits to executives, and adjustments related to professional services expenses. Also, Mr. Ostrander reviewed the company's internal aircraft logs and used this information to allocate additional executive payroll costs to nonregulated operations based on extensive use of the company's aircraft for both nonregulated operations and personal use by company executives, their families, and associates.

<u>2005/2004 - Verizon Vermont</u>: On behalf of the Vermont Department of Public Service, Mr. Ostrander evaluated Verizon Vermont's revenue requirements, Yellow Pages, affiliate transactions, work force reductions, depreciation issues, infrastructure/modernization, and policy issues as part of a new alternative regulation plan ("ARP") to go in place in 2005, after the expiration of the current plan. Mr. Ostrander previously conducted an earnings review and evaluation of the prior ARP five years ago in Vermont.

<u>2005 - Southwestern Bell Kansas</u>: On behalf of CURB, Mr. Ostrander assisted with the review of SWBT's request for deregulation of local and other services in certain metro exchanges.

<u>2005/2004/2003 - Cable & Wireless Barbados ("C&W")</u>: On behalf of the Fair Trading Commission ("FTC"), the regulatory agency in Barbados), Mr. Ostrander evaluated a proposal by C&W in 2003/2004 to move away from flat-rate local service to introduce "measured or usage-based" local service at increased rates, as well as policy issues to expand cellular competition and other competition issues. Mr. Ostrander addressed the revenue requirements of C&W, proposed significant revisions to these revenue requirements, and reviewed the C&W cost model and the costs of local, cellular, and other services. The FTC's final decision in July 2004 rejected the C&W proposal, and maintained local rates at existing levels without a switch to measured service.

<u>2004/2003 - Cable & Wireless Eastern Caribbean States:</u> On behalf of the Eastern Caribbean Telecommunications Authority ("ECTEL"), the regulatory agency for certain Caribbean nations), and the nations of St. Lucia, Grenada, St. Vincent, St. Kitts/Nevis, Mr. Ostrander evaluated implementation of the first price caps plan, policy to introduce and expand cellular and other competition in these Caribbean nations, reviewed C&W cost models, evaluated the cost of fixed local and cellular service, as well as other issues. This project resulted in substantial regulatory concessions to customers and significant reductions in prices and increases in infrastructure investment by competitors.

Kentucky Office of Attorney General
Summary of TIER Revenue Requirements and OAG Adjustments
Big Rivers Electric Corporation - Case No. 2013-00199
Adjusted Forecasted Test Period

REDACTED
Exhibit BCO-2
Schedule A-1

A	B	C	D	E	F	G	H	I
			Option 1	Option 2		Confidential Color Coded	Option 1	Option 2
Line No.	Description	BREC Filing	OAG Direct	OAG Direct	Adj. No.	Adj. Description	OAG Adjustments	OAG Adjustments
						OAG Operating Adjustments:		
1	Operating Revenues	265,660,567	265,660,567	265,660,567	OAG-1-DB	Remove Sebree Smelter lost net revenues	($70,396,884)	
2	Operating Expenses	286,338,831	286,338,831	286,338,831	OAG-2-DB	Remove expenses of idled plant		[redacted]
3	Int. Exp. on LT Debt	43,765,994	43,765,994	43,765,994	OAG-3-LH	Include transmission revenues		($13,248,779)
4	Total Cost of Electric Service	330,104,825	330,104,825	330,104,825	OAG-4-BCO	Revise forecasted payroll		[redacted]
5	Gross Operating Margin	(64,444,258)	(64,444,258)	(64,444,258)	OAG-5-BCO	Remove general pay increases		
6	Other Non-operating Income	4,551,213	4,551,213	4,551,213	OAG-6-BCO	Adjust rate case expense		
7	Net Margin	(59,893,045)	(59,893,045)	(59,893,045)	OAG-7-BCO	Century reimbursement for ACES fees		
8								
9	ADJUSTMENTS:							
10	OAG Adjustments - Int. Exp. on LT Debt		$0	$0				
11	OAG Adjustments - Gross Margin		$70,396,884	[redacted]		Total Operating Adjustments	($70,396,884)	[redacted]
12	OAG Adjusted Operating Margin	(64,444,258)	5,952,626					
13						OAG Non-Operating Adjustments:		
14	OAG Adjustments - Non-operating		$0	$0		July 2012 re-finance RUS note - patronage	$0	$0
15	OAG Adjusted Net Margin	(59,893,045)	10,503,839	[redacted]				
16								
17	Interest income on reserve (Note 2)							
18	OAG Adjustments - Int. Income on res.							
19	Adjusted Int. Income on Reserve					Total Non-Operating Adjustments	$0	$0
20								
22	Unadjusted Actual TIER (deduct Res. income)	1.00	1.00	[redacted]		OAG Interest Expense Adjustments:		
23	Unadjusted Actual MFIR (include Res.income)	-0.37	1.24			July 2012 re-finance RUS Note	$0	$0
24								
25	BREC Proposed TIER (Note 1)	1.24	1.24	1.24				
26	OAG Proposed TIER (Loan Agreement) (Note 1)	1.10	1.10	1.10		Total Interest Expense Adjustments	$0	$0
27								
28	Margins Required for TIER 1.24	$10,503,839	$10,503,839	[redacted]		OAG Interest Income on Reserve Adjs.		
29	Revenue Required for TIER 1.24	-$70,396,884	$0				$0	$0
30	Revenue Required - BREC 1.24 TIER	$70,396,884	$0		Note 2			
31	Proposed Rate Increase - BREC 1.24 TIER	$70,396,884	$0	$0		Total Interest Income on Reserve Adjs.	$0	$0
32	Note - Negative/Credit amount means no revenues are required and no change in customer rates.							
33	Margins Required for TIER 1.10	$4,376,599	$4,376,599	[redacted]		Total OAG Adjustments above	($70,396,884)	[redacted]
34	Revenue Required for TIER 1.10	-$64,269,644	$0					
35	Revenue Required - OAG 1.10 TIER	$64,269,644	$0			Brevitz sponsored adjustments	($70,396,884)	[redacted]
36	Proposed Rate Increase - OAG 1.10 TIER	$64,269,644	$0	$0		Holloway sponsored adjustments	$0	($13,248,779)
37	Note - Negative/Credit amount means no revenues are required and no change in customer rates.					Ostrander sponsored adjustments	$0	[redacted]
38	Difference between 1.24 and 1.10 TIER	-$6,127,239	$0	-$6,127,239		Total OAG Adjustments	($70,396,884)	
39								

40 Note 1 - TIER and MFIR Calculation (TIER calculation same as Exhibit Wolfram-2, page 1 of 15):
41 Smelter Contract TIER 1.24 = Margin + Int. Exp. on LT Debt/Interest Exp. on LT Debt.
42 Loan Agreement MFIR 1.10 = Margin + Int. Exp. on LT Debt + Income Taxes/Int. Exp. on LT Debt (Same as TIER calculation because BREC has no income taxes).
43 Note 2 - It is not clear if BREC properly included int. income from Reserve in 2015 forecasted amount, although this may be included in Other Non-Operating Income of $4,551,213 above.

Kentucky Office of Attorney General
Remove Alcan Net Revenues/Margin
Big Rivers Electric Corporation - Case No. 2013-00199
Adjusted Forecasted Test Period

Exhibit BCO-2
Schedule A-2
Adj. OAG-1-DB

A	B	C	D
Line No.	Sebree Smelter Impact	OAG Adj.	Source
1	**Adj. OAG-1-DB**	**70,396,884**	Brevitz testimony

Kentucky Office of Attorney General
Remove Expenses for Idling Wilson and Coleman Plants
Big Rivers Electric Corporation - Case No. 2013-00199
Adjusted Forecasted Test Period

REDACTED
Exhibit BCO-2
Schedule A-3
Adj. OAG-2-DB

A	B	C	D	E	F	G
Line No.		OAG Adj.	Source			
1	Adj. OAG-2-DB	[redacted]	Revised KIUC 1-21			
2						
3	Note: BREC did not revise or update the response to OAG 1-105 and 1-106 regarding these same expenses,					
4	so the revised expenses at KIUC 1-21 were used.				Revised -	Unrevised -
5					KIUC 1-21	OAG 1-105/106
6	Wilson & Coleman Idled Costs (Revised KIUC 1-21):		Wilson	Coleman	Total	Total
7	Depreciation expense		[redacted]			
8	Property tax expense					
9	Property insurance expense					
10	Interest expense					
11	[redacted]					
12	Confidential - Labor/labor overhead					
13	Confidential Total Wilson & Coleman Idled Costs					

Kentucky Office of Attorney General
Increase Transmission Revenues
Big Rivers Electric Corporation - Case No. 2013-00199
Adjusted Forecasted Test Period

Exhibit BCO-2
Schedule A-4
Adj. OAG-3-LH

A	B	C	D
1	**Adj. OAG-3-LH**	**13,248,779**	Holloway testimony

Kentucky Office of Attorney General
Revise Forecasted Test Period Payroll for Employee Reductions
Big Rivers Electric Corporation - Case No. 2013-00199
Adjusted Forecasted Test Period

REDACTED
Exhibit BCO-2
Schedule A-5
Adj. OAG-4-BCO

A	B	C	D	E	F	G	H
1							
2	Adj. OAG-4-BCO		[redacted]				
3							
4		Base		Forecasted		Employee	
5		Period		Test Period		Reduction	
6	Average No. of Employees	611		431		(180)	Note 2
7							
8		Expensed	%	Capitalized	%	Total	
9	Base Period Labor	[redacted]					Note 1
10	Base Period Benefits						Note 1
11	Total Base Period Labor/Benefits						
12	Avg. No. of employees base period						
13	Avg. Payroll Exp. per Employee						
14	Employee Reduction - Base to Forecast Period						
15	OAG Calculated Payroll Exp. Reduction						
16			[redacted]	Base Period Exp. Labor/Benefits			
17				Forecasted Test Period Exp. Labor/Benefits			
18	BREC Calculated Payroll Exp. Reduction	[redacted]					
19	Adj. OAG-4-BCO						
20							
21	Forecasted Test Period Labor	[redacted]					Note 1
22	Forecasted Test Period Benefits						Note 1
23	Total Forecasted Test Period Labor/Benefits						
24	Avg. No. of employees forecasted test period						
25	Avg. Payroll Exp. per Employee						
26							
27	Note 1 - AG 1-237						
28	Note 2 - AG 1-289 and Staff 1-31						

Kentucky Office of Attorney General
Remove General Pay Increases in Forecasted Test Period
Big Rivers Electric Corporation - Case No. 2013-00199
Adjusted Forecasted Test Period

REDACTED
Exhibit BCO-2
Schedule A-6
Adj. OAG-5-BCO

A	B	C	D	E	G	H	I	J
1								
2	Adj. OAG-5-BCO		[redacted]					
3								
4			Base	Forecasted	Effective			
5			Period	Test Period	Date			
6	Non-Bargaining Wage Increase			[redacted]	Jan. 2, 2015	Note 2		
7	Bargaining Generation Wage Increase			[redacted]	Sept. 15, 2014	Note 2		
8	Bargaining Transmission Wage Increase			[redacted]	Oct. 15, 2014	Note 2		
9	Total Wage Increases			[redacted]				
10	Percent Expensed		[redacted]	[redacted]				
11	OAG-5-BCO Adj. - Expensed Wage Increase			[redacted]				
12						Percent	Percent	
13	Test Period	Labor Type	Exp.	Capital	Total	Exp.	Capital	Note
14								
15	Forecasted Test Period - Jan. 2015	Exempt			[redacted]			Note 1
16	Forecasted Test Period - Jan. 2015	Non-Exempt			[redacted]			Note 1
17	FTP - Total	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Note 1
18								
19	Base Period - Sept. 2013	Exempt			[redacted]			Note 1
20	Base Period - Sept. 2013	Non-Exempt			[redacted]			Note 1
21	BP - Total	Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Note 1
22								
23	Note 1 - AG 1-238							
24	Note 2 - PSC 1-34 and AG 1-237							

Kentucky Office of Attorney General
Adjust Rate Case Expense
Big Rivers Electric Corporation - Case No. 2013-00199
Adjusted Forecasted Test Period

REDACTED
Exhibit BCO-2
Schedule A-7
Adj. OAG-6-BCO

A	B	C	D	E	F
	Adj. OAG-6-BCO			[redacted]	
		2012-00535	2013-00199		
		Prior	Current	Total	
Line	Rate Case Adjustment	Rate Case	Rate Case	Adjust.	
1	Total BREC rate case expenses	[redacted]			PSC 1-54a
2	OAG Adjustment				
3	OAG Adjusted Amount				
4	Amort. 3 years				
5	OAG rate case expense allowed				
6	BREC rate case expense amortized				Exh. 49 - Richert
7	Adj. OAG-6-BCO				

Kentucky Office of Attorney General	REDACTED
Century Reimbursement of ACES Fees	**Exhibit BCO-2**
Big Rivers Electric Corporation - Case No. 2013-00199	**Schedule A-8**
Adjusted Forecasted Test Period	**Adj. OAG-7-BCO**

A	B	C	D
1	**Adj. OAG-7-BCO**	[redacted]	Ostrander testimony

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION, INC.	)	Case No. 2013-00199
FOR AN ADJUSTMENT OF RATES	)	

AFFIDAVIT OF BION C. OSTRANDER

State of Kansas)

Bion C. Ostrander, being first duly sworn, states the following: The prepared Pre-Filed Direct Testimony, and the Schedules and Appendix attached thereto constitute the direct testimony of Affiant in the above-styled case. Affiant states that he would give the answers set forth in the Pre-Filed Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct. Further affiant saith not.

Bion C. Ostrander
Bion C. Ostrander

SUBSCRIBED AND SWORN to before me this 23 day of October, 2013.

Robin R. Zmudka
NOTARY PUBLIC

My Commission Expires: 9·6·2014

Robin R. Zmudka
NOTARY PUBLIC—STATE OF KANSAS
MY APPT EXP: 9-6-2014