COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES SUPPORTED BY FULLY FORECASTED TEST PERIOD	))))	CASE NO. 2013-00199

NOTICE OF FILING

Notice is given to all parties that the following materials have been filed into the record of this proceeding:

- The digital video recordings of the evidentiary hearing conducted January 7 – January 9, 2014 in this proceeding;

- Certifications of the accuracy and correctness of the digital video recordings;

- All exhibits introduced at the evidentiary hearing conducted January 7 – January 9, 2014 in this proceeding;

- The written logs listing, *inter alia*, the date and time of where each witness' testimony begins and ends on the digital video recordings of the evidentiary hearing conducted January 7 – January 9, 2014.

A copy of this Notice, the certifications of the digital video records, exhibit lists, and hearing logs have been served by first class mail upon all persons listed at the end of this Notice. Parties desiring electronic copies of the digital video recordings of the hearing in Windows Media format may download copies at:

http://psc.ky.gov/av_broadcast/2013-00199/2013-00199_07Jan14_Inter.asx

http://psc.ky.gov/av_broadcast/2013-00199/2013-00199_08Jan14_Inter.asx

http://psc.ky.gov/av_broadcast/2013-00199/2013-00199_09Jan14_Inter.asx

Parties wishing annotated digital video recordings may submit a written request by electronic mail to pscfilings@ky.gov. A minimal fee will be assessed for copies of these recordings.

The exhibits introduced at the evidentiary hearing may be downloaded at http://psc.ky.gov/pscscf/2013%20cases/2013-00199/.

Done at Frankfort, Kentucky, this 17th day of January 2014.

Linda Faulkner

Linda Faulkner
Director, Filings Division
Public Service Commission of Kentucky

Mark A Bailey
President CEO
Big Rivers Electric Corporation
201 Third Street
Henderson, KY 42419-0024

Honorable Thomas C Brite
Attorney At Law
Brite & Hopkins, PLLC
83 Ballpark Road
P.O. Box 309
Hardinsburg, KENTUCKY 40143

Thomas J Cmar
5042 North Leavitt Street, Suite 1
Chicago, ILLINOIS 60625

Shannon Fisk
Earthjustice
1617 JFK Boulevard, Suite 1675
Philadelphia, PENNSYLVANIA 19103

Jennifer B Hans
Assistant Attorney General's Office
1024 Capital Center Drive, Ste 200
Frankfort, KENTUCKY 40601-8204

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CALIFORNIA 94105

J. Christopher Hopgood
Dorsey, King, Gray,
Norment & Hopgood
318 Second Street
Henderson, KENTUCKY 42420

Honorable Michael L Kurtz
Attorney at Law
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

Burns E Mercer
Manager
Meade County R.E.C.C.
P. O. Box 489
Brandenburg, KY 40108-0489

Honorable James M Miller
Attorney at Law
Sullivan, Mountjoy, Stainback
& Miller, PSC
100 St. Ann Street
P.O. Box 727
Owensboro, KENTUCKY 42302-0727

Ruben Mojica
Sierra Club Environmental Law Program
85 2nd Street, 2nd Floor
San Francisco, CALIFORNIA 94105

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

Billie J Richert
Vice President Accounting, Rates & CFO
Big Rivers Electric Corporation
201 Third Street
Henderson, KY 42419-0024

Melissa D Yates
Attorney
Denton & Keuler, LLP
555 Jefferson Street
P. O. Box 929
Paducah, KENTUCKY 42002-0929

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In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES SUPPORTED BY FULLY FORECASTED TEST PERIOD	) CASE NO. 2013-00199

CERTIFICATE

I, Sonya Harward, hereby certify that:

1. The attached DVD contains a digital recording of the hearing conducted in the above-styled proceeding on January 7, 2014; (excluding any confidential segments, which were recorded on a separate DVD and will be maintained in the non-public records of the Commission, along with the Confidential Exhibits and Hearing Log). The hearing was recorded on three consecutive days, January 7, 2014, January 8, 2014, and January 9, 2014, separately. (Confidential portions were also recorded separately).

2. I am responsible for the preparation of the digital recording;

3. The digital recording accurately and correctly depicts the hearing of January 7, 2014 (excluding any confidential segments);

4. The "Exhibit List" attached to this Certificate correctly lists all exhibits introduced at the hearing of January 7, 2014 (excluding any confidential exhibits).

5. The "Hearing Log" attached to this Certificate accurately and correctly states the events that occurred at the hearing of January 7, 2014 (excluding any confidential segments) and the time at which each occurred.

Given this 10th day of January, 2014.

Sonya Harward (Boyd)

Sonya Harward (Boyd), Notary Public
State at Large
My commission expires: August 27, 2017

Date:	Type:	Location:	Department:
1/7/2014	General Rates	Public Service Commission	Hearing Room 1 (HR 1)

Judge: David Armstrong; Linda Breathitt; Jim Gardner
Witness: Mark Bailey - Big Rivers; Billie Richert - Big Rivers
Clerk: Sonya Harward

Event Time	Log Event	
10:03:02 AM	Session Started	
10:03:07 AM	Chairman Armstrong	
	Note: Harward, Sonya	Preliminary remarks and introduction of Commissioners.
10:03:38 AM	Introduction of Attorneys	
	Note: Harward, Sonya	Atty. Kamuf noted that there was a list of the order of witnesses provided for them.
	Note: Harward, Sonya	Big Rivers - Tyson Kamuf, James Miller, and Tip Depp; Sierra Club - Joe Childers, Shannon Fisk, Kristin Henry, Thomas Cmar, and Bethany Baxter; AG - Jennifer Hans, Larry Cook, and Angela Goad; KIUC - Mike Kurtz, Kurt Boehm, and Jody Cohn; PSC - Quang Nguyen, Richard Raff, and Jeb Pinney; Kenergy Corp. - Christopher Hopgood; Jackson Purchase Energy - Melissa Yates; and Meade Co. RECC - Thomas Bright.
10:05:57 AM	Public Comments	
	Note: Harward, Sonya	Public present today were permitted to speak.
10:06:46 AM	Mike Baker - Public (Public - Exhibit 1)	
	Note: Harward, Sonya	Director of Economic Development for Hancock Industrial Foundation
10:07:25 AM	Camera Lock Camera 6 Activated	
10:11:26 AM	Camera Lock Deactivated	
10:11:45 AM	Kyle Estes - Public (Public - Exhibit 2)	
	Note: Harward, Sonya	Superintendent for Hancock Co. Public Schools
10:11:50 AM	Camera Lock Camera 6 Activated	
10:16:20 AM	Camera Lock Deactivated	
10:16:40 AM	Jack McCaslin - Public	
	Note: Harward, Sonya	Hancock County Judge / Executive
10:16:40 AM	Camera Lock Camera 6 Activated	
10:20:10 AM	Camera Lock Deactivated	
10:20:16 AM	Rita Stevens - Public	
	Note: Harward, Sonya	Mayor of the city of Hawesville
10:20:22 AM	Camera Lock Camera 6 Activated	
10:22:51 AM	Camera Lock Deactivated	
10:23:06 AM	Chairman Armstrong ends public session for the day and begins testimony portion of hearing.	
10:23:31 AM	Big Rivers Witness Mark Bailey takes the stand and is sworn in.	
	Note: Harward, Sonya	President and CEO of Big Rivers Electric Corporation
10:24:38 AM	Atty. Kamuf (BR) direct exam. of Witness Bailey	
	Note: Harward, Sonya	Accepted filed testimony as accurate with a few changes.
10:24:54 AM	Corrections to Rebuttal Testimony of Witness Bailey	
	Note: Harward, Sonya	Rebuttal Testimony, page 6, line 19, should read 68.6M, not 68.4M; page 7, line 1, should read 238.5M, not 220.4M; and line 3, should read 102.1M, not 83.8M.

10:27:06 AM	Atty. Cook (AG) cross exam. of Witness Bailey	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 7, line 8, regarding layoffs.
10:30:26 AM	POST HEARING DATA REQUEST from AG	
	Note: Harward, Sonya	Provide sample Layoff Notice at Coleman and Wilson
10:31:11 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 8, lines 14 through 20.
10:35:05 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 4, line 22.
10:37:10 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Discussing Hawesville closing and the increase in rates to Alcan, and then Alcan's notice of termination.
10:39:23 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 10, beginning at line 4.
10:41:36 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 11, lines 2 through 13.
10:45:33 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Asking who has better load factor, rural or industrial customers.
10:46:13 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 6, line 16, regarding change in figures for requested revenue and other expenses associated with the load.
10:51:12 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Referencing the Testimony of Steve Henry, page 4, line 3, regarding Mr. Henry's concern in 111 percent power rate increase for his company and that it will leave them with the highest power rate of all of their mills in the US; and asked about how Witness thinks it would affect company's competitiveness.
10:54:03 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Referencing the Testimony of Steve Henry, page 9, lines 3-6. Would you dispute this testimony?
10:55:20 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Referencing Testimony of Bill Cummings, page 4, lines 8-10, regarding the mill having the highest rates of any tissue mill.
10:56:27 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Referencing Testimony of Bill Cummings, page 5, beginning at line 21.
	Note: Harward, Sonya	Also referencing Testimony of Bill Cummings, page 7, beginning at line 17.
	Note: Harward, Sonya	Also referencing Testimony of Bill Cummings, page 6, beginning at line 13.
11:00:43 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Asking if other industrial customers expect same assistance with market priced power as given to Sebree and Hawesville.
	Note: Harward, Sonya	Discussing additional options that other customers have.
11:10:31 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Referencing the Testimony of Steve Henry, page 4, lines 15-19, regarding discounts to new customers.
11:13:03 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 6, lines 8-13, regarding revenues being requested.

11:16:15 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 10, question starting on line 22, regarding rate classes.
11:17:15 AM	Vice Chairman Gardner interjects a question	
	Note: Harward, Sonya	Confirming that CN 12-535 elimated substities between rate classes.
11:17:55 AM	Atty. Cook continues cross exam. of Witness Bailey	
	Note: Harward, Sonya	Discussing comments made at public meeting in Henderson.
11:22:50 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Discussing how other businesses can also avoid bankruptcy.
11:26:33 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Discussing MISO's reporting of discontinued use of certain types of power in the near future.
11:29:04 AM	AG - Exhibit 1	
	Note: Harward, Sonya	The State Corporation Commission of the State of Kansas, Docket No. 13-FBEE-803-MIS, Order Granting Siting Permit
11:29:11 AM	Commissioner Breathitt interjected a question.	
	Note: Harward, Sonya	How old is Wilson?
11:29:39 AM	Atty. Kamuf Objection	
	Note: Harward, Sonya	Not sure why witness is going to be asked additional questions about exhibits being handed out since he's already said he is unfamiliar with the information.
11:30:16 AM	AG - Exhibit 2 (This document was introduced by AG but was not accpeted into the record.)	
	Note: Harward, Sonya	From 3 Websites - Clean Line Energy Partners, Grain Belt Express Clean Line; Rock Island Clean Line; and Plains & Eastern Clean Line.
11:32:03 AM	Atty. Kamuf Objection	
	Note: Harward, Sonya	Witness has not read this and has already stated he is unfamiliar with the information.
11:32:32 AM	Atty. Cook response to objection	
	Note: Harward, Sonya	Not asking Witness to testify about it but wanted to introduce it and discuss the affect it may have on Big River's price and has relevance to mitigation claim.
11:33:27 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Referencing AG - Exhibit 1 to this Hearing, after page 22.
11:37:34 AM	Atty. Cook asked for AG - Exhibits 1 and 2 be entered into record.	
11:37:42 AM	Atty. Kamuf Objection to AG - Exhibit 2	
11:37:57 AM	Atty. Cook's Response to Objection	
11:39:35 AM	Chairman Armstrong	
	Note: Harward, Sonya	Judgement will be deferred to end of the hearing as to whether this Exhibit will be entered into the record.
11:40:02 AM	Atty. Cook resumes cross exam. of Witness Bailey	
11:41:01 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 13, line 16, about restarting Wilson and Coleman plants.
11:47:44 AM	AG - Exhibit 3	
	Note: Harward, Sonya	Letter to Chairman Armstrong dated December 16, 2013, stamped as rec'd at PSC on Dec. 26, 2013.
11:58:56 AM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Questioning about communications with lenders.
12:02:27 PM	POST HEARING DATA REQUEST from AG	
	Note: Harward, Sonya	Provide any written communications with rating agencies about the mitigation plan.
12:04:40 PM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Discussing replacement load.

12:09:51 PM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Asked when access to market priced power was first discussed with Century for Sebree power. (Or with Alcan when they owned Sebree.)
12:17:40 PM	AG - Exhibit 4	
	Note: Harward, Sonya	Response to AG's Initial Request for Information dated August 19, 2013, Item 107 (includes answer to question which comes from a response in CN 12-535)
12:21:23 PM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Asking if Witness can say that Big Rivers will have no further rates cases until at least 2016.
12:25:06 PM	BREAK	
12:25:38 PM	Session Paused	
1:31:49 PM	Session Resumed	
1:31:55 PM	Atty. Cook resumed cross exam. of Witness Bailey	
	Note: Harward, Sonya	Asking if any research has been done on market value of plants that are like Wilson and Coleman.
1:35:37 PM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 4, line 20, through page 5, line 5.
1:43:26 PM	AG - Exhibit 5	
	Note: Harward, Sonya	Letter from Century Aluminum to Mark Bailey, dated June 12, 2012.
1:47:14 PM	Atty. Cook to Witness Bailey	
	Note: Harward, Sonya	Questioning about when the Board was advised that a mitigation plan was being discussed with Century.
1:49:54 PM	AG - Exhibit 6	
	Note: Harward, Sonya	Response from Big Rivers to KIUC Initial Request for Information dated December 19, 2012, Volume 2, Responses to Item Nos. 9 through 22, filed January 3, 2013
1:56:01 PM	Atty. Cook concludes his cross exam. of Witness Bailey	
1:56:22 PM	Atty. Kurtz (KIUC) cross exam. of Witness Bailey	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 6, starting at line 1, regarding rates sold to smelters.
1:59:50 PM	Atty. Depp (BR) Objection	
	Note: Harward, Sonya	More agrumentative than questioning.
1:59:57 PM	Chairman Sustained Objection	
2:01:22 PM	KIUC - Exhibit 1	
	Note: Harward, Sonya	Four pages of quotes accumulated from previous cases.
2:01:40 PM	Commissioner Breathitt interjects clarifying question to Witness Bailey	
	Note: Harward, Sonya	Clarifing question concerning response about bankruptcy being almost inevitable.
2:02:41 PM	Atty. Kamuf Objection	
	Note: Harward, Sonya	Objection to KIUC - Exhibit 1 of this Hearing
2:03:12 PM	Atty. Kurtz Response to Objection	
2:04:42 PM	Chairman Armstrong accepts Exhibit into the case.	
2:04:55 PM	Atty. Kurtz to Witness Bailey	
	Note: Harward, Sonya	Questioning about KIUC - Exhibit 1 to Hearing
2:10:55 PM	KIUC - Exhibit 2	
	Note: Harward, Sonya	Moody's Investors Service, Issuer Comment: Kentucky PSC order to increase wholesale rates charged by Big Rivers, a credit positive, Global Credit Research 01 Nov. 2013
2:14:24 PM	Atty. Kurtz to Witness Bailey	
	Note: Harward, Sonya	Discussing BR's operating TIER that it's requesting in this case and its profits.

2:14:48 PM	KIUC - Exhibit 3	
	Note: Harward, Sonya	Letter to Jeff Derouen from Tyson Kamuf, dated Dec. 20, 2013, regarding updates to Application, Responses to Comm. Staff's Initial DR, and Comm. Staff's 3rd DR
2:20:30 PM	Atty. Kurtz to Witness Bailey	
	Note: Harward, Sonya	Questioning about cash balances listed in KIUC - Exhibit 3 of this Hearing.
2:21:47 PM	Atty. Kurtz concludes his cross exam. of Witness Bailey	
2:21:56 PM	Atty. Cmar (Sierra Club) cross exam. of Witness Bailey	
2:23:10 PM	Camera Lock Camera 7 Activated	
2:23:18 PM	Camera Lock Deactivated	
2:23:28 PM	Camera Lock Camera 7 Activated	
2:23:33 PM	Camera Lock Deactivated	
2:23:45 PM	SC - Exhibit 1	
	Note: Harward, Sonya	Henry Hub Natural Gas Spot Price, Source: U.S. Energy Information Administration
2:24:17 PM	Atty. Kamuf Objection	
	Note: Harward, Sonya	Objects to SC - Exhibit 1
2:24:44 PM	Chairman Armstrong will rule after hearing discussion on Exhibit	
2:24:48 PM	Atty. Cmar to Witness Bailey	
	Note: Harward, Sonya	Questioning about SC - Exhibit 1 to this Hearing
2:24:48 PM	Camera Lock Camera 7 Activated	
2:25:14 PM	Camera Lock Deactivated	
2:25:30 PM	Camera Lock Camera 7 Activated	
2:25:58 PM	Camera Lock Deactivated	
2:26:09 PM	Camera Lock Camera 7 Activated	
2:26:14 PM	Camera Lock Deactivated	
2:26:20 PM	Camera Lock Camera 7 Activated	
2:26:39 PM	Camera Lock Deactivated	
2:26:40 PM	Atty. Cmar asks that SC - Exhibit 1 be submitted into the record.	
2:26:50 PM	Atty. Kamuf further Objection to SC - Exhibit 1	
2:27:07 PM	Atty. Cmar Response to Objection	
2:27:27 PM	Chairman Armstrong	
	Note: Harward, Sonya	Allows Exhibit to be discussed.
	Note: Harward, Sonya	Commission will recieve the Exhibit.
2:27:53 PM	Atty. Cmar continues cross exam. of Witness Bailey	
2:32:42 PM	Atty. Cmar to Witness Bailey	
	Note: Harward, Sonya	Discussing bringing plants up to regulation standards.
2:36:40 PM	Atty. Cmar to Witness Bailey	
	Note: Harward, Sonya	Asking how much time is needed before Big Rivers decides if the mitigation plan works.
2:40:00 PM	Atty, Cmar to Witness Bailey	
	Note: Harward, Sonya	Continued questioning about Big Rivers retiring the Wilson and Coleman plants if they are net revenue losers.
2:41:27 PM	Atty, Cmar to Witness Bailey	
	Note: Harward, Sonya	Questioning about bankruptcy.
2:45:24 PM	SC - Exhibit 2 - CONFIDENTIAL	
	Note: Harward, Sonya	CN 2013-0099, SC Response to BREC Requests, Item No. 1, by Frank Ackerman
2:45:39 PM	SC - Exhibit 3 - CONFIDENTIAL	
	Note: Harward, Sonya	CN 2013-0099, SC Response to Commission Staff Requests, Item No. 1, by Frank Ackerman

2:54:22 PM	Atty. Depp	
	Note: Harward, Sonya	SC - Exhibits 2 and 3 contain CONFIDENTIAL information and are different than those filed and posted on the PSC website.
2:55:24 PM	BREAK	
2:55:29 PM	Session Paused	
3:08:37 PM	Session Resumed	
3:08:40 PM	Session Paused	
3:08:44 PM	Session Resumed	
3:09:19 PM	Session Paused	
3:09:30 PM	Session Resumed	
3:09:37 PM	Atty. Cmar	
	Note: Harward, Sonya	Confirmed that SC - Exhibits 2 and 3 will be CONFIDENTIAL
3:10:10 PM	Atty. Cmar has concluded his cross exam. of Witness Bailey	
3:10:26 PM	Atty. Nguyen (PSC) cross exam. of Witness Bailey	
3:11:53 PM	Atty. Nguyen to Witness Bailey	
	Note: Harward, Sonya	Referencing Item 7 of Staff's 2nd Information Request (2-7)
3:15:17 PM	POST HEARING REQUEST by PSC Staff	
	Note: Harward, Sonya	Provide comparison of total compensation in the base and forecast periods for individuals considered senior management or part of your staff. List total dollar amount for each group and the number of employees at each level.
3:16:20 PM	Atty. Nguyen to Witness Bailey	
	Note: Harward, Sonya	Questioning about if any bonuses awarded to any BR staff.
3:22:53 PM	Commissioner Breathitt interjected a question.	
	Note: Harward, Sonya	Asking a clarifing question about NorthStar (as it pertains to the bonuses).
3:24:03 PM	POST HEARING REQUEST by PSC	
	Note: Harward, Sonya	Provide Load Mitigation Plan.
	Note: Harward, Sonya	Provide Corrective Action Plan filed with RUS
3:26:53 PM	Atty. Nguyen to Witness Bailey	
	Note: Harward, Sonya	Referencing KIUC - Exhibit 3 of this Hearing.
3:31:23 PM	Atty. Nguyen to Witness Bailey	
	Note: Harward, Sonya	Asking about the affect of rate increase on rate payers.
3:36:16 PM	Atty. Kamuf Interjection	
	Note: Harward, Sonya	Stated that prices being requested for plants is confidential.
3:37:12 PM	Atty. Nguyen to Witness Bailey	
	Note: Harward, Sonya	Continued questioning about the sale price of the plants.
3:40:39 PM	Atty. Nguyen to Witness Bailey	
	Note: Harward, Sonya	Questioning about legislation discussed earlier concerning needing Coleman and Wilson plants
3:41:36 PM	Commissioner Breathitt and Vice Chairman Gardner	
	Note: Harward, Sonya	Asking about what legislative initative may be.
	Note: Harward, Sonya	Asking if BR should have asked Century people yesterday if they'd come back on the system.
3:44:33 PM	Atty. Nguyen to Witness Bailey	
	Note: Harward, Sonya	Asking about the potential for cogeneration services in its system.
3:45:33 PM	Atty. Nguyen to Witness Bailey	
	Note: Harward, Sonya	Asking about Gain Sharing program - does exceeding budget of wholesale margins trigger incentive payments?
3:50:54 PM	Atty. Nguyen concludes his cross exam. of Witness Bailey	
3:50:57 PM	Vice Chairman Gardner cross exam. of Witness Bailey	
3:52:46 PM	Vice Chairman Gardner to Witness Bailey	
	Note: Harward, Sonya	Questioning about 12-535 dealing with more than just Hawesville case, but this case only deals with idling of Sebree.

3:54:37 PM	Vice Chairman Gardner to Witness Bailey	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 6.
3:58:47 PM	POST HEARING REQUEST by Vice Chairman Gardner	
	Note: Harward, Sonya	What the elements are in the cost reduction numbers being discussed.
4:00:02 PM	Vice Chairman Gardner to Witness Bailey	
	Note: Harward, Sonya	Questioning about how many employees will be let go with Wilson and Coleman plants closing.
4:03:05 PM	Vice Chairman Gardner to Witness Bailey	
	Note: Harward, Sonya	Asking what are actual costs if you shut down a facility and what is necessary revenue requirement.
4:09:07 PM	Vice Chairman Gardner to Witness Bailey	
	Note: Harward, Sonya	Asking about any discussions once Century purchased Alcan due to owning two units nearby.
4:10:48 PM	Vice Chairman Gardner to Witness Bailey	
	Note: Harward, Sonya	Referencing AG - Exhibit 3 to this Hearing.
4:16:31 PM	Vice Chairman Gardner to Witness Bailey	
	Note: Harward, Sonya	Questioning continued about load mitigation plan.
4:18:11 PM	Vice Chairman Gardner to Witness Bailey	
	Note: Harward, Sonya	Read from Brief filed by Big Rivers in CN 2012-00535, page 38, and questioning why Big Rivers is changing approaches in the instant case.
4:22:34 PM	Vice Chairman Gardner to Witness Bailey	
	Note: Harward, Sonya	Questioning about CN 12-535 having been a short term case, and how bigger issues were to be dealt with in instant case.
4:29:02 PM	Vice Chairman Gardner concludes his cross exam. of Witness Bailey	
4:29:07 PM	Commissioner Breathitt cross exam. of Witness Bailey	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 13, lines 9-13.
4:33:57 PM	Commissioner Breathitt to Witness Bailey	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 12, section 7.
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 14, where IRP is due.
4:36:25 PM	Commissioner Breathitt to Witness Bailey	
	Note: Harward, Sonya	Asking about potential legislation, and provision where smelters cannot go back on Big Rivers.
4:39:43 PM	Commissioner Breathitt concludes her cross exam. of Witness Bailey	
4:39:48 PM	Chairman Armstrong	
	Note: Harward, Sonya	Asked if there is any additional public wishing to make a public comment.
4:40:03 PM	Atty. Kamuf re-direct of Witness Bailey	
4:43:44 PM	Atty. Kamuf to Witness Bailey	
	Note: Harward, Sonya	Asking clarifying question about how Coleman and Wilson can also be started earlier than planned.
4:45:30 PM	Atty. Kamuf to Witness Bailey	
	Note: Harward, Sonya	Referencing KIUC - Exhibit 1 in this Hearning.
4:51:34 PM	Atty. Kamuf to Witness Bailey	
	Note: Harward, Sonya	Referencing KIUC - Exhibit 3 of this Hearing.
4:56:28 PM	Atty. Cook re-cross of Witness Bailey	
	Note: Harward, Sonya	Questioning concerning Coleman and Wilson ability to start earlier than planned.
4:57:30 PM	Atty. Kurtz re-cross of Witness Bailey	
	Note: Harward, Sonya	Asking questions concerning if there is any requirement to tear down a power plant versus letting it sit.
5:04:22 PM	Atty. Kurtz to Witness Bailey	
	Note: Harward, Sonya	Asking about Nebraska prices versus Kentucky prices.

5:05:11 PM	Atty. Kurtz to Witness Bailey	
	Note: Harward, Sonya	Questioning about his response to smelters not being allowed to return to the system.
5:08:10 PM	Atty. Kurtz to Witness Bailey	
	Note: Harward, Sonya	Asking about Gain Share and how much will go to employees in 2013 and how much went to them in 2012.
5:08:58 PM	Atty. Cmar re-cross of Witness Bailey	
5:10:37 PM	Atty. Cmar to Witness Bailey	
	Note: Harward, Sonya	Questioning about cost of demolition.
5:13:42 PM	Atty. Nguyen re-cross of Witness Bailey	
	Note: Harward, Sonya	Questioning about his response to what would happen if there was a reduction in the requested rate increase.
5:16:32 PM	Vice Chairman Gardner re-cross of Witness Bailey	
	Note: Harward, Sonya	Referencing Jack McCaslin's public comments about hurting economic development.
5:18:39 PM	Vice Chairman Gardner to Witness Bailey	
	Note: Harward, Sonya	Asking some environmental questions.
5:20:09 PM	Chairman Armstrong	
	Note: Harward, Sonya	Reminding all that there will be public comments via video when we resume tomorrow at 10am.
5:21:36 PM	Witness Bailey is dismissed from the stand.	
5:22:50 PM	Witness Billie Richert takes the stand and is sworn in.	
	Note: Harward, Sonya	VP of Accounting and CFO at Big Rivers Electric Corporation
5:23:59 PM	Atty. Kamuf direct exam. of Witness Richert	
5:24:10 PM	Witness Richert provides changes to her testimony.	
	Note: Harward, Sonya	Rebuttal Testimony, page 13 of 38, changes several numbers.
5:26:00 PM	Atty. Cook cross exam. of Witness Richert	
5:27:57 PM	Atty. Cook to Witness Richert	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 5, line 17, asking if there is a typo there.
5:29:23 PM	Atty. Cook to Witness Richert	
	Note: Harward, Sonya	Asking about level of communication with lenders in 2013.
5:30:14 PM	Atty. Cook to Witness Richert	
	Note: Harward, Sonya	Referencing Witness's Response to AG 1-3. Have there been additional communications since this response?
5:31:42 PM	POST HEARING REQUEST by AG	
	Note: Harward, Sonya	Provide any written documents of any communicaiton between Big Rivers and it's lenders since last response to AG 1-3.
5:31:51 PM	Atty. Kamuf Objection	
	Note: Harward, Sonya	Objection to on-going discovery by AG's office.
5:32:02 PM	Atty. Cook Response to Objection	
5:32:33 PM	Chairman Armstrong Response	
5:32:49 PM	Chairman Armstrong asked that documents be provided by Big Rivers to AG.	
5:33:23 PM	Atty. Cook to Witness Richert	
	Note: Harward, Sonya	Referencing a response to AG 1-14, regarding updates to Corrective Plan.
5:36:25 PM	Atty. Cook to Witness Richert	
	Note: Harward, Sonya	Asking if communications with rating agencies have been normal or unusal in 2013.
5:37:32 PM	Atty. Cook to Witness Richert	
	Note: Harward, Sonya	Referencing Witness's Response to AG 1-4, anything new to update?
5:38:58 PM	Atty. Cook to Witness Richert	
	Note: Harward, Sonya	Referencing AG - Exhibit 6 to this Hearing.
5:42:06 PM	Atty. Cook to Witness Richert	
	Note: Harward, Sonya	Referencing Response to AG 1-5

5:42:53 PM	Atty. Cook to Witness Richert	
	Note: Harward, Sonya	Referencing Response to AG 1-17 and the status of review discussed in response.
5:44:13 PM	Vice Chairman Gardner interjected with a clarifying question.	
	Note: Harward, Sonya	Asking what application she was discussing.
5:45:04 PM	Atty. Cook to Witness Richert	
	Note: Harward, Sonya	Referencing Response to AG 1-26.
5:48:00 PM	Hearing going into Confidential Session	
5:48:06 PM	Private Recording Activated	
5:52:57 PM	Public Recording Activated	
5:53:05 PM	Hearing resumes in Public Sesion	
5:53:09 PM	Atty. Kurtz cross exam. of Witness Richert	
	Note: Harward, Sonya	Discussing depreciation.
5:57:03 PM	Atty. Kurtz to Witness Richert	
	Note: Harward, Sonya	Continued questioning about debt service coverage ratio.
5:59:26 PM	KIUC - Exhibit 4	
	Note: Harward, Sonya	Portions of Orders from Commission decisions in PSC CNs 9613 and 12-535
6:01:04 PM	Atty. Depp Objection	
	Note: Harward, Sonya	Asking Witness for Legal meaning is inappropriate.
6:02:59 PM	Atty. Kurtz to Witness Richert	
	Note: Harward, Sonya	Continuing questions about KIUC - Exhibit 4 of this Hearing.
6:03:32 PM	Atty. Depp Objection	
	Note: Harward, Sonya	Counsel is testifying.
6:04:23 PM	Atty. Depp renewed Objection	
6:04:57 PM	Atty. Kurtz to Witness Richert	
	Note: Harward, Sonya	Asking about other parts of KIUC - Exhibit 4 of this Hearing.
6:06:02 PM	Chairman Armstrong sustained Objection	
6:06:30 PM	Atty. Kurtz to Witness Richert	
	Note: Harward, Sonya	Asking about minimum amount of cash Big Rivers is required to hold.
6:06:52 PM	KIUC - Exhibit 5	
	Note: Harward, Sonya	Big Rivers Board Policy, Policy Number 118, Financial Policy (Incorporates Annual Fiscal Review Policy)
6:12:38 PM	KIUC - Exhibit 6a (This document was introduced by KIUC but was not accpeted into the record.) and Exhibit 6b - CONFIDENTIAL	
	Note: Harward, Sonya	At the end of the hearing, this Exhibit was split into two parts. The first 3 pages were titled 6a and the last page titled 6b. 6a was not accepted ito the record and 6b was accepted into the record. Both parts are still confidential.
	Note: Harward, Sonya	Big Rivers' Temporary Cash Investments With and Without Cash from Coleman and Wilson Plant Depreciation
6:15:56 PM	Atty. Cmar passes out a reference to assist with KIUC - Exhibit 6	
6:18:31 PM	Chairman Armstrong suggested allowing Witness to review and respond later.	
6:19:29 PM	Camera Lock Camera 7 Activated	
6:19:33 PM	Atty. Cmar	
	Note: Harward, Sonya	Explains where he got his handout from.
6:19:42 PM	Camera Lock Deactivated	
6:20:50 PM	Adjourned for the day.	
6:20:56 PM	Session Paused	
6:25:09 PM	Session Ended	

Exhibit List Report

2013-00199_07Jan2014

Big Rivers Corporation

Name:	Description:
AG - Exhibit 1	The State Corporation Commission of the State of Kansas, Docket No. 13-FBEE-803-MIS, Order Granting Siting Permit
AG - Exhibit 3	Letter to Chairman Armstrong dated December 16, 2013, stamped as rec'd at PSC on Dec. 26, 2013.
AG - Exhibit 4	Response to AG's Initial Request for Information dated August 19, 2013, Item 107 (includes answer to question which comes from a response in CN 12-535)
AG - Exhibit 5	Letter from Century Aluminum to Mark Bailey, dated June 12, 2012.
AG - Exhibit 6	Response from Big Rivers to KIUC Initial Request for Information dated December 19, 2012, Volume 2, Responses to Item Nos. 9 through 22, filed January 3, 2013
KIUC - Exhibit 1	Four pages of quotes accumulated from previous cases.
KIUC - Exhibit 2	Moody's Investors Service, Issuer Comment: Kentucky PSC order to increase wholesale rates charged by Big Rivers, a credit positive, Global Credit Research 01 Nov. 2013
KIUC - Exhibit 3	Letter to Jeff Derouen from Tyson Kamuf, dated Dec. 20, 2013, regarding updates to Application, Responses to Comm. Staff's Initial DR, and Comm. Staff's 3rd DR
KIUC - Exhibit 4	Portions of Orders from Commission decisions in PSC CNs 9613 and 12-535
KIUC - Exhibit 5	Big Rivers Board Policy, Policy Number 118, Financial Policy (Incorporates Annual Fiscal Review Policy)
KIUC - Exhibit 6b - CONFIDENTIAL	Big Rivers Long-Tem Financial Forecast, page 3 of 7
Not Accepted - AG - Exhibit 2	From 3 Websites - Clean Line Energy Partners, Grain Belt Express Clean Line; Rock Island Clean Line; and Plains & Eastern Clean Line. (This document was introduced by AG but was not accpeted into the record.)
Not accepted - KIUC - Exhibit 6a - CONFIDENTIAL	Big Rivers' Temporary Cash Investments With and Without Cash from Coleman and Wilson Plant Depreciation. (This document was introduced by KIUC but was not accpeted into the record.)
Public - Exhibit 1	Letter of Public Comment from Mike Baker
Public - Exhibit 2	Letter of Public Comment from Kyle Estes
SC - Exhibit 1	Henry Hub Natural Gas Spot Price, Source: U.S. Energy Information Administration
SC - Exhibit 2 - CONFIDENTIAL	CN 2013-0099, SC Response to BREC Requests, Item No. 1, by Frank Ackerman
SC - Exhibit 3 - CONFIDENTIAL	CN 2013-0099, SC Response to Commission Staff Requests, Item No. 1, by Frank Ackerman

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES SUPPORTED BY FULLY FORECASTED TEST PERIOD	) CASE NO. 2013-00199

CERTIFICATE

I, Sonya Harward, hereby certify that:

1. The attached DVD contains a digital recording of the hearing conducted in the above-styled proceeding on January 8, 2014; (excluding any confidential segments, which were recorded on a separate DVD and will be maintained in the non-public records of the Commission, along with the Confidential Exhibits and Hearing Log). The hearing was recorded on three consecutive days, January 7, 2014, January 8, 2014, and January 9, 2014, separately. (Confidential portions were also recorded separately).

2. I am responsible for the preparation of the digital recording;

3. The digital recording accurately and correctly depicts the hearing of January 8, 2014 (excluding any confidential segments);

4. The "Exhibit List" attached to this Certificate correctly lists all exhibits introduced at the hearing of January 8, 2014 (excluding any confidential exhibits).

5. The "Hearing Log" attached to this Certificate accurately and correctly states the events that occurred at the hearing of January 8, 2014 (excluding any confidential segments) and the time at which each occurred.

Given this 10th day of January, 2014.

Sonya Harward (Boyd)

Sonya Harward (Boyd), Notary Public
State at Large
My commission expires: August 27, 2017

JAVS Session Report - Detail

2013-00199_08Jan2014

Big Rivers Electric Corporation

Date:	Type:	Location:	Department:
1/8/2014	General Rates	Public Service Commission	Hearing Room 1 (HR 1)

Judge: David Armstrong; Linda Breathitt; Jim Gardner
Witness: Billie Richert - Big Rivers
Clerk: Sonya Harward

Event Time	Log Event	
10:13:41 AM	Session Started	
10:13:46 AM	Camera Lock Deactivated	
10:13:48 AM	Vice Chairman Gardner	
	Note: Harward, Sonya	Preliminary comments and video conference call instruction. Remote locations taking public comment in Brandenburg, Owensboro, and Paducah.
10:19:10 AM	Public Comments in Brandenburg	
	Note: Harward, Sonya	No one to speak.
10:19:31 AM	Public Comments in Owensboro	
10:19:53 AM	Rex Gossett - Public	
	Note: Harward, Sonya	Resident of Ohio County
10:22:12 AM	Burt Atchen - Public	
	Note: Harward, Sonya	Works in Hawesville, KY
10:24:09 AM	Camera Lock Camera 1 Activated	
10:24:10 AM	Nicholas Knott - Public	
	Note: Harward, Sonya	Member in community his whole life.
10:24:17 AM	Camera Lock Deactivated	
10:25:17 AM	Don Kelly - Public	
	Note: Harward, Sonya	Resident of Owensboro, retired industrial manager.
10:27:27 AM	John Warren - Public	
	Note: Harward, Sonya	Resident of Owensboro, Contract Poultry Grower for Tyson Foods.
10:30:28 AM	Grover Hardin - Public	
	Note: Harward, Sonya	Plant Manager for the Owensboro Kimberly Clarke facility.
10:33:05 AM	Dewayne Russell - Public	
	Note: Harward, Sonya	Resident of Owensboro, KY
10:37:31 AM	Lane Orten - Public	
	Note: Harward, Sonya	Resident of Owensboro
10:39:46 AM	Public Comments in Paducah	
10:39:58 AM	Jack Marshall - Public	
	Note: Harward, Sonya	Resident of Paducah and Jackson Purchase Board Member.
10:41:38 AM	Dr. Bill Murphy - Public	
10:43:16 AM	Vice Chairman Gardner confirming that all public comments have been made at all sites.	
10:43:40 AM	Vice Chairman Gardner closing Public Comments	
10:44:33 AM	BREAK	
10:44:39 AM	Session Paused	
10:49:27 AM	Session Resumed	
10:49:32 AM	Vice Chairman Gardner	
	Note: Harward, Sonya	Reminds Witness Richert that she's still under oath.
10:49:57 AM	Atty. Kurtz (KIUC) resuming cross exam. of Witness Richert	
	Note: Harward, Sonya	Resumes questioning about financial report and cash balance.

10:51:23 AM	Atty. Kurz to Witness Richert	
	Note: Harward, Sonya	Referencing KIUC - Exhibit 6 of this Hearing, and confirming last page is from May report of Big Rivers.
10:53:00 AM	Atty. Kurz to Witness Richert	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 20.
10:55:59 AM	Atty. Kurz to Witness Richert	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 22, line 18.
10:59:11 AM	Atty. Kurz to Witness Richert	
	Note: Harward, Sonya	Discussing changes in use of money reserved for specific purposes.
11:00:10 AM	KIUC - Exhibit 7	
	Note: Harward, Sonya	Figure 1, Number of Large Industrial Customers by mW size, Direct Testimony of Stephen J. Baron at pages 13-14, CN 2013-00199
11:05:57 AM	KIUC - Exhibit 8	
	Note: Harward, Sonya	The Vulnerability of Kentucky's Manufacturing Economy to Increasing Electricity Prices, Aron Patrick, Kentucky Energy and Environment Cabinet, Department of Energy Development and Independence, October 2012, energy.ky.gov
11:10:18 AM	Atty. Kurz to Witness Richert	
	Note: Harward, Sonya	Discussing treating business customers equally by using reserves left over from rural residental customers mitigation.
11:13:15 AM	Atty. Kurz to Witness Richert	
	Note: Harward, Sonya	Referencing page 6 of KIUC - Exhibit 8 of this Hearing.
	Note: Harward, Sonya	Referencing page 4 of KIUC - Exhibit 8 of this Hearing.
11:16:22 AM	Atty. Kurtz concludes his cross exam. of Witness Richert.	
11:16:26 AM	Atty. Cmar (Sierra Club) cross exam. of Witness Richert	
	Note: Harward, Sonya	Questioning about depreciation.
11:18:46 AM	Atty. Cmar to Witness Richert	
	Note: Harward, Sonya	Discussing cash balances.
11:26:00 AM	Break	
11:26:13 AM	Session Paused	
11:26:15 AM	Session Resumed	
11:26:18 AM	Session Paused	
11:26:26 AM	Session Ended	

Date:	**Type:**	**Location:**	**Department:**
1/10/2014	General Rates	Public Service Commission	Hearing Room 1 (HR 1)

Judge: David Armstrong; Linda Breathitt; Jim Gardner
Witness: Billie Richert - Big Rivers
Clerk: Sonya Harward

Event Time	**Log Event**
11:25:48 AM	Session Started
11:25:53 AM	Session Paused
11:26:06 AM	Session Ended

Date:	Type:	Location:	Department:
1/8/2014	General Rates	Public Service Commission	Hearing Room 1 (HR 1)

Judge: David Armstrong; Linda Breathitt; Jim Gardner
Witness: Robert Berry - Big Rivers; Chris Bradley - Big Rivers; Ted Kelly - for Big Rivers; Ralph Mabey - for Big Rivers; Billie Richert - Big Rivers; Deanna Speed - Big Rivers; Daniel Walker - for Big Rivers; Jeff Williams - Big Rivers
Clerk: Sonya Harward

Event Time	Log Event	
11:37:50 AM	Session Started	
11:38:11 AM	Hearing resumed.	
	Note: Harward, Sonya	Record for this day will be in two parts due to glitch not allowing program to go into confidential mode during the first part of the recording.
11:38:12 AM	Hearing going into Confidential Session	
11:38:16 AM	Private Recording Activated	
12:04:20 PM	Public Recording Activated	
12:04:25 PM	Hearing resuming in Public Session	
12:04:27 PM	Atty. Nguyen (PSC) cross exam. of Witness Richert	
12:06:00 PM	POST HEARING DATA REQUEST by PSC	
	Note: Harward, Sonya	Provide monthly fuel cost once Sebree leaves Big Rivers system.
12:07:53 PM	Atty. Nguyen to Witness Richert	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 5, beginning at line 15.
12:11:25 PM	Atty. Nguyen to Witness Richert	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 13, and the Witness's Response to Item 1 to Comm. Staff's 4th Info. Request, page 6 to attachment of this response.
12:15:24 PM	Atty. Nguyen to Witness Richert	
	Note: Harward, Sonya	Referencing Response to Comm. Staff 2nd Info. Request, Item 3.
12:17:39 PM	Atty. Nguyen to Witness Richert	
	Note: Harward, Sonya	Referencing Tab 28 of Big Rivers' Application, attachment 3 at pages 17-18 of 27.
12:20:26 PM	Atty. Nguyen to Witness Richert	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 31, lines 7-11.
12:22:20 PM	Atty. Nguyen to Witness Richert	
	Note: Harward, Sonya	Witness's Response to Item 2 to Comm. Staff's 4th Info. Request, attachment to Part A.
12:30:19 PM	Atty. Nguyen to Witness Richert	
	Note: Harward, Sonya	Discussing flow through cases.
12:31:58 PM	POST HEARING DATA REQUEST by PSC	
	Note: Harward, Sonya	Provide accounting entries made monthly when economic and rural reserve funds were established.
12:36:28 PM	Atty. Nguyen to Witness Richert	
	Note: Harward, Sonya	Discussing creditors allowing BR to sell plants at net book value.
12:37:50 PM	Vice Chairman Gardner to Witness Richert	
	Note: Harward, Sonya	Question about getting creditors' approval to sell plants at any value.
12:38:45 PM	BIG RIVERS TO ADDRESS IN BRIEF	
	Note: Harward, Sonya	Will Big Rivers have to get consent from Creditors to sell the plants at a particular price?
12:39:35 PM	Atty. Nguyen concludes his cross exam. of Witness Richert.	

12:39:40 PM	Commissioner Breathitt cross exam. to Witness Richert	
12:41:45 PM	Commissioner Breathitt to Witness Richert	
	Note: Harward, Sonya	Asked if BR can provide anything else that PSC may need to make a informed decision. Witness suggested a schedule on the impact of not recieving depreciation.
12:43:20 PM	Commissioner Breathitt to Witness Richert	
	Note: Harward, Sonya	Witness lays out next steps for Big Rivers.
12:46:03 PM	Chairman Armstong to Witness Richert	
12:46:56 PM	Vice Chairman Gardner cross exam. of Witness Richert	
12:49:55 PM	Vice Chairman Gardner to Witness Richert	
	Note: Harward, Sonya	Questioning about including revenue in a forecast test year.
12:54:37 PM	Vice Chairman Gardner to Witness Richert	
	Note: Harward, Sonya	Asking about borrowing needs right now and in forecasted test year.
12:58:40 PM	Commissioners conclude cross exam. of Witness Richert	
12:58:58 PM	Atty. Kamuf redirect of Witness Richert	
1:06:38 PM	Atty. Kamuf to Witness Richert	
	Note: Harward, Sonya	Continuing to follow up on questions.
1:09:25 PM	Atty. Kamuf to Witness Richert	
	Note: Harward, Sonya	Following up on questions asked by Atty. Nguyen.
1:14:34 PM	Atty. Cook re-cross exam. of Witness Richert	
1:15:56 PM	Atty. Cook to Witness Richert	
	Note: Harward, Sonya	Asking about rating agencies conducting reviews of mitigation plan.
1:17:37 PM	Atty. Cook to Witness Richert	
	Note: Harward, Sonya	Discussing public comments that were made earlier by Mr. Murphy.
1:18:46 PM	Atty. Kurtz re-cross exam. of Witness Richert	
1:21:07 PM	Atty. Kurtz to Witness Richert	
	Note: Harward, Sonya	Asking about cost of severance for employees.
1:22:56 PM	Atty. Cmar re-cross exam. of Witness Richert	
	Note: Harward, Sonya	Asking about spending on MATS.
1:25:56 PM	Atty. Kamuf additional re-direct of Witness Richert	
	Note: Harward, Sonya	Asking follow up questions.
1:27:28 PM	Break	
1:27:46 PM	Session Paused	
2:31:21 PM	Session Resumed	
2:31:44 PM	Vice Chairman Gardner asks for next witness.	
2:31:46 PM	Witness Ted Kelly - Big Rivers - takes stand and is sworn in.	
	Note: Harward, Sonya	Burns & McDonnell, Principal and Head of Business Analysis Group
2:32:25 PM	Atty. Kamuf direct exam. of Witness Kelly	
	Note: Harward, Sonya	Witness confirms that testimony is still accurate and has no changes.
2:32:39 PM	Atty. Henry (Sierra Club) cross exam. of Witness Kelly	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 21.
2:34:27 PM	SC - Exhibit 5	
	Note: Harward, Sonya	Report on the Comprehensive Depreciation Study, Prepared for Big Rivers Electric Corp., Henderson, KY, dated November 2012, Project Number 70000, Burns & McDonnell
2:42:34 PM	Atty. Henry to Witness Kelly	
	Note: Harward, Sonya	Questioning about depreciation and how it is calculated.
2:43:15 PM	Atty. Henry concludes her cross exam. to Witness Kelly	
2:43:21 PM	Vice Chairman Gardner cross exam. of Witness Kelly	
2:46:20 PM	Video Conference Activated	
2:46:25 PM	Vice Chairman Gardner to Witness Kelly	
	Note: Harward, Sonya	Continuing questioning about studies given to lenders.

2:48:53 PM	Vice Chairman Gardner to Witness Kelly	
	Note: Harward, Sonya	Is Depreciation Study different from Eng. Assessment, per Witness's Rebuttal Testimony on page 12.
2:50:15 PM	Vice Chairman Gardner concludes his cross exam. of Witness Kelly.	
2:50:20 PM	Atty. Kamuf redirect exam. of Witness Kelly	
2:51:29 PM	Atty. Kamuf to Witness Kelly	
	Note: Harward, Sonya	Opinion on depreciation of an idled facility.
2:52:21 PM	Video Conference Deactivated	
2:53:49 PM	Atty. Henry re-cross. exam. of Witness Kelly	
2:53:51 PM	Video Conference Activated	
2:53:53 PM	Video Conference Deactivated	
2:56:48 PM	Vice Chairman Gardner to Witness Kelly	
	Note: Harward, Sonya	Follow up questions.
2:59:35 PM	Witness Kelly dismissed from the stand.	
2:59:43 PM	Witness Ralph Mabey - for Big Rivers - takes the stand and is sworn in.	
	Note: Harward, Sonya	Prof. of Law at Univ. of Utah, Senior Counsel for a firm
3:00:40 PM	Atty. Kamuf direct exam. of Witness Mabey	
	Note: Harward, Sonya	Witness confirmed that his testimony was still accurate with no changes.
3:01:11 PM	Atty. Hans (AG) cross exam. of Witness Mabey	
	Note: Harward, Sonya	Questioning about what materials were reviewed in this case by the Witness and his firm.
3:06:12 PM	Atty. Kurtz cross exam. of Witness Mabey	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 9, line 12, and page 13, line 21.
3:09:45 PM	Atty. Kurtz to Witness Mabey	
	Note: Harward, Sonya	Walking through KIUC rate plan.
3:25:00 PM	Atty. Kurtz to Witness Mabey	
	Note: Harward, Sonya	Discussing refinancing and increasing term of loans.
3:31:02 PM	Atty. Fisk (Sierra Club) cross exam. of Witness Mabey	
3:37:30 PM	Atty. Fisk to Witness Mabey	
	Note: Harward, Sonya	Discussing Witness's views about Mitigation Plan.
3:40:55 PM	Atty. Fisk to Witness Mabey	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 17, lines 10-12, and the Testimony of Frank Ackerman.
3:45:26 PM	Atty. Fisk to Witness Mabey	
	Note: Harward, Sonya	Referencing testimony by Mr. Snyder in the previous rate case.
3:48:23 PM	Atty. Fisk to Witness Mabey	
	Note: Harward, Sonya	Asking if PSC should grant everything Big Rivers is asking for in order to avoid bankruptcy.
3:50:05 PM	Atty. Fisk to Witness Mabey	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 6.
3:52:42 PM	SC - Exhibit 6	
	Note: Harward, Sonya	Westlaw, 196 B. R. 868, 29 Bankr.Ct.Dec. 99, Bankr. L. Rep. P 77,066, United States Bankruptcy Court, D. Utah, Central Division, In re Bonneville Pacific Corp., Debtor, Bankruptcy No. 91A-27701, May 22, 1996
3:57:34 PM	Vice Chairman to Atty. Fisk	
	Note: Harward, Sonya	Any other evidence? No need to read provisions, Commission can do that on their own.
3:58:23 PM	Vice Chairman Gardner cross exam. of Witness Mabey	
	Note: Harward, Sonya	Asking about amount of time to conduct bankruptcy work and how much he is billing for his time.
4:01:28 PM	Vice Chairman Gardner to Witness Mabey	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 7.

4:04:41 PM	Vice Chairman Gardner to Witness Mabey		
		Note: Harward, Sonya	Asking a few legal questions concerning the bankruptcy.
4:08:08 PM	Atty. Kamuf re-direct of Witness Mabey		
4:09:20 PM	Atty. Kamuf to Witness Mabey		
		Note: Harward, Sonya	Referencing page 25 of Frank Ackerman Testimony.
4:11:13 PM	Atty. Kamuf to Witness Mabey		
		Note: Harward, Sonya	Follow up to questions asked by Atty. Fisk.
4:13:35 PM	Witness Mabey dismissed from the stand.		
4:13:59 PM	Session Paused		
4:34:56 PM	Session Resumed		
4:35:04 PM	Witness Daniel Walker - for Big Rivers - takes the stand and is sworn in.		
		Note: Harward, Sonya	Walker and Associates, Finance Consultant, advises cooperatives on financing, rating agency relationships, and regulatory issues.
4:36:01 PM	Atty. Kamuf direct exam. of Witness Walker		
		Note: Harward, Sonya	Witness confirms that his testimony is still accurate and has no changes.
4:36:22 PM	Atty. Cmar cross exam. of Witness Walker		
4:41:14 PM	Commissioner Breathitt cross exam. of Witness Walker		
		Note: Harward, Sonya	Asking about BR's rating and what the investment grades are for the different agencies.
4:46:10 PM	Vice Chairman Gardner cross exam. of Witness Walker		
		Note: Harward, Sonya	Is it necessary to give Big Rivers what it's asking for?
4:49:30 PM	Atty. Kamuf re-direct. of Witness Walker		
4:49:42 PM	Atty. Nguyen cross exam. of Witness Walker		
4:53:53 PM	Witness Walker is dismissed from the stand.		
4:54:03 PM	Witness Deanna Speed - Big Rivers - takes the stand and is sworn in.		
		Note: Harward, Sonya	Director of Rates and Budgets for Big Rivers
4:54:45 PM	Atty. Kamuf direct exam. of Witness Speed		
		Note: Harward, Sonya	Witness confirms that her testimony is still accurate and has no changes.
4:54:56 PM	Vice Chairman Gardner cross exam. of Witness Speed		
4:55:48 PM	Witness Speed is dismissed from the stand.		
4:55:53 PM	Robert Berry - Big Rivers - takes stand and is sworn in.		
		Note: Harward, Sonya	COO of Big Rivers
4:56:30 PM	Atty. Kamuf direct exam. of Witness Berry		
		Note: Harward, Sonya	Accepts testimony with one change. In Rebuttal Testimony, Berry Rebuttal 5, under column Century Sebree, line 13, replace 5,735,942 with 6,000,917.00 and that changes the total there as well.
4:58:35 PM	Atty. Cook cross exam. of Witness Berry		
		Note: Harward, Sonya	Question about public comment from Mr. Murphy earlier in the day.
5:02:34 PM	Atty. Cook to Witness Berry		
		Note: Harward, Sonya	Referencing AG - Exhibit 4 of this Hearing.
5:06:04 PM	Atty. Cook to Witness Berry		
		Note: Harward, Sonya	Referencing AG 1-98, which has an electronic confidential attachment.
5:07:25 PM	Atty. Cook to Witness Berry		
		Note: Harward, Sonya	Discussing Mitigation plan, bringing both plants back on line if shut down, and that they'll have off-system revenues.
5:16:50 PM	Atty. Cook to Witness Berry		
		Note: Harward, Sonya	Asking about contract wtih city of Wayne.
5:23:53 PM	Atty. Cook to Witness Berry		
		Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 15, beginning at line 4.

5:25:59 PM	Atty. Cook to Witness Berry	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, pages 25-27.
5:26:29 PM	POST HEARING DATA REQUEST by AG	
	Note: Harward, Sonya	Provide SSR Agreement filed with FERC and the Protest that Century filed with FERC about the various SSR budget items.
5:28:28 PM	Atty. Kurtz cross exam. of Witness Berry	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 9.
5:29:26 PM	Hearing going into Confidential Session	
5:29:37 PM	Private Recording Activated	
5:36:45 PM	Atty. Kurtz to Witness Berry	
	Note: Harward, Sonya	Continued questioning Witness
5:39:05 PM	Public Recording Activated	
5:39:09 PM	Hearing resuming in Public Session	
5:41:13 PM	Atty. Kurtz to Witness Berry	
	Note: Harward, Sonya	Questioning about delivering power and congestion.
5:42:27 PM	Atty. Kamuf Objection	
	Note: Harward, Sonya	The contracts being discussed are not before Commission at this time and have been previously discussed.
5:42:41 PM	Vice Chairman Gardner allows Atty. Kurtz to continue line of questioning.	
5:42:50 PM	Atty. Kurtz to Witness Berry	
	Note: Harward, Sonya	Continues asking about contracts.
5:44:57 PM	KIUC - Exhibit 9 (This document was introduced by KIUC but was not accpeted into the record.)	
	Note: Harward, Sonya	Collection of various news stories from websites.
5:45:45 PM	Atty. Kamuf Objection	
	Note: Harward, Sonya	Atty. Kurtz continues to enter materials into the record that no witness asked about..
5:47:00 PM	Vice Chairman allows Exhibit	
5:47:04 PM	Atty. Kurtz to Witness Berry	
	Note: Harward, Sonya	Questioning about KIUC - Exhibit 9 of this Hearing.
5:48:32 PM	Atty. Kurtz to Witness Berry	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 28.
5:50:35 PM	KIUC - Exhibit 10	
	Note: Harward, Sonya	Big Rivers Electric Corp. Tariff, PSC KY No. 24, Original Sheet 29, Cancelling No. 23 and Original Sheet 52, Standard Rate - LICX - Large Industrial Customer Expansion, dated Dec. 201, 2011
5:53:05 PM	Atty. Fisk cross exam. of Witness Berry	
5:53:24 PM	Camera Lock Camera 7 Activated	
5:53:35 PM	Camera Lock Deactivated	
5:54:28 PM	POST HEARING DATA REQUEST by Sierra Club	
	Note: Harward, Sonya	Provide spreadsheet of the analysis to determine that BR would not need a scrubber for Wilson if Coleman were idled.
5:54:32 PM	Vice Chairman interjects clarifying question.	
5:55:23 PM	Atty. Fisk to Witness Berry	
	Note: Harward, Sonya	Continues asking questions about scrubbers.
5:56:20 PM	Atty. Fisk to Witness Berry	
	Note: Harward, Sonya	Discussing Nebraska's rates from Big Rivers.
5:58:21 PM	Atty. Fisk to Witness Berry	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 5, lines 8-10.
5:59:25 PM	Hearing going into Confidential Session	
5:59:30 PM	Private Recording Activated	
6:27:04 PM	Public Recording Activated	
6:27:07 PM	BREAK	
6:27:27 PM	Session Paused	
7:17:12 PM	Session Resumed	

7:17:18 PM	Private Recording Activated	
8:13:11 PM	Public Recording Activated	
8:13:14 PM	Hearing resuming in Public Session	
8:13:17 PM	Atty. Fisk resuming cross exam. of Witness Berry in Public Session	
	Note: Harward, Sonya	Referencing Ackerman Testimony, page 24.
8:18:25 PM	SC - Exhibit 13	
	Note: Harward, Sonya	Big Rivers Electric Corporation Comments on the Proposed Effluent Limitations Guidelines adn Standards for the Steam Electric Power Generating Point Source Category, dated Sept. 20, 2013
8:21:15 PM	SC - Exhibit 14	
	Note: Harward, Sonya	CN 2013-00199, Response to Sierra Club's Second Request for Information, Item 20, dated Sept. 16, 2013
8:23:18 PM	POST HEARING DATA REQUEST by Sierra Club	
	Note: Harward, Sonya	Provide report by Burns and McDonnell regarding the Clean Water Act Effluent Limitation Guidelines to determine compliance options and estimated costs, as mentioned in BR's response to SC 2-20. It was noted that it may not be completed until after the case is closed.
8:24:15 PM	SC - Exhibit 15	
	Note: Harward, Sonya	CN 2013-00199, Response to Sierra Club's Second Request for Information, Item 21, dated Sept. 16, 2013
8:26:37 PM	POST HEARING DATA REQUEST by Sierra Club	
	Note: Harward, Sonya	Provide the production cost model sensitivity run evaluating the fuel switch from coal to natural gas at the RD Green Station as mentioned in BR's response to SC 2-21.
8:28:31 PM	SC - 16 Exhibit - CONFIDENTIAL	
	Note: Harward, Sonya	Big Rivers Electric Corporation Environmental Compliance Study, by Sargent & Lundy, dated Feb. 13, 2012
8:30:21 PM	Atty. Nguyen cross exam. of Witness Berry	
8:32:16 PM	POST HEARING DATA RESPONSE by PSC Staff	
	Note: Harward, Sonya	Provide the components of those fixed and variable costs that make up that $33.40.
8:33:43 PM	Atty. Nguyen cross exam. of Witness Berry	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 22 , begining on line 20
8:37:15 PM	Atty. Nguyen to Witness Berry	
	Note: Harward, Sonya	Also referencing Big Rivers' Budget Variance Repor
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 10, beginning on line 13.
8:46:30 PM	Atty. Nguyen to Witness Berry	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 23, beginning at line 4.
8:48:48 PM	Vice Chairman Gardner interjected a clarifying question.	
8:49:18 PM	Atty. Nguyen to Witness Berry	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 23, beginning at line 12.
8:50:40 PM	Commissioner Breathitt interjected a clarifying comment.	
8:55:08 PM	Atty. Nguyen to Witness Berry	
	Note: Harward, Sonya	Referencing Exhibit Berry Rebuttal 5, line 17.
8:56:23 PM	Vice Chairman Gardner cross exam. of Witness Berry	
8:59:00 PM	Vice Chairman Gardner to Witness Berry	
	Note: Harward, Sonya	Questioning about useful life and economic life of a plant.
9:01:56 PM	Commissioner Breathitt cross exam. of Witness Berry	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 13, starting on line 6.
9:04:48 PM	Atty. Kamuf re-direct of Witness Berry	

9:07:40 PM	Atty. Kamuf to Witness Berry		
		Note: Harward, Sonya	Questioning about ongoing search for replacement load.
9:08:56 PM	Atty. Kurtz re-cross of Witness Berry		
		Note: Harward, Sonya	Questioning about new smelter contracts.
9:11:52 PM	Atty. Fisk re-cross to Witness Berry		
9:12:57 PM	Witness Berry is dismissed from the stand.		
9:13:05 PM	Vice Chairman Gardner		
		Note: Harward, Sonya	Asks if anyone has questions for next few witnesses.
9:13:24 PM	Witness Chris Bradley - Big Rivers - takes the stand and is sworn in.		
		Note: Harward, Sonya	Manager of Energy Control and Compliance for Big Rivers
9:14:10 PM	Atty. Kamuf direct of Witness Bradley		
		Note: Harward, Sonya	Adopts testimony of David Crockett and the Witness's own responses to data requests with no corrections.
9:14:37 PM	Witness Bradley is dismissed from the stand.		
9:14:46 PM	Witness Jeff Williams - Big Rivers - takes the stand and is sworn in.		
		Note: Harward, Sonya	Manager of Budgets for Big Rivers
9:15:13 PM	Atty. Kamuf direct of Witness Williams		
		Note: Harward, Sonya	Confirms that his testimony is still accurate and has no changes.
9:15:27 PM	Witness Williams is dismissed from the stand.		
9:15:39 PM	Hearing adjourned for the evening.		
9:15:44 PM	Session Paused		
9:31:54 PM	Session Ended		

Exhibit List Report

2013-00199_08Jan2014

Big Rivers Electric Corporation

Name:	Description:
KIUC - Exhibit 7	Figure 1, Number of Large Industrial Customers by mW size, Direct Testimony of Stephen J. Baron at pages 13-14, CN 2013-00199
KIUC - Exhibit 8	The Vulnerability of Kentucky's Manufacturing Economy to Increasing Electricity Prices, Aron Patrick, Kentucky Energy and Environment Cabinet, Department of Energy Development and Independence, October 2012, energy.ky.gov

Exhibit List Report

2013-00199_08Jan2014-2

Big Rivers Electric Corporation

Name:	Description:
KIUC - Exhibit 10	Big Rivers Electric Corp. Tariff, PSC KY No. 24, Original Sheet 29, Cancelling No. 23 and Original Sheet 52, Standard Rate - LICX - Large Industrial Customer Expansion, dated Dec. 201, 2011
Not accepted - KIUC - Exhibit 09	Collection of various news stories from websites. (This document was introduced by KIUC but was not accpeted into the record.)
SC - Exhibit 04 - CONFIDENTIAL	Big Rivers Long-Term Financial Forecast, 7 pages
SC - Exhibit 05	Report on the Comprehensive Depreciation Study, Prepared for Big Rivers Electric Corp., Henderson, KY, dated November 2012, Project Number 70000, Burns & McDonnell
SC - Exhibit 06	Westlaw, 196 B. R. 868, 29 Bankr.Ct.Dec. 99, Bankr. L. Rep. P 77,066, United States Bankruptcy Court, D. Utah, Central Division, In re Bonneville Pacific Corp., Debtor, Bankruptcy No. 91A-27701, May 22, 1996
SC - Exhibit 07 - CONFIDENTIAL	Annual Capacity Price Forecast (Nominal $/kW-yr)
SC - Exhibit 08 - CONFIDENTIAL	CN 2013-00199, Big Rivers' Response to Commission Staff's Second Request for Information, Item 14, dated Aug. 19, 2013, with a confidential attachment as part of the response.
SC - Exhibit 09 - CONFIDENTIAL	CN 2013-00199, Big Rivers' Response to Sierra Club's Second Request for Information, Item 10, dated Sept. 30, 2013
SC - Exhibit 10	Letter to Honorable Kimberly D. Bose, Secretary of FERC, from Michael L. Kessler of Midwest Independetnnt Transmission, and Richard A. Drom of Andrews Kurth LLP, both are Attorney's for MISO, dated Sept. 3, 2013
SC - Exhibit 11 - CONFIDENTIAL	CN 2013-00199, Response to Commission Staff's Second Request for Information, Item 16, dated Aug. 19, 2013
SC - Exhibit 12 - CONFIDENTIAL	CN 2013-00199, Response to Commission Staff's Second Request for Information, Item 15, dated Aug. 19, 2013
SC - Exhibit 13	Big Rivers Electric Corporation Comments on the Proposed Effluent Limitations Guidelines adn Standards for the Steam Electric Power Generating Point Source Category, dated Sept. 20, 2013
SC - Exhibit 14	CN 2013-00199, Response to Sierra Club's Second Request for Information, Item 20, dated Sept. 16, 2013
SC - Exhibit 15	CN 2013-00199, Response to Sierra Club's Second Request for Information, Item 21, dated Sept. 16, 2013
SC - Exhibit 16 - CONFIDENTIAL	Big Rivers Electric Corporation Environmental Compliance Study, by Sargent & Lundy, dated Feb. 13, 2012

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES SUPPORTED BY FULLY FORECASTED TEST PERIOD	) CASE NO. 2013-00199

CERTIFICATE

I, Sonya Harward, hereby certify that:

1. The attached DVD contains a digital recording of the hearing conducted in the above-styled proceeding on January 9, 2014; (excluding any confidential segments, which were recorded on a separate DVD and will be maintained in the non-public records of the Commission, along with the Confidential Exhibits and Hearing Log). The hearing was recorded on three consecutive days, January 7, 2014, January 8, 2014, and January 9, 2014, separately. (Confidential portions were also recorded separately).

2. I am responsible for the preparation of the digital recording;

3. The digital recording accurately and correctly depicts the hearing of January 9, 2014 (excluding any confidential segments);

4. The "Exhibit List" attached to this Certificate correctly lists all exhibits introduced at the hearing of January 9, 2014 (excluding any confidential exhibits).

5. The "Hearing Log" attached to this Certificate accurately and correctly states the events that occurred at the hearing of January 9, 2014 (excluding any confidential segments) and the time at which each occurred.

Given this 10th day of January, 2014.

Sonya Harward (Boyd)

Sonya Harward (Boyd), Notary Public
State at Large
My commission expires: August 27, 2017

Date:	Type:	Location:	Department:
1/9/2014	General Rates	Public Service Commission	Hearing Room 1 (HR 1)

Judge: David Armstrong; Linda Breathitt; Jim Gardner
Witness: Frank Ackerman - for Sierra Club; Mark Bailey - Big Rivers; Stephen Baron - for KIUC; Lindsay Barron - Big Rivers; David Brevitz - for AG; Michael Carter - for KIUC; Bill Cummings - for KIUC; Thomas Davis - Big Rivers; Philip Hayet - for KIUC; Steve Henry - for KIUC; Larry Holloway - for AG; Lane Kollen - for KIUC; Bion Ostrander - for AG; Chris Warren - Big Rivers; John Wolfram - for Big Rivers
Clerk: Sonya Harward

Event Time	Log Event	
9:28:26 AM	Session Started	
9:28:28 AM	Vice Chairman resumes Hearing	
9:28:31 AM	Camera Lock Deactivated	
9:28:49 AM	Witness Lindsay Barron - Big Rivers - takes the stand and is sworn in.	
	Note: Harward, Sonya	VP Energy Services for Big Rivers
9:29:10 AM	Atty. Kamuf (BR) direct exam.of Witness Barron	
	Note: Harward, Sonya	Witness accepts her testimony as accurate and has no changes.
9:29:23 AM	Atty. Cook (AG) cross exam. of Witness Barron	
9:32:40 AM	Atty. Cook to Witness Barron	
	Note: Harward, Sonya	Discussing how replacement load forecast was developed.
9:35:09 AM	POST HEARING DATA REQUEST by AG	
	Note: Harward, Sonya	Copy of presentation given at meeting with the State Economic Development Cabinet.
9:38:30 AM	Atty. Cook to Witness Barron	
	Note: Harward, Sonya	Discussing budgeted money for economic development.
9:39:17 AM	Atty. Kurtz (KIUC) cross exam. of Witness Barron	
	Note: Harward, Sonya	Discussing public comments made on Jan. 8, 2014.
9:41:50 AM	Atty. Kurtz to Witness Barron	
	Note: Harward, Sonya	Discussing load forecast.
9:43:17 AM	Atty. Kurtz to Witness Barron	
	Note: Harward, Sonya	Referencing SC - Exhibit 4 of this Hearing.
9:48:00 AM	Atty. Kurtz to Witness Barron	
	Note: Harward, Sonya	Discussing replacement load.
9:49:13 AM	Atty. Kurtz to Witness Barron	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 12, beginning at line 20.
9:52:46 AM	Atty. Kamuf Objection	
	Note: Harward, Sonya	Allow Witness to respond to question.
9:52:50 AM	Vice Chairman Gardner	
	Note: Harward, Sonya	Asked Atty. Kurtz to allow Witness to complete answer.
9:53:10 AM	Atty. Kurtz to Witness Barron	
	Note: Harward, Sonya	Referencing KIUC - Exhibit 8 of this Hearing, page 9.
10:00:05 AM	Atty. Kurtz to Witness Barron	
	Note: Harward, Sonya	Discussing selling power to Nebraska at half the price as to Kentucky customers.
10:01:07 AM	Atty. Kamuf Objection	
	Note: Harward, Sonya	Asks that Atty. Kurtz make less comments.
10:02:55 AM	Atty. Kurtz to Witness Barron	
	Note: Harward, Sonya	Questioning about negotiations with some customers.

10:03:52 AM	Vice Chariman	
	Note: Harward, Sonya	Stopped Atty. Kurtz to allow Witness Barron to answer.
10:04:05 AM	Atty. Kurtz to Witness Barron	
	Note: Harward, Sonya	Restated question.
10:04:58 AM	Atty. Henry (SC) cross exam. of Witness Barron	
10:05:20 AM	SC - Exhibit 17	
	Note: Harward, Sonya	Letter from Big Rivers, Lindsay Barron, to to Lance Hedquist, South Sioux City, dated Dec. 11, 2013
10:09:40 AM	Atty. Henry to Witness Barron	
	Note: Harward, Sonya	Questioning about Nebraska future rates.
10:10:27 AM	Kamuf Objection	
	Note: Harward, Sonya	About line of questioning.
10:10:30 AM	Vice Chairman Gardner	
	Note: Harward, Sonya	Atty. Henry can continue line of questioning as Witness opened herself to it.
10:11:53 AM	SC - Exhibit 18 (This document was introduced by SC but was not accpeted into the record.)	
	Note: Harward, Sonya	Mixing variability with reliability, 2013 Information Guide, from a website.
10:14:47 AM	Atty. Henry to Witness Barron	
	Note: Harward, Sonya	Referencing SC - Exhibit 17, page 2, of this Hearing.
10:16:04 AM	SC - Exhibit 19	
	Note: Harward, Sonya	2013-00199, Response to Sierra Club's Initial Request for Information, Item 20, dated Aug. 19, 2013
10:17:55 AM	Vice Chairman Gardner	
	Note: Harward, Sonya	Allow Witness to expand on her answer.
10:20:14 AM	Atty. Henry to Witness Barron	
	Note: Harward, Sonya	Continued questioning about long run price elasticity.
10:22:35 AM	Atty. Henry to Witness Barron	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 8, line 16, through page 9, line 7.
10:26:10 AM	Atty. Henry to Witness Barron	
	Note: Harward, Sonya	Continued questioning about zero price elasticity.
10:28:50 AM	SC - Exhibit 20	
	Note: Harward, Sonya	U.S. Energy Information Administration - Average Retail Price of Electricity in 2011 (Also, Exhibit 8 to John Wolfram's Testimony)
10:33:26 AM	Atty. Henry to Witness Barron	
	Note: Harward, Sonya	Continuing to reference SC - Exhibit 20, page 4, of this Hearing
10:34:15 AM	Atty. Depp Objection	
	Note: Harward, Sonya	Due to time, better to ask questions of Witness Wolfram.
10:34:25 AM	Atty. Henry's Response to Objection	
10:36:10 AM	SC - Exhibit 21	
	Note: Harward, Sonya	2013-00199, Big Rivers' Response to Sierra Club's Second Request for Information, dated Sept. 16, 2013
10:41:45 AM	Atty. Henry to Witness Barron	
	Note: Harward, Sonya	Additional questioning about zero price elasticity and any studies regarding the subject.
10:44:03 AM	Vice Chairman Gardner	
	Note: Harward, Sonya	Asked Atty. Henry to move on, this line of questioning has been addressed.
10:45:47 AM	Atty. Henry to Witness Barron	
	Note: Harward, Sonya	Referencing Ackerman Testimony, pages 15 -20.
10:47:50 AM	Atty. Henry to Witness Barron	
	Note: Harward, Sonya	Referencing Ackerman Testimony, Exhibit 4, page 88.

10:52:00 AM	Atty. Henry to Witness Barron	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 9, line 19, through page 10, line 19.
10:52:57 AM	SC - Exhibit 22 - Amended	
	Note: Harward, Sonya	This Exhibit was amended to only include the title page and page 81.
	Note: Harward, Sonya	2011 Integrated Resource Plan by Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Incorporated, dated Nov. 1, 2011.
10:57:51 AM	Witness Barron	
	Note: Harward, Sonya	Referencing Vectron materials in response to a question from Atty. Henry.
10:58:08 AM	Atty. Henry Objection	
	Note: Harward, Sonya	Materials being referenced are not in the record.
10:58:16 AM	Vice Chairman Gardner	
	Note: Harward, Sonya	Response to Objection
10:58:21 AM	Attys. Depp and Kamuf Response to Objection	
	Note: Harward, Sonya	Atty. Henry opened the door for response.
10:59:10 AM	Vice Chairman cross exam. of Witness Barron	
	Note: Harward, Sonya	Discussing load forecast that is submitted to RUS for review and approval every two years.
11:08:29 AM	Vice Chairman Gardner to Witness Barron	
	Note: Harward, Sonya	Asking if increases at Big Rivers were studied over the last few years in regards to impact.
11:09:35 AM	Commissioner Breathitt cross exam. of Witness Barron	
11:10:35 AM	Vice Chairman Gardner to Witness Barron	
	Note: Harward, Sonya	Asking about a number in Witness's Testimony, Barron Exhibit 3.
11:12:35 AM	Witness Barron dismissed from the stand.	
11:12:54 AM	Witness Tom Davis - Big Rivers - takes the stand and is sworn in.	
	Note: Harward, Sonya	VP of Administrative Services, Big Rivers
11:13:35 AM	Atty. Kamuf direct exam. of Witness Davis	
	Note: Harward, Sonya	Witness accepts his testimony as accurate and has no changes.
11:13:57 AM	Atty. Cook cross exam. of Witness Davis	
	Note: Harward, Sonya	Referencing Witness's Rubuttal Testimony, page 12, line 19.
11:15:19 AM	Atty. Cook to Witness Davis	
	Note: Harward, Sonya	Referencing AG's Supplemental Response to the PSC Request for Info., Supplemental 7, regarding a potential correction on 2nd page, line 2.
11:18:31 AM	Witness Davis	
	Note: Harward, Sonya	Change to Witness's Rebuttal Testimony, page 12, line 19, number should be $3.1M, subject to check.
11:19:23 AM	Discussion about the correction.	
11:20:54 AM	Atty. Kurtz cross exam. of Witness Davis	
	Note: Harward, Sonya	Asking about public comment from Jackson Purchase Board Member on Jan. 8, 2014.
11:21:21 AM	Atty. Kurtz to Witness Davis	
	Note: Harward, Sonya	Asking about NorthStar and bonuses.
11:28:24 AM	Atty. Kurtz to Witness Davis	
	Note: Harward, Sonya	Asking about employees incentive to making the company more profitable for personal gain.
11:29:33 AM	Witness Davis dismissed from the stand.	
11:29:54 AM	BREAK	
11:30:18 AM	Session Paused	
11:43:43 AM	Session Resumed	
11:43:48 AM	Recall of Witness Bailey to the stand.	

11:43:50 AM	Atty. Kurtz to Witness Bailey	
	Note: Harward, Sonya	Questioning about public comments by Jackson Purchase Board Member from Jan. 8, 2014.
11:44:21 AM	Atty. Kurtz to Witness Bailey	
	Note: Harward, Sonya	Questioning about NorthStar.
11:44:54 AM	Witness Bailey	
	Note: Harward, Sonya	Referencing BR's Response to KIUC's Second Information Request, Item 48.
11:49:30 AM	Witness Bailey dismissed from the stand.	
11:49:36 AM	Witness Chris Warren - Big Rivers - takes the stand and is sworn in.	
	Note: Harward, Sonya	Forecast and Financial Analyst for Big Rivers
11:50:08 AM	Atty. Kamuf direct exam. of Witness Warren	
	Note: Harward, Sonya	Witness accepts his testimony as accurate with no changes.
11:50:17 AM	Atty. Cook cross exam. of Witness Warren	
11:55:32 AM	Atty. Cook to Witness Warren	
	Note: Harward, Sonya	Referencing PSC 1-57.
11:56:31 AM	AG - Exhibit 7 - CONFIDENTIAL	
	Note: Harward, Sonya	Rates Tab PSC 2-14, Financial Forecast (2014-2027), dated 5-16-2013
11:57:17 AM	Hearing going into Confidential Session	
11:57:31 AM	Private Recording Activated	
12:04:01 PM	Public Recording Activated	
12:04:04 PM	Hearing resumed in Public Session	
12:04:25 PM	Atty. Cook to Witness Warren	
	Note: Harward, Sonya	Referencing AG - Exhibit 7.
12:11:30 PM	Atty. Cook to Witness Warren	
	Note: Harward, Sonya	Questioning about other financial models like BR's that he may have done at his previous job.
12:16:05 PM	Atty. Cook to Witness Warren	
	Note: Harward, Sonya	Referencing Wolfram Rebuttal Testimony, attachment Warren Exhibit 3.2.
12:17:57 PM	POST HEARING DATA REQUEST by AG	
	Note: Harward, Sonya	Provide basis for changes Witness made to Wolfram Rebuttal Testimony, Exhibit 3.2.
12:18:04 PM	Atty. Kamuf Objection	
	Note: Harward, Sonya	Objection to Post Hearing Data Request
12:18:11 PM	Atty. Cook	
	Note: Harward, Sonya	Response to Objection
12:19:26 PM	Vice Chairman Gardner	
	Note: Harward, Sonya	Provide data that has been requested.
12:19:53 PM	Atty. Cook to Witness Warren	
	Note: Harward, Sonya	Referencing Wolfram Rebuttal Testimony, Exhibit 2.2, line 1.
12:21:54 PM	Atty. Cook to Witness Warren	
	Note: Harward, Sonya	Referencing Wolfram Direct Testimony, Exhibit 2, page 1 of 15, line 1.
12:24:24 PM	Atty. Kurtz cross exam. of Witness Warren	
12:25:19 PM	Going into Confidential Session	
12:25:51 PM	Private Recording Activated	
12:32:02 PM	Public Recording Activated	
12:32:04 PM	Hearing resumed in Public Session.	
12:32:08 PM	Atty. Cmar to Witness Warren	
12:35:55 PM	Vice Chairman Gardner interjected a question to Witness Warren.	
	Note: Harward, Sonya	Asked who told him to include specific information in the model.

12:38:00 PM	Atty. Nguyen cross exam. of Witness Warren	
	Note: Harward, Sonya	Referencing Wolfram Rebuttal Testimony, pages 34-35.
12:39:16 PM	POST HEARING DATA REQUEST by PSC	
	Note: Harward, Sonya	Provide Exhibit 2.2, from Wolfram Rebuttal Testimony, in Excel spreadsheet format.
12:39:38 PM	Commissioner Breathitt cross exam. of Witness Warren	
12:40:10 PM	Atty. Kamuf re-direct of Witness Warren	
12:43:31 PM	Witness Warren dismissed from stand.	
12:43:48 PM	Vice Chairman	
	Note: Harward, Sonya	Discussing order of witnesses for the rest of the day.
12:46:05 PM	BREAK	
12:46:09 PM	Session Paused	
1:44:21 PM	Session Resumed	
1:44:24 PM	Witness John Wolfram - for Big Rivers - takes the stand and is sworn in.	
	Note: Harward, Sonya	Founder and Principal of Catalyst Consulting
1:44:57 PM	Atty. Kamuf direct exam. of Witness Wolfram	
	Note: Harward, Sonya	Correction to Witness's Rebuttal Testimony, page 20 of 39, line 19, currently reads as Feb 1, 2014 but should read as Jan. 31, 2015.
1:44:57 PM	Camera Lock Deactivated	
1:45:48 PM	Atty. Cook cross exam. of Witness Wolfram	
1:46:50 PM	Atty. Cook to Witness Wolfram	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, Exhibit 2
	Note: Harward, Sonya	Referencing Revised Response, Exhibit 2.2, regarding change to the number of $292M.
1:49:37 PM	Atty. Cook cross exam. of Witness Wolfram	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 16, line 11.
1:52:05 PM	Atty. Cook to Witness Wolfram	
	Note: Harward, Sonya	Referencing Berry Direct Testimony, page 13, lines 19-22.
1:54:16 PM	Atty. Cook to Witness Wolfram	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 18, line 8.
1:59:21 PM	Atty. Cook to Witness Wolfram	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 33, line 6.
2:02:18 PM	AG - Exhibit 8	
	Note: Harward, Sonya	Allocation of Smelter Transmission Revenue to Customers
2:03:44 PM	Atty. Cook to Witness Wolfram	
	Note: Harward, Sonya	In conjunction with questioning about AG - Exhibit 8 of this Hearing, referencing Witness's Rebuttal Testimony, Wolfram Exhibit 4.2, and Witness's Direct Testimony, Wolfram Exhibit 4.
2:15:38 PM	Atty. Cook to Witness Wolfram	
	Note: Harward, Sonya	Questioning continuing about AG - Exhibit 8 of this Hearing.
2:16:24 PM	Vice Chairman Gardner interjects a clarifying question.	
2:23:58 PM	Atty. Kurtz cross exam. of Witness Wolfram	
	Note: Harward, Sonya	Continuing to reference AG - Exhibit 8.
2:29:03 PM	KIUC - Exhibit 11	
	Note: Harward, Sonya	Two Pages: Big Rivers Electric Corporation, Cost of Study Service Estimate of Retail Rate Increase (also Exhibit Wolfram 7.2); and Before Accelerated MRSM & RER Credit and After Accelerated MRSM & RER Credit., by Gregory Starheim, President and CEO
2:31:01 PM	Atty. Depp Objection	
	Note: Harward, Sonya	Witness is not familiar with the Kenergy case being discussed.
2:31:03 PM	Vice Chairman Response to Objection	
2:31:49 PM	Atty..Kurtz to Witness Wolfram	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, Wolfram Exhibit 8.

2:39:32 PM	Atty. Depp Objection	
	Note: Harward, Sonya	Assuming evidence not in the record.
2:40:00 PM	KIUC - Exhibit 12	
	Note: Harward, Sonya	U.S. Energy Information Administration - Average Retail Price of Electricity in 2012 - Residential
2:40:44 PM	KIUC - Exhibit 13	
	Note: Harward, Sonya	U.S. Energy Information Administration - Average Retail Price of Electricity in 2012 - Industrial
2:43:35 PM	Atty. Henry cross exam. of Witness Wolfram	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 8, lines 1-9.
2:45:01 PM	Camera Lock Camera 7 Activated	
2:45:07 PM	Camera Lock Deactivated	
2:45:28 PM	Camera Lock Camera 7 Activated	
2:45:37 PM	Camera Lock Deactivated	
2:46:08 PM	Camera Lock Camera 7 Activated	
2:46:14 PM	Camera Lock Deactivated	
2:46:30 PM	Camera Lock Camera 7 Activated	
2:46:42 PM	Atty. Henry to Witness Wolfram	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, page 14, line 22, through page 15, line 6.
	Note: Harward, Sonya	Referencing Berry Rebuttal Testimony, page 19, lines 4-7.
2:47:51 PM	Camera Lock Deactivated	
2:48:04 PM	Camera Lock Camera 7 Activated	
2:48:16 PM	Camera Lock Deactivated	
2:48:59 PM	Camera Lock Camera 7 Activated	
2:49:22 PM	SC - Exhibit 23	
	Note: Harward, Sonya	U.S. Energy Information Administration - Average Retail Price of Electricity in 2011 - Residential and Industrial
2:52:05 PM	Camera Lock Deactivated	
2:52:08 PM	Camera Lock Camera 7 Activated	
2:52:29 PM	Camera Lock Deactivated	
2:53:12 PM	Camera Lock Camera 7 Activated	
2:53:45 PM	Camera Lock Deactivated	
2:54:19 PM	Vice Chairman Gardner	
	Note: Harward, Sonya	Responds to Witness's reluctance to comment on comparison he's being asked to make.
2:54:38 PM	Camera Lock Camera 7 Activated	
2:58:08 PM	Atty. Nguyen cross exam. of Witness Wolfram	
2:58:11 PM	Camera Lock Deactivated	
2:59:15 PM	Atty. Nguyen to Witness Wolfram	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, pages 32 and 33.
3:00:27 PM	Vice Chairman Gardner interjects a clarifying question.	
3:01:14 PM	Atty. Nguyen to Witness Wolfram	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, table on page 37.
3:04:00 PM	Atty. Nguyen to Witness Wolfram	
	Note: Harward, Sonya	Referencing Big Rivers' Response to Staff's Second Request for Information, Item 24.
3:06:13 PM	Atty. Nguyen to Witness Wolfram	
	Note: Harward, Sonya	Referencing Big Rivers' Response to Staff's Third Request for Information, Item 6.
3:08:16 PM	POST HEARING DATA REQUEST by PSC Staff	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, Exhibit 5.2. Provide a breakdown for the kWh and kW billing determinants for each of the three members.

3:10:06 PM	Atty. Nguyen to Witness Wolfram	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, Exhibit 2.2, page 12 of 15.
3:11:35 PM	Commissioner Breathitt cross exam. of Witness Wolfram	
	Note: Harward, Sonya	Referencing Witness's Rebuttal Testimony, Exhibit 2.2, page Ex. 2.2, page 13 of 15.
3:12:51 PM	POST HEARING DATA REQUEST by Commissioner Breathitt	
	Note: Harward, Sonya	Explain why in June and December of 2014 the DSM expenses are so much higher than the months prior.
3:13:19 PM	Vice Chairman Gardner cross exam. of Witness Wolfram	
3:14:37 PM	Vice Chairman Gardner to Witness Wolfram	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 25.
3:18:32 PM	Vice Chairman Gardner to Witness Wolfram	
	Note: Harward, Sonya	Continues questioning about information provided in CN 2012-00535
3:19:43 PM	Vice Chairman Gardner to Witness Wolfram	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 27.
3:20:15 PM	Vice Chairman Gardner to Witness Wolfram	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 33.
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 29.
3:22:00 PM	Vice Chairman Gardner to Witness Wolfram	
	Note: Harward, Sonya	Questioning about laying-up costs of Wilson and Coleman.
3:24:44 PM	Atty. Kamuf redirect exam. of Witness Wolfram	
3:25:59 PM	Atty. Kamuf to Witness Wolfram	
	Note: Harward, Sonya	Referencing Holloway 3, pages 8 and 9.
3:28:16 PM	Atty. Cook re-cross of Witness Wolfram	
3:32:09 PM	Witness Wolfram dismissed from the stand.	
3:32:19 PM	Atty. Kamuf	
	Note: Harward, Sonya	This concludes the testimony of witnesses for Big Rivers.
3:33:26 PM	BREAK	
3:33:38 PM	Session Paused	
3:48:24 PM	Session Resumed	
3:48:28 PM	Vice Chairman	
	Note: Harward, Sonya	There were no objections to this.
	Note: Harward, Sonya	Chairman Armstrong has an engagement and will not be back this evening but has the video he can review.
3:48:32 PM	Witness Bill Cummings - for KIUC - takes the stand and is sworn in.	
	Note: Harward, Sonya	Energy Supply Manager for Kimberly Clark
3:49:06 PM	Atty. Kurtz direct exam. of Witness Cummings	
3:49:16 PM	Commissioner Breathitt cross exam. of Witness Cummings	
3:53:00 PM	Vice Chairman Gardner cross exam. of Witness Cummings	
3:54:23 PM	Witness Cummings is dismissed from the stand.	
3:55:03 PM	Witness Stephen Baron - for KIUC - takes the stand and is sworn in.	
	Note: Harward, Sonya	President of J. Kennedy and Assoc.
3:55:48 PM	Atty. Kurtz direct exam. of Witness Baron	
	Note: Harward, Sonya	Witness makes a change to his testimony that he discusses.
3:58:56 PM	Atty. Kamuf cross exam. of Witness Baron	
	Note: Harward, Sonya	Asking for clarification of the change to Witness's testimony.
4:02:16 PM	Commissioner Breathitt interjects with a clarifying question.	
4:07:35 PM	Atty. Kamuf to Witness Baron	
	Note: Harward, Sonya	Discussing other recommendations that Witness still supports.
4:09:59 PM	Atty. Kamuf to Witness Baron	
	Note: Harward, Sonya	Referencing Witness's Testimony, page 23, lines 16-17.

4:13:59 PM	Atty. Kamuf to Witness Baron	
	Note: Harward, Sonya	Referencing Witness's Testimony, page 11, lines 18-19, regarding idled plant and closed mine.
4:16:03 PM	Atty. Hans (AG) cross exam. of Witness Baron	
	Note: Harward, Sonya	Asking about revised recommendation, referencing Witness's Testimony, page 3, lines 18-20.
4:24:15 PM	Atty. Hans to Witness Baron	
	Note: Harward, Sonya	Asking if Witness or KIUC has discussed your proposals wtih any of the commerical interests or stakeholders in Big Rivers' territory.
4:25:39 PM	Atty. Hans to Witness Baron	
	Note: Harward, Sonya	Questioning about an Order the Commission has addressed concerning RERs.
4:26:25 PM	Atty. Nguyen cross exam. of Witness Baron	
	Note: Harward, Sonya	Asking clarifying questions about revision to Witness's Testimony.
4:30:31 PM	POST HEARING DATA REQUEST by PSC Staff	
	Note: Harward, Sonya	Provide, in electronic format, the supporting calculations for how the numbers being discussed were detemined.
4:35:02 PM	Atty. Nguyen to Witness Baron	
	Note: Harward, Sonya	For clarification, discussing Meade Schedule 1 Rate Class and various Jackson Schedules.
4:39:29 PM	POST HEARING DATA REQUEST by PSC Staff	
	Note: Harward, Sonya	Provide rates classes for each of the three distribution member coops.
4:40:41 PM	Vice Chairman Gardner cross exam. of Witness Baron	
4:44:38 PM	Vice Chairman Gardner to Witness Baron	
	Note: Harward, Sonya	Referencing Witness's Testimony, top of page 10.
4:46:54 PM	Atty. Kurtz re-direct of Witness Baron	
4:51:22 PM	Atty. Kamuf re-cross of Witness Baron	
4:54:21 PM	Atty. Kamuf to Witness Baron	
	Note: Harward, Sonya	Asking general questions regarding Kollen Testimony.
4:58:30 PM	Atty. Kamuf to Witness Baron	
	Note: Harward, Sonya	Why was new RER proposal not made sooner?
4:59:18 PM	Atty. Nguyen re-cross of Witness Baron	
5:00:22 PM	Witness Baron dismissed from stand.	
5:00:33 PM	Witness Frank Ackerman - SC - takes the stand and is sworn in.	
	Note: Harward, Sonya	Senior Economic Analyst at Synapse Energy
5:01:11 PM	Atty. Cmar direct exam. of Witness Ackerman	
	Note: Harward, Sonya	Witness accepts his Testimony as accurate with no changes.
5:01:33 PM	Atty. Kamuf cross exam. of Witness Ackerman	
	Note: Harward, Sonya	Referencing Witness's Testimony, page 19, line 3.
5:02:50 PM	BR - Exhibit 1	
	Note: Harward, Sonya	Web Article "Replacing Old Coal", Environmental Law Program, from Sierra Club website.
5:04:23 PM	BR - Exhibit 2	
	Note: Harward, Sonya	Web Article "How Many Dirty Coal-Burning Plants Have We Directed", Beyond Coal, from Sierra Club website.
5:06:10 PM	BR - Exhibit 3	
	Note: Harward, Sonya	Web Article " Dirty, Dangerous, adn Run Amok, Beyond Natural Gas, from Sierra Club website.
5:07:38 PM	Atty. Kamuf to Witness Ackerman	
	Note: Harward, Sonya	Referencing Witness's Testimony, pages 28 and 29.
5:13:08 PM	Vice Chairman Gardner cross exam. of Witness Ackerman	
5:13:38 PM	Vice Chairman Gardner	
	Note: Harward, Sonya	Asking if certain numbers are confidential before asking Witness about them.

5:17:59 PM	Vice Chairman Gardner to Witness Ackerman
	Note: Harward, Sonya — Asking questions regarding price elasticity.
5:22:24 PM	Atty. Cmar re-direct of Witness Ackerman
5:22:56 PM	Camera Lock Camera 7 Activated
5:23:12 PM	Camera Lock Deactivated
5:23:40 PM	Camera Lock Camera 7 Activated
5:23:56 PM	Camera Lock Deactivated
5:29:10 PM	Vice Chairman Gardner re-cross of Witness Ackerman
5:30:50 PM	Witness Ackerman is dismissed from the stand.
5:31:13 PM	Witness Steve Henry - for KIUC - takes the stand and is sworn in.
	Note: Harward, Sonya — General Manager at Domtar Paper
5:32:03 PM	Atty. Kurtz direct exam. of Witness Henry
	Note: Harward, Sonya — Witness has change to Testimony, page 9, line 16, agrees that primary alternative is the new proposal outlined by Witness Baron.
5:33:10 PM	Atty. Depp cross exam. of Witness Henry
5:37:15 PM	Atty. Depp to Witness Henry
	Note: Harward, Sonya — Referencing Witness's Response to Big Rivers Data Request, 1-56, regarding whether or not Domtar is pursuing any current Legislation.
5:39:40 PM	Commissioner Breathitt cross exam. of Witness Henry
	Note: Harward, Sonya — Referencing Witness's Testimony, page 9, lines 7-13, regarding brown power.
5:43:47 PM	Vice Chairman Gardner cross exam. of Witness Henry
5:45:00 PM	Commissioner Breathitt to Witness Henry
5:45:38 PM	Atty. Kurtz re-direct of Witness Henry
5:46:37 PM	Atty. Depp re-cross of Witness Henry
5:47:14 PM	Witness Henry dismissed from the stand.
5:47:37 PM	Atty. Joe Childers now stepping in for Sierra Club
5:47:47 PM	Witness Michael Carter - KIUC - takes the stand and is sworn in.
	Note: Harward, Sonya — Aleris International
5:48:06 PM	Atty. Kurtz direct exam. of Witness Clark
	Note: Harward, Sonya — Adopting Testimony of Kelly Thomas, one change, page 8, change to agree with revised plan laid out by Witness Baron.
5:48:47 PM	Commissioner Breathitt cross exam. of Witness Carter
5:50:14 PM	Witness Carter dismissed from the stand.
5:51:28 PM	Session Paused
5:52:08 PM	Session Resumed
5:52:10 PM	Vice Chairman
	Note: Harward, Sonya — Asked about finishing the Hearing this evening and was assured that would be the case.
5:52:20 PM	BREAK
5:52:31 PM	Session Paused
6:09:14 PM	Session Resumed
6:09:19 PM	Witness Bion Ostrander - for AG - takes the stand and is sworn in.
	Note: Harward, Sonya — Ostrander Consulting
6:09:44 PM	Atty. Cook direct exam. of Witness Ostrander
	Note: Harward, Sonya — Change to Witness's Testimony, page 29, line 5, after the word "rate", the word "case" should be inserted.
6:10:09 PM	Camera Lock Deactivated
6:10:33 PM	Atty. Depp cross exam. of Witness Ostrander
6:12:05 PM	Vice Chairman Gardner cross exam. of Witness
6:13:04 PM	Commissioner Breathitt cross exam. of Witness Ostrander
6:13:39 PM	Vice Chairman to Witness Ostrander
	Note: Harward, Sonya — Referencing an NRRI article about Forecasting Test Year

6:15:24 PM	Vice Chairman to Witness Ostrander	
	Note: Harward, Sonya	Gives disclosure of how he knows about the article and being on the Advisory Board of the NRRI.
6:16:17 PM	Atty. Depp re-cross of Witness Ostrander	
6:17:20 PM	Witness Ostrander dismissed from the stand.	
6:18:48 PM	Witness Larry Holloway - for AG - takes the stand and is sworn in.	
	Note: Harward, Sonya	Independent Consultant, and Operations Manager for Kansas Power
6:19:25 PM	Atty. Cook direct exam. of Witness Holloway	
	Note: Harward, Sonya	Witness lists numerous changes to various parts of his Testimony.
6:26:14 PM	Atty. Depp cross exam. of Witness Holloway	
6:26:54 PM	Atty. Depp to Witness Holloway	
	Note: Harward, Sonya	Referencing Exhibit Holloway 3.
6:28:23 PM	Vice Chairman Gardner cross exam. of Witness Holloway	
	Note: Harward, Sonya	Asks for Witness's view about whether transmission revenues should not be considered as a reduction in the revenue requirement, but instead should be used to increase economic reserve to the members.
6:35:21 PM	Vice Chairman Gardner to Witness Holloway	
	Note: Harward, Sonya	Continues questioning
6:36:11 PM	Atty. Cook re-direct of Witness Holloway	
6:37:09 PM	Witness Holloway dismissed from the stand.	
6:37:27 PM	Witness David Brevitz - AG - takes the stand and is sworn in.	
	Note: Harward, Sonya	Principal and President of Brevitz Consulting Services
6:38:20 PM	Atty. Cook direct exam. of Witness Brevitz	
	Note: Harward, Sonya	Correction to Witness's Testimony on page 39, line 8, delete "is less than 1.0" and insert "is not positive".
6:38:54 PM	Atty. Depp cross exam. of Witness Brevitz	
6:39:51 PM	Atty. Depp to Witness Brevitz	
	Note: Harward, Sonya	Referencing AG's Repsonse to BR's Date Request, 1-35.
6:40:58 PM	Vice Chairman cross exam. of Witness Brevitz	
	Note: Harward, Sonya	Referencing Witness's Direct Testimony, page 29.
6:44:23 PM	Witness Brevitz dismissed from the stand.	
6:44:40 PM	Witness Philip Hayet - KIUC - takes the stand and is sworn in.	
	Note: Harward, Sonya	Director of Consulting for J. Kennedy & Associates
6:45:23 PM	Atty. Kurtz direct exam. of Witness Hayet	
	Note: Harward, Sonya	Witness accepts Testimony as accurate and has no changes.
6:45:37 PM	Atty. Kamuf cross exam. of Witness Hayet	
	Note: Harward, Sonya	Referencing Witness's Testimony, page 29, lines 5-6.
	Note: Harward, Sonya	Referencing Witness's Testimony, page 39, regarding MATS.
	Note: Harward, Sonya	Referencing Witness's Testimony, pages 40-41.
6:50:11 PM	Vice Chairman Gardner cross exam. of Witness Hayet.	
6:53:05 PM	Vice Chairman Gardner to Witness Hayet	
	Note: Harward, Sonya	Asking question with respect to CO2.
6:55:32 PM	Commissioner Breathitt interjects a clarifying question.	
6:59:35 PM	Vice Chairman Gardner to Witness Hayet	
7:01:30 PM	Witness Hayet dismissed from the stand.	
7:01:43 PM	Witness Lane Kollen - KIUC - takes the stand and is sworn in.	
	Note: Harward, Sonya	Vice President of J. Kennedy and Associates.
7:02:33 PM	Atty. Kurtz direct exam. of Witness Kollen	
	Note: Harward, Sonya	Has several changes to Testimony [changes submitted as KIUC - Exhibit 14 to this Hearing.]
7:03:11 PM	Session Paused	
7:03:23 PM	Session Resumed	

7:03:33 PM	KIUC - Exhibit 14	
	Note: Harward, Sonya	Changes to various parts of Witness Kollen's Testimony
7:11:58 PM	Atty. Kamuf	
	Note: Harward, Sonya	Comments that he does not have time to look at all of the changes to Witness Kollen's Testimony since they are numerous, but wishes to continue with the Hearing at this time.
7:12:44 PM	Atty. Nguyen	
	Note: Harward, Sonya	Asked about changes on pages 72 and 73 of KIUC - Exhibit 14 of this Hearing.
7:13:35 PM	Atty. Kurtz	
	Note: Harward, Sonya	Asking Witness additional questions about his changes.
7:14:15 PM	Atty. Kamuf cross exam. of Witness Kollen	
7:14:23 PM	BR - Exhibit 4	
	Note: Harward, Sonya	Case No. 2013-00413, Direct Testimony and Exhibits of Lane Kollen, dated December 2013
7:16:02 PM	Vice Chairman Gardner cross exam. of Witness Kollen	
7:16:19 PM	BREAK	
7:16:22 PM	Session Paused	
7:20:30 PM	Session Resumed	
7:20:36 PM	Vice Chairman Gardner to Witness Kollen	
	Note: Harward, Sonya	Referencing Witness's Testimony, page 11.
7:22:24 PM	Hearing going into Confidential Session	
7:22:27 PM	Private Recording Activated	
7:27:51 PM	Public Recording Activated	
7:27:56 PM	Vice Chairman Gardner to Witness Kollen	
	Note: Harward, Sonya	Referencing Witness's Testimony, page 11.
7:35:52 PM	Commissioner Breathitt cross exam. of Witness Kollen	
7:39:15 PM	Atty. Kurtz redirect of Witness Kollen	
7:40:36 PM	Witness Kollen is dismissed from the stand.	
7:40:51 PM	All Testimony is complete.	
7:40:58 PM	BREAK	
7:41:15 PM	Session Paused	
7:43:50 PM	Session Resumed	
7:43:57 PM	Vice Chairman Garnder - Exhibits	
	Note: Harward, Sonya	All Exhibits, Party by Party, are discussed and entered or denied entry into the record.
8:02:26 PM	Deadlines	
	Note: Harward, Sonya	Briefs due 2/14/14. (no limit)
	Note: Harward, Sonya	Post Hearing Data Requests due 1/24/14.
8:05:59 PM	Atty. Kurtz	
	Note: Harward, Sonya	Asking about companies intent due to the suspension ending on Jan. 27.
8:06:48 PM	Vice Chairman and Parties	
	Note: Harward, Sonya	Discussion about Suspension Period and Company's rates going into effect.
8:08:53 PM	Vice Chairman Gardner	
	Note: Harward, Sonya	Closing statements.
8:09:33 PM	Hearing Adjourned	
8:09:38 PM	Session Paused	
10:26:37 AM	Session Ended	

Exhibit List Report

2013-00199_09Jan2014

Big Rivers Electric Corporation

Name:	Description:
AG - Exhibit 7 - CONFIDENTIAL	Rates Tab PSC 2-14, Financial Forecast (2014-2027), dated 5-16-2013
AG - Exhibit 8	Allocation of Smelter Transmission Revenue to Customers
BR - Exhibit 1	Web Article "Replacing Old Coal", Environmental Law Program, from Sierra Club website.
BR - Exhibit 2	Web Article "How Many Dirty Coal-Burning Plants Have We Directed", Beyond Coal, from Sierra Club website.
BR - Exhibit 3	Web Article " Dirty, Dangerous, and Run Amok, Beyond Natural Gas, from Sierra Club website.
BR - Exhibit 4	Case No. 2013-00413, Direct Testimony and Exhibits of Lane Kollen, dated December 2013
KIUC - Exhibit 11	Two Pages: Big Rivers Electric Corporation, Cost of Study Service Estimate of Retail Rate Increase (also Exhibit Wolfram 7.2); and Before Accelerated MRSM & RER Credit and After Accelerated MRSM & RER Credit., by Gregory Starheim, President and CEO
KIUC - Exhibit 12	U.S. Energy Information Administration - Average Retail Price of Electricity in 2012 - Residential
KIUC - Exhibit 13	U.S. Energy Information Administration - Average Retail Price of Electricity in 2012 - Industrial
KIUC - Exhibit 14	Changes to various parts of Witness Kollen's Testimony
Not accepted - SC - Exhibit 18	Mixing variability with reliability, 2013 Information Guide, from website. (This document was introduced by KUIC but was not accpeted into the record.)
SC - Exhibit 17	Letter from Big Rivers, Lindsay Barron, to to Lance Hedquist, South Sioux City, dated Dec. 11, 2013
SC - Exhibit 19	2013-00199, Big Rivers' Response to Sierra Club's Initial Request for Information, Item 20, dated Aug. 19, 2013
SC - Exhibit 20	U.S. Energy Information Administration - Average Retail Price of Electricity in 2011 (Also, Exhibit 8 to John Wolfram's Testimony)
SC - Exhibit 21	2013-00199, Response to Sierra Club's Second Request for Information, dated Sept. 16, 2013
SC - Exhibit 22 - Amended	2011 Integrated Resource Plan by Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Incorporated, dated Nov. 1, 2011 - Amended to only include the title page and page 81.
SC - Exhibit 23	U.S. Energy Information Administration - Average Retail Price of Electricity in 2011 - Residential and Industrial

Big Rivers Electric Rate Case Hearing – Sebree Smelter

Kentucky Public Service Commission

January 7, 2014

Hancock County Industrial Foundation Testimony

This past July, as Director of the Hancock County Industrial Foundation, I came before the commission to express our concerns with the current challenges facing our industries and our electrical power provider, Big Rivers Electric. Hancock County is home to *Century Aluminum, Aleris Rolled Products, Domtar Paper*, Southwire *Aluminum, Dal-Tile* Co., Pre-coat Metals, Big Rivers Coleman and many additional manufacturing support jobs. Over 2500 high wage jobs!

Today, six months later, I come before this body again to plead on behalf of our county, our industry, our economy and our future. With over 60% of all jobs in manufacturing, Hancock County's economy, and yes, future is firmly anchored in the success and sustainability of our industry. As I reminded the commission in July, the Department of Commerce found Hancock County (at 73%) to be the nation's number one county in percentage of wages paid by manufacturers. While aluminum smelting, rolling, drawn wire, paper manufacturing, steel coating, forming and tile manufacturing are diverse industries, they share a critical element, reliable, sustainable and competitive electrical supply.

The case before you, like the case of July last year, has significant and far reaching implications. While ground zero in this case is our neighbors in Henderson County, the implications extend beyond a single manufacturing plant, a single city, a single neighborhood. Adding to the unique elements of this case is the fact that two of the nation's nine operating smelters are within the Big Rivers supply area. An extraordinary and complex customer-supplier arrangement, no doubt! Unique problems call for unique and creative solutions.

The Hancock County Industrial Foundation's primary mission is to assist existing industry with traditional economic development tools, workforce development programs and promote a strong local business climate. The Foundation also works to insure an environment beneficial to new prospective industries. Reliable, competitive power is critical to both existing and prospective industry. As in all customer supplier arrangements, the relationship must be a win-win. Our presence here today is clear indication that element was not achieved with Century and Big Rivers. It now falls to this Commission to debate, mandate and regulate the win-win for all parties involved. The Hancock County Industrial Foundation and its Board of Directors, is represented by officials from all the above industries including Big Rivers Coleman and Kenergy. Our goal, like everyone here today, is a win-win solution. A tall order, no question!

Now the good news! Our industrial heritage, not only in Hancock County, but in the Commonwealth was built by smart, creative and courageous people from all segments of our communities. People working together and committed to thriving sustainable economies for current and future Kentucky generations. Today's problems will require those same working together strategies to insure a robust industrial future.

We're confident the Commission will use its experience, authorities and resources to find the new win-win for our communities and our continuing industrial heritage!

Thank you.

Mike Baker, Director
Hancock County Industrial Foundation
1605 US Highway 60W
Hawesville, KY 42348
270-313-6719

PUBLIC COMMENT 1

Hancock County Public Schools

83 STATE ROUTE 3543
HAWESVILLE, KENTUCKY 42348
PHONE (270) 927-6914
FAX (270) 927-6916

Hancock County Schools
Together For Children

Superintendent
KYLE ESTES

1-7-14
Address to Public Service Commission

Good Morning, Ladies and Gentlemen of the PSC (Public Service Commission).

My name is Kyle Estes; I am the Superintendent of Schools for the Hancock County School System, in Hawesville KY.

Hancock County Public Schools has a strong tradition of performing among the top 10 county districts in the state. We value that high performance and intend to maintain that status for years to come.

Part of the reason we are able to achieve this educational distinction is because of our middle class community values. I attributed much of our community culture to the good paying wages of business and factories such as Domtar, Aleris, Southwire, and Century Al. and to modest cost of living in our area. With the proposed rate increase, coupled with the recently approved rate increase, I feel our community strengths may be in jeopardy.

Families in our area, just like those across the nation are living on tight budgets. These families have and will continue to be hit hard by the increase approved in the fall of this past year, let alone any additional increases.

I understand and sympathize with the difficult situation Big Rivers finds itself, but I disagree with the solution of citizens shouldering the burden of subsidizing excessive power generation and Big River's 965 million debt payment. Big River's own Communication and Community Relations Manager, Marty Littrel, disagrees with passing on the rate increase as he called on legislators to assist in this endeavor, stating in the July 26, 2012 Clarion, that "It requires more financial assistance than Big Rivers and our customers can afford." I would argue that if Big River's management staff, such as Marty Littrell, know this rate increase is unfair and unjust to its customers, then I am certain most of those in this room have the sentiment.

The proposed rate increase will jeopardize businesses such as Southwire, Aleris, and Domtar's competitiveness in their respective classes. In industries that have thin margins, this could and I would argue will ultimately lead to at least some of these businesses departure from the area. This would have a devastating effect on the community and the school system.

For example, if Domtar closed their Hawesville plant the direct impact would be a net loss of income of $258,913 of utility tax income, $79,807 property tax income, and tangibly assessed income exceeding $100,000. Total, this comes to $438,720 of lost income to the local school system. To put this in context, this is approximately 4% of our entire estimated expenditures. Or to put it another way, it is approximately 8 teachers that would be laid off work.

As I stated earlier, this is merely the direct financial impact of losing Domtar. The indirect effects of losing this employer to our county's educational system are potentially much worse.

Hancock County Public School's enrollment is approximately 1622, K-12. Approximately, 7% of our student body has a parent or guardian that work for Domtar. If Hancock County were to lose Domtar and each of those parents pulled up roots and left the area to find employment elsewhere, the results would be much more catastrophic for the school system. The loss of this 7% enrollment would mean a loss of $513,904 of the state's portion of SEEK dollars. This loss coupled with the direct tax loss of $438,000 would result in a net decrease in revenue of over $900,000 or 8.5% of the school district's current budget.

I understand this is a complex issue with ramifications if the rate does or does not pass. My reason for being here today is to ask you to consider the widespread impact of this rate increase and how it will affect the community for our young people and ask you to consider any and all other possible solutions.

Thank you for your time, and May God Bless each of you.

Kyle Estes,
Superintendent, Hancock County Schools

Thursday, July 26, 2012 | For 119 Years The Voice Of The People Of Hancock County | 75¢

Visit The Hancock Clarion Web Page: www.hancockclarion.com

Hancock Clarion

VOLUME 119—NUMBER 30 • HAWESVILLE, KENTUCKY

Century ramps up pressure on Big Rivers

By Ralph Dickerson

The public relations campaign launched by Century Aluminum concerning its power dispute with Big Rivers Electric Cooperative ramped up this week as smelter officials spoke at both the Lewisport City Council meeting on Thursday evening, and at the Hancock County Fiscal Court meeting Monday evening. Century officials said they need the community's help getting Big Rivers back to the negotiating table.

"What we need from you guys is help solving this problem," Dave Whitmore, plant manager of Century's Hawesville smelter said. "It is dire straits. What we need to do is get Big Rivers back to the table. There are no bad guys here; we need a solution to this, and there are solutions."

According to John Hoerner, vice president of North American Operations, Century needs short term relief immediately to keep the plant in operation.

"If we cannot get Big Rivers back to the table and seriously talking about a resolution, we have a hard decision to make before Labor Day," Hoerner said.

Marty Littrel, Communications and Community Relations Manager for Big Rivers, said it came as a surprise to the company that Century said the company walked away from the table. He said the company wants to work with Century.

"We've never walked away from the negotiating table," Littrel said. "It is interesting to hear this comment that we have walked away, we never have. The truth is we can't agree on where we are at. Obviously Big Rivers has limits on what it can do."

A not-for-profit utility, Big Rivers does not make a high margin on its electric sales. According to Big Rivers' 2012 Annual Report, last year the company earned $561,909,000 in operating revenue. It cost the utility $511,111,006 to make the electricity, and other nonoperating related expenses dropped the company's profit margin to $5,600,000. Littrel said this information translates into this simple fact: it costs Big Rivers $49.60 per megawatt hour to produce electricity.

"We have some of the cheapest electric rates in the United States," Littrel said. "If we cannot produce it cheap enough, I do not know what kind of long term solution there is."

Century officials say the power from Big Rivers simply costs too much, especially considering the depressed condition of the price of aluminum on the London Metal Exchange. Approximately five years ago aluminum traded at approximately $3,000 per ton on the LME. Today, it trades in the neighborhood of $1,900 per ton.

At a time of depressed aluminum prices, Century pays more for electricity than it did in the past. In 2005, Century paid $25 per MwH for power. In 2009, as part of the Big Rivers unwind agreement, Century signed a long-term power contract with Big Rivers. The Kentucky Public Service Commission approved the rate schedule in the contract.

In 2009 Century paid a rate of $36 per megawatt hour, according to company figures, $44 per MwH in 2010, $45 per MwH in 2011 and $49 per MwH this year. The company provided a sheet that showed future rates of $51 per MwH in 2013, $56 per MwH in 2014 and $61 per MwH in 2015.

"I've been in smelting for 25 years," Whitmore said. "You cannot make aluminum at these prices."

See BIG RIVERS on page 2

An Air Evac Lifeteam helicopter prepares to transport a trauma patient to a nearby hospital. The crew landed at the Hancock County High School, one of 22 landing zones designated throughout the county. —Clarion photo by D.W.

Hancock EMS utilizing Air Evac helicopter service more often

By Ralph Dickerson

Several years ago Air Evac Lifeteam started to sell air ambulance memberships in the county, and roughly two years ago the service located a base in Hardinsburg, Ky., only minutes away from the county by air. With the base so close, Hancock County Emergency Services utilizes the service frequently.

"It is growing constantly," Hancock County Emergency Services Director Rick Montague said. "When we first started, it was mainly for trauma patients, people that were in car accidents, accidents at the plants and things like that."

Today Hancock EMS uses the air ambulance service for heart attack and stroke patients in addition to the trauma patients. With Owensboro Medical Health Systems now being a stroke center, Montague said it makes sense to fly patients instead of taking them by ground ambulance. He said in the case of a stroke medicines exist that if given to a patient quick enough reverses the effects of a stroke. With Owensboro being about 10 minutes away by air, the chance of a full recovery increases dramatically.

"Flying from the south part of the county, the Roseville/Cabot area, to the stroke center versus driving saves 15-20 minutes," Montague said.

With Hancock County EMS using the service so much, what guidelines exist for calling in the air ambulance? Montague said the paramedic on scene makes the determination of whether to use an air ambulance or not.

"If the injury deems going to a trauma center—a severe head injury or extreme broken extremities where a trauma center can do the patient more good than a general hospital, we fly them out," Montague said.

Montague said no such thing as a routine accident or injury exists; each injury brings its own specific challenges and problems for the paramedic to treat. As an example he mentioned a head injury suffered in an automobile accident.

Montague said when the paramedic starts treatment, the paramedic starts asking questions of the patient. The answers given are not the most important thing in the exam, but how the person answers. If the person seems distant, possesses trouble focusing on the question or does not react in a generally considered normal way, a more severe problem may exist other than a simple bump on the head.

"There could be swelling to the brain," Montague said. "There could be a bleed, there could be a lot of things going on. I am not taking anything away from our local emergency rooms, but a trauma center can do much more for them."

Even a broken leg presents problems that sometimes requires quick transport to a trauma center. Most people do not realize that several major veins and arteries traverse the legs, and a broken leg possesses the chance of being life threatening.

"An extreme break to the leg can cut circulation off," Montague said. "Just the break alone could cause a person to lose the leg. If we get them to a facility that can handle that type of injury, the patient is better off."

When Air Evac moved into the area, Montague and representatives from the company toured the county and looked for landing zones for the helicopter. They developed 22 such zones in the county, meaning a landing zone is close by no matter

See AIR EVAC on page 14

Hancock County High School marching band members practice their new routine during band camp last week. The group will give its first performance at halftime of the Hornet football team's home opener on August 24. —Clarion photo by S.W.

Scottish man, wife, raising rare horses in county

By Dave Taylor

Driving along Goering Road at the intersection of state Route 144, one might notice an inconspicuous pile along the side of the road with a sign poked in it that says "Free. Help yourself." It's horse poop, and there's plenty more where that came from.

This peculiar sight hints at more peculiarities on the farm, where a guy from Scotland and his northern Indiana wife raise several uncommon breeds of horses in the south east part of Hancock County.

Icelandic horses, Fell ponies, Spotted Draft horses, and Scotland's own Clydesdales roam the farm owned by Brian and Sue Brown.

"They're very not typical for here," said Sue, who is originally from Lakeville, Ind. She and Brian aren't very typical for here either.

He is from Edinburgh, Scotland and still carries a pretty thick accent. She's seriously tattooed and grew up in a small town that bordered Michigan. They met on an online message board about 16 years ago, talking about riding motorcycles. Her great-grandparents were from Scotland and she asked him what the riding was like there.

"He said, 'Well I really can't tell you, you just have to come and see it,' never knowing I was buying a plane ticket at the time," she said. "Four days later I was on his doorstep and I think he about had a heart attack."

They soon married and moved to southern Indiana, but Kentucky was calling her name.

"All my life I wanted to come to Kentucky," she said. "It just took me forever to convince anybody to do it."

Now they live on the former farm of Mary Anne and Ronnie Powers, where in some ways, Brian said, things aren't too much different than back in Scotland.

"Actually if you look around," he said, "if you replace a lot of these trees with pine trees you've got Scotland."

The main difference is that he can afford it here. Land there is expensive and difficult to come by.

"The entire United Kingdom can pretty much fit in Indiana so it's a premium land and if you're not born into it, forget it," he said.

Now they have acres and acres on which to play. He works nights at Waupaca and she works night security at Domtar, but the days belong to their horses.

People tend to first notice the Clydesdales, they said, because of their use in TV commercials.

"They don't know they're Clydesdales, but they know they're Budweiser horses," said Brian.

"You've seen the Budweiser Clydesdales," he said. "They're huge... They shouldn't be like that... These guys are endangered, they're actually an endangered species. So they have done a lot for the breed but they've also done it for commercialism as well."

The mother of one of their Clydesdales, Squirt, was in the Budweiser stable.

Some have described the Brown's horses as big puppies. One, Arya, will even shake hands like a dog.

She also has her particular tastes.

When Brian worked at Holiday World years back, he said she got rather accustomed to the goodies he'd bring home.

"I couldn't come home without bringing her a cup of Pepsi," he said.

Other horses on their farm have impressive lineage, like the Fell pony that can be traced back to the queen's stable.

See HORSES on page 10

Brian Brown stands between two of the 18 horses he and his wife Sue raise on D'Archangel Farm in the south east part of the county. The couple raises the uncommon breeds Clydesdales, Spotted Draft horses, Fell ponies and Icelandic horses. —Clarion photo by Dave Taylor

Big Rivers-

—Continued from page 1

Whitmore said Century Aluminum wants to be in the community for several more decades, and wants the two sides to continue to discuss the issue and find a solution. Whitmore called Big Rivers a special utility in that, in reality, it serves only five customers: Century, Rio Tinto, the Jackson Purchase Electric Cooperative, Meade County Rural Electric and Kenergy. He said if one, or both, of the smelters close, it creates a domino effect on Big Rivers customers.

"If we close the smelter, everybody faces a huge increase in electricity rates," Whitmore said. "This is an issue that affects all areas of the community."

During the meeting with the Lewisport City Council Thursday, Mayor Chad Gregory said he hoped the two sides quickly resumed talks. Gregory said he did not know how Big Rivers planned to justify a large rate increase on its customers if the plants closed.

"I cannot see why they want to cut their biggest customer unless they have something bigger planned in their grand scheme," Gregory said. "If they get rid of you guys they cannot service their debt."

Mike Baker, Hancock County's Industrial Foundation Director, and John Hoerner, both attended Monday evening's Hancock County Fiscal Court meeting. Baker said the problem seems to be that officials and residents of far western Kentucky do not seem to understand the impact of losing Century and Rio Tinto on their electric rates.

Hoerner said during the recent discussions with Big Rivers officials, the CEO of Jackson Purchase opposed giving the smelters a rate reduction. Hancock County Judge/Executive Jack McCaslin said an outreach effort needs to be developed to inform people of the impact of closing the two smelters.

According to information from Big River CEO Mark Bailey, losing the two smelters means a rate increase of over 30-percent on residential customers, and over 50-percent for industrial customers. A dispute exists over which scenario leads to a larger rate increase on customers.

Century officials say losing the smelters results in a larger electric rate increase to customers versus doing nothing. Littrel said, in reality, the reverse is true. He said if the smelters close residential customers receive a 34-percent increase on their rates. If the utility grants $110 million in concessions, a figure developed by Big Rivers, residents receive a 37-percent increase in rates.

"We do not want to see Century or any customer close operations," Littrel said. "We have 112,000 customers, not just one or two. We have to make decisions that are in the best interest of all of our customers. We cannot control the profitability of Century nor any other industry."

Century officials disagree about Big Rivers wanting to keep the two smelters open. Both Big Rivers and Century agree on one item: Big Rivers needs to make about $300 million in upgrades to all of its facilities to meet new EPA regulations. Big Rivers needs to make those modifications by April of 2015.

"What they want is for us to go away so they do not have to have the environmental upgrades," Hoerner said.

Magistrate Larry Sosh asked for clarification on this point. He specifically asked Hoerner if shutting down the plants lowered the investment costs for Big Rivers. Hoerner said yes because it allowed the company to close some of its power plants and cut costs.

During the meeting with the Lewisport City Council a few days earlier, Jason Curry, the Human Resources Manager for Century, told of an exchange with Big Rivers officials during a meeting that supported Hoerner's point. He asked Big Rivers officials what the company planned to do if the two smelters closed.

"They point blank said, 'we have a backup plan. We will idle capacity, we will lay-off some of our folks and we will keep moving forward,'" Curry said. "That's pretty disappointing to talk about people's jobs like that."

Littrel said if the two smelters closed, Big Rivers needed to examine its options, which might include shutting down some of its power stations. He also said a chance existed of other industrial prospects moving into the area and using the power vacated by the two smelters. He said other options also existed.

"If open market prices go up, we would not have to idle any plants," he said.

If Century does close its doors, the county loses 1,200 jobs linked to the operation of the smelter. The plant employs over 700 employees, with nearly half, 300, hailing from Hancock County. Hancock County Judge/Executive Jack McCaslin said Century alone pays the county approximately $600,000 each year in Occupational Tax. He said if the plant closes, the county faces the prospect of cutting services, raising taxes, or both.

Kip Price, Century's Director of Marketing, said he knows first hand the impact of a plant the size of Century closing. His family lives in Ravenswood, WVa. Century curtailed operations at the plant there a few years ago.

"My parents and brother have seen about a 38-percent (electric) rate increase since the plant shut down," Price said. "Their property taxes have gone up three times over."

As a solution to the problem, Century proposed an adjustable rate schedule.

"We are willing to shoulder more of the burden when the LME comes up," Hoerner told Hancock County Fiscal Court members Monday evening. "We need a long term deal, but short term help."

For his part, Littrel did not favor this approach. He said it placed all of the risk on the remaining Big Rivers' customers, and let Century profit when conditions improved.

In addition, with the volatility in the LME, Littrel said it created a planning nightmare for other industries. He said they needed stability in their rates to properly plan, and the adjustable rate schedule proposed by Century makes it hard.

"That is the potential flaw in this plan," Littrel said.

Lewisport City Council member Josephine Hagan asked if Century officials wanted members of the council to contact elected state officials. The Century delegation said yes.

"I have been involved in this for a long time, and I do not know the answer," Hancock County Judge/Executive McCaslin said Monday evening. "It seems to me it is going to have to be the legislators to get Big Rivers back to the table again. Century cannot do it on their own."

Magistrate John Mark Gray asked Whitmore if the public relations campaign seemed to be bearing fruit. He said yes, and that both local state congressmen, representative Dwight Butler and senator Carroll Gibson, called him and want to see a solution to the impasse between Century and Big Rivers.

In an effort to bring more legislative help to the situation, McCaslin contacted U.S. Senator Mitch McConnell's office, asking the senator to contact both parties in an effort to get them back to the table. McCaslin said to his knowledge, McConnell has not contacted either party, but his field agent Holly Lewis did contact officials about the situation.

At the state level, the legislature authorized an independent group to examine the issue of the power dispute, and to see what other states did to help their industries. The group reports back its findings in November.

"We are participating in that as we speak," Littrel said.

From Century's standpoint, waiting until November to start to seek a solution is too long. The company says it wants to be here for the long haul, but needs to see some positive movement immediately, otherwise the company needed to start to examine its options in regards to the plant. Judge McCaslin asked the Century officials if the company reached a deal with Big Rivers, how long would it take for it to go through the PSC approval process. Hoerner told him five months.

"Can you all last that long?" McCaslin asked.

Whitmore said if they reached an agreement with Big Rivers, and they saw a rate case being crafted and presented to the PSC, the company could hold out.

Littrel called the situation with Century complex, and that the state needed to help in some way.

"There is no quick and easy solution to this matter," Littrel said. "I can tell you it requires more financial assistance than Big Rivers and our customers can afford."

Obituaries

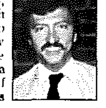
Robert Harold Hobbs

Robert Harold Hobbs, 49, of Lewisport, passed away Monday, July 23, 2012 at the University of Kentucky Chandler Medical Center in Lexington, after an illness. Bob was born Thursday, February 7, 1963 to his parents, Roy Russell and Alberta Louise Richards Hobbs. He was a Professor of Business; teaching most recently at Midway College and Brescia University. He was also a member of St. Columba Catholic Parrish in Lewisport where his funeral mass will be held.

Bob is survived by his mother, Alberta L. Hobbs of Port Charlotte, Florida; his brothers, David L. and Julia Hobbs of Lewisport and Daniel L. Hobbs of Hawesville.

Visitation will be from 9:30 to 10:30 a.m. Thursday at Taylor-Wood Funeral Home Chapel. A funeral mass will take place 11:00 a.m. at St. Columba Catholic Parrish, with Father Oneko Crispin officiating. Burial will follow in Lewisport Cemetery. Expressions of sympathy may be made in Bob's name to Eileen Murphy, Development and Alumni Relations, University of California, San Francisco, Neurosurgery Research, 220 Montgomery Street, fifth floor, San Francisco, CA 94143-0248. Online condolence may be expressed at taylorwoodfh.com.

Joseph "Dale" Greenwell



Joseph "Dale" Greenwell, 58, of Maceo, KY, died Monday, July 23, 2012, at Owensboro Medical Health System. He retired from Owensboro National Bank and had previously worked for Lincoln Services. He served in the National Guard, was a Kentucky Colonel, a member of Owensboro Christian Church and was a Gideon. He loved spending time with his grandkids, watching UK Basketball, attending many friend's and families' barbecues, camping, and fishing. Dale was given the gift of life by his daughter, Brittanie, on September 21, 2001, when she selflessly donated her kidney to him. His family would like to ask everyone to consider becoming an organ donor. He is preceded in death by his father, Richard "Dick" Greenwell.

Survivors include his wife of 24 years, Cindy Greenwell; children, Brad Crump (Alicia) of Philpot and Brittanie Hite of Maceo; grandchildren, Kaitlin Hite, Ashley Hite, Graham Hicks, Tristan Coombs, and Ava Grace Crump; mother, Betty Clark Greenwell; siblings, Richard Greenwell (Barbara), Marlene Freels (Ricky), Bonnie Emmick (Byron), and Robin Greenwell; eight nieces and nephews and 14 great-nieces and nephews; and his furry companion, a Jack Russell Terrier, Rowdy Boy.

Services will be held at noon on Friday in the chapel of Glenn Funeral Home and Crematory. Visitation will be from 2 p.m. until 8 p.m. on Thursday and after 10 a.m. on Friday at the funeral home.

Expressions of sympathy may take the form of donations to the National Kidney Foundation, 250 East Liberty Street #710, Louisville, KY 40202. Online condolences may be left for the family at www.glennfuneralhome.com.

Denis Wayne "Deny" Wheatley

Denis Wayne "Deny" Wheatley, 46, of Hawesville, went to be with his Lord and Savior at his home Sunday, July 22, 2012 with his family by his side. Deny was born June 24, 1966 in Tell City, In. to Denis F. Wheatley and Martha Edge Wheatley. He was a member of Immaculate Conception Catholic Church and was retired from the Hancock County Road Department. He was preceded in death by his grandparents, Franklin and Sylvia Wheatley and John W. and Gladys Edge. Deny enjoyed spending time with his family and friends, hunting, horseback riding and camping.

Survivors include his wife of 22 years, Connie Brandle Wheatley; four children, Logan Wheatley, Shaina Wheatley, Austin Wheatley and Laura Wheatley all at home; his parents, Denis F. and Martha Wheatley of Hawesville; four sisters, Tina Powers of Hawesville, Johnce' Roberts of Gray, TN, Malinda Stewart of Hawesville, Amy Hess of Tell City, IN; three brothers, Tim Wheatley, Frank Wheatley and Edmon Wheatley all of Hawesville, many nieces and nephews and great nieces and great nephews.

Services were held Wednesday, July 25, 2012 at Immaculate Conception Catholic Church in Hawesville with Father Chrispin Oneko officiating. Burial was in Mt. Calvary Cemetery. The family requests all donations be made to the American Cancer Society. Online condolences may be left for Deny's family at www.gibsonandsonfh.com.

Wanda L. Morris

Wanda L. Morris, 81, of Bowling Green, KY, passed away surrounded by her friends and family at 6:02 a.m., Wednesday, July 18, 2012 at Greenview Regional Hospital. She was the daughter of the late Lemuel and Lillian Gibbs Lamar. Wanda was the wife of the late Rev. Wallace J. Morris. She served faithfully with him in pastorates at Westpoint Baptist Church, Mt. Eden Baptist Church, Mt. Carmel Baptist Church, Crabtree Ave. Baptist Church, Forest Park Baptist Church and Woodburn Baptist Church. Wanda was also a loving mother, grandmother and friend who touched the lives of many.

Survivors include three daughters, Suzanne Morris Wheeley, husband Mike of Woodburn, KY, Brenda Morris Stuart, husband Denny of Bowling Green, KY and Melody Morris Pudlo, husband Steve of Hendersonville, TN; two brothers, Leroy Lamar, wife Patty of Hawesville, KY, Charles L. Lamar, Jr., wife Mary Ellen of Owensboro, KY; a sister, Nelda Emmick, husband Jimmy of Lewisport, KY; six grandchildren, Allison Wheeley Street, Adam Morris Wheeley, Rebecca Davis, Eli Thomas, Aaron Pudlo and Emily Pudlo; two great grandchildren, Caidyn Street and Madisyn Street, and several nieces and nephews. Wanda is preceded in death by a brother, W. E. Lamar.

Funeral services were held Saturday, July 21 at Woodburn Baptist Church with burial at Fairview Cemetery #2.

What's On Your Mind?

Dear Editor,

While reading your article on the old grocery stores I thought of a cute story that happened to my wife and I at Raley's Grocery. In 1963, I was working at the Lewisport Murray Tile Company and I would sometimes leave our grocery list in the morning for Mr. Raley to fill then pick up the groceries after work on the way home. One day when I stopped to pick up the groceries Mr. Raley said he could fill all that was on the list except one item. He showed me the list and Barbara had added to the list: (an 8 pound bouncing baby boy). She was pregnant with our second child at the time. I think Mr. Raley told me later that he had a lot of fun telling that story.

Charles and Barbara Campbell

Dear Editor,

Your article on Ray Snyder really resonated with me. Ray is about five years older than me so I missed him in high school. I remember his father, Walter Snyder, ran a store at Chambers. My dad, Coy Jackson, traded there. My sister, Wanda Nugent, and I used to walk to Chambers and get some stuff from Mr. Snyder. There was a family on the road that had a dog that liked to bite. One day "Beans Rice" and Wanda and I walked about one mile to the store. Beans had a BB gun. When we got to Mr. Ingrams place the dog came out. Beans fired at him and missed and we both got in behind Wanda. The dog bit me!

I remember one time Walter Snyder's daughter (the one that married Charlie Schaffer) gave me a nickel. I could buy a coke for a nickel but that seemed like a big waste too me so I traded in the nickel for five pennies and spent them on penny candy over the next few weeks.

I am good friends with her son, Charlie (Dr. Charlie), here in Huntsville, AL. I have been gone from Hancock County for a long time but almost every week there is something in the Clarion that brings back the memories.

Coy Jackson

Dear Editor,

There were two grocery stores omitted from the Old Country Store article. Kenneth Banks had one on Cross Main St. John and Tula Sinclair had one on the corner where the cigarette place is now. I ran a cream station "Blue Valley" next to Sinclair's in 1949-50 and lived up over it 1950-51. Just thought you might like to know, since you asked if anyone remembered when groceries were bought on credit.

Really do enjoy your article brings back lots of memories to us older folks. And is history for the younger generation. You are doing a great job, thank you.

Frances Bruce

Dear Editor,

I look forward to reading the Clarion online each Thursday. We don't receive hard copy until Monday or Tuesday. I enjoyed Donn's feature about Mayfield and Snyders and early groceries.

Certainly hope Century and Big Rivers can get together– will be a sad day if plant closes.

Keep up the good work at the Clarion.

Barbara Grant

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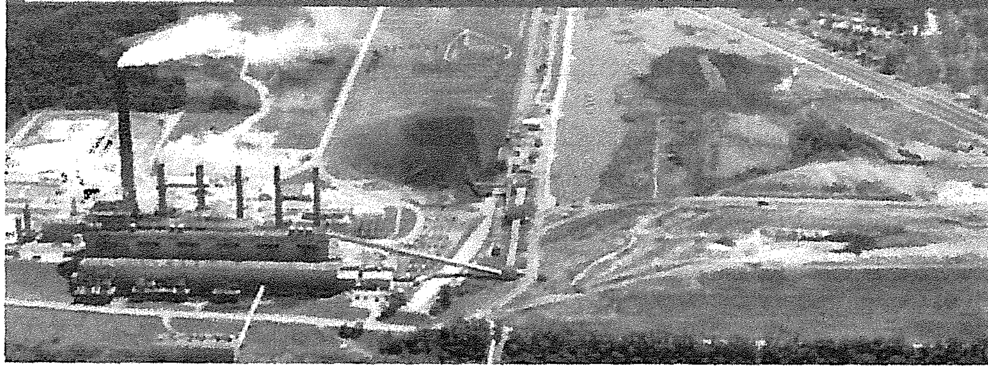

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REPLACING OLD COAL

With the "coal rush" of new proposed plants winding down, the Environmental Law Program has begun targeting the 500-plus existing coal-fired power plants in the U.S. for retirement. Many of these plants were "grandfathered" and exempted from clean air laws. Our legal team has begun engaging numerous plants nationwide in strategic legal actions, forcing them to internalize their true environmental costs, which in many cases will lead to a smart decision -- to retire the plant.

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News & Victories

James De Young Coal Plant Agreement (2014)
On December 18, 2013, the City of Holland and the Holland Board of Public Works have announced an agreement with the Sierra Club to cease burning coal at the three remaining coal-burning units at the nearly 75-year-old James De Young power plant. This settlement resolves...

[illegible] (2013)
On July 10, 2013 Franklin Circuit Court Judge Phillip Shepherd issued a landmark environmental ruling in Frankfort, Kentucky. At issue was a water discharge (NPDES) permit that allowed Louisville Gas & Electric's Trimble County coal-fired power plant to discharge large amounts of scrubber...

Unit 2 Set to Retire at Big Sandy Plant (2013)
On October 7, 2013, the Kentucky Public Service Commission approved a settlement agreement between Sierra Club and Kentucky Power Company regarding the retirement of the Unit 2 boiler at the Big Sandy coal-fired power plant. Originally, Kentucky Power wanted to retrofit Unit 2 of the Big Sandy...

[illegible] (2013)
On September 12, 2013, the Sierra Club, Cape Fear Riverkeeper, and Waterkeeper Alliance, represented by the Southern Environmental Law Center, filed suit against Duke Energy Progress to clean up the company's toxic coal ash pollution of Sutton Lake near Wilmington, NC, as well as coal ash pollution...

[illegible] (2013)

[illegible] (2013)

[illegible] (2013)

[illegible] (2013)

[illegible] (2013)

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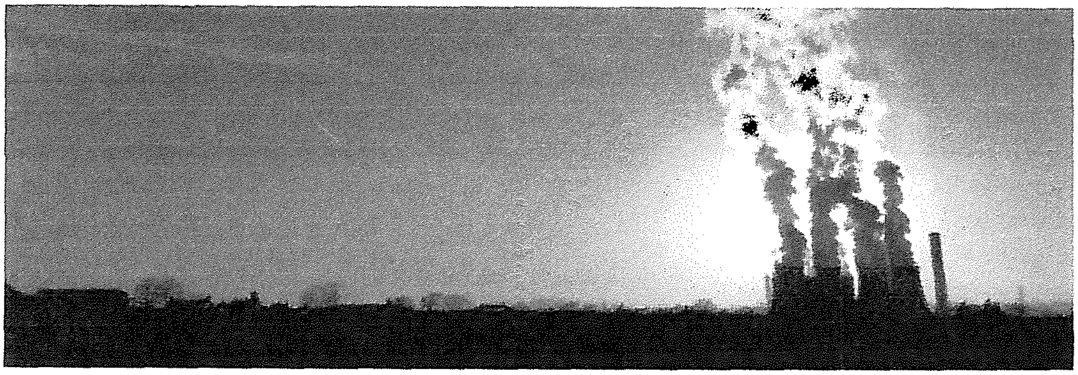
BREC EXHIBIT 1

VICTORIES

Protect American clean energy jobs!
Tell your representative and senators to protect our health and our future by renewing the wind energy production tax credit



HOW MANY DIRTY COAL-BURNING PLANTS HAVE WE RETIRED?

DIRTY POWER PLANTS RETIRED

159 down

364 to go

The plants counted here are "planned retirements" plants that have announced they will retire and have set a specific retirement date.

and there's more:

DIRTY BOILERS RETIRED

455 down

819 to go

BREC EXHIBIT 2

ach coal-burning plant is made up of specific number of boilers. Since not all coal plants are the same size, the number tracked here shows the total number of coal boilers in the U.S. that have been announced for retirement.

that means:

DIRTY MEGAWATTS RETIRED

65,072 down

277,940 to go

An average coal-burning plant is 500 MW which powers roughly 260,000 houses a year.

and that also means:

CLEAN ENERGY MEGAWATTS

66,400 installed

708,600 to go

As old coal plants retire, we're working to make sure that clean energy like wind and solar will step in to replace them, providing many new jobs for American workers.

RETIRING ONE DIRTY COAL-BURNING PLANT WILL PREVENT:

more than 29 premature deaths

47 heart attacks

146 asthma attacks

22 asthma emergency room visits

mbers are per year; data from the Clean Air Task Force

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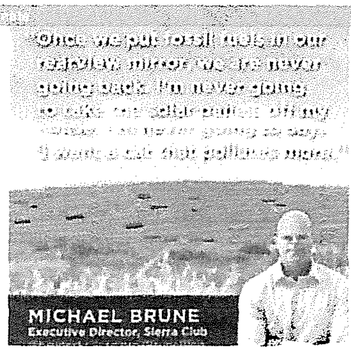

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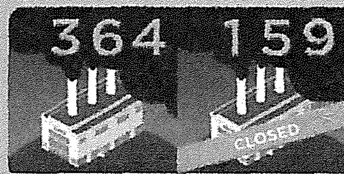
READ:

Executive Director Michael Brune's post about going all in

COAL-BURNING POWER PLANT

COUNTDOWN



159 retired, 364 to go. FIND OUT MORE

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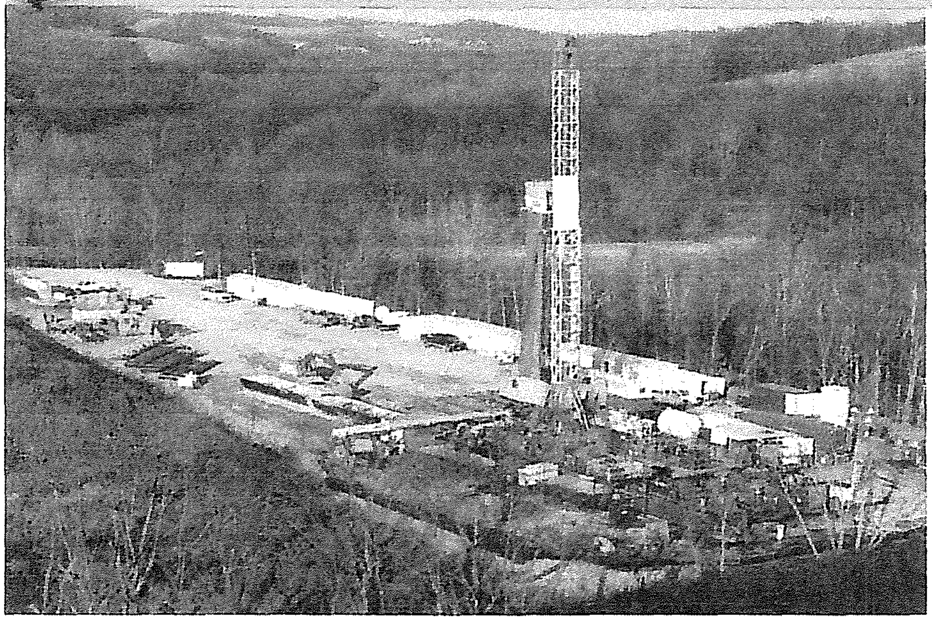
- International Climate Program

Resources
- Coal Tracker
- Factsheets

NATURAL GAS

Explore, enjoy and protect the planet — SIERRA CLUB

WHAT WE DO RESOURCES TAKE ACTION CONNECT



YOU CAN

HELP

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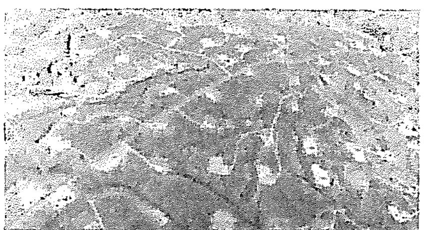
DIRTY, DANGEROUS, AND RUN AMOK

Natural gas drillers exploit government loopholes, ignore decades-old environmental protections, and disregard the health of entire communities. "Fracking," a violent process that dislodges gas deposits from shale rock formations, is known to contaminate drinking water, pollute the air, and cause earthquakes. If drillers can't extract natural gas without destroying landscapes and endangering the health of families, then we should not drill for natural gas.

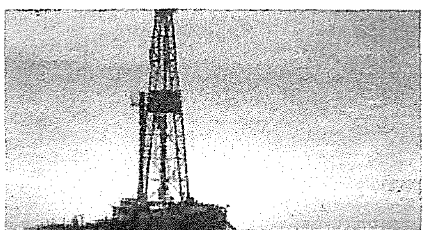
> *"No state has adequate protections in place. Even where there are rules, they are poorly monitored and enforced. Thanks to the multiple federal exemptions, we can't even count on the federal government to keep us safe! Together, though, we can change that! No industry, no matter how wealthy or powerful, can withstand the righteous passion of the American people. The out-of-control rush to drill has put oil and gas industry profits ahead of our health, our families, our property, our communities, and our futures. If drillers can't extract natural gas without destroying landscapes and endangering the health of families, then we should not drill for natural gas."*
> —Allison Chin, Sierra Club president, July 28, 2012, at the Stop the Frack Attack rally

WHAT WE DO



WHY MOVE BEYOND NATURAL GAS?

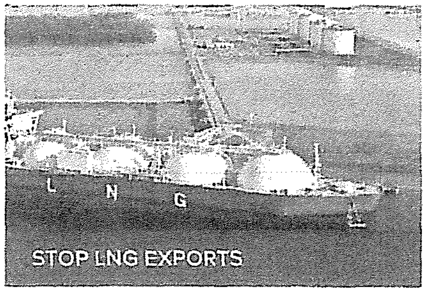
Fracking for natural gas damages the land, pollutes water and air, and causes illness in surrounding communities.



END DESTRUCTIVE DRILLING

If we can't drill safely, then we shouldn't be drilling at all. Natural gas production is environmentally damaging and harms public health.

Latest studies from the International Energy Agency reveal a switch from coal to gas would lead to a global temperature rise of more than 3.5 degrees Celsius, an outcome we simply cannot afford.



Exporting liquefied natural gas (LNG) to overseas markets is a dirty, dangerous practice that lets the industry make a killing at the expense of human health.

Support our battle to protect the environment with funding that's convenient for you.

$50 $100 $250 $500

Get the Sierra Club *Insider*, our email newsletter. News, green lifestyle tips, and ways to take action: right to your inbox, twice a month.

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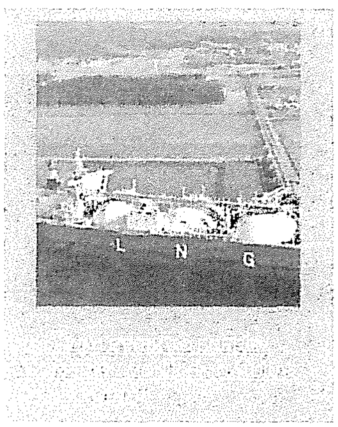

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

JOINT APPLICATION OF KENERGY CORP.	)
AND BIG RIVERS ELECTRIC CORPORATION FOR	) CASE NO. 2013-00413
APPROVAL OF CONTRACTS AND FOR A	)
DECLARATORY ORDER	)

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

DECEMBER 2013

BREC EXHIBIT 4

COMMONWEALTH OF KENTUCKY

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

JOINT APPLICATION OF KENERGY CORP. AND BIG RIVERS ELECTRIC CORPORATION FOR APPROVAL OF CONTRACTS AND FOR A DECLARATORY ORDER	**)) CASE NO. 2013-00413))**

DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

A. Qualifications

Q. Please state your name and business address.

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

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

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

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration degree in accounting and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts degree in theology from Luther Rice University. I am a Certified Public Accountant ("CPA"), with a practicing license, a Certified Management Accountant ("CMA"), and a Chartered Global Management Accountant ("CGMA"). I am a member of several professional organizations.

I have been an active participant in the utility industry for more than thirty years, initially as an employee of The Toledo Edison Company from 1976 to 1983 and thereafter as a consultant in the industry since 1983. I have testified as an expert witness on planning, ratemaking, accounting, finance, restructuring, deregulation, market, and tax issues in proceedings before federal and state regulatory commissions and courts on hundreds of occasions.

I have testified before the Kentucky Public Service Commission ("Commission") on dozens of occasions, including numerous cases involving Big Rivers Electric Corporation since 1986 and the complex interrelationships among the Company's creditors, the owners of the Hawesville and Sebree Smelters, and the Company's other Rural and Large Industrial customers. I was personally involved in and provided expert testimony in Case Nos. 9613 and 9885, in which I testified on behalf of the Attorney General regarding the Workout Plan in 1986 and 1987, respectively; Case No. 10217, in which I testified on behalf of Alcan Aluminum and National Southwire regarding the Workout Plan in 1988; Case No. 92-490 on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC") and the Attorney General regarding fuel costs; Case No. 96-327 on behalf of KIUC regarding environmental costs; Case No. 97-204 on behalf of Alcan and Southwire regarding Restructuring; Case No. 2009-00040 on behalf of KIUC regarding emergency rate relief and cash requirements; Case No. 2011-00036 on behalf of KIUC regarding a base rate increase; Case No. 2012-00063 on behalf of KIUC regarding environmental retrofits; Case No. 2012-00535 on behalf of KIUC regarding the rate increase caused by the Century Hawesville Smelter ("Hawesville Smelter") Notice of Termination; Case No. 2013-00221 on behalf of KIUC regarding the Hawesville electric service agreements providing that Smelter access to market power; and Case No. 2013-00199 on behalf of KIUC regarding the rate increase caused by the Century Sebree Smelter ("Sebree Smelter") Notice of Termination.

I also have testified before the Commission on numerous occasions on behalf of KIUC in other base rate cases, environmental rate cases, and fuel adjustment cases involving Kentucky Power Company, Louisville Gas and Electric Company, Kentucky Utilities Company, and East Kentucky Power Cooperative. My qualifications and regulatory appearances are further detailed in my Exhibit___ (LK-1).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc., a group of large industrial customers taking electric service from Big Rivers Electric Corporation ("Big Rivers" or "BREC") and Kenergy Corp. ("Kenergy"). The members of KIUC participating in this case are Aleris International, Inc., Domtar Paper Co., LLC, and Kimberly Clark Corporation. They are the three largest customers served by Big Rivers and are included in the Large Industrial class.

B. Purpose And Summary Of Testimony

Q. Please describe the purpose of your testimony and summarize your conclusions and recommendations.

A. The purpose of my testimony is to respond to the request by BREC and Kenergy Corp. ("Kenergy") (together, the "Companies") for approval of the electric service arrangements ("agreements") between and among BREC, Kenergy, Century Aluminum Company ("Century parent"), and Century Aluminum Sebree LLC ("Century Sebree"); an alternate service agreement; and a declaratory order; all on an expedited schedule. The Sebree Smelter is the single largest customer presently taking electric service from Big Rivers. The new agreements constitute the "rate" that the Sebree Smelter will be charged for electric service.

The Commission must determine whether the rate is fair, just, and reasonable and whether it provides an unreasonable preference or advantage to the Sebree Smelter and/or an unreasonable prejudice or disadvantage to other non-Smelter customers in accordance with the requirements of KRS 278.030 and the prohibitions set forth in KRS 278.170.

The new rate agreements will allow the Sebree Smelter on January 31, 2014 to bypass the cost-based generating service presently provided by BREC using its generating resources and instead acquire electric service through purchases at lower market prices through the MISO markets and/or through other bilateral agreements. The new rate agreements will allow the Sebree Smelter preferential access to the market in order to reduce the cost of its electric service and to do so without paying a market access charge to Big Rivers for the costs that were incurred to provide it service, but which cannot now be avoided.

The circumstances resulting in the Sebree Smelter seeking market access are far different than the circumstances of the Hawesville Smelter. The Commission should consider the unique circumstances of the Sebree Smelter to determine the appropriate rate in this proceeding. The Commission's decision to provide the Hawesville Smelter a 30% ($60 million per year) rate reduction through market pricing was necessary to avoid an immediate shutdown. Even with such a huge rate reduction, the Hawesville smelter went from losing $5 million per month to merely break even.

The same is not true for the much more efficient and profitable Sebree Smelter. The Sebree Smelter made $29 million in plant profit in 2012 at its cost-based rate of $48.68/mWh. The plant profit will increase by an additional $39 million if it receives a rate reduction due to market access and prices. The most recent Big Rivers estimate of the market-based rate for the Sebree Smelter is approximately $37/mWh. Alcan repeatedly represented to Big Rivers and Kenergy that the Sebree smelter was sustainable for the long-term at a rate of $43/mWh. The market access charge that I propose will result in an effective rate to Sebree of $43/mWh. The difference between market pricing and $43/mWh would yield nearly $21 million annually. This amount would be an important component of a comprehensive and balanced solution to address Big Rivers' problems of excess capacity and financial integrity, while also addressing the effects on the non-Smelter customers. This proposal still will provide the profitable Sebree smelter a rate reduction, just not as large a reduction as the Companies request in this proceeding.

C. The Sebree Smelter Made $29 Million In Profits In 2012 At Its Cost-Based Pricing Of $48.68/mWh And Its Annual Profits Would Increase By An Additional $39 Million With A Rate Reduction From Market Pricing. The Very Efficient And Profitable Sebree Smelter Does Not Require The Same Concessions That Were Provided To Keep The Hawesville Smelter Open And Retain Its Jobs. The Hawesville Smelter Needed A Significant Rate Reduction From Market Pricing Just To Go From Losing Five Million Dollars Per Month To Break Even

Q. Should the Commission consider the unique circumstances of the Sebree Smelter rather than simply adopt essentially the same agreements that it adopted for the Hawesville Smelter in Case No. 2013-00221?

A. Yes. The Sebree Smelter provided its Notice of Termination on January 31, 2013, citing its inability to economically continue smelting operations at projected cost-based rate of approximately \$60/mWh. This \$60/mWh rate reflected Sebree's share of the August 20, 2013 rate increase caused by the Hawesville Smelter Notice of Termination. However, the Sebree Smelter has no inherent right to market access or to bypass the Big Rivers generating resources and the related costs. Thus, the Commission must consider the unique circumstances of the Sebree Smelter to determine the right balance between allowing access to lower-cost market power and the consequences that will be imposed on the non-Smelter customers.

Q. Are the circumstances of the Sebree Smelter far different than the Hawesville Smelter?

A. Yes. Thus, the Sebree Smelter new rate agreements should be considered on their own merit and should not be adopted simply because they were patterned after the Hawesville Smelter agreements. The facts in Case No. 2013-00221 for the Hawesville Smelter agreements do not apply in the same manner to the Sebree Smelter.

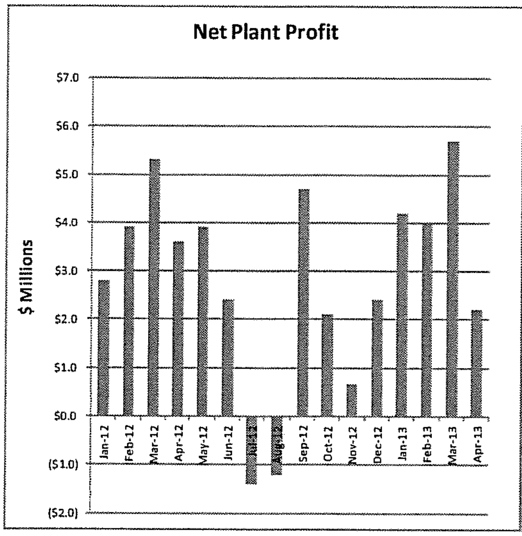
The Commission should be careful that it does not rely on facts uniquely relevant to the Hawesville Smelter as the basis to authorize an excessive reduction in the Sebree Smelter rate and an unnecessary transfer of cost responsibility from the Sebree Smelter to the remaining non-Smelter customers. The Commission should be careful that it does not improperly enrich the Sebree Smelter while impoverishing the remaining non-Smelter customers.

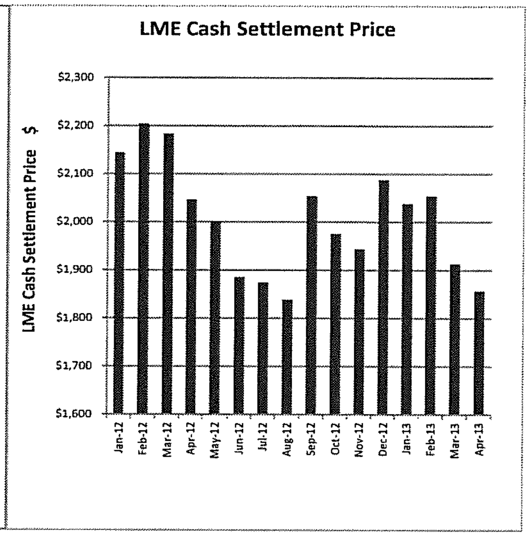
The Sebree Smelter is profitable, operates more efficiently, and has a lower financial breakeven point than the Hawesville Smelter. The Sebree Smelter does not require the same concessions that were authorized for the Hawesville Smelter. The Sebree Smelter can continue to operate for the long-term if the Commission includes a reasonable market access charge.

Q. How profitable is the Sebree Smelter?

A. The Sebree Smelter made $29 million in profit in 2012 at an average cost-based rate of $48.68/mWh and an average London Metal Exchange ("LME") price of $2,019 per tonne. The Sebree smelter made $30 million in profit in the 12 months ending April 2013 based on a lower average LME price of $1,959 per tonne and an average cost-based rate of approximately $49/mWh. The greater profitability at a lower LME and approximately the same rate demonstrates that the Sebree Smelter continued to reduce its financial breakeven point as it continued to improve efficiencies and continued to invest capital.

The following graphs show the Sebree Smelter net plant profit compared to the LME cash settlement price for the months January 2012 through April 2013 at the average cost-based rate of $48.68 and without the effects of the most recent rate increase on August 20, 2013.





I obtained the Sebree Smelter profitability data from the Companies' response to KIUC 1-12(b), in which they provided copies of the Sebree Smelter's monthly plant newsletters dated December 2012 and May 2013. The Smelter's monthly plant profit for 2012 is shown on page 7 of the response and the monthly plant profit for the first four months of 2013 is shown on page 16 of the response. I've attached a copy of the response to KIUC 1-12(b) as my Exhibit___(LK-2).

The Sebree Smelter's financial results were "sweet," according to the headline in the May 2013 newsletter, which generally resulted in employee bonuses well in excess of the 100% targets for each department. Employee bonuses for the first four months of 2013 ranged from $590 to $1,410. These bonuses were possible because the Sebree Smelter was profitable. However, this is the opposite of the situation at Hawesville where that Smelter was losing $5 million per month and struggling to survive. The basic question facing the Commission now is whether giving the Sebree Smelter a rate reduction so that its profit increases from good to great, with the non-Smelter customers picking up the tab, is fair, just and reasonable and not unduly preferential.

Q. Will the transition of the Sebree Smelter from Big Rivers' generation and related costs to the market increase its profitability?

A. Yes. The reduction in the Sebree Smelter's cost of power will significantly increase its profitability. The Sebree Smelter presently pays \$59.4/mWh after the increase granted in Case No. 2012-00535. A reduction to a market rate of \$36.58/mWh, based on Big Rivers' most recent projection of market prices provided to Alcan earlier this year, will increase the Sebree Smelter's profitability by approximately \$74 million annually, all else equal. Going from \$48.68/mWh (Sebree's pre-August 20, 2013 rate) to a market rate of \$36.58/mWh would increase Sebree's profitability by approximately \$39 million, all else equal.

Q. How much will it cost the remaining non-Smelter customers to fund this increase in the Sebree Smelter's profitability?

A. It will cost the remaining non-Smelter customers \$70.4 million annually to allow the Sebree Smelter to acquire its power at market-based pricing through Kenergy, based on the pending request by Big Rivers to increase base rates in Case No. 2013-00199. In that rate case proceeding, Big Rivers attributes the entirety of its request to the

Sebree Smelter termination. The request seeks to recover the fixed costs that Big Rivers incurred to serve the Sebree Smelter and that it still will incur even though the Sebree Smelter no longer will obtain its power from the Big Rivers generating resources. These fixed costs cannot be avoided, at least in the short-term, and will be "stranded" when the new rate agreements are implemented.

Q. If the Sebree Smelter was profitable at a rate of $48.68/mWh, then why did RTA provide its Notice of Termination on January 31, 2013?

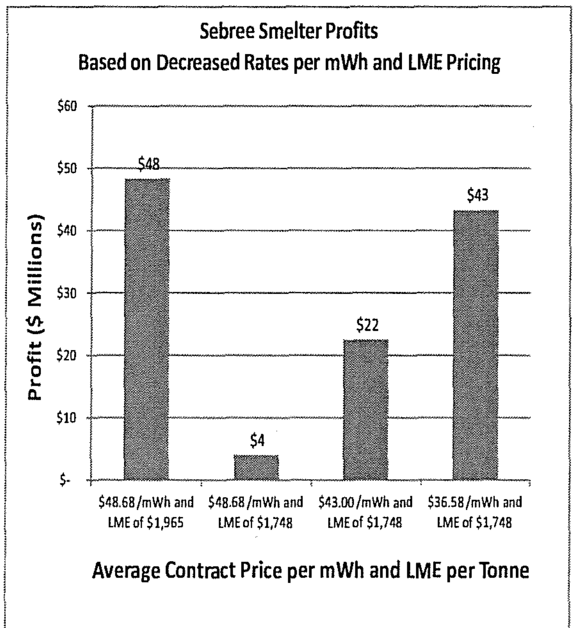
A. The Sebree Smelter faced increases in its rate from $48.68/mWh to approximately $60.0/mWh. The projected increase in its rate was due primarily to the pending rate increase in Case No. 2102-00535 wherein Big Rivers sought to recover the stranded fixed costs caused by the Hawesville Smelter termination.[1] Alcan cited the projected increase in its rate as the reason for its termination.

Q. How sensitive is the Sebree Smelter profitability to lower LME prices?

A. The following chart portrays my estimates of profitability for the Sebree Smelter based on various combinations of rates and LME prices. The "Sebree Solution" of $43/mWh discussed below is the price Alcan offered on to pay to ensure Sebree's long term viability. Alcan offered the "Sebree Solution" price of $43/mWh to Big Rivers and Kenergy on November 8, 2012, which I subsequently discuss in greater

[1] See Case No. 2012-00535, Direct Testimony of Lane Kollen, Exhibit_LK-2.

detail. The first bar represents the Smelter's annual profit using the actual rate in effect and the average LME price for the first four months of 2013. The second bar represents the Smelter's annual profit at the actual rate in effect for the first four months of 2013 and the lowest daily LME price that has occurred so far in 2013. The third bar represents the Smelter's annual profit at the $43/mWh offered by Alcan as the "Sebree Solution" rate and the lowest daily LME price during 2013. The fourth bar represents the Smelter's annual profit at the estimated market price and the lowest daily LME price during 2013.



Thus, even at lower LME prices, the Smelter still remains profitable and becomes even more profitable as the rate is reduced, first to the "Sebree Solution" offer rate, and then to the estimated market rate.

Q. According to Big Rivers, the underlying foundation for its negotiations with Century was to ensure that no additional costs were experienced by its customers as a result of this transaction. Is this a sufficient foundation?

A. No. With all due respect to Big Rivers, this was not the right foundation for its negotiations regarding the Sebree Smelter rate. While this "foundation" may appear laudable on the surface, it ignored, and thus missed, the critical opportunity to eliminate or at least reduce the stranded costs imposed on the non-Smelter customers. In so doing, Big Rivers failed to strike the right balance between the Sebree Smelter's continued viability and the rates of the remaining non-Smelter customers. This task now falls to the Commission.

Q. Did Big Rivers or Kenergy ever perform any financial analysis of the Sebree Smelter to determine the validity of the Smelter's claim for rate relief or market access?

A. No. "Neither Big Rivers nor Kenergy performed any financial analysis of whether a market-based power supply was necessary to keep the Sebree smelter in operation . . . The only financial information Big Rivers has regarding the profitability of the Alcan smelter comes from monthly plant newsletters," according to the Companies' response to KIUC 1-12(b).

Q. Why is it significant that neither Big Rivers nor Kenergy ever performed any financial analysis of the need to provide the Sebree Smelter market access?

A. It is significant because the Companies have provided no quantitative support whatsoever for the severe reduction in the Sebree Smelter rate they propose in this proceeding. The Companies provided no evidence that the proposed rate is fair, just and reasonable pursuant to the requirements of KRS 278.030. They provided no evidence that the proposed rate does not provide an "unreasonable preference or advantage" to the Sebree Smelter or an "unreasonable prejudice or disadvantage" to the non-Smelter customers, neither of which is permitted pursuant to KRS 278.170.

The evidence that I present demonstrates that the reduction from the present rate to the proposed rate is excessive and that a reduction of the magnitude the Companies propose is unnecessary in order to maintain the profitability and economic viability of the Sebree Smelter. The Commission should use the financial information that is available to ensure that it achieves the right balance and allocation of stranded fixed costs between the Sebree Smelter and the remaining non-Smelter customers rather than simply allocating the entirety of the stranded costs to the non-Smelter customers. My recommendations will enhance the financial stability of Big Rivers and lessen the likelihood that it will have to reorganize under the bankruptcy laws.

Q. In contrast to the Sebree Smelter, was the Hawesville Smelter profitable when the Commission issued its Order in Case No. 2013-00221?

A. No. Unlike the Sebree Smelter, the Hawesville Smelter was losing $5 million per month. The Hawesville smelter was not profitable at $48.68/mWh, the average Smelter rate prior to the Hawesville termination in August 2013, according to the testimony of Sean Byrne, the plant manager, filed in Case No. 2013-00221 on July 19, 2013. Mr. Byrne estimated that bypassing the Big Rivers generating resources and purchasing in the market could reduce the Hawesville Smelter's rate by approximately 30%. A 30% reduction would be equivalent to a rate of approximately $34/mWh and would result in annual savings to the Hawesville Smelter of approximately $60 million compared to the $48.68/mWh rate. In its post-hearing brief, Century represented that even with this reduction in the rate, the Hawesville Smelter would barely breakeven.]

D. There Are Other Significant Differences Compared To The Hawesville Agreements

Q. Are there other significant differences compared to the Hawesville agreements that distinguish the two transactions?

A. Yes. Big Rivers provided a list of 15 "principal substantive differences" between the two transactions and the related agreements in response to AG 1-5. These 15 differences include changes in the Kenergy tariff, Direct Agreement, and

Arrangement Agreement to explicitly recognize that Big Rivers has no obligation to supply the Smelter from its resources; the equipment necessary to access market power; the reimbursement of Big Rivers' costs; the obligation to purchase zonal resource credits; and the amounts that may be recovered or returned to the Smelter due to the operation of an SSR; among others. I have included a copy of the Big Rivers' response to AG 1-5 as my Exhibit___(LK-3).

E. The Commission Should Adopt A Market Access Charge As One Component Of A Fair, Just and Reasonable Rate And As Part Of A Comprehensive Financial Solution In Which All Stakeholders Participate To Keep Big Rivers Solvent

Q. Given the far different circumstances for the Sebree Smelter compared to the Hawesville Smelter, what are your recommendations?

A. I recommend that the Commission modify the rate to include a market access charge. The market access charge would be imposed on the Sebree Smelter, collected by Kenergy as a component of the distribution rate, and then remitted to Big Rivers. This approach is similar to that adopted by other states to provide the incumbent utility recovery of its stranded fixed costs when customers were allowed to access market power and bypass the utility's generating resources.

As filed, the agreements will result in an "unreasonable preference or advantage" to the Sebree Smelter and an "unreasonable prejudice or disadvantage" to the remaining non-Smelter customers, both of which are prohibited by KRS 278.170.

As proposed, the agreements allow the single largest customer on the Big Rivers' system to preferentially access lower priced market power. None of the non-Smelter customers are able to access lower priced market power. The agreements economically prejudice the other non-Smelter customers by requiring them to pay the stranded costs that were incurred by Big Rivers to serve that one customer and that now cannot be avoided. The agreements will result in a massive and excessive rate reduction for only that one customer, but will result in massive rate increases to the remaining non-Smelter customers, who did not cause or strand the costs that were incurred to serve the Sebree Smelter and who will be forced to subsidize the Smelter's preferential access to the lower-cost market power.

In this proceeding, the Commission will set the Sebree Smelter rate prospectively so that it is implemented at the same time as the other provisions of the agreements. The imposition of a market access charge would not rewrite the *prior* Smelter contract with Big Rivers that will terminate on January 31, 2014; rather, a market access charge is an essential component of the rate going forward under the *new* rate agreements that are at issue in this proceeding.

I recommend that the additional revenue from the Sebree Smelter be credited to the remaining non-Smelter customers through the Economic Reserve. Alternatively, the Commission should reduce the revenue requirement in Case No. 2013-00199. The two different approaches should yield approximately the same results; however, there will be a delay of several months under the approach where the Economic Reserve is credited and extended until the customers actually receive the benefit of the revenues.

In addition, I recommend that the Commission explicitly retain authority over the electric service arrangements and, more specifically, the rate, as it did for the Hawesville Smelter electric service arrangements in Case No. 2013-00221.

I also recommend that the Commission adopt the same reporting requirements for the Sebree Smelter that it adopted for the Hawesville Smelter in Case No. 2013-00221, except that all parties to this case should be served with copies.

Q. What market access charge rate do you recommend?

A. I recommend that the stranded cost or market access charge be calculated as the monthly difference between the market-based rate and \$43/mWh. This would set the Sebree rate at a minimum of \$43/mWh. This is the rate presented by Alcan as the "Sebree Solution" to ensure Sebree's long term viability. Because the market access charge would change monthly, its volatility would not lend itself to a base rate reduction. Instead, it should be handled as a formula rate similar to the fuel adjustment clause or environmental surcharge. The monthly revenue stream from the market access charge would be transferred from Kenergy to Big Rivers to lower the rates of all non-smelter ratepayers. The Commission could extend the life of the Economic Reserve and the MRSM tariff to provide monthly credits on all non-

Smelter customer bills.

Q. Please provide a further description of the $43/mWh that you recommend for the Sebree Smelter rate.

A. Alcan developed this rate based on its assessment of the cost for Big Rivers to serve the Sebree Smelter, excluding any share of the excess capacity and related stranded costs caused by the Hawesville Smelter termination, and offered it to Big Rivers as a viable long-term "solution" prior to providing its Notice of Termination. Big Rivers provided a copy of an Alcan presentation dated November 8, 2012 and correspondence between the parties that address the $43/mWh rate in response to KIUC 1-12(a), a copy of which I have attached as my Exhibit___(LK-4).

In offering its "Sebree Solution" and the $43/mWh rate, Alcan cited certain competitive advantages it had that were not available to other smelters and that enabled it to pay more than the global smelter average electric rate. These advantages include:

- Location in the U.S. Midwest, access to the Midwest premium
- First-quartile operating cost, excluding electricity
- Lower capital costs compared to new facilities
- Skilled and committed employees
- Value added aluminum

It should be noted that the Sebree Smelter is one of the most efficient smelters in the world on operating (non-energy) cost and that, prior to the Century acquisition of the Smelter, Alcan invested over $100 million in the smelter over the preceding five years and planned to invest another $70 million in the next five years. This information was provided by Alcan in a presentation during the negotiations with Big Rivers and was included in the Companies' response to KIUC 1-12(a).

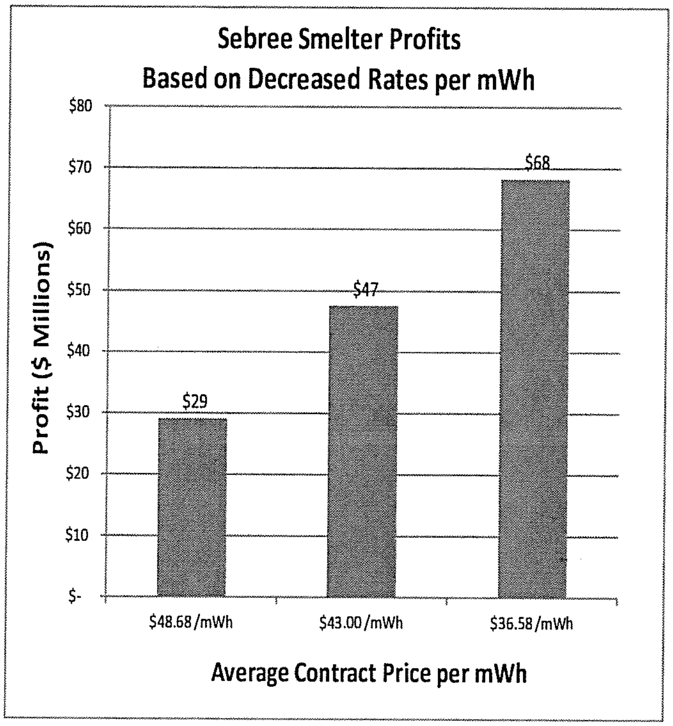
At the time when Alcan developed this proposal in November 2012, its all-in rate was nearly $49/mWh. In calendar year 2012, the Sebree smelter earned profits of $29 million while paying a power rate of $49/mwh.

Q. Will the transition to the market and lower prices further increase the Sebree Smelter's profitability?

A. Yes. Market prices presently are significantly below the $43/mWh offer from Alcan that Big Rivers rejected. Big Rivers estimated that the market price would be $36.58 2014 in its most recent projection provided to Alcan earlier this year. Big Rivers provided these estimates in response to KIUC 1-16(c), a copy of which I have attached as my Exhibit___(LK-5). A reduction from $48.68/mWh rate in effect prior to the Century increase to $36.58/mWh will increase the Smelter's profitability by $39 million.

The following chart graphically portray the Sebree Smelter profitability at nearly $49/mWh, at the $43/mWh offered by Alcan, and at the estimated

$36.58/mWh market price for the next several years based on the information that we presently have available.



Q. Are there other factors that should be considered regarding the Sebree Smelter's profitability?

A. Yes. The preceding chart showed that the Sebree Smelter profitability actually increased even though the LME prices trended downward in 2013. That is to be expected. Alcan continually invested in the Sebree Smelter to reduce its economic breakeven by improving efficiencies and increasing its output, according to testimony filed by Mr. Stephane LeBlanc, the former Sebree Smelter plant manager, in Case No. 2011-00036. In that case, Mr. LeBlanc testified that Alcan was able to systematically reduce costs at the plant and that Alcan planned to spend "$16 million on equipment upgrades that would generate more production with same fixed cost which increases plant's viability" and that this was "in addition to further working to reduce our operating cost."

Another factor that the Commission should consider is that Century acquired the Sebree Smelter in June 2013 at a bargain price (below the net book value) and recognized a pretax gain on the transaction of more than $5 million, according to the Century 10-Q for the quarter ending June 30, 2013. I have attached a copy of the relevant pages from the Century 10-Q as my Exhibit___(LK-6). Kenergy reported to its Board of Directors that the purchase was at a "ridiculously low price" and "well below the $211M offer that Alcan had received previously." The Sebree Smelter was profitable before Century acquired it and with a reduction in fixed costs due to the change in ownership, it will be even more profitable in the future.

The Commission does not need to and should not force the non-Smelter customers to subsidize the Sebree Smelter any more than is absolutely necessary. The Sebree Smelter already is profitable and it is not in imminent danger of shut down for economic reasons. This is in stark contrast to the Hawesville smelter which needed a 30% rate reduction just to break even and avoid an immediate shutdown.

II. THE SEBREE SMELTER TRANSITION TO MARKET WILL CAUSE EXCESS CAPACITY AND STRAND THE COSTS THAT WERE INCURRED TO SERVE ITS LOAD AND CANNOT NOW BE AVOIDED

A. The Big Rivers Generating Resources Were Constructed, Acquired, And Financed To Serve The Smelters

Q. Please provide a historical perspective for these massive rate increases caused by the Smelters' decisions to terminate their contracts, abandon the Big Rivers cost-based supply resources, and seek access to market-priced power.

A. There is a lengthy history between Big Rivers and the Smelters whereby the Smelters have aggressively sought to minimize their cost of power through various transactions and pricing mechanisms, and more specifically, by shifting back and forth between cost-based generation service from Big Rivers and market access and/or bilateral agreements with other parties.

Prior to 1998, the Smelters were all-requirements customers of Big Rivers and subject to regulated rates based on the costs incurred by Big Rivers. Big Rivers built and financed its generating and transmission systems to meet the needs of the Smelters, which together comprised between 70% and 80% of the Big Rivers load.

Big Rivers built and financed the Reid-Green Station Two plant complex in close proximity to the Sebree Smelter primarily to serve the Sebree Smelter load. Big Rivers built and financed the Coleman plant in close proximity to the Hawesville Smelter primarily to serve the Hawesville Smelter load. Big Rivers financed the generating plants on the basis of long-term contracts entered into by the owners of the Smelters and the predecessor distribution cooperatives serving the Smelters at retail (now Kenergy). I have attached a copy of the transcript from Case No. 2007-00455 (the Unwind Transaction proceeding, which I subsequently discuss in greater detail) wherein this history is recounted by Mr. William Blackburn, a former Vice President and long-time employee of Big Rivers, as my Exhibit___(LK-7).

In the 1980s, Big Rivers built and financed the Wilson plant in part to serve a projected increase in the Hawesville Smelter load, although the Hawesville Smelter actually did not increase its load at that time.

The construction of the Wilson plant resulted in significant excess generating capacity and the related costs. The construction of the Wilson plant also resulted in excessive fuel costs due to fraudulent contracts. These mostly self-imposed circumstances caused the Company severe financial distress and subsequently led to a default on its debt. In response to these circumstances, the Commission oversaw a "workout" process in the late 1980s that resulted in an increase in rates, creditor concessions, and the adoption of variable rates for the Smelters tied in part to the LME price of aluminum. The Big Rivers "workout plan" relied heavily on sales by Big Rivers of its excess capacity into the market at prices greater than its variable costs to generate.

When market prices subsequently plummeted in the late 1990s, the Company's market sales margins also plummeted and it was forced to file for bankruptcy so that it could restructure its operations and its debt and rescind the fraudulent coal contracts. Under the oversight of the Bankruptcy Court, the Company entered into a series of transactions and agreements with its creditors and other parties that fundamentally transformed the structure and operation of the Company, including its relationships with the Smelters and its obligation to serve the Smelter loads, and restructured its debt.

Under the Reorganization Plan approved by the Bankruptcy Court and the transaction documents approved by the Commission in Case Nos. 97-204 and 98-267, Big Rivers restructured and downsized its operations and its obligations. The Company entered into an agreement to lease its power plants to Western Kentucky Energy Corp. ("WKEC"), an affiliate of LG&E Energy Corp., for a 25 year term. WKEC also assumed the operation and maintenance of the Company's generating plants. This restructuring allowed the Company to reduce its scope of operations, reduce staffing, and reduce its expenses. The Company used the lease income from WKEC to cover the debt service costs incurred to finance the generating plants.

Pursuant to these agreements, Big Rivers also successfully shed the Smelter loads and its obligation to serve the Smelters. The agreements specified that LG&E Energy Marketing, Inc. ("LEM"), an affiliate of WKEC, "will supply directly to Henderson Union and Green River the wholesale power needed to serve Alcan [Sebree Smelter] and Southwire [Hawesville Smelter] *with LEM assuming all the risks for the Smelter loads,*" according to the Commission's Order in Case No. 97-204 at 9. (emphasis added).

To meet its non-Smelter load requirements, Big Rivers then entered into a power purchase agreement with LEM for the same 25 year term as the lease. Although the Big Rivers agreement with LEM did not terminate until 2023, the Hawesville Smelter agreement terminated in 2010 and the Sebree Smelter Agreement terminated in 2011. The Smelter termination dates ultimately contributed to the Unwind Transaction, which led to the most recent circumstances, including the requests in this proceeding.

The 1998 bankruptcy reorganization was extremely beneficial. It allowed the Company to downsize, reduce its cost structure, reduce the operating risk and cost exposure from operating and maintaining its generating plants, shed the uncertainty and risk of any load obligation to the Smelters, and eliminate the excess capacity that previously existed by matching its supply to its non-Smelter load requirements. In its Order in Case No. 97-204, the Commission stated that "Once the necessary approvals for the Reorganization Plan have been secured, *Big Rivers will be out of the generating business while retaining its wholesale supply, transmission, and planning functions."* (emphasis added). The Commission's Order in Case No. 97-204 provides a more detailed description of the Company's troubled history and the 1998 reorganization at pages 1-11.

This arrangement continued until 2009 when the Unwind Transaction was consummated, primarily to resolve the scheduled termination of the Smelter agreements with LEM and to address LEM's desire to prematurely terminate the power purchase agreement with Big Rivers. At that time, the Smelters faced market prices significantly greater than the LEM contract prices and significantly greater than the rates/contract prices they could achieve if they again were served by Big Rivers at cost-based rates. More specifically, the Smelters paid LEM a fixed rate of $25/mWh for approximately 70% of their requirements and an average rate of $50 to $60/mWh for market purchases to meet their remaining requirements. This resulted in a blended cost to the Smelters of $35/mWh, according to the Commission's Order in Case No. 2007-00455 at 14. In other words, the Smelters faced market prices of $50 to $60/mWh for all of their requirements after their agreements with LEM terminated in 2010 and 2011. The Smelters claimed that they would be forced to shut down if the Unwind Transaction was not approved because they could not economically operate the Smelters at market prices.

Consequently, the agreements between Big Rivers, WKEC, and LEM were terminated early, including the lease agreement, and Big Rivers re-entered the generating business so that it could serve the Smelters, among other reasons. Big Rivers commenced operating and maintaining its power plants and again assumed the risk and obligation to supply the Smelter loads. Big Rivers entered into new agreements with each of the Smelters to supply their loads at rates/contract prices that were cost-based and that could be adjusted as the Company's costs increased or otherwise changed. Big Rivers and the Smelters also received cash payments from LEM in conjunction with the Unwind Transaction. The amounts received by Big

Rivers were used to restructure its debt, establish cash reserves, and to establish the Economic Reserve ("ER") fund and the Rural Economic Reserve ("RER") fund. The ER and RER were established to buy down future non-Smelter customer rate increases due to projected increases in fuel and environmental costs. However, the Smelters agreed to assume the risk and pay for increases in Big Rivers' fuel and environmental costs under cost-based rates in exchange for the cash payments received upfront from LEM. The Commission's Order in Case No. 2007-00455 provides a more detailed description of the Unwind Transaction and the circumstances that led to that transaction at pages 1-23.

Q. Did the new agreements pursuant to the Unwind Transaction provide the Smelters with an option to terminate if market prices subsequently were less than Big Rivers' cost-based rates or to avoid cost-based rate increases?

A. No. The Smelter agreements did not have a market price "opt-out" provision. The agreements did not grant either Smelter an option to bypass the Big Rivers' generating resources and cost-based rates if market prices declined below those cost-based rates. The only "out" pursuant to the agreements was if the Smelter planned to cease smelting operations and to shut down permanently. Pursuant to this provision, the Smelter was required to provide a statement, under oath, from its Chief Executive Officer, that it planned to cease smelting operations, and that it had no plans to continue or resume smelting operations in the future.

This provision was essential to protect Big Rivers and its non-Smelter customers from the risk of the Smelters subsequently bypassing Big Rivers and meeting their power requirements in whole or part through market purchases if market prices dropped below Big Rivers' cost-based rates. The purpose of the provision was to protect customers from the stranded costs and massive rate increases that bypass would cause if the fixed costs incurred to serve the Smelter load instead were allocated to the non-Smelter customers.

B. The Smelters Caused The Big Rivers Excess Capacity And Stranded Costs

Q. Did the Smelters cause the excess capacity and stranded costs on the Big Rivers system?

A. Yes. The Smelters ultimately concluded that the "out" provision in their contracts really did not require them to shut down and cease smelting operations permanently. Instead, the Smelters concluded that the "out" provision could be used to bypass the Big Rivers generation resources and obtain lower cost market prices while avoiding paying for any of the fixed costs that were incurred to serve them.

Prior to providing their respective Termination Notices, each Smelter engaged in negotiations with Big Rivers to obtain rate reductions. These negotiations were unsuccessful, even though Alcan offered to continue purchasing from Big Rivers at a lower rate of $43/mWh that still would have paid Big Rivers a portion of the fixed costs incurred to serve the Sebree Smelter.

Pursuant to those contracts, the CEOs of the parent companies of each Smelter certified that they intended to terminate and that they had no current intention to continue operations at the Smelters once they terminated service with Big Rivers. Century provided Big Rivers its Notice of Termination on August 20, 2012. The President and CEO of Century parent certified that Century had "made a business judgment in good faith to terminate and cease all aluminum smelting at the Hawesville Smelter" and certified that it had "no current intention of recommencing smelting operations at the Hawesville smelter."

Despite the representations made in its Notice, Century shortly thereafter commenced negotiations with Big Rivers on or about October 1, 2012 in an attempt to continue operating the Hawesville Smelter, bypass the Big Rivers supply resources and costs, and acquire lower cost market-priced power. After Century provided its Notice, Big Rivers filed the Century rate case on January 15, 2013, primarily to recover the "stranded" fixed costs from the remaining customers that no longer would be paid by Century. The Commission authorized a rate increase of $54.2 million in that case.

Two weeks after Big Rivers filed the Century rate case, on January 31, 2013, Alcan provided Big Rivers its Notice of Termination. The CEO of its parent company certified that it had made a business judgment in good faith to terminate and cease all aluminum smelting at the Sebree Smelter. Big Rivers filed the "Alcan" rate case on June 28, 2013, specifically and solely to recover the "stranded" fixed costs from the non-Smelter customers that no longer would be paid by the Sebree Smelter. That request for an increase of $70.4 million on the non-Smelter customers still is pending.

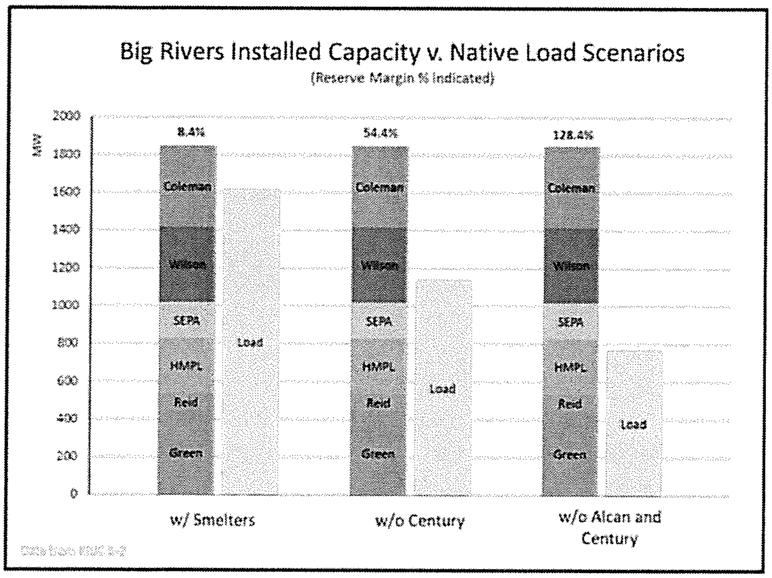
Q. Are the Smelter terminations the primary cause of the Century and pending Alcan rate increases?

A. Yes. The Rural and Large Industrial customers face massive rate increases, while the Smelters anticipate massive reductions, achieved by bypassing the Big Rivers generation resources and costs, thereby stranding the fixed costs and attempting to transfer their responsibility for those costs onto the non-Smelter customers.

Q. Why should the Commission modify the agreements so that the Sebree Smelter rate includes a stranded cost or market access charge to mitigate the imposition of stranded costs on non-Smelter customers?

A. First, Big Rivers sized its system and incurred the investments in the generating plants to serve the Smelter loads. Big Rivers reacquired its generating plants from WKEC primarily to serve the Smelters at lower cost-based rates so that they could economically continue smelting operations. In other words, the Smelters caused Big Rivers to incur the fixed costs that now cannot be avoided unless Big Rivers successfully divests the generating plants.

Second, the Smelter terminations caused the excess capacity and caused the related fixed costs to be stranded. Excess capacity is measured by the reserve margin. The Big Rivers reserve margin is the difference between the mW of capacity owned or purchased by Big Rivers and the mW of load that it is obligated to serve divided by the mW of load. The required planning reserve margin in MISO is 16.7%. After the Sebree termination, Big Rivers will have a reserve margin of 128.4%, or more than 900 mW of capacity in excess of what it requires to serve the remaining non-Smelter load. 900 mW is enough power to serve approximately 400,000 homeowners. The following graph portrays the Big Rivers reserve margin when it served both the Hawesville Smelter and the Sebree Smelter, after the termination of the Hawesville Smelter, and then after the termination of the Sebree Smelter.



The Smelters used the termination provisions of their present contracts to bypass and avoid their responsibility to contribute to the fixed costs that were incurred by Big Rivers to serve them. The Smelters did so by claiming that they had made business judgments in good faith to terminate and cease all aluminum smelting and that they had no current intention of recommencing smelting operations. Their actions have been inconsistent with these representations.

Third, there is strong precedent for the imposition of stranded cost or market access charges on customers in other states that have allowed market access, generally through deregulation of generation. In those states, the incumbent utilities were allowed to recover their stranded costs from "shopping" customers through non-bypassable distribution charges. The customers who accessed the market were not allowed to escape their obligation to pay the utility for the costs that the utility incurred to serve them and that now could not be avoided. Nor were the customers who accessed the market able to force the utility's non-shopping customers to pay the utility on their behalf. I provide a more extensive discussion of stranded costs and the obligation of the customers to pay these costs in the next section of my testimony.

Finally, a contribution toward the Big Rivers' stranded fixed costs by the Sebree Smelter in the form of a market access fee will enhance the financial stability of Big Rivers. This will lessen the chances that the utility will have to reorganize under the bankruptcy laws. Avoiding such a crisis is balanced and reasonable.

III. THE COMMISSION SHOULD INCLUDE A MARKET ACCESS CHARGE IN THE SEBREE SMELTER RATE

Q. Do you recommend that the Commission actually include a stranded cost or market access charge to mitigate the stranded fixed costs at this time?

A. Yes. The Commission should modify the new rate agreements to include a market access charge. This is essential because the agreements in this proceeding establish the rate. The revenues from such a charge then should be used to effectively reduce the revenue requirement for the non-Smelter customers in Case No. 2013-00199.

Q. Please describe how the market access charge should be calculated and applied.

A. The market access charge should be computed each month in a manner similar to the fuel adjustment clause whereby the actual market cost for the month is subtracted from the $43/mWh benchmark and then actually collected as a distribution charge by Kenergy in the second month following. Kenergy then would remit the revenues to Big Rivers. Big Rivers would recognize the revenues each month on an accrual basis in accordance with GAAP. In that manner, there will be no lag in recognizing the revenues for accounting purposes. The amount received by Big Rivers would be refunded to consumers through the operation of the Economic Reserve. The $43/mWh benchmark should be adjusted annually for inflation so that the relative position of the parties remains constant over time.

Q. Should the Commission authorize a market access charge that could be negative?

A. No. The market access charge should never be negative. The only circumstance where the computation could result in a negative rate would be if the market price is more than the \$43/mWh. If that occurs, then the market access charge would be \$0. The purpose of the market access charge is to require the Sebree Smelter to pay a portion of the stranded fixed costs that it incurred. The purpose is not to protect the Sebree Smelter from market prices greater than \$43/mWh or to provide a hedge against market price increases. A negative charge would be an additional subsidy to the Sebree Smelter by the non-Smelter customers and is inappropriate.

Q. Should the Commission view the electric service arrangements as a "take it or leave it" proposition?

A. No. The Commission is statutorily charged with setting rates at fair, just, and reasonable levels and on a non-discriminatory basis. The electric service arrangements constitute the "rate" to the Sebree Smelter. The Commission should impose its judgment on the requested rates, the same as it does in every other utility rate case that it considers.

Q. Do the electric service arrangements require Big Rivers to retain its excess capacity in order to provide the Smelters an option to return to the Big Rivers system at some time in the future?

A. No. Big Rivers is not obligated to maintain sufficient capacity to allow the Smelters to return to the Big Rivers system, according to the specific terms in several of the contracts. Consequently, Big Rivers should make every effort to mitigate its fixed costs by minimizing any operation and maintenance expense and capital expenditures at the idled power plants, including, but not limited to, retirement or sale of the units if economically justified.

IV. THE EXPERIENCE IN OTHER STATES DEMONSTRATES THE NECESSITY AND EQUITY OF A STRANDED COST OR MARKET ACCESS CHARGE

Q. Please define the term stranded costs.

A. Stranded costs are fixed costs that were incurred to provide utility service and now cannot be avoided, at least in the short-term, if customers are allowed to access market power and bypass the incumbent utility's generation resources.

These costs include the cost of utility generating plants and related infrastructure (depreciation), costs to finance the generating plants and infrastructure (interest and margin or return on equity), property taxes, insurance, ongoing and unavoidable operation and maintenance expense, and ongoing and unavoidable administrative and general expenses.

Q. Are these the same type of stranded costs that Big Rivers seeks to recover from its non-Smelter customers in the pending rate case, Case No. 2013-00199?

A. Yes. As a result of the Smelter terminations, Big Rivers plans to shut down the 420 mW of capacity at the Wilson generating plant and the 450 mW of capacity at the Coleman generating plant. In Case No. 2013-00199, Big Rivers attributed the shutdown of the Wilson generating plant and the entirety of the rate increase request to the Sebree Smelter termination. In Case No. 2012-00535, Big Rivers attributed the shutdown of the Coleman generating plant to the Hawesville Smelter termination and nearly the entirety of the rate increase request to the Hawesville Smelter termination.

Once the Sebree Smelter transitions to market-based pricing and bypasses the Big Rivers generating resources, it will be more economic for Big Rivers to shut down the Wilson plant than to continue to operate the plant and sell the output into the MISO markets. In other words, Big Rivers projects that the revenues from sales into the MISO markets will be less than the costs to continue to operate the Wilson plant even without consideration of the fixed costs. Once the Coleman plant is no longer necessary as an SSR and the Hawesville Smelter no longer pays certain of the Coleman plant costs, then it will be more economic for Big Rivers to shut down the Coleman plant.

Unfortunately, Big Rivers will not be able to avoid the fixed costs of the

Wilson and Coleman generating plants in the near-term, although it could reduce or eliminate these costs if it sold or retired the plants. Thus, the Smelter terminations stranded these fixed costs and they will remain stranded and unavoidable until the circumstances change.

Q. Who should pay these stranded fixed costs?

A. There are only three potential parties who can do so: 1) the Smelters, who caused the stranded costs to be incurred to serve them, 2) the remaining non-Smelter customers, who do not have a market access option and cannot bypass the Big Rivers generating resources and related costs, and 3) the Company's creditors.

Big Rivers itself cannot pay the stranded fixed costs, except temporarily and then only if it has available margins and cash in excess of its debt service requirements and the contractual obligations to its creditors. It is owned by the distribution cooperative members, which in turn are owned by their members and customers. Their investment in Big Rivers is represented by the members' equity and margins. Unlike the investor owned utilities, Big Rivers has no shareholders. Big Rivers also is financed by the creditors. Their investment in Big Rivers is represented by the debt outstanding.

Of the three parties that can pay the stranded costs, the obvious choice is the Smelters. Big Rivers incurred the fixed costs to serve them. The Smelters caused the excess capacity and stranded fixed costs when they terminated their contracts.

While Hawesville Smelter currently has no ability to pay, the profitable Sebree Smelter certainly does. The second most obvious choice is the creditors, all of which have some degree of control over Big Rivers and indicia of ownership. For example, the RUS exercises supervisory control over Big Rivers and must approve nearly every major management decision. The creditors are sophisticated lenders who understood the risk of the Smelter terminations and were actively involved in the Unwind Transaction, yet they elected not to require long-term contracts with the Smelters to ensure repayment. The creditors also refinanced Big Rivers' debt last year and loaned additional amounts with the full knowledge of the likely and impending Smelter terminations. They assumed the risk in exchange for added profits from increased lending. The least appropriate choice is the non-Smelter customers. Big Rivers did not incur the fixed costs to serve them. The non-Smelter customers did not cause the excess capacity or the stranded costs.

Q. What is the precedent for recovery of stranded costs in other states where customers are allowed market access?

A. Many states deregulated their generation service in the late 1990s through the early 2000s. These states include Connecticut, Texas, Ohio, Maine, New Hampshire, New Jersey, New York, and Pennsylvania. For most utilities, the transition to market access resulted in stranded generation costs, where the stranded costs generally were defined as the excess of the net present value of the cost of service, assuming recovery of the net book value of the utility's generating assets, over the net present value of the projected market revenues.

The stranded costs caused by the customers who accessed the market and no longer took generation service from the incumbent utility were charged to those customers who "shopped" in the form of a non-bypassable stranded cost distribution charge by the incumbent utility.[2]

In this case, approval of the proposed Sebree Smelter agreements would effectively deregulate electric generation service only for the Sebree smelter, allowing it to purchase electric generation service from the market even though it will do so pursuant to the agreements and will remain a retail customer of Kenergy. Accordingly, it would be not only reasonable, but also consistent with the precedent in other states if the Commission required the Sebree Smelter to pay at least a portion of the stranded costs that it caused by its decision to purchase electric service from the market and bypass the Big Rivers generation resources.

Q. Do you have any final comments?

A. Yes. The Commission should view the market access charge as one component of a comprehensive solution to the Smelter terminations and the allocation of the stranded

[2] Connecticut General Statutes Annotated §16-245g; 220 Illinois Compiled Statutes Annotated §5/16-108; 35 Maine Revised Statutes §3208; Maryland Code, Public Utilities §7-513; Massachusetts General Laws 164 §1G; New Hampshire Revised Statutes §374-F:3; New Jersey Statutes 48:3-61; Ohio Revised Code R.C. §4928.37; 66 Pennsylvania Consolidated Statutes §2808; Rhode Island General Laws §39-1-27.4; Texas Code §39.252.

costs among the various stakeholders. The Commission implemented one component in Case No. 2012-00535 when it allocated to the creditors the risk of recovering deferred depreciation expense. The market access charge component ensures that the Sebree Smelter pays at least a modest amount toward the costs that were incurred by Big Rivers to provide service and that will be stranded when it transitions to market-based rates provided by Kenergy. A financial contribution from the Sebree Smelter will improve the finances of Big Rivers and lessen its bankruptcy risk.

Q. Does this complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

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

Lane Kollen

Lane Kollen

Sworn to and subscribed before me on this 20th day of December 2013.

Jessica K. I

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2015
CHEROKEE COUNTY, GEORGIA

AG HEARING EXH. NO. __

THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

Before Commissioners: Mark Sievers, Chairman
Thomas E. Wright
Shari Feist Albrecht

In the Matter of the Application of Grain Belt Express Clean Line LLC for a Siting Permit for the Construction of a High Voltage Direct Current Transmission Line in Ford, Hodgeman, Edwards, Pawnee, Barton, Russell, Osborne, Mitchell, Cloud, Washington, Marshall, Nemaha, Brown, and Doniphan Counties Pursuant to K.S.A. 66-1,177, et seq.	)	Docket No. 13-GBEE-803-MIS

ORDER GRANTING SITING PERMIT

This matter comes before the State Corporation Commission of the State of Kansas (Commission) for consideration and decision. Having examined its files and records, the Commission finds and concludes as follows:

1. On July 15, 2013, Grain Belt Express Clean Line LLC (Grain Belt Express) filed an Application with the Commission pursuant to the Kansas Electric Transmission Siting Act (Siting Act), K.S.A. 66-1,177 *et seq*. The Application is for a siting permit conferring on Grain Belt Express the right to construct the Kansas portion of a multi-terminal ±600 kilovolt (kV) high voltage direct current (HVDC) transmission line, and an HVDC converter station and associated transmission facilities, running from near the Spearville 345 kV substation in Ford County, Kansas, to a delivery point near the Sullivan 765 kV substation in Sullivan County, Indiana.[1] The line proposed by Grain Belt Express will go through Ford, Hodgeman, Edwards, Pawnee, Barton, Russell, Osborne, Mitchell, Cloud, Washington, Marshall, Nemaha, Brown, and Doniphan Counties in Kansas.

[1] *See* Application, p. 1 (July 15, 2013).

OAG EXHIBIT __/__

2. The Commission has jurisdiction over the Application under the Siting Act. The Commission has full power, authority, and jurisdiction to supervise and control electric public utilities doing business in Kansas and is empowered to do all things necessary and convenient for the exercise of such power, authority, and jurisdiction.[2]

3. The following parties were granted intervention in this docket: Thomas and Deborah Stallbaumer, *pro se*; Matthew Stallbaumer, *pro se*; Cynthia Dettke Thoreson, *pro se*; Nancy Vogelsberg-Busch, *pro se*; Donald Miller and Jana Reed, *pro se*; the Irene Miller Family Trust; Mai Oil Operations, Inc.; ITC Great Plains, LLC; Mid-Kansas Electric Company, LLC; Sunflower Electric Power Corporation; Westar Energy, Inc. and Kansas Gas and Electric Company (Westar); Nemaha-Marshall County Electric Cooperative; the Board of Marshall County Commissioners; and the Coalition for Landowners, the Environment, and Natural Resources (CLEANR).

4. In issuing or withholding a siting permit, the Commission must decide the necessity and reasonableness of the location of the proposed electric transmission line, taking into consideration the benefit to consumers in and outside Kansas as well as economic development benefits in Kansas. The Commission may condition the permit as it deems just and reasonable and to best protect the rights of all interested parties and the general public.[3]

5. Grain Belt Express estimates it will cost approximately $900,000,000 to construct the Kansas DC Facilities. The Grain Belt Express Project is a merchant transmission line, and its cost will not be recovered through the SPP cost allocation process. The cost of the Project will be

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[2] K.S.A. 66-101; K.S.A. 66-101a; K.S.A. 66-104.
[3] K.S.A. 66-1,180.

borne by the investors in Clean Line and Grain Belt Express's transmission customers, and not by the electricity consumers of Kansas.[4]

6. Grain Belt Express engaged the services of Louis Berger to assist in selecting the Proposed Route. Louis Berger is a privately held consulting firm providing engineering, architecture, program and construction management, environmental planning and science, and economic development services on an international scale.[5]

7. In collaboration with Louis Berger, Grain Belt Express conducted a series of community roundtable meetings to obtain proactive input on routing opportunities and constraints, as well as a series of public open house meetings designed to elicit input from residents and landowners along several potential routes. Grain Belt Express also obtained feedback from state and federal agencies, as well as public interest groups. Grain Belt Express conducted the open houses and obtained stakeholder participation in hopes of minimizing and mitigating potential adverse impacts of the Project. Grain Belt Express carefully considered all inputs received when selecting the Proposed Route.[6]

8. Grain Belt Express plans to use both lattice structures and tubular steel monopole structures for the Project, based on specific conditions at particular locations or in particular segments of the line. Most structures are expected to be between 100 to 175 feet tall, with taller structures potentially required at river crossings and in certain other situations such as where longer span lengths are required. The foundation piers of the typical structure will be 3 feet to 6 feet in diameter for lattice structures and 7 feet to 11 feet in diameter for monopoles. The transmission line will be bipolar with two bundles of three conductors. Typical span lengths will

[4] Application at ¶ 8.
[5] *Id.* at ¶ 9.
[6] *Id.* at ¶ 10.

be 1,500 feet between structures where lattice structures are used and 1,200 feet between structures where monopoles are used, with shorter or longer span lengths where warranted by conditions in specific locations. The ±600 kV converter stations will be rated at approximately 3,756 MW in Kansas.[7]

9. The nominal width of the DC Line right-of-way will be 150 to 200 feet. Landowners will be able to use the DC Line right-of-way for any agricultural purpose, provided said purpose does not interfere with the use of the Project by Grain Belt Express, and is not hazardous to the landowner, the Project, or to the public generally. No structures will be allowed in any portion of the right-of-way. Trees and brush in the right-of-way will be trimmed or removed as necessary. Except in the case of certificated organic farms, or upon request by the landowner or by neighboring landowners, herbicides may be used to control vegetation in the right-of-way.[8]

10. Easements will be procured from landowners prior to construction. Landowners will be compensated for damages related to crop losses that are directly attributable to construction of the Project. In its transmission line easements, Grain Belt Express will provide landowners with indemnification protections and with certain releases of liability.[9]

11. Construction of the proposed route is scheduled to start as early as 2016 with completion as early as 2018.[10]

12. The Commission entered into the record the following testimony:

a. Grain Belt Express: Direct testimony of Michael Skelly, Mark Lawlor, David Berry, Wayne Galli, and Timothy Gaul; Rebuttal testimony of

[7] *Id.* at ¶ 13.
[8] *Id.* at ¶¶ 18, 19.
[9] *Id.* at ¶ 20.
[10] *Id.* at ¶ 21.

Mark Lawlor and Wayne Galli; Testimony in Response to Written and Public Hearing Comments of Wayne Galli, Timothy Gaul, Mark Lawlor and John McBeath; and Rebuttal Testimony in Response to Staff's Response to Public Comments of Mark Lawlor.

b. Commission Staff: Direct testimony of Michael Wegner and Thomas DeBaun; Testimony in Response to Public Comments of Michael Wegner and Thomas DeBaun; and Supplemental testimony of Michael Wegner.

c. Westar: Direct testimony of David Benak.

d. Matthew Stallbaumer: Direct testimony.

13. With their Application, Grain Belt Express submitted a list of landowners of record whose land or interest therein was: (1) proposed to be acquired to construct the proposed line, or (2) located within 1,000 feet of the center line of the easement where the line is proposed to be located, exceeding the 660-feet statutory requirement.[11]

14. The Commission conducted four public hearings in this docket pursuant to K.S.A. 66-1,178: on August 12, 2013, in Seneca, Kansas, on August 14, 2013, in Beloit, Kansas, on August 20, 2013, in Russell, Kansas, and on August 22, 2013, in Kinsley, Kansas. At each of the public hearings, any member of the public who indicated a desire to speak before the Commission was granted an opportunity to ask questions of Grain Belt Express and Commssion Staff prior to entering sworn testimony into the record in this case. No one was barred from entering sworn testimony at any of the four public hearings. Staff estimates more than 700 people attended the public hearings and the Commission received 56 sworn statements from the

[11] *Id.* at ¶ 23 and Exhibit D (landowner list).

public. In response to comments made at the public hearings, Staff filed testimony addressing concerns raised as well as route modifications proposed by several affected landowners.

15. In an affidavit filed August 9, 2013, Grain Belt Express explained they delivered by certified mail, return receipt requested, to owners of record of property located within 1,000 feet of the center line of its proposed HVDC transmission line: notice of the Application for a siting permit, a copy of a map of the proposed route, written notice of the dates, times, and locations of the four public hearings to be held before the Commission, and detailed information on how to submit a public comment directly with the Commission's Public Affairs and Consumer Protection Division within the established comment period.[12] The Commission received and entered into the record over 2,600 public comments in this docket, including petitions, telephoned comments, emailed comments, and letters.

16. The Commission finds Grain Belt Express complied with the requirement to send notice to all landowners of record whose land or interest therein is proposed to be acquired in connection with the construction of the line.[13] The Applicant exceeded the requirements of K.S.A. 66-1,178(a)(2) by including landowners within 1,000 feet of the center line of the easement of the proposed line. The Commission finds Grain Belt Express complied with the publication notice requirement and agrees with Staff's assessment that the Applicant provided adequate notice to landowners.

17. Mai Oil argues it was not properly notified of the proposed line as an oil and gas mineral rights owner, citing K.S.A. 66-1,178(a)(2). "Ordinary words are to be given their ordinary meanings without adding something that is not readily found in the statute or

[12] *See* Affidavit of Publication and Notice to Landowners, pp. 1-2 and 35-75 (Aug. 9, 2013).
[13] K.S.A. 66-1,179.

eliminating that which is readily found therein."[14] In construing a statute, the intent of legislature governs, when it can be ascertained from the statute.[15] Ordinary words are interpreted without adding something not found in the statute or eliminating language found in the statute.[16] The ordinary words contained in K.S.A. 66-1,178(a)(2) indicate only "the names and addresses of *the landowners of record* whose land or interest therein is proposed to be acquired in connection with the construction of or is located within 660 feet of the center line of the easement where the line is proposed to be located" are required to be listed in a utility's line siting application and given notice of the proposed line. (Emphasis added). Any contention by Mai Oil that the notice requirement of K.S.A. 66-1,178(a)(2) includes owners of oil and gas interests thus fails. Moreover, Mai Oil's attorney testified at the public hearing held in Russell, Kansas.[17] Mai Oil therefore had constructive notice of the proposed line and the public hearings in this case.

18. The Commission held an evidentiary hearing on October 8, 2013. Grain Belt Express, Staff, ITC Great Plains, Nemaha-Marshall County Electric Cooperative, and CLEANR appeared by counsel. The Irene Miller Family Trust, Mai Oil, and the Board of Marshall County Commissioners did not appear by counsel, and Westar, Mid-Kansas, and Sunflower all waived their appearances at the hearing. Eight witnesses appeared at the hearing, five on behalf of the Applicant, two on behalf of Staff, and Matthew Stallbaumer. Testimony of Westar's witness was admitted into the record without objection. The Commission limited several intervenors' participation in the proceedings to making opening statements and filing post-hearing briefs.

[14] *Bluestem Tel. Co. v. Kansas Corp. Comm'n*, 33 Kan. App. 2d 817, 109 P.3d 194, 196 (2005).
[15] *Bluestem*, 33 Kan. App. 2d at 824.
[16] *Id.* at 824-25.
[17] Transcript of Proceedings, Russell, Kansas Public Hearing, August 20, 2013, Testimony of Dennis Davidson, pp. 30-33.

Necessity of the Proposed Line

19. In issuing a siting permit, the Commission must determine the necessity of the proposed transmission line. In deciding necessity, the Commission considers "the benefit to both consumers in Kansas and consumers outside the state and economic development benefits in Kansas."[18] The Commission is required to "issue or withhold the permit applied for and may condition such permit as the commission may deem just and reasonable and as may, in its judgment, best protect the rights of all interested parties and those of the general public."[19]

20. While the Kansas Legislature did not define the criteria to determine necessity of a proposed electric transmission line, the Commission considers whether the line promotes the public interest.[20]

21. Addressing the purpose of the proposed line, Grain Belt Express explained:

> a. "The proposed Project is designed to facilitate the development and export of wind resources from western Kansas to load and population centers in Missouri, Illinois, Indiana, and states farther east. By connecting Kansas' abundant supply of wind with large and growing markets for wind power, the Grain Belt Express Project will facilitate construction of thousands of megawatts ('MW') of new wind power generation facilities in Kansas."[21]

22. Grain Belt Express also asserts the proposed line will expand renewable generation resources and transmission infrastructure in Kansas, while using HVDC technology which allows for better control when injecting variable wind generation into the grid. Compared with AC lines, HVDC technology allows the transfer of significantly more power with less power loss over long distances, and utilizes narrower rights of way, shorter structures, and fewer

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[18] K.S.A. 66-1,180.
[19] *Id.*
[20] *See* Order Granting Siting Permit, Docket No. 09-ITCE-729-MIS, ¶ 39 (July 13, 2009).
[21] Application at ¶ 4; Direct Testimony of Michael Peter Skelly, p. 6 (July 15, 2013) (Skelly Direct); Direct Testimony of David A. Berry, p. 5 (July 15, 2013) (Berry Direct).

conductors.[22] Grain Belt Express argues the proposed project will make possible more wind generation that would displace other, less environmentally friendly sources of energy, and would provide economic benefits to Kansas in the form of landowner contracts with generators for royalties and construction of wind farms that would not otherwise be built due to insufficient transmission facilities.[23] In Kansas, the proposed project is estimated to result in approximately 2,340 jobs annually during the three-year construction period, and an estimated 135 jobs to operate and maintain the project on an ongoing basis.[24] Additionally, construction of the associated wind facilities in Kansas is estimated to generate between 15,542 and 19,656 Kansas jobs, while operating and maintaining the wind farms is expected to generate 528 Kansas jobs.[25] Estimates are that during construction, the project would add $131.5 million to salaries and wages spent in Kansas, $371 million to Kansas's aggregate economic product, and $6.76 million a year to state income and sales tax revenues.[26]

23. The construction of wind farms and manufacture of wind turbine components facilitated by this project are estimated to result in between $779 million and $1.026 billion of salaries and earnings for those employed in that industry in Kansas. The economic impact of those earnings in the Kansas economy is estimated to between $2.284 billion and $3.268 billion. The operations of these wind farms were estimated to generate 528 jobs, $25 million in earnings

[22] Initial Brief of Grain Belt Express Clean Line LLC, p. 6 (October 17, 2013) (Grain Belt Express Initial Brief); Direct Testimony of Mark Owen Lawlor, Exhibit MOL-5 (July 15, 2013) (Lawlor Direct).
[23] Grain Belt Express Initial Brief, pp. 6, 16; Skelly Direct, p. 6; Berry Direct, pp. 12, 19-20, 23-24; Transcript of Proceedings, Testimony of Thomas DeBaun, pp. 212-213 (October 8, 2013) (Transcript).
[24] Berry Direct, p. 11.
[25] *Id.* at pp. 10-11.
[26] David Loomis and J. Lon Carlson, Economic Impact Study of the Proposed Grain Belt Express Clean Line Project (June 10, 2013), Exhibit DAB-2 Berry Direct (hereinafter cited as "*Economic Development Study*").

and add $73 million to the aggregate economy in Kansas.[27] The project and new wind farms will also provide additional tax revenue for local and State government authorities.[28]

24. Grain Belt Express further posits the proposed project will not duplicate the transmission services being provided by other public utilities in Kansas.[29] It explains the Southwest Power Pool (SPP) projects are developed to meet the intraregional needs of the SPP member utilities, whereas the Grain Belt Express project will provide interregional transmission, making Kansas wind exports to other Regional Transmission Organization (RTO) markets possible[30] without adding costs to Kansas ratepayers.[31] Furthermore, the potential wind generation in Kansas is substantially greater than the transmission capacity available on the SPP system.[32] Grain Belt Express also argues its project will benefit wholesale competition in the electricity market,[33] and will not have any negative impact on Kansas electric customers or public utility shareholders.[34] Finally, Grain Belt Express argues the economic benefits of the proposed project established in its uncontroverted testimony amount to hundreds of millions of dollars for Kansas citizens and businesses.

25. Grain Belt committed to landowner compensation that would pay the market value of the land for an easement to cross land, plus compensation for structures that could be taken as a one-time payment or as an annual payment for as long as the transmission structures

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[27] Berry Direct, p. 11.
[28] *Id.* at p. 8.
[29] *Id.* at pp. 4-5.
[30] Transcript, DeBaun, p. 215.
[31] Skelly Direct, p. 5.
[32] Transcript, DeBaun, p. 213.
[33] Skelly Direct, p.6; Berry Direct, pp. 12-13, Exhibit DAB-3.
[34] Skelly Direct, p.6; Berry Direct, p. 22.

are in place.[35] Thus, landowners would receive the market value of their land over which the lines pass while continuing to use the land so long as the use did not interfere with the lines.

26. In addition, because Kansas statutes exempt transmission lines from paying property taxes for the first 10 years of their operation,[36] Grain Belt committed to pay local governments a one-time Construction Mitigation Payment fee of $7,500 per mile prior to the commencement of construction.[37] Since the Kansas portion of the project is about 370 miles long, this commitment amounts to $2.8 million in payments to local governments in Kansas.

27. Grain Belt provided evidence it is capable of undertaking this project. One of Grain Belt's investors is National Grid, a major utility with headquarters in the UK.[38] Also, the project in Kansas is not the only transmission project being undertaken by Grain Belt. Grain Belt's affiliates are also developing three other high voltage long distance DC transmission projects and an AC transmission line.[39]

28. Staff recommends the Commission find Grain Belt Express's proposed project is necessary on the grounds the project has the potential to benefit Kansas directly and to produce economic development benefits for both Kansas and the SPP region.[40] Staff witnesses testified the project is necessary to further wind development in Kansas,[41] would promote current and past Kansas Governors' initiatives which support wind development in Kansas,[42] furthers the Kansas Electric Transmission Authority's (KETA) mission to build electric transmission

[35] Testimony of Mark Lawlor in Response of Written and Public Hearing Comments, p. 20 (Sept. 10, 2013) (Lawlor Response).
[36] *See* K.S.A. 79-259.
[37] Lawlor Respone, pp. 14-15.
[38] Skelly Direct, p. 17.
[39] Skelly Direct.p. 11.
[40] Direct Testimony of Thomas B. DeBaun p. 11 (Aug. 9, 2013) (DeBaun Direct).
[41] Transcript, Cross-Examination of DeBaun, p. 212; DeBaun Direct, p. 6.
[42] *Id.* at, p. 213; DeBaun Direct, pp. 6-7.

facilities in Kansas for the exportation of wind energy into other states,[43] and addresses an SPP goal to develop transmission systems to export wind energy.[44] An additional benefit Staff identifies is the "merchant" nature of the proposed project, based on the fact the "cost causer" or the end users of the demand, rather than Kansas ratepayers, will pay for the costs of the project.[45]

29. In this case, the evidence presented indicated that the project was being undertaken to incent the construction of wind farms in southwestern Kansas and carry wind generated electric energy to eastern markets. Thus, the commercial premise of the project is that but for the transmission line, the wind farms in southwestern Kansas would not be built.

30. Testimony indicated markets to the west, north and south were not economically feasible.[46] Thus, the testimony suggested that the route from southwestern Kansas to the east presented the only route to access economically feasible markets.

31. Testimony also indicated the demand for renewable energy from the states in the Midcontinent Independent System Operator, Inc. (MISO) and the Pennsylvania-New Jersey-Maryland Interconnection, L.L.C. (PJM) grids would be 99.7 million MWh in 2015, 157.3 million MWh in 2020 and 194.8 million MWh in 2025.[47] This demand greatly exceeds the renewable generation capacity of the MISO and PJM states, which testimony estimated to be 83.1 million MWh in 2010.[48] Thus, the evidence shows Grain Belt Express has a ready market for Kansas wind generated power carried east over its proposed transmission facilities.

[43] *Id.*; DeBaun Direct, p. 7.
[44] *Id.* at p. 214; DeBaun Direct, p. 6.
[45] *Id.* at p. 224; DeBaun Direct, p. 9.
[46] Transcript, Lawlor, pp. 106-108.
[47] Berry Direct, p. 21, Exhibit DAB-4.
[48] *Id.* at p. 21.

32. The Commission finds it is physically necessary to build a transmission facility that runs between southwest Kansas to eastern Kansas if one wishes to sell wind energy from southwestern Kansas to markets east of Kansas.

33. Testimony indicated the project would enable about 15 million MWhs annually of electricity generated by Kansas wind farms to be delivered and sold into the MISO and PJM grids.[49] As described above and contained in the Economic Development Study, testimony indicated the construction and operation of the wind farms and manufacture of wind turbine components in Kansas would add between $2.3 and $3.3 billion to the Kansas economy.

34. Grain Belt Express's Executive Vice President of Strategy and Finance, David Berry, sponsored a study of the benefits of the project to consumers in and outside of Kansas.[50] The general approach taken was to develop a simulation model of electric demand in the MISO and PJM states, to make assumptions about future demand in those states in 2019 and to simulate how the sale of Kansas wind energy into these markets would affect aggregate electric generation costs and emissions levels of various pollutants.

35. Grain Belt Express's analysis of consumer benefits is that consumers – largely outside of Kansas in the PJM and MISO states – benefit by a reduction in the cost of electric power generation ranging between $354 million annually to $546 million annually depending on the assumptions made about 2019 demand levels. Grain Belt Express also asserts that consumers would benefit by reductions in emissions levels.

36. After reviewing the record, the Commission finds substantial evidence in the record as a whole to support a finding of necessity to build Grain Belt Express's proposed 600

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[49] *Id.* at p. 13.
[50] Bob Cleveland and Gary Moland, Grain Belt Express Project Benefits Study (Oct. 30, 2012), Exhibit DAB-3, Berry Direct (hereinafter cited as "*Benefits Study*").

kV transmission line. The Commission finds that the evidence in the record establishes the need for this line to address wind energy development in Kansas. Without this project, hundreds of millions of economic development dollars would not be spent in Kansas, and the potential for large scale wind farm development would be lost. The Commission finds that this project will have significant short- and long-term economic development benefits for the state of Kansas.

37. The Commission finds and concludes that the proposed transmission line provides benefits to electric customers both inside and outside of Kansas and economic development benefits in Kansas. The Kansas economy will benefit from construction activities which will require food, fuel, lodging and other local supplies and services. In addition, the proposed line and associated economic activity will have the long-term lasting impact of added Kansas jobs and will achieve the transmission and wind development goals of SPP, KETA, and current and past Kansas Governors.

Reasonableness of the Proposed Line's Route

38. In determining whether to issue a siting permit, the Commission must also determine the reasonableness of the location of the proposed electric transmission line.[51] The Commission may condition a siting permit as it "may deem just and reasonable, and as may, in its judgment, best protect the rights of all interested parties and those of the general public."[52] Kansas courts have held that a condition is reasonable if it is based on substantial, competent evidence.[53]

39. The proposed route is supported by an exhaustive routing effort documented in the Kansas Route Selection Study (Routing Study) prepared by Louis Berger and sponsored by

[51] K.S.A. 66-1,180.
[52] *Id.*
[53] *See Kansas Electric Power Coop., Inc. v. State Corporation Comm'n*, 235 Kan. 661, 665, 683 (1984).

Grain Belt Express witness Timothy Gaul. This effort included a three-stage public outreach campaign to gather information relevant to the routing process from state and local officials, community leaders, landowners, agencies, conservation focused non-governmental organizations, and other stakeholders.[54] Grain Belt Express recorded the information gathered through the public outreach effort and integrated it into the process of route development, refinement, and ultimately, the selection of the proposed route.[55]

40. In developing the Routing Study, the Routing Team[56] identified a range of routing constraints and opportunities through the use of Digital Aerial Photography, GIS data sources, outreach efforts, and route reconnaissance. The Routing Team used this information in combination with General and Technical Guidelines to develop routes that attempted to minimize the overall effect of the line on natural and human environments while avoiding unreasonable and circuitous routes and unreasonable costs.[57] The General Guidelines in the Routing Study consist of a series of ten principles, including maximizing the length of the route, avoiding impacts to public resource lands and critical habitats, and minimizing substantial visual impacts, among others.[58] The Technical Guidelines in the Routing Study address the physical limitations, design, right-of-way requirements, and reliability concerns of the project infrastructure.[59] These guidelines consist of eight technical principles that addressed issues such as placement of structures, the crossing of existing transmission lines, and separation distances when paralleling existing transmission lines.[60]

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[54] Lawlor Direct, pp. 6-15.
[55] Direct Testimony of Timothy B. Gaul, Exhibit TBG-1, pp. 2-2 through 2-4 (July 15, 2013) (Gaul Direct); Lawlor Direct, pp. 6-15; Transcript, Wegner, p. 243.
[56] For members of the Routing Team, *see* Gaul Direct, Exhibit TBG-1, Appendix A; Transcript, Gaul, p. 158.
[57] Gaul Direct, Exhibit TBG-1, pp. 2-6 through 2-9.
[58] *Id.*, p. 2-4.
[59] *Id.*
[60] *Id.*, pp. 2-5 through 2-6.

41. Staff reviewed the Applicant's process to route the line and found both the process utilized and the preferred route to be reasonable.[61] Staff based its determination of reasonableness on both the Route Selection Study and Staff's own reconnaissance of the proposed route.[62]

42. The Commission finds and concludes the process to determine the route of Grain Belt Express's proposed transmission line and the route proposed by the Applicant are reasonable.

Modifications to the Route

43. Landowners presented several route modifications to Grain Belt Express and Staff during the pendency of this proceeding. Staff and Grain Belt Express agreed four alternative routes were reasonable. Those four alternative routes are as follows:

a. <u>Swenson/Johnson Alternative Route:</u> This proposal moves the line approximately ½ mile to the north and provides for a greater distance away from the Swenson's home, saving their shelterbelt, routing through the Johnson's pasture land and spanning the edge of the Johnson's center pivot.
b. <u>Steele Alternative Route:</u> This proposal moves the line ½ mile north instead of moving through the middle of the section and would begin in the northeast corner of the Blau property.
c. <u>Schmitt/Huffman Alternative Route:</u> This proposal routes the line parallel to the existing electric line located around the Schmitt's feedlot. Staff recommended the Commission approve an alternative wherein Grain Belt Express makes its line crossing as requested and then continues in a parallel manner, thus avoiding the Schmitt's farm buildings.
d. <u>Dockendorf Alternative Route:</u> This proposal suggests moving the line approximately ¼ to ½ mile east in Sections 23 and 13 of Township 24

[61] Staff's Post Hearing Brief, pp. 18-20 (Oct. 24, 2013); Transcript, Wegner, pp. 221-235.
[62] Direct Testimony of Michael J. Wegner, P.E., pp. 7, 9, 10-13, (Aug. 9, 2013) (Wegner Direct); Transcript, Wegner, pp. 243-244.

South, Range 20 West. Grain Belt Express has sent notice to other landowners that would be affected by this alternative.

44. In deciding whether an alternative route is reasonable, the Commission has traditionally considered the additional cost directly attributable to the alternative route. However, the mere fact that an alternative route is estimated to cost more than the filed route does not preclude a finding that an alternative route is reasonable and should be adopted. Other factors to consider include benefits gained by choosing the alternative route and the harm avoided by moving the filed route.[63]

45. The Commission has evaluated each proposed route modification. The Commission has an obligation to balance the interests of landowners in minimizing the impact on their property with the costs associated with the project. As discussed above, Staff found Grain Belt Express's proposed route to be reasonable, as well as several proposed route modifications.

46. The Commission finds the route proposed in the Application is reasonable. After considering comments from landowners and the responses of Grain Belt Express and Staff, the Commission finds the modifications to the proposed route spelled out in paragraph 43 are also reasonable and are in the public interest.

47. During the pendency of this proceeding, several individuals or parties have argued Grain Belt Express should be required to bury the proposed transmission line in whole or in part. Grain Belt Express witness Galli testified numerous times that burying the line is not only technically impracticable but economically infeasible.[64] Staff witness DeBaun also concluded

[63] *See* Order Granting Siting Permit, Docket No. 10-ITCE-557-MIS, ¶ 58 (June 30, 2010).
[64] Testimony of Dr. Wayne Galli in Response to Written and Public Hearing Comments, pp. 7-8 (Sept. 10, 2013) (Galli Response); Direct Testimony of Dr. Anothony Wayne Galli, P.E., pp. 7-8 (July 15, 2013) (Galli Direct); Transcript, Galli, pp. 179-181.

underground construction of the Grain Belt Express project is not a viable alternative.[65] Grain Belt Express presented further testimony and exhibits demonstrating the technical and economic barriers to burying the line.[66] The Commission finds the record evidence demonstrates burying Grain Belt Express's proposed transmission line would be both technically impracticable and economically infeasible.

48. Several parties also raised concerns regarding the proposed line's impact on oil and gas facilities and potential future drilling sites. Grain Belt Express has stated it "recognize[s] the value of oil and gas production in the state and . . . [does] not want to negatively impact that. So we are of a position that we will make routing and engineering adjustments to provide the appropriate amount of setback and space in order . . . to work with those facilities."[67] Staff's position is these concerns are micro-siting issues which should be addressed during Grain Belt Express's final planning and engineering stages of the project. The Commission agrees. Grain Belt Express is directed to work with owners of oil and gas facilities along the proposed route and develop adjustments to the route as necessary to minimize impact to such facilities.

49. Other concerns raised by individuals or parties in this proceeding include the following: concerns over the subsidization of wind generation, complaints about the 120-day statutory deadline for a Commission order in line siting cases, concerns about Grain Belt Express's lack of experience and ability to build the project, concerns about the potential for creating a utility corridor, concerns that the power generated and transmitted will not be used in Kansas, visual impacts, impact on land value, impact on aerial spraying of crops, impact on

[65] Testimony of Thomas B. DeBaun in Response to Public Comments, pp. 12-15 (Sept. 12, 2013) (DeBaun Response).
[66] Galli Response, pp. 4, 8; Galli Direct, p. 7; Transcript, Galli, pp. 196, 199-200; Transcript, Lawlor, p. 127; Transcript, Skelly, pp. 137, 140; Galli Direct, pp. 7-8; Grain Belt Express Exhibit 3.
[67] Transcript, Cross-Examination of Lawlor, p. 92.

farming global positioning systems, eminent domain issues, health impacts on humans and livestock due to electromagnetic fields and lightning, concerns regarding potential crossing of existing electric facilities, concern over the 10-year tax exemption for line siting projects granted in K.S.A. 79-259, and inverse condemnation concerns. The Commission understands from the public comments and materials presented by certain parties in this case that these are issues of great concern to them. However, the Commission finds most of these issues are either best addressed in separate proceedings before the district courts of Kansas or do not fall within the Commission's jurisdiction to grant or withhold line siting applications under the statutory standard expressed above. Specifically, these concerns do not address the necessity of the line, the reasonableness of the proposed route, economic development benefits, benefits to consumers, or conditions that should be imposed on the line.

Conditions

50. Staff recommended the Commission make any order approving the Application contingent on the following:

a. Grain Belt Express must also obtain requisite approval from Missouri, Illinois, and Indiana to construct the project;
b. A sunset provision allowing Grain Belt Express five years from the date of the Commission's Order to begin construction of the project in Kansas or otherwise be required to reapply;
c. A requirement Grain Belt Express continue providing quarterly project updates to the Commission until the project has been completed or otherwise abandoned;
d. The project remains a "merchant" transmission line only and not become subject to funding by Kansas ratepayers as provided in the Order Approving Stipulation and Agreement in Docket No. 11-GBEE-624-COC.

51. Grain Belt Express did not object to the conditions proposed by Staff, but offered alternative language for two of the conditions which Staff witnesses did not object to at the evidentiary hearing.[68] The proposed alternative language is as follows:

a. The cost of the Project and any AC Collector System owned by Grain Belt Express will not be recovered through the SPP cost allocation process or from Kansas ratepayers.
b. Prior to commencing construction of the DC component of the Grain Belt Project in Kansas, Grain Belt Express will obtain the state or federal siting approvals required by law to begin construction on the entirety of the direct current portion of the Grain Belt Project outside the state of Kansas. For the avoidance of doubt, transmission line siting approvals from the Missouri, Illinois, and Indiana state utility commissions shall be sufficient to satisfy this condition.

52. The Commission finds the conditions as recommended by Staff and modified by Grain Belt Express are reasonable and should be adopted.

53. Prior to commencing construction of the direct current component of the Grain Belt Project in Kansas, Grain Belt Express will obtain the state or federal siting approvals required by law to begin construction on the entirety of the direct current portion of the Grain Belt Project outside the state of Kansas. For the avoidance of doubt, transmission line siting approvals from the Missouri, Illinois, and Indiana state utility commissions shall be sufficient to satisfy this condition.

54. The cost of the Project and any AC Collector System owned by Grain Belt Express will not be recovered through the SPP cost allocation process or from Kansas ratepayers.

55. Grain Belt Express is allowed five years from the date of the Commission's Order to begin construction of the project in Kansas or otherwise be required to reapply.

[68] Transcript, DeBaun, pp. 220-221; Transcript, Wegner, pp. 239-240.

56. Finally, Grain Belt Express shall continue providing quarterly project updates to the Executive Director, General Counsel and Director of Utilities of the Commission as directed in Docket No. 11-GBEE-624-COC until the project has been completed or otherwise abandoned. The requirement to file such quarterly reports is hereby transferred from Docket No. 11-GBEE-624-COC to the present docket.

Conclusion

57. The Commission finds the Grain Belt Express line will make possible the utilization of heretofore undeveloped wind energy potential in Kansas and will have significant short- and long-term economic development benefits for Kansas and the SPP region. Therefore, based upon a review of the record as a whole, the Commission concludes the proposed electric transmission line is necessary and the proposed route is reasonable. The Commission approves certain route modifications as discussed above.

58. Approval of the siting permit is expressly conditioned on Grain Belt Express's continued flexibility in working with all affected landowners. The Commission approves minor adjustments to the location of the line as necessary to minimize landowner impact but requires material, major adjustments, and any such adjustment for which landowners would not have received notice, be approved by the Commission before implementation.

59. Finally, the Commission emphasizes the duty of Grain Belt Express to restore affected land to the condition which existed prior to the construction once construction of the line is complete, to the extent reasonably possible.[69]

[69] *See* K.S.A. 66-1,183.

IT IS, THEREFORE, BY THE COMMISSION ORDERED THAT:

A. The Commission finds the proposed electric transmission line is necessary and proposed route is reasonable. Certain modifications to the proposed route are also reasonable. The Commission grants Grain Belt Express's Application for a siting permit to construct an electric transmission line with certain proposed route modifications approved in this Order.

B. The Commission approves of minor adjustments to the location of the line as necessary to minimize landowner impact, but requires material, major adjustments, and any such adjustment for which landowners would not have received notice, be approved by the Commission before implementation.

C. Prior to commencing construction of the direct current component of the Grain Belt Project in Kansas, Grain Belt Express will obtain the state or federal siting approvals required by law to begin construction on the entirety of the direct current portion of the Grain Belt Project outside the state of Kansas. For the avoidance of doubt, transmission line siting approvals from the Missouri, Illinois, and Indiana state utility commissions shall be sufficient to satisfy this condition.

D. This Order is conditional upon the cost of the Project and any AC Collector System owned by Grain Belt Express not being recovered through the SPP cost allocation process or from Kansas ratepayers.

E. Grain Belt Express is allowed five years from the date of the Commission's Order to begin construction of the project in Kansas or otherwise be required to reapply.

C. The Commission requires the Applicant to submit quarterly reports detailing the progress and costs of the project and a final report once construction is complete.

D. This Order will be served by electronic mail. Parties have 15 days from the date of service of this Order in which to petition the Commission for reconsideration.[70]

E. The Commission retains jurisdiction over the subject matter and the parties for the purpose of entering further orders as it deems necessary.

BY THE COMMISSION IT IS SO ORDERED.

Sievers, Chairman; Wright, Commissioner; Albrecht, Commissioner.

Dated: 11-7-2013

Kim Christiansen
Executive Director

ORDER MAILED NOV 07 2013
Electronic

JV

[70] K.S.A. 66-118b; K.S.A. 77-529(a)(1).

Docket 13-GBEE-803-MIS

Concurring Statement of Chairman Mark Sievers NOV 07 2013

I. BACKGROUND

At a high level, this application by Grain Belt Clean Line Express, LLC ("*Grain Belt*") represents a $2.2 billion transmission line project (about $900 million in Kansas) that is intended to enable $7 billion of investment in the development and sale of wind energy produced in southwestern Kansas for sale at points east of Kansas. It will cross 14 counties in Kansas, then on through Missouri, Illinois and Indiana. It will be more than 750 miles long (370 miles in Kansas) and deliver Kansas wind-generated electric energy into eastern power grids operated by the Midcontinent Interconnection Operator ("*MISO*") and the PJM Interconnection that operates the grid in eastern United States (originally the Pennsylvania-New Jersey-Maryland (PJM) Interconnection).

The western end of the line will have an AC/DC converter station near Spearville, Kansas. The eastern end will have converter stations in Sullivan, Indiana connecting to Indiana Michigan Power Company and the PJM Interconnection. There will also be a midpoint converter in Missouri to connect to Ameren Missouri and MISO's grid.[1]

Grain Belt's application and business model is a "merchant model" in the sense that its costs will be recovered from the wind farms that generate energy in southwestern Kansas and from the eastern consumers who buy the Kansas power.[2] Thus, unlike utility transmission projects the Commission has reviewed and approved in the past, this project will have no impact on Kansas' electric utility rates.

The high level estimated economic impacts of the project are that it would create 2,340 jobs in Kansas during the 3 year construction period; 135 jobs in Kansas during the operations of the line; and between 15,000 and 19,000 jobs in the wind industry depending on assumptions regarding the percentage of wind turbine components built. Estimates are that during construction the project would add $131.5 million to salaries and wages spent in Kansas, $371 million to Kansas' aggregate economic product, and $6.76 million a year to state income and sales tax revenues.[3]

The construction of wind farms and manufacture of wind turbine components facilitated by this project are estimated to result in between $779 million and $1.026 billion of salaries and earnings for those employed in that industry in Kansas. The economic impact of those earnings in the Kansas economy is estimated to between $2.284 billion and $3.268 billion. The

[1] David Berry Direct Testimony, p. 7 (July 15, 2013).

[2] Michael Skelly Direct Testimony pp. 7-8 (July 15, 2013).

[3] David Loomis and J. Lon Carlson, Economic Impact Study of the Proposed Grain Belt Express Clean Line Project, (June 10, 2013) (attached as Exhibit DAB-2 to the prefiled testimony of David Berry (hereinafter cited as "*Economic Development Study*")).

operations of these wind farms were estimated to generate 528 jobs, $25 million in earnings and add $73 million to the aggregate economy in Kansas.[4]

Unlike other transmission line cases heard by the Commission where the general level of landowner compensation was not presented, Grain Belt committed to landowner compensation that would pay the market value of the land for an easement to cross land, plus compensation for structures that could be taken as a one-time payment or as an annual payment for as long as the transmission structures are in place.[5] Thus, landowners would receive the market value of their land over which the lines pass while continuing to use the land so long as the use did not interfere with the lines. Also, unlike other transmission projects that have come before the Commission, Grain Belt has also established a written code of conduct for its property managers charged with negotiating agreements with landowners.[6]

The value of this proposed compensation to Kansas is hard to estimate as it depends on local property values. The US Department of Agriculture's most recent survey of farmland property reports that the average farm real estate value per acre in Kansas is about $1,900/acre; somewhat more for cropland, less for pastureland.[7] Since the Kansas portion of the project is 370 miles long and assuming that landowner compensation will be made for a 200 foot strip along the line,[8] that represents about 8,970 acres for which right-of-way compensation would be made. Thus, this commitment represents roughly $17 million in easement payments to Kansas landowners. Payments for crop damages, field repair, and impacts to center pivot irrigators that will reduce the effective area of the irrigation equipment or require new equipment would be in addition to this amount, as well as payments for transmission line structures (towers).

In addition, because Kansas statutes exempt transmission lines from paying property taxes for the first 10 years of their operation,[9] Grain Belt committed to pay local governments a one-time Construction Mitigation Payment fee of $7,500 per mile prior to the commencement of construction.[10] Since the Kansas portion of the project is about 370 miles long, this commitment amounts to $2.8 million in payments to local governments in Kansas.

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[4] David Berry Direct Testimony, p. 11 (July 15, 2013).

[5] Mark Lawlor, Responsive Testimony, p. 20 (Sept. 10, 2013). ("Grain Belt Express is offering a payment to the landowner for the transmission easement itself, a payment per structure, and additional payments as compensation for crop damages, field repair, and impacts to center pivot irrigators that will reduce the effective area of the irrigation equipment or require new equipment. The landowner will retain the ability to continue agricultural production on the entirety of the easement except for the relatively small footprint of the structures. During our public outreach process, landowners expressed a desire to have the option for a recurring annual payment. As a result, Grain Belt Express is offering the landowner, at his or her option, either a one-time payment or a recurring annual payment for the structures on their property. If elected by the landowner, the annual structure payment will be made as long as the above-ground transmission structures are present on the property and Grain Belt Express retains an easement. Total compensation to landowners with structures on their property will exceed 100% of the fair market value of the easement area.").

[6] Mark Lawlor Direct Testimony, Exhibit MOL-8 (July 15, 2013).

[7] US Department of Agriculture, Land Values 2013 Summary (August 2013).

[8] Application, C. Right of Way, ¶18 (July 15, 2013).

[9] K.S.A. 79-259.

[10] Mark Lawlor, Responsive Testimony, pp. 14-15 (Sept. 10, 2013).

Grain Belt provided sufficient evidence it is capable of taking on this project. Testimony in this case was that one of Grain Belt's investors is National Grid, a major utility with headquarters in the UK.[11] Also, the project in Kansas is not the only transmission project being undertaken by Grain Belt. Grain Belt's affiliates are also developing three other high voltage long distance DC transmission projects and one AC transmission line.[12]

A. Studies

The record in this matter is very large. Several significant studies were submitted in support of the project, including:

1. *Route Selection Study*. This study described the process and data used by the applicant to iterate from early conceptual routes, to potential routes, to alternative routes and, finally, to the proposed route presented to the Commission.[13]

2. *Economic Development Study*. This study quantified and estimated the economic development impacts of the project to Kansas.[14]

3. *Benefits Study*. This study quantified and estimated the benefits of the project to consumers in and outside of Kansas.[15]

4. *Burial Study*. This study quantified and estimated the costs of burying the line rather than stringing it on overhead facilities.[16]

5. *HVDC Environmental Issues Study*. This study analyzed the issues surrounding high voltage direct current transmission lines.[17]

6. *Transmission Line Design Study*. This study analyzed the general design of the transmission line.[18]

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[11] Michael Skelly Direct Testimony, p. 17 (July 15, 2013).
[12] *Id.* at p. 11.
[13] Louis Berger Group, Inc., Kansas Route Selection Study (July 8, 2013) (attached as Exhibit TBG-1 to the prefiled direct testimony of Timothy Gaul (hereinafter cited as "*Route Selection Study*")).
[14] Economic Development Study.
[15] Bob Cleveland and Gary Moland, Grain Belt Express Project Benefits Study (Oct. 30, 2012) (Exhibit DAB-3 attached to the prefiled direct testimony of David Berry (hereinafter cited as "*Benefits Study*")).
[16] Grain Belt Exhibit 3, Power Engineers, 500kv DC White Paper Project, Underground DC Feasibility Report (Nov. 11, 2010) (hereinafter cited as "*Burial Study*").
[17] Oak Ridge National Laboratories, HVDC Power Transmission Environmental Issues Review (April 1997) (Exhibit AWG-6 attached to the prefiled direct testimony of Dr. Anthony Galli (hereinafter cited as "*HVDC Environmental Issues Study*")).
[18] Power Engineers, Grain Belt Express HVDC Line Preliminary Design Criteria (Jan. 27, 2011) (Exhibit AWG-3 attached to the prefiled direct testimony of Dr. Anthony Galli (hereinafter cited as "*Line Design Study*")).

B. Public Comments

While the volume of public comments received by the Commission was quite large and many opinions were expressed, the project is generally supported by many in southwestern Kansas and opposed by groups in northeastern Kansas.

As part of its filing in this matter, Grain Belt included letters of support from more than 260 individuals and officials representing 12 counties, 6 cities, 8 economic development agencies, 4 colleges or universities, 4 utilities (including the largest municipal utility, the Kansas City Board of Public Utilities), and also numerous businesses, farmers and associations that would be affected by the project.[19]

As described in its prefiled testimony supporting its application,[20] Grain Belt conducted three rounds of public outreach before the public hearings were scheduled. Those public outreach efforts that preceded the public hearings included:

1. *Stage 1 Meetings.* These were meetings with Kansas state agencies (*e.g.*, Kansas Chamber of Commerce, Department of Wildlife and Parks), local utilities, legislators, economic development agencies, county commissioners and other community leaders. The intent was to develop information about local communities, wildlife habitats, existing infrastructure, pipelines, transmission lines, etc. About 100 of those meetings were held.

2. *Roundtables.* These were larger group meetings to include anyone suggested by county commissioners as having a broad understanding of the local community and geography. A total of 19 roundtable meetings were held with attendance of slightly more than 300 individuals.[21]

3. *Open Houses.* Once the alternative routes were identified, Grain Belt mailed invitations to landowners of record with property within about 1½ miles from the center lines of each potential route segment to attend an open house to describe and discuss the project. Invitations were sent to more than 11,200 people and advertisements were placed in 24 local newspapers to publicize the open house in addition to the mailed invitations.[22]

The table below summarizes the on-the-record public testimony/comments heard by the Commission at public hearings in Seneca, Beloit, Russell and Kinsley.

[19] Mark Lawlor Direct Testimony Exhibit MOL-8 (July 15, 2013).
[20] Mark Lawlor Direct Testimony pp. 6-15 (July 15, 2013).
[21] Mark Lawlor Direct Testimony, Exhibit MOL-1 (July 15, 2013).
[22] Mark Lawlor Direct Testimony, Exhibit MOL-3 (July 15, 2013).

Testimony About the Proposed Route			
Public Hearing Location	*Approximate # of Attendees*	*Favorable*	*Opposition*
Seneca	400	6	11 1 conditional
Beloit	225	7	4 1 conditional
Russell	150	4	1 2 conditional
Kinsley	175	15	2 1 conditional
Total	950	32	18 5 conditional

More than 2,500 written comments concerning the proposed project were received by the Commission's Public Affairs and Consumer Protection ("*PACP*") group. A large majority of those comments came in the form of an on-line electronic petition in opposition to the project posted on change.org, a web site that facilitates posting and gathering petition signatures. Among the written comments received, about 470 (about 18%) did not live in Kansas.

II. RECOMMENDATIONS

I support approval of the Grain Belt proposal. This statement and the materials that follow outline the reasons for my vote, the record and reasoning I relied on in forming my opinion, and generally the reasons I did not agree with the arguments made by opponents to the proposal. Based on the evidence in the record, I believe the proposed route with the modifications presented in this proceeding meets the mandatory statutory standards that it is necessary and reasonable, benefits consumers in and outside of Kansas, and has significant economic development benefits.

My support also comes with the following recommended conditions to best protect the rights of all interested parties and those of the general public:

1. The routing proposals made by Staff should be approved.

2. The approval should allow for minor adjustments to facilitate to-date unforeseen conditions or mutually agreeable adjustments made by the affected landowner and Grain Belt.

3. The approval should be conditioned on the landowner compensation methodology and Construction Mitigation Payment plan proposed by Grain Belt.

4. Construction of the facilities should comply with the standards described in the Transmission Line Design Study.

5. As recommended by Staff, the transmission line shall be operated as a merchant model free of the subsidies inherent in large transmission facilities built at the direction of the Southwest Power Pool ("*SPP*").

6. As recommended by Staff, the authority to construct this line should sunset if Grain Belt has not commenced construction prior to the sunset date. I recommend a sunset date of five years in recognition of the complexity of this project and its construction over four states.

III. LAW GOVERNING TRANSMISSION LINE SITING

I am an economist and a lawyer, which colors how I analyzed the comments and facts of this case. Law involves a determination of what is required by statute and case law. Economics often involves an assessment of public policy and normative analyses (*i.e.*, what ought to be).

As an economist, I believe line siting cases present an application of the economic issues surrounding conflicting property rights and the rights of others to control someone else's property use. There are three major questions on this issue, generally. First, should a landowner or any other property rights holder be empowered to prevent a utility company from acquiring an easement through eminent domain? Second, should a utility be empowered to acquire an easement through eminent domain over the objections of a landowner or any property rights holders? Lastly, should an adjacent landowner or interested party who objects to transmission lines because they spoil their view be empowered to restrict a utility and landowner from mutually agreeing to place a transmission line on the landowner's property?

To an economist, line siting presents an application of the Coase Theorem and the allocation and resolution of conflicting property rights. The overarching public policy of the Coase Theorem is that issues surrounding conflicting property rights are best addressed by institutions that facilitate private negotiations between the affected parties, such as landowners and transmission developers.[23] In Kansas, the mechanisms of public meetings, open houses and notice to affected parties can be considered such institutions.

As a lawyer, as a starting point, I view line siting cases (and most utility rate cases for that matter) as an application of the takings and due process clauses of the 5th and 14th Amendments to the U.S. Constitution which provides that "nor [shall anyone] be deprived of life, liberty, or property, without due process of law; nor shall private property be taken for public use, without just compensation." It is important to note that the 5th Amendment does *not* prohibit private property from being taken for public purposes; just that there must be due

[23] Docket No. 11-ITCE-644-MIS, Order Granting Siting Permit (July 12, 2011) (containing a description of the Coase Theorem and the allocation of competing property rights in a docket siting a 345 kV transmission line).

process and just compensation.[24] Due process includes notice and a fair opportunity to be heard; such as in a public or evidentiary hearing. Just compensation includes the process whereby "fair" payment is determined; that includes, payment for land in cases of eminent domain or rates in the case of utility rate making cases. Also, note the US Supreme Court has held that "public use" under the takings clause can include economic development projects with private sector benefits.[25]

The starting point of any analysis in line siting is the Kansas statutes and laws governing electric transmission lines. These statutes reflect the public policies enacted by the elected officials who represent Kansans and bind the Commission in the exercise of its authority.

The process set out in Kansas transmission statutes go to the heart of many of the public comments made. I note that the Commission is not a "super legislature" that may override the laws passed by the legislature (or the Supreme Court). Likewise, the Commission is not a "super zoning authority" that regulates local land use policies and aesthetics. For example, many commenters complained about inadequate notice to landowners and the short (120 day) review period. Both the mechanics of notice and the review period are explicitly defined by the statutes enacted by the legislature which the Commission cannot change. If the public is dissatisfied with the statutes, then it is the responsibility of elected officials to make the necessary changes. The Commission cannot change or override the statutes enacted by the Kansas legislature.

K.S.A. 66-1,178 and 66-1,179 generally specify the statutory *process* by which the Commission reviews transmission line siting applications.[26] They require that:

1. All electric utilities must obtain a transmission siting permit before beginning construction of an electric transmission line or exercising eminent domain to acquire any interest in land in connection with such construction.

2. An application must be made with the Commission specifying the proposed location and the names and addresses of landowners whose land or interest lies *within 660 feet* of the center line of the proposed route.

3. The Commission *must* hold a public hearing within 90 days of the filing of the application in one of the counties where the proposed line is located.

[24] There is no 5th Amendment equivalent in the Kansas Constitution, but Article 12, Sec 4 of the Kansas Constitution provides that "No right of way shall be appropriated to the use of any corporation, until full compensation therefor be first made in money, or secured by a deposit of money, to the owner, irrespective of any benefit from any improvement proposed by such corporation." Eminent domain in Kansas is performed subject to the Eminent Domain Procedure Act at K.S.A. 26-501 *et seq.*

[25] Kelo v. City of New London, 545 U.S. 469, 478-80 (2005) (In *Kelo*, the city of New London sought to directly condemn 115 privately owned properties and transfer them to a private non-profit as part of plan to build a new "village." This development was projected to create in excess of 1,000 jobs, increase tax and other revenues, and to revitalize an economically distressed area." Opponents generally argued that such a "taking" was not permissible because it was not a "public use" under the 5th Amendment, but rather a transfer of private property for the developer's private use.).

[26] K.S.A. 66-1,178 and 66-1,179.

4. There be publication of notice of a public hearing in the newspaper of public record and written notice to the affected landowners.

5. The Commission *may* hold an evidentiary hearing.

6. The Commission must issue a final decision no later than 120 days after the application is filed.

It is worth noting that the requirement of notice to landowners within 660 feet of the transmission line and the requirement that the Commission issue a final decision in 120 days were added by the Kansas legislature in 2000.[27] In that respect, they represent a relatively recent judgment of and policy adopted by the Kansas legislature that transmission proceedings must be completed in 120 days and that the critical landowner interests are those located within a 1,320 foot path centered on the transmission line.

The *legal standard* to be applied by the Commission in reviewing a transmission siting application and deciding whether to grant a permit is specified in K.S.A 66-1,180, as follows:

> The commission *shall* make its decision with respect to the *necessity for* and the *reasonableness of* the location of the proposed electric transmission line, *taking into consideration the benefit to both consumers in Kansas and consumers outside the state and economic development benefits in Kansas.* The commission shall issue or withhold the permit applied for and may condition such permit as the commission may deem just and reasonable and as may, in its judgment, best protect the rights of all interested parties and those of the general public.[28]

The statutory standard "taking into consideration the benefit to both consumers in Kansas and consumers outside the state and economic development benefits in Kansas" was added by the Kansas legislature in 2003 reflecting a legislative intent and policy that consumer and economic development be considered in an analysis of the necessity and reasonableness of a line. Said differently, the *mandatory* statutory standard ("the Commission shall") to be applied is consideration of the *necessity* of the line and the *reasonableness* of the line based on consideration of the "benefit to both consumers in Kansas and consumers outside the state and economic development benefits in Kansas." Thus, the Commission may do one of three things: (1) issue the permit for the proposed line; (2) deny the permit; or (3) issue the permit conditioned on what the Commission concludes would best protect the rights of interested parties and the general public.

The Kansas Constitution includes a provision that strictly limits use of state money to invest in infrastructure projects, reflecting a public policy that private, not public money be used

[27] S.B. 257, Ch. 85, (2000).
[28] K.S.A. 66-1,180 (emphasis added).

for such facilities and that economic development is a legitimate public policy goal for infrastructure investments.[29]

In 2001, the Kansas Legislature enacted K.S.A. 79-259 which exempted transmission lines from property taxes for the first 10 years of operations. I interpret this as an expression of legislative intent to promote investment in and deployment of electric transmission facilities in Kansas. In 2005, the Kansas Legislature enacted the Kansas Electric Transmission Authority Act, which created the Kansas Electric Transmission Authority ("KETA"). KETA is a public agency generally empowered to plan, secure financing, and build transmission lines when private entities and public utilities decline to build transmission facilities in Kansas. The purpose of KETA is a reflection of the public policies the Kansas Legislature enacted with respect to electric transmission lines.[30]

I interpret the Kansas Constitution, K.S.A. 79-259 exempting transmission lines from property taxes for 10 years, and the KETA statutes to express an explicit legislative desire and public policy to promote economic development and facilitate the consumption of Kansas energy through investment in transmission facilities (the KETA statutes and K.S.A. 79-259) and that such investment should be made by private not public entities (the Kansas Constitutional provisions).

Granting a transmission line siting permit does not give a utility *carte blanche* to acquire property through eminent domain or general authority to destroy private property. For example, K.S.A. 66-1,183 specifies that "[i]t shall be the duty of every electric utility which constructs an electric transmission line to restore the land upon which such line is constructed to its condition which existed prior to such construction."

Exercise of the power of eminent domain is explicitly authorized for public utilities and the procedure by which that power *may* be exercised is specified in the Kansas Eminent Domain Procedure Act.[31] Knowing that, it is important to emphasize two facts. First, the Commission is *not* involved in eminent domain proceedings that set the price of property acquired – the Commission's line siting proceeding simply determines the necessity and reasonableness of the proposed route. Second, overwhelmingly, property acquisition along a transmission line does *not* require the parties to resort to eminent domain. The affected parties (*i.e.*, the utility and the landowners) have powerful private economic incentives to reach voluntary agreements rather than resort to court-driven eminent domain proceedings where a judge rather than the parties

[29] KAN. CONST. art IX, § 9 (The state shall *never* be a party in carrying on any work of internal improvement except that ... it may, for the purpose of stimulating economic development and private sector job creation in all areas of the state, participate in the development of a capital formation system and have a limited role in such system through investment of state funds authorized in accordance with law.) (emphasis added).

[30] K.S.A. 74-99d01(b) ("The purpose for which the Kansas electric transmission authority is created is to further ensure reliable operation of the integrated electrical transmission system, diversify and expand the Kansas economy and facilitate the consumption of Kansas energy through improvements in the state's electric transmission infrastructure.").

[31] K.S.A. 26-501 *et seq.*

determines the value of property. Testimony in this case indicated that eminent domain is rarely used in transmission siting negotiations with landowners.[32]

IV. THE PROPOSED ROUTE IS NECESSARY

In past siting decisions, the Commission has interpreted "necessity" consistent with the meaning of "necessity" as used in the phrase "public convenience and necessity." Generally, I understand that standard to be summarized as follows: a project is considered necessary if the public would be significantly disadvantaged, inconvenienced or handicapped by its absence.[33]

In this case, the evidence presented indicated that the project was being undertaken to incent the construction of wind farms in southwestern Kansas and carry wind-generated electric energy to eastern markets. Thus, the commercial premise of the project is that but for the transmission line, the wind farms in southwestern Kansas would not be built.

Testimony was presented that indicated that markets to the west, north and south were not economically feasible.[34] Thus, the testimony suggested that the route from southwestern Kansas to the east presented the only route to access economically feasible markets.

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[32] Grain Belt's President and CEO, Michael Skelly testified (Tr. pp 153-155) as follows:

CHAIRMAN SIEVERS: Did you propose this model because as a public utility you would have the power of eminent domain and could condemn property if you had a hold out?

MR. SKELLY: So we do not want to use eminent domain. We want to and are trying to negotiate fair prices with affected landowners and we have -- we are in the process of doing that right now, and when I say fair process, what we are doing, are going to pay 100 percent of the fee value and then we are going to make annual payments for the structures on the land which is sort of a page from the wind notebook where wind farm owners typically pay on an annual basis for each turbine that's located on someone's land. With respect to eminent domain, again, we don't want to use it, but we do have a hard time imagining that you could go from around Dodge City, Kansas, to Southern Indiana without running into a landowner who was opposed and then you would end up with a project that you either couldn't build or it zigged and zagged so much that it would be prohibitively expensive.

CHAIRMAN SIEVERS: Do you have any estimate as to how often you think you might have to utilize eminent domain?

MR. SKELLY: So we looked to examples with other projects at condemnation rates in the low single digits and that's what we aspire to, if not lower than that. I mean, the best would be zero.

[33] See, *e.g.*, In the Matter of the Application of ITC Great Plains, LLC for a Siting Permit for the Construction of a 345 kV Transmission Line in Edwards, Ellis, Ford, Hodgeman, Pawnee and Rush Counties, Kansas, Order Granting Siting Permit, Docket 09-ITCE-729-MIS ¶39 (July 13, 2009)

[34] Tr. pp. 106-108. The testimony was as follows:

CHAIRMAN SIEVERS: Okay. Why didn't you go west?

MR. LAWLOR: The short answer is, is probably length to the, you know, to the significant supply, the band centers. There are -- you know, closest, you know, appreciable market would be Colorado, and they have significant wind resources in that state. So beyond that you're talking about, you know, California, Phoenix and Las Vegas. And so we, we acknowledge there is a need for that, but we have a sister project that would actually start farther west, New Mexico in this case, and move power that direction. So it's really a proximity question. Kansas wind resources closer proximity to eastern markets.

CHAIRMAN SIEVERS: Okay. Why didn't you go south, sell into the Dallas market?

Testimony was also presented that indicated that the demand for renewable energy from the states in the MISO and PJM grids would be 99.7 million MWh in 2015, 157.3 million MWh in 2020 and 194.8 million MWh in 2025.[35] This demand greatly exceeds the renewable generation capacity of the MISO and PJM states, which testimony estimated to be 83.1 million MWh in 2010.[36] Thus, Grain Belt believes it has a ready market for Kansas wind generated power carried east over its transmission facilities.

Testimony in this case was that the project would enable about 15 million MWhs annually of electricity generated by Kansas wind farms to be delivered and sold into the Midcontinent Interconnection Operator ("MISO") and PJM grids.[37] As described below and contained in the Economic Development Study, testimony was presented that indicates that the construction and operations of the wind farms and manufacture of wind turbine components in Kansas would add between $2.3 and $3.3 billion to the Kansas economy.[38]

Based on the record, it seems obvious that if the project is not built, Kansas will not realize the benefits of the wind farm construction described in the application and that would disadvantage, inconvenience or handicap the public.

V. THE PROPOSED ROUTE IS REASONABLE

In past transmission cases, the Commission has defined a condition as reasonable simply if it is based on substantial, competent evidence.[39] But I believe an inquiry into reasonableness is broader than simply asking whether the evidence is substantial and competent. In my view, reasonableness includes an inquiry into whether the condition is just or fair, rational, appropriate under the circumstances, ordinary, customary or usual.

In this matter, the evidence supports a conclusion that the process by which the proposed route was selected and modified was just or fair, rational and appropriate under the

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MR. LAWLOR: Similar -- well, Texas has a fairly significant wind resource. They have their own RTO, they have their own grid, as you know, and they are on track to, to meet their demand in the State of Texas with resources in that state.

CHAIRMAN SIEVERS: Okay. Why didn't you go to New Orleans?

MR. LAWLOR: There is, in short, not, not a significant enough market for, you know, a project of this size. We view -- New Orleans is part of the Southeast, where we have yet again a sister project in Oklahoma, the Panhandle, that would feed into that particular region.

CHAIRMAN SIEVERS: Okay. And why didn't you go to Minnesota?

MR. LAWLOR: Again, Minnesota has enough wind resource in their state to meet their relatively small load.

CHAIRMAN SIEVERS: So is it your testimony that the only economically feasible market to sell Kansas wind generated in the southwest is into the MISO and the PJM markets?

MR. LAWLOR: That, that is accurate.

[35] David Berry Direct Testimony at pg 21 and Exhibit DAB-4 (July 15, 2013).

[36] David Berry Direct Testimony at pg 21 (July 15, 2013).

[37] *Id.* at p. 13.

[38] *Id.* at p. 11.

circumstances. It was developed through an iterative analysis of various transmission routes seeking public input and analyzing alternative routes until the proposed route was selected.

The process by which the proposed route was selected was described in detail in the Route Selection Study attached to Mr. Gaul's direct testimony. The route selection process sought and received considerable public input and feedback to iterate to the final proposed route. Those public outreach efforts that preceded the public hearings included the meetings described above.

At a high level, Figure 4.5 in the Route Selection Study best illustrates why the northern route is preferable to central or southern routes through Kansas. Simply put, if the line were placed through a southern or central route it would be forced to pass through areas of high population density making the project economically infeasible.

Considerable public comment urged the Commission to require that the line be buried. However, the evidence in the record does not support such a proposal as a reasonable condition. Grain Belt Exhibit 3 presents a comprehensive study of the issues and costs associated with burying 500 kV DC line. The conclusions of that study are that compared to overhead construction, the costs of burying such a line would increase costs between 10 and 20 times the costs of an overhead line.[40]

There was also public comment that focused on the aesthetics of the line and urging the Commission to find that the proposed line is unreasonable because it interferes with the views and nature of life in rural Kansas. In the public hearings, testimony from David Blau, a Kansas farmer, at the Kinsley public hearing stood out to me.

> Visual esthetics. While this man-made structure that impedes our ability to see across the vast Kansas landscape is a bit of an eyesore, with progress comes sacrifice. At one time, this land wasn't cluttered with center pivot irrigations either, but now it's a part of our everyday landscape and is essential to the farming industry in this region. I bet not many would be willing to give up the center pivots now.[41]

Moreover, the Commission is not a zoning authority and aesthetic considerations are not included in the statutory criteria the Commission must consider in evaluating line siting applications. I found no legal authority that suggests that the Commission must make such an evaluation as part of its decision making in these cases.

VI. BENEFITS TO CONSUMERS INSIDE AND OUTSIDE OF KANSAS

Grain Belt's Executive Vice President of Strategy and Finance, David Barry, sponsored a study of the benefits of the project to consumers in and outside of Kansas.[42] The general approach taken was to develop a simulation model of electric demand in the MISO and PJM

[40] Burial Study, pg. 28.
[41] Blau Testimony, Kinsley, pg. 49.
[42] Bob Cleveland and Gary Moland, Grain Belt Express Project Benefits Study (Oct. 30, 2012) (Exhibit DAB-3 attached to David Berry's prefiled direct testimony (hereinafter cited as "*Benefits Study*")).

states, to make assumptions about future demand in those states in 2019, and to simulate how the sale of Kansas wind energy into these markets would affect aggregate electric generation costs (which drive the prices consumers pay) and emissions levels of various pollutants (which affect health). Four future scenarios were assumed for the analysis:

> *Business As Usual* - Energy demand grows under a moderate economic recovery with no major changes to existing environmental policy, generating technologies, fuel commodity prices, or other key energy market assumptions.
>
> *Slow Growth* - Continuation of depressed economic conditions characterized by slow demand growth, continued low fuel commodity prices, and minimal transmission/generation expansion.
>
> *Robust Economy* - Strong recovery in economic activity characterized by accelerated growth in electrical demand, higher fuel prices and emission allowances prices, and increased activity in new generation and transmission projects.
>
> *Green Economy* - Expansion in environmental policy including carbon regulation and a federal renewable portfolio standard under robust economic conditions including high demand growth, an increase in fuel prices, and increased activity in new generation and transmission projects.[43]

Using PRODMOD software, the impacts of selling Kansas wind energy into the PJM and MISO markets were simulated and the following results were reported:

2019 DEMAND COST SAVINGS IN $ MILLIONS				
Area/Region	**Business as Usual**	**Slow Growth**	**Robust Economy**	**Green Economy**
Indiana	13	14	79	89
PJM	421	310	830	379
Midwest ISO	119	30	370	78

Environmental Benefits of Grain Belt Express Project				
Environmental Improvement	**Business as Usual**	**Slow Growth**	**Robust Economy**	**Green Economy**
Reduction in NO_x (tons)	15,538	7,254	3,504	3,556
Reduction in SO_x (tons)	9,868	9,730	6,374	7,841
Reduction in CO^2 (tons)	7,434,958	10,345,743	5,704,144	5,402,264
Reduction in Hg (lbs)	83	110	46	96
Reduction in Water (Mgal)	3,150	3,915	2,556	2,800

Thus, Grain Belt's analysis of consumer benefits is that consumers—largely in the PJM and MISO states—benefit by reducing the cost of electric power ranging between $354 million

[43] Benefits Study pg 1.

annually to $546 million annually depending on the assumption one makes about demand levels in 2019. Grain Belt also asserts that consumers also benefit by reductions in emissions levels.

The Commission is not an environmental regulator and estimating the economic benefits with any precision based on assumptions six years from now over many states included in the PJM and MISO footprints seems questionable to me. However, there was no competing evidence in the record to suggest that consumers would not benefit in some manner. Certainly, the simulation model does provide some indication of the range and magnitude of benefits.

At a conceptual level, Grain Belt does not have the power to force anyone to purchase its power. Thus, if utilities in the MISO and PJM markets purchase power from Grain Belt, they must believe that the purchase makes them better off in some manner—either by reducing emissions mandates, meeting a state renewable portfolio standard, or reducing costs. In my view, if there is a viable market for Kansas wind energy in eastern states—the business premise upon which this project is based – then there must be some benefit to be gained in eastern states.

VII. Economic Development Benefits in Kansas

Grain Belt's Executive Vice President of Strategy and Finance, David Barry sponsored a study of the economic development benefits of the project in Kansas.[44] The study used the Jobs and Economic Development Impact ("*JEDI*") model developed by the National Renewable Energy Laboratory ("*NREL*"), which, in turn used the IMPLAN input-output economic model to estimate macro-economic development impacts of the project.

Estimates of the economic development impacts were presented separately for the construction and operation of the transmission facility, construction and operation of the wind farms, and the manufacture of wind turbine components in Kansas.

The table below summarizes the economic development impacts associated with the construction process of the Grain Belt line in Kansas ($ figures are in millions of $):[45]

Estimated State-Level Economic Development Impacts Associated with Construction Activities		
Component		**Impact**
Installation of Structures	Jobs	4,149
	Salaries	$235.1
	Output	$594.6
Manufacture of Structures	Jobs	592
	Salaries	$36.5
	Output	$134.0
Manufacture of Wire	Jobs	176

[44] Economic Development Study.
[45] *Id.* at Table 3.3.

Estimated State-Level Economic Development Impacts Associated with Construction Activities		
Component		Impact
	Salaries	$12.2
	Output	$67.5
Architectural Services	Jobs	438
	Salaries	$29.2
	Output	$61.6
Rights of Way	Jobs	313
	Salaries	$6.8
	Output	$47.4
Financial	Jobs	108
	Salaries	$3.7
	Output	$22.8
Electric Power	Jobs	23
	Salaries	$1.8
	Output	$9.9
Installation of Converters	Jobs	1,221
	Salaries	$69.2
	Output	$174.9
Totals	Jobs	7,021
	Salaries	$394.4
	Output	$1,113.0

At a high level and taken at face value, these estimates mean that the construction phase will add about 7,000 jobs to the Kansas economy, grow wages and benefits paid into the Kansas workforce by about $394 million and as the money spent flows through the Kansas economy, total economic output will grow by about $1.1 billion. When the line is operational, the Economic Development Study reports that the operations and maintenance will add 135 jobs to the Kansas economy, grow annual wages/salaries by $7.6 million, and increase aggregate state output by $17.7 million.[46]

In addition to economic development benefits associated with the Grain Belt transmission line, estimates were presented of the economic development impacts of wind generation built in response to the availability of the Grain Belt transmission line. To develop those estimates, the Economic Development Study identified impacts based on assumptions about the proportion of wind turbine components that were made in Kansas. The Economic Development Study identified seven companies that manufacture wind turbine components[47] and modeled two scenarios; one where 30% of the wind turbine components used in the wind farms connected to the Grain Belt line were manufactured in Kansas and another where 90% of the wind turbine

[46] *Id.* at p. 2, Table ES-2.
[47] *Id.* at p. 30, Table 4.1.

components were manufactured in Kansas. The Economic Development Study assumed that 4,000 MW of wind turbine capacity would be built and connected to the Grain Belt line.

The table below summarizes the Kansas impacts of wind farm construction and operations associated with the Grain Belt line:

Reported Economic Development Impacts of Wind Farm Construction and Operations			
		30% Scenario	**90% Scenario**
During Construction	Jobs	15,542	19,656
	Salaries	$778.8	$1,026.1
	Output	$2,283.5	$3,267.7
During Operational Years (annual figures)	Jobs	528	528
	Salaries	$25.0	$25.0
	Output	$73.3	$73.3

Thus, at a high level and taking the figures at face value, the Economic Development Study reports that the wind farm construction induced by the Grain Belt line would create between 15,000 and 19,000 jobs during the construction phase, grow Kansas wages and salaries by between $778 million and $1 billion, and add between $2.3 and $3.3 billion to the Kansas economy.

Certainly, input-output models have their critics, and they are only as good as the inputs into and assumptions of the model, but the JEDI and IMPLAN models are widely used as mechanisms to assess economic development impacts. I find the results to be a credible assessment of the general magnitude of the economic development impacts of the proposed line.

<u>**CERTIFICATE OF SERVICE**</u>

NOV 07 2013

13-GBEE-803-MIS

I, the undersigned, hereby certify that a true and correct copy of the above and foregoing Order Granting Siting Permit was served by electronic mail this 7th day of November, 2013, to the following parties who have waived receipt of follow-up hard copies:

JOHN J. MCNISH, ATTORNEY AT LAW
BOLTON & MCNISH, LLC
916 BROADWAY STREET
PO BOX 386
MARYSVILLE, KS 66508
Fax: 785-562-2124
jmcnish@bluevalley.net

GLENDA CAFER, ATTORNEY
CAFER LAW OFFICE, L.L.C.
3321 SW 6TH ST
TOPEKA, KS 66606
Fax: 785-233-3040
glenda@caferlaw.com

TERRI PEMBERTON, ATTORNEY
CAFER LAW OFFICE, L.L.C.
3321 SW 6TH ST
TOPEKA, KS 66606
Fax: 785-233-3040
terri@caferlaw.com

CYNTHIA A. DETTKE THORESON
1206 WALNUT
MARYSVILLE, KS 66508
Fax: 785-713-2872
cthoreson@gmail.com

SUSAN B. CUNNINGHAM, COUNSEL
DENTONS US LLP
7028 SW 69TH ST
AUBURN, KS 66402-9421
Fax: 816-531-7545
susan.cunningham@dentons.com

DONALD L. MILLER
3555 E HAMPTON LN
GILBERT, AZ 85295
dnmilikan@cox.net

CARY J. KOTTLER, GENERAL COUNSEL
GRAIN BELT EXPRESS CLEAN LINE LLC
1001 MCKINNEY ST STE 700
HOUSTON, TX 77002-6448
ckottler@cleanlineenergy.com

ERIN SZALKOWSKI
GRAIN BELT EXPRESS CLEAN LINE LLC
1001 MCKINNEY ST STE 700
HOUSTON, TX 77002-6448
eszalkowski@cleanlineenergy.com

MITCHELL L. HERREN, ATTORNEY
HINKLE LAW FIRM L.L.C.
8621 E 21ST ST N STE 200
WICHITA, KS 67206-2991
Fax: 316-630-8375
mherren@hinklaw.com

CASEY L. JONES, ATTORNEY
HINKLE LAW FIRM L.L.C.
8621 E 21ST ST N STE 200
WICHITA, KS 67206-2991
Fax: 316-630-8375
cjones@hinklaw.com

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ALAN K. MYERS, VICE PRESIDENT-TECHNICAL
ITC GREAT PLAINS, LLC
3500 SW FAIRLAWN RD STE 101
TOPEKA, KS 66614-3979
amyers@itctransco.com

KRISTINE M. SCHMIDT, PRESIDENT
ITC GREAT PLAINS, LLC
3500 SW FAIRLAWN RD STE 101
TOPEKA, KS 66614-3979
kschmidt@itctransco.com

CHRIS WINLAND, MANAGER REG STRATEGY
ITC GREAT PLAINS, LLC
3500 SW FAIRLAWN RD STE 101
TOPEKA, KS 66614-3979
cwinland@itctransco.com

MATTHEW S. CARSTENS, SR. COUNSEL-CAP. PROJECTS & MAINTENANCE
ITC HOLDINGS CORP
123 5TH STREET SE
CEDAR RAPIDS, IA 52401
mcarstens@itctransco.com

HOLLY FISHER, ATTORNEY
ITC HOLDINGS CORP
3500 SW FAIRLAWN RD STE 101
TOPEKA, KS 66614
hfisher@itctransco.com

JANA L. REED
3224 MAIN
GREAT BEND, KS 67530
reed1arizona@yahoo.com

ANDREW FRENCH, LITIGATION COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604-4027
Fax: 785-271-3314
a.french@kcc.ks.gov

JUDY JENKINS, LITIGATION COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604-4027
Fax: 785-271-3167
j.jenkins@kcc.ks.gov

JAY VAN BLARICUM, ADVISORY COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604-4027
Fax: 785-271-3354
j.vanblaricum@kcc.ks.gov

LAURA E. JOHNSON-MCNISH, MARSHALL COUNTY ATTORNEY
LAURA E. JOHNSON-MCNISH
1201 BROADWAY
MARYSVILLE, KS 66508
Fax: 785-562-2971
ms_co_attorney@yahoo.com

MATTHEW STALLBAUMER
5201 SW 23RD TERRACE
TOPEKA, KS 66614
mstallbaumer@ogdenpubs.com

NANCY VOGELSBERG-BUSCH
NANCY VOGLESBERG-BUSCH
896 15TH ROAD
HOME, KS 66438
nancyvb@bluevalley.net

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RODGER A. SWANSON, VP & TO
PEOPLES BANK & TRUST CO.
101 S MAIN ST
PO BOX 1226
MCPHERSON, KS 67460
rodger.swanson@peoplesbankonline.com

THOMAS AND DEBORAH STALLBAUMER
514 N 7TH
SENECA, KS 66538
teestall@att.net

MARK D. CALCARA, ATTORNEY
WATKINS CALCARA CHTD.
1321 MAIN ST STE 300
PO DRAWER 1110
GREAT BEND, KS 67530
Fax: 620-792-2775
mcalcara@wcrf.com

CATHRYN J. DINGES, CORPORATE COUNSEL
WESTAR ENERGY, INC.
818 S KANSAS AVE
PO BOX 889
TOPEKA, KS 66601-0889
Fax: 785-575-8136
cathy.dinges@westarenergy.com

LINDSAY SHEPARD, EXECUTIVE MANAGER CORPORATE COMPLIANCE & ASSOCIATE GENERAL COUNSEL
SUNFLOWER ELECTRIC POWER CORPORATION
301 W. 13TH
PO BOX 1020 (67601-1020)
HAYS, KS 67601
Fax: 785-623-3395
lshepard@sunflower.net

DENNIS R. DAVIDSON, ATTORNEY AT LAW
THOMPSON ARTHUR & DAVIDSON
525 NORTH MAIN STREET
PO BOX 111
RUSSELL, KS 67665-0111
Fax: 785-483-3504
dennis.tad@eaglecom.net

TAYLOR P. CALCARA, ATTORNEY
WATKINS CALCARA CHTD.
1321 MAIN ST STE 300
PO DRAWER 1110
GREAT BEND, KS 67530
Fax: 620-792-2775
tcalcara@wcrf.com

Sheryl L. Sparks

Sheryl L. Sparks
Administrative Specialist

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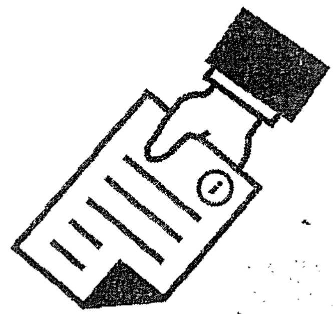
CLEAN LINE ENERGY PARTNERS

GRAIN BELT EXPRESS CLEAN LINE

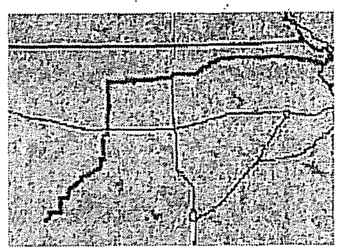
AG HEARING EXH. NO. __

WELCOME TO THE GRAIN BELT EXPRESS CLEAN LINE WEBSITE

Renewable energy provides Americans with jobs, clean air, and energy security. However, continued growth of the wind energy industry depends on the expansion of the U.S. electric **transmission grid**. The United States has some of the best renewable resources in the world, but they are predominantly located far from large population centers. The challenge lies in connecting these rich resources to communities that need the power—a challenge Clean Line Energy is working to address.



Respond To RFI



Kansas Route

Missouri Landowner Info

DELIVERING CLEAN ENERGY TO MILLIONS OF HOMES

An effective **transmission** solution requires the appropriate technology. The Grain Belt Express Clean Line will deliver up to 3,500 **megawatts** of low-cost wind power from western Kansas to Missouri, Illinois, Indiana and states farther east that have strong demand for clean, reliable energy. The clean energy will be transported via an approximately 750-mile overhead, **direct current** transmission line. DC is the most efficient and cost effective technology to move large amounts of power over long distances, due to its lower electricity losses and smaller footprint than comparable **alternating current (AC)** lines.

OAG EXHIBIT 2

DENIED Admittance

Grain Belt Express Clean Line Landowner Code of Conduct

UPDATES

View Project News

Project Video

Project Overview

Construction Simulation

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CLEAN LINE ENERGY PARTNERS

ROCK ISLAND CLEAN LINE

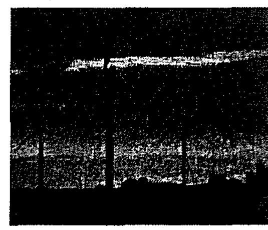
WELCOME TO THE ROCK ISLAND CLEAN LINE WEBSITE

Renewable energy provides Americans with jobs, clean air, and energy security. However, the continued growth of this budding industry depends upon the expansion of the U.S. electric transmission grid. Americans have come to realize the benefits of using renewable energy and are now more than ever encouraged to take advantage of the opportunities made possible by a clean energy economy. While the United States has some of the best renewable resources in the world, they are predominantly located in remote areas. The challenge lies in transporting the energy generated from these resources to communities that need the power—a challenge Clean Line Energy is working to solve.

DELIVERING CLEAN ENERGY TO MILLIONS OF HOMES

An effective transmission solution requires the appropriate technology and the right project. The Rock Island Clean Line will deliver 3,500 megawatts of wind power from northwest Iowa and the surrounding region to communities in Illinois and in other states to the east, areas that have a strong demand for clean, reliable energy. The clean energy will be transported via an approximately 500-mile overhead, direct current transmission line. Due to its low electricity losses and smaller footprint, direct current transmission is the most efficient technology to move large amounts of electricity over long distances.

Project Videos



Project Overview

Construction Simulation

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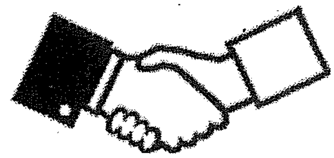
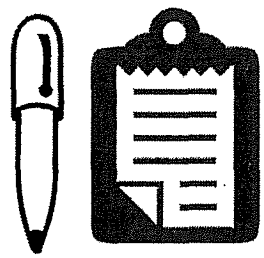


Illinois Agricultural Impact Mitigation Agreement



Rock Island Clean Line Landowner Code of Conduct

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CLEAN LINE ENERGY PARTNERS

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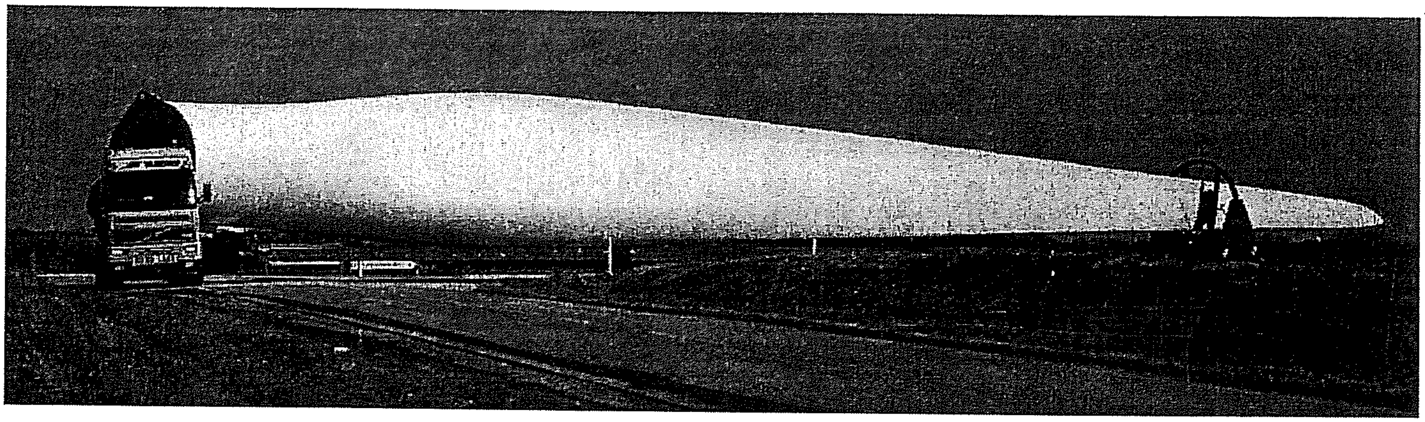
PLAINS & EASTERN CLEAN LINE

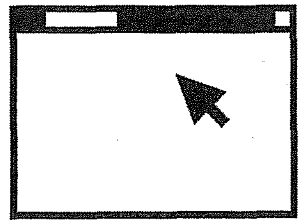


WELCOME TO THE PLAINS & EASTERN CLEAN LINE WEBSITE

Renewable energy provides Americans with jobs, clean air, and energy security. However, the continued growth of this burgeoning industry depends upon the expansion of the U.S. electric **transmission grid**. Americans have come to realize the benefits of using renewable energy and are now more than ever encouraged to take advantage of the opportunities made possible by a clean energy economy. While the United States has some of the best renewable resources in the world, they are predominantly located in remote areas. The challenge lies in transporting the energy generated from these resources to communities that need the power—a challenge Clean Line Energy is working to solve.

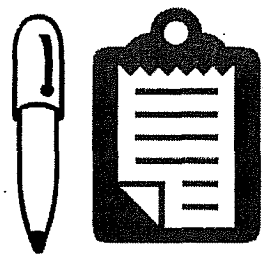
DELIVERING CLEAN ENERGY TO MILLIONS OF HOMES

An effective **transmission** solution requires the appropriate technology and the right project. The Plains & Eastern Clean Line transmission project will connect thousands of megawatts of clean energy generation from western Oklahoma, southwest Kansas, and the Texas Panhandle with utilities and customers in Tennessee, Arkansas, and other markets in the Mid-South and Southeast. The project will be developed in two 3,500 megawatt phases, with the first phase of the approximately 700-mile overhead **high voltage direct current transmission (HVDC)** transmission line currently under development. HVDC is the most efficient and cost effective technology to move large amounts of electricity over long distances due to its lower electricity losses and smaller footprint than comparable **alternating current (AC)** lines.



Click here to visit the Plains & Eastern EIS website

View Project Updates



Plains & Eastern Clean Line Landowner Code of Conduct

Project Videos

Project Overview

Construction Simulation

1001 McKinney Street, Suite 700, Houston, TX 77002 • T (877) 573-2851 • F (832) 319-6311

December 16, 2013

Chairman Armstrong
Public Service Commission
P.O. Box 615
Frankfort, Ky 40602-0615

RE: Big Rivers Electric Corporation

Dear Chairman Armstrong:

I am a long-term employee of Big Rivers Electric and a member of Kenergy. I am very concerned with the state of affairs at Big Rivers, as a result of the CEO and management team and the lack of true oversight by the Board of Directors.

A review of the departure of key employees during the last few years is a clear sign of the lacking of CEO leadership. When in excess of 5 senior level, VP or above, have left the organization, many before their planned retirement dates, this is a clear sign of lack of trust in the CEO. As a remaining employee, I must ask, "What is leading to this high turnover? Is there a problem with the top management and Board of Directors?"

To address specifics and not generalities, first let's start at the top with the Board of Directors. I am not sure the Board of Directors understands their duty. They seem to just follow along with whatever the CEO or attorney presents, without question. Directors typically arrive on Thursday evening at 6:00 PM for a meal provided by Big Rivers followed by the "Workshop" and adjourns at 8:00 PM. The next day the Board begins at 8:00 AM to go through the official agenda. Much of the time is spent with various employees presenting canned reports. The Board also takes whatever official action the CEO or attorney requests. The Board usually adjourns at 10:30 to 11:00 AM with a 15-30 minute break included. The Board has spent nearly 4 hours doing the business of Big Rivers. For this short time the Board has received 2 days of fees, a free meal, a motel stay and been paid a mileage fee. I must ask, "If I as a member of Kenergy are getting my money's worth?" Are the Board of Directors serving to receive their fees or are just being bought and paid for by the CEO?

The Board of Directors attends numerous other functions in the name of Big Rivers. They attend the NRECA Annual Meeting, the NRECA Regional Meetings, NRECA Director's Conference, CFC Meetings, ACES Meetings, and many others. At each of these meetings the Board members receive fees and expenses. Again, I must ask, "Are the Board members serving for fees or are they serving to help the various parties, employees or members?" Would the Board serve if the fee were a smaller amount or eliminated? I ask you to look at the total fees paid to each Board member, as the ratepayers are funding these fees and expenses.

Today's Big Rivers in not the same organization I came to work for years ago. The leadership is self-serving and cares little for the members who pay the bills and are the owners. The CEO and VP's seem to care more about their high salaries and their large bonuses. Other employees are making average wages. Big Rivers continues to provide selective end-of-the-year bonuses, even though you as KPSC have questioned the giving of the bonuses. Big Rivers seems to thumb its nose at the PSC.

During the most recent rate case, it surprised a number of employees the amount of the increase that was given, this on top of extremely large margins, in excess of $26,000,000 with a budgeted margin of $3,000,000. This provided Big Rivers with a windfall of $23,000,000 to provide the bonuses. This entire margin was before the increase, which was given. I and the other members have to pay the large margins; many members cannot afford these rates, to provide for the CEO.

The CEO of Big Rivers openly mocks the PSC, saying he has the confidence of the PSC Chairman, as shown by his remarks in the last case. Big Rivers has the attitude they can do as they please and how they please. The CEO and VP's have no concern for the cooperatives or the members, such as myself, being served by Kenergy. Big Rivers is not focused on the same values as existed when I was hired. The organization has become very self-centered and lost it cooperative focus, in spite of the many good employees. The leadership at the top is not concerned with the average member; the CEO has lost all touch with the cooperative principles and good management. I am very concerned, if things continue in this direction, Big Rivers will no longer be here.

The load mitigation and replacement plan as presented and approved by the Board of Directors during the April, May, or June meeting and filed with RUS does not agree with the facts as presented to you during the last case. The CEO said it did not matter that the facts did not match, the PSC would believe anything he said. The plan as filed with RUS does not show an offset of lowered rates if replacement load is found.

My request to you, is to look at Big Rivers from the Board of Directors, CEO, VP's, and the entire organization to determine if this organization is meeting its original goals and objectives and will the organization survive in the future. As I am nearing my retirement age, I would like to feel proud to say I worked at Big Rivers; today I can not say that. I ask for your help, for the good of all the good employees. Please provide some oversight and help those who are affected, both employees and those retail members.

I speak for myself, but also for many other employees who feel we have been cast aside by our CEO. Out of fear for my job, before my retirement date, I will not sign this letter.

Thanks for your consideration in this important matter, for all of Western Kentucky.

Concerned Big Rivers employee and Kenergy member.

Cc: Attorney General

Commissioner Gardner
Commissioner Breathitt
KPSC Executive Director
KIUC
Sierra Club

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Initial Request for Information
dated August 19, 2013

AG HEARING EXH. NO. __

September 3, 2013

Item 107) *Please provide a copy of any and all economic analysis(es) upon which Big Rivers bases or will base its decision to close the Wilson generation unit, and/or any other generation unit(s).*

a. Explain fully why idling Wilson is better and more cost-effective than selling it.

Response) Please see Big Rivers' response to AG 1-108(a) in Case No 2012-00535.

Witness) Robert W. Berry

OAG EXHIBIT 4

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

Response to the Office of the Attorney General's Initial Request for Information Dated February 14, 2013

February 28, 2013

Item 108) ***Please provide a copy of any and all economic analysis(es) upon which Big Rivers bases or will base its decision to close the Wilson generation unit, and/or any other generation unit(s).***

a. Explain fully why idling Wilson is better and more cost-effective than selling it.

Response) The economic analysis is not complete and will be made available when completed.

a. Big Rivers does not necessarily believe that idling the Wilson Station is better or more cost-effective than selling the unit. If Big Rivers were able to sell the asset at a price greater than or equivalent to its Net Book Value on the asset, Big Rivers Members would be able to save the $72.6 Million (2014-2016) referenced in AG-107(e), as well as the annual depreciation, interest, insurance, property taxes, and layup maintenance. Please see Big Rivers' response to PSC 2-18 for a discussion of its current efforts regarding the sale of Wilson Station.

Witness) Robert W. Berry

2013-00413
KIUC Exh 1

AG HEARING EXH. NO. __

Century ALUMINUM
Hawesville Operations

June 12, 2012

Mark Bailey
President and CEO
Big Rivers Electric Corporation
201 Third Street
Henderson, KY 42419

Serge Gosselin
Plant Manager
Sebree Works - Aluminum
9404 State Route 2096
Robards, KY 42452

Re: June 14 Meeting with Governor Beshear.

Gentlemen:

As you know, Governor Beshear has requested a meeting with us on June 14th to address the issue of current power prices. As we have communicated to you and to the Governor, the Hawesville aluminum smelter cannot sustain operations at Big Rivers' current and projected power rates. We see this meeting as an opportunity to come to an agreement among the attendees on a plan to solve this pressing issue. So that all parties can be prepared to engage in meaningful negotiations on the 14th, we are proposing the following modifications to the rate provisions of the current contract. Specifically the rate provisions of the Retail and Wholesale Electric Service Agreements would be replaced by one of the following:

(1) Power service would be provided by BREC from BREC resources, but the applicable rate would be a market-based rate for all MWh delivered to Hawesville with the rate equal to "day ahead" index market price at the MISO/BREC interface—the BREC.BREC MISO node; or
(2) Power service would be provided by BREC from BREC resources, but the rate would be based on the actual variable operating costs incurred by BREC at specified units plus a fixed adder of $XX/MWh not to exceed market price as defined in Section (1); or

Century Aluminum of Kentucky, General Partnership
Post Office Box 500
Hawesville, KY 42348

(270) 685-2493 Phone
(270) 852-2899 Fax

A Century Aluminum Company

OAG EXHIBIT 5

(3) At Hawesville's request, Big Rivers would obtain price quotes for 24X7 firm power with capacity for delivery at the MISO/Big Rivers Interface – the BREC.BREC MISO node – in amounts (MWh) and durations (start date/end date) as requested by Hawesville. Big Rivers would acquire such forward purchases at the lowest available price provided the price met Hawesville's threshold. The rate for all power delivered to Hawesville would be:

(a) The contract price ($/MWh) for all MWh purchased and delivered under such forward contracts;

(b) The "day ahead" index price at the MISO/Big Rivers Interface for all energy imbalance, including when load is not covered by a forward contract; and

Hawesville would have the right to curtail any portion of its load at any time, provided that under the third option Big Rivers would remarket any unused forward purchases and Hawesville would pay or receive a payment for the net difference. Hawesville would pay Kenergy the existing retail fee in §4.12 of the Retail Agreement under each option.

We look forward to discussing this proposal at the meeting with the Governor. In the meantime, we are happy to discuss the proposal with you or answer any questions you may have.

Very Truly Yours,

John Hoerner

John Hoerner

Cc: Governor Steve Beshear; Chief of Staff, Mike Haydon

AG HEARING EXH. NO. __

ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

THE APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR	)	Case No.
APPROVAL TO ISSUE EVIDENCE OF	)	2012-00492
INDEBTEDNESS	)	

Response to the Kentucky Industrial Utility Customers'
Initial Request for Information
dated December 19, 2012

Volume 2
Responses to Item Nos. 9 through 22

FILED: January 3, 2013

ORIGINAL

OAG EXHIBIT 6

Confidential

BIG RIVERS ELECTRIC CORPORATION

DISCLOSURE STATEMENT

July 12, 2012

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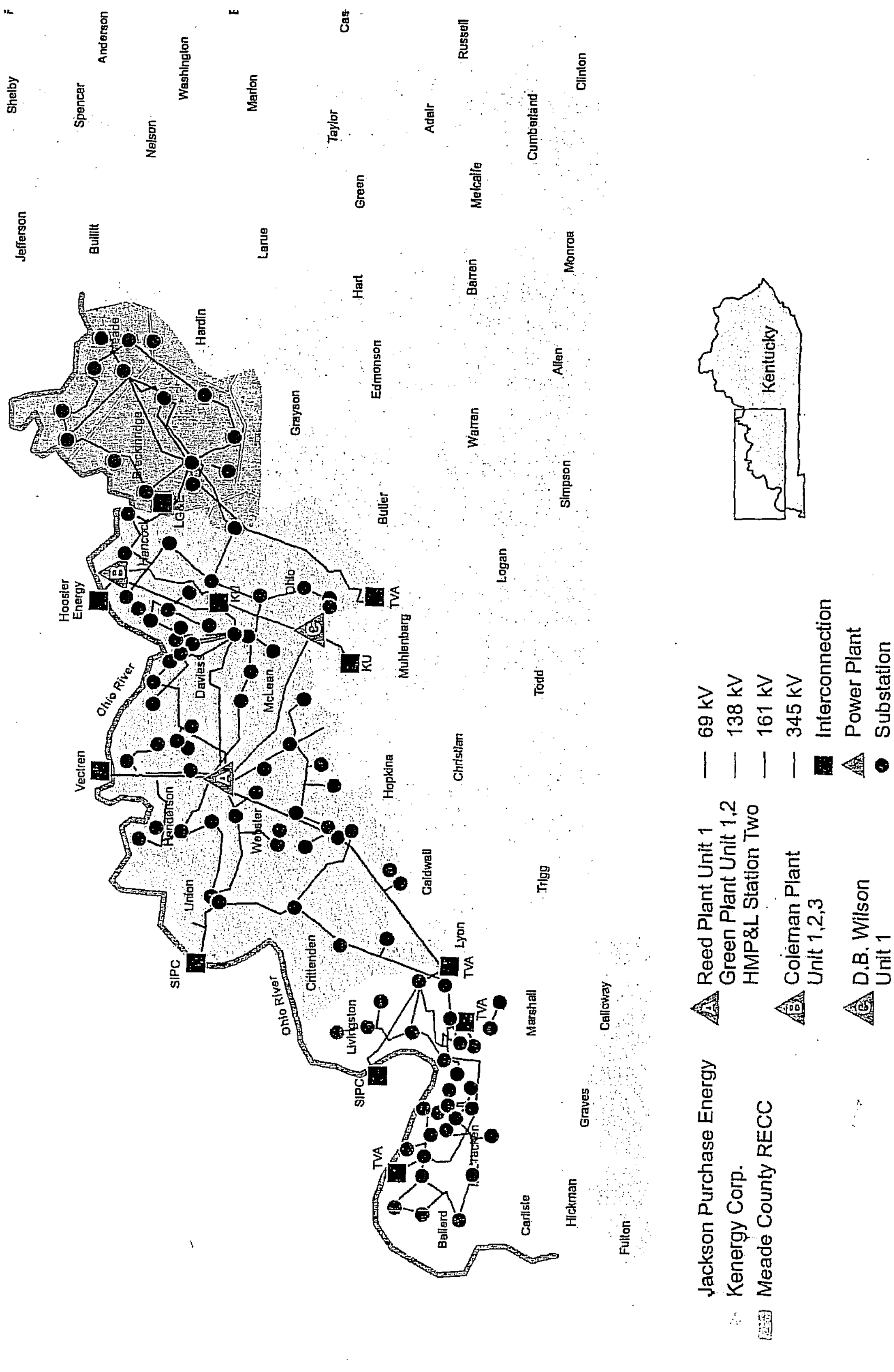

HSUSA:750982154.2

Big Rivers Electric Corporation
201 Third Street
Henderson, Kentucky 42420

Officers

Mark A. Bailey, President and Chief Executive Officer
Robert W. Berry, Vice President of Production

Senior Staff

David G. Crockett, Vice President of System Operations
James V. Haner, Vice President of Administrative Services
Mark A. Hite, Vice President of Accounting and Interim Chief Financial Officer
Eric M. Robeson, Vice President of Environmental Services and Construction
Albert M. Yockey, Vice President of Governmental Relations & Enterprise Risk Management

Directors

James G. Sills, Chair
Louis Wayne Elliott, Vice Chair
Larry F. Elder, Secretary-Treasurer
Lee Bearden
Paul Edd Butler
William C. Denton

Members

Kenergy Corp.
Jackson Purchase Energy Corporation
Meade County Rural Electric Cooperative Corporation

BIG RIVERS ELECTRIC CORPORATION

INTRODUCTION

General

Big Rivers Electric Corporation ("Big Rivers" or the "Company") is an electric generation and transmission ("G&T") rural electric cooperative corporation. It was organized as a not-for-profit rural electric cooperative under the laws of Kentucky in June, 1961 to enable its Members (as defined herein) to pool their resources and provide for the power and transmission needs of their combined service territories. The Company currently operates as a taxable cooperative. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Critical Accounting Policies – Accounting for Income Taxes." Big Rivers provides wholesale electric service to its three Members under a number of wholesale power contracts which contracts, in the aggregate, supply the total wholesale power requirements of the Members (see "Wholesale Power Contracts"), except the requirements of Kenergy Corp. ("Kenergy") for service to two aluminum smelters required by the Smelters Agreements (as defined herein). The two aluminum smelters are Rio Tinto Alcan ("Alcan"), a product group of Rio Tinto, and Century Aluminum of Kentucky General Partnership ("Century"), a wholly-owned subsidiary of Century Aluminum Company. Alcan and Century are referred to herein as the "Smelters." For a discussion of certain recent statements made on behalf of the Smelters, see the discussion under the caption "THE SMELTER AGREEMENTS."

Big Rivers owns 1,444 net MW of electric generating facilities, described herein under "GENERATION AND TRANSMISSION ASSETS – Generation Resources" and approximately 1,266 miles of transmission lines and 22 substations, described herein under "GENERATION AND TRANSMISSION ASSETS – Transmission."

In addition to its owned electric generation and transmission facilities, Big Rivers operates the 312 net MW Henderson Municipal Power and Light ("HMP&L") Station Two Generating Facility ("Station Two") in accordance with a Power Plant Construction and Operation Agreement dated August 1, 1970 between HMP&L and Big Rivers (the "Station Two Operation Agreement"), and purchases all the power and energy from Station Two not used by HMP&L to serve the needs of the City of Henderson, Kentucky (the "City" or the "City of Henderson"), in accordance with a Power Sales Contract between HMP&L and Big Rivers dated August 1, 1970 (the "Station Two Power Sales Contract"). See "GENERATION AND TRANSMISSION ASSETS – Other Power Supply Resources – *Station Two Facility*."

In 2011, the Company's average wholesale revenue per kWh to the Members, including amounts withdrawn from the economic reserve, was $.04678 per kWh for rural loads and $.04168 per kWh for large industrial loads (exclusive of the Smelter loads and Domtar cogenerator backup served by Kenergy). The Company's average wholesale revenue per kWh to Kenergy to serve the two Smelter loads in 2011 was $.04448 per kWh on sales of 6.9 million MWh. Excluding the Smelters, sales to its Members were 3.3 million MWh in 2011, 2.4 million MWh for rural loads and 0.9 million MWh for large industrial loads. Member Non-Smelter MWh sales in 2011 decreased by 2.0% from 2010. Rural loads in 2011 decreased by 4.4% from 2010 while large industrial loads increased by 4.3%. To the extent surplus capacity and energy are available, Big Rivers may sell electricity to non-Member utilities and power marketers ("Non-Members"). During 2011, the Company sold approximately 3.1 million MWh to Non-Members.

Cooperative Structure

In general, a cooperative is a business organization owned by its members, which are also its customers. Cooperatives provide goods or services to their members on a not-for-profit basis, in part by eliminating the need to produce profits or a return on equity in excess of required margins. Generally, electric cooperatives design rates on an overall basis to recover cost-of-service and collect a reasonable amount of revenue in excess of expenses (i.e., margins). Margins are typically repaid to the members in subsequent years on the basis of their patronage during the years the margins were earned.

A G&T cooperative is a cooperative engaged primarily in providing wholesale electricity to its members, which may be either wholesale or retail power suppliers. Electricity sold by a G&T cooperative is provided from its own generating facilities or through power purchase agreements with its wholesale power suppliers. A distribution cooperative is a local membership cooperative whose members are the individual retail customers of an electric distribution system.

The Members

The Members of Big Rivers are Kenergy, Meade County Rural Electric Cooperative Corporation ("Meade") and Jackson Purchase Energy Corporation ("Jackson Purchase", and collectively with Kenergy and Meade, the "Members"). The Members of Big Rivers are local consumer-owned distribution cooperatives providing retail electric service on a not-for-profit basis to their customers, who are their members. The customer base of the Members generally consists of residential, commercial and industrial consumers within specific geographic areas. The Members provide electric power and energy to customers located in portions of 22 western Kentucky counties. As of December 31, 2011, the Members served approximately 113,000 member-customers (meters). Kenergy has approximately 55,300 retail members, Meade has approximately 28,500 retail members and Jackson Purchase has approximately 29,200 retail members. See APPENDIX B – "MEMBER FINANCIAL AND STATISTICAL INFORMATION."

Bankruptcy and Subsequent Operation

In September 1996, Big Rivers filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code. The filing was precipitated largely by the Company's inability to sell its capacity in excess of that required to serve its Members at prices sufficient to cover all of its costs, which shortfall was exacerbated by long-term coal contracts under which prices had escalated well above market prices. In July 1998, a bankruptcy court-approved Plan of Reorganization (the "Plan of Reorganization") became effective. The Plan of Reorganization fundamentally changed the operations of the Company and resulted in the restructuring of the Company's long-term debt.

In accordance with the Plan of Reorganization, the Company leased all of its generating facilities to Western Kentucky Energy Corp. ("WKEC"), a wholly-owned subsidiary of LG&E Energy Corp. (LG&E, and subsequently E.ON U.S., LLC ("E.ON"). WKEC assumed and agreed to perform and discharge all of the Company's obligations under these assets that first arose or accrued on or after the effective date of the Plan of Reorganization. In addition to assuming responsibility for operation of the generating facilities owned by the Company, WKE Station Two Inc. ("WKE Station Two"), another wholly owned subsidiary of LG&E, assumed responsibility for the operation of Station Two and the Company's obligation to purchase power from Station Two under the Station Two Power Sales Contract. Pursuant to the Plan of Reorganization, WKEC and WKE Station Two (which was subsequently merged into WKEC) became responsible for the Company's prior responsibilities to operate and maintain the generating facilities owned by the Company and Station Two. Capital costs for these generating facilities were shared by WKEC and the Company in several different ratios depending upon whether or not the capital expenditures were incurred in order to comply with a state law enacted after the effective date of the Plan of Reorganization or a revision or change of an existing law enacted after such date. Operation and maintenance costs, including fuel, were, for the most part, the responsibility of WKEC.

The Plan of Reorganization (the "LG&E Arrangements") also included a power purchase agreement (the "LEM Power Purchase Agreement") between the Company and LG&E Energy Marketing Inc. ("LEM"). The LEM Power Purchase Agreement established minimum hourly and annual power purchase amounts that Big Rivers was required to take and certain maximum hourly and annual power purchase amounts that LEM was required to make available to the Company. The Company paid specified fixed rates for power purchased under the LEM Power Purchase Agreement that were not dependent upon market prices for electric power and energy nor the costs associated with power and energy generated by the generating facilities owned by the Company and operated by WKE Station Two.

Throughout the duration of the LG&E Arrangements Big Rivers received lease payments from WKEC of approximately $31 million annually. These lease payments were subject to adjustment for certain environmental costs and changes in the amount of power available to Big Rivers from LEM. The Company was responsible for 70% of all property taxes on the generating facilities leased to WKE Station Two during the LG&E Arrangements and WKEC paid 30%.

The Plan of Reorganization required LEM to pay Big Rivers an average of approximately $18 million annually, which amount corresponded to the estimated margins the Company had anticipated to realize from sales to its Members to supply the loads of the Smelters. The Plan of Reorganization also required the transfer of responsibility for providing the wholesale power and energy to Kenergy necessary to serve the needs of the Smelters from Big Rivers to LEM.

The Company provided transmission service to the Members and Non-Members pursuant to its Open Access Transmission Tariff ("OATT"). Under the LG&E Arrangements, LEM paid Big Rivers a minimum $5 million annually for transmission service.

Unwind of LG&E Arrangements

In March 2007, Big Rivers executed a Transaction Termination Agreement (the "Termination Agreement") among LEM, WKEC and Big Rivers setting forth the term and conditions upon which the Company and E.ON agreed to terminate the LG&E Arrangements (the "Unwind"). Protracted negotiations with creditors, governmental agencies, the Smelters and others followed the execution of the Termination Agreement. The closing of the Unwind took place on July 16, 2009.

Summary of Major Provisions of Unwind

In connection with the closing of the Unwind, E.ON compensated Big Rivers with approximately $864.6 million of value and Big Rivers took certain other actions as set forth below:

- E.ON made a cash payment to the Company of approximately $506.7 million. This amount represented (1) a termination payment by WKEC to the Company to compensate it for the risks associated with assuming responsibility for the operation of the Company's owned generating facilities and Station Two and (2) the netted amount of various payment obligations by both WKEC and the Company contemplated by the Termination Agreement.

- WKEC waived the requirement in the LG&E Arrangements that the Company make a payment at the expiration or early termination of the LG&E Arrangements in respect of the residual value of WKEC's capital contributions to the Company's owned generating facilities and Station Two. Additionally, WKEC conveyed to the Company certain utility plant assets used in connection with the operation of the Company's owned generating plants previously leased to WKEC. The value of these items was approximately $188.0 million.

- The Company established three reserves, (1) an economic reserve with an initial principal amount equal to $157 million (the "Economic Reserve"), (2) a second economic reserve with an initial principal amount equal to $60.9 million (the "Rural Economic Reserve"), and (3) a transition reserve with an initial principal amount equal to $35 million (the "Transition Reserve"). The Economic Reserve and Rural Economic Reserve accounts were established to help the Company cushion the effect of any potential future rate increases for fuel, environmental, and purchase power expenses on its rates to the Members for service to their non-Smelter members. The Transition Reserve account was established as a financial reserve account that would help the Company mitigate financial costs, if any, associated with the termination of the Smelter Agreements by a Smelter. In 2011 Big Rivers used the $35 million from the Transition Reserve to prepay a portion of its Rural Utilities Service ("RUS") related debt and Big Rivers will use a portion of the proceeds of a bank loan to replenish the Transition Reserve. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Executive Overview."

- WKEC conveyed to the Company a flue gas desulphurization ("FGD") system which had recently been constructed at the Company's Kenneth C. Coleman Plant (the "Coleman Plant"). The value ascribed to the flue gas desulphurization facility was approximately $98.5 million.

- WKEC conveyed to the Company personal property and inventories of coal, petroleum coke, fuel oil, lime, limestone and spare parts, and materials and supplies. The value of these items was approximately $55.0 million.

- WKEC forgave a promissory note of approximately $15.4 million the Company owed to LEM.

- WKEC conveyed to the Company 14,000 sulfur dioxide ("SO_2") allowances allotted by the United States Environmental Protection Agency ("EPA") with a fair market value of approximately $1.0 million on July 16, 2009.

- The lease of the generating facilities to WKEC and all the other property interests of WKEC and LEM in the generating facilities previously leased to WKEC were terminated.

- The Station Two Agreement was terminated and the Company resumed its responsibility to operate Station Two and to purchase the output of Station Two in excess of the City's requirements in accordance with the Station Two Power Sales Contract.

Change in Capital Structure Resulting from Unwind

On July 16, 2009, the Company prepaid $140.2 million of the indebtedness it owed to the RUS and the schedule of maximum permitted outstanding balances on the amortizing debt the Company owed to the RUS was adjusted. The non-interest bearing RUS Series B Note was also restructured in concert with the Unwind into a single "bullet" payment due December 31, 2023. The Company's debt to RUS was incurred primarily to finance its generating assets. In connection with the Unwind the Company obligated itself to reduce the maximum permitted outstanding balances of its RUS debt by $60.0 million by October 1, 2012 and $200.0 million by January 1, 2016. The Company is using the proceeds of certain bank loans to satisfy these obligations. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Executive Overview."

The chart set forth below shows the impact of the Unwind on the Company's outstanding debt.

Debt Instrument	Pre-Unwind Balance	Unwind Close Transaction	Post-Unwind Balance
		(In millions of dollars)	
RUS Series A Note	$ 740.0	$140.2 (1)	$599.8
RUS Series B Note	106.5	0.0	106.5
LEM Settlement Note	15.4	15.4 (2)	0.0
PMCC Note	12.4	12.4 (3)	0.0
County of Ohio, Kentucky, promissory note (1983 Series) 1983 Series Pollution Control Bonds	58.8	0.0	58.8
County of Ohio, Kentucky, promissory note (2001A Series) 2001A Series Pollution Control Bonds	83.3	0.0	83.3
	$1,016.4	$168.0	$848.4

(1) Big Rivers payment to RUS on Unwind closing date.
(2) Forgiveness of debt by E.ON.
(3) Big Rivers payment to Philip Morris Capital Corporation on Unwind closing date.

As a result of the Unwind, the Company went from an equity to total capitalization ratio of -19% as of December 31, 2008, to 35.3% as of December 31, 2011.

Resumption of Operational Responsibilities in Connection with Generating Facilities

In connection with the Unwind, the lease of the Company generating facilities to WKEC was terminated and the Company resumed responsibility for the operation of its generating facilities. Thus, the Company assumed responsibility for the risks associated with such operation (e.g. fuel, capital costs associated with change in law). The Company intends to use the output of its generating facilities to supply the needs of the Members, including approximately 850 MW of power that is necessary for Kenergy to supply its contractual obligations to the Smelters, which were primarily serviced by LEM prior to the Unwind. See "THE SMELTER AGREEMENTS" and APPENDIX D – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS." Power and energy generated above the Members' requirements will be sold into the wholesale power market.

Wholesale Power Contracts with Members

Each of Meade, Jackson Purchase and Kenergy is party to a wholesale power contract with Big Rivers (the "All Requirements Contracts") providing that Big Rivers sells and delivers to the Member, and the Member purchase and receive from Big Rivers, all the electric power and energy which the Member requires for the operation of the Member's system (except Kenergy's requirements for the Smelters) to the extent that Big Rivers has power and energy and facilities available. The term of each All Requirements Contract extends through December 31, 2043 and neither of the parties may unilaterally terminate the contract, without cause, prior to such date. Each All Requirements Contract may be terminated by either party thereto after December 31, 2043, upon six months' notice.

The All Requirements Contracts require each Member to pay the Company monthly for capacity and energy furnished. The All Requirements Contracts provide that if a Member fails to pay any bill by the first business day following the twenty-fourth day of the month, the Company may, upon five (5) business days' written notice, discontinue delivery of electric power and energy. The All Requirements Contracts also provide that, so long as any notes and note guarantees are outstanding from the Company to the RUS, the Member may not reorganize, dissolve, consolidate, merge, or sell, lease or transfer all or a substantial portion of its assets unless it has either (i) obtained the Company's written consent and the written consent of the RUS, or (ii) paid a portion of the outstanding indebtedness on the notes and the Company's other commitments and obligations then outstanding, such portion to be determined by the Company with RUS approval. The All Requirements Contracts may only be amended with the approval of the RUS and upon compliance with such other reasonable terms and conditions as the Company and RUS may agree.

Each Member is required to pay the Company for capacity and energy furnished under its All Requirements Contract in accordance with the Company's established rates as approved by the Kentucky Public Service Commission ("KPSC"). All Requirements Contracts with the Members provide that the Company's board of directors (the "Board of Directors") establish rates to produce revenue sufficient, but only sufficient, together with all of the Company's other revenue, to pay the cost of operation and maintenance of all of the Company's generation, transmission and related facilities, to pay the cost of capacity and energy purchased by the Company for resale, to pay the cost of transmission service, to pay the principal of and interest on all the Company's indebtedness and to provide for the establishment and maintenance of reasonable financial reserves.

The All Requirements Contracts require the Company's Board of Directors to review the rates at least annually and to revise such rates as necessary to produce revenue as described above. Big Rivers must give Members no less than thirty (30) days' or more than forty-five (45) days' written notice of every rate revision. The Company's electric rate revisions are subject to the approval of the RUS and the KPSC, after which the Members are permitted to incorporate such rate changes into their own rate structures. See "RATE AND ENVIRONMENTAL REGULATION – Kentucky Rate Regulation" for information relating to rate regulation by the KPSC.

Smelter Agreements with Kenergy

In addition to the All Requirements Contracts, Big Rivers and Kenergy are parties to two wholesale electric service agreements under which the Company provides a fixed amount of power and energy of 850 MW that is necessary for Kenergy to supply its contractual obligations to the Smelters through December 31, 2023. These agreements are exceptions to the "all requirements" obligations in the All Requirements Contracts with Kenergy. See "THE SMELTER AGREEMENTS" and APPENDIX D – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS."

Existing Generation and Transmission Resources

The Company owns interests in seven base load coal-fired generating units and one oil- or natural gas-fired combustion turbine generating unit, all of which are in commercial operation. These units provide the Company with approximately 1,444 MW of capacity. See "GENERATION AND TRANSMISSION ASSETS – Generation Resources" for a discussion of the Company's existing generation facilities. The Company also has a variety of purchase arrangements, including the Station Two Power Sales Contract with the City of Henderson and a contract with (the "SEPA Contract") the Southeastern Power Administration ("SEPA"), which together supply the Company with up to 375 MW of power. The Company purchases 197 MW from HMP&L pursuant to the Station Two Power Purchase Agreement and up to 178 MW under the SEPA Contract. The Company normally uses its entitlement under the SEPA Contract for peaking; however, as a result of problems with certain dams on the Cumberland River hydro system, the Company's capacity entitlement has been suspended and the Company currently is receiving only energy. See "GENERATION AND TRANSMISSION ASSETS – Other Power Supply Resources" for a discussion of the Company's power purchase arrangements. The Company also owns 1,266 miles of transmission lines and 22 substations and has additional access to approximately 100 MW of firm transmission service through an agreement with another utility. The Company is a participant in the Midwest Independent System Operator, Inc. ("MISO"). MISO is a non-profit regional transmission organization operating in 13 states in the Midwest United States and Manitoba, Canada. MISO has functional control of the operation of its participants transmission facilities of 100 kilovolts ("kV"). In addition to operating the bulk transmission system of its participants, MISO also operates the Midwest Market (the "MISO Market"). In the MISO Market, the Company and other participants submit day-ahead or real-time bids and offers for the purchase or sale of energy at various locations. MISO then directs each MISO Market participant whether to operate its generation facilities and determines the price of energy at each location for a particular time period.

SELECTED FINANCIAL DATA

The following financial data present selected information relating to the Company's financial condition and results of operations. The Balance Sheet data as of December 31, 2011 and 2010 and the Statement of Revenues and Expenses data for years ended December 31, 2011, 2010 and 2009 were derived from the Company's audited financial statements included in APPENDIX A. The Balance Sheet data as of December 31, 2009 and the Statement of Revenues and Expenses data for the years ended December 31, 2008 and 2007 were derived from the Company's audited financial statements for those years. The information shown below should be read in conjunction with the financial statements and the related notes thereto in Appendix A. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS."

BIG RIVERS
STATEMENT OF REVENUES AND EXPENSES
(dollars in thousands)

	Year Ended December 31, (Audited)				
	2011	2010	2009	2008	2007
Operating revenues:					
Member tariff electric energy revenues	$456,351	$432,100	$259,579	$114,513	$113,281
Other electric energy revenues	102,021[1]	82,390	67,151	90,006	148,611
Lease revenue	—	—	32,027	58,423	58,265
Other operating revenues	3,617	12,834	14,603	10,239	9,713
Total operating revenues	561,989	527,324	373,360	273,181	329,870
Operating expenses:					
Operations:					
Fuel for electric generation	226,229	207,749	80,655	—	—
Power purchased and interchanged	112,262	99,421	116,883	114,643	169,768
Production, excluding fuel	50,410	52,507	22,381	—	—
Transmission and other	39,085	35,273	35,444	28,600	27,196
Maintenance	47,718	46,880	29,820	4,258	4,240
Depreciation and amortization	35,407	34,242	32,485	31,041	30,632
Total operating expenses	511,111	476,072	317,668	178,542	231,836
Electric operating margins	50,878	51,252	55,692	94,639	98,034
Interest expense and other:					
Interest, net of capitalized interest	45,226	46,570	59,898	65,719	60,932
Interest on obligations related to long-term lease	—	—	—	6,991	9,919
Amort. of loss from termination of lease	—	—	2,172	811	—
Income tax expense	100	259	1,025	5,934	—
Other, net	220	166	112	123	103
Total interest expense and other	45,546	46,995	63,207	79,578	70,954
Operating margin before non-operating margin	5,332	4,257	(7,515)	15,061	27,080
Non-operating margin:					
Interest income on restricted investments under long-term lease	—	—	—	8,742	12,481
Gain on "Unwind" Transaction	—	—	537,978	—	—
Interest income and other	268	2,734	867	4,013	7,616
Total non-operating margin	268	2,734	538,845	12,755	20,097
Net margin	$5,600	$6,991	$531,330	$ 27,816	$ 47,177

[1] Includes Domtar cogenerator backup power revenues.

BALANCE SHEET
(dollars in thousands)

	December 31, (Audited) 2011	2010	2009
Assets:			
Utility plant, net	$1,092,063	$1,091,566	$1,078,274
Restricted investments under long-term lease	–	–	–
Restricted Investments – Member rate mitigation	163,162	217,562	243,225
Other deposits and investments, at cost	5,911	5,473	5,342
Current Assets:			
Cash and cash equivalents	44,849	44,780	60,290
Accounts receivable	44,287	45,905	47,493
Fuel inventory	33,894	37,328	37,830
Non-fuel inventory	25,295	23,218	20,412
Prepaid expenses	4,217	2,502	3,233
Total current assets	152,542	153,733	169,258
Deferred loss–termination of sale-leaseback	–	–	–
Deferred charges and other	4,244	3,851	9,384
Total assets	$1,417,922	$1,472,185	$1,505,483
Equities (Deficit) and Liabilities:			
Capitalization:			
Equities (deficit)	$389,820	$386,575	$379,392
Long-term debt	714,254	809,623	834,367
Total capitalization	1,104,074	1,196,198	1,213,759
Current liabilities:			
Current maturities of long-term debt and obligations	72,145[2]	7,373	14,185
Notes payable	–	10,000	–
Purchased power payable	1,878	1,516	3,362
Accounts payable	28,446	29,782	30,657
Accrued expenses	10,380	10,627	9,864
Accrued interest	9,899	11,134	9,097
Total current liabilities	122,748	70,432	67,165
Deferred credits and other:			
Regulatory liabilities – Member rate mitigation	169,001	185,893	207,348
Other	22,099	19,662	17,211
Total deferred credits and other	191,100	205,555	224,559
Total equities and liabilities	$1,417,922	$1,472,185	$1,505,483

[2] Includes $60 million due to the RUS by October 1, 2012, that the Company intends to refinance with the proceeds of certain bank loans.

CAPITALIZATION

The Company's capitalization derived from the financial statements included in APPENDIX A is as follows:

	December 31, (Audited) 2011 (in thousands)
Long-Term debt:	
Secured by the Mortgage Indenture:	
RUS Series A Note	$521,250
RUS Series B Note	123,049
1983 Series Pollution Control Bonds	58,800
2001A Series Pollution Control Bonds	83,300
Total long-term debt	$786,399
Less: current portion	72,145[3]
Total long-term debt, excluding current portion	714,254
Equity:	
Accumulated Margins	397,098
Other Equities and Accumulated Other Comprehensive Income	(7,278)
Total Equities	$389,820
Total capitalization	$1,104,074

[Remainder of page intentionally left blank]

[3] Includes $60 million due to the RUS by October 1, 2012, that the Company intends to refinance with the proceeds of certain bank loans.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Caution Regarding Forward Looking Statements

This Disclosure Statement contains forward-looking statements regarding matters that could have an impact on the Company's business, financial condition and future operations. These include statements regarding expected capital expenditures, sales to Members, and liquidity and capital resources. Some forward-looking statements can be identified by use of terms such as "may," "will," "expects," "anticipates," "believes," "intends," "projects," "plans," or similar terms. These forward-looking statements, based on the Company's expectations and estimates, are not guarantees of future performance and are subject to risks, uncertainties, and other factors that could cause actual events or results to differ materially from those expressed in these statements. These risks, uncertainties, and other factors include, but are not limited to, general business conditions, changes in demand for power, federal and state legislative and regulatory actions and legal and administrative proceedings, changes in and compliance with environmental laws and policies, weather conditions, the cost of commodities used in Big Rivers' industry and unanticipated changes in operating expenses, capital expenditures and tax liabilities. Some of the factors that could cause the Company's actual results to differ from those anticipated by these forward-looking statements are described under the caption "RATE AND ENVIRONMENTAL REGULATIONS." Any forward-looking statement speaks only as of the date on which the statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which the statement is made even if new information becomes available or other events occur in the future.

Executive Overview

Under the Unwind, the Company obligated itself to reduce the maximum permitted balances of its RUS Series A Note by $60.0 million on October 1, 2012 and $200.0 million on January 1, 2016. The Company expects to meet these obligations through the issuance of long-term debt. The Company also has significant projected capital expenditures including approximately $283.5 million in pollution control expenditures in order to keep its coal-fired units in compliance with various EPA standards. Big Rivers sought KPSC approval for its 2012 environmental compliance plan ("ECP") in an April 2012 filing. Big Rivers expects to finance the costs of the ECP using an unsecured line of credit as bridge financing to permanent, long-term financing. The Company also has a $50.0 million unsecured revolving credit agreement with CoBank ACB ("CoBank") that expires July 16, 2012, that it is seeking to renew for a five year term as described below.

The Company has entered into letters of intent with CoBank and the National Rural Utilities Cooperative Finance Corporation ("CFC"). Big Rivers will borrow $235 million from CoBank in the form of a secured term loan. Also, Big Rivers will enter into an unsecured revolving credit agreement with CoBank to replace its current revolving credit agreement with CoBank. Big Rivers will borrow $302 million from CFC under a secured term loan. On July 2, 2012 Big Rivers borrowed $25 million under the existing CFC revolving credit agreement and prepaid that amount on the RUS Series A Note. Big Rivers plans to repay this borrowing in connection with the closing of the bank loans. The proceeds of both the CFC and the CoBank loans will be used primarily to prepay a portion of the RUS Series A Note. It is expected that the application of the prepayment, together with the use of a portion of the proceeds of the CFC and the CoBank loans will result in the reduction of the maximum debt balance on the RUS Series A Note from $561.6 million to $84.6 million. A portion of the CoBank loan will also be used to replenish the Transition Reserve investment account in the amount of $35 million. Big Rivers expects to use a combination of loan proceeds, cash flows from operations, secured debt offerings in the public debt market and/or loans from the Federal Financing Bank ("FFB") guaranteed by RUS to finance its operating costs and its capital expenditures, including the ECP, through 2015.

On March 28, 2012, Big Rivers filed an application to the KPSC seeking approval to issue both secured and unsecured debt in connection with the CoBank and the CFC loans. The application was approved May 25, 2012, and Big Rivers plans to close the loans July 27, 2012. Since the closing is not scheduled until later this month, the Company and CoBank have extended the term of the expiring CoBank revolving credit agreement for a period of six months.

The Company is currently forecasting a MFI Ratio (as defined herein under the caption "Cooperative Operations – Coverage Ratio") of 1.10 for 2012, as required by the Indenture dated as of July 1, 2009, as supplemented and amended (the "Mortgage Indenture"), which MFI Ratio will result in net margins of $4.5 million. During the year ended December 31, 2011, Big Rivers achieved net margins of approximately $5.6 million and the MFI Ratio was 1.12.

Critical Accounting Policies

General

The Company prepares its financial statements in conformity with accounting principles generally accepted in the United States. Management exercises judgment in the selection and application of these principles, including making certain estimates and assumptions that impact the Company's results of operations and the amount of its total assets and liabilities reported in the Company's financial statements. The Company considers critical accounting policies to be those policies that, when applied by management under a particular set of assumptions or conditions, could materially impact the Company's financial results if such assumptions or conditions were different than those considered by management. Set forth below are certain accounting policies that are considered by management to be critical and to possibly involve significant risk, which means that they typically require difficult, subjective or complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain. Other significant accounting policies and recently issued accounting standards are discussed in Note One – "Significant Accounting Policies" of Notes to Financial Statements in APPENDIX A.

Use of Accounting Policies and Estimates

The application of accounting policies and estimates is a continuing process. As the Company's operations change and accounting guidance evolve, its accounting policies and estimates may be revised. The Company has identified a number of critical accounting policies and estimates that require significant judgments. The Company bases its judgments and estimates on experience and various other assumptions that the Company believes are reasonable at the time of application. The Company's judgments and estimates may change as time passes and more information about the environment in which it operates becomes available. If actual results are different than the estimated amounts recorded, adjustments are made taking the new information into consideration. The Company discusses its critical accounting policies, significant estimates and other certain accounting policies with the Board of Directors, as appropriate. The Company's critical accounting policies and significant estimates are discussed below.

Regulatory Accounting

The Company's accrual basis accounting policies follow the Uniform System of Accounts as prescribed by RUS Bulletin 1767B-1, as adopted by the KPSC. These regulatory agencies retain authority over the Company and periodically issue orders and instructions on various accounting and ratemaking matters. The Company's operations meet the criteria for application of regulatory accounting treatment. As a result, the Company records approved regulatory assets and liabilities that result from the regulated ratemaking process that would not ordinarily be recorded under Generally Accepted Accounting Principles. The Company had no Regulatory Assets at December 31, 2011 and the Company's Regulatory Liabilities were $169.0 million. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in Member rates. Regulatory liabilities generally represent amounts established by the Company's regulator to mitigate the net effect on the Members of fuel and environmental surcharges and surcredits. These amounts are recorded in revenue as the underlying fuel and environmental costs are incurred. The Company continually assesses whether any regulatory account it has is probable of future recovery or refund by considering factors such as applicable regulatory environment changes, historical regulatory treatment for similar costs, recent rate orders to other regulated entities and the status of any pending or potential legislation. Based on this continual assessment, the Company believes its existing regulatory liabilities are probable of future refund. This assessment reflects the current political and regulatory climate at the state level, and is subject to change in the future. If future recovery of a regulatory asset or refund of a regulatory liability ceases to be probable, the asset or liability write-off would be recognized in operating income.

Revenue Recognition

Revenues on sales of electricity are recognized as earned when the electricity is provided. Revenues under the wholesale power contracts for sales to Members including the Smelter Agreements are based on month-end meter readings and billed the month following the month of service.

Off-Balance Sheet Arrangements

The Company had no off-balance sheet arrangements as of December 31, 2011.

Accounting for Loss Contingencies

The Company is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its financial statements, the Company makes judgments regarding the future outcome of contingent events and records a loss contingency when it is determined that it is probable that a loss has occurred and the amount of the loss can be reasonably estimated. The Company regularly reviews current information available to determine whether any such accruals should be adjusted and whether new accruals are required. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the financial statements may differ from the actual outcome once the contingency is resolved, which could have a material impact on the Company's future operating results, financial position or cash flows. The Company had no contingent matters requiring accrual at December 31, 2011.

Depreciation of Utility Plant

Utility plant is recorded at original cost. Replacements of depreciable property units are also charged to utility plant. Replacements of minor items of property are charged to maintenance expense. The Company performed a depreciation study in 1998 that resulted in depreciation rates based on extended remaining service lives. Depreciation of utility plant is recorded using the straight-line method and rates based on the estimated remaining years of service determined by such study. This study, which significantly reduced depreciation expenses, was approved by the KPSC and the RUS in 1998 and made effective as of July 1, 1998. These depreciation rates remained in effect up to December 1, 2011.

On March 1, 2011, the Company filed a new depreciation study with the KPSC as part of a request for approval of an increase in member rates. The new depreciation study, which was approved by the KPSC in its order dated November 17, 2011, resulted in an 11% increase in depreciation expense and became effective December 1, 2011.

Accounting for Income Taxes

The Company was formed in 1961 as a tax exempt cooperative under section 501(c)(12) of the Internal Revenue Code. To retain exempt status, at least 85% of the Company's receipts must be generated from transactions with the Members. In 1983, sales to Members did not meet the 85% requirement due to sales to Non-Members. Since 1983, the Internal Revenue Service ("IRS") considers the Company a taxable organization. Beginning with 2010, post-Unwind, the Company believes that its sales to Members satisfy the 85% requirement and the Company now could qualify for exempt status. In order to qualify for exempt status the Company would need to apply to the IRS. The Company has no current intentions of applying for exempt status. The Company is also subject to Kentucky income tax.

Deferred tax assets and liabilities are recognized for the future tax consequences attributable to temporary differences between the book basis and tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to reverse, be recovered or be settled. The probability of realizing deferred tax assets in the future is based on forecasts of future taxable income and the use of tax planning that could impact the Company's ability to realize deferred tax assets. If future utilization of deferred tax assets is uncertain, a valuation allowance may be recorded against them.

In assessing the likelihood of realization of its deferred tax assets, the Company considers estimates of the amount and character, patronage or non-patronage, of future taxable income. Actual income taxes could vary from estimated amounts due to the impacts of various items, including changes in income tax laws, the Company's forecasted financial condition and results of operations in future periods, as well as results of audits and examinations of filed tax returns by taxing authorities. Although the Company believes its assessment of its income tax estimates are reasonable, actual results could differ from the estimates.

At December 31, 2011, the Company reported deferred tax assets of $53.9 million, of which $12.8 million related to net operating losses and $19.7 million related to the RUS Series B Note. At December 31, 2011, accrued net operating losses totaled $32.4 million, expiring at various times between years 2011 and 2031. Additionally, at December 31, 2011, the Company reported deferred tax liabilities of $9 thousand resulting from pollution control bond refunding costs.

Pension and Other Postretirement Benefits

The Company has noncontributory defined benefit pension plans covering approximately 100 of its 627 member work force. The salaried employees defined benefit pension plan was closed to new entrants effective January 1, 2008, and the bargaining employees defined benefit pension plan was closed to new hires effective November 1, 2008. For those not covered in the defined benefit plans, the Company established base contribution accounts in the defined contribution thrift and 401(k) savings plans, which were renamed the retirement savings plans. The base contribution account is funded by employer contributions based on graduated percentages of the employee's pay, depending on age.

The Company also provides certain postretirement medical benefits for retired employees and their spouses. Generally, except for retirees who were part of the generation union, the Company pays 85% of the premium cost for all retirees age 62 to age 65. It pays 25% of the premium cost for spouses under age 62. For salaried retirees age 55 to age 62, the Company pays 25% of the premium cost. Beginning at age 65, the Company pays 25% of the premium cost if the retiree is enrolled in Medicare Part B. For each generation bargaining retiree, the Company establishes a retiree medical account at retirement equal to $1,200 per year of service up to 30 years ($1,250 per year for those retiring on or after January 1, 2012). The account balance is credited with interest based on the 10-year Treasury Rate subject to a minimum of 4% and a maximum of 7%. The account is to be used for the sole purpose of paying 100% of the premium cost for the retiree and spouse.

The calculations of defined benefit pension expenses, other postretirement benefit expenses, and pension and other postretirement benefit liabilities, require the use of assumptions. Changes in these assumptions can result in different expenses and reported liability amounts, and future actual experience can differ from the assumptions. The Company believes the most critical assumptions are the expected long-term rate of return on plan assets and the assumed discount rate. Additionally, medical and prescription drug cost trend rate assumptions are critical in estimating other postretirement benefits.

Funding requirements for defined benefit pension plans are determined by government regulations. The Company's defined benefit pension plans are fully funded for the purposes of the Employee Retirement Income Security Act of 1974, as amended ("ERISA"), and the Company has made additional voluntary contributions. At December 31, 2011, for the defined benefit pension plans, the fair value of plan assets exceeded the present value of the accumulated benefit obligation by $2.5 million. The Company funds it's other postretirement benefit plan obligations on a pay-as-you-go basis, on a cash basis as benefits are paid. No assets have been segregated and restricted to provide for the other postretirement benefits. At December 31, 2011, the present value of the projected benefit obligation for the other postretirement benefit plans was $18.0 million.

Cooperative Operations

Utility Margins

The Company operates its electric business on a not-for-profit basis and, accordingly, seeks to generate revenue sufficient to recover its cost of service and produce net margins sufficient to establish reasonable financial reserves, meet financial coverage requirements and accumulate additional equity as determined by the Board of Directors. Revenue in excess of expenses in any year is designated as net margins in the Company's Statements of Operations. The Company designates retained net margins in its Balance Sheets as patronage capital which it assigns to each of its patrons, including the Members, on the basis of its business with the Company. Any distributions of patronage capital are subject to the discretion of the Board of Directors and restrictions contained in the Mortgage Indenture. See APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE MORTGAGE INDENTURE – Covenants."

Rate Structure

Under the wholesale power contracts, the Members pay the Company for all power and energy supplied at rates approved by the KPSC. The rates to all Members are bundled and include rates for capacity (also referred to as demand), energy, transmission, ancillary service and other special rates. In addition to the demand and energy rates, the Company has a fuel adjustment clause, an environmental surcharge clause, and a purchased power adjustment clause for purchased power not recovered in the fuel adjustment clause above a base amount under which it can increase or decrease charges to the Members based on the variance between the Company's actual cost and the cost included in its base rates. See APPENDIX D – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS."

Coverage Ratio

Subject to any necessary regulatory approvals, such as KPSC approval and RUS approval, if required, the Mortgage Indenture requires the Company to establish and collect rates for the use or the sale of the output, capacity or service of its electric generation and transmission system which are reasonably expected to yield margins for interest, for the twelve-month period commencing with the effective date of the rates, equal to at least 1.10 times total interest charges on debt secured under the Mortgage Indenture during that twelve-month period (the "MFI Ratio"). The MFI Ratio is calculated by dividing the Margins for Interest for a period by the Interest Charges for such period. For the definition of "Margins for Interest" and "Interest Charges" see APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE MORTGAGE INDENTURE – Covenants." A failure by the Company to actually achieve a 1.10 MFI Ratio will not itself constitute an Event of Default under the Mortgage Indenture. A failure to establish Rates reasonably expected to achieve a 1.10 MFI Ratio, however, will be an Event of Default if such failure continues for 30 days after the Company receives notice thereof from either the Indenture Trustee or the holders of not less than 20% in principal amount of the outstanding Mortgage Indenture Obligations, unless such failure results from the Company's inability to obtain regulatory approval. However, in order to issue additional Obligations under the Mortgage Indenture, the Company must certify that its MFI Ratio was at least 1.10 during the immediately preceding fiscal year (or, if the certification is made within 90 days of the end of a fiscal year, the second preceding fiscal year) or during any consecutive 12-month period within the 15 month period immediately preceding the request for the issuance of additional Mortgage Indenture Obligations. The 2011 net margins were $5.6 million and the MFI Ratio was 1.12.

Results of Operations

Sales to Members

Electric sales to the Members are made pursuant to wholesale power contracts with each Member. The table below sets forth the Sales to Members in MWhs for 2011, 2010 and 2009. The Smelter sales are shown both before and after the closing of the Unwind. Before the closing of the Unwind, the Company supplied only a small portion of the Smelters' needs. Since the Unwind, the Company supplies 850 MW of the Smelters' needs. The wholesale rate to Kenergy for the Smelters averaged $44.48 per MWh for 2011, $44.05 per MWh for 2010 and $46.22 per MWh for 2009.

Rural Member sales include residential and commercial loads. The 2011 rural Member sales reflect a .11 million MWh decline or a 4.44% decrease from 2010. This decline is attributable to the mild weather in 2011. The 2010 rural member sales reflect a .24 million MWh increase or a 10.71% increase from 2009 primarily due to the hot summer weather. Industrial Member sales were relatively flat over the three year period.

Smelter sales in 2011 were .50 million MWh or 7.87% higher than 2010. The increase is primarily due to restarting an idle potline at Century. Smelter sales in 2010 were 2.88 million MWh or 83.00% higher than 2009, reflecting a full year of post-Unwind sales.

Sales to Members
(in millions of MWhr)

	2011	**2010**	**2009**
Rural Member	2.37	2.48	2.24
Industrial Member*	0.97	0.93	0.92
Smelter (Pre-Unwind)	0.00	0.00	0.58
Smelter (Post-Unwind)	6.85	6.35	2.89
	10.19	9.76	6.63

*Excludes Domtar cogeneration backup power.

Sales to Non-Members

The table below sets forth the Sales to Non-Members in megawatt-hours for 2011, 2010 and 2009. After the closing of the Unwind on July 16, 2009, the Company had access to all of the generation available from its production assets, which enabled it to sell any excess on the open market. The excess generation was sold in the market to third parties. Non-Member sales in 2011 reflect a .85 million MWh or 38.46% increase from 2010 due to a full year of MISO membership. The 2010 Non-Member sales are 1.04 million MWh or 88.89% higher than 2009, reflective of a full year of post-Unwind operations.

Sales to Non-Members
(in millions of MWhr)

	2011	2010	2009
Non-Member.............................	3.06	2.21	1.17

*Includes Domtar cogeneration backup power.

Other Revenue

The table below sets forth the Other Revenue for 2011, 2010 and 2009. After the closing of the Unwind on July 16, 2009, the lease payments from E.ON for the Company's generation assets were terminated, resulting in a decrease of $32.0 million in 2010. In December 2010, Big Rivers became a member of MISO. As a result, other operating revenue declined in the subsequent year. Other operating revenue in 2011 was $9.2 million or 71.82% lower than 2010 due to the first full year of MISO membership. Prior to MISO membership, other operating revenue was an equal off-set to certain related operating expenses below. Increases and decreases were due to changes in transmission revenue from the Company's internal Non-Member energy services departmental activities. Since entrance into MISO, other operating revenue provides only a partial offset to the related operating expenses.

Other Revenue
(in thousands)

	2011	2010	2009
Lease revenue...........................	---	---	$32,027
Other operating revenue...........	$3,617	$12,834	14,603
	$3,617	$12,834	$46,630

Operating Expenses

The table below sets forth the Operating Expenses for 2011, 2010 and 2009. Fuel, production and maintenance expenses in 2011 were $17.2 million or 5.61% higher than in 2010. Higher fuel expense resulting from increased generation and higher fuel pricing was the primary driver. These expenses were $174.3 million or 131.18% higher in 2010 than in 2009 due to the first full year of post-Unwind operation. After the closing of the Unwind on July 16, 2009, the Company became responsible for the operating expenses for the generating fleet. The 2011 power purchased was $12.8 million or 12.92% higher than 2010 as a result of the first full year of MISO membership. The 2010 power purchased was $17.5 million or 14.94% lower than in 2009. Prior to the Unwind, the Company purchased all of its power while post-Unwind the Company primarily purchased replacement power. Transmission expenses for 2011 were $3.81 million or 10.81% higher than 2010 as a result of the first full year of membership fees due to membership in MISO. Depreciation expense increased during the last 3 years as a result of a higher capital balance being depreciated.

Operating Expenses
(in thousands)

	2011	2010	2009
Fuel for electric generation	$226,229	$207,749	$ 80,655
Power purchased and interchanged	112,262	99,421	116,883
Production, excluding fuel	50,410	52,507	22,381
Transmission and other	39,085	35,273	35,444
Maintenance	47,718	46,880	29,820
Depreciation	35,407	34,242	32,485
	$511,111	$476,072	$317,668

Interest and Other Charges

The table below sets forth Interest and Other Charges for 2011, 2010 and 2009. The Company paid RUS $140.2 million at closing of the Unwind, which served to decrease the Company's interest expense going forward. The Company continued to make debt service payments in 2010 and 2011, including utilizing the $35 million from the Transition Reserve to prepay the RUS Series A Note in 2011.

Interest and Other Charges
(in thousands)

	2011	2010	2009
Interest, net of capitalized interest	$45,226	$46,570	$59,898
Amort. of loss from termination of lease	-	-	2,172
Income tax expense	100	259	1,025
Other, net	220	166	112
	$45,546	$46,995	$63,207

Operating Margin

The table below sets forth the Operating Margin for 2011, 2010 and 2009. Operating Margin for 2011 was $1.1 million or 25.25% higher than 2010. During 2011 the KPSC issued an order approving an increase in Member base electric rates resulting in a 6.19% increase in total Member revenue. The increase was effective as of September 1, 2011. During 2011 Big Rivers also completed its first full year of membership with MISO. The MISO administration fees largely offset the increase in net sales margin in 2011. Operating Margin for 2010 was $11.8 million higher than 2009. After the closing of the Unwind on July 16, 2009, a major 8.5 week planned outage for the D.B. Wilson Unit No. 1 Plant ("Wilson Plant")was completed in the fall. This expense, coupled with lower Member sales due to the weather, resulted in the lower operating margin in 2009 versus 2010.

Operating Margin
(in thousands)

	2011	2010	2009
Operating Margin	$5,332	$4,257	$(7,515)

Non-Operating Margin

The table below sets forth the amount of Non-Operating Margins for 2011, 2010 and 2009. The Non-Operating Margin in 2011 included interest income and patronage allocations. In addition to interest income and patronage allocations, the Non-Operating Margin in 2010 also included a write-off of the reserve for obsolescence that was established for certain materials and supplies inventory upon the Unwind closing. The Non-Operating Margin in 2009 resulted predominantly from the closing of the Unwind.

Non-Operating Margin
(in thousands)

	2011	2010	2009
Gain on Unwind	-	-	$537,978
Interest income and other	268	$2,734	867
	$268	$2,734	$538,845

Net Margin

The 2011 net margin was $1.4 million or 19.90% lower than 2010. Three items account for the majority of the decline in 2011 net margin. First, 2011 reflects an additional expense of $4.6 million related to a full year of MISO membership fees. Second, following a thorough analysis during 2010, the balance of the reserve for obsolescence that was established for certain materials and supplies inventory upon the Unwind closing was written off, resulting in a positive impact of $1.9 million to the 2010 net margin. Third, largely offsetting the unfavorable expense variance is a $5.0 million increase in net sales margin (electric sales revenue less variable cost) in 2011. This is principally due to the Member rate increase and higher Smelter and off-system sales volumes in 2011, largely offset by lower market pricing in off-system sales.

The 2010 net margin was $524.3 or 98.68% lower than 2009. While the 2009 net margin was $531.3 million, when the one-time $538 million Unwind gain is excluded, 2009 reflected a $6.6 million loss. There are three items that explain the majority of the $13.6 million net improvement, excluding Unwind gain, in the 2010 net margin. First, interest expense reflected a $16.2 million favorable variance, primarily due to a $222.1 million reduction in long-term debt since 2008. Second, the balance of the reserve for obsolescence that was previously discussed was written off, resulting in a non-operating margin of $1.9 million. Third, electric operating margin reflected a $4.4 million unfavorable variance for the first full year of post-Unwind operations, principally due to a depressed market price for off-system sales.

Net Margin
(in thousands)

	2011	2010	2009
Net Margin	$5,600	$6,991	$531,330

Financial Condition.

As of December 31, 2011 compared to December 31, 2010

The Company's total assets decreased $54.3 million, to $1,417.9 million as of December 31, 2011, from $1,472.2 million as of December 31, 2010. The primary reasons are that in 2011 Big Rivers used $35 million from the Transition Reserve to prepay a portion of its RUS Series A Note, and the continuing use of the Economic Reserve to mitigate the non-smelter member rate impact stemming from the fuel adjustment clause and the environmental surcharge. Regarding long-term debt, a $60 million bullet payment on the RUS Series A Note is due by October 1, 2012 and was reclassified from long-term debt to current maturities in the balance sheet. As a result, working capital at December 31, 2011, decreased $53.5 million and long-term obligations decreased by $95.3 million from 2010 primarily due to the debt prepayment and current maturities. The Company will refinance the payment relating to the RUS Series A Note with the proceeds of a bank loan.

Operating revenues for the year ended December 31, 2011, were $34.7 million higher than the year ended December 31, 2010, as a result of a combination of off-system sales, Century restarting a potline, and the Member base rate increase effective September 1, 2011. Operating expenses for 2011 increased to $511.1 as compared to $476.1 in 2010. Additional fuel expenses resulting from increased generation and higher fuel pricing was the primary driver. Net margins were $5.6 million in 2011, a $1.4 million decline from 2010 primarily due to a full year of MISO membership fees, largely offset by the improved net sales margin (electric sales revenues less variable costs) resulting from the Member base rate increase.

As of December 31, 2010 compared to December 31, 2009

The Company's total assets decreased to $1,472.2 million as of December 31, 2010, from $1,505.5 million as of December 31, 2009, reflecting a voluntary prepayment of $23.9 million in 2010 on the RUS Series A Note, which the Company has since clawed back by avoiding quarterly debt service payments. As a result, working capital at December 31, 2010, decreased $18.8 million and long-term obligations decreased by $24.8 million from 2009.

Operating revenues for the year ended December 31, 2010, were $153.9 million higher than the year ended December 31, 2009, as a result of the first full year of operation after the Unwind. Operating expenses for 2010 increased to $476.1 as compared to $317.7 in 2009, also the result of the first full year of operation after the Unwind. Net margins were $7.0 million in 2010, a $524.3 million decline from 2009 resulting from the $538 million gain recorded in 2009 due to the July 16, 2009, Unwind closing.

As of December 31, 2009 compared to December 31, 2008

The Company's total assets increased to $1,505.5 million as of December 31, 2009, from $1,074.4 million as of December 31, 2008, reflecting cash and other compensation it received in connection with the Unwind. Working capital at December 31, 2009 increased $119.6 million from that of 2008 as a result of the Unwind. The Company's long-term obligations decreased by $153.0 million primarily reflecting the payment of $140.2 million on its 5.75% RUS Series A Note on the closing date of the Unwind. The Company's equity increased to $379.4 million as of December 31, 2009, from $(154.6) million as of December 31, 2008, again reflecting compensation to the Company in connection with the Unwind.

Operating revenues for the year ended December 31, 2009 were $373.4 million as compared to $273.2 million for the year ended December 31, 2008 as a result of the increase in sales to the Smelters after the Unwind Operating expenses for 2009 increased to $317.7 million as compared to $178.5 million in 2008 as a result of increases in fuel, production, transmission and maintenance expenses after the Unwind. Net margins were $531.3 million in 2009 compared to $27.8 million in 2008, primarily a result of the Unwind.

Liquidity and Capital Resources

At December 31, 2011, the Company held cash and cash equivalents of approximately $44.8 million. The Company expects to rely upon its cash flows from operations and existing cash and cash equivalents, revolving credit agreements, and loan proceeds to fund its operating costs and capital requirements during 2012.

In July 2009, the Company entered into a three year, $50.0 million unsecured revolving credit agreement with CoBank. The CoBank credit agreement may be used for capital expenditures and general corporate purposes. On April 30, 2012, the Company had no outstanding amount under the CoBank credit agreement. Since the closing on its new revolving credit agreement with CoBank is not scheduled until later this month, the Company has recently extended this facility until January 16, 2013. This agreement will be replaced with a similar CoBank revolving credit agreement with a five year term discussed under "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Executive Overview."

In July 2009, the Company entered into a five year, $50.0 million unsecured revolving credit facility with CFC. The CFC credit agreement may be used for capital expenditures, general corporate purposes or the issuance of letters of credit. As of April 30, 2012, letters of credit in the aggregate amount of $6.8 million were outstanding under the CFC credit agreement. The Company recently drew down $25 million under this facility and applied it to a portion of the $60.0 million reduction in the maximum permitted balances of the RUS Series A Note due on October 1, 2012. The Company plans to repay this borrowing in connection with the closing of the bank loans under "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Executive Overview."

Amounts available under these revolving credit facilities are accessible should there be a need for additional short-term financing. The Company expects that a combination of loan proceeds, cash flows from operations, the existing cash and cash equivalents balance, revolving credit agreements and secured debt offerings in the public debt market and/or RUS-guaranteed loans from the FFB will be sufficient to fund its operating costs and capital requirements during 2012 through 2015.

For a discussion of financing for the Company's projected capital expenditures, see "*Budgeted Capital Expenditures of Big Rivers Electric Corporation*" and "*Capital Requirements*" below.

Budgeted Capital Expenditures of Big Rivers Electric Corporation

The Company annually budgets expenditures required for additional electric generation and transmission facilities and capital for enhancement of existing facilities. The Company reviews these projections frequently in order to update its calculations to reflect changes in future plans, construction costs, market factors and other items affecting its forecasts. The actual capital expenditures could vary significantly from the budget because of unforeseen construction, changes in resource requirements, changes in actual or forecasted load growth or other issues. The Company's 2012 approved budget for capital expenditures, excluding the City's share of Station Two and capitalized interest, is $82.6 million. The Company's long range capital plan details actual and projected construction requirements and system upgrades of approximately $550.4 million, excluding the City's share of Station Two and capitalized interest, for the years 2012 through 2015 as follows:

Budgeted Capital Expenditures*

	2012	2013	2014	2015	Total
Environmental Additions	$13,894,230	$100,464,745	$130,000,000	$70,000,000	$314,358,975
Transmission	11,998,799	6,266,285	5,266,884	2,170,387	25,702,355
Generation	52,359,189	50,672,121	50,740,554	41,554,812	195,326,676
Administration	4,374,393	2,210,864	6,491,000	1,962,164	15,038,421
	$82,626,611	$159,614,015	$192,498,438	$115,687,363	$550,426,427

**Excludes the City's share of Station Two and capitalized interest.*

Some of the more significant capital investments in generation and environmental additions that are represented in the table above for each year are as follows:

For 2012, major capital investments in the budget include $13.9 million on Cross-State Air Pollution Rule ("CSAPR") and Mercury and Other Air Toxins ("MATS") related assets for environmental compliance; $4.5 million for the Robert D. Green Plant ("Green Plant") Units No. 1 and 2 FGD refurbishment project; $3.0 million for the finishing superheater project and $3.0 million for the secondary air heater project at the Wilson Plant; $2.5 million is included for the Coleman Plant Unit No. 1 hot reheat section tube replacement. Additionally, transmission expenditures include the two-way radio project budgeted for $2.8 million and the White Oak substation project for $2.5 million.;

In 2013, major capital investments in the budget include $100.5 million on continued costs related to the CSAPR and MATS projects to meet environmental standards; $2.8 million for the continuation of the White Oak substation relating to transmission; $2.8 million for continued costs on the Green Plant Units No. 1 and 2 FGD refurbishment project; $2.5 million for the Wilson Plant burner replacement project. Additionally, the Coleman Plant had 3 major projects: $2.0 million for the water treatment facility dike elevation, $2.0 million for the Coleman Unit No. 2 primary superheater and $2.5 million for the Coleman Unit No. 2 hot reheat tube replacement.

For 2014 and 2015, the major emphasis of capital spending in the budget will be the environmental projects relating to the CSAPR and MATS. Budgeted spending for these environmental projects will be $130.0 million in 2014 and $70.0 million in 2015.

Big Rivers expects to spend approximately $283.5 million from 2012 thru 2016 for projects identified in its 2012 ECP submitted to the KPSC on April 2, 2012. Major components of this plan include replacement of the FGD system at the Wilson Plant and installation of selective catalytic reduction ("SCR") equipment at Green Plant Unit No. 2.

Historically, RUS loan guarantees have provided the principal source of financing for generation and transmission cooperatives. The availability and magnitude of RUS-guaranteed loan funds are subject to annual federal budget appropriations and thus cannot be assured. Currently, RUS-guaranteed loan funds are subject to increased uncertainty because of budgetary and political pressures faced by Congress. The President's budget proposal for fiscal year 2013 provides for $6.1 billion in loans – a reduction of less than 10% from 2012 levels. Not more than $2 billion could be made available for environmental improvements to fossil-fueled generation that would reduce emissions, with the remaining funding limited to renewable energy, transmission, distribution and carbon-capture projects on generation facilities, and low emission peaking units affiliated with energy facilities that produce electricity from solar, wind and other intermittent sources of energy. Although Congress has historically rejected proposals to dramatically curtail the RUS loan program, there can be no assurance that it will continue to do so. Because of these factors, the Company cannot predict the amount or cost of RUS-guaranteed loans that may be available to it in the future. In addition, RUS has a moratorium on any loans for new base load coal or nuclear generation. The Company also seeks borrowing opportunities to issue secured debt in the public market, private and public, including tax-exempt bond financing, and borrowing from banks.

Capital Requirements

The Company expects to finance substantially all of its projected capital expenditures for the years 2012 through 2015 with a combination of loan proceeds, internally generated funds, revolving credit agreements, secured debt offerings in the capital market and/or RUS-guaranteed loans.

Debt and Lease Obligations

Big Rivers' long-term debt totaling $786.4 million as of December 31, 2011 is detailed in Note 4 (Debt and Other Long-Term Obligations) of the audited financial statements included in APPENDIX A. Outstanding debt consists of the RUS Series A Note ($521.3 million), the RUS Series B Note ($123.0 million), and two pollution control issues (totaling $142.1 million) as described below.

The Company has outstanding $58.8 million County of Ohio, Kentucky Pollution Control Refunding Bonds, Series 1983 (Big Rivers Electric Corporation Project) (the "Series 1983 Bonds"), which bear interest at a variable rate. Currently, the Series 1983 Bonds are being held as bank bonds by the liquidity provider, bearing an interest rate of 3.25%, as the remarketing agent has been unsuccessful at marketing them at the prescribed maximum rate, 120% of the variable rate index. The Company also has outstanding $83.3 million County of Ohio, Kentucky Pollution Control Refunding Revenue Bonds (Big Rivers Corporation Project), Series 2010 Bonds which bear interest at a fixed interest rate of 6% per annum.

The scheduled maturities of the Company's long-term debt at December 31, 2011 were as follows:

Payments Due by Period

	Total	2012	2013	2014	2015	Thereafter
				(in millions)		
Long-Term Debt(1)(2)	$786.4	$72.1	$79.3	$21.7	$23.0	$590.3

(1) In the operation of its business the Company has various other contracts for the purchase of electricity that are not included in the table above but are described elsewhere herein. For a discussion of the Company's long-term power purchase obligations, see "GENERATION AND TRANSMISSION ASSETS – Other Power Supply Resources."

(2) Payments do not reflect the planned prepayment of the RUS Series A Note and the reduction of the maximum debt balance on such Note from $561,603,000 to $84,603,000 expected to take place on June 29, 2012.

Ratings Triggers

The Company's credit ratings as of the date of this Disclosure Statement are Baa1, stable outlook, from Moody's Investor Service ("Moody's"), BBB-, stable outlook, from Fitch Ratings ("Fitch") and BBB-, stable outlook, from Standard & Poor's Credit Market Services, a division of the McGraw-Hill Companies ("S&P").

Under the loan agreement with RUS, if the Company fails to maintain two investment grade credit ratings, it must notify RUS in writing to that effect within five days after becoming aware of such failure. Next, within 30 days of the date of failing to maintain two investment grade credit ratings, the Company must, in consultation with RUS, provide a written plan satisfactory to the RUS setting forth the actions that will be taken that are reasonably expected to achieve two investment grade credit ratings. Before the Company would be impacted by this restriction, both Fitch and S&P would have to downgrade it one rating step. In the case of Moody's, its rating would have to be lowered three rating steps coupled with at least one rating downgrade from Fitch or S&P.

A change in the Company's credit rating also would have an impact on the current CoBank revolving credit agreement. This agreement contains an adjustment to the annual fees and interest rate paid on any advances based on Big Rivers' existing credit rating. An improvement in the credit rating would lower the Company's cost and a deterioration in the Company's credit rating would increase its cost under this agreement. This agreement allows the Company to utilize its highest unsecured credit rating in setting fees and interest rates. Currently, Moody's is the Company's highest secured credit rating and sets the costs under this agreement at the rating level equal to one notch lower. A one-step downgrade by Moody's would result in a .0250% increase in the unused fee and a .50% increase in the interest rate margin.

RATE AND ENVIRONMENTAL REGULATIONS

General

Many aspects of the Company's business are subject to a complex set of energy, environmental and other governmental laws and regulations at the federal, state and local level.

Kentucky Rate Regulation

The KPSC regulates the Company's rates for the sale of wholesale power to the Members. Among other things, Kentucky law authorizes the KPSC to (i) approve the Company's rates on a "fair, just and reasonable" standard, (ii) regulate the Company's construction of new generation and transmission facilities by issuing certificates of public convenience and necessity, (iii) approve changes in ownership or control of the Company through sales of assets or otherwise, (iv) approve the issuance or assumption of securities or evidence of indebtedness, other than to RUS, and (v) administer the state laws assigning each jurisdictional electric utility the exclusive right to provide electric service within specified geographic boundaries.

In its order approving the Unwind Transaction, the KPSC stipulated that Big Rivers file a rate case within three years of the Unwind closing date or by July 2012. On March 1, 2011, the Company filed an application with the KPSC requesting, among other things, authority to adjust its rates for wholesale electric service. The KPSC entered an order on November 17, 2011, granting Big Rivers an annual revenue increase of $26.7 million. After several appeals and procedural events, this case is back before the KPSC for rehearing on four issues raised by Big Rivers, and three issues raised by an intervenor. The intervenor in the case seeks, among other things, an approximate $6.2 million reduction in the revenue relief granted in the order in connection with the depreciation study, and will presumably ask that any relief obtained be retroactive to the effective date of the rates approved in the order (September 1, 2011). The matters raised by Big Rivers on rehearing could increase Big Rivers' annual revenue by $2.7 million.

On March 28, 2012, Big Rivers submitted its application to the KPSC seeking approval to issue a term note secured under the Indenture to CoBank in the amount of $235 million, issue an unsecured note to CoBank in the amount of $50 million, issue a term note secured under the Indenture to CFC in the amount of $302 million and, in connection with the CFC term loan, to purchase interest bearing capital term certificates from CFC in the amount of approximately $43.2 million. The application with the KPSC was approved on May 25, 2012, and the planned closing date for these transactions with CoBank and CFC is June 29, 2012.

Big Rivers submitted an application on April 2, 2012, seeking KPSC approval for its 2012 ECP. This ECP will consist of $283.5 million of capital projects, primarily for a new scrubber at the Wilson Plant and a new SCR facility at the Green Plant, and certain additional operations and maintenance costs. The purpose of the ECP is to allow Big Rivers to comply, in the most cost-effective manner, with the EPA's rules for CSAPR and MATS.. Among other things, the ECP filing will seek to recover the costs of the ECP through the environmental surcharge tariff rider, an automatic cost-recovery mechanism that is similar in function to the fuel adjustment clause. The regulatory process is expected to last six months after the filing date.

RUS Regulation

In addition to the KPSC's direct regulation of the Company, RUS has certain rights through its loan documents with the Company that impact its operations (i.e., RUS must consent to the construction of new facilities which are part of the electric system, certain sales or dispositions of property, the execution of certain types of contracts and the making of loans or investments).

Environmental Regulations

Big Rivers is subject to various federal, state and local laws, rules and regulations with regard to air quality, water quality, waste management and other environmental matters.

These laws, rules and regulations often require Big Rivers to undertake considerable efforts and substantial costs to obtain licenses, permits and approvals from various federal, state and local agencies. If Big Rivers fails to comply with these laws, regulations, licenses, permits or approvals, Big Rivers could be held civilly or criminally liable. Big Rivers' operations are subject to environmental laws and regulations that are complex, change frequently and have tended to become more stringent over time. An inability to comply with environmental standards could result in reduced operating levels or the complete shutdown of facilities that are not in compliance.

Federal, state and local standards and procedures that regulate the environmental impact of Big Rivers' operations are subject to change. These changes may arise from continuing legislative, regulatory and judicial actions regarding such standards and procedures. Consequently, there is no assurance that environmental regulations applicable to Big Rivers' facilities will not become materially more stringent, or that Big Rivers will always be able to obtain and renew all required operating permits. Big Rivers cannot predict at this time whether any additional legislation or rules will be enacted that will affect its operations, and if such laws or rules are enacted, what the cost to Big Rivers might be in the future because of such actions.

From time to time, Big Rivers may be alleged to be in violation of or in default under orders, statutes, rules, regulations, permits or compliance plans relating to the environment. From time to time, Big Rivers may be defending notices of violation, enforcement proceedings or challenges to draft or final construction or operating permits. In addition, Big Rivers may be involved in legal proceedings arising in the ordinary course of business.

Clean Air

Clean Air Act. The Clean Air Act, as amended (the "Clean Air Act"), regulates emissions of air pollutants, establishes national air quality standards for major pollutants, and requires permitting of both new and existing sources of air pollution. Many of the existing and proposed regulations under the Clean Air Act could have a disproportionate impact on coal-based power plants, in particular older plants such as Big Rivers', because older plants may not have originally been required to install the same pollution control equipment as newer facilities. On the other hand, as retrofits become available and feasible, the

Company may incur greater costs than competing generating sources to bring facilities up to current standards. Several of the Company's facilities have, in the past decade, been retrofitted with new pollution control equipment, including flue gas desulfurization and selective catalytic reduction equipment, in response to regulatory changes.

Acid Rain Program. The acid rain program requires nationwide reductions of SO_2 emissions using a cap-and-trade program reducing allowable emission rates and allocating emission allowances to power plants for SO_2 emissions based on historical or calculated levels. The Company has sufficient SO_2 allowances to comply for the foreseeable future according to the Company's modeled emissions and allowance allocations.

Cross-State Air Pollution Rule. On July 11, 2008, the United States Court of Appeals for the D.C. Circuit ("D.C. Circuit") vacated the Clean Air Interstate Rule ("CAIR"), which was promulgated by the EPA in March 2005 to reduce nitrogen oxides ("NO_x") and SO_2 air emissions that move across certain state boundaries, primarily in the eastern United States. The CAIR would have been applicable in 28 eastern states, including Kentucky. The D.C. Circuit remanded the CAIR to EPA to promulgate a rule that is consistent with the court's opinion. On December 23, 2008, the court held that the original CAIR program will remain in effect until EPA promulgates such a new regulation.

On July 6, 2010, EPA published a proposed rule, known as the Transport Rule, as the replacement to the CAIR. On July 7, 2011, EPA published the final rule, now known as CSAPR. The CSAPR requires 27 states in the eastern half of the United States, including Kentucky, to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particulate pollution in other states. The final rule maintains the January 1, 2012 and January 1, 2014 phase-in dates that were in the proposed Transport Rule. The CSAPR imposes tighter emissions caps than the proposed Transport Rule. The CSAPR emission limits may be further reduced as the EPA finalizes more restrictive ozone and particulate matter National Ambient Air Quality Standards ("NAAQS") in the 2012-2013 timeframe.

The CSAPR is being challenged in the D.C. Circuit. On December 30, 2011, the court granted a stay of the CSAPR and directed the EPA to continue the administration of CAIR program in the interim. The court subsequently ordered an expedited schedule and heard oral arguments in April 2012. It is unknown when the court will issue its decision on the merits, but under the expedited schedule, the decision may be issued in the next few months. Big Rivers is in compliance with the current version of CAIR, Big Rivers projects it will have to reduce SO_2 emissions approximately 50% during Phase 3 of CSAPR and NO_x annual emissions by 16%. Big Rivers filed the ECP with the KPSC on April 2, 2012. Included in the filing are projects to replace the FGD at Wilson Plant and install an SCR at Green Plant Unit No. 2. Big Rivers believes that these two projects, along with other minor improvements, should allow Big Rivers to comply with the emission reductions contemplated in the CSAPR. Big Rivers has not yet obtained the necessary regulatory approval of its plans or environmental permits for these projects.

Mercury. In May 2005, EPA issued the Clean Air Mercury Rule ("CAMR") to permanently cap and reduce mercury emissions from fossil-fuel-fired electric utility steam generating units. CAMR was expected to reduce utility emissions of mercury from 48 tons per year to 38 tons per year in 2010 then to 15 tons per year in 2018. On February 8, 2008, the D.C. Circuit vacated CAMR, and reinstated the status of mercury as a hazardous air pollutant under the Clean Air Act. The result of this decision is that mercury emissions from such generating units are subject to the more stringent requirements of maximum achievable control technology ("MACT") applicable to hazardous air pollutants. In resolution of the CAMR litigation, the EPA entered into a consent decree that requires it to publish final hazardous air pollutants regulations for emissions from fossil-fuel-fired electric utility steam generating units by November 15, 2011.

On February 16, 2012, the final rule to reduce emissions of toxic air pollutants from fossil-fuel-fired electric utility steam generating units and to revise the new source performance standards ("NSPS") for fossil-fuel-fired electric utility steam generating units was published. The final rule, known as the MATS rule, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals from air emissions. To achieve these standards, coal units with no pollution control equipment installed (i.e., uncontrolled coal units) will have to make capital investments and incur higher operating expenses. Coal units with existing controls that do not meet the required standards may need to upgrade existing controls or add new controls to comply. The MATS rule requires generating stations to meet the new standards three years after the rule takes effect, with specific guidelines for an additional one or two years in limited cases. The rule took effect on April 16, 2012. Big Rivers also included plans in its ECP filing that would address the mercury reductions contained in MATS. Big Rivers plans on installing activated carbon and dry sorbent injection systems at its Wilson, Coleman and Green Plants to meet these emission reductions. Big Rivers has not yet obtained the necessary regulatory approval of its plans or environmental permits for these projects.

Multi-Pollutant Legislation. In recent years, bills proposing mandatory emission reductions of NO_x, SO_2 and mercury and in some cases, carbon dioxide ("CO_2"), from electric utilities, have been introduce to the United States Senate. The proposed emission reductions were ultimately more stringent than the emission controls under prior Clean Air Act regulatory programs, CAIR and CAMR. The Senate did not pass any of these bills, but similar bills could be introduced and considered in the future. The Company cannot predict whether it or similar multi-pollutant legislation will ultimately become law. As a result, it is too early to determine what impact, if any, such a law and any implementing regulations may have on the Company.

Regional Haze. On June 15, 2005, the EPA issued the Clean Air Visibility Rule, amending regulations governing visibility in national parks and wilderness areas throughout the United States. Under the amended rule, certain types of older sources may be required to install best available retrofit technology ("BART"). The amended rules could result in requirements for newer and cleaner technologies and additional controls for particulate matter ("PM"), SO_2 and NO_x emissions from utility sources. Under the Clean Air Visibility Rule, the states were required to develop regional haze plans as part of their state implementation plans ("SIPs"), and identify the facilities that would have to reduce emissions and then set BART emissions limits for those facilities.

Kentucky submitted its regional haze SIP revisions to EPA on June 25, 2008. Kentucky submitted revisions to its regional haze SIP revisions to EPA on May 28, 2010. On March 30, 2012, EPA issued a final rule concluding its review of Kentucky's regional haze SIP revisions. In that final rule, EPA issued a limited approval of the revisions, which results in approval of Kentucky's entire regional haze SIP and all the elements. The EPA also issued a limited disapproval of the SIP revisions to the extent that the revisions rely on the CAIR program to address the impact of emissions from Kentucky's fossil-fuel-fired electric utility steam generating units. The issuance of the limited disapproval provides EPA with the authority to issue a federal implementation plan ("FIP") at any time.

On December 30, 2011, EPA proposed to find that the trading program in the CSAPR would achieve greater reasonable progress towards visibility goals than would BART in the states in which CSAPR applies. Based on this proposed finding, EPA also proposed to revise the regional haze rule to allow states to substitute participation in the CSAPR trading programs for source-specific BART. In order to address the deficiencies in SIPs that rely on their participation in CAIR to satisfy certain regional haze requirements, EPA also proposed a FIP, which allow states to replace reliance on the CAIR requirements in those SIPs with reliance on the CSAPR as an alternative to BART. EPA has not taken final action on this proposed rule yet.

Under Kentucky's regional haze SIP, the Company's facilities are exempt from the requirement to install BART for SO_2, NO_x and PM emissions. The exemption for SO_2 and NO_x emissions is based on Kentucky's participation in the CAIR program. Because the CAIR program was invalidated, states cannot rely on their participation in the CAIR program as a substitute for meeting BART requirements. As discussed above, EPA has proposed to allow states subject to CSAPR to rely on their participation in the CSAPR trading programs to substitute source-specific BART. If that rule is not finalized, states, including Kentucky, may have to evaluate SO_2 and NO_x emissions from fossil-fuel-fired electric utility steam generating units, including Big Rivers' facilities. It is therefore possible that the Company will be required to install BART for SO_2 and NO_x emissions at certain facilities. The determination under the regional haze SIP to exempt the Company's facilities from BART for PM emissions was based on air quality modeling information submitted by the Company in May 2007. At that time, the modeling information showed that PM emissions from the Company's facilities were not contributing to regional haze at any Class I area.

National Ambient Air Quality Standards. The Clean Air Act also requires EPA to establish NAAQS for certain air pollutants. When a NAAQS has been established, each state must identify areas in its state that do not meet the EPA standard (known as "non-attainment areas") and develop regulatory measures in its SIP to reduce or control the emissions of that air pollutant in order to meet the standard and become an "attainment area." EPA is in the process of reviewing NAAQS for certain air pollutants that are emitted by power plants including NO_x, SO_2, ozone, and PM. When a stricter NAAQS is finalized and becomes effective, air pollution sources including power plants, could face stricter emission standards. The impact of any new standards under the NAAQS program will depend on the final federal regulations and resulting revisions to Kentucky's SIP, so Big Rivers cannot determine such impacts at this time.

Opacity. PM emissions from the Company's facilities have, in the past, resulted in notices of violation and occasional complaints from neighbors and local government agencies. The complaints have declined in recent years, following the installation of SCR and/or FGD air pollution controls at the Wilson Plant, the Green Plant, the Henderson Plant and the Coleman Plant. Even though there have been improvements in some of the emissions characteristics, plume opacity and other impacts may continue to arise in connection with the installation and the operation of the SCR and FGD controls. Additionally, the scrubbed units at the Green, Coleman and Wilson plants are "wet scrubbed" units with "wet stacks." A phenomenon commonly associated with wet scrubbers is the occasional and unexpected appearance of a visible plume that begins some distance after the exhaust exits the stack. The actual cause of the plume is unknown. The Company continues to monitor the occurrence of the plumes and address notices of violations or other agency actions as they arise. Although no material fines or penalties have been assessed against the Company, the Company has sought permit amendments to address this issue. It is possible that additional investment or pollution controls may be required to reduce these impacts.

New Source Review. In 1999-2000, the U.S. Justice Department, acting on behalf of the EPA, filed a number of complaints and notices of violation against multiple utilities across the country for alleged violations of the New Source Review ("NSR") provisions of the Clean Air Act. Generally, the government alleged that projects performed at various coal-fired units were major modifications, as defined in the Clean Air Act, and that the utilities violated the Clean Air Act when they undertook these projects without obtaining major source permits under the Prevention of Significant Deterioration ("PSD") and/or Title V programs. As part of the enforcement effort, the EPA also sent requests for information letters to numerous other utilities requesting extensive and detailed information on the repairs and modifications made by those utilities to their coal fired boilers. In 2000, WKE received an information request from EPA, when it was the operator of the facilities, and WKE submitted the requested information to EPA. To date, EPA has not requested any additional information.

In 2007, the U.S. Supreme Court upheld EPA's definition of a major modification as one that increases the actual annual emission of a pollutant from a facility above the actual average for the two prior years, and, under President Obama's administration, EPA has announced plans to enforce the NSR provisions. The Company cannot predict whether EPA or other governmental authorities will consider any of the past maintenance projects or capital improvements at its facilities to have violated NSR requirements as a result of the uncertain interpretation of this program and recent court decisions. If violations are established, the Company could be required to install new pollution control equipment in addition to the modifications that have already been completed or planned, and be liable for other payments or penalties.

Global Climate Change

CO_2, a major constituent of emissions from fossil-fuel combustion, and other greenhouse gases ("GHG") are generally believed to be linked to global warming resulting in climate change. Control of such emissions is the subject of debate in the United States, on local, state and national levels. In the United States, no federal legislation limiting GHG emissions has yet been enacted, but there have been significant developments relating to monitoring and regulation of GHG emissions by EPA, certain state governments and regional governmental organizations. In addition, the United States Congress is considering federal legislation that could impose a cap-and-trade system or other measures to reduce GHG emissions, such as carbon tax.

EPA Regulatory Action under the Clean Air Act

On April 2, 2007, the United States Supreme Court issued a decision in Massachusetts v. EPA holding that EPA has the authority to regulate GHG emissions under the Clean Air Act. Air pollutants, including GHGs, which are regulated by actually controlling emissions under any Clean Air Act program, must be taken into account when considering permits issued under other programs, such as the PSD Permit Program or the Title V Permit Program. A PSD permit is required before commencement of construction of new major stationary sources or major modifications of such sources and contains requirements including but not limited to the application of BACT. Title V permits must be applied for within one year a source becomes subject to the program. Title V permits are operating permits for major sources that consolidate all Clean Air Act requirements (arising, for example, under the Acid Rain, New Source Performance Standards, National Emission Standards for Hazardous Air Pollutants, and/or PSD programs) into a single document, provide for review of the documents by EPA, state agencies and the public, and contain monitoring, reporting and certification requirements.

On May 13, 2010, EPA issued a final rule for determining the applicability of the PSD and Title V programs to GHG emissions from major stationary sources. The rule, known as the "Tailoring Rule," establishes criteria for identifying facilities required to obtain PSD permits and the emissions thresholds at which permitting and other regulatory requirements apply. The applicability threshold levels established by this rule include both a mass-based calculation and a metric known as the carbon dioxide equivalent, or "CO_2e", which incorporates the global warming potential for each of the six individual gases that comprise the collective GHG defined by EPA. The Tailoring Rule established two initial steps for phasing in the GHG permitting requirements and indicated a third phase would be established at a later date.

The first step became effective on January 2, 2011, and requires sources subject to PSD and/or Title V permits due to their non-GHG emissions (such as fossil-fuel based electric generating facilities for their NO_x, SO_2 and other emissions) to address GHG emissions in new permit applications or renewals. Construction or modification of major sources will become subject to PSD requirements for their GHG emissions if the construction or modification results in a net increase in the overall mass of GHG emissions exceeding 75,000 tons per year ("tpy") on a CO_2e basis. New and modified major sources required to obtain a PSD permit would be required to conduct a BACT review for their GHG emissions. According to EPA guidance, most of the initial permitting decisions will focus on improved energy efficiency.

With respect to Title V requirements under the first step of the Tailoring Rule, effective January 2, 2011, sources required to have Title V permits for non-GHG pollutants are required to address GHGs as part of their Title V permitting. When any source applies for, renews, or revises a Title V permit, Clean Air Act requirements for monitoring, recordkeeping and reporting will be included in the renewed permit. This part of the rule does not create any new emissions controls or limitations for GHGs; it only creates the requirement for these sources to monitor, record and report their GHG emissions. In the Tailoring Rule, EPA notes that the existing requirements created by the October 30, 2009, final rule for mandatory monitoring and annual reporting of GHGs from various categories of facilities including electric generating facilities will generally be sufficient to satisfy these new Title V requirements. The GHG monitoring and reporting rule requires facilities to have begun data collection on January 1, 2010. On March 18, 2011, EPA issued a final rule extending the deadline to submit the first annual reports from March 31, 2011, to September 30, 2011. The second step of the Tailoring Rule was effective July 1, 2011, and is applicable to new facilities or modification to existing facilities that exceed certain GHG emission thresholds, even if the facility is not subject to PSD or non-GHG emissions. The second phase requirements apply to any new, major sources as well as to any major modification of existing facilities, depending on their levels of emissions of both GHG and non-GHG pollutants

On March 8, 2012, EPA's proposed rule for the third step in the Tailoring Rule was published. EPA proposes to maintain the applicability thresholds for GHG-emitting sources at the current levels. EPA also proposes two permitting streamlining approaches to improve the administration of the PSD and Title V permitting programs.

In addition to the PSD permit program, EPA is also in the process of developing a GHG regulatory program under the NSPS provisions of the Clean Air Act. On December 23, 2010, EPA entered a settlement agreement and agreed to issue NSPS and emission guidelines for GHG emissions from new and modified fossil-fuel-fired fossil-fuel-fired electric utility steam generating units. On April 13, 2012, EPA's proposed rule for standards of performance for GHG emissions for new fossil-fuel-fired electric utility steam generating units was published. EPA may issue more rulemakings in order to meet the terms of the settlement agreement.

The Company's costs of compliance with these new regulations are not fully known at this time. The requirements for monitoring, reporting and record keeping with respect to GHG emissions from existing units should not have a material adverse effect, but the consequences of new permit requirements in connection with new units or modifications of existing units could be significant, as could any new proposed regulations affecting permitting and controls for the Company's existing units.

Federal Legislation

In addition to EPA's regulatory actions establishing federal regulation of GHG emissions, the United States Congress has considered several energy and climate change-related pieces of legislation that proposed, among other things, a cap-and-trade system to regulate and reduce the emission of CO_2 and other GHGs and a federal renewable energy portfolio standard. The 112th Congress may consider new GHG proposals and it is possible that Congress will agree to set limits on GHG emissions or set clean or renewable energy standards for the electric utility sector. The timeline and impact of climate change legislation cannot be accurately assessed at this time, but it is expected that any enactment of statutes to regulate GHG emissions will have a significant impact on fossil-fueled generation facilities.

Litigation

Many of the issues raised by global climate change are being litigated in courts throughout the United States. Plaintiffs have asserted in some cases that GHG emissions from electric generation are causing a public nuisance and should be abated by electric generation facilities. The Company cannot currently predict how GHG emissions issues will arise in connection with pending or future permit proceedings or whether litigation based on climate change issues will adversely affect its operations, or its construction and development plans.

Water

The Federal Clean Water Act regulates the discharge of process wastewater and certain storm water under the National Pollutant Discharge Elimination System ("NPDES") permit program. Such permits are issued for five-year periods and continue in effect if renewal applications are timely filed. At the present time, applications for renewal of some of the Company's NPDES permits are awaiting review by the Kentucky Division of Water. The Company has all other material required permits under the program for all of its electric generating plants. The water quality regulations require the Company to comply with Kentucky's water quality standards, including sampling and monitoring of the waters discharged from the facilities. The Company continually samples and monitors the discharges and reports the results thereof in accordance with its permits.

Section 316(b) of the Clean Water Act requires the EPA to ensure that the location, design, construction and capacity of cooling water intake structures reflect the best technology available to protect aquatic organisms from being killed or injured by impingement or entrainment. In February 2004, the EPA issued final regulations establishing standards for cooling water intake structures at existing large power plants. The rule provided several compliance alternatives for existing plants such as using existing technologies, adding fish protection systems or using restoration measures.

On January 25, 2007, the United States Second Circuit Court of Appeals remanded key components of the Clean Water Act 316(b) Phase II Rule. The court ruled that EPA could not allow use of restoration measures to satisfy performance standards, nor could it consider cost-benefit analysis in selecting "best technology available." The United States Supreme Court heard the appeal of the Second Circuit decision and held on April 1, 2009, that it is permissible for utility companies and regulators to apply cost-benefit analysis under the Clean Water Act. EPA published the new 316(b) rules on April 20, 2011, and EPA is required to finalize the rulemaking no later than July 27, 2012.

The impact of Section 316(b) on Big Rivers is limited to the Robert A. Reid Plant ("Reid Plant") and the Coleman Plant. The degree of such impact will depend upon the form of the new rule that EPA publishes. If EPA allows a cost-benefit analysis to determine the best technology available, the Company expects the impact to the Reid Plant and the Coleman Plant will be minimal based on information obtained from previous studies conducted on the quantity and type of fish impinged on the intake screens at Reid Plant and Coleman Plant.

Other Environmental Matters

The Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA" or "Superfund"), requires cleanup of sites from which there has been a release or threatened release of hazardous substances and authorizes the EPA to take any necessary response action at Superfund sites, including ordering potentially responsible parties ("PRPs") liable for the release to take or pay for such actions. PRPs are broadly defined under CERCLA to include past and present owners and operators of, as well as generators of wastes sent to, a site. Big Rivers historically has sent wastes, such as coal ash or wastewater that could have included hazardous substances, to third-party disposal sites or treatment plants. Based on such disposal, the Company can become a PRP with respect to such sites. The Company is not aware of any material liabilities with respect to such disposal, but can provide no assurance that such liabilities will not be asserted in the future. In addition, the Company has experienced and is likely to continue to experience in the future spills and releases of fuel oil and other materials that could trigger cleanup obligations under CERCLA and result in additional compliance costs. As a result, there can be no assurance that the Company will not incur liability under CERCLA in the future.

Electro-Magnetic Fields. A number of electrical industry studies have been conducted regarding the potential long-term health effects resulting from exposure to electro-magnetic fields ("EMF") created by high voltage transmission and distribution equipment. At this time, any relationship between EMF and certain adverse health effects appears inconclusive; however, electric utilities have been experiencing challenges in various forms claiming financial damages associated with electrical equipment which creates EMF. In the future, if the scientific community reaches a consensus that EMF presents a health hazard, the Company may be required to take remedial actions at its facilities. The cost of these actions cannot be estimated with certainty at this time. Such costs, however, could be significant, depending on the particular mitigation measures undertaken, especially if relocation of existing power lines is required.

Coal Ash. The Company's coal-based generating facilities produce coal ash waste that requires disposal. The Company disposes of the coal ash in its onsite landfills and impoundments and possesses the proper industrial solid waste permits to operate its landfills in accordance with local, state and federal regulations and laws. However, the Company must continually expand the capacity of its landfills and waste management facilities to accommodate larger amounts of ash. If the Company becomes unable to dispose of coal ash on site, its disposal costs may increase considerably. On the other hand, the Company is continually evaluating methods for beneficial reuse of waste ash. Currently, all of the ash the Company generates is exempt from regulation as "hazardous waste."

On June 21, 2010, the EPA published a proposed rule describing two possible regulatory options it is considering under the Resource Conservation and Recovery Act ("RCRA") for the disposal of coal ash generated from the combustion of coal by electric utilities and independent power producers. Under either option, EPA would regulate the construction of impoundments and landfills, and seek to ensure both the physical and environmental integrity of disposal facilities.

Under the first proposed regulatory option, EPA would list coal ash destined for disposal in landfills or surface impoundments as "special wastes" subject to regulation under Subtitle C of RCRA. Subtitle C regulations set forth EPA's hazardous waste regulatory program, which regulate the generation, handling, transport and disposal of wastes. The proposed rule would create a new category of waste under Subtitle C, so that coal ash would not be classified as a hazardous waste, but would be subject to many of the regulatory requirements applicable to such wastes. Under this option, coal ash would be subject to technical and permitting requirements from the point of generation to final disposal. Generators, transporters, and treatment, storage and disposal facilities would be subject to federal requirements and permits. EPA is considering imposing disposal facility requirements such as liners, groundwater monitoring, fugitive dust controls, financial assurance, corrective action, closure of units, and post-closure care. This first option also proposes requirements for dam safety and stability for surface impoundments, land disposal restrictions, treatment standards for coal ash, and a prohibition on the disposal of treated coal ash below the natural water table. The first option would not apply to certain beneficial reuses of coal ash.

Under the second proposed regulatory option, EPA would regulate the disposal of coal ash under Subtitle D of RCRA, the regulatory program for non-hazardous solid wastes. Under this option, EPA is considering issuing national minimum criteria to ensure the safe disposal of coal ash, which would subject disposal units to location standards, composite liner requirements, groundwater monitoring and corrective action standards for releases, closure and post-closure care requirements, and requirements to address the stability of surface impoundments. Existing surface impoundments would not have to close or install composite liners and could continue to operate for their useful life. The second option would not regulate the generation, storage, or treatment of coal ash prior to disposal, and no federal permits would be required.

The proposed rule also states that EPA is considering listing coal ash as a hazardous substance under CERCLA, and includes proposals for alternative methods to adjust the statutory reportable quantity for coal ash. The extension of CERCLA to coal ash could significantly increase the Company's liability for cleanup of past and future coal ash disposal.

EPA issued a Notice of Data Availability for comment on October 12, 2011. EPA is conducting a human health risk assessment on coal combustion residual beneficial use to be released prior to the final rule. EPA has not decided which regulatory approach it will take with respect to the management and disposal of coal ash. The Company is therefore unable to determine the effects of this proposed rule at this time.

As part of EPA's scrutiny of how ash impoundments are permitted and operated, EPA recently assessed ash impoundments at many facilities throughout the country, including some of the Company's facilities. A dam safety assessment report for Reid Plant, Green Plant and Station Two was prepared for EPA in December 2009. All of the ash ponds at these facilities received "fair" ratings – a rating that reflected EPA's view that the Company's geotechnical information was not complete – but no critical deficiencies were noted. Minor repairs required by EPA during this review were completed during the 2010 construction season. The geotechnical investigation recommended by EPA has been completed by the Company. Coal ash waste management and disposal is an evolving issue and the Company expects to continue to incur costs to upgrade and expand its ash impoundments as regulations change.

FERC Regulation

As a transmission owning, generation owning, and market participant member of the MISO, the Company's sale of power at wholesale and its transmission of power in interstate commerce are regulated by the Federal Energy Regulatory Commission ("FERC"). The KPSC maintains jurisdiction over the Company's wholesale power rates to its Members and over the transmission rates applicable under the MISO's FERC-approved Open Access Transmission, Energy and Operating Reserve Markets Tariff ("MISO Tariff").

Energy Policy Act of 1992

The Energy Policy Act of 1992 ("EPAct 1992") made fundamental changes in the federal regulation of the electric utility industry, particularly in the area of transmission access. The purpose of these changes, in part, was to bring about increased competition in the wholesale electric power supply market. These changes have increased, and will continue to increase, competition in the electric utility industry. Specifically, EPAct 1992 provided that any electric utility, federal power marketing agency or any other person generating electric energy for sale for resale may apply to FERC for an order requiring a transmitting utility like the Company to provide interconnection and transmission services to the applicant. After notice and an opportunity for hearing, FERC may issue an order under Section 210 or 211 of the Federal Power Act ("FPA") requiring such interconnection or transmission service to be provided, subject to appropriate compensation to the utility providing such service. However, EPAct 1992 specifically denied FERC authority to require "retail wheeling" under which a retail customer of one utility could obtain electric power and energy from another utility or nonutility power generator and require a transmitting utility to "wheel" it to the retail customer.

Order No. 888 and Successor Orders

In 1996, to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient lower cost power to the nation's electricity consumers, FERC issued Orders Nos. 888 and 889. Orders Nos. 888 and 889, as amended by Orders Nos. 888-A and 889-A in 1997, were intended to deny public utilities any unfair advantage over competitors resulting from their ownership and control of transmission facilities by requiring each FERC-jurisdictional public utility to file a pro forma OATT and to follow certain rules of conduct for open-access providers, including a requirement to separate operationally power sales from transmission. In Order Nos. 890, 890-A and 890-B, issued (respectively) in February and December 2007 and June 2008, FERC reaffirmed and modified the requirements under Order Nos. 888 and 888-A, specifically, by modifying the pro forma OATT provisions on (among other things) calculating available transfer capability, transmission planning, point-to-point transmission service options, energy imbalance service, rollover rights for long-term firm transmission service, and the price caps on capacity reassignments. Under the reciprocity requirement adopted in Order No. 888 and reaffirmed in Order No. 890, non-jurisdictional utilities like the Company must provide comparable transmission service as a condition of receiving service from jurisdictional utilities under the pro forma OATT. The Company's transmission facilities located in the Eastern Interconnection provided transmission service under an OATT that was approved by FERC for reciprocity purposes until the Company became a member of MISO in December 2010 and its OATT was terminated. Since December 2010, the Company's transmission facilities have been under the functional control of MISO and operated under the terms and conditions of the MISO Tariff.

Energy Policy Act of 2005

On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 ("EPAct 2005"). The significant provisions of EPAct 2005 that could affect the Company are in the areas of (1) reliability; (2) siting of new transmission facilities; (3) potential FERC authority over transmission service and the rates of non-rate-regulated utilities; (4) native load obligations; and (5) expansion of FERC's enforcement authority. In addition, Congress repealed the Public Utility Holding Company Act of 1935 ("PUHCA 1935"), and replaced it with the Public Utility Holding Company Act of 2005 ("PUHCA 2005"), thereby effectively repealing many of the more onerous provisions of PUHCA 1935. As an electric cooperative, the Company generally is not subject to the new requirements of PUHCA 2005. EPAct 2005 also created incentives for the construction of transmission facilities; gave FERC authority to establish mandatory reliability standards through a new entity that FERC would certify as the Electric Reliability Organization ("ERO"); authorized the Department of Energy and FERC to grant permits enabling entities, in certain circumstances, to use a federal right of eminent domain to build new transmission lines; and adopted provisions enabling transmission providers to reserve transmission capacity for their native load service obligations. FERC has adopted regulations to implement the new regulations and requirements concerning siting, transmission access, native load preferences and enforcement.

Concerning the expansion of FERC's authority to order transmission access to transmission systems owned or operated by non-rate-regulated utilities, EPAct 2005 added new section 211A to the FPA. Section 211A authorizes FERC to order non-rate-regulated utilities like the Company to provide transmission service at rates and terms that are comparable to those by which the non-rate-regulated utility provides transmission service to itself. However, the non-rate-regulated utilities subject to any such requirements are not subject to the full panoply of FERC regulations established under Section 205 and 206 of the FPA that are applicable to transmission-owning public utilities. FERC also is required, with certain limited exceptions, to exempt any non-rate-regulated utility that sells less than 4 million kWh per year. FERC has declined to order transmission access pursuant to Section 211A on a generic basis, and instead will act on a case-by-case basis. In December 2011, FERC issued its first order under Section 211A in which FERC directed a non-jurisdictional transmission provider to provide transmission service on terms and conditions that are comparable to those under which the transmission provider provides transmission service to itself and that are not unduly discriminatory or preferential. That order is currently pending rehearing.

In 2006, FERC used its authority under Section 215 of the FPA to certify the North American Electric Reliability Corporation ("NERC") as the ERO responsible for the development of mandatory reliability standards subject to FERC review and approval. NERC's mandatory reliability standards apply to any entity that owns, operates or uses the bulk power system. Under EPAct 2005, FERC and the ERO have authority to impose penalties for violations of the reliability standards. In March and July 2007, FERC issued (respectively) Order Nos. 693 and 693-A largely approving the first set of reliability standards filed by NERC for FERC review and approval. FERC also directed NERC to consider revisions to a number of the standards, and other reliability standards and amendments proposed by NERC remain pending before FERC. Since 2007, the Commission has approved and directed modification to many more NERC reliability standards. As an owner and operator of generation and transmission facilities, the Company is subject to certain of the NERC reliability standards. The Company is currently scheduled for a routine audit of its compliance with the reliability standards. The audit is scheduled to occur at the Company's facility from May 6, 2013, to May 10, 2013. If the auditors identify areas of non-compliance, the Company could be subject to penalties or sanctions.

EPAct 2005 also added new sections 220, 221 and 222 to the FPA, which generally prohibit fraud and manipulation in the energy markets and promote price transparency. Under FERC's implementing rules, the anti-fraud rules apply to all entities, including non-jurisdictional utilities, to the extent they engage in activities or transactions in connection with sales and transmission services subject to FERC's public-utility jurisdiction.

Order No. 1000

In 2011, FERC issued Order No. 1000 to build on certain of its reforms in Order No. 888 and Order No. 890. The requirements set forth in Order No. 1000 apply only to "new transmission facilities" and include the consideration and evaluation of possible transmission alternatives at a regional transmission planning level and the development of a regional transmission plan; the development of procedures for interregional planning to determine whether interregional transmission facilities are more efficient or cost effective than certain regional facilities; the development of methods for regional and interregional cost allocation that is roughly commensurate with the estimated benefits; and, for those projects eligible for cost sharing, removal of transmission providers' "right of first refusal" in order to allow competition from non-incumbent developers. In general, Order No. 1000 permits each region to develop its own processes and procedures to comply with the requirements. MISO, of which Big Rivers is a member, continues to progress through a stakeholder process to discuss and develop proposals for compliance with Order No. 1000. As of the date of this Disclosure Statement, however, since MISO has not fully developed such processes and procedures, the impact of Order No. 1000 on the Company cannot be determined.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Risk Management Policies

The Company is exposed to significant market risks associated with electricity and coal prices, counter-party credit exposure, interest rates and equity prices. Interest rate risk is associated with the changes in interest rates that impact its variable rate debt instruments and fixed income investments. The Company's energy related commodity price risks involve changes in the market price of power, natural gas, and solid fuels and the impact of such changes on its ability to generate sufficient revenue to cover the Company's operational costs. Big Rivers has established comprehensive risk management policies to monitor and manage these risks. The Company's vice president of enterprise risk management and strategic planning is responsible for monitoring and reporting on its risk management policies, including delegation of authority levels. The Company has an Internal Risk Management Committee that regularly meets and the vice president of enterprise risk management and strategic planning reports to the Board of Directors monthly. The vice president of enterprise risk management and strategic planning is responsible for oversight of market risk, credit risk, etc., including monitoring exposure limits.

To manage the Company's market risks, it may enter into various derivative instruments including swaps, forward contracts, futures contracts and options. Management believes adequate safeguards, reporting mechanisms, and procedures are in place to protect the Company from unauthorized use of such derivative instruments. The Company has established certain risk management strategies relating to the sales and purchase prices for the commodities which form its core business, in order to provide insulation from volatile market prices. With respect to the Company's power sales, the Board of Directors has established guidelines which are intended to ensure that derivatives and other financial instruments are used for hedging purposes and not for speculation. Those guidelines provide that hedging activity shall be used only to minimize risk and not to create any greater risk. Risk management status and performance must be reported to the Board of Directors on a monthly basis, and counterparties must meet capitalization requirements before the Company will engage with such counterparty.

Electricity and Coal Price Risk

The Company is exposed to the impact of market fluctuations in the prices of electricity and coal as a result of its ownership and operation of electric generating facilities. The Company's exposure to coal and purchased power risk is limited by cost-based Member rate recovery through two cost-recovery clauses, namely the fuel adjustment clause ("FAC") and the non-FAC purchased power adjustment. Due to timing of the cost-recovery, there is a two month lag for the FAC between when costs are incurred and when the Member portion is recovered through rates. For the non-FAC purchase power adjustment due to timing of the cost recovery, there is a two month lag between when the costs are incurred and when the Member-Smelter portion is recovered through rates that represent approximately two-thirds of the costs. Generally, the remaining one-third of the non-FAC purchase power adjustment cost, related to the non-smelter members, is deferred as a regulatory account over a twelve month period beginning July 1 of a given year through June 30 of the following year. The non-smelter member recovery (whether positive or negative) begins on September 1, two months after the end of the deferral period, and ends twelve months later on August 31.

Price risk represents the potential risk of loss from adverse changes in the market price of electricity or coal. Because the Company is long on power, both capacity and energy, it is exposed to the illiquidity of the long-term power market and volatility of the market price of electricity and coal. The Company's long position in the energy market is approximately 150 MWs or 8% of its availability capacity. The excess capacity and energy will be consumed in the future through normal growth. Further, price risk resulting from the volatility in the price of coal is off-set by a month recovery rider for fuel that has been approved by the KPSC.

The Company generally only enters into market power sales contracts that qualify for the normal sales and purchases exception. Income recognition and realization related to normal sales and normal purchases contracts generally coincide with the physical delivery of the power. For all such contracts, as long as completion of the transaction remains probable, no recognition of the contract's fair value is required to be reported in the Company's financial statements until settlement or physical delivery.

In a further effort to mitigate coal price volatility, the Company has established a hedge policy in which near-term requirements of fuel are secured at a higher percentage and future year coal requirements are contracted at a varying percent of open fuel position per year across a five-year time horizon. Thus, in any given year within the five-year hedge plan, there is a portion of fuel supply contracted at known prices.

Marketable Securities Price Risk; Pension Plan Assets

The Company maintains investments to fund the cost of providing its non-contributory defined benefit retirement plans. Those investments are exposed to price fluctuations in equity markets and changes in interest rates. The Company has established asset allocation targets for its pension plan holdings that take into consideration the investment objectives and the risk profile with respect to the trust in which the assets are held. The target asset allocation for equity securities is 65% of the value of the plan assets and the holdings are diversified to achieve broad market diversification to reduce exposure to and any adverse impact of a single investment, sector or geographic region. A significant decline in the value of plan asset holdings could require the Company to increase its funding of the pension plan in future periods, which could adversely affect cash flows in those periods. Additionally, a decline in the fair value of plan assets, absent additional cash contributions to the plan, could increase the amount of pension cost required to be recorded in future periods, which could adversely affect its results of operations in those periods. A 10% decline in the fair value of the Company's plan assets equals $2.8 million.

Interest Rate Risk

The Company is exposed to risk resulting from changes in interest rates as a result of the use of variable rate debt as a source of financing as well as the fixed income investments in its various portfolios. The Company manages its interest rate exposure by limiting the total amount of its variable rate exposure to within a particular amount of its total debt and by actively monitoring the effects of market changes in interest rates. As of December 31, 2011, $727.6 million of $786.4 million of outstanding long-term indebtedness secured under the Mortgage Indenture accrued interest at fixed rates to their final maturity. As of December 31, 2011, the Company had outstanding variable rate debt of $58.8 million. This debt consists of the Series 1983 Bonds which mature in 2013.

Commodity Price Risk

The average rate to the Members is affected by the price Big Rivers can obtain in the market for energy produced by its generating facilities in excess of the Members' requirements. Higher prices produce greater Non-Member revenue that is used to offset Member revenue requirements. The Company's exposure to the risk of fluctuating power prices is declining as its historically high levels of excess generation are being used to meet increasing Member requirements, including the Smelters. The Company's excess capacity generation in 2011 is approximately 8%.

Additionally, if one or more the Company's generating facilities is not able to produce power when required due to operational factors, the Company may have to forego Non-Member sales opportunities or purchase energy in the wholesale market at higher prices to meet Member requirements.

Credit Risk

Credit risk represents the loss that the Company would incur if a counterparty failed to perform under its contractual obligations. To reduce credit exposure, the Company establishes credit limits and seeks to enter into netting agreements with counterparties that permit it to offset receivables and payables. To control the credit risk associated with credit sales of power the Company utilizes a credit approval process, monitor counterparty limits and require that counterparties have adequate credit ratings. The Company attempts to further reduce credit risk with certain counterparties by entering into agreements that enable it to obtain collateral or to terminate or reset the terms of transactions after specified time periods or upon the occurrence of credit-related events. Where appropriate, the Company also obtains cash or letters of credit from counterparties to provide credit support outside of collateral agreements, based on financial analysis of the counterparty and the regulatory or contractual terms and conditions applicable to each transaction.

The Company generally executes only physical delivery contracts. The Company frequently uses master collateral agreements to mitigate certain credit exposures. The collateral agreements provide for a counterparty to post cash or letters of credit in excess of an established threshold. The threshold amount represents an unsecured credit limit, determined in accordance with the Company's credit policy. Collateral agreements also provide that the inability to post collateral is sufficient cause to terminate contracts and liquidate all positions.

Due to the possibility of extreme volatility in the prices of energy commodities and derivatives, the market value of contractual positions with individual counterparties could exceed established credit limits or collateral provided by those counterparties. If such a counterparty were then to fail to perform its obligations under its contract, the Company could sustain a loss that could have a material impact on its financial results. The probability of a material impact is lessened by the fact that the Company only has a relatively small amount of power to sell long-term and presently does not plan on transacting multi-year long-term contracts.

BIG RIVERS' MEMBERS

General

The Members are local consumer-owned cooperative corporations serving retail residential, commercial and industrial customers on a non-profit basis. The territories served by the Members include portions of 22 counties in western Kentucky. The Members serve approximately 113,000 consumers. The majority of the Members' customers are individual residences.

Territorial Integrity

Distribution cooperatives generally exercise a monopoly in their service areas, except in certain areas where a municipality or the Tennessee Valley Authority ("TVA") may have the concurrent right to provide retail electric service. Under a Kentucky statute adopted in 1972, the Members are "Retail Electric Suppliers" that are certified by the KPSC as the exclusive suppliers of energy to their respective certified service areas. Thus, the Members are the exclusive suppliers of energy to electricity consumers located in their respective certified service areas. If a Retail Electric Supplier is providing adequate service within its certified territory, other Retail Electric Suppliers may not sell power to retail customers located within that certified territory. Municipal utilities are not Retail Electric Suppliers under the statute. If a new electric consuming facility locates in two or more adjacent certified territories, the KPSC determines which Retail Electric Supplier may provide retail electric service to that facility based on a number of factors, designed to avoid wasteful duplication of electric generation facilities.

Rate Regulation of Members

The KPSC regulates the retail energy rates of the Members. Under Kentucky law, a utility may revise its rates on 30 days' notice to the KPSC of the proposed changes and the effective date of such changes. The KPSC has the statutory power to suspend such changes pending a hearing for a period not to exceed six months from the proposed effective date of such changes. This suspension period begins with the effective date named by the utility, and thus, the utility may avoid or minimize the effect of such suspension by naming an early effective date in its notice to the KPSC. Rate changes may be placed in effect, in whole or in part, during any such suspension period on a finding by the KPSC that an emergency exists or that the utility's credit or operations will be materially impaired by the suspension. Rates placed into effect on an emergency basis are subject to refund to the extent that the final rates approved by the KPSC are lower than the emergency rates. The KPSC's decision on a new rate schedule filed by a utility must be issued not later than ten months after the filing of the rate schedule.

Member Information

Financial Information

The Members operate their systems on a not-for-profit basis. Accumulated margins constitute patronage capital for the consumer members. Refunds of accumulated patronage capital to the individual consumer members are made from time to time on a patronage basis subject to limitations contained in Member mortgages to the RUS, if applicable.

The Members are the Company's owners and not its subsidiaries. Except with respect to the obligations of the Members under their respective wholesale power contracts and the Smelter Agreements, Big Rivers has no legal interest in, or obligation in respect of, any of the assets, liabilities, equity, revenue or margins of its Members, other than its rights under these contracts. The revenues of the Members are not pledged to Big Rivers, but their revenues are the source from which they pay for power and energy and transmission services purchased from Big Rivers. Revenues of the Members are, however, often pledged under their respective mortgages. Tables 1 through 6 in Appendix B present a three-year summary of the balance sheets, statements of operations and selected statistical information with respect to the Members.

Statistical Information

The Company serves directly and indirectly a diverse customer base that includes farms and residences, commercial and industrial facilities, mining, irrigation and other miscellaneous customers. Farm and residential customers constitute the largest class of customers in terms of numbers throughout the Member service areas. The table below shows energy sales and revenue by customer class for the year 2011 for the Members.

2011 Sales By Members [(1)]

	kWh Sales (in thousands)	kWh Sales (%)	Revenue (in thousands)	Revenue (%)
Farm & Residential	1,530,359	14%	$112,855	23%
Commercial and Industrial (excluding the Smelters)	1,746,161	17%	86,044	17%
Aluminum Smelters	7,228,844	69%	303,364	60%
Other	3,409	0%	437	0%
Total	10,508,773	100%	$502,700	100%

(1) The information in this table has been compiled by Big Rivers from information obtained from the Annual Statistical Report Rural Electric Borrowers (Publication 201.1) and RUS Form 7 prepared by the Members and filed with RUS. Big Rivers has not independently verified this information.

THE SMELTER AGREEMENTS

The Company and Kenergy have entered into electric service arrangements with the Smelters. The Smelters have largely identical obligations under the agreements described below, so the following discussion does not distinguish between obligations to a particular Smelter, even though, from a legal perspective, their rights and obligations are separate and not joint.

The principal terms and conditions relating to the Company's sale of electric services to Kenergy for resale to the Smelters are set forth in six agreements, three with respect to service to each Smelter. The basic structure of the sale of electric services is that the Company sells the electric services to Kenergy and then Kenergy in turns sells those electric services to each Smelter. Because the Smelters are customers of Kenergy, Big Rivers has entered into two, separate wholesale service agreements (each a "Smelter Agreement") with Kenergy. Under each Smelter Agreement, the Company supplies Kenergy with electric service for resale to a particular Smelter. Kenergy has entered into a separate retail electric service agreement (a "Smelter Retail Agreement") with each Smelter. The Company and each Smelter have also entered into a Smelter Coordination Agreement (a "Smelter Coordination Agreement" and, together with the Smelter Agreements and the Smelter Retail Agreements, the "Smelter Agreements") that sets forth certain direct obligations between the Company and a Smelter. Due to the pass-through nature of the principal obligations between the Company and each Smelter, the Smelter Agreement and the Smelter Retail Agreement relating to each Smelter are substantially the same.

The aggregate amount of energy made available to the Smelters under the Smelter Retail Agreements consists of three types of energy referred to as (1) Base Monthly Energy, (2) Supplemental Energy and (3) Back-Up Energy. "Base Monthly Energy" is 368 MW per hour for Alcan and 482 MW per hour for Century. See APPENDIX D – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS – Nature of Service."

The obligation of Kenergy to supply electric service to the Smelters pursuant to the Smelter Retail Agreements will terminate on December 31, 2023, unless terminated earlier pursuant to the terms thereof. A Smelter may terminate its Smelter Retail Agreement upon not less than one year's prior written notice of such termination to Kenergy and the Company if such Smelter ceases all smelting operations in Kenergy's service territory. See APPENDIX D – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS – Termination Rights."

Pricing under the Smelter Agreements is designed so that the Base Rate for the Smelters will always be at least the rate charged to large direct-served industrial customers having an equivalent load factor, plus $.25 per MWh. The contracts provide that the Smelters are obligated to pay various surcharges, including fuel adjustment surcharges and environmental surcharges. In addition, the Smelter Agreements provide for annual adjustments to rates designed to assist the Company in achieving positive margins in each year. See APPENDIX D – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS – Smelter Payment Obligations."

The Smelters intervened in the Company's last rate case, and pressed their case by saying that keeping the Smelter rates low and predictable was important to reduce the risk that the Smelters would have to cease operations upon the next downward cycle in the world price of aluminum. The Smelters say that they are very sensitive to the price they pay for electricity because the cost of electricity is approximately one-third of the cost of the aluminum smelting process.

Although the KPSC's November 17, 2011, Order in the rate case did not give the Company the full amount of the rate increase it sought, the Smelters have since been lobbying state government in Kentucky for financial relief to enhance the financial viability of their respective Kentucky operations. The Smelters have made public statements that the unanticipated magnitude of the current and future rate increases projected by Big Rivers as well as Big Rivers' recent evaluation of the impact of environmental legislation is what drives the current need for a statewide solution to the Smelters' increasing utility costs. Local representatives of Alcan informed economic development officials in state government in February of this year that projected power rates in 2013-2015 make it difficult for Alcan to envision a long-term future for the Sebree plant. Alcan said that a power rate of $26-$28/MWh would generally ensure that the Sebree smelter remains profitable during a periodic downturn in the London Metals Exchange ("LME") price, and would ensure continued operation for the foreseeable future. They say that without relief their Sebree smelter cannot sustain the next downturn in the world price of aluminum.

At the same time Century informed the same officials that for the immediate future, a rate averaging about $34/MWh from mid-2012 through 2015 would be a competitive rate for its Hawesville smelter. Local representatives of Century have told Big Rivers and others in state government that rates at the status quo level are not sustainable for Century's Hawesville smelter even in the short term, and that $50/MWh power puts their smelter's viability at great risk. Century wrote Big Rivers on April 18, 2012, stating that at the current LME prices the Hawesville aluminum smelter cannot sustain operations at Big Rivers' current and projected power rates, and requesting to renegotiate the power rate provisions of its contract. Big Rivers has commenced discussions with Century relating to the sustainability of the Hawesville smelter. Century reported on April 24, 2012, that with the current power price forecast and assuming that the LME remains at its current level, the Hawesville plant is not viable from an economic standpoint. Century publicly stated that the future of the Hawesville smelter would be discussed by Century's Board of directors at its late June meeting. This meeting has taken place and the Company is not aware of what actions, if any, were taken by Century's Board relating to the Hawesville smelter.

The Smelters have been pursuing projects that they say improve the profitability of their respective facilities. Century completed the restart of a fifth potline in 2011. Alcan completed a $50 million bake furnace project, and announced in February 2012 that it is undertaking a $20 million project to boost electric amperage and produce greater volumes of aluminum. Alcan has also reached agreement with Kenergy and Big Rivers to purchase an additional 10 MW of energy for the one year period beginning July 1, 2012, through June 30, 2013.

Alcan announced in October of 2011 that it had put 13 of its smelter operations worldwide on the block for potential sale. The Sebree smelter was included on the list. According to the Alcan release, there is no timeline for any of these sales to occur.

On June 14, 2012, at the request of the Governor of Kentucky, representatives of the Commonwealth met with representatives of Big Rivers and the Smelters to discuss ways to reduce the Smelters' costs in order to make them more economically viable. A number of approaches were discussed including, but not limited to, suggestions that Big Rivers reduce rates to the Smelters to a rate averaging about $35/MWh. Any reduction in the rates to the Smelters would involve an increase in the rates for other industrial customers and rural customers. The discussions that took place on June 14 were preliminary and will be followed by further exploratory discussions in the near future. Any reduction in the rates charged by Big Rivers to the Smelters and concomitant increase in the rates charged to other customers would require action by the Board of Big Rivers and by the KPSC, among others. In addition, it would likely result in renegotiation of the Smelter Agreements. Other approaches that have been advanced include allowing the Smelters more freedom in purchases from other sources and termination of the Smelter Agreements.

Since the meeting on June 14th, the Smelters have advanced other proposals to Big Rivers requesting significant rate reductions for the Smelters. Big Rivers offered a counterproposal and it has been rejected by the Smelters. On June 25, 2012, Big Rivers advised the Smelters that the gap between their demand and the Big Rivers' proposal is far larger than Big Rivers has the ability to close. There can be no assurances as to the outcome of this situation and as to whether one or both of the Smelters will give one year's notice, terminate its Smelter Agreement and close its smelting operations. Also, on July 8, 2012 Century informed Big Rivers that it was hiring a consultant to evaluate the available transmission capacity, potential congestion, and potential voltage stability issues if the Hawesville plant were to import power for its entire load into Big Rivers' system under a variety of operational scenarios of Big Rivers' generation. Big Rivers can give no assurances as to the outcome of this development.

For a more detailed summary of the provisions of the Smelter Agreements, see APPENDIX D – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS."

POWER SUPPLY PLANNING

Every other year Big Rivers prepares load forecasts for the three Members. These individual forecasts serve as the basis for Big Rivers' load forecast, which is filed with the RUS. The last load forecast was prepared and filed in 2011. Additionally, every three years an Integrated Resource Plan ("IRP") is prepared in accordance with Kentucky Administrative Rule 807 KAR 5:5058 and filed with the KPSC. The last IRP was filed with the KPSC in November 2010. The next IRP will be filed with the KPSC in 2013. Both of these studies examine a future time frame of 15 years.

GENERATION AND TRANSMISSION ASSETS

Generation Resources

General

The following table sets forth certain information about the Company's owned generating facilities and Station Two.

Generating Facility	Type of Fuel	Net Capacity[2] (MW)	Big Rivers' Entitlement Share (MW)	Commercial Operation Date
Kenneth C. Coleman Plant				
Unit 1	Coal	150	150	1969
Unit 2	Coal	138	138	1970
Unit 3	Coal	155	155	1972
Robert D. Green Plant				
Unit 1	Coal	231	231	1979
Unit 2	Coal	223	223	1981
Robert A. Reid Plant				
Unit 1	Coal	65	65	1966
Combustion Turbine	Oil-Natural Gas	65	65	1976
D.B. Wilson Plant Unit No. 1	Coal	417	417	1986
Station Two Facility Units No. 1 and No. 2[1]	Coal	312	197	1973/1974
Total		1,756	1,641	

(1) Big Rivers operates but does not own the two units at Station Two and not all net capacity of such facility is available to it.
(2) Net capacity means net nameplate as adjusted for parasitic load.

Kenneth C. Coleman Plant

The Coleman Plant is a three unit, coal-fired steam electric generating unit located near Hawesville, Kentucky. Each of the units has a turbine nameplate rating of 160 MW. Units No. 1 has a net capacity of 150 MW, No. 2 has a net nameplate capacity of 138 MW while Unit No. 3 has a net capacity of 155 MW. All three boilers are positive pressure, outdoor units; the turbine generators are semi-outdoor and the station was retrofitted with a FGD system in 2007. The equivalent availability factor for the Coleman Plant for 2011 was 92.9%.

Environmental controls in place at the Coleman Plant include the use of precipitators (air pollution control devices that collect particles from gaseous emissions) which limit particulate emissions to a maximum of 0.27 pounds per million British thermal unit ("Btu"), and the use of a FGD system which is 97% effective in reducing SO_2 emissions. Coleman Plant's permitted SO_2 emissions limit is a maximum of 5.2 pounds per million Btu. The Coleman Units do not have a Title V permit NO_x limit.

Robert D. Green Plant

The Green Plant is a two unit, coal-fired steam electric generating station located on the same site as the Reid Plant and the Station Two Facility described below. Both boilers at the Green Plant are balanced draft units and they were designed and built with low NO_x burners. The Green Plant is also equipped with a FGD system. Unit No. 1 has a net nameplate capacity of 231 MW while Unit No. 2 has a net capacity of 223 MW. The equivalent availability factor for the Green Plant for 2011 was 94.4%.

Environmental controls in place at the Green Plant include the use of precipitators which limit particulate emissions to a maximum of 0.1 pounds per million Btu, and the use of a FGD system which limits SO_2 emissions to a maximum of 0.8 pounds per million Btu. NO_x emissions are limited to a maximum of 0.7 pounds per million Btu.

Robert A. Reid Plant

The Reid Plant, located near Sebree, Kentucky, is a coal-fired steam electric generating unit with a net capacity of 65 MW and an oil- or natural gas-fired combustion turbine generating unit with a net capacity of 65 MW. The combustion turbine is used for power emergencies and for peaking purposes. The equivalent availability factor for the Reid Plant for 2011 was 92.6%.

Environmental controls in place at the Reid Plant include the use of precipitators which limit particulate emissions to a maximum of 0.28 pounds per million Btu, and the use of medium-sulfur coal which limit SO_2 emissions to a maximum of 5.2 pounds per million Btu. The Reid unit does not have a Title V permit NO_x limit.

D.B. Wilson Unit No. 1 Plant

The single unit Wilson Plant is the largest and newest generating unit in the Company's system. The Wilson Plant, located near Centertown, Kentucky on the Green River, is a coal-fired, balanced draft steam electric generating unit equipped with a FGD system. The unit has a net nameplate capacity of 417 MW. The equivalent availability factor for the Wilson Plant for 2011 was 94.8%.

Environmental controls in place at the Wilson Plant include the use of a precipitator which limits particulate emissions to a maximum of 0.03 pounds per million Btu, and the use of a FGD system which is 90% effective in removing SO_2 emissions. NO_x emissions are limited to a maximum of 0.6 pounds per million Btu.

Other Power Supply Resources

Station Two Facility

The two units at Station Two have a total net nameplate capacity of 312 MW. Station Two is located on the same site as the Reid Plant and the Green Plant, near Henderson. Station Two consists of two positive pressure outdoor type boilers with scrubbers installed. The equivalent availability factor for Station Two for 2011 was 89.8%.

In connection with the Unwind, in July 2009, the Company became responsible for the operation of Station Two in accordance with the terms of the Station Two Operation Agreement and for purchase of capacity and energy in accordance with the terms of the Station Two Power Sales Contract. (See "Station Two Power Sales Contract"). In connection with the Unwind, the Company and WKEC entered into an Indemnification Agreement under which WKEC has agreed to indemnify the Company against potential lost revenue if the contract provisions of the Station Two Power Sales Contract are interpreted against the Company (See "Station Two Power Sales Contract").

Station Two Operation Agreement

The Company operates Station Two in accordance with the Station Two Operation Agreement. The Station Two Operation Agreement provides that the Company will provide, as an independent contractor, all operating personnel, materials, supplies and technical services for the operation of Station Two. It also provides for the allocation of certain costs of operation and maintenance between Station Two and the Company's Reid Plant which shares some common facilities with Station Two. The Station Two Operation Agreement provides that the Company prepares an operating budget, including both capital and operating expenditures, for Station Two which is subject to the approval of the City of Henderson. Such budget then becomes the basis for monthly payments by the City of Henderson to the Company, with an annual reconciliation of such budgeted expenditures and the actual annual expenditures for Station Two. The Station Two Operation Agreement obligates the Company to maintain property and liability insurance with respect to Station Two and to operate and maintain Station Two in accordance with standards and specifications equal to those provided by the National Electric Safety Code of the United States Bureau of Standards and well as those required by any regulatory authority having jurisdiction. Each party's obligations under the Station Two Operation Agreement are subject to the occurrence of "uncontrollable force" (*e.g.*, events not within control of either party and which by exercise of due diligence and foresight could not reasonably be avoided). The obligations of the City of Henderson under the Station Two Operation Agreement are payable solely from the revenues of the City's electric utility system and do not constitute a general obligation of the City of Henderson. The City of Henderson has covenanted in the Station Two Operation Agreement that it will, subject to any necessary regulatory body approvals, maintain rates for service by its electric system sufficient to pay the costs of ownership, proper operation and maintenance of Station Two. The rates for electric service charged by the City of Henderson are not subject to any regulatory body approval. The term of the Station Two Operation Agreement extends for the operating life of Station Two.

Station Two Power Sales Contract

The Company purchases a portion of the power and energy produced by Station Two in accordance with a Power Sales Contract between the City of Henderson and the Company (the "Station Two Power Sales Contract"). The Station Two Power Sales Contract provides for the allocation of the capacity of Station Two between the City of Henderson and the Company based upon the City's determination of its needs to serve its retail customers. The Station Two Power Sales Contract requires the City of Henderson to give the Company a rolling five years' advance notice of the allocation of capacity between the City of Henderson and the Company, but changes of up to 5 MW in the City's allocation are permitted on a yearly basis. The Station Two Power Sales Contract limits the ability of the City of Henderson to add commercial or industrial customers in excess of 30 MW each to its system if to do so would require the withdrawal of existing capacity from Station Two or any other generating facilities on the City's existing electrical system. The Station Two Power Sales Contract also permits the City of Henderson to utilize up to a total of 25 MW of capacity from capacity otherwise allocated to the Company from Station Two for "economic development loads" consisting of new customers on the City's system or certain expansions of capacity by an existing customer. The Company's right to take its reserved portion of the capacity of Station Two is subject to the City of Henderson's prior right to take its allocated capacity. Thus, in the event of an outage or curtailment of the output of Station Two, the City's right to the output has a priority. Each party is entitled to all the energy from Station Two associated with its reserved capacity, subject to the Company's right to "Excess Henderson Energy" described below. The current capacity allocations of the City of Henderson and the Company effective June 1, 2012, are 37% and 63%, respectively.

The Company and the City of Henderson share capacity costs for Station Two in accordance with each party's respective allocated capacities. These capacity costs include the costs of operation, maintenance, administration and general expenses for Station Two as well as any amounts paid or payable to the Company under the terms of the Station Two Operation Agreement. The Company and the City of Henderson are each responsible for providing their respective portions of the fuel consumed by Station Two based on each party's respective uses of electric energy from Station Two.

The obligations of each party are subject to "uncontrollable force", having the same definition as in the Station Two Operation Agreement. However, the Company's obligation to make payments for its allocated capacity of Station Two is not excused for any reason including the occurrence of "uncontrollable force".

The Station Two Power Sales Contract permits the City of Henderson to terminate that agreement on 30 days' notice for the Company's failure to make any payment properly owing under the Station Two Power Sales Contract and, in such event, to make sales to others of power generated by Station Two and allocated to the Company on 5 days' notice to the Company and to apply the proceeds of such sales to the capacity charges the Company owes.

In accordance with the Station Two Power Sales Contract, the Company and the City of Henderson have established separate operation and maintenance funds in the amounts of $400,000 and $100,000, respectively, to fund expenditures for operation and maintenance for Station Two, such expenditures to be made from such funds in proportion to the then effective allocation of Station Two capacity between the Company and the City of Henderson. In accordance with the Station Two Power Sales Contract, the Company has agreed to fund up to $1.05 million to fund its portion of major renewals or replacements to the Station Two required on an emergency basis.

The term of the Station Two Power Sales Contract extends through the end of the economic operating life of Station Two.

Excess Henderson Energy

Big Rivers and the City of Henderson are engaged in an arbitration proceeding regarding their respective rights under the Station Two Power Sales Contract to energy associated with the City of Henderson's reserved capacity that the City of Henderson does not require for service to its native load. Big Rivers' position is that, to the extent the City of Henderson does not take the full amount of energy associated with its reserved capacity from Station Two (such excess, "Excess Henderson Energy"), Big Rivers may take and utilize all such energy for a price of $1.50 per MWh plus the cost of all fuel, reagent and sludge disposal costs associated with such Excess Henderson Energy. Big Rivers further asserts that the Station Two Power Sales Contract precludes the City of Henderson from offering Excess Henderson Energy to a third party without first offering Big Rivers the opportunity to purchase in accordance with the preceding sentence. The City of Henderson alleges that the Station Two Power Sales Contract permits the City to schedule and take energy from its allocated capacity of Station Two, and sell it to third parties after first offering such energy to Big Rivers at the price a third party is willing to pay. The arbitration panel issued its award on May 31, 2012, finding, among other things, that the disputed "excess energy shall be considered to belong to [the City of Henderson] which it may offer to third parties subject to Big Rivers first right to purchase such energy" at "the price at which [the City of Henderson] has a firm offer from a third party." On June 26, 2012, attorneys for the City of Henderson placed a demand on Big Rivers for the amount of $3,753,013.09, which, they allege, represents the amount of fixed costs associated with Excess Henderson Energy from August 2009 to May 30, 2012 minus a credit to Big Rivers for the $1.50 for each MWh taken. Big Rivers and its counsel are still analyzing the implications of the award, Big Rivers' options under the circumstances and the recent demand letter from the City of Henderson. In addition, as described above under the caption "*Station Two Facility*", WKEC and Big

Rivers have entered into an Indemnification Agreement relating to the Station Two Power Sales Contract and Big Rivers understands that WKEC and its counsel are also analyzing the implications of the award, WKEC's option under the circumstances and the recent demand letter from the City of Henderson.

SEPA Contract

In addition to the Company's generation resources, the Company fulfills its power supply responsibilities to the Members with their allocations from SEPA. The Company normally uses entitlement under the SEPA Contract for peaking. However, as a result of problems with certain dams on the Cumberland River hydro system, the Company's capacity entitlement has been suspended and it currently is receiving only energy. Generally, the Company must schedule and accept 1,500 hours of the contracted 178 MW each fiscal year ending June 30. The maximum amount scheduled in any month shall not exceed 240 hours and the minimum amount scheduled in any month shall not be less than 60 hours. The fee arrangement for generation is a take-or-pay contract, currently the Company pays a fixed monthly charge in the amount of approximately $260,937 and $17.69 per MWh for energy. These charges will continue until the dam work is completed and the SEPA Contract is restored to full service. SEPA cannot give notice of termination prior to October 1, 2029, with an effective date of September 30, 2032.

Transmission

In December 2010, the Company transferred functional control of its transmission system operated at 100 kV and above to MISO. In addition to operating the bulk transmission system of its participants, MISO also operates the MISO Market. In the MISO Market, the Company and other participants submit day-ahead or real-time bids and offers for the purchase or sale of energy at various locations. MISO then directs each MISO Market participant whether to operate its generation facilities and determines the price of energy at each location for a particular time period. The Company operates and maintains its transmission facilities and provides transmission services to the Members and Non-Members through MISO. As of December 31, 2011, the Company had in service 834 miles of 69 kV transmission lines, 14 miles of 138 kV transmission lines, 350 miles of 161 kV transmission lines and 68 miles of 345 kV transmission lines. The Company also owns 22 substations. The Company has completed or substantially completed six of the seven system improvements identified as phase two transmission projects. The Company has a construction work agreement with the TVA whereby TVA will pursue the completion of the one remaining project. The Company's available transfer capability for exporting power off system is approximately 1,202 MW with the completion of the six phase two transmission improvements. The current firm transmission capability is sufficient to allow the Company to export all available excess generation capacity plus an amount equal to the peak demand of both Smelters on its system. With the completion of the TVA construction projects currently estimated to be in 2014-2015, the Company's export capability will be increased to approximately 1,263 MW to TVA and 1,210 MW to MISO in 2016.

Southeastern Electric Reliability Council ("SERC") Investigation

Big Rivers is currently the subject of a non-public investigation initiated by SERC in February 2009. The staff from NERC and FERC also participated in the investigation. In June 2011, SERC initiated a formal assessment to determine the Company's compliance relative to eight reliability standards and requirements as a result of findings of possible violations by the investigation team. Aside from one minor instance, which has been disclosed to SERC, Big Rivers believes that it has been, and is, in compliance with all reliability standards and requirements. However, penalties for violations of reliability standards can be substantial. SERC recently has determined that two of the eight possible violations are not violations. At this time the assessment is still ongoing and the Company cannot estimate the amount or range of potential liability, if any.

Interconnections

Big Rivers has several interconnections between its transmission system and those of other power suppliers. These interconnections permit mutual support in emergencies, decrease overall transmission losses, facilitate the arrangement of electric power and energy sales and minimize the duplication of transmission lines. Big Rivers currently has interconnection agreements with seven power suppliers: HMP&L, MISO, Southern Illinois Power Cooperative, Hoosier Energy Rural Electric Cooperative, and Southern Indiana Gas and Electric Company – Vectren, Kentucky Utilities Company and Louisville Gas and Electric Company, and TVA. However, Big Rivers cannot purchase power from TVA due to restrictions on TVA's authority to sell power outside of its service area fixed by statute. An agreement with TVA provides transmission service by TVA to enable Big Rivers to interchange power and energy with four utilities located in the southern United States.

In addition to interconnections with neighboring transmission systems, Big Rivers has also received a request from an independent power producer that may locate within its local balancing area and interconnect new generators to the transmission system. This independent power producer has applied through MISO to connect to Big Rivers' transmission facilities. MISO worked with Big Rivers to study the impacts of such interconnection and to identify the cost of accommodating the interconnection. This generation interconnection will be effectuated through a standard-form, three-way interconnection agreement among Big Rivers, MISO and the independent power producer seeking use of MISO's transmission service.

Open Access Transmission Tariff

Effective December 2010 the use of the Company's transmission facilities is governed by the MISO Tariff. The Company provides the MISO with its revenue requirement for use in establishing the rate for transmission services under the MISO Tariff, but such revenue requirement is not directly reviewed by FERC. As a MISO transmission owner, the Company also participates in the MISO transmission planning process, and is responsible for investments in transmission projects assigned to it in accordance with that process. Participation in the MISO transmission planning process increases the scope of the Company's regional planning process and subjects it to decisions by the MISO and, ultimately, FERC, concerning allocations of costs for meeting regional transmission needs. Finally, the Company is subject to the MISO reserve requirements established pursuant to Module E of the MISO Tariff.

MANAGEMENT

Big Rivers is governed by a Board of Directors comprised of six persons. Each Member has two directors on the Board of Directors. Each director is elected by a majority vote of the delegates at the annual membership meeting in September. Each Member designates one delegate to represent it at the annual membership meeting. At least one of the two directors from each Member must be, at the time of their election, a director of such Member. Each term is for a three year period, ending the later of September 1 or the annual meeting date, and staggered such that two directors from different Members are elected each year.

The following are the Company's principal management personnel with a brief summary of their qualifications:

Mark A. Bailey, President and Chief Executive Officer, received a Bachelor of Science in Electrical Engineering from Ohio Northern University in 1974, and a Master of Science in Management from the Massachusetts Institute of Technology in 1988. He was employed by American Electric Power Company ("AEP") for nearly 30 years, beginning as an Electrical Engineer in 1974. Mr. Bailey was employed as Vice President of AEP subsidiary Indiana Michigan Power Company until AEP's reorganization in 1996, when he became Director-Regions with American Electric Power Service Corporation ("AEPSC"), also a subsidiary of AEP. He was employed as Vice President of Transmission Asset Management for AEPSC from June 2000 until his employment as President and Chief Executive Officer with Kenergy Corp. in 2004. Mr. Bailey was employed as Executive Vice President and Chief Operating Officer beginning in June 2007 until being elected by the Board of Directors to his current position in October 2008.

Robert W. Berry, Vice President of Production, graduated from the University of Kentucky Community College system with an Associate degree in Mechanical Engineering Technology and Mid-Continent University with a Bachelor of Science in Business Management. He was employed by Big Rivers from 1981 to 1998 and served in various maintenance positions such as Superintendent of Maintenance and Maintenance Manager. In 1998 he was employed by Western Kentucky Energy and served in various positions such as Maintenance Manager, Plant Manager and General Manager until the Unwind transaction closed in July 2009, at which time he assumed his current position.

David G. Crockett, Vice President of System Operations, graduated from the University of Kentucky with a Bachelor of Science in Electrical Engineering in 1972. He has been employed with Big Rivers since 1972. He served in various engineering positions before assuming the responsibility of Manager of Energy Control in 1998. Mr. Crockett assumed his current position as Vice President System Operations in 2006.

James V. Haner, Vice President of Administrative Services, graduated from the University of Kentucky with a Bachelor of Science in Accounting in 1970. He has been employed with Big Rivers since 1972. He served in various accounting and finance capacities prior to transferring to administrative services in 1991. He assumed duties as Manager Human Resources in 1998. Mr. Haner assumed his current position of Vice President Administrative Services in 2005.

Mark A. Hite, Vice President of Accounting and Interim Chief Financial Officer, graduated from the University of Evansville with a Bachelor of Science in Accounting in 1980 and a Master of Business Administration in 1985. He is a licensed CPA. Mr. Hite has been employed with Big Rivers since 1983, and has served in various accounting and finance capacities prior to assuming his current position of Vice President of Accounting. He was appointed Interim Chief Financial Officer in 2012.

Eric M. Robeson, Vice President of Environmental Services and Construction, graduated from Rose Hulman Institute of Technology in 1977 with a Bachelor of Science in Mechanical Engineering and Ball State University in 1988 with a Masters of Business Administration. He is a registered Professional Engineer in the state of Indiana. Mr. Robeson worked at Vectren (and its predecessor company Sigeco) from 1980 to 2011. He served a variety of engineering and managerial positions including Plant Manager, Director of Generation Planning, and Director of Infrastructure Services. He joined Big Rivers in 2011 as Vice President of Construction overseeing environmental compliance efforts and assumed his current position in February 2012.

Albert M. Yockey, Vice President of Governmental Relations & Enterprise Risk Management, graduated from the University of Pittsburgh with a Bachelor of Science in Electrical Engineering in 1972, a Master of Science from Lehigh University in 1979, and a Juris Doctor from Capital University Law School in 1994. He is a licensed attorney in Ohio. Mr. Yockey was employed in operation and planning positions with Pennsylvania Power and Light Co. from 1972 through 1985. He was employed in planning, regulatory, and compliance positions with American Electric Power Company from 1985 until February 2008. Mr. Yockey joined Big Rivers as Vice President of Enterprise Risk Management and Strategic Planning in 2008 and assumed his current position in July 2009.

Big Rivers has 627 full-time employees. The International Brotherhood of Electrical Workers, Local 1701, represents 371 of Big Rivers' generation and transmission operating employees. The Company's contracts with this union expire on September 14, 2012, and October 14, 2012, respectively. The Company believes that its relations with labor are good.

OAG EXHIBIT 7

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

Or

In the Confidential File Materials at PSC

Allocation of Smelter Transmission Revenue to Customers

Row		Hawesville	Sebree*	Total	
1	**Annual Smelter Transmission Revenue per SC 1-12 and Berry Rebutttal-5 Update***	$7,512,837	$6,000,917	$13,513,754	
		Rurals	**Large Industrials**	**Total**	
2	Exhibit Wolfram-4 p. 13 - 12 CP Allocators	5,128,900	1,347,348	6,476,248	Also Wolfram 4.2 page 13
3	As a percentage	79.20%	20.80%	100.00%	
4	**Allocation of Transmission Revenue to Each Class if 12 CP allocators are used**	**$10,702,291**	**$2,811,463**	**$13,513,754**	
5	Exhibit Wolfram-4, p. 13 Energy Allocators	2,308,552,000	983,179,000	3,291,731,000	Also Wolfram 4.2 page 13
6	As a percentage	70.13%	29.87%	100.00%	
7	**Allocation of Transmission Revenue to Each Class if Energy allocators are used**	**$9,477,446**	**$4,036,308**	**$13,513,754**	
8	**Difference in Allocation methods**	**$1,224,845**	($1,224,845)		

References to Wolfram Cost of Service Study

Row	Item	Allocation	Direct Testimony	Rebuttal Testimony
9	Plant in Service - Transmission Plant	12 CP	Wolfram-4 page 1	Also Wolfram 4.2 page 1
10	Net Utility Plant - Transmission Plant	12 CP	Wolfram-4 page 2	Also Wolfram 4.2 page 2
11	Net Cost Rate Base - Transmission Plant	12 CP	Wolfram-4 page 3	Also Wolfram 4.2 page 3
12	O&M Expenses - Transmission Plant	12 CP	Wolfram-4 page 4	Also Wolfram 4.2 page 4
13	Labor Expenses - Transmission Plant	12 CP	Wolfram-4 page 5	Also Wolfram 4.2 page 5
14	Depreciation Expenses - Transmission Plant	12 CP	Wolfram-4 page 6	Also Wolfram 4.2 page 6
15	Property and Other Taxes - Transmission Plant	12 CP	Wolfram-4 page 7	Also Wolfram 4.2 page 7
16	Interest Expenses - Transmission Plant	12 CP	Wolfram-4 page 8	Also Wolfram 4.2 page 8

* Includes Berry Rebuttal-5 Update Provided in Hearing on 1/8/2014

OAG EXHIBIT 8

Case No. 2009-00040 - *In the Matter of Application of Big Rivers Electric Corporation for a General Adjustment in Rates*

Big Rivers' Claims

- "The rate increase proposed by Big Rivers, including the interim implementation of that rate increase, is the only option Big Rivers has identified that will allow it to generate the cash required, along with other actions, to meet its needs on a timely basis."[1]

- "There is no room for movement in this rate request: every dollar sought is needed to meet Big Rivers' very real debt obligations between now and next January."[2]

- "Without implementing a rate increase that will produce $16.6 million ($24.9 million annually starting April 1, 2009) by early January 2010, Big Rivers projects that it will run out of cash and be insolvent."[3]

- "I will stop short of saying we are in a crisis, but we desperately need this increase to avert a crisis."[4]

- "There is no room for movement in the amount of rate relief we are requesting; we are requesting the minimum amount necessary to avoid insolvency in January 2010."[5]

- "With those cash reserves now greatly depleted Big Rivers is extremely vulnerable to potential unanticipated costs. Absent restoration of cash reserves any one of a number of categories of unanticipated costs could place Big Rivers back in bankruptcy."[6]

The Ultimate Result

KPSC issues an Order May 27, 2009 denying Big Rivers' requested interim rate increase. Big Rivers does not go bankrupt.

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[1] Big Rivers Application, Case No. 2009-00040 (March 2, 2009) at 5:1-4.
[2] Direct Testimony of Mark A. Bailey, Case No. 2009-00040 (March 2, 2009)("2009 Bailey Testimony") at 4:11-12.
[3] 2009 Bailey Testimony at 7:2-4.
[4] 2009 Bailey Testimony at 24:13-14.
[5] 2009 Bailey Testimony at 24:23-25:2.
[6] Direct Testimony of C. William Blackburn, Case No. 2009-00040 (March 2, 2009) at 43:7-10.

KIUC EXHIBIT 1

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

Big Rivers' Claims

- "*Is there any leeway in Big Rivers' request?* No...."[7]

- "*What will be the consequence if the Commission does not approve the full proposed rate adjustment?* Without the full rate increase requested by Big Rivers, Big Rivers may lose one or more of its investment grade credit ratings, which would likely mean, at a minimum, higher borrowing costs. If Big Rivers does not maintain two investment grade credit ratings, it will be required by the RUS to file promptly for additional rate relief that will position it to obtain those investment grade credit ratings. In the worst case, loss of investment grade credit ratings could jeopardize the solvency and indeed the very existence of Big Rivers."[8]

- "The full amount of base rate increases is simply necessary at this time in order for Big Rivers to adequately recover its costs and to meet its existing debt covenants with its creditors."[9]

- "Big Rivers is only requesting the minimum increase necessary so that it can meet its financial obligations and maintain its investment grade credit ratings, as required by its debt covenants....there is no leeway in Big Rivers' request for rate relief in this proceeding."[10]

- "...the entire revenue increase sought by Big Rivers in this proceeding is needed to help keep Big Rivers financially viable."[11]

The Ultimate Result

The Commission issues an Order November 17, 2011 reducing Big Rivers' requested $39.34 million base rate increase to approximately $26.74 million. On January 29, 2013, the Commission issues an Order on rehearing increasing the level of the base rate increase to approximately $27.79 million. Big Rivers does not go bankrupt.

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[7] Direct Testimony of Mark A. Bailey, Case No. 2011-00036 (March 1, 2011) ("2011 Bailey Testimony") at 12:12-13.
[8] 2011 Bailey Testimony at 14:8-16.
[9] 2011 Bailey Testimony at 21:13-15.
[10] Rebuttal Testimony of Mark A. Bailey, Case No. 2011-00036 (July 6, 2011)("2011 Bailey Rebuttal Testimony") at 8:9-13.
[11] 2011 Bailey Rebuttal Testimony at 16:9-11.

Case No. 2012-00535 - *In the Matter of Application of Big Rivers Electric Corporation for a General Adjustment in Rates*

Big Rivers' Claims

- "The bottom line is that Big Rivers needs the full amount of the increase it is seeking."[12]
- "...I simply cannot stress enough how important it is for Big Rivers to receive the full amount of the increase it is seeking."[13]
- "...the entire amount of Big Rivers' proposed rate relief is absolutely necessary."[14]
- "The total increase is necessary to allow Big Rivers to meet its financial obligations to its creditors and to attract necessary capital in order to provide service to our members in 2013 and beyond."[15]
- "We have asked for the bare minimum possible to meet our debt service and continue funding an appropriately reduced scale of operations in light of Century's unilateral contract termination."[16]
- "...the Commission faces a stark choice in this case between: (i) granting the relief requested by Big Rivers; and (ii) the bankruptcy advocated by the intervenors...as the Commission evaluates the totality of the circumstances, it should not-as intervenors suggest-ignore the negative consequences that are likely to occur as a result of denying or modifying the rate adjustments we have sought..."[17]
- "In my judgment, denial of the full rate relief is likely to trigger a sequence of events that will force Big Rivers to cease operations or seek bankruptcy protection."[18]

The Ultimate Result

The Commission issues an Order October 29, 2013 reducing Big Rivers' requested $68.6 million base rate increase to approximately $54.23 million. Big Rivers does not challenge the Commission's ruling on rehearing and does not file for bankruptcy.

Indeed, Big Rivers later emphasizes that Moody's viewed the Order favorably, even with a reduction to Big Rivers' proposed rate increase, citing Moody's view that the rate increase ultimately granted by the Commission "is credit positive." Big Rivers even calls the Commission's Order a "'breath of fresh air' to the rating agencies and banks."[19]

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[12] Direct Testimony of Mark A. Bailey Testimony, Case No. 2012-00535 (January 15, 2013)("2012 Bailey Testimony") at 9:1-2.
[13] 2012 Bailey Testimony at 11:20-21.
[14] 2012 Bailey Testimony at 16:8-9.
[15] Direct Testimony of Billie J. Richert, Case No. 2012-00535 (January 15, 2013) at 5:23-6:2.
[16] Rebuttal Testimony of Mark A. Bailey, Case No. 2012-00535 (June 24, 2013) ("2012 Bailey Rebuttal Testimony") at 4:5-6.
[17] 2012 Bailey Rebuttal Testimony at 4:19-5:5.
[18] 2012 Bailey Rebuttal Testimony at 5:12-14.
[19] Rebuttal Testimony of Daniel M. Walker, Case No. 2013-00199 (December 17, 2013) at 5:19-6:12.

Case No. 2013-00199 - *In the Matter of Application of Big Rivers Electric Corporation for a General Adjustment in Rates*

Big Rivers' Claims

- "If Big Rivers is not granted the rate relief it seeks in both this case and the Century Rate Case, Big Rivers will be in a position from which it may not be able to recover, and it, its members, and the members' retail customers will suffer."[20]

- "Big Rivers rate application places it on stable financial footing and protects the Members by providing the only reasonable opportunity to avoid bankruptcy."[21]

- "…the Kentucky Public Service Commission ('Commission') has a choice in this case between granting the relief requested by Big Rivers and forcing Big Rivers into bankruptcy."[22]

- "Big Rivers seeks to protect its Members by establishing a reasonable rate that will restore its financial stability. Its proposed rates are designed to do exactly that, and they provide the only reasonable course of action to avoid bankruptcy."[23]

- "…if the Commission withdraws its support in this case by denying Big Rivers' proposed rate adjustment or disallowing the recovery of depreciation expense for Wilson Station…, the creditors and rating agencies will likely also withdraw their support of Big Rivers and leave Big Rivers with no realistic option but to enter bankruptcy."[24]

- "An out-of-court workout is unlikely; bankruptcy is probable if any of the opposing intervenors' positions are accepted by the Commission."[25]

- "Failure to grant the requested rate adjustment will result in Big Rivers' bankruptcy rather than an out-of-court restructuring…"[26]

- "…Big Rivers would likely face bankruptcy if its proposed rates are denied, leading to serious negative consequences for Big Rivers' Members and their retail customers throughout western Kentucky."[27]

The Ultimate Result

Still Unknown.

---

[20] Direct Testimony of Mark A. Bailey, Case No. 2013-00199 (June 28, 2013) at 15:15-17.
[21] Rebuttal Testimony of Mark A. Bailey, Case No. 2013-00199 (December 17, 2013) at 9:1-3.
[22] Rebuttal Testimony of Billie J. Richert, Case No. 2013-00199 (December 17, 2013) ("Richert Rebuttal Testimony") at 3:21-23.
[23] Richert Rebuttal Testimony at 6:3-5.
[24] Richert Rebuttal Testimony at 8:19-9:2.
[25] Rebuttal Testimony of Ralph R. Mabey, Case No. 2013-00199 (December 17, 2013) ("Mabey Rebuttal Testimony") at 7:12-14.
[26] Mabey Rebuttal Testimony at 35:15-16.
[27] Rebuttal Testimony of Lindsay N. Barron, Case No. 2013-00199 (December 17, 2013) at 13:8-10.

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

Global Credit Research - 01 Nov 2013

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

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

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

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

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

On June 28, 2013, BREC filed another rate case proceeding, seeking KPSC approval for its rate strategy to address load loss when the Sebree smelter notice of termination period expires on January 31, 2014. Included in the $70.4 million rate increase is the Sebree

KIUC EXHIBIT 2

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

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

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

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

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SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC
ATTORNEYS AT LAW

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

December 20, 2013

Via Overnight or USPS Delivery

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

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

Dear Mr. Derouen:

Big Rivers Electric Corporation ("Big Rivers") hereby files an original and ten (10) copies of the following in the aforementioned docket:

1. *Sixth Update* to Tab 35 of Big Rivers Application filed June 28, 2013;
2. *Sixth Update* to its responses to Item 43 and Item 54 of the Commission Staff's Initial Request for Information dated June 10, 2013;
3. *Third Update* to its response to Item 3 of the Commission Staff's Third Request for Information dated September 16, 2013.

Please confirm the Commission's receipt of this information by having the Commission's date stamp placed on the enclosed additional copy and returning to Big Rivers in the self-addressed, postage paid envelop provided.

I certify that on this date, a copy of this letter and a copy of the updated responses were served on each of the persons on the attached service list by first-class U.S. Mail.

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

Sincerely yours,

Tyson A. Kamuf /tdk

Tyson A. Kamuf

CC: Billie Richert
DeAnna Speed

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

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

KIUC EXHIBIT 3

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART A - FINANCIAL**	BORROWER DESIGNATION KY0062 PERIOD ENDED Nov-13
INSTRUCTIONS - See help in the online application.	

SECTION A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	THIS YEAR (b)	BUDGET (c)	THIS MONTH (d)
1. Electric Energy Revenues	515,459,383.23	516,601,650.53	499,478,545.00	37,555,275.12
2. Income From Leased Property (Net)	0.00	0.00	0.00	0.00
3. Other Operating Revenue and Income	4,596,020.01	6,564,112.00	3,388,837.00	1,110,463.92
4. **Total Operation Revenues & Patronage Capital** *(1 thru 3)*	**520,055,403.24**	**523,165,762.53**	**502,867,382.00**	**38,665,739.04**
5. Operating Expense - Production - Excluding Fuel	44,111,403.21	44,396,532.17	48,015,195.00	3,401,896.03
6. Operating Expense - Production - Fuel	205,119,841.29	196,877,357.03	212,296,554.00	10,452,710.18
7. Operating Expense - Other Power Supply	102,819,695.91	108,991,611.10	81,584,141.00	9,894,326.89
8. Operating Expense - Transmission	9,084,376.64	9,846,974.85	8,280,762.00	750,778.23
9. Operating Expense - RTO/ISO	2,069,307.83	2,084,278.93	1,912,944.00	120,789.09
10. Operating Expense - Distribution	0.00	0.00	0.00	0.00
11. Operating Expense - Customer Accounts	0.00	209,047.62	0.00	0.00
12. Operating Expense - Customer Service & Information	630,359.03	1,246,332.16	1,317,052.00	200,011.95
13. Operating Expense - Sales	146,208.41	111,001.86	121,254.00	9,479.17
14. Operating Expense - Administrative & General	23,806,699.57	23,787,096.62	26,057,958.00	1,991,516.30
15. **Total Operation Expense** *(5 thru 14)*	**387,787,891.89**	**387,550,232.34**	**379,585,860.00**	**26,821,507.84**
16. Maintenance Expense - Production	37,885,035.04	33,915,006.91	39,699,127.00	4,189,010.11
17. Maintenance Expense - Transmission	4,306,153.23	4,109,630.27	4,620,737.00	277,870.94
18. Maintenance Expense - RTO/ISO	0.00	0.00	0.00	0.00
19. Maintenance Expense - Distribution	0.00	0.00	0.00	0.00
20. Maintenance Expense - General Plant	152,862.02	229,264.27	196,683.00	14,980.58
21. **Total Maintenance Expense** *(16 thru 20)*	**42,344,050.29**	**38,253,901.45**	**44,516,547.00**	**4,481,861.63**
22. Depreciation and Amortization Expense	37,664,804.87	36,371,239.56	38,652,197.00	2,969,655.97
23. Taxes	3,810.88	2,336.04	885.00	<56.88>
24. Interest on Long-Term Debt	41,234,198.88	39,696,457.55	42,340,666.00	3,317,506.24
25. Interest Charged to Construction - Credit	<722,093.00>	<216,206.00>	<595,972.00>	<4,590.00>
26. Other Interest Expense	100,826.11	172.64	0.00	14.00
27. Asset Retirement Obligations	0.00	0.00	0.00	0.00
28. Other Deductions	424,927.67	1,054,007.64	510,564.00	11,843.97
29. **Total Cost Of Electric Service** *(15 + 21 thru 28)*	**508,838,417.59**	**502,712,141.22**	**505,010,747.00**	**37,597,742.77**
30. **Operating Margins** *(4 less 29)*	**11,216,985.65**	**20,453,621.31**	**<2,143,365.00>**	**1,067,996.27**
31. Interest Income	749,654.48	1,759,560.89	1,854,540.00	152,483.46
32. Allowance For Funds Used During Construction	0.00	0.00	0.00	0.00
33. Income (Loss) from Equity Investments	0.00	0.00	0.00	0.00
34. Other Non-operating Income (Net)	0.00	0.00	0.00	0.00
35. Generation & Transmission Capital Credits	0.00	0.00	0.00	0.00
36. Other Capital Credits and Patronage Dividends	58,674.04	2,041,282.33	1,271,325.00	0.00
37. Extraordinary Items	0.00	0.00	0.00	0.00
38. **Net Patronage Capital Or Margins** *(30 thru 37)*	12,025,314.17	24,254,464.53	982,500.00	1,220,479.73

Case No. 2013-00199
Attachment for *Sixth Updated* Response to PSC 1-43
Witness: Billie J. Richert

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

TIER

	Actual	Budget	Fav/(Unfav)
Interest on Long-Term Debt	36,379	38,475	2,096
Net Margins	23,034	600	22,434
TIER - YTD September	1.63	1.02	0.61
TIER (12 months ending 10/31)	1.60	1.13	0.47

Notes:

TIER = (Net Margins + Interest on Long-Term Debt) divided by Interest on Long-Term Debt

Big Rivers ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Cash & Temporary Investments

	Actual	Budget	Fav/(Unfav)	2012 Actual	Fav/(Unfav)
October 31st	94,598	105,982	(11,384)	117,335	(22,737)

The October 31, 2013 cash balance compared to budget is unfavorable due to paying off the 1983 pollution control bonds, partially offset by beginning balance favorability of $8.8m, and by changes in working capital.

The unfavorable variance to prior-year is driven by paying off the 1983 pollution control bonds, partially offset by changes in working capital.

Lines of Credit
As of October 31st

Original Amount	$ 50,000
Letters of Credit Outstanding	(8,625)
Advances Outstanding	0
Available Lines of Credit	$ 41,375

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

BIG RIVERS ELECTRIC CORPORATION'S NOTICE OF CHANGES IN RATES AND TARIFFS FOR WHOLESALE ELECTRIC SERVICE AND OF A FINANCIAL WORKOUT PLAN) CASE NO. 9613

INDEX

KIUC EXHIBIT 4

We emphatically reject the claim of REA, the banks, and Big Rivers that the members of the cooperative ultimately bear the total risk and responsibility for the utility's debts. The distribution cooperatives and their members do not stand in the same position as shareholders of an investor-owned company. The REA, with its oversight and monitoring responsibility, bears a substantial amount of the risk associated with Big Rivers' actions. The creditor banks are compensated for the risks they take. Cooperative members must shoulder a portion of the risk, too, since they have a say in the affairs of the utility. Nor are the aluminum companies exempt from responsibility. Until the downturn of recent years, these companies or their predecessors were in frequent contact with Big Rivers' management. Rather than allocate the risk among all parties now, we have chosen to give the participants an opportunity to discuss the allocation among themselves as a revised workout plan is negotiated.

ISSUES

Commission Jurisdiction Over Workout Plan

Big Rivers has not sought Commission approval of the workout plan itself. Approval is being sought only for the proposed rates which are based on the workout plan. However, the workout plan will directly impact Big Rivers' financial stability. Since the proposed rates will produce revenues less than Big Rivers' full cost of service, they can only be found to meet the statutory criteria of fair, just, and reasonable if the workout plan itself is economically feasible and reasonable. Consequently, the Commission cannot accede to Big Rivers' request that the proposed

In determining the value of a utility's property, this statute grants the Commission significantly more latitude than is available to those commissions that are constrained by a statutorily mandated used and useful criteria. The establishment of fair, just, and reasonable rates involves a balancing of utility and ratepayer interests. After balancing these interests, the Commission may conclude in a given case that rates should be based upon prudent investments even where facilities are cancelled prior to completion of construction. On the other hand, in considering the need for facilities on an economic basis, the Commission may decide that it is not in the customers' interest to pay rates that include the cost of unneeded facilities.

The controlling statutory standard for the establishment of utility rates is set forth in KRS 278.030(1): "Every utility may demand, collect and receive fair, just and reasonable rates for the services rendered or to be rendered by it to any person." A relevant Kentucky decision on valuing utility facilities is Fern Lake Co. v. Public Service Commission, Ky., 357 S.W.2d 701 (1962).

In Fern Lake, the Commission refused to permit a water utility, Kentucky Water Service Co., to increase the booked original cost of its water facilities despite its claim that the facilities had been intentionally undervalued as a convenience and conservative accounting practice. The Commission upheld the use of the book value on finding that the water facilities were substantially in excess of that needed to render service and, consequently, the lower book value accounted for this excess.

The Commission recognizes that the prior negotiations between Big Rivers and its creditors were protracted. However, there must now be an intensive effort among all participants to work together and expend their best efforts. The negotiations must proceed expeditiously, and the Commission will be available to assist in the process.

The Order initiating the new proceeding will provide that:

1. A revised workout plan and flexible power rates for NSA and Alcan should be submitted no later than July 17, 1987;

2. A hearing will be held on July 28, 1987, for the purpose of receiving testimony and cross-examination concerning the revised workout plan and the flexible rates;

3. The record of evidence in this rate case will be incorporated by reference in the new docket and all parties in the rate case will be designated parties therein.

GUIDELINES FOR REVISED WORKOUT PLAN

The Big Rivers power system is a valuable resource to the citizens of Western Kentucky and the Commission is looking for a reasonable, workable, long-term solution to Big Rivers' problems. In this Order the Commission has asserted its statutory right to review and approve a revised workout plan. The overall goal of the revised workout plan should be to stabilize the Big Rivers service area and provide for economic growth to diversify Big Rivers' load. The plan must offer an equitable balance among all interests. Any acceptable revised workout plan must seriously consider the following guidelines.

1. It is the opinion of the Commission that a good starting point for negotiation is the Sunflower Electric Cooperative Debt Restructure Plan. Recognizing the disturbing lack of load diversity and Big Rivers' dependence upon a sluggish aluminum industry, provisions similar to the Sunflower Plan which are not contingent upon an immediate rate increase and guaranteed full repayment of debt are desirable.

2. The immediate and primary source for debt service is off-system sales. Therefore, an agreement on off-system sales should be used in calculating any schedule of debt repayment. Big Rivers' ratepayers should not have unlimited responsibility for the payment of Big Rivers' debt. Furthermore, they should not be required to provide all the revenues required to offset shortfalls arising from insufficient off-system sales.

3. The interests of all affected parties must be considered: rural consumers, industrial customers and creditors. Big Rivers should meet with the creditors to negotiate a revised workout plan. Big Rivers and the aluminum companies should negotiate a flexible rate plan that recognizes the cyclical nature of the industry and the revenue requirements of the utility. Big Rivers, the Attorney General, and other interested parties should meet to discuss the negotiation and determine how the interests of customers other than NSA and Alcan can best be protected.

4. While the Commission expects and the public interest requires that all participants negotiate expeditiously and in good faith, the Commission will make the ultimate decision as to a reasonable long-term solution and no participant will have a veto.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR AN ADJUSTMENT OF RATES	)))	CASE NO. 2012-00535

ORDER

On January 15, 2013, Big Rivers Electric Corporation ("Big Rivers") tendered an application requesting approval to increase its wholesale electric rates for service to its three member-owner distribution cooperatives, Jackson Purchase Energy Cooperative ("JPEC"), Kenergy Corp. ("Kenergy"), and Meade County Rural Electric Cooperative Corporation ("Meade County"). Big Rivers proposed to increase its wholesale electric base rates by $74.5 million,[1] or 21.4 percent, effective February 18, 2013, based on a forecasted test year covering the period from September 2013 through August 2014. The Commission found that an investigation would be necessary to determine the reasonableness of Big Rivers' proposed rates and suspended them for six months, up to and including August 17, 2013, pursuant to KRS 278.190(2).[2]

[1] Recognizing the additional revenue awarded in the rehearing order in Case No. 2011-00036, Application of Big Rivers Electric Corporation for a General Adjustment in Rates (Ky. PSC Feb. 21, 2013) along with the correction of errors in its application, in its February 28, 2013 response to Item 36 of Commission Staff's Second Request for Information, Big Rivers lowered its calculated revenue deficiency to $73.0 million. Recognizing the elimination of the interest expense on pollution control bonds it chose not to refinance, as approved in Case No. 2012-00492, Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness (Ky. PSC Mar. 26, 2013), in its June 24, 2013 rebuttal testimony, Big Rivers lowered its calculated revenue deficiency further to $68.6 million.

[2] *See* Commission Order entered Feb. 1, 2013.

reopening the facility is justified by new or increased system load or higher market prices for power.

Under the circumstances presented in this case, the Commission finds that in setting rates, we must balance the interests of both the utility and its ratepayers. In performing this duty, the Commission acknowledges that this excess generating capacity is not a result of any imprudent decisions by Big Rivers,[45] but is a direct result of Big Rivers' actions to reacquire its generating facilities in an effort to keep the smelters operating in western Kentucky. We also acknowledge that Big Rivers is a cooperatively organized utility. Unlike an investor-owned utility which has equity capital supplied by shareholders who choose to invest in the enterprise, a cooperative utility is owned by its members, who are its customers. In addition, Big Rivers' facilities are financed substantially with debt. Absent sufficient revenue to pay the interest on that debt, Big Rivers will be in default on its financial obligations and this could lead to bankruptcy.

Having considered all of these factors, the Commission finds it both reasonable and necessary to exclude some costs of the Coleman Station from Big Rivers' rates. It would simply not be fair to require ratepayers to pay all of costs of the excess capacity. Therefore, we will exclude the depreciation expense associated with the Coleman Station from rates at this time, as discussed more fully later in this Order. Further, we find it reasonable to afford Big Rivers the time to pursue its mitigation strategies, including operational changes to reduce costs, seeking to acquire replacement load, increasing off-system sales, and attempting to sell or lease its generating facilities. The

[45] No party to this case alleges that the current excess capacity situation is a result of imprudent action or decision by Big Rivers.

decision we make today is not an easy one, and some of our rate-making adjustments may be viewed as atypical. But we firmly believe that today's decision fairly balances the interests of all stakeholders. Ratepayers will not be required to pay for depreciation on the Coleman Station that is currently excess capacity, and Big Rivers' will to be able to avoid a default on its debts, continue to provide safe and reliable electric service to the 112,000 customers served by its member-owners, be able to implement its mitigation plan, and possibly attract new load.

SIGNIFICANT PAYROLL COST INCREASES

The AG argued that Big Rivers awarded pay increases to some of its top officers, primarily during the period of the Unwind Transaction, that were excessive, or "significant" in the AG's words, and that such increases should not be allowed for rate making purposes. Although he claimed that these increases totaled approximately $4.4 million, the AG's recommended adjustment was limited to pay increases awarded in 2009 and 2011 and certain bonuses/incentives resulting in an overall adjustment to decrease Big Rivers' expenses by $1,444,273.[46]

Big Rivers responded to the AG's recommendation by explaining that the pay increases awarded in 2009 in connection with the Unwind Transaction recognized the increase in its organization's size upon reacquiring control of its generating facilities, which resulted in its becoming a generating and transmission cooperative rather than being solely a transmission cooperative.[47] Big Rivers also described various increases in the responsibilities of its chief executive officer ("CEO"), as well as its chief operating

[46] Ostrander Testimony at 35.

[47] Haner Rebuttal at 9.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR AN ADJUSTMENT OF RATES	)))	CASE NO. 2012-00535

ORDER

By Order issued on October 29, 2013 ("Rate Order"), the Commission granted Big Rivers Electric Corporation ("Big Rivers") an increase in its wholesale base rates to generate additional annual revenues of $54,227,241.[1] A motion was filed by Big Rivers on November 20, 2013, seeking clarification on the issue of whether it has the authority to record as a regulatory asset the severance costs it incurs as a result of idling the Coleman Generating Station. On that same date, the Attorney General for the Commonwealth of Kentucky ("AG"), Ben Taylor and Sierra Club ("Sierra Club"), and Kentucky Industrial Utility Customers, Inc. ("KIUC") (collectively, "the Intervenors") filed a request for rehearing on three issues related to the Rate Order. On November 27, 2013, Big Rivers filed a response in opposition to the Intervenors' request for rehearing. On December 9, 2013, Big Rivers filed a Motion for Leave to Withdraw its Motion for Clarification. With this Order, the Commission grants Big Rivers' motion for leave to withdraw its motion for clarification, grants rehearing on one of the issues raised in the Intervenors' petition, and denies rehearing on the remaining two issues raised by the Intervenors. Descriptions of the issues raised by the Intervenors and our decisions thereon are discussed as follows.

[1] Big Rivers had sought an increase of approximately $74.5 million.

that deferring depreciation expense in accordance with the Rate Order would violate GAAP and argues that the Intervenors have not shown that GAAP somehow commits the Commission to grant rate recovery in contravention of the plain language of the Rate Order.[7] Finally, Big Rivers points out that KIUC supported, as an alternative to ceasing depreciation on an idled plant, the deferral and recording as a regulatory asset the idled plant's depreciation and that no other intervenor opposed this alternative. Given that KIUC's current opposition represents a disavowal of its earlier position and that the AG and Sierra Club had earlier opportunities to raise concerns they may have had with the KIUC alternative but did not raise them, Big Rivers contends that rehearing on this issue should be denied.

The Commission notes, as did Big Rivers, that the language in the Rate Order states that the Coleman "depreciation expense may be considered for recovery in rates at a future point in time." Contrary to the Intervenors' argument, the Rate Order provided no specific guarantee of Big Rivers' recovery of the deferred depreciation in the future. The Commission also notes that the Rate Order authorizes the Coleman depreciation to be deferred for ratemaking and accounting purposes. While the Commission has exclusive jurisdiction over Big Rivers as to rates and regulatory accounting, it has no jurisdiction over Big Rivers' obligations under GAAP accounting. If Big Rivers' load-mitigation plan, which the Rate Order did not criticize, is successful and Coleman is a revenue-producing asset in the future, Big Rivers should have the right to seek consideration of offsetting those future Coleman revenues against its deferred Coleman depreciation. If the mitigation plan is unsuccessful and Coleman produces no or little future revenue, it would not be reasonable to require ratepayers to pay the

[7] *Id.*, at 3.

deferred Coleman depreciation. These are the factors considered by the Commission in reaching its decision on the Coleman depreciation and why the Rate Order stated that future recovery of this depreciation "may be considered."

Finally, in recognition that the deferral adopted by the Commission was KIUC's alternative recommendation and that the AG and Sierra Club offered no opposition to this alternative, we conclude that none of the Intervenors has presented sufficient grounds to support rehearing on this issue. Accordingly, the Commission finds that the Intervenors' rehearing request on the deferral of the Coleman depreciation should be denied.

Filing of SSR Agreement with the Federal Energy Regulatory Commission ("FERC")

On November 1, 2013, MISO filed with FERC the SSR agreement entered into by MISO and Big Rivers regarding the operation of Coleman. The Intervenors claim that the agreement provides for Big Rivers to receive $40.974 million annually from MISO for fixed and capital-cost recovery related to operation of Coleman as an SSR, or $12.313 million greater than the amount estimated by Big Rivers and accepted by the Commission in setting Big Rivers' revenue requirement in this case. While the agreement is subject to FERC approval, the Intervenors argue that the Commission should reduce the amount of the increase granted to Big Rivers by $12.313 million (or the amount approved by FERC in excess of the $28.661 million now reflected in Big Rivers' rates) for as long as the SSR agreement is in effect.

The Intervenors state that the Commission can reduce rates and order refunds of the $12.313 million difference or re-open the record and take additional evidence on this issue. The Intervenors note that once the SSR agreement expires, the transmission

Subject: Financial Policy (Incorporates Annual Fiscal Review Policy)	Original Effective Date 07/16/2009 Original Approval Date 07/20/2007 Date Last Revised 01/20/2012	Approved By: Board

1. **Purpose**

The purpose of Big Rivers Electric Corporation's ("Big Rivers") Financial Policy is to provide a framework to enable Big Rivers to timely meet its financial obligations and maintain its financial viability. This policy sets forth responsibilities and guidelines related to the financial management process, including key financial metrics.

The financial metrics will be pursuant to Big Rivers' by-laws, loan covenants, mortgage, trust indenture, etc., and quantified in accordance with generally accepted accounting principles ("GAAP"). Application of this policy seeks to ensure Big Rivers' ability to maintain the necessary financial metrics to meet its proper investment grade credit rating target and ensure its ability to timely access capital, both short-term and long-term.

2. **Objectives**

The overall objectives of this policy are to ensure:

a. **Maintenance of the long-term financial forecasting model** – Big Rivers will maintain a financial forecast that reflects current assumptions on key modeling inputs (e.g., load, resource plans, fuel costs, financing, labor costs, etc.).

b. **Timely access to capital** – Big Rivers will ensure access to sufficient low-cost capital, both short-term and long-term, by maintaining its investment grade credit rating, meeting bond covenants, adhering to indenture requirements, maintaining proper liquidity, etc.

c. **Financial transparency** – Big Rivers will provide appropriate financial information in a timely manner to its stakeholders (Board, members, creditors, regulators, etc.), including financial forecasts and performance metrics.

d. **Member wholesale rates** – Big Rivers will seek low-cost member wholesale rates, with minimal volatility. Management will analyze existing and alternative rate structures, seeking rational cost allocation methodology.

e. **Financial analysis** – As appropriate, Big Rivers will strive to ensure accurate and consistent assumptions and methodology are employed in project evaluations, whereby such evaluations may include net present value (NPV), internal rate of return (IRR), payback, etc.

3. **Goals**

a. **Member rates and margins** – Big Rivers will seek to maintain member tariff rates that enable it to meet its debt covenants and ensure that sufficient positive margins and net cash flows are generated to meet Times Interest Earned Ratio ("TIER"), Margins for Interest Ratio ("MFIR") and Debt Service Coverage Ratio ("DSCR") criteria.

b. **Cash Requirement** – Big Rivers will seek to maintain a minimum first of the month cash balance of 45 days of forecasted fixed operation and maintenance expenses (where variable costs equal fuel, reagents, disposal, allowances, purchased power-energy, including the variable cost associated with Big Rivers' share of Station Two).

c. **Equity** – Big Rivers will seek to maintain a minimum equity to total assets ratio of 20 percent to ensure its ability to maintain the targeted investment grade credit rating and ensure access to low-cost sources of capital.

d. **Budgeting and capital planning** – Big Rivers will develop an annual O&M budget and capital budget and present it to the Board for approval prior to the start of the year in question. The Board will approve O&M and capital spending both through its approval of the annual budget, the 3 year financial plan, and through specific approval of individual projects pursuant to company policy.

e. **Financing** – Big Rivers will meet its capital needs through a combination of internally generated funds and debt financing consistent with company policy. Big Rivers may elect to utilize debt to finance projects based on an analysis of borrowing costs, internal rate of return, equity ratio, etc. Borrowing funds may be prudent if sufficient debt capacity exists. Regulatory, legal and reliability requirements are other important financing considerations, as is liquidity.

4. **<u>Other Relevant Company Policies</u>**

a. **Financial Forecasting**

1. GAAP – All financial forecasts will be consistent with GAAP.
2. Financial Forecast Updates – At a minimum, Big Rivers will review and update the financial forecasting model on an annual basis. Big Rivers will periodically update the financial forecast based on known and forecasted changes. The financial forecast will be reviewed with the Board annually. Additionally, Big Rivers will assess its liquidity on a monthly basis when comparing the forecast with monthly actuals.
3. Risk analysis –The financial forecasting model will seek to assess risks, with output expressed in terms of key financial measures, like margins, MFIR and TIER. Risk analysis will be performed with the financial forecasting model. The Aces Power Marketing (APM) probabilistic portfolio optimization model will provide key input to the financial forecasting model. A longer term Integrated Resource Planning ("IRP") tool will also provide key input to the financial forecasting model.

b. **Strategic Planning** -The strategic planning effort will culminate with the capital and O&M budget, the 3 year financial plan, and the financial forecast. Financial forecast modeling of alternative strategies will occur in support of on-going strategic planning. The strategic plan will be reviewed with and approved by the Board annually.

c. **Debt Financing Sources**
1. Federal Financing Bank ("FFB") supported by Rural Utilities Service ("RUS") loan guarantees
2. CoBank, National Rural Utilities Cooperative Finance Corporation ("CFC") and other capital market lenders
3. The Trust Indenture should enable Big Rivers to access the capital markets on a timely basis.

d. **Interest Rate Hedging** – Big Rivers is authorized to utilize interest rate hedging instruments to effectively fix borrowing rates. While not allowed for speculative purposes, subject to Board approval Big Rivers may hedge the risk associated with interest rate volatility for existing and proposed debt.

5. **<u>Annual Fiscal Review</u>**

The CFO shall conduct an annual fiscal review with the Board consisting of appropriate information presented in a clear and concise manner. Specific reporting requirements are as follows:

a. **Cost of capital and cost of debt** - Review the prior year's cost of capital and the cost of debt as defined in Appendix A of this policy. For comparison, the report will compare the most recent fiscal year to the prior five years and will also compare actual with any covenants or targets that may have been set.

b. **Capital expenditures** - Review the prior year's capital expenditures and disclose the means of financing them. The Board will be apprised of Big Rivers' equity ratio and debt capacity. For comparison, the report will compare the most recent fiscal year to the prior five years and will also compare actual with any covenants or targets that may have been set.

c. **Margins, equities and capital credits** - Review Big Rivers' prior year's margins, equities, capital credit allocation, and retirement of capital credits. For comparison, the report will compare the most recent fiscal year to the prior five years and will also compare actual with any covenants or targets that may have been set.

d. **MFIR, TIER and DSCR** - Review the prior year's MFIR, TIER and DSCR as defined in Appendix A of this policy. The Board will be apprised of Big Rivers' credit ratings. For comparison, the report will compare the most recent fiscal year to the prior five years and will also compare actual with any covenants or targets that may have been set.

e. **Cash** - Review Big Rivers' cash reserves and lines of credit, assessing its liquidity. Big Rivers shall calculate its 45-day (minimum) cash requirement for fixed operation and maintenance expenses, based on the 12-month historical period. For comparison, the report will compare the most recent fiscal year to the prior five years and will also compare actual with any covenants or targets that may have been set.

f. **Member wholesale rates** - Review Big Rivers' tariff rates and the revenues generated therefrom. For comparison, the report will compare the most recent fiscal year to the prior five years and will also compare actual with any covenants or targets that may have been set.

6. Administration

The CEO and CFO shall be responsible for the administration of this policy, including 1) making periodic reports to the Board and 2) recommending changes hereto which require Board approval.

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APPENDIX A

Cost of Debt = $\dfrac{\text{Interest expense on long-term debt}}{\text{13-month average principal balance}}$

Cost of Capital = Cost of Debt (above)

$$+ \frac{\text{Depreciation and Amortization}}{\text{13-month average gross plant in service}}$$

$$+ \frac{\text{Property Taxes}}{\text{13-month average gross plant in service}}$$

$$+ \frac{\text{Property Insurance}}{\text{13-month average gross plant in service}}$$

Times Interest Earned Ratio (TIER)

$$\frac{\text{Net Margins + Interest expense on long-term debt (including interest charged to construction)}}{\text{Interest expense on long-term debt (including interest charged to construction)}}$$

Debt Service Coverage Ratio (DSCR)

$$\frac{\text{Net Margins + Interest Expense on Long-Term Debt + Depreciation and Amortization (including interest charged to construction)}}{\text{Interest Expense on Long-Term Debt and Principal Due on Long-Term Debt (including interest charged to construction)}}$$

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Margins for Interest Ratio (MFIR)

$$\frac{\text{Margins for Interest}^1 + \text{Interest Charges}^2}{\text{Interest Charges}^2}$$

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

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

KIUC EXHIBIT 6

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

Or

In the Confidential File Materials at PSC

KIUC EXHIBIT 6a

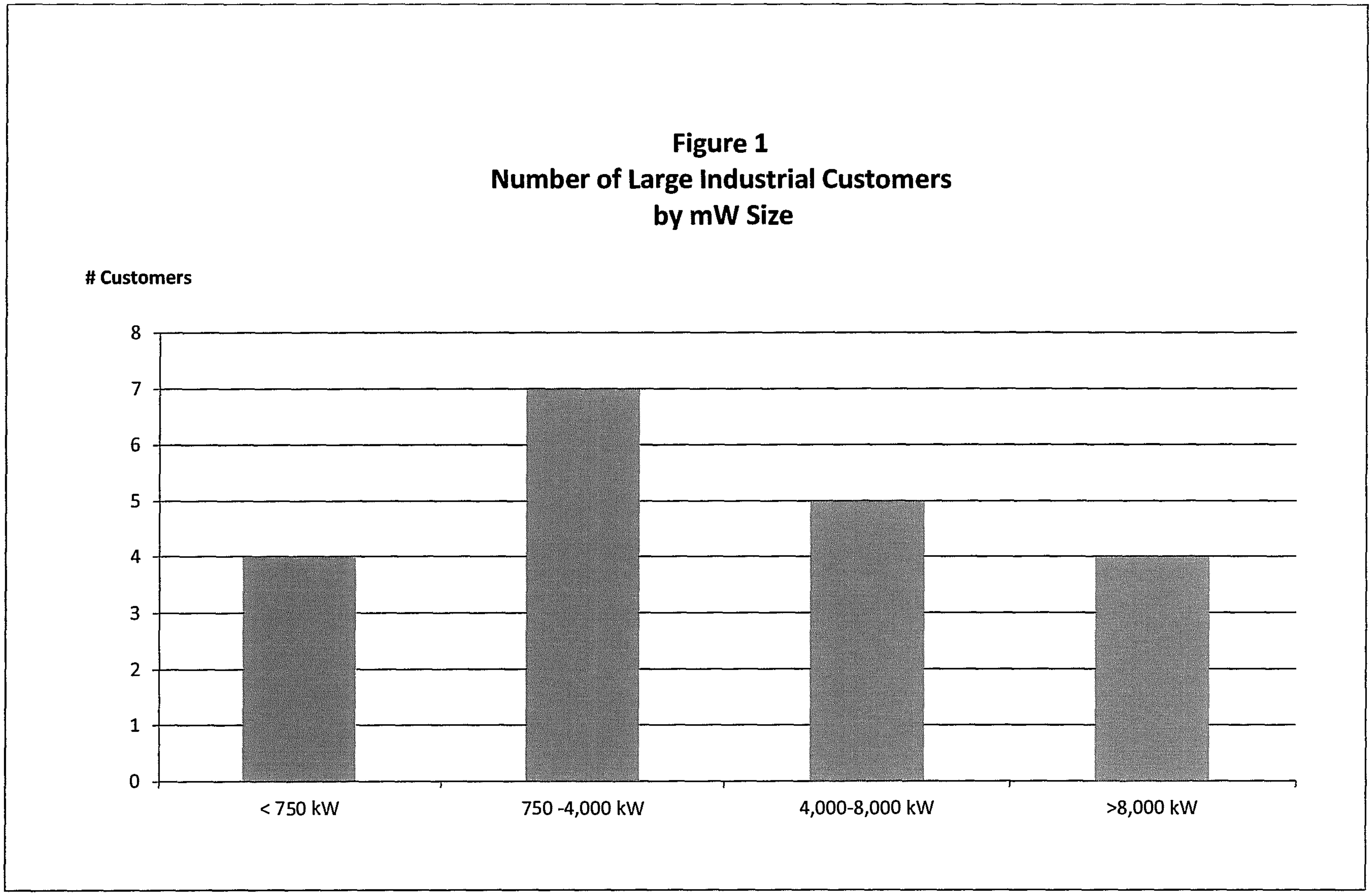
(CONFIDENTIAL)

DENIED ADMITTANCE AS EXHIBIT

Maintained on the Confidential Materials DVD

Or

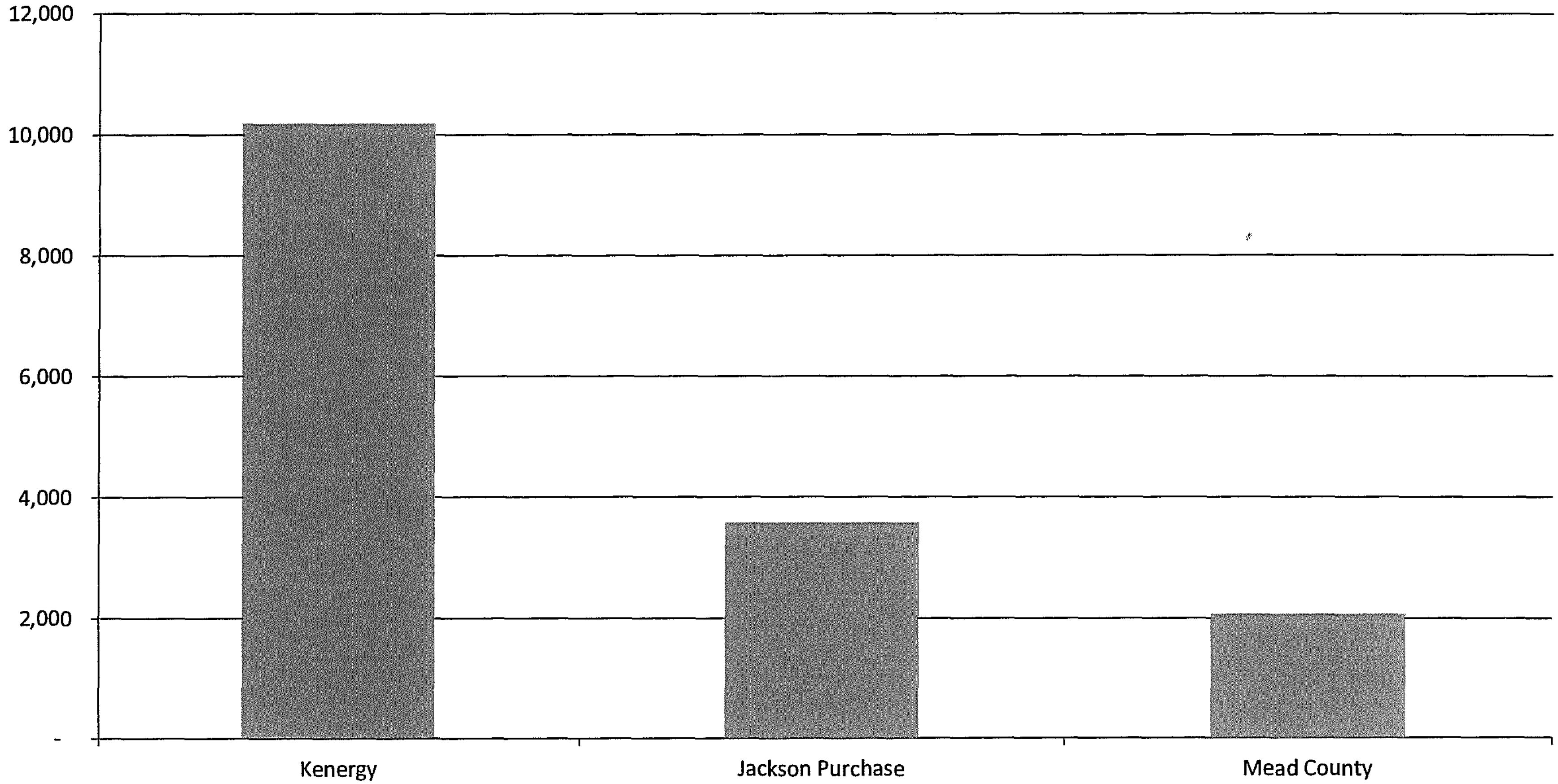
In the Confidential File Materials at PSC



Direct Testimony of Stephen J. Baron at p. 12
Case No. 2013-00199

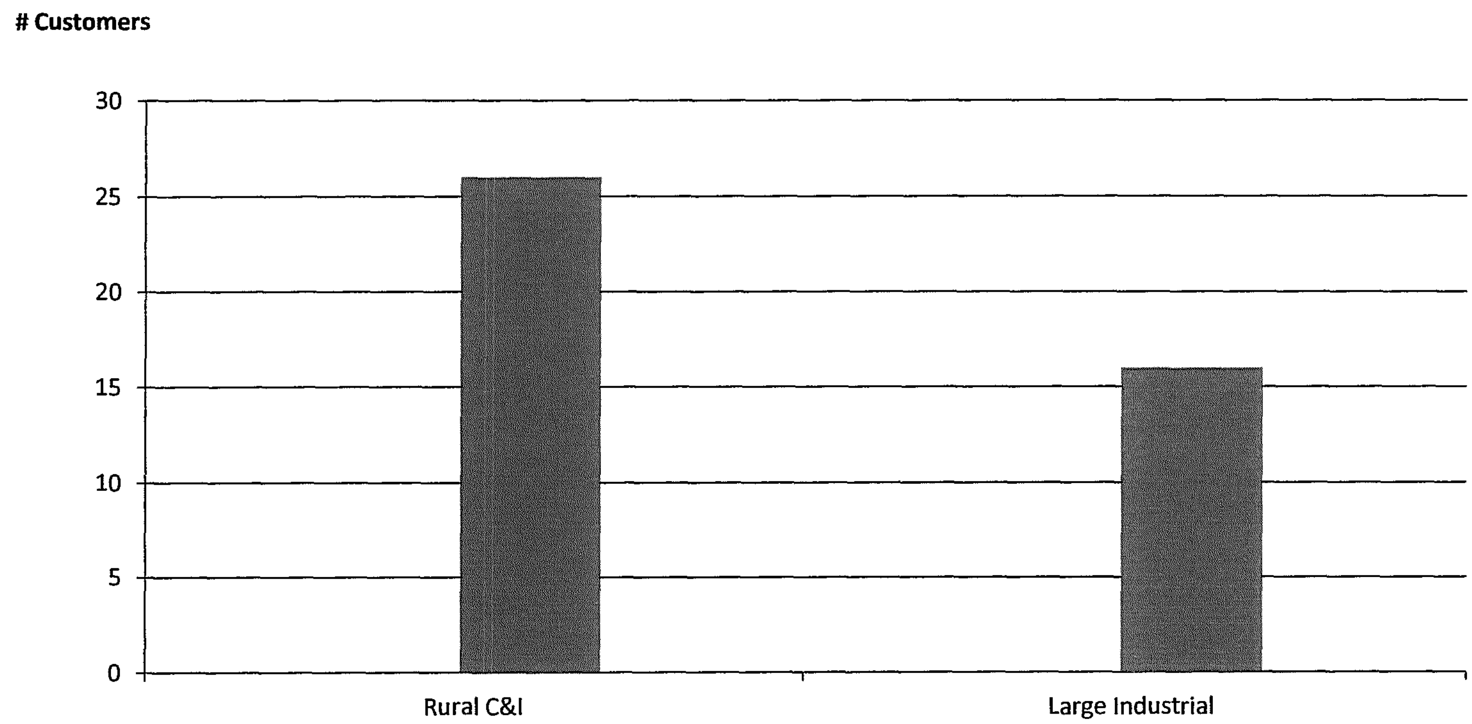
KIUC EXHIBIT 7

Figure 2
Base Period Number of
Rural C&I Customers



Direct Testimony of Stephen J. Baron at p. 13
Case No. 2013-00199

Figure 3
Number of Rural C&I Customers vs.
Number of Large Industrial Customers
With Demands > 1,000 kW



Direct Testimony of Stephen J. Baron at p. 14
Case No. 2013-00199

The Vulnerability of Kentucky's Manufacturing Economy to Increasing Electricity Prices

Aron Patrick

Kentucky Energy and Environment Cabinet
Department for Energy Development and Independence

October, 2012

energy.ky.gov

KIUC EXHIBIT 8

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Executive Summary

Kentucky's low electricity prices have fostered the single-most electricity-intensive manufacturing economy in the United States, a manufacturing economy that is now threatened by future electricity price increases. This study builds upon the notion that low energy costs are a catalyst for commercial growth by quantifying the specific vulnerability of the largest economic sectors of the Commonwealth, in terms of total employment, to future electricity price increases. Using a statistical analysis technique called *multiple regression of panel data with fixed effects*, this study modeled the responsiveness of employment across the United States to changes in the price of electricity from 1990 to 2010 for the top five employment sectors in Kentucky: manufacturing, retail services, hospitality, healthcare, and government. *Elasticities* were developed for each of these economic sectors to calculate changes in employment, given a specific change in the price of electricity, and can be generally applied to the 48 contiguous United States.

Given a 25% forecasted increase in the real price of electricity in Kentucky between 2011 and 2025, this study estimates the Commonwealth will likely lose, or fail to create, approximately 30,000 full-time jobs in the long-term. Manufacturing establishments were found to be most responsive to changes in electricity prices and can be expected to permanently shed 17,500 full-time jobs. The other largest employment sectors in Kentucky, retail stores, restaurants, and hotels, were less than half as responsive as the manufacturing sector to increasing electricity prices, and combined, can be expected to fail to create 12,500 full-time jobs. However, in the fourth and fifth largest employment sectors, healthcare and government, no statistically significant relationship could be identified between electricity prices and total employment.

While total employment in Kentucky is expected to continue to rise in other sectors, **the Commonwealth should develop strategies to mitigate vulnerability to energy price increases, volatility, and risk exposure. Additionally, Kentucky should maintain focus on education and workforce development in emerging industries that are less reliant on energy-intensive manufacturing processes.** These forecasted electricity price increases, in addition to the current trend towards off-shoring and automation of manufacturing processes, have the potential to transform the economies of manufacturing states like Kentucky.

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The Vulnerability of Kentucky's Manufacturing Economy to Increasing Electricity Prices

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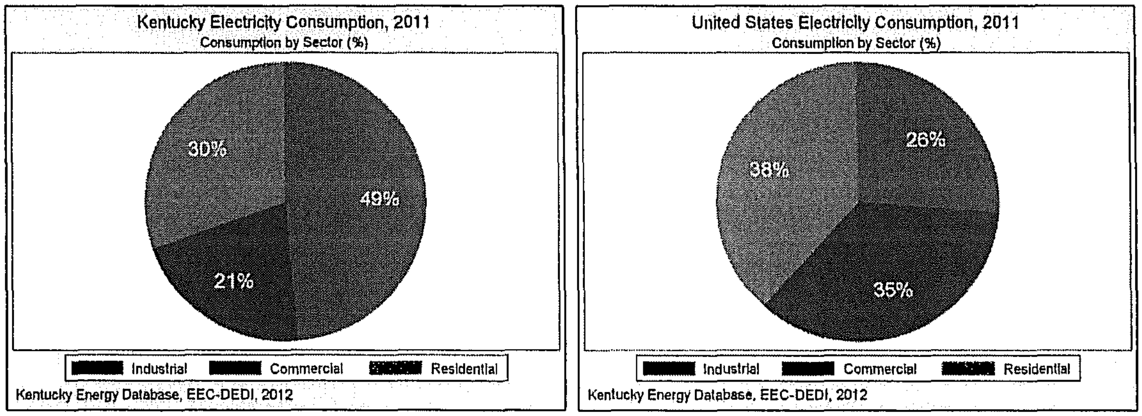
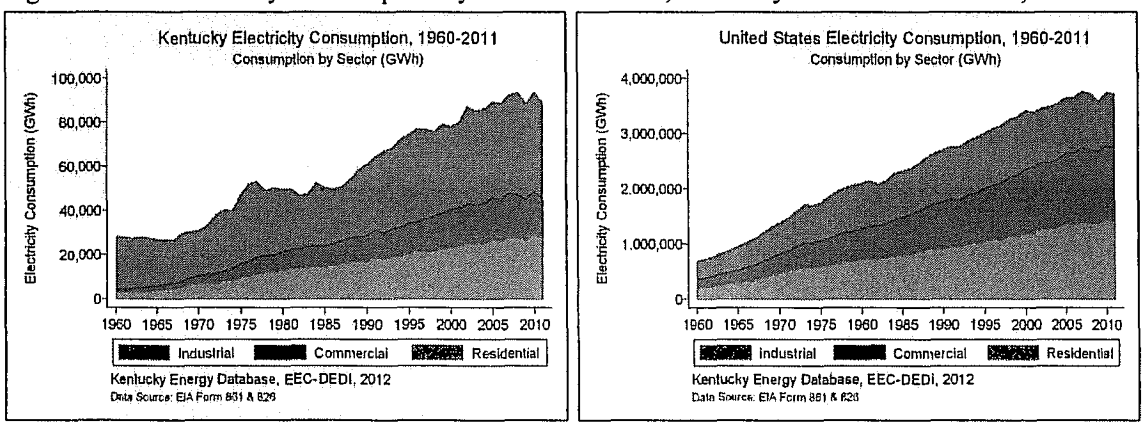
Kentucky's Energy-Intensive Economy

In 2011, 49% of all electricity consumed in Kentucky went to industrial users, compared with 26% for the United States as a whole, as illustrated in Figures 1 and 2 below. The reason for this is obvious—industries requiring large amounts of electricity for production have an incentive to locate in states where they can anticipate that electricity costs will remain low. The industrial nature of Kentucky's electricity load is by no means a recent development. Ever since the first power plants were built in the Commonwealth, most of the electricity produced went to large factories. Over the past 50 years for which there is reliable data, industrial users have consumed an average of 60% of all electricity generated in Kentucky annually, as illustrated in Figure 3 below. These proportions for the United States as a whole have historically been far more balanced, as illustrated in Figure 4 below.

Figures 1 & 2: Electricity Consumption by Economic Sector, Kentucky vs. the United States, 2011



Figures 3 & 4: Electricity Consumption by Economic Sector, Kentucky vs. the United States, 1960-2011



Coal has historically provided the Commonwealth both low-cost electricity and energy security. Nominal electricity prices in Kentucky have increased since 1970 at about 2% annually, which is less than the average rate of inflation during this same period. When adjusted for inflation,[1] as illustrated in Figure 5 on page 3, real electricity prices actually fell in Kentucky from 1980 to 2003, and have risen over the past decade with increases in the price of all fossil fuels. Since 1992, Kentucky has maintained one of the lowest four electricity prices in the nation, running neck and neck with the coal and hydroelectric states of Idaho, Wyoming, Washington, and West Virginia.

Figure 6 on page 3 illustrates that Kentucky is home to the most electricity-intensive economy in the United States. Simply stated, *this means that Kentucky industries use more kilowatt-hours of electricity to produce one dollar of GDP than any other state and are, therefore, more sensitive to changes in electricity prices than any other state.*

In 2009, the most-electricity-intensive sectors nationally were aluminum smelting, iron & steel mills, paper mills, chemical production, and glass manufacturing, which required on average between 0.5 and 4.5 kilowatt-hours of electricity to produce \$1 worth of goods. At current Kentucky industrial electricity prices, each dollar of shipments from these industries required between \$0.025 and \$0.222 worth of electricity. In other words, up to a quarter of total revenues in these industries go to electricity costs. In Kentucky, the most-intensive of these manufacturing processes, which require more than 0.5 kilowatt-hours of electricity to produce \$1 of goods, directly contributed \$5 billion, or 3.2%, to the Commonwealth's total 2009 GDP and employed 12,685 Kentuckians.[2] The national average electricity-intensity of each NAICS manufacturing sector present in Kentucky is summarized in Table 1 on page 4 along with the total number of employees and the contribution of each industry to Kentucky's 2009 State GDP based on data provided by the U.S. Census Bureau's Annual Survey of Manufactures and the U.S. Bureau of Economic Analysis.[3] This table provides an approximate rank ordering of sensitivity to electricity prices between types of manufacturing operations present in Kentucky.

Figure 5: Total Real Electricity Prices, 1970-2010, Kentucky vs. the United States

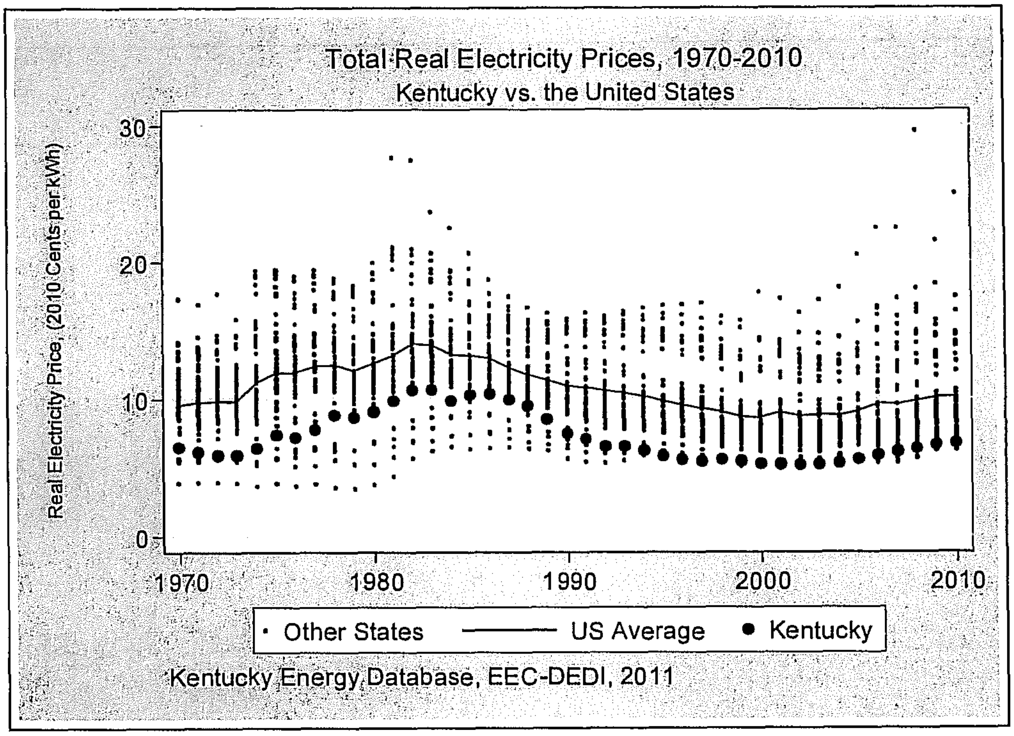


Figure 6: Total Electricity Intensity of Production, 1963-2010, Kentucky vs. the United States

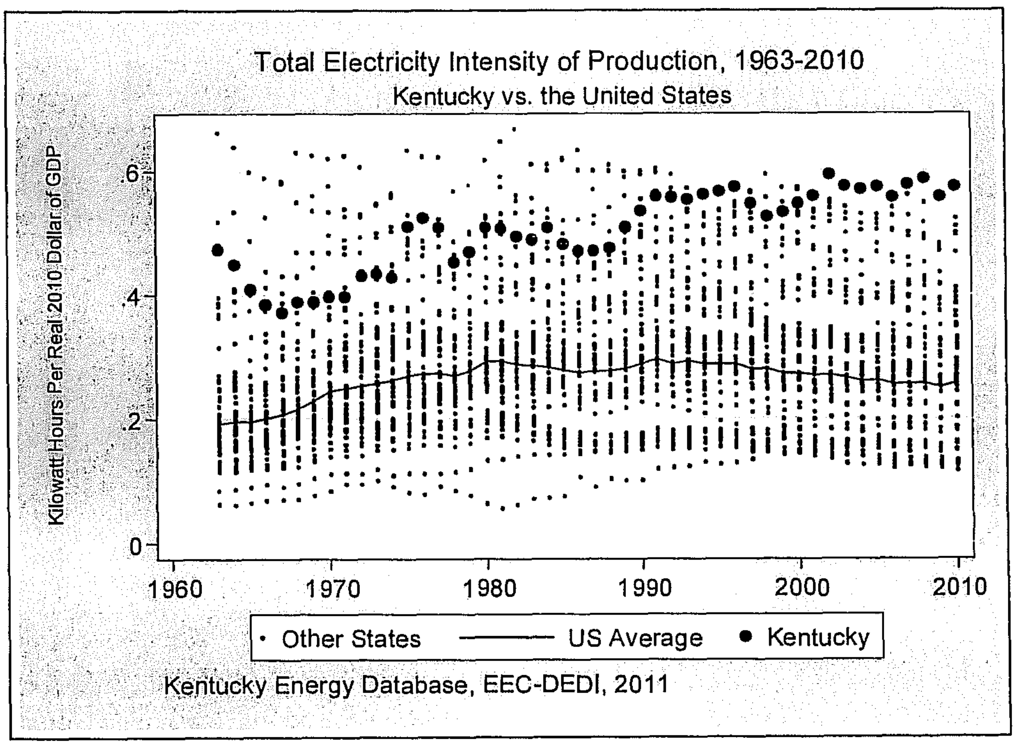


Table 1: National Manufacturing Sector Electricity-Intensity and Kentucky Employment by NAICS, 2009

NAICS 4	NAICS Description	National Electricity Intensity of Production (kWh per $ of Shipment)	Kentucky Average Workers	Kentucky Production Worker Hours (1,000)	Kentucky Value added ($1,000)
3313	Aluminum Production & Processing	4.37313	3,482	6,930	1,083,373
3311	Iron & Steel Mills & Ferroalloy	1.57640	2,954	6,083	232,537
3221	Pulp, Paper, & Paperboard Mills	1.11598	1,192	2,382	1,142,732
3251	Basic Chemical	0.71269	3,043	6,000	2,245,950
3272	Glass & Glass Product	0.60508	2,015	4,151	287,908
3315	Foundries	0.39152	1,595	3,403	104,152
3252	Resin, Syn Rubber, & Artificial Syn Fibers & Filaments	0.35947	1,845	3,799	544,965
3273	Cement & Concrete Product	0.34890	1,688	2,996	236,878
3279	Other Nonmetallic Mineral Product	0.32072	755	1,352	82,074
3132	Fabric Mills	0.30503	857	1,299	
3328	Coating, Engraving, Heat Treating, & Allied Activities	0.29064	730	1,434	62,744
3261	Plastics Product	0.28636	9,552	19,369	1,369,277
3121	Beverage	0.23187	1,941	3,563	
3211	Sawmills & Wood Preservation	0.21894	1,743	3,387	173,367
3359	Other Electrical Equipment & Component	0.21885	1,237	2,283	256,187
3321	Forging & Stamping	0.21571	1,462	2,883	200,502
3262	Rubber Product	0.21049	1,161	2,209	130,931
3116	Animal Slaughtering & Processing	0.17398	8,233	17,208	1,126,612
3114	Fruit & Vegetable Preserving & Specialty Food	0.16088	3,214	6,478	466,909
3118	Bakeries & Tortilla	0.16008	4,018	6,983	740,444
3222	Converted Paper Product	0.15944	5,636	10,950	1,167,297
3344	Semiconductor & Other Electronic Component	0.15703	707	1,315	44,721
3326	Spring & Wire Product	0.14747	2,359	4,496	246,093
3363	Motor Vehicle Parts	0.14719	16,660	31,037	2,942,269
3259	Other Chemical Product & Preparation	0.14596	915	1,965	184,767
3231	Printing & Related Support Activities	0.14519	8,092	15,155	846,289
3327	Machine Shops, Turned Product, & Screw, Nut, & Bolt	0.14463	2,772	5,570	336,332
3329	Other Fabricated Metal Product	0.14187	2,699	4,948	456,340
3219	Other Wood Product	0.14074	5,764	10,705	413,340
3324	Boiler, Tank, & Shipping Container	0.13796	885	1,701	196,781
3336	Engine, Turbine, & Power Transmission Equipment	0.13598	1,209	2,138	127,183
3335	Metalworking Machinery	0.13253	1,331	2,250	139,843
3241	Petroleum & Coal Products	0.13014	740	1,456	
3371	Household & Institutional Furniture & Kitchen Cabinet	0.12103	1,597	2,765	
3115	Dairy Product	0.11755	1,531	3,136	321,496
3364	Aerospace Product & Parts	0.11584	1,257	2,322	420,386
3372	Office Furniture (Including Fixtures)	0.11478	1,017	2,017	
3399	Other Miscellaneous	0.10128	2,006	3,913	325,240
3352	Household Appliance	0.09877	1,576	2,858	
3339	Other General Purpose Machinery	0.09456	3,307	6,293	758,199
3119	Other Food	0.09371	1,570	2,906	579,615
3255	Paint, Coating, & Adhesive	0.09362	907	1,777	537,129
3366	Ship & Boat Building	0.09142	980	2,081	
3334	Ventilation, Heating, Ac, & Commercial Refrigeration	0.08948	2,071	3,765	376,925
3323	Architectural & Structural Metals	0.08879	3,402	6,355	436,994
3353	Electrical Equipment	0.08174	1,107	1,977	293,203
3331	Agriculture, Construction, & Mining Machinery	0.07432	1,407	2,201	209,643
3391	Medical Equipment & Supplies	0.07185	1,242	2,395	165,180
3362	Motor Vehicle Body & Trailer	0.06701	808	1,622	76,925
3256	Soap, Cleaning Compound, & Toilet Preparation	0.05454	957	2,136	442,283
3122	Tobacco	0.04605	593	1,095	
3361	Motor Vehicle	0.03654	11,384	22,724	

Figure 7: Kentucky Gross Domestic Product by Economic Sector, 2009 [4]

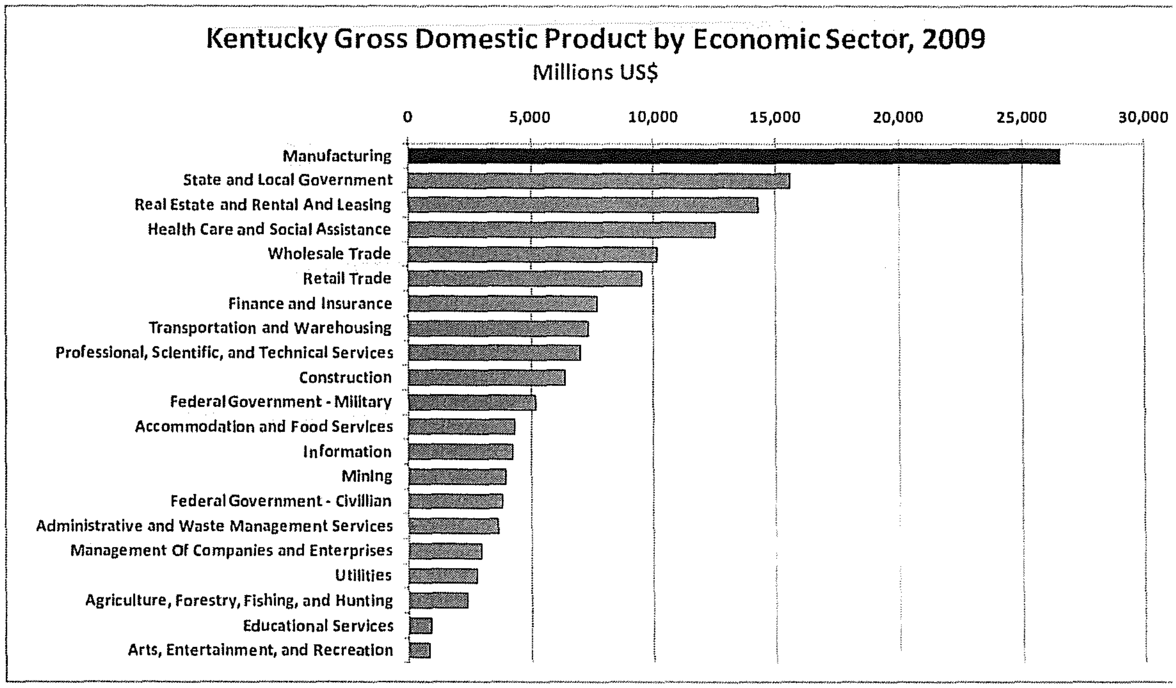
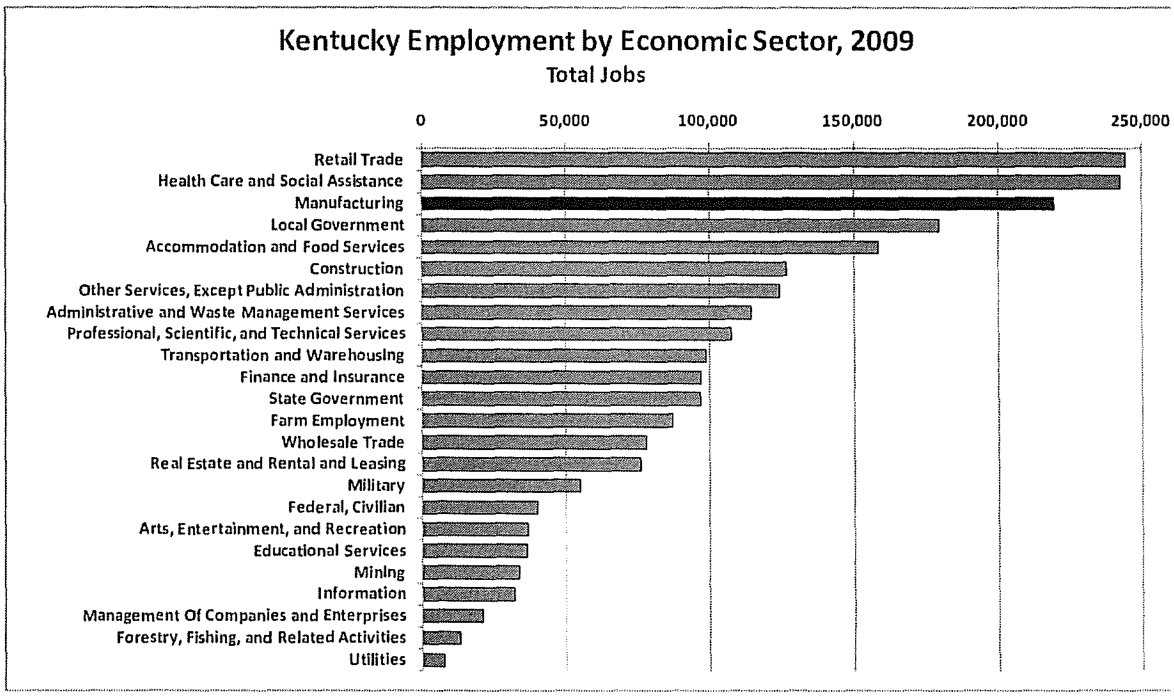


Figure 8: Kentucky Employment by Economic Sector, 2009



Kentucky's electricity-intensive manufacturing economy is threatened by increasing electricity prices. While the price of electricity is only one of several factors influencing industrial location decisions, Kentucky's historically low and stable electricity prices have fostered the most electricity-intensive economy in the United States. In the twenty-first century, the bulwark of the Kentucky economy is clearly manufactured goods—the Commonwealth's single largest source of economic activity. Even mid-recession, as illustrated in Figures 6 and 7 on page 5, manufacturing in Kentucky accounted for more than $26.6 billion in 2009, or 17% of State GDP, and directly employed 213,330 Kentuckians—2.5 times more than were employed as farmers and 11 times more than were employed as coal miners. In addition to being Kentucky's largest source of revenue and a leading source of employment, manufacturing is *sui generis*, fulfilling a unique economic function in that most goods are exported, bringing revenue to the Commonwealth from other economies. This is in contrast to the other top employment opportunities in Kentucky: retail services, health care, local government, food service, and construction, which principally depend upon local sources of revenue. Employment opportunities in manufacturing pay more than the two larger employment sectors, retail and hospitality. Large manufacturers, such as General Electric, Toyota, and Ford Motor in Kentucky, also have a more significant multiplier effect on a regional economy because they encourage suppliers to collocate with manufacturing facilities.[5]And this may well be the greatest significance of coal for the Commonwealth: not the number of persons employed in coal mining operations, nor the direct revenue generated from coal exports, *but rather the sheer size of the manufacturing industry that has located in Kentucky because of low energy costs.*

A variety of econometric studies[6,7] have been conducted to estimate the relationship between electricity prices and employment, also finding that increased electricity prices are associated with reductions in employment. However, none of these studies have taken into account the regional disparities in both the forecasted electricity price increases as well as distribution of electricity-intensive manufacturing as a percentage of total employment or state gross domestic product (GDP). Furthermore, none of these existing studies have specifically analyzed the impact of increasing prices on the most relevant employment sectors in the Commonwealth of Kentucky: manufacturing, retail, hospitality, healthcare and government.

A 2011 report prepared for the Kentucky state government found that increases in the price of electricity are associated with decreases in overall levels of employment. Specifically, the authors posit that a onetime increase of 25% in the price of electricity would reduce the long-run growth rate in total employment from an average of 3.0% to 2.49% per annum.[8] This current study builds upon the their work by using sector-specific employment as the dependent variable rather than total employment in all sectors to identify particular vulnerabilities within the Kentucky economy.

Beyond absolute price, the mere presence of price volatility may make it difficult for electricity-intensive manufacturing businesses to plan ahead and may also discourage capital investment in these engines of economic growth. Electricity price volatility could be included as an independent variable in future studies. For example, one could surmise that during a period of electricity price increases, companies would leave or not expand their existing operations, and this would not necessarily be recovered during periods of declining electricity prices.

Business Response Options to Increasing Electricity Prices

Faced with increasing electricity prices, energy-intensive businesses have the following response options.

1. Pass the price increase directly to consumers, in non-competitive markets.
2. Ignore the price increase and accept a reduction in profit margins.
3. Implement energy efficiency measures to lower total electricity consumption.
4. Substitute electricity with alternative energy sources, where available and competitively priced.
5. Seek government incentives or intervention.
6. Implement efficiency in other areas, including labor costs.
7. Relocate to an area where costs of production will be lower.
8. Close.

Option 1, passing the price increases directly to product end users, will only be a viable option if that industry has a captive or non-competitive market. If market competition is tight or if there are already lower-cost alternatives available to consumers, manufacturers may have limited room to increase prices. Electricity-intensive industries will not likely be able to choose option 2, since electricity expenditures are such a significant portion of their costs of doing business. In such cases, businesses have probably also already implemented energy efficiency measures, option 3, to increase profit margins. However, as much as possible, more efficient use of electricity is preferable under most conditions.

The use of energy substitutes, option 4, for energy-intensive industries in Kentucky may mean substituting direct natural gas combustion for electricity. However, natural gas price volatility, supply, and pipeline access may be prohibiting factors to large scale natural gas substitution.

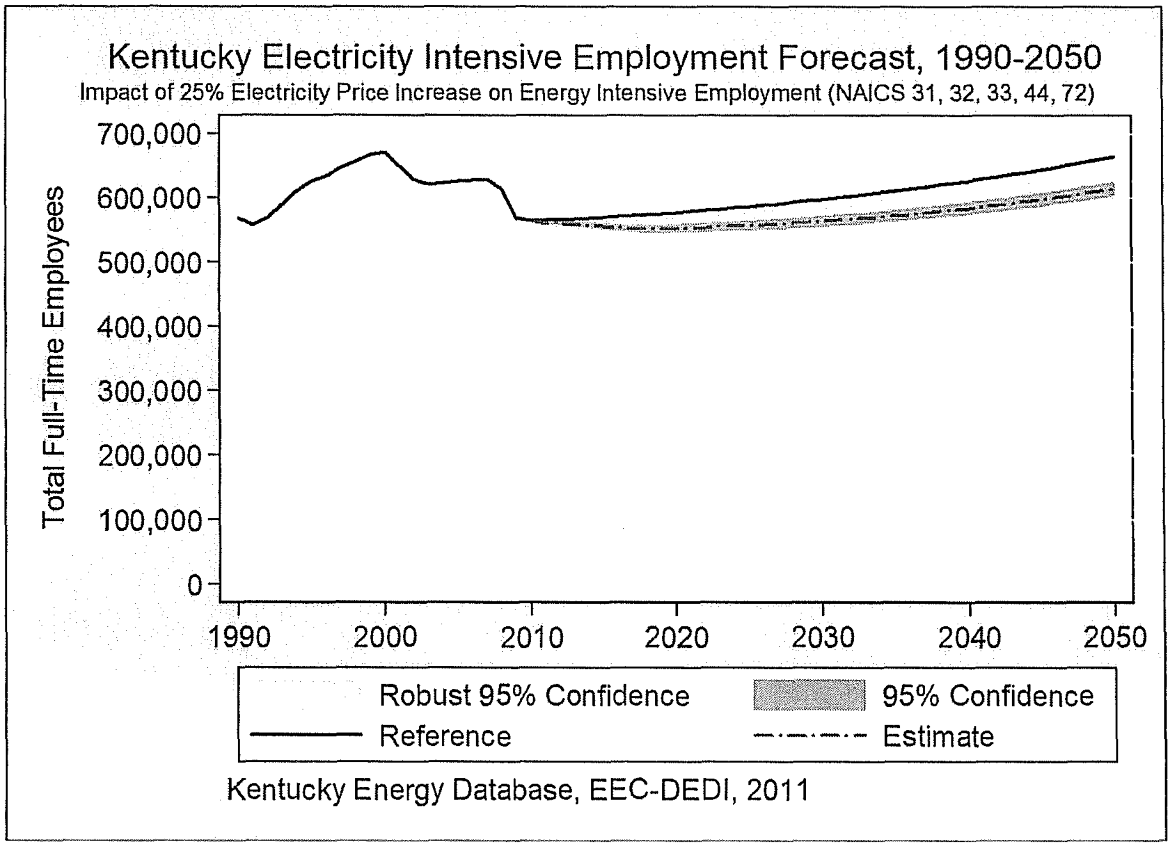
Businesses may also turn to government to either subsidize increasing electricity costs or offset them through taxpayer or ratepayer-funded incentives, option 5. Indeed, many other state governments already offer such incentives to electricity-intensive industries; however, in practice, the long-term affordability of such subsidies must be part of the government's evaluation criterion.

Whenever a business chooses options 6, 7, or 8, there should be a negative impact on total employment. Options 7 and 8 could be measured in total number of employees, whereas option 6 would be better measured using total labor hours or wage data.

Findings

This study builds upon the notion that low energy costs are a catalyst for commercial growth by quantifying the precise vulnerability of the largest economic sectors of the Commonwealth, in terms of total employment, to future electricity price increases. Using a statistical analysis technique called *multiple regression of panel data with fixed effects*, discussed in greater detail in the Statistical Appendix on pages 13 to 19, this study modeled the responsiveness of employment across the United States to changes in the price of electricity from 1990 to 2010 for the top five employment sectors in Kentucky: manufacturing, retail services, hospitality, healthcare, and government. *Elasticities* were developed for each of these economic sectors to calculate changes in employment, given a specific change in the price of electricity, and can be generally applied to the 48 contiguous United States.

Figure 9: Kentucky Electricity Intensive Employment Forecast, 1990-2050



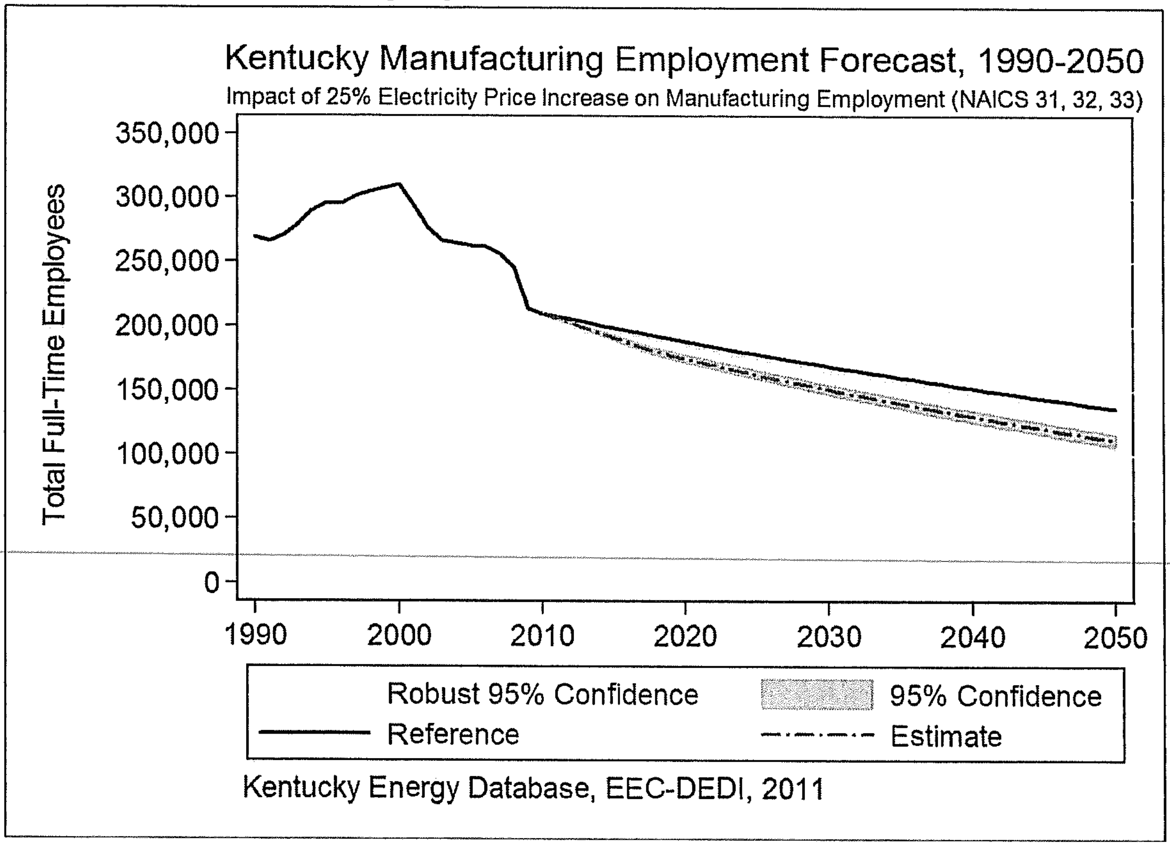
Given the potential cumulative increase of 25% in real electricity prices between 2011 and 2025, this multiple regression model estimates that Kentucky will likely lose, or fail to create, 30,000 full-time jobs long-term. Manufacturing establishments were the most vulnerable to electricity price increases and can be expected to permanently shed 17,500 full-time jobs. Evidence suggests that, once lost, similar manufacturing employment opportunities will never return. The relative extent of this finding is intuitive given that there are 12,685 jobs in the most-electricity intensive manufacturing sectors alone.

Retail stores, restaurants, and hotels were less than half as responsive as the manufacturing sector to increasing electricity prices, and combined, can be expected to fail to create 12,500 full-time jobs. However, in the fourth and fifth largest employment sectors, healthcare and government, no statistically significant relationship between electricity prices and total employment could be identified.

The employment forecast illustrated in Figure 9 above is an aggregation of each of the sector-specific forecasts for the energy-intensive sectors, manufacturing, retail, and hospitality (NAICS 31, 32, 33, 44, & 72). The estimated electricity-related job losses were subtracted from a reference forecast for each sector that simply extrapolated the 20-year average annual growth rate (AGR). The 95% confidence intervals, both with and without robust standard errors, are displayed in gray surrounding the single-point estimations. The delta between the estimate and reference case is the isolated effect of electricity price increases on employment.

Impact on Manufacturing Employment

Figure 10: Kentucky Manufacturing Employment Forecast, 1990-2050

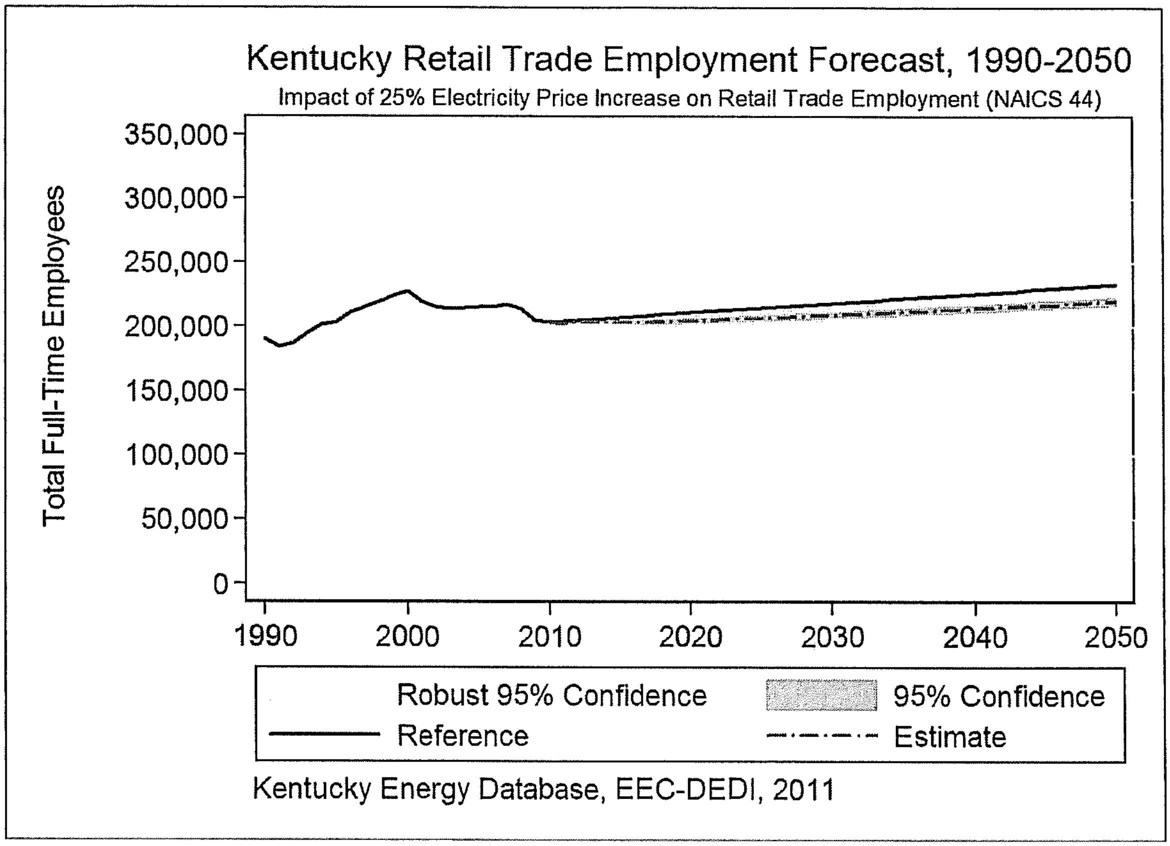


Of the sectors analyzed, manufacturing, Kentucky's largest economic sector, was the most-responsive sector to changes in electricity prices. Specifically, an increase of 10% in real electricity prices was associated with a reduction of 3.37% in absolute manufacturing employment, and with 95% confidence, between -2.77% and -3.97%. This finding was statistically significant below the 0.001 level. When using robust standard errors, however, the 95% confidence interval widened to between -0.83% and -5.92% and the significance level dropped to 0.01. Overall economic activity and time were also significant factors in predicting employment in the manufacturing sector; however, educational attainment as well as the total population levels were not. Time had a statistically significant negative coefficient, reflecting the general trend of contraction of manufacturing both in Kentucky and nationally. Given a 25% increase in real electricity prices by 2025, manufacturing establishments in Kentucky would be expected to permanently shed an additional 17,660 full-time jobs long-run as a direct result of price increases, and with 95% confidence using robust standard errors between 5,764 and 31,022 full-time jobs, *ceteris paribus*.

The manufacturing employment forecast, illustrated in Figure 10 above, was developed by applying the elasticities for the manufacturing sector to the electricity price forecast to estimate electricity price-related job losses, which were subtracted from a baseline forecast developed using the 20-year AGR of -1.16%, and then subtracting predicted historical electricity-related losses, for a net reference AGR of -1.07%.

Impact on Retail Trade Employment

Figure 11: Kentucky Retail Trade Employment Forecast, 1990-2050

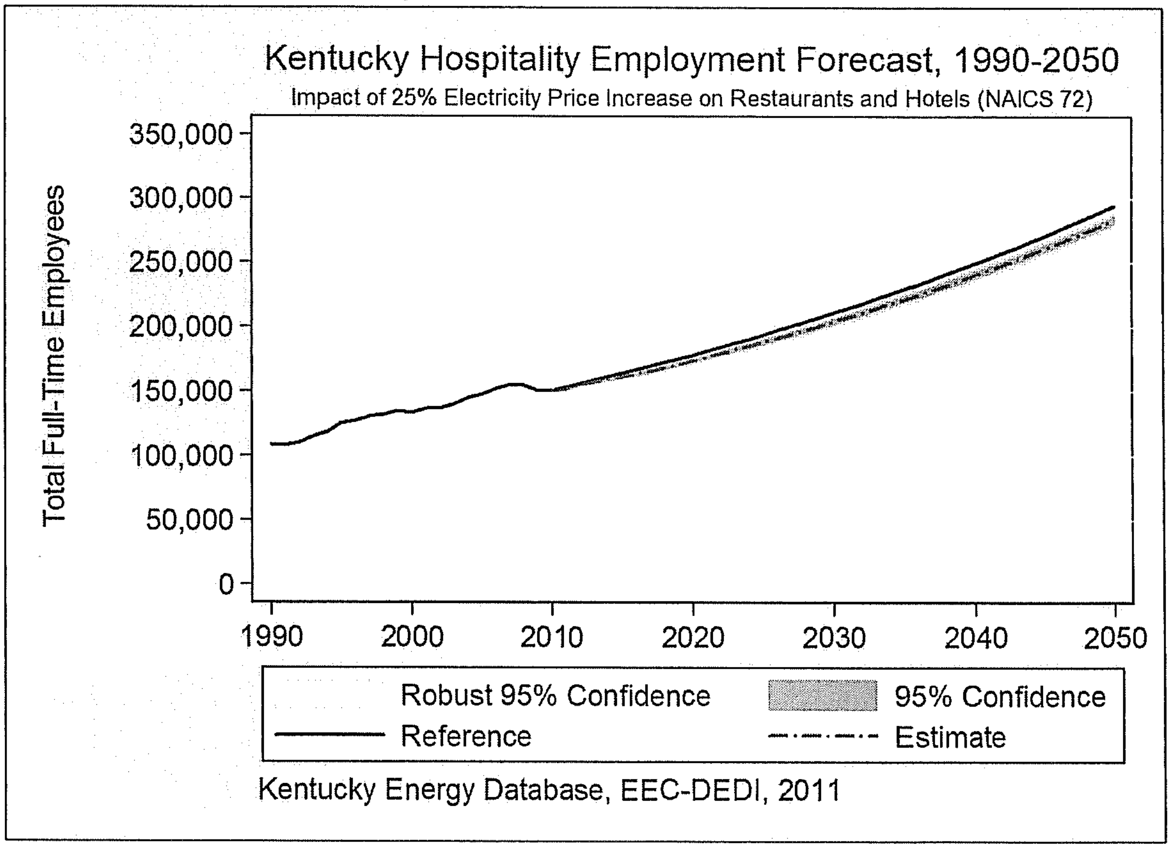


Retail trade, Kentucky's largest employment sector in terms of total employment, was less than half as responsive as the manufacturing sector to increasing electricity prices. Specifically, an increase of 10% in real electricity prices was associated with a reduction of 1.57% in total employment, and with 95% confidence between -1.30% and -1.84%. When using robust standard errors, however, the 95% confidence interval widened between -0.77% and -2.39%. These findings were statistically significant below the 0.001 level. Education was not a significant factor in determining retail employment; whereas economic activity and total population levels were. Given a 25% increase in real electricity prices by 2025, retail establishments in Kentucky would be expected to fail to create 7,225 full-time jobs long-run, and with 95% confidence using robust standard errors, between 3,916 and 12,160 full-time jobs, *ceteris paribus.*

The retail employment forecast, illustrated in Figure 11 above, was developed by applying the elasticities for the retail sector to the electricity price forecast to estimate electricity price-related job losses, which were subtracted from a baseline forecast developed using the 20-year AGR of 0.3584%, and then subtracting predicted historical electricity-related losses, for a net reference AGR of 0.3393%.

Impact on Hospitality Employment

Figure 12: Kentucky Hospitality Employment Forecast, 1990-2050



Employment in hospitality industries such as restaurants and hotels demonstrated a similar, but weaker, responsiveness as retail employment. Specifically, an increase of 10% in real electricity prices was associated with a reduction of 1.42% in total employment, and with 95% confidence between -1.12% and -1.71%. When using robust standard errors, however, the 95% confidence interval widened between -0.78% and -2.06%. This finding was statistically significant below the 0.001 level. Education and total population do not appear to be significant factors in determining hospitality sector employment; whereas economic activity and time were both significant. Given a 25% increase in real electricity prices by 2025, restaurants and hotels in Kentucky would be expected to shed 5,352 full-time jobs long-run, and with 95% confidence using robust standard errors, between 2,940 and 7,765 full-time jobs, *ceteris paribus*.

The retail employment forecast, illustrated in Figure 12 above, was developed by applying the elasticities for the retail sector to the electricity price forecast to estimate electricity price-related job losses, which were subtracted from a baseline forecast developed using the 20-year AGR of 1.6857%.

Impact on Healthcare Employment

Employment in the healthcare industry was much less sensitive to increases in electricity prices, and responsiveness was not statistically significant when using robust standard errors. Specifically, a 10% increase in the price of electricity appears to be associated with a 0.43% reduction in overall healthcare employment. However, with 95% confidence and robust standard errors, these effects are not necessarily distinguishable from zero. Healthcare employment was better predicted by educational attainment of the population, overall economic activity, total population levels, and time. Given that the independent variable of interest, real electricity prices, was not significant when using robust standard errors, no forecast for this sector was developed.

Impact on Government Employment

In government employment, no relationship between electricity prices and total employment could be identified, whereas educational attainment of the population, overall economic activity, and total population levels appeared to have statistically significant effects. Given that the independent variable of interest, real electricity prices, was not significant in any model, no forecast for this sector was developed.

Conclusion

This study demonstrated that electricity price increases alone may force businesses to seek ways to reduce costs or close, causing substantial job losses in Kentucky's electricity-intensive manufacturing sector, and slowing overall long-term job creation in other sectors. The timing of this transition could exacerbate high unemployment and slow economic growth in the near-term. The Commonwealth's vulnerability to these dynamics could also be worsened if leadership is unaware of them and inadequately prepared for the transition. Kentucky's neighboring states of Indiana, Ohio, and West Virginia exhibit similar vulnerabilities due to the potential for increasing electricity costs and the relative size of their manufacturing sectors.

While total employment in the Commonwealth is expected to continue to rise in other sectors, the Commonwealth should maintain focus on education and workforce development in emerging industries that are less reliant on energy-intensive manufacturing processes as well as consider strategies to mitigate vulnerability to price increases and risk exposure.

Data Analyzed

Total employment in Kentucky's top five economic sectors, in terms of number of employees as illustrated in Figure 8 on page 5, served as the dependent variables of interest in this study. Total employment by industry was collected from the Bureau of Economic Analysis (BEA) for all 51 entities and all years from 1990 to 2010. [9] Data was collected for each state as well as the District of Columbia, in each year, and for each industry, organized by North American Industry Classification System (NAICS) codes.

The primary explanatory variable of interest in this study was the natural logarithm of total real electricity price in each state and year expressed in 2010 US$ per kWh. Electricity prices are defined here as the quotient of the total revenue received by electric utilities in state *i* and in year *t* divided by the total kilowatt-hours of electricity sold in that state and year. Electricity *prices* differ from electricity *rates*, which are only a subset of the total cost and often do not include taxes, environmental surcharges, and fuel costs that vary substantially across time and geography. Thus, electricity prices more accurately reflect the cost for one kilowatt-hour of electricity paid by consumers in a given state and year. This variable was assembled using a variety of datasets from the Energy Information Administration (EIA), including data from the State Energy Data System (SEDS) for years 1990 to 2009 for all states,[10] and where certified data was not yet available using Form EIA-861[11] and Form EIA-826 for the year 2010.[12] The correlation between historical electricity prices derived from Form EIA-861 and EIA-826 to the corresponding certified variables was 0.999; thus, there is almost no difference between the historical data and the 2010 update other than it has not yet been certified and included in SEDS.

The following control variables were used: educational attainment, defined as the percentage of the adult population (age 25 years and older) with a bachelor's degree (or higher), collected from the United States Census American Community Survey; population, also collected from the United States Census; state Gross Domestic Product (GDP), collected from the BEA; and year. The following control variables were also tested but ultimately excluded because their effects were not statistically significant: labor force unionization, Standard & Poor's 500 Index, and per capita personal income.

There were a total of 51 states included (N=51), the 50 United States as well as the District of Columbia. However, the model's performance would have been improved by ~5% if the District of Columbia had been excluded. All currency variables, namely the price of electricity and State Gross Domestic Product, were adjusted for inflation to 2010 US$ using the Bureau of Labor Statistics (BLS) Consumer Price Index (CPI), which is intended to account for the generally rising cost of goods during this time period.

Analytical Method

Using a statistical analysis technique called *multiple regression of panel data with fixed effects*, this study modeled the responsiveness of employment across the United States to changes in the real price of electricity from 1990 to 2010 for the top five employment sectors in Kentucky: manufacturing (NAICS 31, 32, & 33), retail services (NAICS 44), hospitality (NAICS 72), healthcare (NAICS 62), and government (NAICS 92). Elasticities were developed for each sector to calculate changes in employment given a specific change in the electricity prices and can be generally applied to any state and year.

To develop these elasticity coefficients, data were organized into a multidimensional panel, i.e. both time series and cross sectional, enabling simultaneous modeling of the relationships of multiple statistics across both space and time (N x t). Since each observation is non-random, and not independent, for example electricity prices in state i and year t are not independent of prices in state i in year t-1, a fixed effects model was used, which builds upon Ordinary Least Squares (OLS) regression by isolating the time-independent constant difference between states that is correlated with the explanatory variables. Two multiple regression of panel data models with fixed effects, both with and without robust standard errors, were constructed for each of the top five employment sectors in Kentucky, for a total of 10 separate multiple regression models.

The multiple regression of panel data model with fixed effects can be generally given by,

$$Y_{it} = \beta_0 + \sum_{j=1}^{k-1} \beta_j X_{jit} + \alpha_i + \varepsilon_{it}$$

Where i and t index states and years, such that y_{it} is the dependent variable of interest, employment by industry, in state i in year t, β_0 is the constant y intercept across all states, X is a k by 1 vector of explanatory variables, $\beta_j X_{jit}$ is the product of the observation for each independent variable j through k for state i in year t and the coefficient of X, k is the total number of included independent variables, α_i is the time-invariant fixed effect for state i, and ε_{it} are the residuals, and where $\varepsilon_{it} \sim N(0, \sigma^2)$, or are approximately normally distributed with a mean of zero.

Multiple regression of panel data using fixed effects facilitated controlling for the numerous factors inherently affecting sector-specific employment as well as electricity prices from state to state that have not been accounted for in the independent variables included in this study to isolate the primary national effect of the variable of interest, real electricity prices, on each of the dependent variables, employment by industry. Since this study aims to isolate the unique effect of electricity prices on employment, the model was rerun five times to derive the coefficient for each of the industries of interest by NAICS code.

A fixed effects model specifically assumes the existence of unobserved time-invariant heterogeneity, often referred to as unobserved variable bias, which in addition to the included independent variables, is affecting the dependent variable. The fixed effects model will attempt to control for these missing or unobserved between unit (interstate) factors, the fixed effects, to isolate the specific net effect of the independent variables of interest on all units (nationally). The fixed effects model also assumes that these between-unit effects are both time invariant and correlated with the independent variables. A fixed effect model is also functionally, although not computationally, equivalent to assigning an independent indicator variable, or dummy variable (0 or 1), for each state, to isolate the specific effect for each state without having to create the 51 additional independent variables.

The Hausman test, which is often used in econometrics to determine the appropriateness of a fixed effect versus a random effect model, is not required here because this study is modeling the entire population of states (*N*), thus necessitating a fixed effects model and obviating a random effects model. A random effect model is only suitable to model the sample (*n*) of the population that has been selected at random.

Table 2 on page 16 shows the multiple regression models with fixed effects estimated for each of the top five employment sectors. These five models were subsequently rerun using robust standard errors in order to prevent biased estimation that could be caused by the presence of outliers in manufacturing employment, such as the District of Columbia, as well as the presence of the residual heteroscedasticity as identified by the Breusch–Pagan post estimation test. Robust standard errors were calculated using the Huber-White sandwich estimator.[13] The resulting five multiple regression models with fixed effects and robust standard errors are shown in Table 3 on page 17. However, using robust standard errors had little impact on the relationships of interest; the effect of electricity prices on manufacturing employment remained significant with a p-value of 0.010.

Prior to analysis, all variables were converted to their natural logarithms such that the estimated coefficients for each may be simply interpreted as elasticities, which measure the percentage change in the dependent variable given a percentage change in one of the independent variables. For electricity prices specifically, the independent variable of interest in this study, the coefficients summarized in the first row of Tables 2 and 3 are the estimated electricity price elasticity of employment for each specific economic sector, which is the expected percentage change in employment given a percentage change in the price of electricity, *ceteris paribus*, or holding all other included independent variables constant.

Since these elasticities were derived through regression of national historical data, they may be generally applied to any state and year and to the United States as a whole for each respective economic sector. The only difficult math in this process is in the development of the elasticity coefficients themselves. Therefore, assuming a reliable electricity price forecast has already been developed, the long-term change in employment in a given sector for other states and for different changes in the price of electricity can be calculated by simply multiplying the number of employees in that sector currently by the forecasted percentage change in real electricity prices, i.e. inflation adjusted, multiplied by the specified elasticity coefficient for that sector. For example, given that there were 209,609 employees in all manufacturing sectors in Kentucky in 2010, and assuming real electricity prices increased by 25%, and given that the electricity price elasticity of manufacturing employment calculated here is 0.337, then the estimated long-term job losses resulting from the increase in electricity prices would 17,660, as illustrated below.

	209,609	*Number of Employees in NAICS Sectors 31, 32, & 33*
x	0.25	*% Change in Electricity Price*
x	0.337	*Sector-Specific Elasticity Coefficient*
=	17,660	*Resulting Long-Term Job Losses*

The employment forecasts illustrated in Figures 12 through 21 on the following pages were produced by integrating the elasticities developed in this study into the Kentucky Electricity Portfolio Model. This facilitated creating dynamic employment forecasts for different electricity price scenarios that were responsive to the forecasted change in real prices in each future year. No lags have been assumed.

Table 2: Model of Electricity Prices & Employment by Economic Sector

Logged Variables	Manufacturing Employment		Retail Employment		Food & Accommodation Employment		Healthcare Employment		Government Employment	
Price of Electricity (Real 2010 US$)	-0.337	***	-0.158	***	-0.142	***	-0.0426	**	0.00084	
	(-0.0307)		(-0.0136)		(-0.0152)		(-0.0158)		(-0.0101)	
Educational Attainment	0.0249		-0.108		-0.0679		-0.536	***	-0.14	**
	(-0.146)		(-0.065)		(-0.0728)		(-0.0758)		(-0.0482)	
State GDP (Real 2010 US$)	0.744	***	0.509	***	0.318	***	0.17	***	0.253	***
	(-0.0514)		(-0.0228)		(-0.0255)		(-0.0265)		(-0.0169)	
Population	0.166	**	0.26	***	0.129	***	0.37	***	0.258	***
	(-0.0532)		(-0.0236)		(-0.0264)		(-0.0275)		(-0.0175)	
Year	-76.05	***	-11.31	***	21.11	***	55.21	***	3.801	*
	(-5.536)		(-2.457)		(-2.752)		(-2.861)		(-1.819)	
Constant	579.4	**	88.85	***	-153.9	***	-413.5	***	-22.72	
	(-41.38)		(-18.36)		(-20.57)		(-21.39)		(-13.6)	
R-Squared	0.7776		0.956		0.9219		0.8885		0.9344	
Observations (*N x t*)	1069		1071		1069		1071		1071	
Number of States (*N*)	51		51		51		51		51	

Standard Errors in Parentheses
Asterisk Denotes Statistical Significance at the Following Levels: * p<0.05, ** p<0.01, *** p<0.001
All Variables Transformed into their Natural Logarithms

Table 3: Model of Electricity Prices & Employment by Economic Sector With Robust Standard Errors

Logged Variables	Manufacturing Employment		Retail Employment		Food & Accommodation Employment		Healthcare Employment		Government Employment	
Price of Electricity (Real 2010 US$)	-0.337	*	-0.158	***	-0.142	***	-0.0426		0.00084	
	(-0.127)		(-0.0404)		(-0.032)		(-0.0377)		(-0.0285)	
Educational Attainment	0.0249		-0.108		-0.0679		-0.536		-0.14	
	(-0.598)		(-0.23)		(-0.216)		(-0.345)		(-0.155)	
State GDP (Real 2010 US$)	0.744	***	0.509	***	0.318	***	0.17		0.253	***
	(-0.141)		(-0.115)		(-0.0789)		(-0.0939)		(-0.0719)	
Population	0.166		0.26		0.129		0.37	*	0.258	*
	(-0.19)		(-0.134)		(-0.0835)		(-0.155)		(-0.124)	
Year	-76.05	**	-11.31		21.11	*	55.21	***	3.801	
	(-22.38)		(-10.79)		(-9.212)		(-14.23)		(-5.988)	
Constant	579.4	**	88.85		-153.9	*	-413.5	***	-22.72	
	(-166.9)		(-80.3)		(-68.98)		(-106.3)		(-44.06)	
R-Squared	0.7776		0.956		0.9219		0.8885		0.9344	
Observations ($N x t$)	1069		1071		1069		1071		1071	
Number of States (N)	51		51		51		51		51	

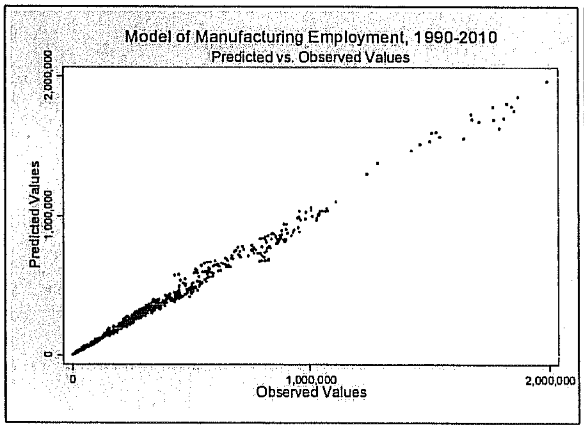
Robust Standard Errors in Parentheses
Asterisk Denotes Statistical Significance at the Following Levels: * $p<0.05$, ** $p<0.01$, *** $p<0.001$
All Variables Transformed into their Natural Logarithms.

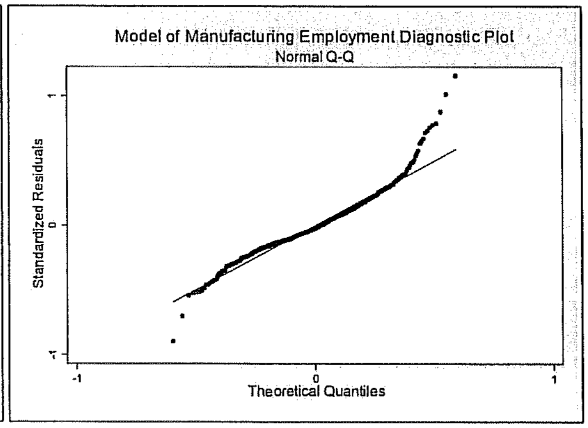
Model Diagnostic Plots

For each economic sector below, the diagnostic plot on the left shows the model's predicted employment versus employment that was actually observed in that state and year, such that all deviations from a perfect line illustrate model error (ε_{it}). The predicted values in all graphics include not only the homogenous, i.e. national, model components, including the constant (β_0) and the product of each variable j to k and the coefficient of each ($\beta_j X_{jit}$), but also the time-invariant interstate fixed effect (α_i) in the response variable, employment, estimated for each state.

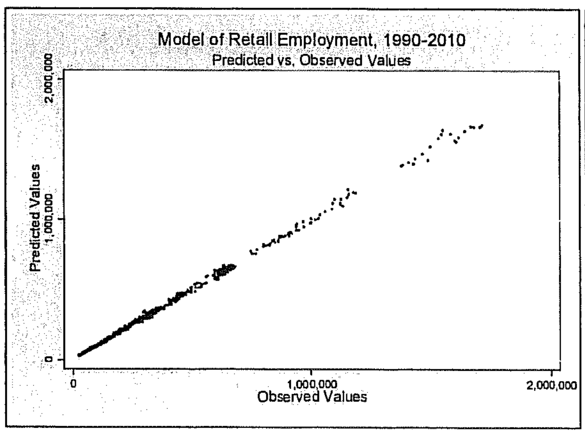
The Q-Q plot on the right illustrates the standardized residuals of the model for each economic sector versus their normal theoretical quantiles and are intended to demonstrate that the residuals are approximately normally distributed with a mean of zero, such that $\varepsilon_{it} \sim N(0, \sigma^2)$.

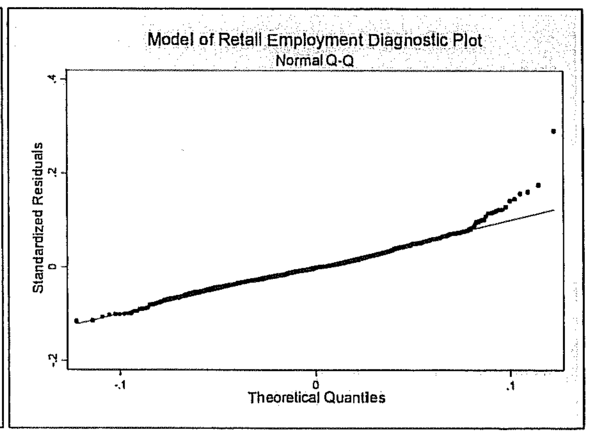
Figures 13 & 14: Model of Manufacturing Employment Diagnostic Plots



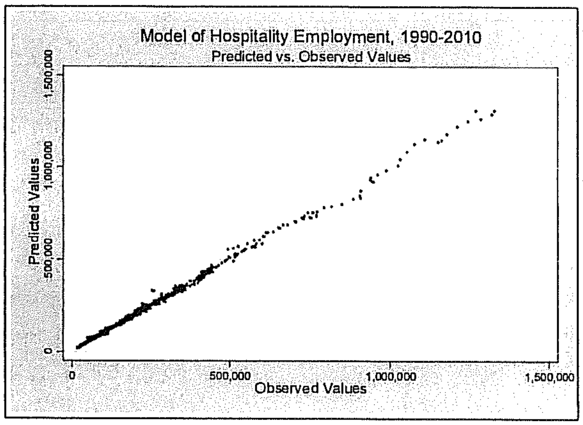


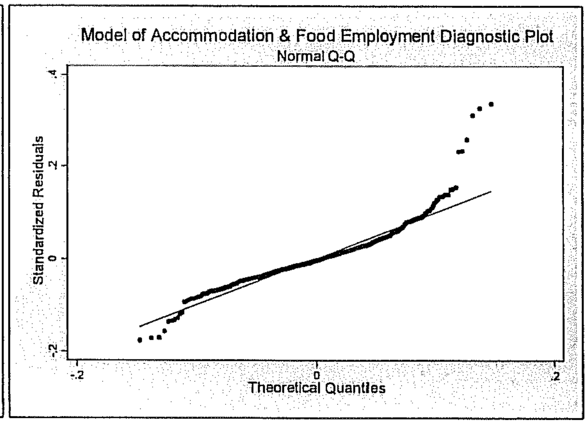
Figures 15 & 16: Model of Retail Employment Diagnostic Plots



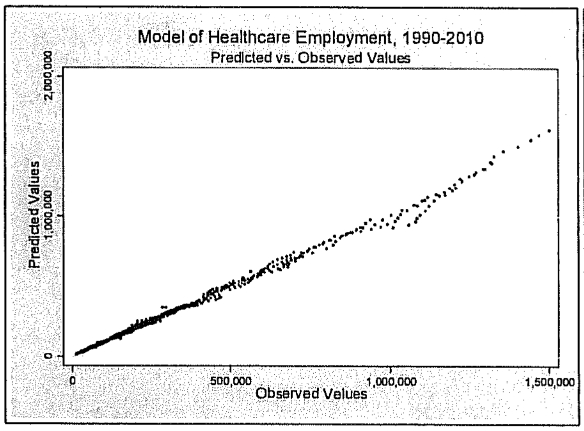


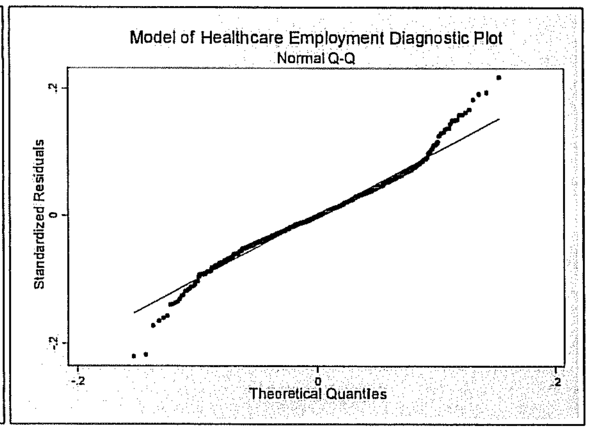
Figures 17 & 18: Model of Food & Accommodation Employment Diagnostic Plots



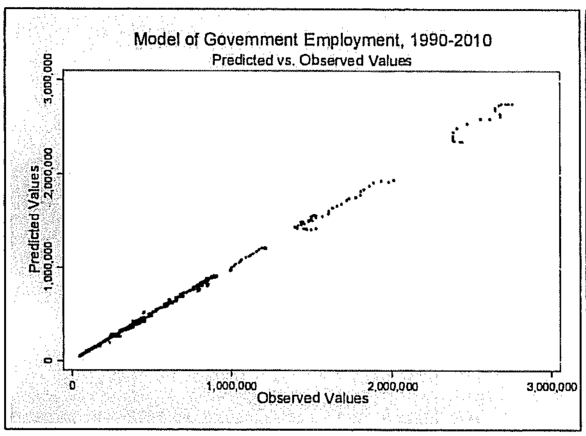


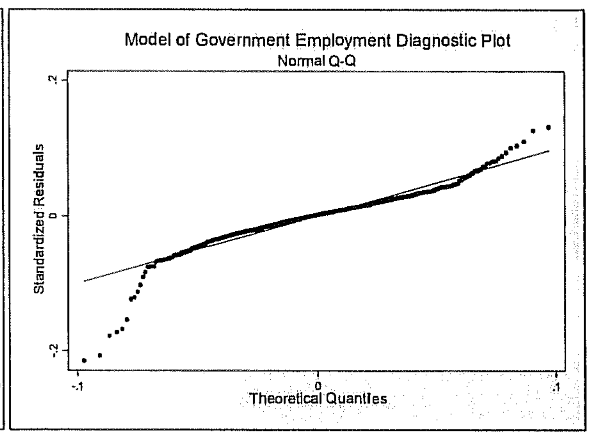
Figures 19 & 20: Healthcare Employment Diagnostic Plots





Figures 21 & 22: Model of Government Employment Diagnostic Plots





Acknowledgments

The Kentucky Energy and Environment Cabinet Department for Energy Development and Independence would like to recognize the following individuals for their numerous contributions to this research or paper: Bob Amato, Dr. Arne Bathke, John Davies, Dr. John Garen, Tim Hughes, Dr. Christopher Jepsen, Yang Luo, Dr. Talina Mathews, Bob Patrick, Dr. Len Peters, Joel Perry, Dr. John Rogness, Edward Roualdes, Dr. Jim Saunoris, Kate Shanks, Michael Skapes, Dr. Stephen Voss, Alan Waddell, Shaoceng Wei, Karen Wilson, and Zhiheng Xie.

References

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[1] U.S. Bureau of Labor Statistics Consumer Price Index, 2011. http://www.bls.gov/cpi/

[2] United States Bureau of Economic Analysis, GDP and Total Employment by Industry. http://bea.gov/regional/index.htm

[3] Electricity intensity data was calculated by dividing total electricity consumption for each NAICS sector by the total value of shipments that sector as collected in the U.S. Census Annual Survey of Manufacturers.

[4] Chart data derived from the United States Bureau of Economic Analysis, GDP and Total Employment by Industry. http://bea.gov/regional/index.htm

[5] Bae, Sohu. "The Responses of Manufacturing Business to Geographical Difference in Electricity Prices," *The Annals of Regional Science*, San Francisco State University, March 11, 2008.

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[12] U.S. Form EIA-826, 2010. www.eia.gov/cneaf/electricity/page/eia826.html

[13] White, Halbert. *Asymptotic Theory for Econometricians*, 1984.

City Council Votes To Purchase New Power Contract With Big Rivers

Posted: 18 December, 2013

WAYNE (KTCH/KCTY) - The Wayne City Council met for its regular meeting Tuesday night and voted to give a five-year notice to Nebraska Public Power District (NPPD) on Intent to Reduce the City's Contract Power Purchase.

The City of Wayne is halfway through a 20-year power purchasing contract with NPPD, and was informed at the beginning of this year that they would need to sign a new 20-year contract by Dec. 31, 2013 at a 68 percent increased rate from the first half of the contract. This notice from NPPD caused the city to pursue other options for power.

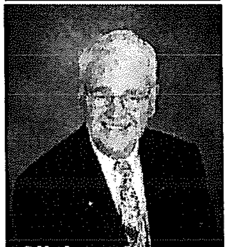
A five-year notice to NPPD will reduce rates for the City of Wayne to 10 percent by 2019, and continue at that level until the contract ends in 2022.

The City Council voted to accept an offer to purchase bulk power from Big Rivers Electric Corporation of Kentucky. The new purchase agreement will supplement the District's existing bulk power purchases from NPPD through 2021 and then provide power to meet all the District's needs through 2027. The contract with Big Rivers will supply power to Wayne for 10 years at a rate 13 percent below the rate of NPPD.

The City Council also voted to accept proposal and award contract to Advanced Gaming Technologies to operate Keno-type lottery within the City of Wayne, which will be used at Ken Jorgensen's new restaurant establishment when it opens.

In other business, the council approved the application of Gander Foods, LLC, doing business as Godfather's Pizza, for a Retail Class CK Liquor License, and Mayor Ken Chamberlain introduced Jason Sears as the new police sergeant. Lauran Lofgren, library director, also presented the 2013 PLTS Advocacy Award to Charlene Rasmussen. The Advocacy Award is given by the Nebraska Library Association.

The next City Council meeting will be held on Tuesday, Jan. 7.



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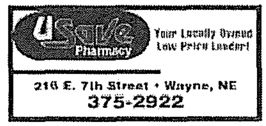
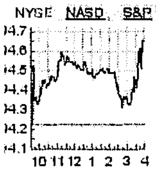
DENIED Admittance



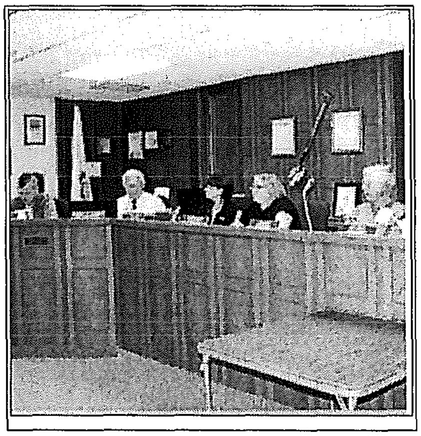


ARCHIVES > NEWS

Electric power highlights council agenda

By CLARA OSTEN
Of the Herald

Published:
Tuesday, December 24, 2013 11:16 AM CST



Facing deadlines of Dec. 31, the Wayne City Council debated how, when and where to purchase electricity for the city of Wayne in coming years.

Early this year the city received notice from Nebraska Public Power (NPPD) that the city would be asked to sign a new 25-year contract with NPPD, even though the city's current contract with NPPD will not expire until 2022.

At that time the city organized a group with Northeast Nebraska Public Power, Wakefield, Emerson and South Sioux City hired a rate consultant to explore options available to electric customers.

A number of proposals were obtained and the group selected Big Rivers Energy Cooperative as th lost cost proposal. Big Rivers has offered to enter into a 10-year contract with the city to provide power at a rate 13 percent below whatever the NPPD rate is for the duration of the contract.

At Tuesday's meeting, the council voted to give notice to NPPD on its intent to reduce its contract power purchases by 90 percent, beginning in 2019. The city will continue to be an NPPD contract customer at 10 percent until the end of the current contract in 2022.

Discussion from council members centered on NPPD's contract with the city on the capacity lease agreement for the Wayne power plant.

Amy Miller, attorney for the city, explained several things that could happen when the city sends NPPD its notice to reduce the amount of power it intends to purchase, including the termination of the contract for use of the power plant and the $640,000 per year the city receives from this lease. She noted that if NPPD choses to stop making the lease payments, the city could sue NPPD, although litigation could take several months to be completed.

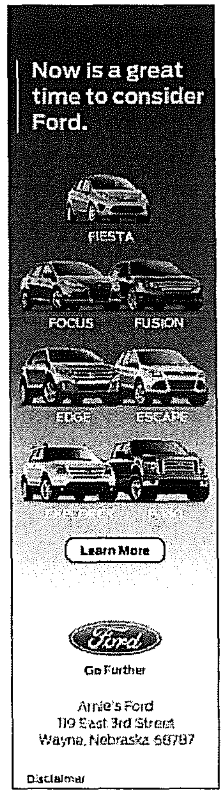
Following the city's vote to give NPPD notice of intent to reduce it contract power purchases, council members debated the best course of action for purchase of power.

Options included purchasing power on the open market at a variable (and unknown) rate, or entering into a 10-year contract with Big Rivers at a set rate. Both options have a break even date when the city will realize substantial savings on electric power.

After debate, council members voted to enter into an agreement with Big Rivers before Dec. 31, 2013 to ensure the 13 percent savings compared to NPPD rates.

In other action, the council approved a resolution which will make the findings and declaring portions of the city of Wayne to be blighted and substandard. The area affected is in the North Central Redevelopment Area.

Council members voted to table the third and final reading of an ordinance that would allow for the annexation of land northeast of the current city limits.



Discussion centered on what the boundaries of the annexed area would be and the benefits to potential developers to be within the city limits or to be outside city limits.

The council will next meet in regular session on Tuesday, Jan. 7 at 5:30 p.m. in council chambers.

« Previous Article
Corbin to headline 2014 Wayne County Fair

Article Rating

Current Rating: 0 of 0 votes! **Rate File:** Select Rating

Reader Comments

The following are comments from the readers. In no way do they represent the view of mywaynenews.com.

concerned resident wrote on Dec 18, 2013 12:04 PM:
" There are members of the city council and City of Wayne always preaching for residents to shop local. Maybe they should practice what they preach. "

concerned wrote on Dec 18, 2013 5:00 PM:
" The power rates have been ridiculous. And for some reason we are still paying for the ice storm that happened in 2006 in southern Nebraska. And im sure with all the down poles south of town from the tornado that we will have to start paying for that as well. Look at your electric bill. They charge an additional 8 to 20 dolars on it. I think it is terrible that I have to pay over 200 dolars a month for electricity. I am glad the city decided to go with another provider and a shorter contract. open your eyes. "

concerned resident wrote on Dec 19, 2013 7:00 AM:
" Do you really think that just because you changed companies that Big River Energy in Kentucky is going to come and put up poles from storms that occur and they will do it for free? If that is the case I am all for it. You need to open your eyes if you think that is true. When the tornado happened NPPD was right there putting in countless hours putting up poles. You will be waiting a long time for them to get here from Kentucky. In my opinion cheaper is not always the best answer, you have to consider the service you receive. Bad decision all the way around. I guess I can start shopping out of town, save money at the same time and not feel guilty because it did not bother our city to shop elsewhere. "

concerned wrote on Dec 19, 2013 12:55 PM:
" I will agree that they were right there putting up poles after the tornado right away for countless hours. KUDOS. But why do I have to pay for mother natures incidents? I have insurance on all my stuff for these type of events! And they want the city to enter into 25 year contracts!?! I give the city KUDOS for no entering into a long contract With all the new developments of energy there is going to be something that will cost less and produce the same in the years to come. All NPPD was looking to do is hook the city for the next 25 years, Like they already have been. The average wage in wayne is like $10 to $12 dollars. you can not expect people to afford energy that we currently pay on them wages. "

concerned resident wrote on Dec 19, 2013 1:36 PM:
" The wages that are paid in Wayne are slightly above poverty and it is a go nowhere place. You would never know people in Wayne are having trouble paying their electricity like yourself by listening to the Wayne Works ad on KTCH. I guess that is expected because they are only interviewing Insurance agents, College employees, PMC employees and not the $10 to $12 per hour people. Obviously you did not have to use your insurance for any tornado damage or you would have found out how bad your insurance coverage really was. Insurance is a form of legalized stealing. We all pay for mother nature incidents whether the disaster is in Wayne or somewhere else in the United States. If you are so concerned about electricity being so expensive maybe you should look at your City water bill and maybe we should look to get that service somewhere else because all they are doing is hooking residents of Wayne. "

concerned wrote on Dec 19, 2013 9:36 PM:
" All of our utilities are high agreed. But thus story was about electricty. I did have to use my insurance for tornado damages. And now I have to find a way to save a $1000 to cover deductible. I will end this whole thread by saying do what u have to survive. Its not getting any easier out there. I have small children and have to save were I can. So the moral of this is I am open to buying power elsewere I will flat out tell you I hardy buy stuff in wayne because wayne businuess' s are too greedy and high on prices. I am a prooerty tax payer in wayne and I have expressed concerns on how they are using our tax dollars. Everyone has there opinions. You want to waste your money than go right ahead. I know that I want my kids better off than we are right now in this country. "

Anonymous wrote on Dec 20, 2013 11:36 AM:
" The way I read it, NPPD is still our transmission source for the power, no matter where it comes from. They are still responsible for helping maintain poles and replacing them in storm situtations. in fact, most entities have agreements in place to help each other out in the event of a storm, regardless of who you are a customer of. "

Dave Haney wrote on Dec 20, 2013 9:42 PM:
" buying power at a cheaper rate is good but will the rate payers benefit or just the power company???.NPPD will still benefit because they do charge other power companys too send power over there transmission lines.i suppose it will be a wait and see situation. "

Submit a Comment

We encourage your feedback and dialog, all comments will be reviewed by our Web staff before appearing on the Web site.

Name:

Email:

Comments:

Image Verification: (Case sensitive)

ORG GROUPS

MEMBER & CUSTOMER SUPPORT

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View SPP's TARIFF

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Special Meeting of Members Teleconference Minutes 9/8/08 (328.6 KB/pdf)

Special Meeting of Members Teleconference Background 9/8/08 (457.7 KB/pdf)

more ››

Members

Visit the Member and Customer Support page for more information.

Balancing Authority/Control Area within SPP
^ Transmission Owner
* Transmission Using Member
@ Transmission Owning Member

Terms defined in Tariff and Bylaws.

Cooperatives
- Arkansas Electric Cooperative Corporation *
- East Texas Electric Cooperative, Inc. * ^
- Golden Spread Electric Cooperative, Inc. *
- Kansas Electric Power Cooperative, Inc. *
- Lea County Electric Cooperative, Inc. * ^
- Mid-Kansas Electric Company, LLC @ ^
- Midwest Energy, Inc. @ ^
- Northeast Texas Electric Cooperative, Inc. *
- Rayburn Country Electric Cooperative *
- Sunflower Electric Power Corporation @ # ^
- Tex-La Cooperative of Texas, Inc. * ^
- Tri-County Electric Cooperative, Inc. * ^
- Western Farmers Electric Cooperative @ # ^

Independent Power Producers
- Acciona Wind Energy USA, LLC *
- Calpine Energy Services, L.P. *
- Cielo Wind Services, Inc. *
- CPV Renewable Energy Company, LLC *
- Dogwood Energy, LLC *
- EDP Renewables North America LLC *
- Enel Green Power North America, Inc. *
- Entergy Asset Management *
- Flat Ridge 2 Wind Energy, LLC *
- NextEra Energy Resources, LLC *
- Tenaska Power Services Co. *

Independent Transmission Companies
- Duke-American Transmission Company, LLC *
- Grain Belt Express Clean Line LLC *
- Hunt Transmission Services, LLC *
- ITC Great Plains, LLC * ^
- NextEra Energy Transmission, LLC *
- Plains and Eastern Clean Line LLC *
- Prairie Wind Transmission, LLC *
- Trans-Elect Development Company, LLC *
- Transource Energy, LLC *

Investor-Owned
- American Electric Power
  - AEP Oklahoma Transmission Company, Inc. * ^
  - AEP Southwestern Transmission Company, Inc. *
  - Public Service Company of Oklahoma @ ^
  - Southwestern Electric Power Company @ ^
- Cleco Power, LLC * #
- Empire District Electric Company @ # ^
- Entergy Services, Inc. *
- Exelon Generation Company, LLC *
- Kansas City Power & Light Company @ # ^
  - KCP&L Greater Missouri Operations Company @ # ^
- Oklahoma Gas and Electric Company @ # ^
- Westar Energy, Inc. @ # ^
  - Kansas Gas and Electric Company @ ^
- Xcel Energy
  - Southwestern Public Service Company @ # ^

Marketers
- Cargill Power Markets LLC *
- DTE Energy Trading, Inc. *
- Duke Energy Transmission Holding Company, LLC *
- Dynegy Power Marketing, Inc. *
- Edison Mission Marketing & Trading, Inc. *
- El Paso Merchant Energy, L.P. *
- Luminant Energy Company, LLC *
- Noble Americas Gas & Power Corp *
- NRG Power Marketing, Inc *
- Shell Energy North America (US), L.P. *
- Williams Power Company, Inc. *
- XO Energy SW, LP *

Municipals

Board of Public Utilities of Kansas City, Kansas * #
City of Coffeyville * ^
City of Independence, Missouri * #
City Utilities of Springfield * # ^
Clarksdale Public Utilities Commission *
Kansas Municipal Energy Agency *
Kansas Power Pool (KPP) * ^
Lafayette Utilities System * #
Lincoln Electric System * # ^
Oklahoma Municipal Power Authority * ^
Public Service Commission of Yazoo City *

State Agencies

Grand River Dam Authority @ # ^
Louisiana Energy and Power Authority * #
Nebraska Public Power District @ # ^
Omaha Public Power District @ # ^

SPP Contract Participants

Southwestern Power Administration # ^

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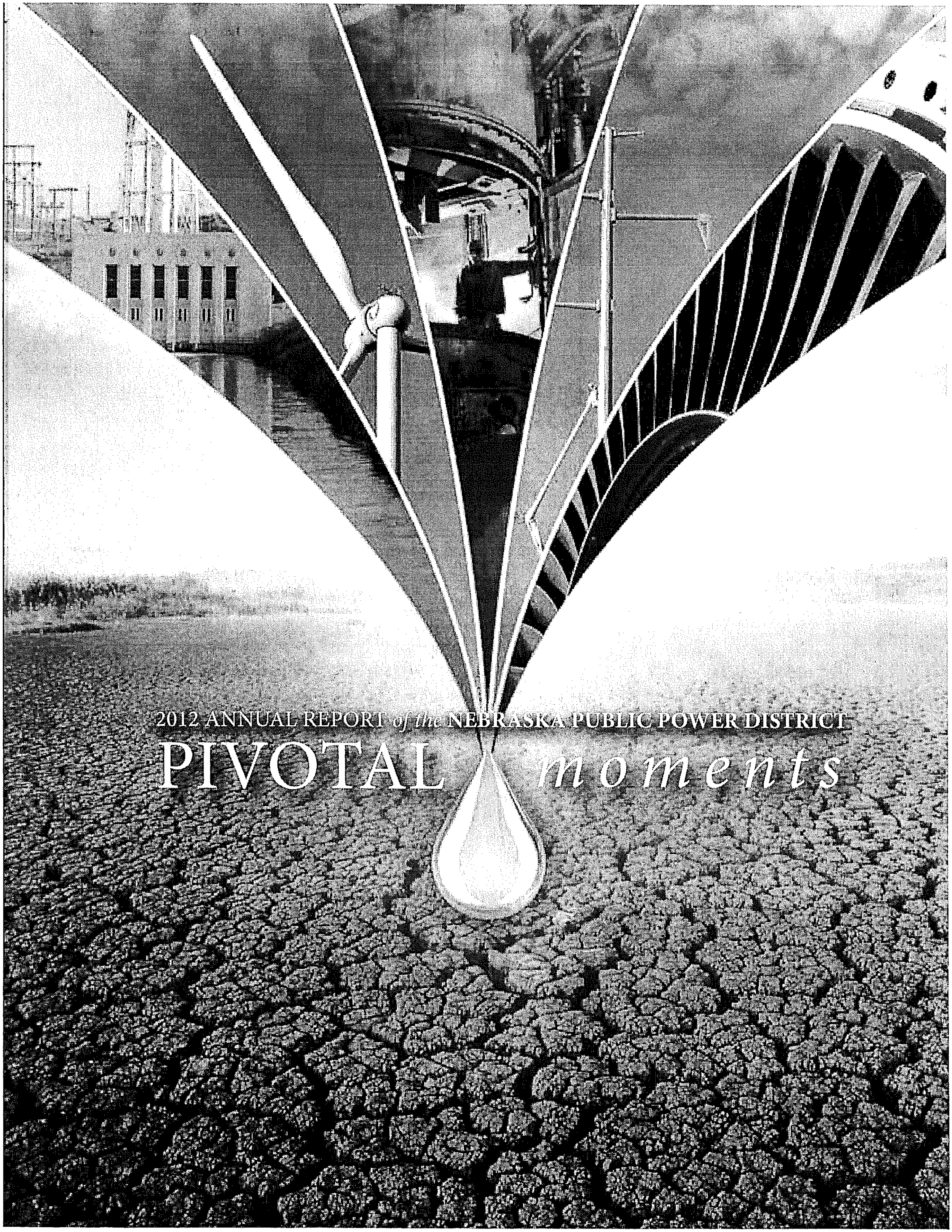
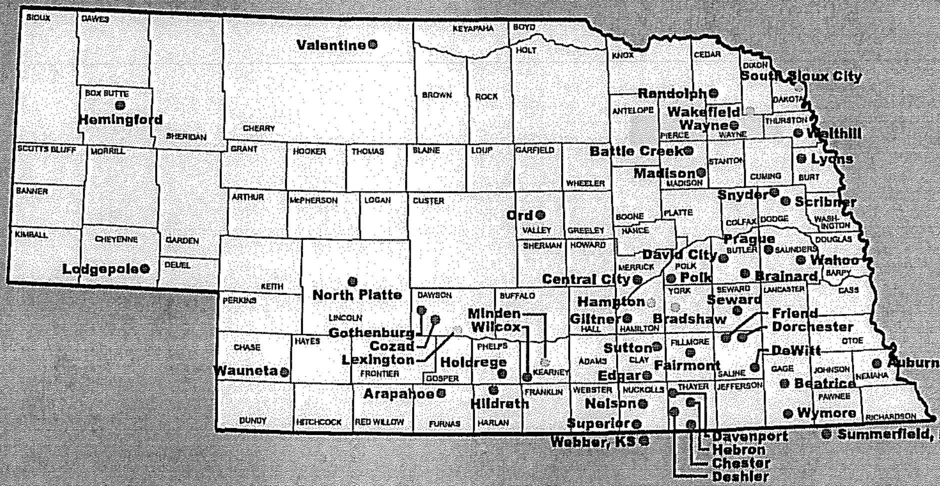


2012 ANNUAL REPORT *of the* NEBRASKA PUBLIC POWER DISTRICT

PIVOTAL *moments*

NPPD Municipal Wholesale Customers

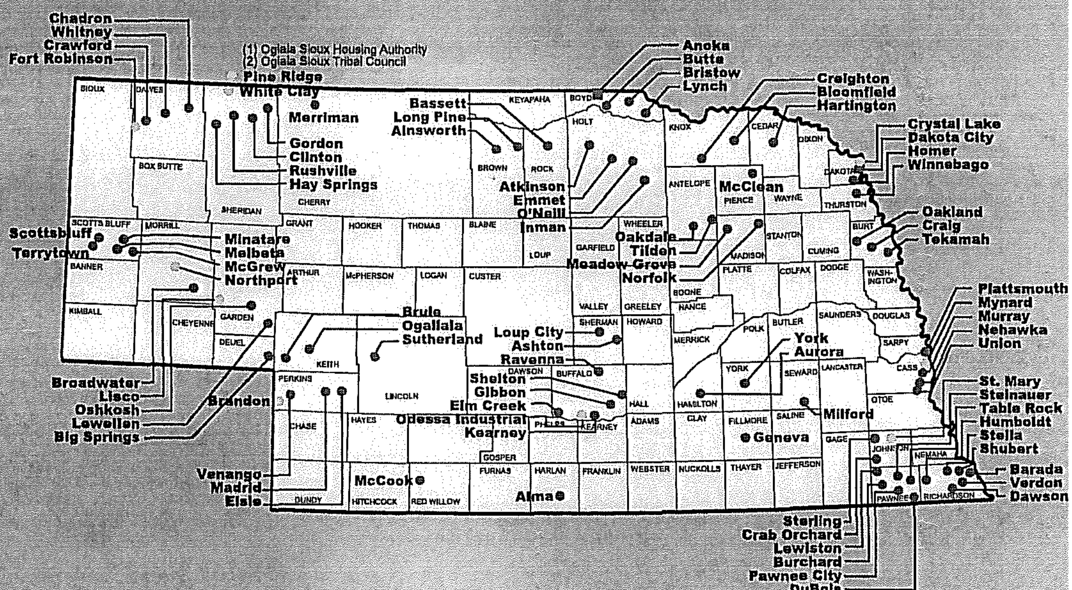


LEGEND

Municipal Wholesale Customers

Operations & Maintenance Towns

NPPD Retail Customers



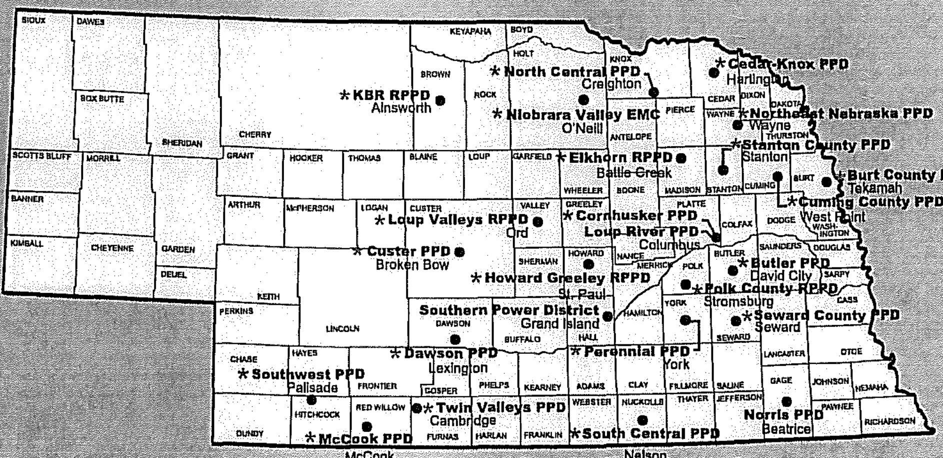
LEGEND

Professional Retail Operations Agreement Towns

NPPD Owned Municipal Distribution

NPPD Owned Rural Distribution

Public Power District & Electric Membership Cooperatives Wholesale Customers



LEGEND

* Member of Nebraska Electric Generation & Transmission Cooperative, Inc.

SALES	Average Number of Customers	Electric Energy MWh Sales Amount	%	Revenues from Electric Sales (000's) Amount	%	Revenue Per kWh
Retail:						
Residential	68,683	797,242	4.1	$ 98,046	9.1	12.30¢
Rural and Farm	3,126	84,789	0.4	9,456	0.9	11.15¢
Commercial	15,105	908,589	4.7	87,322	8.1	9.61¢
Industrial	59	1,236,850	6.4	70,634	6.5	5.71¢
Public Lighting	193	18,902	0.1	3,196	0.3	16.91¢
Municipal Power	181	29,052	0.2	2,765	0.3	9.52¢
Miscellaneous Municipal	2,008	138,534	0.7	9,651	0.9	6.97¢
Total Retail Sales	89,355	3,213,958	16.6	281,070	26.1	8.75¢
Wholesale:						
51 Municipalities (Total Requirements)		1,921,070	10.0	114,730	10.6	5.97¢
25 Public Power Districts and Cooperatives (Total Requirements)		8,034,460	41.7	440,156	40.7	5.48¢
Total Wholesale Sales (Excluding Sales to LES and Other Utilities)		9,955,530	51.7	554,886	51.3	5.57¢
Total Retail and Wholesale Sales (Excluding Sales to LES and Other Utilities)		13,169,488	68.3	835,956	77.4	6.35¢
LES[1]		1,146,969	6.0	34,673	3.2	3.02¢
Other Utilities (Nonfirm and Other Sales)		4,958,569	25.7	136,599	12.6	2.75¢
Total Electric Energy Sales		19,275,026	100.0	1,007,228	93.2	5.23¢
Other Operating Revenues (Net of Deferred)				73,770	6.8	
Total Operating Revenues				$ 1,080,998	100.0	

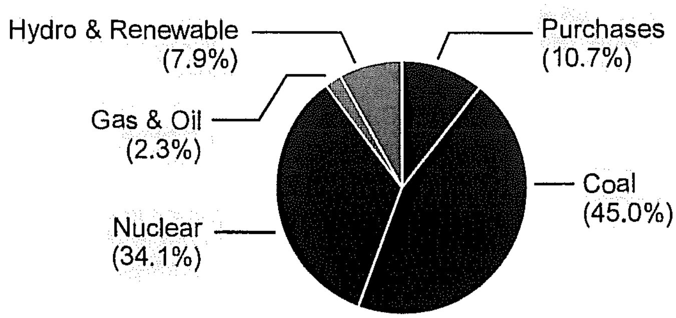
GENERATION	MWh Amount	%	Production Costs (000's) Amount	%
Production (Including Interchange)[2]	16,451,593	81.8	$ 486,576	77.2
Power Purchased	3,668,085	18.2	143,579	22.8
Total Power Produced and Purchased	20,119,678	100.0	$ 630,155	100.0

(1) Sales to Lincoln Electric System ("LES") include power and energy produced at Nebraska Public Power District's Gerald Gentleman Station and Sheldon Station.
(2) Costs include only fuel, operation, and maintenance costs. Debt service and capital related costs are excluded.

Miles of Transmission and Subtransmission Line in Service	5,172
Number of Employees (Filled Full-Time and Part-Time Positions)	2,177
2012 Contractual and Tax Payments (000's):	
Payments to Retail Communities	$ 25,773
Payments in Lieu of Taxes	$ 9,673

SOURCES OF ENERGY - 2012

For service to retail and to total requirements wholesale customers (excludes sales to Other Utilities and LES).



STANDARD RATE – LICX – Large Industrial Customer Expansion [T]

Applicability:

This schedule shall be applicable as follows:

To purchases made by a Member Cooperative for service to any New Customer initiating service after August 31, 1999, including New Customers with a QF as defined in Rate Schedule QFP and QFS, that either initially contracts for ten (10) MWs or more of capacity or whose aggregate peak load at any time amounts to ten (10) MWs or greater (including any later increases to such load) in which case the entire load shall be thereafter subject to this rate schedule. [T]

To purchases made by a Member Cooperative for expanded load requirements of Existing Customers, including Existing Customers with a QF as defined in Rate Schedules QFP and QFS, where: (i) the customer was in existence and served under the then effective LIC Rate Schedule any time during the Base Year and, (ii) the expanded load requirements are increases in peak load which in the aggregate result in a peak demand which is at least ten (10) MWs greater than the customer's Base Year peak demand. [T]

To purchases made by a Member Cooperative for the expanded load requirements of Existing Customers, including Existing Customers with a QF as defined in Rate Schedules QFP and QFS, where: (i) the customer's load was in existence and served through a rural delivery point as defined in Rate Schedule RDS, (ii) the expanded load requirements are increases in peak load which in aggregate result in a peak demand which is at least ten (10) MWs greater than the customer's Base Year peak demand; and (iii) the customer requires service through a dedicated delivery point as defined in Rate Schedule LIC. [T]

Availability:

This schedule is available to any of the Member Cooperatives of Big Rivers for service to certain large industrial or commercial loads as specified in item (a) defining applicability. For all loads meeting the applicability criteria below, no other Big Rivers' tariff rate will be available. As an alternative to this rate schedule, the Member Cooperative may negotiate a "Special Contract Rate" with Big Rivers for application on a case by case basis for loads meeting the applicability criteria above.

STANDARD RATE – LICX – Large Industrial Customer Expansion – (*continued*) [T]

Conditions of Service:

To receive service hereunder, the Member Cooperative must:

Obtain from the customer an executed written contract or amend an existing contract with terms acceptable to Big Rivers. [T]

Enter into a contract with Big Rivers, or amend an existing contract with Big Rivers, to specify the terms and conditions of service between Big Rivers and the Member Cooperative regarding power supply for the customer. [T]

Definitions: [T]

Please see Section 4 for definitions common to all tariffs. [T]

Base Year – "Base Year" shall mean the twelve (12) calendar months from September 1998 through August 1999. [T]

Existing Customer – "Existing Customer" shall mean any customer of a Member Cooperative served as of August 31, 1999. [T]

New Customer – "New Customer" shall mean any customer of a Member Cooperative commencing service on or after September 1, 1999. [T]

Special Contract Rate – "Special Contract Rate" shall mean a rate negotiated with a Member Cooperative to serve the load requirements of a New Customer or an Existing Customer, which will include, upon request by the Member Cooperative, rates based on Real Time Pricing. [T]

STANDARD RATE – LICX – Large Industrial Customer Expansion – (*continued*) [T]

Expansion Demand and Expansion Energy: [T]

Expansion Demand and Expansion Energy for the load requirements of a New Customer shall be the Member Cooperative's total demand and energy requirements for the New Customer, including amounts sufficient to compensate for losses on the Big Rivers' transmission system as set forth in the OATT. [T] [T]

Expansion Demand for the expanded load requirements of an Existing Customer shall be the amount in kW by which the customer's Billing Demand exceeds the customer's Base Year peak demand, plus an additional amount of demand sufficient to compensate for losses on the Big Rivers' transmission system as set forth in the OATT. In those months in which there is Expansion Demand, Expansion Energy shall be the amount in kWh by which the customer's kWh usage for the current month exceeds the customer's actual kWh usage for the corresponding month of the Base Year, plus an additional amount of kWh sufficient to compensate for losses on the Big Rivers' transmission system as set forth in the OATT. [T] [T] [T]

Rates and Charges: [T]

Expansion rate and charges shall be the sum of the following, including but not limited to Real-Time pricing: [T]

(1) **Expansion Demand and Expansion Energy Rates:**
The Expansion Demand rates, Expansion Energy rates, or both shall be established to correspond to the actual costs of power purchased by Big Rivers from Third-Party Suppliers selected by Big Rivers from which Big Rivers procures the supply and delivery of the type and quantity of service required by the Member Cooperative for resale to its customer. Such monthly costs shall include the sum of all Third-Party Supplier charges, including capacity and energy charges, charges to compensate for transmission losses on Third-Party transmission systems, and all transmission and ancillary services charges on Third-Party transmission systems paid by Big Rivers to purchase such Expansion Demand and Expansion Energy and have it delivered to Big Rivers' transmission system.

KENTUCKY
PUBLIC SERVICE COMMISSION
JEFF R. DEROUEN
EXECUTIVE DIRECTOR
TARIFF BRANCH
Bunt Kirtley
EFFECTIVE
9/1/2011
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

STANDARD RATE – LICX – Large Industrial Customer Expansion – (*continued*) [T]

(2) **Expansion Demand Transmission Rate:**
Big Rivers shall assess unbundled charges for network transmission service on the Big Rivers' Transmission System according to the rates in the OATT applied to each kW taken as Expansion Demand. [T]

(3) **Ancillary Services Rates for Expansion Demand and Expansion Energy:**
Big Rivers shall assess unbundled rates for all ancillary services required to serve load served under this rate schedule. Big Rivers shall supply the following six ancillary services as defined and set forth in the OATT: (1) Scheduling System Control and Dispatch; (2) Reactive Supply and Voltage Control from Generation Sources Services; (3) Regulation and Frequency Response Service; (4) Energy Imbalance Service; (5) Operating Reserve – Spinning Reserve Service; and (6) Operating Reserve – Supplemental Reserve Service. [T]

(4) **Big Rivers Adder:**
In addition to the charges described above, Big Rivers shall charge $0.38 per kW/month for each kW billed to the Member Cooperative under this tariff for resale by the Member Cooperative to the qualifying customer. [T]

Meters: [T]
Big Rivers shall provide an appropriate meter to all customers served under this rate schedule. [T]

For All Territory Served By
Cooperative's Transmission System
P.S.C. KY. No. 24

First Revised SHEET NO. 33

Big Rivers Electric Corporation
(Name of Utility)

CANCELLING P.S.C. KY. No. 24

Original SHEET NO. 33

RATES, TERMS AND CONDITIONS – SECTION 1

STANDARD RATE – LICX – Large Industrial Customer Expansion
Billing Form

[T]

INVOICE
BIG RIVERS ELECTRIC CORP. P. O. BOX 24 HENDERSON, KY 42419-0024
MONTH ENDING mm/dd/yy

TO: LARGE INDUSTRIAL CUSTOMER EXPANSION
DELIVERY POINTS

ACCOUNT
SERVICE FROM mm/dd/yy THRU mm/dd/yy
USAGE:

USAGE	DEMAND	TIME	DAY	METER	MULT	KW DEMAND
		00:00 A (or P)	mm/dd		1000	00,000

POWER FACTOR	BASE	PEAK	AVERAGE	kW DEMAND BILLED
EXPANSION DEMAND	00.00%	00.00%	00.00%	000,000

ENERGY	PREVIOUS	PRESENT	DIFFERENCE	MULT.	KWH USED
EXPANSION ENERGY	00000.000	00000.000	0000.000	1000	00,000,000

EXPANSION DEMAND & EXPANSION ENERGY
EXPANSION DEMAND, INCLUDING LOSSES kW TIMES $ EQUALS $
EXPANSION ENERGY, INCLUDING LOSSES kWh TIMES $ EQUALS $
OTHER EXPANSION SERVICE CHARGES EQUALS $
SUBTOTAL $

EXPANSION DEMAND TRANSMISSION
LOAD RATIO SHARE OF NETWORK LOAD $

EXPANSION DEMAND & EXPANSION ENERGY ANCILLARY SERVICES
SCHEDULING SYSTEM CONTROL & DISPATCH SERVICE $
REACTIVE SUPPLY & VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE $
REGULATION & FREQUENCY RESPONSIVE SERVICE $
ENERGY IMBALANCE SERVICE $
OPERATING RESERVE – SPINNING RESERVE SERVICE $
OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE $
SUBTOTAL $

BIG RIVERS ADDER
EXPANSION DEMAND kW TIMES $ EQUALS $

FUEL ADJUSTMENT CLAUSE	0,000,000	kWh	TIMES	$0.0000000		EQUALS	$
NSNFP	0,000,000	kWh	TIMES	$0.0000000		EQUALS	$
					SUBTOTAL		$
ENVIRONMENTAL SURCHARGE	$00,000.00		TIMES	00.00%		EQUALS	$
EXPANSION DEMAND/ENERGY – POWER FACTOR PENALTY		kW	TIMES	$0.0000000		EQUALS	$
UNWIND SURCREDIT	0,000,000	kWh	TIMES	$0.0000000		EQUALS	$
MEMBER RATE STABILITY MECHANISM	0,000,000		AMOUNT				$
CSR	0,000,000		AMOUNT				$
RRES	0,000,000	kWh	TIMES	$0.0000000		EQUALS	$
REBATE ADJUSTMENT	0,000,000		AMOUNT				$
					TOTAL AMOUNT DUE		$

[T]

---------- LOAD FACTOR ----------
ACTUAL BILLED
00.00% 00.00%

MILLS PER KWH
00.00

DUE IN IMMEDIATELY AVAILABLE FUNDS ON OR BEFORE THE FIRST WORKING DAY AFTER THE 24TH OF THE MONTH

KENTUCKY
PUBLIC SERVICE COMMISSION
JEFF R. DEROUEN
EXECUTIVE DIRECTOR
TARIFF BRANCH
Bunt Kirtley
EFFECTIVE
10/1/2012
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

DATE OF ISSUE October 4, 2012 DATE EFFECTIVE October 1, 2012

Mark A. Bailey

ISSUED BY Mark A. Bailey, President and Chief Executive Officer
Big Rivers Electric Corporation, 201 Third Street, Henderson, KY 42420

Issued by Authority of an Order of the Public Service Commission in Case No. 2012-00063 dated October 1, 2012

BIG RIVERS ELECTRIC CORPORATION
Cost of Service Study
Estimate of Retail Rate Increase

12 Months Ended
January 31, 2015

		Current	Proposed	Increase	Increase
Rural Delivery Service					
Estimated Retail Rate ($/kWh)					
All-In Wholesale Rate		0.074886	0.098795	0.023909	31.9%
Estimated Retail Distr Cost Adder		0.033000	0.033000		
Total Retail Rate Estimate		0.107886	0.131795	0.023909	22.2%
Estimated Billings ($/Month)					
Monthly Usage	100 kWh	$ 10.79	$ 13.18	$ 2.39	22.2%
	200	$ 21.58	$ 26.36	$ 4.78	22.2%
	300	$ 32.37	$ 39.54	$ 7.17	22.2%
	400	$ 43.15	$ 52.72	$ 9.57	22.2%
	500	$ 53.94	$ 65.90	$ 11.96	22.2%
	600	$ 64.73	$ 79.08	$ 14.35	22.2%
	700	$ 75.52	$ 92.26	$ 16.74	22.2%
	800	$ 86.31	$ 105.44	$ 19.13	22.2%
	900	$ 97.10	$ 118.62	$ 21.52	22.2%
	1000	$ 107.89	$ 131.80	$ 23.91	22.2%
	1100	$ 118.67	$ 144.97	$ 26.30	22.2%
	1200	$ 129.46	$ 158.15	$ 28.69	22.2%
	1300	$ 140.25	$ 171.33	$ 31.08	22.2%
	1400	$ 151.04	$ 184.51	$ 33.47	22.2%
	1500	$ 161.83	$ 197.69	$ 35.86	22.2%
Large Industrial Customer Service					
Estimated Retail Rate ($/kWh)					
All-In Wholesale Rate		0.059023	0.075324	0.016301	27.6%
Estimated Retail Distribution Cost Adder		0.002000	0.002000		
Total Retail Rate Estimate		0.061023	0.077324	0.016301	26.7%
Estimated Billings ($/Month)					
Monthly Usage	500 kWh	$ 30.51	$ 38.66	$ 8.15	26.7%
	600	$ 36.61	$ 46.39	$ 9.78	26.7%
	700	$ 42.72	$ 54.13	$ 11.41	26.7%
	800	$ 48.82	$ 61.86	$ 13.04	26.7%
	900	$ 54.92	$ 69.59	$ 14.67	26.7%
	1000	$ 61.02	$ 77.32	$ 16.30	26.7%
	1100	$ 67.12	$ 85.06	$ 17.93	26.7%
	1200	$ 73.23	$ 92.79	$ 19.56	26.7%
	1300	$ 79.33	$ 100.52	$ 21.19	26.7%
	1400	$ 85.43	$ 108.25	$ 22.82	26.7%
	1500	$ 91.53	$ 115.99	$ 24.45	26.7%
	1600	$ 97.64	$ 123.72	$ 26.08	26.7%
	1700	$ 103.74	$ 131.45	$ 27.71	26.7%
	1800	$ 109.84	$ 139.18	$ 29.34	26.7%
	1900	$ 115.94	$ 146.92	$ 30.97	26.7%
	2000	$ 122.05	$ 154.65	$ 32.60	26.7%

KIUC EXHIBIT 11

The amount and percent changes by rate class are as follows:

Rate Class	Before Accelerated MRSM & RER Credit(1) Big Rivers Flow-Through Dollars	Before Accelerated MRSM & RER Credit(1) Retail Percent Change	After Accelerated MRSM & RER Credit(2) Big Rivers Flow-Through Dollars	After Accelerated MRSM & RER Credit(2) Retail Percent Change
Residential Service	$19,999,885	29.0%	$0	0.0%
All Non-Residential Single Phase	$3,389,592	28.9%	$0	0.0%
Three-Phase (less than 1,000 KW)	$4,927,431	29.1%	$0	0.0%
Three-Phase (1,001 KW & Over)	$1,846,855	29.4%	$0	0.0%
Unmetered Lighting	$567,212	28.5%	$0	0.0%
Other	$235,055	29.3%	$0	0.0%
Total Non-Direct Served	$30,966,030	29.0%	$0	0.0%

Rate Class			After Accelerated MRSM Only(3)	
Direct Served Customer Class A	N/A	N/A	N/A	N/A
Direct Served Customers Class B	$10,222,420	30.8%	$0	0.0%
Direct Served Customers Class C	$6,857,919	38.7%	$0	0.0%
Total Direct Served	$17,080,339	33.5%	$0	0.0%
Total All	$48,046,369	30.6%	$0	0.0%

The effect of the proposed rates on the average monthly bill by rate class is as follows:

Rate Class	Current Normalized Monthly Bill	Before Accelerated MRSM & RER Credit(1) Impact of Big Rivers Flow-Through	Before Accelerated MRSM & RER Credit(1) Proposed Monthly Bill	Before Accelerated MRSM & RER Credit(1) Percent Change	After Accelerated MRSM & RER Credit(2) (3) Impact of Big Rivers Flow-Through	After Accelerated MRSM & RER Credit(2) (3) Proposed Monthly Bill	After Accelerated MRSM & RER Credit(2) (3) Percent Change
Residential Service	$127.79	$37.00	$164.79	29.0%	$0.00	$127.79	0.0%
All Non-Residential Single Phase	$108.86	$31.45	$140.31	28.9%	$0.00	$108.86	0.0%
Three-Phase (less than 1,000 KW)	$1,390.11	$404.45	$1,794.56	29.1%	$0.00	$1,390.11	0.0%
Three-Phase (1,001 KW & Over)	$34,889.90	$10,260.30	$45,150.20	29.4%	$0.00	$34,889.90	0.0%
Unmetered Lighting	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Direct Served Customer Class A	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Direct Served Customers Class B	$922,757.92	$283,956.10	$1,206,714.02	30.8%	$0.00	$922,757.92	0.0%
Direct Served Customers Class C	$86,926.77	$33,617.25	$120,544.02	38.7%	$0.00	$86,926.77	0.0%

(1) Big Rivers has proposed accelerating the use of the Member Rate Stability Mechanism (MRSM) and the Rural Economic Reserve (RER) to offset the proposed base rate increase.
(2) The (MRSM) is expected to be exhausted in July of 2014 and the (RER) in April of 2015.
(3) Per the proposed Big Rivers tariff and previous Kentucky Public Service Commission order, the RER applies only to the non-direct served classes.

Any corporation, association, or person with a substantial interest in the matter may request to intervene by written request or motion, within thirty (30) days after the date of publication of this notice of the proposed rate changes, although the Kentucky Public Service Commission may grant intervention beyond the thirty (30) day period for good cause shown. The request to intervene shall be submitted to the Kentucky Public Service Commission, 211 Sower Boulevard, P. O. Box 615, Frankfort, Kentucky 40602 and shall set forth the grounds for the request, including the status and interest of the party. Interveners may obtain copies of the application by contacting Kenergy Corp., 6402 Old Corydon Road, Henderson, KY 42420, or by calling (800) 844-4832.

copy of the application and any other filing is available for public inspection at Kenergy's office at the above stated address or at one its branch offices at 315 Hawes Boulevard, Hawesville, KY 42348; 1441 U.S. Highway 231 North, Hartford, KY 42347; 2620 Brown Badgett Loop, Hanson, KY 42413; 3000 U.S. Highway 641, Marion, KY 42064; or 3111 Fairview Drive, Owensboro, KY 42303.

By: Gregory J. Starheim, President and CEO

U.S. Energy Information Administration - Average Retail Price of Electricity in 2012

RESIDENTIAL

Entity	State	Ownership	Average Price (cents/kWh)
City of Frankfort - (KY)	KY	Municipal	7.40
City of Nicholasville - (KY)	KY	Municipal	7.57
City of Bardstown - (KY)	KY	Municipal	7.83
Jackson Purchase Energy Corporation	**KY**	**Cooperative**	**7.84**
Henderson City Utility Comm	KY	Municipal	7.89
Meade County Rural E C C	**KY**	**Cooperative**	**8.02**
Kenergy Corp	**KY**	**Cooperative**	**8.03**
City of Berea Municipal Utility	KY	Municipal	8.21
Kentucky Utilities Co	KY	Investor Owned	8.24
Barbourville Utility Comm	KY	Municipal	8.58
Duke Energy Kentucky	KY	Investor Owned	8.76
Louisville Gas & Electric Co	KY	Investor Owned	9.00
Kentucky Power Co	KY	Investor Owned	9.18
Madisonville Municipal Utils	KY	Municipal	9.36
[redacted]			
Salt River Electric Coop Corp	KY	Cooperative	9.57
City of Franklin - (KY)	KY	Municipal	9.84
City of Russellville - (KY)	KY	Municipal	9.86
City of Hopkinsville	KY	Municipal	9.87
Taylor County Rural E C C	KY	Cooperative	9.87
City of Bowling Green - (KY)	KY	Municipal	9.94
City of Jellico	KY	Municipal	9.94
City of Paducah - (KY)	KY	Municipal	10.04
Cumberland Valley Electric, Inc.	KY	Cooperative	10.12
Nolin Rural Electric Coop Corp	KY	Cooperative	10.30
City of Murray - (KY)	KY	Municipal	10.41
Warren Rural Elec Coop Corp	KY	Cooperative	10.46
Tri-County Elec Member Corp	KY	Cooperative	10.49
City of Glasgow - (KY)	KY	Municipal	10.62
Farmers Rural Electric Coop Corp - (KY)	KY	Cooperative	10.73
South Kentucky Rural E C C	KY	Cooperative	10.74
Shelby Energy Co-op, Inc	KY	Cooperative	10.85
Blue Grass Energy Coop Corp	KY	Cooperative	10.86
Pennyrile Rural Electric Coop	KY	Cooperative	10.88
City of Fulton - (KY)	KY	Municipal	10.89
City of Princeton - (KY)	KY	Municipal	10.89
Big Sandy Rural Elec Coop Corp	KY	Cooperative	10.94
City of Benton - (KY)	KY	Municipal	11.05
Fleming-Mason Energy Coop Inc	KY	Cooperative	11.05
Owen Electric Coop Inc	KY	Cooperative	11.09
Inter County Energy Coop Corp	KY	Cooperative	11.26
Clark Energy Coop Inc - (KY)	KY	Cooperative	11.37
Licking Valley Rural E C C	KY	Cooperative	11.43

KIUC EXHIBIT 12

U.S. Energy Information Administration - Average Retail Price of Electricity in 2012

RESIDENTIAL

Entity	State	Ownership	Average Price (cents/kWh)
City of Mayfield Plant Board	KY	Municipal	11.45
West Kentucky Rural E C C	KY	Cooperative	11.71
Jackson Energy Coop Corp - (KY)	KY	Cooperative	11.73
City of Hickman	KY	Municipal	11.80
City of Owensboro - (KY)	KY	Municipal	11.88
Grayson Rural Electric Coop Corp	KY	Cooperative	12.61
Hickman-Fulton Counties RECC	KY	Cooperative	13.17
Big Rivers Total Rural - GROSS of MRSM	KY	Cooperative	13.46

Source: http://www.eia.gov/electricity/data.cfm#sales (Data from forms EIA-861- schedules 4A & 4D and EIA-861S)

U.S. Energy Information Administration - Average Retail Price of Electricity in 2012

INDUSTRIAL

Entity	State	Ownership	Average Price (cents/kWh)
Electric Energy Inc	KY	investor Owned	3.55
City of Bardstown - (KY)	KY	Municipal	4.39
Tennessee Valley Authority	KY	Federal	4.64
Kenergy Corp	KY	Cooperative	4.73
Big Rivers Total Large Industrial - NET of MRSM	KY	Cooperative	4.96
Henderson City Utility Comm	KY	Municipal	5.17
Owen Electric Coop Inc	KY	Cooperative	5.28
Kentucky Utilities Co	KY	Investor Owned	5.43
Kentucky Power Co	KY	Investor Owned	5.49
City of Hopkinsville	KY	Municipal	6.06
Nolin Rural Electric Coop Corp	KY	Cooperative	6.12
Louisville Gas & Electric Co	KY	Investor Owned	6.17
Jackson Purchase Energy Corporation	KY	Cooperative	6.26
City of Nicholasville - (KY)	KY	Municipal	6.35
Fleming-Mason Energy Coop Inc	KY	Cooperative	6.36
City of Frankfort - (KY)	KY	Municipal	6.71
Blue Grass Energy Coop Corp	KY	Cooperative	6.75
Grayson Rural Electric Coop Corp	KY	Cooperative	6.77
Salt River Electric Coop Corp	KY	Cooperative	6.85
Barbourville Utility Comm	KY	Municipal	6.91
City of Franklin - (KY)	KY	Municipal	6.95
Duke Energy Kentucky	KY	Investor Owned	6.99
Shelby Energy Co-op, Inc	KY	Cooperative	7.01
City of Berea Municipal Utility	KY	Municipal	7.04
Inter County Energy Coop Corp	KY	Cooperative	7.12
Jackson Energy Coop Corp - (KY)	KY	Cooperative	7.21
City of Murray - (KY)	KY	Municipal	7.25
Big Sandy Rural Elec Coop Corp	KY	Cooperative	7.33
West Kentucky Rural E C C	KY	Cooperative	7.52
Farmers Rural Electric Coop Corp - (KY)	KY	Cooperative	7.58
Pennyrile Rural Electric Coop	KY	Cooperative	7.79
Big Rivers Total Large Industrial - GROSS of MRSM	KY	Cooperative	7.91
City of Glasgow - (KY)	KY	Municipal	7.92
Warren Rural Elec Coop Corp	KY	Cooperative	7.97
Licking Valley Rural E C C	KY	Cooperative	8.09
City of Bowling Green - (KY)	KY	Municipal	8.10
Cumberland Valley Electric, Inc.	KY	Cooperative	8.16
City of Paducah - (KY)	KY	Municipal	8.24
South Kentucky Rural E C C	KY	Cooperative	8.52
Clark Energy Coop Inc - (KY)	KY	Cooperative	8.73
City of Russellville - (KY)	KY	Municipal	8.91
City of Benton - (KY)	KY	Municipal	9.03
City of Fulton - (KY)	KY	Municipal	9.06
Tri-County Elec Member Corp	KY	Cooperative	9.08
City of Owensboro - (KY)	KY	Municipal	9.11
City of Mayfield Plant Board	KY	Municipal	9.39
City of Princeton - (KY)	KY	Municipal	10.90
Taylor County Rural E C C	KY	Cooperative	10.96
Hickman-Fulton Counties RECC	KY	Cooperative	13.91

Source: http://www.eia.gov/electricity/data.cfm#sales (Data from forms EIA-861- schedules 4A & 4D and EIA-861S)

KIUC EXHIBIT 13

Summary of KIUC Adjustments to Big Rivers Revenue Requirement
Case No. 2103-00199
$ Million

Big Rivers Original Requested Increase		$70.397
Big River Adjustment to Increase in Rebuttal Testimony		0.830
Big Rivers Revised Requested Increase in Rebuttal Testimony		$71.227
KIUC Adjustments		
Cease Depreciation Expense - Wilson Station	(20.177)	
Include Transmission Revenue from Century Hawesville and Sebree Smelters	(12.781)	
Remove Coleman and Wilson Severance Amortization Expense	(1.680)	
Reduce Non-Recurring Coleman Lay Up Expenses	(1.600)	
Reduce Allocation of ACES Fees to be Paid By Century	(1.333)	
Share Fixed Costs Due to Excess Capacity with Creditors	(23.121)	
Total KIUC Adjustments		(60.693)
Big Rivers Increase after KIUC Adjustments		$10.534

KIUC EXHIBIT 14

RATE INCREASES TO RURAL CLASS FROM CENTURY AND ALCAN TERMINATIONS AFTER RESERVES ARE DEPLETED

RURAL	CENTURY BASE PERIOD [2]		ALCAN TEST YEAR [3]		CENTURY AND ALCAN INCREASE	
	Rural Rate	Rural Revenues	Rural Rate	Rural Revenues	Rural Rate Increases	Percent Increases
Base Rate - Demand		$ 51,194,845		$120,585,568	$ 69,390,724	135.5%
Base Rate - Energy		$ 71,988,650		$ 80,799,320	$ 8,810,670	12.2%
Non-Smelter Non-FAC PPA		$ (3,006,790)		$ (826,876)	$ 2,179,914	-72.5%
FAC		$ 8,424,822		$ 13,737,782	$ 5,312,960	63.1%
Environmental Surcharge		$ 6,134,626		$ 14,086,285	$ 7,951,659	129.6%
Smelter Surcredit		$ (9,950,005)		$ (308,324)	$ 9,641,681	-96.9%
MRSM (Economic Reserve)		$(15,595,604)		$ -	$ 15,595,604	-100.0%
Totals	$0.0451	$109,190,543	$0.0988	$228,073,755	$ 118,883,212	108.9%
Avg Monthly Residential Bill @ 1300 kWh [1]		$ 101.53		$ 171.33	$69.80	
Avg Annual Residential Increase					$837.60	

[1] Includes $0.033/kWh for Member Cooperative Charges As Shown On Ex Wolfram-7.

[2] Base Rates and Revenues From Tab 59 in Case No. 2012-00535.

[3] Test Year Rates and Revenues From Tab 56 in Case No. 2013-00199, Including Adjustments to Rates on Rebuttal Exhibit Wolfram-5.2.

RATE INCREASES TO LARGE INDUSTRIAL CLASS FROM CENTURY AND ALCAN TERMINATIONS AFTER RESERVES ARE DEPLETED

LARGE INDUSTRIAL	CENTURY BASE PERIOD [2]		ALCAN TEST YEAR [3]		CENTURY AND ALCAN INCREASE	
	Large Ind Rate	Large Industrial Revenues	Large Ind Rate	Large Industrial Revenues	Large Ind Rate Increases	Percent Increases
Base Rate		$ 41,207,958		$ 64,100,065	$ 22,892,107	55.6%
Non-Smelter Non-FAC PPA		$ (1,190,863)		$ (356,508)	$ 834,355	-70.1%
FAC		$ 3,326,542		$ 5,843,877	$ 2,517,335	75.7%
Environmental Surcharge		$ 2,252,893		$ 4,603,463	$ 2,350,570	104.3%
Smelter Surcredit		$ (3,961,493)		$ (134,005)	$ 3,827,488	-96.6%
Power Factor Penalty/Adjustments		$ 111,014		$ -	$ (111,014)	-100.0%
MRSM (Economic Reserve)		$ (5,948,917)		$ -	$ 5,948,917	-100.0%
Totals	$0.0376	$ 35,797,133	$0.0753	$ 74,056,892	$ 38,259,759	106.9%

[1] Base Rates and Revenues from Tab 59, Adjusted to Reflect Amounts Reflected in Response to KIUC 1-30 c, In Case No. 2012-00535.

[2] Test Year Rates and Revenues From Tab 56 in Case No. 2013-00199, Including Adjustments to Rates on Rebuttal Exhibit Wolfram-5.2.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
OCT 29 2013
PUBLIC SERVICE COMMISSION

In The Matter Of:

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

PUBLIC VERSION

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

OCTOBER 28, 2013

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

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

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emergency rate relief and cash requirements; Case No. 2011-00036 on behalf of KIUC regarding a base rate increase; Case No. 2012-00535 on behalf of KIUC, the pending base rate increase ("Century rate case" or "Century increase"); and Case No. 2012-00063 on behalf of KIUC regarding environmental retrofits.

I also have testified before the Commission on numerous occasions in other utility base rate cases, environmental rate cases, and fuel adjustment cases on behalf of KIUC involving Kentucky Power Company, Louisville Gas and Electric Company, Kentucky Utilities Company, and East Kentucky Power Cooperative. My qualifications and regulatory appearances are further detailed in my Exhibit___ (LK-1).

Q. On whose behalf are you testifying?

A. I am testifying on behalf of KIUC, a group of large customers taking electric service on the Big Rivers Electric Corporation system. The members of KIUC participating in this case are Aleris, Inc., Domtar, Inc., and Kimberly-Clark Corporation. These members of KIUC are the three largest customers in the Large Industrial class served by Big Rivers.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address and make recommendations in response to the Company's request for a base rate increase of $70.397 million, the entirety of

adjusted to $71.227 million in rebuttal testimony which is attributable to the loss of the Alcan Primary Products Corporation ("Alcan") load upon termination of its contract for service on January 31, 2014 and the Company's inability to economically sell the resulting excess energy into a depressed energy market, according to Mr. Bailey's Direct Testimony at pages 5-6.

II. SUMMARY OF KIUC'S RECOMMENDATIONS

Q. Please summarize your testimony.

A. This is the third Big Rivers base rate increase request in the last three years. In addition to this request, the Century rate increase is still pending, although it was implemented on August 20, 2013 subject to refund. The Company's requests in the two pending Smelter termination driven rate cases, along with the actual base rate increase in Case No. 2011-00 and increases in other tariff components, sum to all-in rate increases at wholesale of ~~168%~~ 160% for Rural customers and ~~135%~~ 130% for Large Industrial customers. The Company's request in this case, along with the pending Century base rate increase and the increases in other tariff components compared to the base year in the Century case sum to all-in increases of ~~115%~~ 109% at wholesale and ~~72%~~ 69% at retail for Rural customers and ~~112%~~ 107% at wholesale for Large Industrial customers.

The sheer magnitude of the series of rate increases sought by the Company is staggering and will have a profound and lasting effect on the economy in Western

See Replacement Table

Summary of KIUC Adjustments to Big Rivers Revenue Requirement Case No. 2103-00199 $ Million		
Big Rivers Requested Increase		$70.397
KIUC Adjustments		
Cease Depreciation Expense - Wilson and Coleman Stations	(26.644)	
Include Transmission Revenue from Century Hawesville and Sebree Smelters	(12.781)	
Reduce Non-Recurring Coleman Lay Up Expenses	(1.600)	
Remove MATS 2014 Capital Expenditures for Wilson and Coleman Stations	(0.694)	
Reduce Allocation of ACES Fees to be Paid By Century	(1.333)	
Share Fixed Costs Due to Excess Capacity with Creditors	(18.786)	
Total KIUC Adjustments		(61.838)
Big Rivers Increase after KIUC Adjustments		$8.559

III. THE COMPANY'S REQUESTS IN THE CENTURY AND ALCAN CASES, ALONG WITH CHANGES IN OTHER RATE COMPONENTS, WILL RESULT IN ALL-IN RATE INCREASES OF ~~72%~~ 69% FOR RURAL CUSTOMERS AND ~~112%~~ 107% FOR LARGE INDUSTRIAL CUSTOMERS

Q. What is the "all-in" rate impact of the Smelter terminations?

A. The Company estimates that the "all-in" rate impact of the Smelter terminations for the Century and Alcan base rate cases combined together with the increases in other rate components, including the FAC and ECR, will be ~~115%~~ 109% at wholesale for the Rural customers, ~~72%~~ 69% at retail for the Member Cooperative residential, commercial and small industrial customers, and ~~112%~~ 107% for the Large Industrial customers as shown in the following table. The increase to the average residential customer using 1300 kWh per month will be nearly ~~$900~~ $838 each year. The sources for the data used in the following tables are indicated on the tables.

See Replacement Tables

RATE INCREASES TO RURAL CLASS FROM CENTURY AND ALCAN TERMINATIONS
AFTER RESERVES ARE DEPLETED

RURAL	CENTURY BASE PERIOD [1]		ALCAN TEST YEAR [2]		CENTURY AND ALCAN INCREASES	
	Rural Rate	Rural Revenues	Rural Rate	Rural Revenues	Rural Rate Increases	Percent Increases
Base Rate - Demand		$ 51,194,845		$126,899,244	$ 75,704,400	147.9%
Base Rate - Energy		$ 71,988,650		$ 80,799,320	$ 8,810,670	12.2%
Non-Smelter Non-FAC PPA		$ (3,006,790)		$ (826,876)	$ 2,179,914	-72.5%
FAC		$ 8,424,822		$ 13,737,782	$ 5,312,960	63.1%
Environmental Surcharge		$ 6,134,626		$ 14,168,287	$ 8,033,661	131 0%
Smelter Surcredit		$ (9,950,005)		$ (308,324)	$ 9,641,681	-96.9%
MRSM (Economic Reserve)		$(15,595,604)		$ -	$ 15,595,604	-100 0%
Totals	$0 0451	$109,190,543	$0 1016	$234,469,433	$ 125,278,890	114 7%
Avg Monthly Residential Bill @ 1300 kWh [1]		$ 101 53		$ 174 94	$73 40	
Avg Annual Residential Increase					$880 82	

[1] Includes $0 003/kWh for Member Cooperative Charges As Shown On Ex Wolfram-7.
[2] Base Rates and Revenues From Tab 59 in Case No 2012-00535.
[2] Test Year Rates and Revenues From Tab 56 in Case No. 2013-00199.

RATE INCREASES TO LARGE INDUSTRIAL CLASS FROM
CENTURY AND ALCAN TERMINATIONS
AFTER RESERVES ARE DEPLETED

LARGE INDUSTRIAL	CENTURY BASE PERIOD [1]		ALCAN TEST YEAR [2]		CENTURY AND ALCAN INCREASES	
	Large Ind Rate	Large Industrial Revenues	Large Ind Rate	Large Industrial Revenues	Large Ind Rate Increases	Percent Increases
Base Rate		$ 41,207,958		$ 65,809,791	$ 24,601,833	59 7%
Non-Smelter Non-FAC PPA		$ (1,190,863)		$ (356,508)	$ 834,355	-70 1%
FAC		$ 3,326,542		$ 5,843,877	$ 2,517,335	75.7%
Environmental Surcharge		$ 2,252,893		$ 4,608,733	$ 2,355,840	104 6%
Smelter Surcredit		$ (3,961,493)		$ (134,005)	$ 3,827,488	-96 6%
Power Factor Penalty/Adjustments		$ 111,014		$ -	$ (111,014)	-100 0%
MRSM (Economic Reserve)		$ (5,948,917)		$ -	$ 5,948,917	-100 0%
Totals	$0 0376	$ 35,797,133	$0 0782	$ 75,771,888	$ 39,974,755	111 7%

[1] Base Rates and Revenues from Tab 59, Adjusted to Reflect Amounts Reflected in Response to KIUC 1-30 c, In Case No 2012-00535.
[2] Test Year Rates and Revenues From Tab 56 in Case No 2013-00199.

- Use the Reserve funds for the benefit of both Rural and Large Industrial customers on a non-discriminatory basis;
- Direct Big Rivers to work with all stakeholders to achieve a reasonable negotiated solution to the Company's excess capacity and related fixed costs prior to the depletion of the Reserve Funds.

Q. Is there an additional element to the KIUC Rate Plan that you propose in this proceeding?

A. Yes. I recommend that the Commission approve a reasonable rate increase of no more than ~~\$8.559~~ million in this proceeding.
\$10.534

Q. What are the benefits of the KIUC Rate Plan?

A. There are many benefits to KIUC's approach, including:

- avoiding rate shock to customers;
- achieving an equitable sharing of the excess capacity costs resulting from the Century and Alcan terminations rather than forcing Big Rivers' remaining customers to take on 100% of the burden of the stranded generating capacity and the related fixed costs;
- maintaining and improving the Company's credit metrics until February 2015 due to the use of the Economic Reserve and Rural Economic Reserve funds while the Company works with its stakeholders to resolve its problems of excess capacity and the related fixed costs;
- providing a reasonable incentive for the creditors to work with Big Rivers in a cooperative manner prior to the depletion of the ratepayer Reserve Funds;
- providing additional time for resolution of the significant uncertainties surrounding the Century and Alcan terminations departure, including, but not limited to, the impacts of MISO's "must run" ("SSR") decision on Coleman;
- providing additional time to comprehensively study and address the Company's future and structure; and
- providing additional time to sell or otherwise dispose of the Company's excess

A. The Company's original claimed revenue requirement still includes [redacted] million in fixed costs for these plants, consisting of [redacted] million for the Wilson plant and [redacted] million for the Coleman plant. These annual costs could be avoided in whole or part if the Company sold or otherwise divested these power plants. The fixed costs include O&M expense, property insurance expense, property tax expense, depreciation expense, interest expense, and the TIER margin. These amounts were provided by the Company in its Confidential responses to AG 1-105 and AG 1-106, which I have replicated as my Confidential Exhibit___(LK-3) and Confidential Exhibit___(LK-4), respectively. The Company removed depreciation expense for the Coleman plant from its claimed revenue requirement in its Rebuttal Testimony.

Q. Are the Company's attempts to sell the ownership or output of the Wilson and Coleman plants serious offers to divest these assets and reduce its excess capacity?

A. No. The Company has submitted bids in response to numerous requests for proposal issued by other utilities, according to its Confidential responses to PSC 2-15 and PSC 2-16. However, these bids are not serious offers to sell. Rather, they are a collective exercise in futility because they reflect the fact that the Company has decided that it will not sell the plants unless it can sell them at [redacted] Not surprisingly, the Company's bids

B. <u>There Should Be No Depreciation Expense On the Wilson and Coleman Plants During the Shutdown</u>

Q. Please describe the Company's request to recover depreciation expense on the Wilson ~~and Coleman~~ plant~~s~~ even though they are shut down during the test year.

A. The Company plans to shutdown both the Wilson and Coleman plants during the test year and has removed the variable expenses and avoidable fixed O&M expenses (payroll and related expenses plus avoidable fixed departmental expenses ("FDE")) from the test year expenses and revenue requirement, with certain exceptions that should be corrected and that I subsequently address. The most significant of these exceptions is that the Company failed to remove the depreciation expense on the Wilson ~~and Coleman~~ plant~~s~~, despite the fact that the RUS Uniform System of Accounts ("USOA") requires that it cease depreciation expense on the plants after they are shutdown. Under the USOA and the circumstances in this case, depreciation is an avoidable fixed expense.

In the Century rate case, the Company argued that depreciation expense should continue on the plants during the shutdown and should be included in the revenue requirement. The Company argues the same position in this case, according to its response to AG 2-89. Thus, the Company originally included $26.643 million in depreciation expense on the Wilson and Coleman plants in the revenue requirement in this case, consisting of $20.177 million for the Wilson plant and $6.466 million for the Coleman plant. These amounts were provided by the Company in its Confidential responses to AG 1-105 and AG 1-106, which I have replicated as my Confidential Exhibit___(LK-3) and Confidential Exhibit___(LK-4), respectively. The depreciation expense for the Coleman plant was removed from the claimed revenue requirement in the Company's Rebuttal.

Q. **Does the Company have any valid authoritative support for its argument that the accounting rules require it to continue depreciation on the Wilson and Coleman plants after they are shut down?**

A. No. In response to Staff's cross-examination questions on this issue at the hearing in Case No. 2012-00535, Ms. Billie Richert, the Company's CFO, stated that "*there are no definitive pronouncements or standards*" on whether depreciation should be ceased on an idled plant.[6]

Q. **Is the Company correct on this issue?**

A. No. The RUS USOA requires the utility to cease depreciation on generating assets removed from service until they again are returned to service. The USOA limits depreciation expense to the plant in service recorded in Account 101 *Electric Plant in Service*. Once the Wilson and Coleman plants are shutdown, their costs no longer qualify under the USOA as plant in service and no longer qualify for depreciation expense. In order to be included in plant in service, the USOA requires that the original cost of electric plant included in Account 101 must be "*used by the utility in its electric utility operations.*" Specifically, for Account 101, the USOA states:

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6 Tr. July 2, 2013 at 10:48:30.

A. Yes. Another utility, Northern States Power Company ("NSP," a subsidiary of Xcel Energy), recently proposed a similar deferral of the depreciation expense on Sherco 3, one of its coal-fired units, which was idled for an extended period due to a catastrophic equipment failure.[13] In that proceeding, NSP offered to defer the depreciation expense associated with Sherco 3, amortize that deferral over the remaining life of the unit, and essentially suspend and restart the remaining life when the unit was placed back in service. The Administrative Law Judge accepted the Company's offer to defer the depreciation expense for the test year.

Although NSP is subject to the FERC USOA, and not the RUS USOA, the accounting requirements for plant that is temporarily shut down are the same for the two USOAs. Instead of setting the depreciation rate to 0%, the NSP approach was to continue to compute the depreciation expense for accounting purposes, but to include $0 in the revenue requirement, defer the difference by recording negative depreciation expense, and record the difference as a regulatory asset. The net effect was the same for ratemaking purposes as if the Company had used a 0% depreciation rate for both accounting and ratemaking purposes.

Q. Is the cash flow generated by depreciation alone, excluding the depreciation on the Wilson and Coleman plants, sufficient for the Company to make its debt principal repayments during the shutdown period?

A. Yes. The Company originally included $49.138 million in depreciation and amortization expense in the test year. The depreciation expense on the Wilson and Coleman plants comprises $26.643 million of this total amount. If the Commission directs the Company to cease

13 Minnesota Public Utilities Commission, Docket No. OAH 68-2500-30266 PUC E-002/GR-12-961.

Q. If the Company cannot shut down the Wilson and Coleman plants because MISO determines that one or both are must run units because of the Smelter load and for that reason cannot cease depreciation, then what effect will this have on the KIUC Rate Plan?

A. If MISO determines that either Wilson or Coleman is must run because of the Smelter load at either Hawesville or Sebree, then there will be an increase in the revenue requirement, all else equal. This increase should be recovered directly from Century or, if that is not possible, then it should be equitably shared between the Company's customers and creditors.

As I previously discussed, depreciation is an avoidable expense during a temporary shutdown, similar to payroll expense and other fixed departmental expenses. If the Smelters cease operating, then the Company will not incur the depreciation expense. However, if the plants are not shut down and are required to operate for reliability purposes to allow the Smelters market access, then this expense should be charged to and recovered from Century. The market-based rates paid by Century remain regulated by the Commission and still are subject to the "fair, just and reasonable" and nondiscrimination standards. Costs caused by Century, including depreciation expense that otherwise could be avoided, should be paid by the cost causer. Otherwise, the other customers will be required to inappropriately subsidize the Smelters for this component of the cost to serve them even with market access.

If that is not possible for whatever reason, then the increase in the revenue requirement should be shared 31.3% to customers and 68.7% to creditors. Under the KIUC Rate Plan, this would add ~~$8.339~~ $6.315 million (~~$26.443~~ $20.177 million in depreciation expense on the Wilson and Coleman plants times 31.3% customer share of stranded fixed costs) to the rate

Q. How should the Commission treat these nonrecurring expenses?

A. The Commission should treat all nonrecurring revenues and expenses in the same manner. I recommend that the Commission defer the Coleman layup expenses and amortize them over five years, the same treatment as the Company proposes for the Coleman severance expenses.

Q. What is the effect of your recommendation?

A. The effect of my recommendation is a reduction of $1.600 million in the revenue requirement.

E. Mercury and Air Toxics Standards ("MATS") Capital Expenditures Will Not Be Incurred for the Wilson and Coleman Plants In the Test Year

Q. Did Big Rivers include MATS compliance capital expenditures for the Wilson and Coleman plants in the test year?

A. Yes. The Company included [redacted] million for the Wilson plant and [redacted] million for the Coleman plant for MATS compliance in capital expenditures and plant additions in the test year, according to its Confidential response to KIUC 2-42. These costs were included in the worksheet tab labeled "ECP" (environmental compliance plan) in the financial model. The capital expenditures were assumed to be in-service by September 1, 2014. These amounts are direct expenditures only and do not include capitalized interest during construction.

Q. Does Big Rivers still plan to install the MATS compliance equipment on the Wilson and Coleman plants during the test year?

A. No. Big Rivers does not intend to install the MATS compliance equipment or make the capital expenditures for these plants unless they are returned to service, according to its Confidential response to KIUC 2-42. I have attached a copy of this response as my Confidential Exhibit___(LK-12), which confirms this plan.

Q. Should the Commission remove the effects of the MATS capital expenditures for the Wilson and Coleman plants from the Company's revenue requirement?

A. Yes. The Company does not plan to install the MATS equipment or incur the capital expenditures during the test year. As I previously noted, this partially offsets the reduction in cash flow from ceasing depreciation on the Wilson and Coleman plants during the shutdown period.

Q. What is the effect on the revenue requirement of removing the MATS capital expenditures from the test year?

A. The effect is to reduce the revenue requirement by $0.682 million dollars. The revenue requirement includes the interest expense, related margin using a 1.24 TIER, depreciation expense, property tax expense, and property insurance expense. The Company included interest expense using a 3.0% ECP financing interest rate. The

~~Company included depreciation expense based on the depreciation rates that it proposed in the Century rate case and that are reflected in its request in this case. I have attached the calculation of the effect on the revenue requirement as my Confidential Exhibit___(LK-13).~~

F. <u>MISO Capacity Charges and Severance Expense Will Not Be Incurred if Coleman Is Not Shut Down</u>

Q. Please describe the Company's request to defer and amortize MISO capacity charges that it will incur from February 2014 to May 2014 if Coleman is shut down.

A. The Company assumed that it will incur $0.511 million in MISO capacity charges if Coleman is shutdown contemporaneous with the Alcan termination on January 31, 2014. The Company seeks to defer this amount and recover $0.102 million in amortization expense based on a five year amortization period.

Q. Please describe the Company's request to recover Coleman plant severance expenses.

A. The Company estimates that it will incur $3.713 million in labor severance costs to shutdown of the Coleman plant contemporaneous with the Alcan termination on January 31, 2014. The Company proposes to defer this amount and recover $0.743 million in amortization expense based on a five year amortization period. The

This sharing is equitable because the Rural and Large Industrial customers did not cause the excess capacity and should not be required to pay for the entirety of the cost. Arguably, they should not be required to pay for any of the cost of capacity that no longer is used and useful in providing utility service. However, the equitable sharing that I propose provides a balanced approach.

I also note that my recommendation applies only to the base rate increase. The remaining customers still will incur the entirety of the FAC and ECR rate increases.

Q. Have you quantified the effect of your recommendation?

A. Yes. The effect is to reduce the Company's revenue requirement by ~~$18.786~~ $23.121 million to reflect my recommendation to share 68.7% of the base rate impact of the excess capacity caused by the Century termination with the Company's creditors. To calculate this amount, I multiplied the Company's quantification of the base rate increase caused by the Century termination, net of cost reductions, or ~~$27.345~~ $33.655 million, times the 68.7% allocation to the creditors.

Q. What is the net effect of all of your recommendations on the Company's proposed revenue requirement?

A. The net effect is a reduction of ~~$61.838~~ $60.693 million in the Company's revised proposed increase of ~~$70.397~~ $71.227 million, or an increase of no more than ~~$8.559~~ $10.534 million.

Q. What effect will your recommendations have on depletion of the Reserve funds under the KIUC Rate Plan?

A. The Reserve funds will be depleted in ~~early February 2015~~ late December 2014 or early January 2015 instead of the mid to late February 2015 date calculated by Mr. Baron based on his recommendation to treat all customers equally with respect to the Reserve funds that were created by the Commission. In other words, if the Commission adopts all of the KIUC revenue requirement recommendations, then the reduction in the Company's revenues will accelerate the depletion of the Rural Economic Reserve by approximately two months ~~weeks.~~ That is because only one of the KIUC recommendations will affect the depletion of that Reserve fund, i.e., the adjustment to reflect a sharing of the stranded fixed costs associated with excess capacity with the creditors.

None of the other KIUC adjustments affect the Company's margin. For example, if the Commission directs the Company to cease depreciation on the Wilson and Coleman plants, then depreciation expense and the revenue to recover depreciation expense still will match and there will be no reduction in the Company's margins. As another example, if the Commission reflects the Century transmission revenue in the revenue requirement and the Company receives that revenue, then there will be no reduction in the Company's margins. As yet another example, the Company will not make the MATS capital expenditures for the Wilson and Coleman plants in the test year. Thus, removing the effects of these

Henry Hub Natural Gas Spot Price

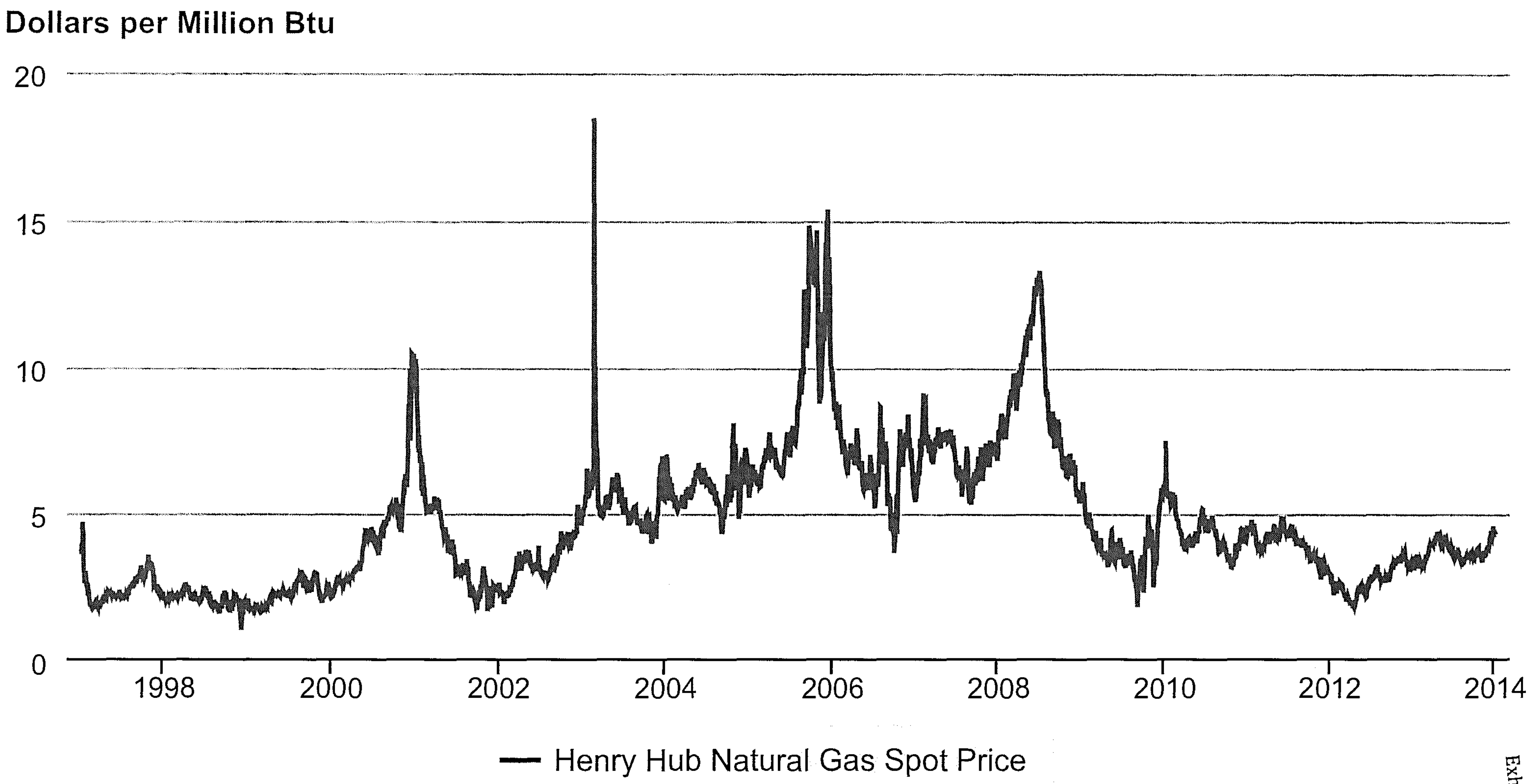

Exhibit -

eia Source: U.S. Energy Information Administration

SC EXHIBIT 1

Back to Contents **Data 1: Henry Hub Natural Gas Spot Price (Dollars per Million Btu)**

Sourcekey	RNGWHHD
Date	Henry Hub Natural Gas Spot Price (Dollars per Million Btu)
Jan 07, 1997	3.82
Jan 08, 1997	3.8
Jan 09, 1997	3.61
Jan 10, 1997	3.92
Jan 13, 1997	4
Jan 14, 1997	4.01
Jan 15, 1997	4.34
Jan 16, 1997	4.71
Jan 17, 1997	3.91
Jan 20, 1997	3.26
Jan 21, 1997	2.99
Jan 22, 1997	3.05
Jan 23, 1997	2.96
Jan 24, 1997	2.62
Jan 27, 1997	2.98
Jan 28, 1997	3.05
Jan 29, 1997	2.91
Jan 30, 1997	2.86
Jan 31, 1997	2.77
Feb 03, 1997	2.49
Feb 04, 1997	2.59
Feb 05, 1997	2.65
Feb 06, 1997	2.51
Feb 07, 1997	2.39
Feb 10, 1997	2.42
Feb 11, 1997	2.34
Feb 12, 1997	2.42
Feb 13, 1997	2.22
Feb 14, 1997	2.12
Feb 18, 1997	1.84
Feb 19, 1997	1.95
Feb 20, 1997	1.92
Feb 21, 1997	1.92
Feb 24, 1997	1.92
Feb 25, 1997	1.77
Feb 26, 1997	1.81
Feb 27, 1997	1.8
Feb 28, 1997	1.78
Mar 03, 1997	1.8
Mar 04, 1997	1.87
Mar 05, 1997	1.92
Mar 06, 1997	1.82
Mar 07, 1997	1.89
Mar 10, 1997	1.95
Mar 11, 1997	1.92
Mar 12, 1997	1.96

Mar 13, 1997	1.98
Mar 14, 1997	1.97
Mar 17, 1997	2.01
Mar 18, 1997	1.91
Mar 19, 1997	1.88
Mar 20, 1997	1.88
Mar 21, 1997	1.87
Mar 24, 1997	1.8
Mar 25, 1997	1.85
Mar 26, 1997	1.85
Mar 27, 1997	1.84
Mar 31, 1997	1.84
Apr 01, 1997	1.95
Apr 02, 1997	1.85
Apr 03, 1997	1.87
Apr 04, 1997	1.91
Apr 07, 1997	1.99
Apr 08, 1997	2.01
Apr 09, 1997	1.96
Apr 10, 1997	1.97
Apr 11, 1997	1.98
Apr 14, 1997	2
Apr 15, 1997	2
Apr 16, 1997	2.02
Apr 17, 1997	2.08
Apr 18, 1997	2.1
Apr 21, 1997	2.09
Apr 22, 1997	2.1
Apr 23, 1997	2.22
Apr 24, 1997	2.11
Apr 25, 1997	2.16
Apr 28, 1997	2.1
Apr 29, 1997	2.09
Apr 30, 1997	2.16
May 01, 1997	2.19
May 02, 1997	2.21
May 05, 1997	2.23
May 06, 1997	2.25
May 07, 1997	2.34
May 08, 1997	2.33
May 09, 1997	2.3
May 12, 1997	2.27
May 13, 1997	2.18
May 14, 1997	2.22
May 15, 1997	2.25
May 16, 1997	2.19
May 19, 1997	2.25
May 20, 1997	2.22
May 21, 1997	2.21
May 22, 1997	2.22
May 23, 1997	2.2
May 27, 1997	2.29

May 28, 1997	2.34
May 29, 1997	2.29
May 30, 1997	2.23
Jun 02, 1997	2.2
Jun 03, 1997	2.11
Jun 04, 1997	2.19
Jun 05, 1997	2.18
Jun 06, 1997	2.19
Jun 09, 1997	2.19
Jun 10, 1997	2.16
Jun 11, 1997	2.16
Jun 12, 1997	2.14
Jun 13, 1997	2.15
Jun 16, 1997	2.2
Jun 17, 1997	2.2
Jun 18, 1997	2.22
Jun 19, 1997	2.23
Jun 20, 1997	2.25
Jun 23, 1997	2.29
Jun 24, 1997	2.32
Jun 25, 1997	2.32
Jun 26, 1997	2.23
Jun 27, 1997	2.17
Jun 30, 1997	2.17
Jul 01, 1997	2.16
Jul 02, 1997	2.14
Jul 03, 1997	2.11
Jul 07, 1997	2.13
Jul 08, 1997	2.13
Jul 09, 1997	2.16
Jul 10, 1997	2.15
Jul 11, 1997	2.16
Jul 14, 1997	2.18
Jul 15, 1997	2.21
Jul 16, 1997	2.24
Jul 17, 1997	2.29
Jul 18, 1997	2.26
Jul 21, 1997	2.17
Jul 22, 1997	2.18
Jul 23, 1997	2.2
Jul 24, 1997	2.24
Jul 25, 1997	2.22
Jul 28, 1997	2.19
Jul 29, 1997	2.23
Jul 30, 1997	2.19
Jul 31, 1997	2.23
Aug 01, 1997	2.24
Aug 04, 1997	2.26
Aug 05, 1997	2.33
Aug 06, 1997	2.38
Aug 07, 1997	2.5
Aug 08, 1997	2.38

Aug 11, 1997	2.53
Aug 12, 1997	2.56
Aug 13, 1997	2.45
Aug 14, 1997	2.57
Aug 15, 1997	2.53
Aug 18, 1997	2.56
Aug 19, 1997	2.61
Aug 20, 1997	2.62
Aug 21, 1997	2.45
Aug 22, 1997	2.47
Aug 25, 1997	2.53
Aug 26, 1997	2.58
Aug 27, 1997	2.51
Aug 28, 1997	2.57
Aug 29, 1997	2.69
Sep 02, 1997	2.82
Sep 03, 1997	2.86
Sep 04, 1997	2.73
Sep 05, 1997	2.67
Sep 08, 1997	2.67
Sep 09, 1997	2.74
Sep 10, 1997	2.74
Sep 11, 1997	2.78
Sep 12, 1997	2.86
Sep 15, 1997	2.88
Sep 16, 1997	2.83
Sep 17, 1997	2.75
Sep 18, 1997	2.84
Sep 19, 1997	2.94
Sep 22, 1997	2.98
Sep 23, 1997	3.09
Sep 24, 1997	3.03
Sep 25, 1997	3.05
Sep 26, 1997	3.24
Sep 29, 1997	3.09
Sep 30, 1997	2.96
Oct 01, 1997	3.08
Oct 02, 1997	2.97
Oct 03, 1997	2.91
Oct 06, 1997	2.96
Oct 07, 1997	2.81
Oct 08, 1997	2.8
Oct 09, 1997	2.8
Oct 10, 1997	2.78
Oct 13, 1997	2.87
Oct 14, 1997	2.84
Oct 15, 1997	2.84
Oct 16, 1997	2.94
Oct 17, 1997	2.97
Oct 20, 1997	3.05
Oct 21, 1997	3.13
Oct 22, 1997	3.24

Oct 23, 1997	3.34
Oct 24, 1997	3.29
Oct 27, 1997	3.46
Oct 28, 1997	3.61
Oct 29, 1997	3.45
Oct 30, 1997	3.34
Oct 31, 1997	3.22
Nov 03, 1997	3.23
Nov 04, 1997	3.15
Nov 05, 1997	3.18
Nov 06, 1997	3.2
Nov 07, 1997	3.05
Nov 10, 1997	3.2
Nov 11, 1997	3.26
Nov 12, 1997	3.28
Nov 13, 1997	3.27
Nov 14, 1997	3.25
Nov 17, 1997	3.1
Nov 18, 1997	3
Nov 19, 1997	2.97
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Dec 31, 2013	4.31
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SC EXHIBIT 2

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

Or

In the Confidential File Materials at PSC

SC EXHIBIT 3

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

Or

In the Confidential File Materials at PSC

SC EXHIBIT 4

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

Or

In the Confidential File Materials at PSC

Exhibit -

Report on the
Comprehensive Depreciation Study

Prepared for
Big Rivers Electric Corporation
Henderson, Kentucky

Big Rivers
ELECTRIC CORPORATION

November 2012
Project Number: 70000

Burns & McDonnell
SINCE 1898

SC EXHIBIT 5

Report on the
Comprehensive Depreciation Study

Prepared for the

Big Rivers Electric Corporation
Henderson, Kentucky

November 2012

Project Number 70000

Prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

November 20, 2012

Mr. Ralph Ashworth
Director Finance
Big Rivers Electric Corporation
201 Third Street
Henderson, KY 42420

Re: 2012 Comprehensive Depreciation Study
Project Number: 70000

Dear Mr. Ashworth:

This report encompasses the 2012 Comprehensive Depreciation Study (the Study), completed by Burns & McDonnell Engineering Company (Burns & McDonnell) on behalf of Big Rivers Electric Corporation (Big Rivers), for Big Rivers' electric plant, transmission, and general plant assets as of July 31, 2012. The Study was prepared in accordance with Big Rivers' Request for Proposal (RFP) dated August 3, 2012. The Study was performed for all facilities accounted for in accordance with Rural Utilities Service (RUS) Bulletin 1767B-1, Uniform System of Accounts.

Big Rivers has committed to filing for a general review of its operations and tariffs to the Kentucky Public Service Commission (KPSC) in the first quarter of 2013. This Study was also completed as a requirement for that filing. The depreciation rates developed as part of this study must be approved by the RUS and KPSC before implementation. This Study reflects the results of Burns & McDonnell's engineering assessment and analysis of the remaining useful lives of Big Rivers' system assets and presents our proposed electric plant, transmission system, and general plant depreciation rates.

The Study presents the proposed remaining life estimates and the corresponding proposed depreciation rates for each account. This Study also provides a comparison of Big Rivers' annual depreciation expense calculated using both the existing and the proposed depreciation rates based on the plant in service as of July 31, 2012. This comparison shows the proposed depreciation rates would result in an increase in depreciation expense of approximately $1.6 million per year.

This report represents the completion of Burns & McDonnell's scope of services for the Study on behalf of Big Rivers. Our project manager and team of engineers who participated in the project would like to extend appreciation to the staff for their assistance during the project. We are available to discuss this report and Burns & McDonnell's findings with you at your convenience.

Sincerely,
Burns & McDonnell

Jon Summerville
Project Manager

Ted J. Kelly
Principal & Project Director

JES/tjk

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

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EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

This report describes the 2012 Comprehensive Depreciation Study (the Study), completed by Burns & McDonnell Engineering Company (Burns & McDonnell) on behalf of Big Rivers Electric Corporation (Big Rivers; or the Cooperative), pertaining to Big Rivers' electric, transmission, and general plant assets in service as of July 31, 2012. The Study was prepared in accordance with Big Rivers' Request for Proposal (RFP) dated August 3, 2012.

INTRODUCTION

The Study desired by Big Rivers was to be performed for all facilities in accordance with Rural Utilities Service (RUS) Bulletin 1767B-1. Big Rivers and Burns & McDonnell jointly completed and filed the last depreciation study titled "Report on the Comprehensive Depreciation Study" with the RUS in February of 2011 (2010 Study). Big Rivers requires a current study be performed because Big Rivers has committed to filing a general review of its operations and tariffs with the Kentucky Public Service Commission (KPSC) in the first quarter of 2013. This Study was completed as a requirement for that filing with the KPSC.

Burns & McDonnell's approach to meeting the requirements for the Study was based substantially on performance of the previously completed physical site observations of the generating and transmission facilities by experienced power plant design engineers and transmission system engineers, respectively. These engineers then applied their experience and engineering judgment in approximating the remaining lives of each of Big Rivers' generating facilities. Generally, the previously completed site visits at included observation of the equipment and facilities and discussions with Big Rivers' staff and included the following activities.

- Observation of transmission and generating plant equipment and facilities
- Evaluation of equipment and facilities condition
- Interview of transmission and production operating and maintenance staff
- Review of organization structure, procedures, and staffing levels
- Determination of transmission and production operating and maintenance practices

- Assessment of transmission and production operating and maintenance experiences
- Collection of pertinent cost and operating data and records
- Collection of environmental data
- Development of facilities descriptions

The projected remaining useful lives of the various transmission assets and generating assets for each plant were then factored into the depreciation rate analysis performed by Burns & McDonnell's depreciation consultants. The Study included analysis of the service life characteristics, projected net salvage values, and depreciation reserves for the generating assets, as well as for the transmission and general plant assets.

The information used in the analysis of Big Rivers' depreciation rates was provided by the Cooperative's staff. This included various computer-generated accounting data, certain performance results, budgets, inspection reports, technical documents such as drawings and specifications, contracts, policies and procedure manuals, and other documents such as prior related studies. Historical data from 1965 to 2012 that was recorded in Big Rivers' Continuing Property Records (CPR) system was used throughout the analyses. For plant categories where sufficient experience data was not available, publicly available industry data was utilized as a representative proxy.

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

Generally accepted depreciation study procedures widely used by the utility industry were followed. Actuarial analysis of average service lives and dispersions based on historical characteristics of the RUS account since inception were developed. Either the Whole Life procedure or the Life Span combined with the Remaining Life technique was used to calculate the proposed depreciation rate for each account, depending on the nature of the types of property units included in the account.

ENGINEERING ASSESSMENT

Estimated remaining useful lives for Big Rivers' generating plant assets were based, in part, on the American Society of Testing and Materials (ASTM) guidelines for high temperature creep design. Per these guidelines, the portions of a generating facility subject to creep stress should be designed to experience at least 200,000 hours of service or 5,000 thermal cycles. Assuming 8,000 hours of full-load operation per year, this equates to 25 years of service.

Because most equipment manufacturers are quite conservative in applying these guidelines, reaching these levels of service does not mean that a generating unit cannot provide reliable service for much longer periods. It does mean that creep-susceptible portions of a generating unit that has logged this level of operation should undergo metallurgical testing to detect the beginning of creep stress damage. Once damage is detected, the affected components should be evaluated regularly and repairs or replacement performed as indicated to facilitate the unit's successful return to service.

Burns & McDonnell recommends that Big Rivers continues to follow a comprehensive program of testing on those units approaching the service limits in the ASTM guidelines. Individual components should be either repaired or replaced as damage is identified. Since creep stress is a long-term phenomenon, there should be adequate time to procure and schedule replacement of any damaged components. All of the Big Rivers generating units have reached the age when this testing program should be performed. This testing is currently being performed by Big Rivers and should continue to be performed.

Since the Unwind Closing in 2009, Big Rivers has not performed major maintenance such as valve inspections and turbine generator inspections on a schedule consistent with prudent utility operations. Based on the assumption that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that all of Big Rivers' generating units cannot remain in service for a long time. Should major maintenance continue to be postponed, it is not likely that all of Big Rivers' generating units will remain in service as long as similar generating units.

In the initial study conducted in 1998 an additional 200,000 hours of operation was assumed as the remaining useful life of each plant beyond the original 200,000 hours from ASTM guidelines, for a total of 400,000 hours. Based on Big Rivers' records of operation, maintenance and component replacements; other service documents; and previously completed on-site inspections; approximately 30,000 – 60,000 hours of additional operation was assumed to calculate the remaining useful life of each unit. The typical operating hours from the 2010 Study along with the actual historical operating hours the last eight years for each unit were assumed to continue for purposes of translating the remaining operating hours into remaining years of service.

DEPRECIATION RATE ANALYSIS

The Study was conducted to analyze the service life characteristics, net salvage indications, and depreciation reserve status based on historical data from Big Rivers' CPR system data, and then to derive appropriate depreciation rates for Big Rivers' electric plant in service, transmission system, and general plant assets. Actuarial analyses were performed using Big Rivers' historical data and applied to individual accounts to estimate useful service lives.

Two primary methods were used to calculate depreciation accruals: the Whole Life method (most General Plant accounts) and the Life Span method combined with the Remaining Life technique (all Production accounts, Transmission accounts, and Account 390 – Structures).

Burns & McDonnell's engineers and depreciation consultants performed analysis of available data and information in order to assess whether specific detailed estimates of terminal removal costs for each of the Big Rivers generating stations could be developed with reasonable substantiation. The significant potential costs that could be required for environmental remediation required at the Big Rivers plant sites were not considered in developing the net salvage values. Instead, the historical removal costs provided by Big Rivers from the 2010 Study were used in calculating the net salvage factors.

Table ES-1 shows each capital plant account balance and reserve balance studied as of July 31, 2012. Table ES-1 also summarizes the results of the depreciation rate analysis by showing the existing depreciation rates and annual depreciation expense compared to the proposed depreciation rates and annual depreciation expense. Detailed calculations for the proposed rates are provided in Appendix A.

Annual depreciation expense based on applying the existing depreciation rates to the July 31, 2012 balances in each account totaled $43.9 million. The application of the proposed depreciation rates to the same July 31, 2012 account balances resulted in estimated annual depreciation expense of approximately $45.5 million, representing an estimated increase in Big Rivers' total annual depreciation expense of approximately $1.6 million.

Table ES-1: 2012 Depreciation Rate Study Summary

Account	Description	As of July 31, 2012 Plant Balance	Reserve Balance	Reserve Ratio	Existing Depreciation Rate	Average Service Life	Remaining Service Life	Net Salvage Factor	Proposed Depreciation Rate	Annual Depreciation Expense Existing	Proposed	Variance
		- $ -	- $ -		- % -	- Years -	- Years -	- % -	- % -	- $ -	- $ -	- $ -
310	Land & Land Improvements	4,537,577	0									
PRODUCTION PLANT [1]												
340	Land	475,968	0									
311	Structures	125,693,531	82,324,994	65.5	1.38%	62.0	28.2	-4.5%	1.38%	1,734,571	1,737,612	3,041
312	Boiler Plant	680,885,710	356,227,283	52.3	1.88%	59.5	26.1	-5.0%	2.02%	12,800,651	13,732,241	931,589
312 A-K	Boiler Plant - Environment Compliance	577,753,481	222,781,719	38.6	2.28%	53.0	26.1	-2.0%	2.43%	13,172,779	14,018,172	843,392
312 L-P	Short-Life Production Plant -Environmental	13,034,034	3,069,236	23.5	20.22%	10.0	4.8	0.0%	15.95%	2,635,482	2,078,941	(556,541)
312 V-Z	Short-Life Production Plant -Other	721,531	(178,280)	-24.7	14.39%	10.0	4.9	0.0%	25.38%	103,828	183,151	79,323
314	Turbine	230,546,435	129,685,979	56.3	1.91%	59.5	26.5	-8.2%	1.96%	4,403,437	4,511,020	107,583
315	Electric Equipment	62,213,068	37,265,920	59.9	1.99%	50.9	18.3	3.0%	2.03%	1,238,040	1,261,703	23,663
316	Miscellaneous Equipment	4,745,114	60,556	1.3	3.78%	57.5	24.3	0.5%	4.04%	179,365	191,836	12,471
341	CT - Structures	154,233	122,610	79.5	1.17%	52.5	19.4	0.0%	1.06%	1,805	1,633	(172)
342	CT - Fuel Holders & Access.	1,442,387	641,686	44.5	9.10%	52.5	19.2	-134.8%	9.92%	131,257	143,063	11,806
343	CT - Prime Movers	4,915,886	3,929,184	79.9	3.02%	52.5	19.4	-38.3%	3.02%	148,460	148,316	(144)
344	CT - Generators	1,102,964	1,027,096	93.1	0.50%	52.5	19.5	0.0%	0.35%	5,515	3,891	(1,624)
345	CT - Accessory Electrical Equipment	399,274	178,372	44.7	2.05%	52.5	18.9	0.0%	2.93%	8,185	11,683	3,498
	Subtotal	1,708,621,193	837,136,354							36,563,375	38,021,262	1,457,887
TRANSMISSION [1]												
350	Land	704,868	0									
352	Structures	6,872,307	3,939,593	57.3	1.90%	52.5	23.3	-2.4%	1.94%	130,574	133,325	2,752
353	Station Equipment	123,005,428	57,372,818	46.6	2.23%	52.5	23.4	-0.2%	2.29%	2,743,021	2,818,401	75,380
354	Towers	8,593,544	5,258,193	61.2	1.42%	57.5	28.5	0.0%	1.36%	122,028	117,062	(4,967)
355	Poles	42,531,008	24,872,625	58.5	2.06%	49.5	20.5	0.0%	2.03%	876,139	861,385	(14,754)
356	Lines	43,877,088	25,179,681	57.4	1.69%	52.5	23.5	0.0%	1.81%	741,523	795,634	54,112
	Subtotal	225,584,244	116,622,910							4,613,285	4,725,807	112,523
GENERAL PLANT [2]												
389	Land	407,251	0									
390	Structures [1]	5,263,520	1,841,773	35.0	2.84%	42.5	11.5	21.8%	3.76%	149,484	198,151	48,667
391.0/391.6/391.7	Office Furniture & Equipment	797,888	(226,065)	-28.3	17.12%	10.0	6.0	8.9%	9.11%	136,598	72,724	(63,875)
391.2, 391.3	Computer	20,489,975	2,105,972	10.3	10.29%	10.0	4.8	1.2%	9.88%	2,108,418	2,024,934	(83,484)
392.2	Vehicles - General	2,085,515	1,222,328	58.6	4.39%	10.0	3.0	14.2%	8.58%	91,554	179,034	87,480
392.3	Vehicles - Transmission	1,257,240	788,792	62.7	6.14%	10.0	4.7	16.9%	8.31%	77,195	104,450	27,256
393	Stores Equipment	98,766	77,948	78.9	4.40%	16.0	5.2	4.4%	5.97%	4,346	5,900	1,554
394	Tools	731,818	441,711	60.4	4.61%	16.0	8.2	2.7%	6.08%	33,737	44,482	10,745
395	Lab Equipment	221,279	176,719	79.9	4.41%	16.0	5.7	2.1%	6.12%	9,758	13,541	3,783
396	Power Operated Equipment	567,875	423,883	74.6	3.70%	16.0	5.6	24.9%	4.69%	21,011	26,644	5,632
397	Communication Equipment	1,670,551	1,488,248	89.1	4.35%	16.0	1.0	-0.1%	6.25%	72,669	104,474	31,805
398	Miscellaneous Equipment	251,254	44,367	17.7	11.80%	16.0	9.0	3.2%	6.05%	29,648	15,200	(14,448)
	Subtotal	33,842,932	8,385,678							2,734,419	2,789,533	55,115
TOTAL		**$1,968,115,264**	**$962,144,943**							**$43,911,079**	**$45,536,603**	**$1,625,524**

[1] Life Span Method depreciation
[2] Whole Life Method depreciation

SUMMARY & CONCLUSIONS

Based on our analysis of the information provided by Big Rivers and the results of the previously completed property observations of the Big Rivers system facilities, Burns & McDonnell has formulated estimates of the remaining useful service lives for each plant and the transmission system assets. From this, proposed depreciation rates have been developed for all of the Cooperative's generation, transmission, and general plant in service, utilizing historical accounting records data, other published depreciation survey information, and generally accepted depreciation analysis methodologies.

Assuming that the recommended equipment testing on the generating plant assets is continued, that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, and assuming that any damaged components of the equipment are either repaired or replaced, Burns & McDonnell finds that there should be no reason, from a mechanical engineering perspective, that all of Big Rivers' generating units could not remain in reliable operating service well into the future. This conclusion is conditioned by the forthcoming statement of limiting conditions.

Therefore, Burns & McDonnell recommends to Big Rivers that it consider pursuing approval and implementation of the proposed depreciation rates for each RUS account as presented in this report. These proposed depreciation rates are projected to increase the total annual depreciation expense of Big Rivers by approximately 3.7 percent.

STATEMENT OF LIMITING CONDITIONS

The analysis and results of the Study developed and presented herein by Burns & McDonnell are based on sound engineering and economic theory. However, certain factors and parameters affecting the performance of the Study must be clearly stated. The estimated remaining useful lives, net salvage rates, and proposed depreciation rates are provided subject to the following limiting conditions:

1. All existing information and facts known to Big Rivers were assumed to have been made available.

2. Assessments of the condition of the assets were based solely on casual observations. No detailed testing of any of the equipment or facilities was performed by Burns & McDonnell.
3. Generally accepted levels of and procedures for operation and maintenance of the plant in service throughout the remaining life was assumed in the future.
4. Emphasis on the engineering assessment of the generating assets and transmission assets was assumed. No physical inspection of transmission and general plant assets was made.

In the preparation of this report, the information provided to us by Big Rivers was used by Burns & McDonnell to make certain assumptions with respect to conditions that may exist in the future. While we believe the assumptions made are reasonable for the purposes of this report, we make no representation that the conditions assumed will, in fact, occur. In addition, while we have no reason to believe that the information provided to us by Big Rivers, and on which we have relied, is inaccurate in any material respect, we have not independently verified such information and cannot guarantee its accuracy or completeness. To the extent that actual future conditions differ from those assumed herein or from the information provided to us, the actual results will vary from those projected.

* * * * *

PART I - INTRODUCTION

PART I
INTRODUCTION

This report describes the Comprehensive Depreciation Study completed by Burns & McDonnell Engineering Company for Big Rivers Electric Corporation (as of July 31, 2012). The Study was prepared in accordance with Big Rivers' Request for Proposal (RFP) dated August 3, 2012. The Study desired by Big Rivers was to be performed for all facilities accounted for in accordance with RUS Bulletin 1767B-1, Uniform System of Accounts.

Part II of the Study, Engineering Assessment, is intended to address the issues identified by the RUS to be covered in the Study:

- Discussion of facility basic design and equipment
- Analysis of plant historical performance
- Review of on-site inspections and analysis of operating conditions
- Discussion of Big Rivers' operation, maintenance, and staffing
- Analysis of external and environmental factors affecting asset useful lives
- Statement of opinion regarding remaining useful lives and proper depreciation rates

Descriptions of each of Big Rivers' generating stations are provided, along with assessments of the recent historical operations and maintenance and the physical condition of each plant developed through the previously completed on-site observations of the facilities. The engineering assessment presented in Part II addresses each of the above areas, with the exception of the development of proposed depreciation rates.

The analyses leading to formulation of proposed new depreciation rates for Big Rivers are described in Part III. Part III provides brief descriptions of the alternative methods used in calculating depreciation rates and identifies the specific method used, as well as the various considerations and assumptions made, in developing the actuarial analyses for each account. Detailed calculations for all the accounts are provided in Appendix A.

Part IV of the Study summarizes the results of the Study and quantifies the estimated impact of the proposed depreciation rates on Big Rivers' annual depreciation expense accrual.

BIG RIVERS ELECTRIC CORPORATION

Big Rivers is a generation and transmission cooperative that provides bulk wholesale electric service to its member distribution cooperatives, with delivery through high voltage transmission facilities it owns and operates. Big Rivers was established as a cooperative and is operated under the authority of the RUS, an agency within the United States Department of Agriculture. Big Rivers is headquartered in Henderson, Kentucky and provides power for retail distribution to all or part of 22 counties in western Kentucky through its three member cooperatives:

- Jackson Purchase Energy Corporation, Paducah, KY
- Meade County Rural Electric Cooperative Corporation, Brandenburg, KY
- Kenergy Corp., Henderson, KY

Big Rivers owns and operates 1,444 MW of generating capacity in four power generating stations: Robert A. Reid (130 MW), Kenneth C. Coleman (443 MW), Robert D. Green (454 MW), and D.B. Wilson (417 MW). Total power capacity is 1,819 MW, including rights to Henderson Municipal Power & Light (HMP&L) Station Two and contracted capacity from Southeastern Power Administration (SEPA).

Big Rivers also owns and operates approximately 1,260 miles of transmission lines, most of which are operated at 69 kilovolts (kV), 161 kV, or 345 kV. In addition, the Cooperative's transmission system includes electric substations with over 3,540 MVa of transformer capacity. General plant facilities of Big Rivers include its headquarters office buildings, a warehouse, the central lab, publications, and communications buildings, the vehicle and power-operated equipment fleets, and all types of equipment, furniture, computers, and other items used in the Cooperative's operations.

PURPOSE OF STUDY

Big Rivers completed and filed its last depreciation study (conducted by Burns & McDonnell) with the RUS in February of 2011. Big Rivers has committed to filing a general review of its operations and tariffs with the KPSC within the first quarter of 2013. The KPSC has required that a new depreciation study be submitted as part of that filing.

Big Rivers solicited proposals and retained Burns & McDonnell to perform the Study in accordance with the RUS' guidelines. This Study includes:

- A discussion of each production facility's basic design and equipment
- A discussion of the composition of the transmission system
- An analysis of each production facility's historical performance
- Previously completed on-site reviews and analyses of each transmission system and production facility's current operating condition
- A discussion of the operating and maintenance procedures and staffing for each production facility and the transmission system
- An analysis of external and environmental factors that may impact the transmission system and each production facility's remaining useful life

PROJECT APPROACH

Burns & McDonnell's approach to meeting the above stated requirements for the Study was identical to the study completed in 2011. The Study was also based (in part) on the performance of previously completed physical site observations of the generating facilities and transmission system by experienced power plant design engineers and transmission system design engineers. These engineers then applied their experience and engineering judgment in approximating the remaining lives of each of Big Rivers' generating facilities and the transmission system. The activities performed during the previously completed site visits included:

- Observation of transmission and generating plant equipment and facilities
- Evaluation of equipment and facilities condition
- Interview of transmission and production operating and maintenance staff

- Review of organization structure, procedures, and staffing levels
- Determination of transmission and production operating and maintenance practices
- Assessment of transmission and production operating and maintenance experiences
- Collection of pertinent cost and operating data and records
- Collection of environmental data
- Development of facilities descriptions

The site observations of the plant facilities and transmission system did not include any internal inspections or examinations, or completion of any performance tests on the equipment and facilities. No system, structural, pipe stress, or other mathematical modeling analysis was included in the scope of the facilities observations.

The significant potential costs that could be required for environmental remediation were not considered in developing the net salvage values. Instead, the historical removal costs provided by Big Rivers in the 2010 Study were used in calculating the net salvage factors.

The projected remaining useful lives of the various generating and transmission assets and the estimates of terminal net salvage values were then factored into the depreciation rate analysis performed by Burns & McDonnell's depreciation consultants. The Study included analysis of the service life characteristics, net salvage values, and depreciation reserves for the generating assets, transmission assets, and general plant assets. Raw historical plant account data from 1965 to 2012 was obtained from Big Rivers' CPR system.

Generally accepted depreciation study procedures and actuarial analyses widely used by the utility industry were followed. Actuarial analyses of average service lives and dispersions based on historical characteristics of the plant retired for each active RUS plant account since inception were developed. Either the Whole Life method or the Life Span method with the Remaining Life technique was used to calculate the proposed depreciation rate for each account, depending on the nature of the types of property units included in an account.

SOURCES OF DATA

Much of the information used in the analysis of Big Rivers' depreciation rates was provided by the Cooperative's staff. This included various computer-generated accounting data from Big Rivers' CPR system, certain performance results, budgets, inspection reports, technical documents such as drawings and specifications, contracts, policies and procedure manuals, and other documents such as prior related studies. Historical data from 1965 to 2012 as recorded in Big Rivers' CPR system was used throughout the analyses.

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

* * * * *

PART II – ENGINEERING ASSESSMENT

PART II
ENGINEERING ASSESSMENT

OVERVIEW

This section of the report provides an engineering assessment of the Big Rivers' generation and transmission plant assets. In completing the assessment Burns & McDonnell interviewed appropriate Big Rivers staff concerning the operation and maintenance of the system assets. The following activities were conducted to examine Big Rivers' generation and transmission plant assets from an engineering perspective.

- A discussion of each production facility's basic design and equipment
- Previously completed on-site reviews and analyses of each production facility's current operating condition
- An analysis of each production facility's historical performance
- A discussion of the operating and maintenance procedures for each production facility
- An analysis of external factors that may impact each facility's useful life
- An opinion, based on the study's findings, regarding the remaining life of each facility
- A discussion of the composition of the transmission system
- An opinion, based on the study's findings, regarding the remaining life of each substation

The engineering assessment presented in this section addresses each of the above areas. The analyses leading to formulation of proposed new depreciation rates for Big Rivers are described in Part III.

Generation Facilities

Table II-1 below provides a description of each unit of Big Rivers' fleet of generating facilities, including the commercial operation date, years in operation, net capacity, heat rate, fuel type, boiler and turbine manufacturer, and emission control equipment.

Table II-1: Big Rivers Power Plant Data

Unit	Commercial Operation Date	Years in Operation	Net Capacity (MW)	2011 Heat Rate (Btu/kWh)	Fuel Type	Boiler Manufacturer	Turbine Manufacturer	Emission Control Equipment		
								SO_2 Control	NO_X Control	Particulate Control
Coleman 1	1969	43	150 MW	10,656	Pulverized Coal	Foster Wheeler	Westinghouse	FGD	Low NO_X Burners/ Overfire Air	Precipitator
Coleman 2	1970	42	138 MW	11,537	Pulverized Coal	Foster Wheeler	Westinghouse	FGD	Low NO_X Burners/ Overfire Air	Precipitator
Coleman 3	1972	40	155 MW	10,609	Pulverized Coal	Riley Stoker	General Electric	FGD	Low NO_X Burners/ Overfire Air	Precipitator
Green 1	1979	33	231 MW	11,270	Pulverized Coal	Babcock & Wilcox	General Electric	FGD	Low NO_X Burners	Precipitator
Green 2	1981	31	223 MW	11,193	Pulverized Coal	Babcock & Wilcox	Westinghouse	FGD	Low NO_X Burners	Precipitator
HMP&L 1	1973	39	153 MW	11,035	Pulverized Coal	Riley Stoker	General Electric	FGD	SCR	Precipitator
HMP&L 2	1974	38	159 MW	11,286	Pulverized Coal	Riley Stoker	Westinghouse	FGD	SCR	Precipitator
Reid 1	1966	46	65 MW	15,027	Pulverized Coal Natural Gas	Riley Stoker	General Electric	Uses Medium Sulfer Coal	Burns Natural Gas to Reduce Nox	Precipitator
Reid CT	1976	36	65 MW	11,750	#2 Oil Natural Gas	na	General Electric	na	na	na
Wilson 1	1986	26	417 MW	10,752	Pulverized Coal	Foster Wheeler	Westinghouse	FGD	SCR	Precipitator

Remaining Useful Life

Estimated remaining useful lives for Big Rivers' generating plant assets were based, in part, on ASTM guidelines for high temperature creep design. Per these guidelines, the portions of a generating facility subject to creep stress should be designed to experience at least 200,000 hours of service or 5,000 thermal cycles. Assuming 8,000 hours of full-load operation per year, this equates to 25 years of service.

Because most equipment manufacturers are quite conservative in applying these guidelines, reaching these levels of service does not mean that a generating unit cannot provide reliable service for longer periods. It does mean that creep-susceptible portions of a generating unit that has logged this level of operation should undergo metallurgical testing to detect the beginning of creep stress damage. Once damage is detected, the affected components should be evaluated regularly and repairs or replacement performed as indicated to facilitate the unit's successful return to service.

Burns & McDonnell recommends that Big Rivers continue to follow a comprehensive program of testing on those units approaching the service limits in the ASTM guidelines. Individual components should be either repaired or replaced as damage is identified. Since creep stress is a long-term phenomenon, there should be adequate time to procure and schedule replacement of any damaged components.

All of the Big Rivers generating units have reached the age when this testing program should be (and is) performed. This testing is currently being performed by Big Rivers and there is no reason, from a mechanical engineering perspective, that all of Big Rivers' generating units cannot remain in service for a long time. The following table provides a summary of the most recent testing performed for each generation unit.

Table II-2: Big Rivers Recent Generation Testing Results

Plant	Last Test	Problems Found	Description	Action Taken
Coleman 1	May 2008	1	Hot reheat hanger attachment.	Addressed immediately through appropriate repairs.
Coleman 2	October 2010	0	No deficiencies found.	
Coleman 3	June 2009	1	Indication of early stage creep.	No operational limits, per EPRI guidelines. Retest in 3-5 years.
Green 1	November 2011	0	No deficiencies found.	
Green 2	May 2009	0	No deficiencies found.	
HMP&L 1	April 2012	0	No relevant indications.	
HMP&L 2	April 2010	0	No evidence of micro cracking or creep damage.	
Reid 1	June 2008	1	Operating stress well within limits.	Retest in 5-10 years.
Wilson 1	November 2009	0	No indications found.	

In the 1998 depreciation study an additional 200,000 hours of operation was assumed as the remaining useful life of each plant beyond the original 200,000 hours taken from ASTM guidelines, for a total of 400,000 hours. Based on Big Rivers' records of operation, maintenance and component replacements; other service documents; and previously completed on-site inspections; five to seven and a half years of additional operation was assumed to calculate the remaining useful life of each unit. The additional five to seven and a half years translates into an additional 30,000 – 60,000 hours of operation for each unit.

The typical operating hours used in the 2010 Study along with the actual operating hours the last eight years for each unit were assumed to continue for purposes of translating the remaining operating hours into remaining years of service. The remaining operating hours are based off Big Rivers' estimate of new depreciation rates going into effect August 31, 2013.

Table II-3 below shows the estimated remaining useful life for each facility assuming **typical operating hours** with an additional **seven and a half years** of operation.

Table II-3: Big Rivers Power Plant Estimated Remaining Lives: Scenario 1

Plant Name	Date in Service	Typical Lifetime Availability	Typical Operating Hours per Year	Plant Years in Service	Total Estimated Hours to Date (8/31/2013)	Calculated 7.5 Year Extension Typical Estimated Remaining Unit Life	Estimated Service Life	7.5 Year Extension Typical Estimated Remaining Unit Life	Estimated Service Life
Coleman 1	November-69	80%	7,008	43.8	307,104	20.8	64.6	20.8	64.6
Coleman 2	September-70	80%	7,008	43.0	301,267	21.6	64.6	20.8	64.6
Coleman 3	January-72	80%	7,008	41.7	291,917	22.9	64.6	20.8	64.6
Green 1	December-79	85%	7,446	33.7	251,185	27.5	61.2	27.5	61.2
Green 2	January-81	85%	7,446	32.6	243,086	28.6	61.2	27.5	61.2
HMP&L 1	June-73	85%	7,446	40.2	299,615	21.0	61.2	21.0	61.2
HMP&L 2	April-74	85%	7,446	39.4	293,413	21.8	61.2	21.0	61.2
Reid	January-66	70%	6,132	47.7	292,236	25.1	72.7	12.3	60.0
Wilson	November-86	90%	7,840	26.8	210,203	31.7	58.5	31.7	58.5

Table II-4 below shows the estimated remaining useful life for each facility assuming **typical operating hours** with an additional **five years** of operation.

Table II-4: Big Rivers Power Plant Estimated Remaining Lives: Scenario 2

Plant Name	Date in Service	Typical Lifetime Availability	Typical Operating Hours per Year	Plant Years in Service	Total Estimated Hours to Date (8/31/2013)	Calculated 5 Year Extension Typical Estimated Remaining Unit Life	Estimated Service Life	5 Year Extension Typical Estimated Remaining Unit Life	Estimated Service Life
Coleman 1	November-69	80%	7,008	43.8	307,104	18.3	62.1	18.3	62.1
Coleman 2	September-70	80%	7,008	43.0	301,267	19.1	62.1	18.3	62.1
Coleman 3	January-72	80%	7,008	41.7	291,917	20.4	62.1	18.3	62.1
Green 1	December-79	85%	7,446	33.7	251,185	25.0	58.7	25.0	58.7
Green 2	January-81	85%	7,446	32.6	243,086	26.1	58.7	25.0	58.7
HMP&L 1	June-73	85%	7,446	40.2	299,615	18.5	58.7	18.5	58.7
HMP&L 2	April-74	85%	7,446	39.4	293,413	19.3	58.7	18.5	58.7
Reid	January-66	70%	6,132	47.7	292,236	22.6	70.2	12.3	60.0
Wilson	November-86	90%	7,840	26.8	210,203	29.2	56.0	29.2	56.0

Table II-5 below shows the estimated remaining useful life for each facility assuming **actual operating hours** with an additional **seven and a half years** of operation.

Table II-5: Big Rivers Power Plant Estimated Remaining Lives: Scenario 3

Plant Name	Date in Service	Actual Operating Hrs Based on 8 Yr Avg	Plant Years in Service	Total Estimated Hours to Date (8/31/2013)	Calculated 7.5 Year Extension Estimated Remaining Unit Life	Estimated Service Life	7.5 Year Extension Estimated Remaining Unit Life	Estimated Service Life
Coleman 1	November-69	7,825	43.8	342,895	14.8	58.6	13.8	56.8
Coleman 2	September-70	8,114	43.0	348,810	13.8	56.8	13.8	56.8
Coleman 3	January-72	8,069	41.7	336,116	15.4	57.1	13.8	56.8
Green 1	December-79	8,146	33.7	274,792	22.9	56.6	22.9	56.6
Green 2	January-81	8,014	32.6	261,617	24.8	57.4	22.9	56.6
HMP&L 1	June-73	7,546	40.2	303,656	20.3	60.5	18.6	58.0
HMP&L 2	April-74	7,914	39.4	311,855	18.6	58.0	18.6	58.0
Reid	January-66	3,059	47.7	145,772	90.6	138.3	12.3	60.0
Wilson	November-86	7,878	26.8	211,211	31.5	58.3	31.5	58.3

Table II-6 below shows the estimated remaining useful life for each facility assuming **actual operating hours** with an additional **five years** of operation.

Table II-6: Big Rivers Power Plant Estimated Remaining Lives: Scenario 4

Plant Name	Date in Service	Actual Operating Hrs Based on 8 Yr Avg	Plant Years in Service	Total Estimated Hours to Date (8/31/2013)	Calculated 5 Year Extension Estimated Remaining Unit Life	Estimated Service Life	5 Year Extension Estimated Remaining Unit Life	Estimated Service Life
Coleman 1	November-69	7,825	43.8	342,895	12.3	56.1	11.3	54.3
Coleman 2	September-70	8,114	43.0	348,810	11.3	54.3	11.3	54.3
Coleman 3	January-72	8,069	41.7	336,116	12.9	54.6	11.3	54.3
Green 1	December-79	8,146	33.7	274,792	20.4	54.1	20.4	54.1
Green 2	January-81	8,014	32.6	261,617	22.3	54.9	20.4	54.1
HMP&L 1	June-73	7,546	40.2	303,656	17.8	58.0	16.1	55.5
HMP&L 2	April-74	7,914	39.4	311,855	16.1	55.5	16.1	55.5
Reid	January-66	3,059	47.7	145,772	88.1	135.8	12.3	60.0
Wilson	November-86	7,878	26.8	211,211	29.0	55.8	29.0	55.8

Table II-7 below shows the estimated remaining useful life for each facility assuming **typical operating hours** with an additional **seven and a half years** of operation and an assumed **65 year life for Wilson**. This table is included at the direction of Big Rivers' management in order to be consistent with the 2010 Study. It is not the opinion of Burns & McDonnell that an assumed 65 year life for Wilson is reasonable to consider. Based on its operation and other recent coal plant retirements throughout the country a useful life of 50 to 60 years is more reasonable.

Table II-7: Big Rivers Power Plant Estimated Remaining Lives: Scenario 5

Plant Name	Date in Service	Typical Lifetime Availability	Typical Operating Hours per Year	Plant Years in Service	Total Estimated Hours to Date (8/31/2013)	Calculated 7.5 Year Extension Remaining Unit Life	Estimated Service Life	7.5 Year Extension Typical Estimated Remaining Unit Life	Estimated Service Life
Coleman 1	November 15, 1969	80%	7,008	43.8	307,104	20.8	64.6	20.8	64.6
Coleman 2	September 15, 1970	80%	7,008	43.0	301,267	21.6	64.6	20.8	64.6
Coleman 3	January 15, 1972	80%	7,008	41.7	291,917	22.9	64.6	20.8	64.6
Green 1	December 15, 1979	85%	7,446	33.7	251,185	27.5	61.2	27.5	61.2
Green 2	January 15, 1981	85%	7,446	32.6	243,086	28.6	61.2	27.5	61.2
HMP&L 1	June 15, 1973	85%	7,446	40.2	299,615	21.0	61.2	21.0	61.2
HMP&L 2	April 15, 1974	85%	7,446	39.4	293,413	21.8	61.2	21.0	61.2
Reid	January 15, 1966	70%	6,132	47.7	292,236	25.1	72.7	12.3	60.0
Wilson	November 15, 1986	90%	7,840	26.8	210,203	31.7	58.5	38.2	65.0

Table II-8 below shows the estimated remaining useful life for each facility assuming **historical operating hours** with an additional **seven and a half years** of operation and an assumed **65 year life for Wilson**. This table is included at the direction of Big Rivers' management in order to be consistent with the 2010 Study. It is not the opinion of Burns & McDonnell that an assumed 65 year life for Wilson is reasonable to consider. Based on its operation and other recent coal plant retirements throughout the country a useful life of 50 to 60 years is more reasonable.

Table II-8: Big Rivers Power Plant Estimated Remaining Lives: Scenario 6

Plant Name	Date in Service	Actual Operating Hrs Based on 8 Yr Avg	Plant Years in Service	Total Estimated Hours to Date (8/31/2013)	Calculated 7.5 Year Extension Estimated Remaining Unit Life	Estimated Service Life	7.5 Year Extension Estimated Remaining Unit	Estimated Service Life
Coleman 1	November 15, 1969	7,825	43.8	342,895	14.8	58.6	13.8	56.8
Coleman 2	September 15, 1970	8,114	43.0	348,810	13.8	56.8	13.8	56.8
Coleman 3	January 15, 1972	8,069	41.7	336,116	15.4	57.1	13.8	56.8
Green 1	December 15, 1979	8,146	33.7	274,792	22.9	56.6	22.9	56.6
Green 2	January 15, 1981	8,014	32.6	261,617	24.8	57.4	22.9	56.6
HMP&L 1	June 15, 1973	7,546	40.2	303,656	20.3	60.5	18.6	58.0
HMP&L 2	April 15, 1974	7,914	39.4	311,855	18.6	58.0	18.6	58.0
Reid	January 15, 1966	3,059	47.7	145,772	90.6	138.3	12.3	60.0
Wilson	November 15, 1986	7,878	26.8	211,211	31.5	58.3	38.2	65.0

The life of these individual units can vary based on a number of factors, however, two major factors are operating hours and maintenance experience. The Green, HMP&L Station Two and Coleman facilities have multiple units, but are forecasted to retire in the same year. This is reasonable for three reasons. First, the units were installed within two to three years of each other. Second, most plant accounts are assigned to the entire generating station, not to individual units of the facility. Most importantly, it is realistic to assume that the entire facility would shut down before significant demolition activities begin to occur. Piecemeal removal at an operating facility would be costly and much of the plant infrastructure would need to remain in service in order to maintain the last unit's ability to function. Big Rivers would maintain and continue to operate each individual unit until such time as the decision was made to retire the entire generating station. The Reid facility is not run nearly as much as the other facilities so its estimated service life could be limited by its ability to find spare parts in the future, not the hours of operation. Burns & McDonnell further considered the results of the previously completed on-site assessments of each of the Big Rivers generating stations in the estimation of the remaining useful lives.

Since the Unwind Closing in 2009, Big Rivers has been unable to perform major maintenance such as valve inspections and turbine generator inspections on a schedule consistent with prudent utility operations. Based on the assumption that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that all of Big Rivers' generating units cannot remain in service for a long time. Should major maintenance continue to be postponed, it is not likely that all of Big Rivers' generating units will remain in service as long as similar generating units.

GENERATION ASSETS

SEBREE SITE

The Sebree site is common to three plants owned and/or operated by Big Rivers: the Robert A. Reid Plant, the Robert D. Green Plant, and the Henderson Municipal Power & Light (HMP&L) Station Two. Although the plants are located on a common site, HMP&L Station Two is actually owned by the City of Henderson, Kentucky. Big Rivers operates HMP&L Station Two for the City. Contractual operations agreements between Big Rivers and the City of Henderson require that Big Rivers maintains separate plant operations, including operating and maintenance staffs (management staff and some specialists are common) and financial budgets/records, for the HMP&L Station Two and Reid stations, from the operations of the Green station.

The Sebree site is generally adequate for the operation of the three plants; however, the configuration of the units necessitates substantial coordination of activities among the plant staff when large areas of common space are required. This has not appeared to be a severe handicap to the site. This sharing of common facilities has produced a degree of operational and capital investment savings. For example, the river water intake structure for the Reid steam turbine unit is also used to provide river water supplies to the Green and HMP&L Station Two stations. Another example of this sharing of facilities relates to the barge unloading system used at the Reid station. When the original unloader was replaced with a more conventional barge unloader, the new unloading system and coal handling served both Reid and HMP&L Station Two. Also, when the new flue gas desulfurization system was added to the HMP&L Station Two units the lime supply and sludge disposal systems of the Green units were used. There is also some coordination among the three generating plants in ash storage; however, this is limited by the difference in the nature of the ash handling requirements for the different types of units.

The Sebree site is located on the banks of the Green River. The main plant area is located at a sufficient elevation such that 100-year floods should not affect the units' generation capabilities. Although a flood in excess of 100-year levels potentially could cause temporary interruptions of generating capability, no significant operational impact is anticipated.

ROBERT D. GREEN PLANT

Facility Description

The Robert D. Green Plant is located on the Sebree site near Sebree, Kentucky, along with the Robert A. Reid Plant and HMP&L Station Two. The Green Plant includes two units that are significantly larger than the units at either the Reid Plant or the HMP&L Station Two. Green Unit 1 is rated for net continuous capacity of 231 MW and Green Unit 2 has a rated net capacity of 223 MW. Unit 1 began commercial operation in 1979 and Unit 2 became operational in 1981. Both units at the Green Plant are coal-fired steam generating units with Babcock & Wilcox boilers providing maximum steam capacity of 1,930,000 pounds per hour. Green 1 is equipped with a General Electric turbine-generator with a nameplate rating of 242,105 kW. Green 2 includes a Westinghouse turbine-generator rated at 242,133 kW.

Steam Turbines

Green 1 turbine generator was supplied by General Electric, while the Green 2 turbine generator was supplied by Westinghouse. Both turbines appear to be in good condition. Turbine 1 underwent a major turbine overhaul in 2007. The unit is on a regular turbine outage schedule of every four years for valves and every eight years for major turbine overhaul. Turbine 2 was last overhauled in 2009, with a generator retaining ring replacement included in the overhaul. The unit is on a regular turbine outage schedule of every four years for valves and every eight years for major turbine overhaul. All evidence and inspections indicate that both turbines are being well maintained.

Boilers

The two Babcock & Wilcox boilers were installed after the initial effects of the regulations limiting NO_X emissions from coal-fired power plant boilers were promulgated. As such, the boilers are equipped with B&W's dual register burners and multiple wind boxes.
Boiler 1 appears to be in excellent condition. The tubes in the secondary superheater were replaced in 2001. Weld overlays were installed on the East and West walls, and reheat tubes were replaced in 2007. Sootblower lanes are shielded and shields are replaced as deficiencies are found. Several steam line hangers had deteriorated and were replaced in 2011. Tube samples of the waterwalls, superheat, and reheat collected in 2011 showed no significant deficiencies. However, based on the internal deposit thickness on the tube samples a water side chemical cleaning is scheduled for 2014.

Boiler 2 appears to be in excellent condition. The tubes in the secondary superheater were replaced in 2001. Weld overlays were installed on the East and West walls in 2005 and 2009. Tubes in the reheat outlet bank were replaced in 2009. Sootblower lanes are shielded and shields are replaced as deficiencies are found. Several steam line hangers had deteriorated and were replaced in 2009. Tube samples of the waterwalls, superheat, and reheat collected in 2009 showed no significant deficiencies.

Draft System

The two Green units were constructed with high efficiency precipitators and wet lime scrubbers. The precipitators appear to be in good condition and currently remove enough particulate to comply with the limit of 0.1 pounds per million Btu. Two precipitator fields were replaced in 2007 and two more in 2009. The FGD scrubbers appear to be in good condition and remove enough SO_2 to comply with the limit of 0.8 pounds per million Btu. The boilers were purchased with the earlier series of low NO_X burners from Babcock & Wilcox Company. Both units were retrofit in 2004 with a coal reburn technology designed by GE-EER. The combination reduces the NO_X emissions below the limit of 0.7 pounds per million Btu. The Ljungstrom air preheaters have had cold end baskets replaced in both units and are currently in good operating condition.

Waste Disposal

The primary water discharge is from the cooling tower blowdown. The blowdown from the cooling towers and other plant drains discharge to the main plant discharge. The waste water is pH adjusted and metals are precipitated. Discharge from these ponds is sent to a plant common pond, which then discharges indirectly to the Green River. Due to the multiple-pond system, accidental discharges reaching the river are considered unlikely. Bottom ash is impounded in the pond. The Green plant's fly ash is used for flue gas desulfurization waste sludge fixation.

Water Supply Systems

The makeup water supply from the Green River to the plant is provided from the intake structure which was originally constructed as part of the circulating water system for Reid Unit 1. Separate water supply pumps serve the Green units. Of all the water requirements of the Green units, the largest user is makeup supply for the cooling towers. Regardless of its end use, all this water is run through a conventional water clarification and treatment facility. The Green station maintains its own chemistry lab and personnel, using common supervision with the HMP&L Station Two units. Plant management provided no indications that plant chemistry control was inadequate.

Fuel Supply and Handling

The primary fuel supply for the Green units has been from nearby Kentucky mines and is delivered by truck and/or barge. The fuel supply for the Green units is delivered separately from the other coal-fired units on the site, and is kept segregated throughout the storage and handling process. This is due to the differing fuel quality requirements as well as contractual issues between Big Rivers and the City of Henderson. There is adequate space on the plant site for fuel storage for the Green units of up to 60 days. The normal fuel inventory is substantially less than the site capacity. A barge unloading facility located on the Green River (separate from the HMP&L Station Two barge unloader) is capable of unloading and delivering coal to the Green units. Lime for use in the scrubbers is delivered by barge. The barge unloader conveyor system is set up to permit transfers of materials from the Green barge unloader to either the coal pile or the lime storage silos. Plant management provided no indication of fuel supply or handling issues during the site visit.

Historical Operating Performance

Burns & McDonnell reviewed the plant's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the level of reliability to meet Big Rivers' electric production requirements. A summary of operating data is provided below in Table II-9.

Table II-9: Robert D. Green Historical Operating Performance Data

		Green Unit 1	Green Unit 2
Gross Generation Capacity	(MW)	250 MW	242 MW
Net Generation Capacity	(MW)	231 MW	223 MW
8 Year Average Capacity Factor	(%)	93.0%	91.5%
2011 Adjusted Net Heat Rate	(Btu/kWh)	11,270	11,193
7 Year Average EFOR	(%)	2.1%	1.5%

Both Green units have been performing well. The 2011 adjusted net heat rate was 11,270 Btu per kWh and 11,193 Btu per kWh for units one and two, respectively, which is competitive with other coal fired power plants in the region. The availability of the units has also been very good. Green Unit 1 has a seven year average Expected Forced Outage Rate (EFOR) of 2.1 percent while Green Unit 2 has a seven year average EFOR of 1.5 percent.

Remaining Useful Life

The Green Unit 1 and Unit 2 are in excellent condition for their age and service requirements. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that this facility cannot remain in service another 20 to 27 years (depending on its operation).

Of particular note is the Boiler Condition Spreadsheet that contains a status report on all of the major components in the boiler as well as the High Energy Piping (HEP) and hangers. A consistent program like this for monitoring status and identifying areas to address in future budgets is very good. The HEP and hanger review addresses the concern over creep damage with an aging plant. This type of review program is critical and is currently being performed on all the units. The spreadsheet does indicate that a HEP and hanger review occurs on all the units.

HENDERSON MUNICIPAL POWER & LIGHT STATION TWO

Facility Description

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

Steam Turbines

HPM&L Unit 1 is equipped with a General Electric turbine-generator, and HMP&L Unit 2 is equipped with a Westinghouse turbine-generator. Both units appear to be in good condition. Turbine 1 was last overhauled in 2008, and Turbine 2 was last overhauled in 2004. Both units are on a regular outage schedule of every 4 years for valves and every 8 years for major overhauls.

Boilers

The two boilers of the HMP&L Station Two appear to be well maintained. A program of monitoring boiler tube failures and tube wear has been activated. This has resulted in replacement of some sections of the reheaters, and similar monitoring and replacement programs should result in minimizing forced outages due to boiler tube failure.

Boiler 1 appears to be in good condition. The radiant superheat inlet and outlet elements were replaced in 2003. The front waterwall release header was replaced in 2005. A low water event occurred in 2007 causing some tubes to rupture and others to warp. The ruptured tubes were replaced with dutchmen and samples were removed for metallurgical analysis. No damage was detected. The boiler was hydro tested and returned to service. Tube samples were taken from the waterwalls, superheater, and reheat in 2012. No degradation was found in the waterwall and based on the internal deposit thickness on the tube samples a water side chemical cleaning is scheduled for 2016. However, the radiant superheater outlet was suffering from severe coal ash corrosion so Big Rivers replaced the burners in 2012 to reduce the fuel velocity and help mitigate the radiant superheater corrosion. These tubes are scheduled to be replaced in 2018. The high temperature reheater was replaced during the 2009 outage. Hangers are being replaced as inspections dictate.

Boiler 2 appears to be in good condition. The radiant superheater inlet and outlet elements were replaced in 2007. The high temperature reheater elements were replaced in 2007. Tube samples were taken in 2012 show the tubes to be in good condition. No significant deficiencies were found. Feedwater corrosion products were almost at the criterion for chemical cleaning.

However, based on the internal deposit thickness on the tube samples water side chemical cleaning is scheduled for 2019. Hangers are also being replaced based on the prioritization list.

Draft System

Precipitators are currently used for particulate emission removal with a limit of 0.21 pounds per MMBtu. The units both have an FGD system in service which is able to achieve a 95 percent SO_3 removal rate. This allows the Plant to meet the SO_2 limit of 5.2 pounds per MMBTu. Both units were retrofit in 2004 with Alstom designed SCR's capable of 90 percent NO_X removal which allow the plant to meet the NO_X limit of 0.5 pounds per MMBtu.

Waste Disposal

All the plant water discharges go through the ash pond. This includes neutralized demineralizer wastes, boiler blowdown, cooling tower blowdown, and miscellaneous plant drains. The ash ponds indirectly discharge to the Green River. Water discharges are monitored in the final pond, and water quality is reported to the state. Due to the multiple pond system, accidental discharges reaching the river are considered unlikely.

Water Supply Systems

The makeup water supply to the HMP&L Station Two units is from the circulating water system of Reid 1. This system, with operating and standby pumps at the river, is capable of delivering far more water than is normally needed by the two HMP&L Station Two units. The river intake was constructed in the 1960s, and is grandfathered for any Corps of Engineers river discharge permits. River water is delivered untreated to the cooling towers, which are equipped with side stream filters. Renovation of the cooling tower water chemistry control system and side stream filters to the circulating water system has apparently been successful.

Fuel Supply and Handling

The primary fuel supply for the HMP&L Station Two units has been from Kentucky mines and is delivered by truck and by barge. The fuel purchasing is in proportion to the utilization of the units. Big Rivers secures enough fuel to produce the unit capacity controlled by the cooperative. The City of Henderson procures enough fuel to produce their portion of the HMP&L Station Two capacity which varies as load growth occurs in Henderson. Once the fuel is received on site, it is delivered either directly to the unit or to the HMP&L Station Two common storage. The coal for the Reid unit is purchased separately, and segregated in storage and use since the HMP&L Station Two units are capable of utilizing higher sulfur, less expensive coal, than the non-scrubbed Reid unit. Fuel for the Green Plant units is handled completely separately, since it is of a different quality. Maintenance of the coal handling systems appears to be adequate.

Historical Operating Performance

Burns & McDonnell reviewed the plant's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the level of reliability necessary to meet Big Rivers' electric production requirements. A summary of operating data is provided below in Table II-10.

Table II-10: HMP&L Station Two Historical Operating Performance Data

		HMP&L Unit 1	HMP&L Unit 2
Gross Generation Capacity	(MW)	165 MW	172 MW
Net Generation Capacity	(MW)	153 MW	159 MW
8 Year Average Capacity Factor	(%)	86.1%	90.3%
2011 Adjusted Net Heat Rate	(Btu/kWh)	11,035	11,286
7 Year Average EFOR	(%)	7.7%	5.1%

Both units have been performing well. The 2011 adjusted net heat rate was 11,035 Btu per kWh and 11,286 Btu per kWh for units one and two, respectively, which is competitive with other coal fired power plants in the region. Unit 1 has a seven year EFOR of 7.7 percent while Unit 2 has a seven year average EFOR of only 5.1 percent.

Remaining Useful Life

Of particular note is the Boiler Condition Spreadsheet that contains a status report on all of the major components in the boiler as well as the High Energy Piping and hangers. A consistent program like this for monitoring status and identifying areas to address in future budgets is consistent with sound maintenance practices. The HEP and hanger review addresses the concern over creep damage with an aging plant. This review program is critical and is currently being performed on all the units. The spreadsheet does indicate that a HEP and hanger review occurs on all the units.

The HMP&L Units are in excellent condition for their age and service requirements. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that this facility cannot remain in service another 16 to 21 years (depending on its operation).

ROBERT A. REID PLANT

Facility Description

The Reid steam turbine generating unit includes a Riley boiler with a steam flow capacity of 690,000 pounds per hour and a General Electric turbine-generator with nameplate capacities of 66,000 kilowatts (kW) for the turbine and 96,000 kVA for the generator. The unit began commercial operation in 1966 and is currently rated at 65 MW.

Steam Turbine

Reid is equipped with a General Electric turbine-generator. The steam turbine was last overhauled in 2000 and does not have another major overhaul scheduled until 2018. The unit has historically been on a regular outage schedule of every four years for valves and every twelve years for major overhauls; however due to its low capacity factor (CF) it is able to run longer without a major overhaul.

Boilers

Reid 1 has a Riley Stoker boiler with two levels of burners on the front wall. The unit has had the lower waterwall tube header stubs replaced in 2004 with no major upgrades since. The boiler appears to be in good operating condition. The boiler is a pressurized furnace, with no induced draft fan.

Draft System

Precipitators are currently used for particulate emission removal with a limit of 0.28 pounds per MMBtu. The unit uses medium sulfur coal in order to meet the SO_2 limit of 5.2 pounds per MMBTU. In 2000, four of the boiler's eight burners were converted to burn natural gas to reduce NO_X emissions.

Waste Disposal

The fly ash of the Reid unit is used in the Green Plant's flue gas desulfurization waste sludge fixation. The bottom ash from the unit is impounded in the ponds.

Water Supply Systems

Circulating water for the Reid unit comes directly from, and returns to, the Green River. This direct river cooling was established before introducing changes to river water temperature was regarded as environmentally degrading and, therefore, the Reid unit is a grandfathered installation. The two 100-percent circulating water pumps are adequate for the Reid unit; however, one of these pumps is run almost continuously since the Reid unit circulating water system also provides the water supplies for HMP&L Station Two. The water supply pumps for the Green units are also installed in the Reid intake structure. The significance of this water supply system is far greater than that of the Reid unit alone, since a loss of the intake structure could shut down both HMP&L Station Two units and both Green units, a total of over 700 MW of generating capacity. However, proper maintenance reduces the probability of this occurrence to a minimum level of concern.

Historical Operating Performance

Burns & McDonnell reviewed the plant's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the level of reliability necessary to meet Big Rivers' electric production requirements. A summary of operating data is provided below in Table II-11.

Table II-11: Robert A. Reid Historical Operating Performance Data

		Reid Unit 1
Gross Generation Capacity	(MW)	72 MW
Net Generation Capacity	(MW)	65 MW
8 Year Average Capacity Factor	(%)	34.9%
2011 Adjusted Net Heat Rate	(Btu/kWh)	15,027
7 Year Average EFOR	(%)	21.2%

The plant has performed commendably over the years. However, the unit had one of the highest heat rates on Big Rivers' system. The 2011 adjusted net heat rate for the unit was reported to be 15,027 Btu per kWh. This is relatively high for coal fired power plants in the region of the country which is why the unit is primarily used for capacity and dispatched mostly as a peaking unit and for market sales. In addition, the seven year average EFOR of 21.2 percent is considered high when compared to other coal fired power plants in the region.

Remaining Useful Life

Of particular note is the Boiler Condition Spreadsheet that contains a status report on all of the major components in the boiler as well as the HEP and hangers. A consistent program like this for monitoring status and identifying areas to address in future budgets is consistent with sound maintenance practices. The HEP and hanger review addresses the concern over creep damage with an aging plant. This review program is critical and is currently being performed on all the units. The spreadsheet does indicate that a HEP and hanger review occurs on all the units. The Reid Plant has not been run as many hours per year as other facilities and is in excellent condition for its age. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, from a mechanical engineering perspective, this unit is estimated to be suitable for ongoing service another 12 years or longer, or until such time spare parts are not available.

D.B. WILSON STATION PLANT

Facility Description

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

Steam Turbine

The unit went commercial in 1986, and was given its first major overhaul in November 1990. The unit has typically been on a regular outage schedule of every 4 years for valves and every 8 years for major overhauls. The most recent major overhaul was in 2009 and the next is planned for 2017.

Boilers

Wilson 1 is a Foster Wheeler boiler capable of producing 3,484,000 lbs / hr of steam. The boiler appears to be in good condition. The last major boiler outage was in 2009. Tube samples were taken of the waterwalls and superheater. A map was created of the waterwall thickness readings to determine where future overlays should be installed. Tube analysis indicated a chemical clean was needed, which is scheduled for the 2013 outage. Holes in the downcomers and cracks in the shelf under the cone-topped canisters were repaired in 2009. The A platen superheater showed no significant indications of corrosion, thinning, or creep. The B platen superheater tubes were replaced in 2009. The A platen superheater is scheduled to be replaced in 2013. Cracks were found in the inlet and outlet headers. The cracks were ground down and re-examined. All of them passed the WFMT examination after being ground down. Tubes were replaced in the finish superheater and alignment castings were installed. Major pitting, metal loss, and corrosion were found in the DA tank. The high energy piping was inspected with Fluorescent Mag Particle testing or UT Shear Wave testing. There were some indications of creep in the piping. The hangers are inspected regularly and adjusted or replaced as needed. Safety valves are cleaned, inspected, and lapped regularly.

Draft System

The Wilson unit is equipped with a precipitator for particulate emission removal and has a limit of 0.03 pounds per MMBtu. The unit is equipped with a FGD which has a 90 percent SO_2 removal efficiency. The unit has a NOx limit of 0.6 pounds per MMBtu, however, the unit was retrofit in 2004 with a Babcock Borsig designed SCR capable of 90 percent NO_X removal efficiency.

Waste Disposal

The solid waste from the FGD, fly ash, and lime is sent to the on-site landfill. The site waste water is pH adjusted and metals are precipitated out. The bottom ash is dewatered and incorporated into FGD waste. The excess fly ash is marketed and sold in the region.

Water Supply Systems

The water supply for the plant is from an independent water intake structure located on the Green River. It appears unlikely that there should ever be an interruption of water supply to the plant. Green River water requires pretreatment before use in the cooling tower or other potable water systems in the plant. This pretreatment system is sized for two operational units so there should be adequate capacity.

Fuel Supply and Handling

The redundant coal delivery systems for the plant, barge, and truck permit supplying the full capacity of the plant from any one of the delivery systems.

Historical Operating Performance

Burns & McDonnell reviewed the plant's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the level of reliability necessary to meet Big Rivers' electric production requirements. A summary of operating data is provided below in Table II-12.

Table II-12: D.B. Wilson Historical Operating Performance Data

		Wilson Unit 1
Gross Generation Capacity	(MW)	440 MW
Net Generation Capacity	(MW)	417 MW
8 Year Average Capacity Factor	(%)	89.9%
2011 Adjusted Net Heat Rate	(Btu/kWh)	10,752
7 Year Average EFOR	(%)	4.6%

Wilson has been performing well. The 2011 adjusted net heat rate was only 10,752 Btu per kWh, which is competitive with other coal fired power plants in the region. The seven year average EFOR was 4.6 percent.

Remaining Useful Life

Of particular note is the Boiler Condition Spreadsheet that contains a status report on all of the major components in the boiler as well as the HEP and hangers. A program like this for monitoring status and identifying areas to address in future budgets is consistent with sound maintenance practices. The HEP and hanger review addresses the concern over creep damage with an aging plant. This review program is critical and is currently being performed on all the units. The spreadsheet does indicate that a HEP and hanger review occurs on all the units. The details provided for the Wilson unit are the most comprehensive and complete. The Wilson Plant is in very good condition for its age and service requirements. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, from a mechanical engineering perspective, this unit could possibly be run for another 29 to 38 years of service.

KENNETH C. COLEMAN PLANT

Facility Description

The Kenneth C. Coleman Plant consists of three coal-fired, steam turbine generating units located near Hawesville, Kentucky, approximately 60 miles east of Henderson, Kentucky. The plant is located on the west bank of the Ohio River. The land to the south is owned by Century Aluminum and is the site of an aluminum reduction plant, a primary customer of power from the Coleman Plant. The plant is located on the flood plain of the Ohio River and operation could be affected by extreme flood levels. In the past, the plant has experienced temporary isolation due to flooding of local access roads. However, the main plant area is located at a sufficient elevation to ensure that 100-year floods should not affect the plant's generation capabilities. Although a flood in excess of 100-year levels potentially could cause temporary interruptions of generating capability, this would not be anticipated to result in major disaster.

Coleman 1 was commercialized in 1969 and is rated for 150 MW of net capacity. The unit is equipped with a Foster Wheeler boiler capable of producing 1,220,000 pounds per hour of steam, and a Westinghouse turbine-generator with nameplate capacity of 160,000 kW. Coleman 2 was commercialized in 1970 and is rated for 138 MW of net capacity. The unit is equipped with a Foster Wheeler boiler capable of producing 1,220,000 pounds per hour of steam, and a Westinghouse turbine-generator with nameplate capacity of 160,000 kW. Coleman 3 was commercialized in 1972 and is rated for 155 MW of net capacity. The unit is equipped with a Riley boiler capable of producing 1,160,000 pounds per hour of steam, and a General Electric turbine-generator with nameplate capacity of 160,000 kW.

Steam Turbines

Turbines are being overhauled on a regular schedule, and the description of the maintenance activities required for the turbine appears to be normal for the age and type of machine. Turbine-generator 1 was last overhauled in 2008. At that time several of the L-2 blades required replacement. The turbine reheat stop valve bonnet studs were replaced. The turbine shaft was ruggedized and L-O turbine-generator end blades repaired. Turbine-generator 2 was last overhauled in 2007. During the overhaul thermocouples were installed in the turbine bearing and pedestals, the turbine-generator valve seats were restored, and the online filtration system was repaired. Turbine-generator 3 is scheduled to be overhauled in 2014. The turbines at the Coleman station appear to be maintained in satisfactory condition. The turbine overhaul schedules are typical for utility stations.

Boilers

Boiler 1 appears to be in reasonably good condition. Waterwall and arch tube samples taken during the 2008 outage proved the tubes to be in good condition, with waterside deposits limited, only minor pitting, and insignificant wall loss. A chemical cleaning is scheduled for 2013. Superheater tubes assessed during the 2008 outage showed significant wall loss due to fireside coal-ash corrosion. Creep analysis indicated that the tubes are below the minimum curve for creep. A repeat assessment of the superheater tubes has been recommended for 2013. The high temperature reheat tubes underwent extensive NDE and isolated tube replacement was performed during planned 2008 outage. NDE found that the leading edge tube of many of the assemblies were thin. Replacement of this section is scheduled for 2013. All soot blower lanes are shielded, and the shields are replaced when deficiencies are found. All piping supports appear to be in good condition and operating properly.

Boiler 2 appears to be in good condition. Waterwall and arch tube samples taken during the 2007 outage showed no significant deficiencies. The economizer life assessment reported the tubes to be in excellent condition and showed negligible corrosion and no evidence of microstructural degradation. The superheater and reheater showed no evidence of overheating or creep. All soot blower lanes are shielded, and all piping supports appear to be in good condition.

Boiler 3 appears to be in good condition. Economizer, waterwall, and arch tube samples taken during the 2009 outage showed minimal wall thinning, typical microstructure, and no thermal degradation. The stainless steel tubes in the reheater showed no evidence of creep or overheat, and none of the measured wall thickness values were below Minimum Wall Thickness (MWT). Ultrasonic Testing and Magnetic Testing of the welds on the high energy piping showed no relevant indications. All supports were found to be in good condition and did not require service.

Draft System

Low NO_X burners were installed and resulted in NO_X levels for all three units of below 0.5 lbs per MMBtu. In 2004 all three boilers were retrofitted with over fire air combustion equipment to further reduce NO_X emissions. In 2006 the Station was retrofitted with a Wheelabrator Air Pollution Control designed limestone scrubber that combines all three generation units into a single FGD absorber capable of 95 percent SO_2 removal.

Waste Disposal

Aside from the circulating water, all plant discharges, including the coal pile runoff, are directed to a newer ash pond. This newer ash pond is a clay-lined structure, which was designed to meet NPDES requirements at the time of its construction in 1980. The bottom ash system sluices directly into the ponds. The required operating time appears to have adequate margin for reliable operation. The site is large enough to accommodate the waste disposal requirements for quite a few years, as long as the plant continues the current practice of dredging the ash pond and disposing of ash off site. The fly ash system is conventional sluice water driven hydrovactor that discharges to an air-separating tank. The fly ash is then ponded with the bottom ash.

Water Supply Systems

The plant cooling water system is a direct, once-through cooling design supplied by the Ohio River. This system was in existence before restrictions on temperature rise or discharge requirements were placed in effect for the Ohio River. Because these units are grandfathered, it is not anticipated that the circulating water supply system design will have to be changed in the future. The plant water supply for service water, demineralizer makeup, and other clear water surfaces originally came from wells located fairly close to the Coleman Plant. As time passed, those wells began to show high mineral content and, therefore, new wells were constructed further out toward the perimeter of the property. These newer wells also began to show high mineral content. The source of the elevated mineral content in the groundwater is believed to have been at least partially derived from an adjacent superfund site. This deteriorating plant service water quality has caused the plant to make two modifications within the last few years. First, a reverse osmosis (RO) unit was installed to act as a pre-filter for the demineralizers. This has brought the demineralizers within normal operating capability to supply water to the system, since the RO unit removes about 90 percent of the total dissolved solids in the input water. The second modification was to bring in rural water district potable water into the plant. A sizable water main was installed from the main supply near the access highway to bring potable water to the plant. The well system is still used to supply all the plant service water requirements except potable water.

Fuel Supply and Handling

The Coleman Plant burns coal as the main fuel. Propane and natural gas are available as ignition fuels only. These fuels cannot generate enough steam to accomplish anything more than to start up the units. With the addition of the FGD in 2006 the plant now has the ability to burn high sulfur coal. The majority of the plant's coal supply is purchased on short-term contracts (less than five years), supplemented by spot market purchases. There appears to be adequate coal supply available to accommodate operation of the Coleman Plant for the foreseeable future. The mills have had gear reducer replacements and liner replacements on an as-needed basis.

Historical Operating Performance

Burns & McDonnell reviewed the plant's historical operating performance to verify that the generating units have competitive heat rates and are capable of providing the level of reliability to meet Big Rivers' electric production requirements. A summary of operating data is provided below in Table II-13.

Table II-13: Kenneth C. Coleman Historical Operating Performance Data

		Coleman Unit 1	Coleman Unit 2	Coleman Unit 3
Gross Generation Capacity	(MW)	160 MW	160 MW	165 MW
Net Generation Capacity	(MW)	150 MW	138 MW	155 MW
8 Year Average Capacity Factor	(%)	89.3%	92.6%	92.1%
2011 Adjusted Net Heat Rate	(Btu/kWh)	10,656	11,537	10,609
7 Year Average EFOR	(%)	4.8%	2.7%	5.9%

All three Coleman units have been performing well. Coleman Units 1, 2, and 3 had 2011 adjusted net heat rates of 10,656; 11,537; and 10,609 Btu per kWh, respectively. The availability of the units has also been good. Coleman Unit 1 had a seven year average EFOR of 4.8 percent, Coleman Unit 2 had a seven year average EFOR of 2.7 percent, and Coleman Unit 3 had a seven year average EFOR of 5.9 percent.

Remaining Useful Life

Of particular note is the Boiler Condition Spreadsheet that contains a status report on all of the major components in the boiler as well as the HEP and hangers. A consistent program like this for monitoring status and identifying areas to address in future budgets is very good. The HEP and hanger review addresses the concern over creep damage with an aging plant. This review program is critical and is currently being performed on all the units. The spreadsheet does indicate that a HEP and hanger review occurs on all the units.

Coleman Units 1, 2, and 3 are in good condition for their age and type. Provided that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, from a mechanical engineering perspective, the facility can be expected to give satisfactory service for another 11 to 21 years (depending on how it is operated).

ROBERT A. REID COMBUSTION TURBINE

Facility Description

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

Remaining Useful Life

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

TRANSMISSION ASSETS

This section of the Study summarizes the engineering assessment of the major electric substation assets of Big Rivers that were in service as of July 31, 2012. The Kentucky Public Service Commission mandated that Big Rivers conduct a new depreciation study as part of its submission in connection with the its intent to file for a general review of its operations and tariffs within three years. During the Study, the following efforts were conducted to examine Big Rivers' substations in service from an engineering perspective:

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

The engineering assessment presented in this part of the Study report addresses each of the above areas. The analyses leading to formulation of proposed new depreciation rates for Big Rivers are described in Part III of the Study.

Remaining Unit Life

Estimated remaining useful lives for Big Rivers' transmission assets were based primarily on national industry standards regarding the expected useful life of major electric substation equipment.

Burns & McDonnell recommends that Big Rivers continue to follow a comprehensive program of testing on all major equipment approaching the manufacturer service limits. Individual components should be either repaired or replaced as damage is identified. Certain tests should continue to be performed on an annual basis, such as analysis of oil samples retrieved from transformers. Other tests, such as thermal imaging of electrical connections, can be done less frequently.

Electrical insulation is subject to loss of dielectric capability, particularly when subjected to heat. Testing programs are generally able to determine the capability of the components, so replacement or repairs can be initiated before the component affects the plant capability or availability. These programs must be implemented and the frequency increased as the equipment ages.

Several of the Big Rivers transmission substations are approaching the age when an electrical insulation testing program should be (and is) performed. Assuming the testing recommended is conducted and assuming any damaged components are either repaired or replaced, there would be no reason, from an electrical engineering perspective, that all of Big Rivers' transmission substations cannot remain in service for a long time.

Burns & McDonnell further considered the results of the previously completed on-site assessments of the major Big Rivers transmission substations in the estimation of the remaining useful lives. The assessments of the major transmission substations are presented in the remainder of this part of the Study.

ROBERT A. REID EHV SUBSTATION

Facility Description

The Reid EHV Substation is a 345kV to 161kV electric substation. The substation contains two 345/161kV transformers, two 345kV circuit switchers and seven 161kV circuit breakers. The substation also contains a 161kV circuit breaker that is owned by the City as part of the City's transmission loop.

A control building located within the substation contains all of the electrical controls associated with the both the circuit switchers and breakers. The control building also houses all of the protection equipment needed to provide adequate electrical protection for both the substation transformers and the associated transmission lines that enter and exit the substation.

Condition Assessment

A physical observation of the Reid EHV substation was made on August 23, 2010. The nameplates on the major substation equipment state the equipment was constructed and installed in 1982. The substation appears to be in good working condition. There are no signs of deterioration or rust located on the steel structures or any of the major equipment. Also, there are no signs of current or past oil leaks from any of the oil insulated equipment.

Maintenance

Based on all observations of the electric substation, maintenance of the major equipment appears to have been performed on a regular basis. The transformers and circuit breakers will need to continue to have regular maintenance in order to maintain good working order.

Remaining Life Assessment

The Reid EHV substation is approximately 30 years old. Assuming a continued level of maintenance on the substation, the Reid substation as a whole can expect to function properly for an additional 27 to 28 years. This results in a projected retirement year for the substation of 2040. For the major equipment located within the substation, such as the transformers, circuit breakers, and control building, this equipment requires a greater level of care and maintenance in order to function for an additional 27 to 28 years. Typically, substation transformers and circuit breakers begin being replaced once they have achieved 40 years of useful life. However, given regular and proper maintenance, this equipment can last 55 to 60 years, depending on the ambient conditions. Associated equipment, such as steel structures, concrete foundations, chain link fences, and other equipment are subject to weather conditions and deteriorate at the same speed as those same types of structures located in other types of facilities.

KENNETH C. COLEMAN EHV SUBSTATION

Facility Description

The Coleman EHV Substation is located near Hawesville, Kentucky, approximately 60 miles east of Henderson, Kentucky. The electric substation is located adjacent to the Kenneth C. Coleman Generating Facility. The Coleman EHV Substation is a 345kV to 161kV electric substation. The substation contains two 345/161kV transformers, two 345kV circuit switchers and eight 161kV circuit breakers.

A control building located within the substation contains all of the electrical controls associated with the both the circuit switchers and breakers. The control building also houses all of the protection equipment needed to provide adequate protection for both the substation transformers and the associated transmission lines that enter and exit the substation.

Maintenance

Based on all observations of the electric substation, maintenance of the major equipment appears to have been performed on a regular basis. The transformers and circuit breakers will need to continue to have regular maintenance performed on these devices in order to maintain good working order.

Condition Assessment

A physical observation of the Coleman EHV substation was made on August 23, 2010. The nameplates on the major substation equipment state the equipment was constructed and installed in 1987. The substation appears to be in good working condition. There are no signs of deterioration or rust located on the steel structures or equipment. Also, there are no signs of current or past oil leaks from any of the oil insulated equipment.

Remaining Life Assessment

The Coleman EHV substation is approximately 25 years old. Assuming a continued level of maintenance on the substation, the Coleman substation as a whole can expect to function properly for an additional 32 to 33 years. This results in a projected retirement year for the unit of 2045. For the major equipment located within the substation, such as the transformers, circuit breakers, and control building, this equipment requires a greater level of care and maintenance in order to function for an additional 32 to 33 years. Typically, substation transformers and circuit breakers are replaced any time after 40 years of useful life has passed. However, given regular and proper maintenance, this equipment can last 55 to 60 years, depending on the ambient conditions. Associated equipment, such as steel structures, concrete foundations, chain link fences, and other equipment are subject to weather conditions and deteriorate at the same speed as those same types of structures located in other types of facilities.

D. B. WILSON STATION EHV SUBSTATION

Facility Description

The Wilson EHV Substation is located at Island, Kentucky, approximately 55 miles from Henderson, Kentucky. This station is located through the entrance to the D.B. Wilson Generating Plant, and is a 345kV to 161kV electric substation. The station currently has two 345/161kV transformers, four 345kV circuit breakers and five 161kV circuit breakers.

A control building located within the substation contains all of the electrical controls associated with the both the circuit switchers and breakers. The control building also houses all of the protection equipment needed to provide adequate protection for both the substation transformers and the associated transmission lines that enter and exit the substation.

Maintenance

Based on all observations of the electric substation, maintenance of the major equipment appears to have been performed on a regular basis. One of the 161kV circuit breakers has been replaced, thus eliminating one of the original oil circuit breakers and installing the newer SF6 type gas circuit breakers. The transformers and circuit breakers will need to have regular maintenance continued on these devices in order to maintain good working order.

Condition Assessment

A physical observation of the Wilson EHV substation was made on August 23, 2010. The nameplates on the major substation equipment state the equipment was constructed and installed in 1982. The substation appears to be in good working condition. There are no signs of deterioration or rust located on the steel structures or equipment. Also, there are no signs of current or past oil leaks from any of the oil insulated equipment.

Remaining Life Assessment

The Wilson EHV substation is approximately 30 years old. Assuming a continued level of maintenance on the substation, the Wilson substation as a whole can expect to function properly for an additional 27 to 28 years. This results in a projected retirement year for the unit of 2040. For the major equipment located within the substation, such as the transformers, circuit breakers, and control building, this equipment requires a greater level of care and maintenance in order to function for an additional 27 to 28 years. Typically, substation transformers and circuit breakers are replaced any time after 40 years of useful life. However, given regular and proper maintenance, this equipment can last 55 to 60 years, depending on ambient conditions. Associated equipment, such as steel structures, concrete foundations, chain link fences, and other equipment are subject to weather conditions and deteriorate at the same speed as those same types of structures located in other types of facilities.

HANCOCK SUBSTATION

Facility Description

The Hancock Substation is located near Hawesville, Kentucky, approximately 60 miles east of Henderson, Kentucky. This substation is located within five miles of the Kenneth C. Coleman Generating Station, and is a 161kV to 69kV electric substation. The station currently has two 161/69kV transformers, five 161kV circuit breakers and four 69kV circuit breakers.

A control building located within the substation contains all of the electrical controls associated with the both the circuit switchers and breakers. The control building also houses all of the protection equipment needed to provide adequate protection for both the substation transformers and the associated transmission lines that enter and exit the substation.

Condition Assessment

A physical observation of the Hancock substation was made on August 23, 2010. The 161kV circuit breakers contained nameplates that state the breakers were manufactured in 2001. However, the substation is far greater in age than the circuit breakers. Located throughout the substation were brown colored glass insulators. This particular style of insulator has not been manufactured by major electric manufacturers since the 1960's. The existing steel structures were beginning to show signs of rust and deterioration, which is expected given the estimated age of the substation.

Maintenance

All of the 161kV circuit breakers had been replaced in 2001, eliminating the original oil circuit breakers and installing newer SF6 type gas circuit breakers. Based on the estimated age of the substation, additional maintenance will need to be performed on the transformers and the remaining oil circuit breakers will need to have regular maintenance continued on these devices in order to maintain good working order. Also, there are no signs of current or past oil leaks from any of the oil insulated equipment.

Remaining Life Assessment

The Hancock Substation is approximately 42 years old. Typically, substation transformers and circuit breakers are replaced any time after 40 years of useful life. However, given regular and proper maintenance, this equipment can last between 50 and 60 years. Brown insulators are considered obsolete by industry standards, and may need to be considered as part of future maintenance work. However, assuming a continued level of maintenance on the substation, the Hancock substation appears to be in good working order and should continue to function properly for an additional 17 to 18 years. This resulted in a projected retirement year for the unit of 2030. For the major oil filled equipment located within the substation, such as the transformers and circuit breakers, this equipment requires a greater level of care and maintenance in order to function for an additional 17 to 18 years.

HARDINSBURG SUBSTATION

Facility Description

The Hardinsburg Substation is located near Hardinsburg, Kentucky, approximately 80 miles east of Henderson, Kentucky. This substation is a 161kV to 69kV electric substation. The station currently has two 161/69kV transformers, five 161kV circuit breakers and seven 69kV circuit breakers.

A control building located within the substation contains all of the electrical controls associated with the both the circuit switchers and breakers. The control building also houses all of the protection equipment needed to provide adequate protection for both the substation transformers and the associated transmission lines that enter and exit the substation.

Condition Assessment

A physical observation of the Hardinsburg substation was made on August 23, 2010. The equipment located within the substation contained nameplates stating their construction in 1968. The steel structures were beginning to show signs of rust and deterioration, which is expected given the estimated age of the substation. However the concrete foundations, ground and conduit connections appeared to be in good operating shape.

Maintenance

Based on the age of the substation, maintenance will need to be performed on the transformers and oil circuit breakers in order to maintain good working order. There were no signs of past or current oil leaks from existing equipment. This demonstrates that the equipment is being properly inspected and maintained on a regular basis.

Remaining Life Assessment

The Hardinsburg Substation is approximately 44 years old. Typically, substation transformers and circuit breakers are replaced any time after 40 years of useful life. However, given regular and proper maintenance, this equipment can last between 50 and 60 years. Assuming a continued level of maintenance on the substation, the Hardinsburg substation appears to be in good working order and should continue to function properly for an additional 17 to 18 years. This results in a projected retirement year for the unit of 2030. For the major oil filled equipment located within the substation, such as the transformers and circuit breakers, this equipment requires a greater level of care and maintenance in order to function for an additional 17 to 18 years.

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PART III – DEPRECIATION RATE ANALYSIS

PART III
DEPRECIATION RATE ANALYSIS

Part III of the Study describes the methodology and presents the results of the analysis performed in the formulation of proposed new depreciation rates for the electric generation, transmission, and general plant assets of Big Rivers. The depreciation rate analysis was performed based on the electric generation, transmission, and general plant historical accounting records of Big Rivers as of July 31, 2012. The methodologies and basis for calculating the proposed depreciation rates and completing this Study is similar to the process utilized in completing the 2010 Study.

STUDY SCOPE & PURPOSE

This depreciation rate analysis was conducted to analyze the service life characteristics, net salvage indications, and depreciation reserve status based on historical data from Big Rivers' CPR system data, and then to derive appropriate depreciation rates for Big Rivers' system plant in service.

The procedures used to analyze Big Rivers' historical data pertaining to useful service lives and net salvage rates are discussed for the assets represented by each plant account. This narrative description of the depreciation rate analysis completed for Big Rivers includes a variety of concepts related to common utility depreciation terminology and study techniques. Various reference materials are readily available that provide thorough explanations of these concepts.[1]

For plant assets in certain accounts there was found to be an insufficient amount of historical plant additions and retirement data in the CPR system on which to perform statistically valid actuarial studies. In these cases, estimates were made based on the historical data from similar accounts, industry standards, and the Engineer's Assessment in Section II. This data, combined with the judgment of the depreciation consultants, was relied upon in the completion of the analysis for those accounts with limited historical data. However, the consideration given to

[1] For further information, refer to industry publications "Public Utility Depreciation Practices", National Association of Regulatory Utility Commissioners (NARUC), August 1996 and "Depreciation Systems", Wolf, Frank and Fitch, Chester, Iowa State University Press, 1994.

extending useful lives is based on the assumption that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations.

DEPRECIATION RATE STUDY METHODS

Two primary methods have been used to calculate depreciation accruals: the Whole Life method (most General Plant accounts) and the Life Span method combined with the Remaining Life technique (all Transmission accounts and all Production accounts and Account 390 – Structures).

Whole Life Method

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

$$\frac{1 - NS}{ASL}$$

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

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

Life Span Method

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

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

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

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

The Remaining Life depreciation rate automatically adjusts for past under- and over-accruals by building those amounts into the depreciation rate calculation using the reserve ratio (RR). The RR is the depreciation reserve amount divided by the plant balance at the point in time of the study (July 31, 2012). The net salvage parameter in the Remaining Life rate equation is the future net salvage rate (FS). The Remaining Life depreciation rate is expressed mathematically below.

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

Sources of Industry Information

Actuarial methods are most accurate and applicable to determination of historic trends for assessing average service lives and salvage specific to a plant account when there is significant annual turnover of plant in that account. However, the limited activity in several accounts prevented actuarial analysis.

Accounts for which insufficient retirement activity had occurred on which to conduct actuarial analysis, or for which the results of such an analysis were inconclusive, other publicly available industry information, the Engineer's Assessment in Section II and the judgment of the depreciation consultant were relied upon to estimate reasonable average service lives. Three engineering publications that provide electric industry information were also considered as a resource for making certain assumptions or for the evaluation of lifespan and salvage value parameters:

1. "Depreciation Statistics from 100 Large United States Electric Utilities – FERC Jurisdiction", Society of Depreciation Professionals Journal, Mougin, Clarence, 1992. (hereinafter "SDP report").

2. "A Survey of Depreciation Statistics", Edison Electric Institute, Robinson, Earl, 1995. (hereinafter "EEI report").

3. "Power Plant Removal Costs Revisited", Society of Depreciation Professionals Journal, Ferguson, John, 1997. (hereinafter "Ferguson report").

Net Salvage Factors

For this Study, Big Rivers provided salvage values and removal costs for 2010 and 2011. Including very large removal costs incurred by Big Rivers in 2010 and 2011 resulted in unrealistic net salvage factors. Therefore, the net salvage factors for each production, transmission, and general plant account were taken directly from the net salvage analysis performed in the 2010 Study. The net salvage factors provided in the 2010 Study are calculated as an average of the available historical data by system account from 1965 to 1998 and estimated values from 1998 to 2010. The net salvage figures used in the depreciation rate formulas in the 2010 Study are for final net salvage, i.e. the gross proceeds realized less any removal cost to raze the structures represented in the account, if any.

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

DEPRECIATION RATE ANALYSIS

Table III-1 summarizes the results of the depreciation rate analysis by capital plant account balance as of July 31, 2012. Table III-1 shows the existing depreciation rates and annual depreciation expense compared to the proposed depreciation rates and annual depreciation expense. Table III-1 also shows the July 31, 2012 plant account balances, reserve ratios, average service lives, remaining service lives and net salvage factors.

Table III-1: 2012 Depreciation Rate Study Summary

Account	Description	As of July 31, 2012 Plant Balance	Reserve Balance	Reserve Ratio	Existing Depreciation Rate	Average Service Life	Remaining Service Life	Net Salvage Factor	Proposed Depreciation Rate	Annual Depreciation Expense Existing	Proposed	Variance
		- $ -	- $ -		- % -	- Years -	- Years -	- % -	- % -	- $ -	- $ -	- $ -
310	Land & Land Improvements	4,537,577	0									
PRODUCTION PLANT [1]												
340	Land	475,968	0									
311	Structures	125,693,531	82,324,994	65.5	1.38%	62.0	28.2	-4.5%	1.38%	1,734,571	1,737,612	3,041
312	Boiler Plant	680,885,710	356,227,283	52.3	1.88%	59.5	26.1	-5.0%	2.02%	12,800,651	13,732,241	931,589
312 A-K	Boiler Plant - Environment Compliance	577,753,481	222,781,719	38.6	2.28%	53.0	26.1	-2.0%	2.43%	13,172,779	14,016,172	843,392
312 L-P	Short-Life Production Plant -Environmental	13,034,034	3,069,236	23.5	20.22%	10.0	4.8	0.0%	15.95%	2,635,482	2,078,941	(556,541)
312 V-Z	Short-Life Production Plant -Other	721,531	(178,280)	-24.7	14.39%	10.0	4.9	0.0%	25.38%	103,828	183,151	79,323
314	Turbine	230,546,435	129,685,979	56.3	1.91%	59.5	26.5	-8.2%	1.96%	4,403,437	4,511,020	107,583
315	Electric Equipment	62,213,068	37,265,920	59.9	1.99%	50.9	18.3	3.0%	2.03%	1,238,040	1,261,703	23,663
316	Miscellaneous Equipment	4,745,114	60,556	1.3	3.78%	57.5	24.3	0.5%	4.04%	179,365	191,836	12,471
341	CT - Structures	154,233	122,610	79.5	1.17%	52.5	19.4	0.0%	1.06%	1,805	1,633	(172)
342	CT - Fuel Holders & Access.	1,442,387	641,686	44.5	9.10%	52.5	19.2	-134.8%	9.92%	131,257	143,063	11,806
343	CT - Prime Movers	4,915,886	3,929,184	79.9	3.02%	52.5	19.4	-38.3%	3.02%	148,460	148,316	(144)
344	CT - Generators	1,102,964	1,027,096	93.1	0.50%	52.5	19.5	0.0%	0.35%	5,515	3,891	(1,624)
345	CT - Accessory Electrical Equipment	399,274	178,372	44.7	2.05%	52.5	18.9	0.0%	2.93%	8,185	11,683	3,498
	Subtotal	1,708,621,193	837,136,354							36,563,375	38,021,262	1,457,887
TRANSMISSION [1]												
350	Land	704,868	0									
352	Structures	6,872,307	3,939,593	57.3	1.90%	52.5	23.3	-2.4%	1.94%	130,574	133,325	2,752
353	Station Equipment	123,005,428	57,372,818	46.6	2.23%	52.5	23.4	-0.2%	2.29%	2,743,021	2,818,401	75,380
354	Towers	8,593,544	5,258,193	61.2	1.42%	57.5	28.5	0.0%	1.36%	122,028	117,062	(4,967)
355	Poles	42,531,008	24,872,625	58.5	2.06%	49.5	20.5	0.0%	2.03%	876,139	861,385	(14,754)
356	Lines	43,877,088	25,179,681	57.4	1.69%	52.5	23.5	0.0%	1.81%	741,523	795,634	54,112
	Subtotal	225,584,244	116,622,910							4,613,285	4,725,807	112,523
GENERAL PLANT [2]												
389	Land	407,251	0									
390	Structures [1]	5,263,520	1,841,773	35.0	2.84%	42.5	11.5	21.8%	3.76%	149,484	198,151	48,667
391.0/391.6/391.7	Office Furniture & Equipment	797,888	(226,065)	-28.3	17.12%	10.0	6.0	8.9%	9.11%	136,598	72,724	(63,875)
391.2, 391.3	Computer	20,489,975	2,105,972	10.3	10.29%	10.0	4.8	1.2%	9.88%	2,108,418	2,024,934	(83,484)
392.2	Vehicles - General	2,085,515	1,222,328	58.6	4.39%	10.0	3.0	14.2%	8.58%	91,554	179,034	87,480
392.3	Vehicles - Transmission	1,257,240	788,792	62.7	6.14%	10.0	4.7	16.9%	8.31%	77,195	104,450	27,256
393	Stores Equipment	98,766	77,948	78.9	4.40%	16.0	5.2	4.4%	5.97%	4,346	5,900	1,554
394	Tools	731,818	441,711	60.4	4.61%	16.0	8.2	2.7%	6.08%	33,737	44,482	10,745
395	Lab Equipment	221,279	176,719	79.9	4.41%	16.0	5.7	2.1%	6.12%	9,758	13,541	3,783
396	Power Operated Equipment	567,875	423,883	74.6	3.70%	16.0	5.6	24.9%	4.69%	21,011	26,644	5,632
397	Communication Equipment	1,670,551	1,488,248	89.1	4.35%	16.0	1.0	-0.1%	6.25%	72,669	104,474	31,805
398	Miscellaneous Equipment	251,254	44,367	17.7	11.80%	16.0	9.0	3.2%	6.05%	29,648	15,200	(14,448)
	Subtotal	33,842,932	8,385,678							2,734,419	2,789,533	55,115
TOTAL		$1,968,115,264	$962,144,943							$43,911,079	$45,536,603	$1,625,524

[1] Life Span Method depreciation
[2] Whole Life Method depreciation

The existing depreciation rates in effect for Big Rivers' system assets were developed in the previous depreciation study based on the April 30, 2010 plant in service. The annual depreciation expense calculated in Table III-1 based on the application of the **existing depreciation rates** to the July 31, 2012 plant balances is approximately **$43.9 million**.

The application of the **proposed depreciation rates** to the July 31, 2012 plant balances resulted in calculated total annual depreciation expense of approximately **$45.5 million**.

This results in an **increase** in Big Rivers' total annual depreciation expense of approximately **$1.6 million, or 3.7%**.

Discussion of the depreciation analysis performed on each Big Rivers plant category or account that resulted in the information shown in Table III-1 is presented below. Detailed calculations for all the accounts shown in Table III-1 are provided in Appendix A.

Steam Production Plant: Accounts 311 to 316

Actuarial analyses based on historical data obtained from Big Rivers CPR system were used to develop the depreciation rates and remaining life for Accounts 311 to 315. Insufficient plant additions prior to retirement activity prevented a reliable actuarial analysis of Account 316 - Miscellaneous Equipment.

The current best estimates of future retirement dates for each generating station as described in Part II: Engineering Assessment were also used as inputs to the Life Span model along with the actuarial analysis and engineers' judgment for each plant account. The life of these individual units can vary based on a number of factors including but not limited to operating hours and maintenance. The Green, HMP&L Station Two and Coleman facilities have multiple units, but are forecasted to retire in the same year. This is reasonable for three reasons. First, the units were installed within two to three years of each other. Second, most plant accounts are assigned to the entire generating station, not to individual units of the facility. Most importantly, it is realistic to assume that the entire facility would shut down before significant demolition activities begin to occur. Piecemeal removal at an operating facility would be costly and much of the plant infrastructure would need to remain in service in order to maintain the last unit's ability to function.

Due to the caustic nature of scrubber operations, scrubber equipment dealing with sulfur dioxide removal and related piping will be expected to have a shorter life than that expected for the vast majority of the production plant. That life expectancy is directly related to the design, wear and tear from variable amounts of daily operation, and the levels of removal based on the particular coal mix being burned.

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

The D. B. Wilson Station is significantly newer than the other facilities. As such, its Plant Balance is significantly larger in comparison to the other facilities. If the remaining service life of each facility is weighted by the plant balances in Account 311 - Structures, Account 312 - Boiler Plant, and Account 314 - Turbine, the weighted average remaining service life is approximately 26 to 28 years. As such, the remaining service life for Account 311 - Structures was assumed to be 28 years and the remaining service life for Account 312 - Boiler Plant and Account 314 - Turbine was assumed to be 26 years.

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

Other Production (Combustion Turbine): Accounts 341 to 346

The investment in Other Production accounts is related to the one 65 MW combustion turbine (CT) located at the Reid plant. These accounts were studied in a method identical to the Steam Production accounts (except Account 316): actuarial analyses based on historical data obtained from Big Rivers CPR system were used to develop the depreciation rates and remaining life for Accounts 341 to 346.

Transmission: Accounts 352 to 356

The investment in Transmission Accounts is derived from Big Rivers' structures, substations and substation equipment, transmission towers, poles and transmission lines. These accounts were studied in a method identical to the Other Production accounts: actuarial analyses based on historical data obtained from Big Rivers CPR system were used to develop the depreciation rates and remaining life for Accounts 352 to 356.

General Plant: Accounts 390 to 398

Structures: Account 390

This account contains the investment for Cooperative buildings identified as Headquarters, Transmission Office/Warehouse, Publications, Communication, Central Laboratory, and 4th Street Warehouse. Actuarial analyses based on historical data obtained from Big Rivers CPR system were used to develop the depreciation rates and remaining life for Account 390.

Office Furniture & Equipment: Accounts 391.0, 391.6 & 391.7

These accounts contain the investment for items typically found in a business office, including desks, tables, bookcases, chairs, copiers, and fax machines. Due to the similarity of content, the three sub-accounts were analyzed together. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Computer Equipment: Accounts 391.2, 391.3

This account contains the investment for the Big Rivers computer system, software, personal computers, engineering computers, tape drives, peripherals, printers, and the facilities management system. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Vehicles, General: Account 392.2

This account contains investment for Big Rivers' cars, vans, light and medium duty trucks, truck mounted tool cabinets, and a variety of air compressor, generator, and equipment trailers. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Vehicles, Transmission: Account 392.3

This account contains investment for heavy-duty trucks, a crane, a lowboy, and a digger derrick. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Stores Equipment: Account 393

This account contains investment for items typically found in a warehouse, predominantly shelves and bins. Other items include lockers, pallet movers, and a forklift. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Tools, Shop & Garage Equipment: Account 394

This account title is most descriptive of the investment in the account. Typical items found in Account 394 include non-expensed line truck tools, test equipment, ladders, chain saws, tampers, lifts, tanks, air compressors, and an oil purification unit. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Laboratory Equipment: Account 395

This account contains a variety of electrical and material laboratory tools, including power supplies, test gear, oscilloscopes, microscopes, analyzers, a gas chromatograph, a solvent extraction system, and a spectrophotometer. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Power Operated Equipment: Account 396

The investment in this account includes tractors, trenchers, mowers, go-tracts, a bulldozer, and a boat and trailer. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Communications Equipment: Account 397

The investment in this account included Motorola mobile and hand radios, mobile base radio system with console and related towers, telephone systems and upgrades, data circuits, antennas, and pagers. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Miscellaneous Equipment: Account 398

The investment in this account includes equipment not categorized into other accounts including video equipment, cameras, kitchen equipment, vacuum cleaners, and a mobile office trailer. Publicly available industry information, industry standards, and the judgment of the depreciation consultant were relied upon to estimate a reasonable average service life for this account.

Detailed calculations for all the accounts shown in Table III-1 are provided in Appendix A.

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PART IV – SUMMARY & CONCLUSIONS

PART IV
SUMMARY & CONCLUSIONS

Burns & McDonnell has completed its assessment and analysis of the remaining useful lives and the depreciation rates pertaining to the electric plant assets of Big Rivers Electric Corporation as reflected in this 2012 Comprehensive Depreciation Study. The Study was prepared in accordance with, and satisfies the requirements of, the Rural Utilities Service as issued to Big Rivers subsequent to its last depreciation study.

The proposed depreciation rates have been developed for all of Big Rivers' generation, transmission, and general plant in service assets based on historical plant accounting records provided by Big Rivers CPR system, other published depreciation survey information, and generally accepted depreciation analysis methodologies. Based on the analysis of the information provided by Big Rivers and the results of the previously completed on-site observations of the Big Rivers generation and transmission facilities, Burns & McDonnell has formulated estimates of the remaining useful service lives for each plant account. The proposed depreciation rates, if implemented by Big Rivers, would result in an estimated increase in depreciation expense of approximately $1.6 million per year based on July 31, 2012 account balances.

Burns & McDonnell recommends that Big Rivers continues to follow a comprehensive program of testing on those units approaching the service limits in the ASTM guidelines. Individual components should be either repaired or replaced as damage is identified. Since creep stress is a long-term phenomenon, there should be adequate time to procure and schedule replacement of any damaged components. All of the Big Rivers generating units have reached the age when this testing program should be performed. This testing is currently being performed by Big Rivers and should continue to be performed.

Since the Unwind Closing in 2009, Big Rivers has not performed major maintenance such as valve inspections and turbine generator inspections on a schedule consistent with prudent utility operations. Based on the assumption that Big Rivers will be able to perform future major maintenance in a manner consistent with prudent utility operations, there is no reason, from a mechanical engineering perspective, that all of Big Rivers' generating units cannot remain in service for a long time. Should major maintenance continue to be postponed, it is not likely that all of Big Rivers' generating units will remain in service as long as similar generating units.

These proposed depreciation rates are projected to increase total annual depreciation expenses of Big Rivers by approximately 3.7 percent. Therefore, Burns & McDonnell recommends to Big Rivers that it consider pursuing approval and implementation of the proposed depreciation rates for each RUS plant account as presented in this report. The existing and proposed depreciation rates are shown below in Table IV-1.

Table IV-1: Existing and Proposed Depreciation Rates

		Existing Depreciation Rate	Proposed Depreciation Rate	Variance
PRODUCTION PLANT				
311	Structures	1.38%	1.38%	0.00%
312	Boiler Plant	1.88%	2.02%	0.14%
312 A-K	Boiler Plant - Environment Compliance	2.28%	2.43%	0.15%
312 L-P	Short-Life Production Plant -Environmental	20.22%	15.95%	-4.27%
312 V-Z	Short-Life Production Plant -Other	14.39%	25.38%	10.99%
314	Turbine	1.91%	1.96%	0.05%
315	Electric Equipment	1.99%	2.03%	0.04%
316	Miscellaneous Equipment	3.78%	4.04%	0.26%
341	CT - Structures	1.17%	1.06%	-0.11%
342	CT - Fuel Holders & Access.	9.10%	9.92%	0.82%
343	CT - Prime Movers	3.02%	3.02%	0.00%
344	CT - Generators	0.50%	0.35%	-0.15%
345	CT - Accessory Electrical Equipment	2.05%	2.93%	0.88%
TRANSMISSION				
352	Structures	1.90%	1.94%	0.04%
353	Station Equipment	2.23%	2.29%	0.06%
354	Towers	1.42%	1.36%	-0.06%
355	Poles	2.06%	2.03%	-0.03%
356	Lines	1.69%	1.81%	0.12%
GENERAL PLANT				
390	Structures [1]	2.84%	3.76%	0.92%
391.0/391.6/391.7	Office Furniture & Equipment	17.12%	9.11%	-8.01%
391.2	Computer	10.29%	9.88%	-0.41%
392.2	Vehicles - General	4.39%	8.58%	4.19%
392.3	Vehicles - Transmission	6.14%	8.31%	2.17%
393	Stores Equipment	4.40%	5.97%	1.57%
394	Tools	4.61%	6.08%	1.47%
395	Lab Equipment	4.41%	6.12%	1.71%
396	Power Operated Equipment	3.70%	4.69%	0.99%
397	Communication Equipment	4.35%	6.25%	1.90%
398	Miscellaneous Equipment	11.80%	6.05%	-5.75%

In the preparation of this report, the information provided by Big Rivers was used by Burns & McDonnell to make certain assumptions with respect to conditions that may exist in the future. Burns & McDonnell believes the assumptions made are reasonable for the purposes of this report and makes no representation that the conditions assumed will, in fact, occur. In addition, while Burns & McDonnell has no reason to believe that the information provided by Big Rivers, and on which was relied upon, is inaccurate in any material respect, it has not been independently verified and its accuracy or completeness cannot be guaranteed. To the extent that actual future conditions differ from those assumed herein or from the information provided, actual results may vary from those projected.

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APPENDIX A

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production Structures Account: 311

Date of Retirement (Mid Year): 2041
Interim Retirement Rate: 0.00067
Study Date, Year-End: 2012
Future Life from Study Date: 28.8
Remaining Life (F/E + .5) = 28.2

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	2,387,104	0	6,879	$ 2,393,983	0.00000
1966	0	0	0	$ 2,393,983	0.00000
1967	0	0	0	$ 2,393,983	0.00000
1968	0	0	0	$ 2,393,983	0.00000
1969	5,316,911	0	4,040	$ 7,714,934	0.00000
1970	3,088,656	0	5,000	$ 10,808,590	0.00000
1971	4,646,588	0	357	$ 15,455,536	0.00000
1972	15,076	9,237	0	$ 15,461,375	0.00060
1973	37,913	0	0	$ 15,499,289	0.00000
1974	27,452	49,315	537	$ 15,477,963	0.00319
1975	466,603	10,019	298	$ 15,934,844	0.00063
1976	69,169	51,378	0	$ 15,972,635	0.00322
1977	126,316	404	0	$ 16,098,549	0.00003
1978	293,082	9,807	0	$ 16,381,824	0.00060
1979	12,146,670	6,495	3,651	$ 28,525,850	0.00023
1980	514,964	4,484	0	$ 29,036,329	0.00015
1981	13,636,470	0	1,079	$ 42,673,679	0.00000
1982	380,544	6,724	0	$ 43,247,698	0.00016
1983	591,717	582	0	$ 43,838,833	0.00001
1984	383,328	209,902	1,891	$ 44,014,150	0.00477
1985	410,671	26,160	429	$ 44,399,089	0.00059
1986	72,148,221	22,532	5,414	$ 116,530,192	0.00019
1987	60,368	15,673	0	$ 116,574,887	0.00013
1988	297,610	10,603	0	$ 116,862,094	0.00009
1989	183,496	15,906	0	$ 117,029,684	0.00014
1990	293,938	5,170	0	$ 117,318,452	0.00004
1991	160,650	1,284	0	$ 117,477,818	0.00001
1992	152,276	19,338	0	$ 117,610,756	0.00016
1993	112,866	141,852	0	$ 117,581,771	0.00121
1994	100,775	32,440	0	$ 117,650,105	0.00028
1995	9,584	292	0	$ 117,659,398	0.00000
1996	0	1,677	0	$ 117,657,720	0.00001
1997	3,083	1,701	0	$ 117,659,102	0.00001
1998	12,000	4,884	0	$ 117,666,218	0.00004
1999	104,692	130,509	0	$ 117,640,601	0.00111
2000	329,091	594,813	0	$ 117,374,979	0.00507
2001	749,931	32,702	0	$ 118,092,108	0.00028
2002	504,946	260,690	0	$ 118,336,364	0.00220
2003	751,866	100,439	0	$ 118,987,613	0.00084
2004	253,068	87,316	0	$ 119,153,566	0.00073
2005	169,295	30,893	0	$ 119,291,958	0.00026
2006	288,443	7,200	0	$ 119,573,201	0.00006
2007	299,533	19,441	0	$ 119,853,293	0.00016
2008	341,876	184,086	0	$ 120,011,083	0.00153
2009	2,356,108	39,450	0	$ 122,327,741	0.00032
2010	226,124	15,683	3,829	$ 122,542,011	0.00013
2011	1,026,685	206,474	94,078	$ 123,458,300	0.00167
TOTAL	$ 125,696,374	$ 2,367,554	$ 127,480	$ 3,512,236,416	0.00067

Interim Retirement Life Table

Year Placed	Age at 12/31/2012	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00067	0.99933	0.99966	27.71883
2011	1.5	0.00067	0.99933	0.99899	27.69994
2010	2.5	0.00067	0.99933	0.99832	27.68127
2009	3.5	0.00067	0.99933	0.99764	27.66261
2008	4.5	0.00067	0.99933	0.99697	27.64396
2007	5.5	0.00067	0.99933	0.99630	27.62533
2006	6.5	0.00067	0.99933	0.99563	27.60671
2005	7.5	0.00067	0.99933	0.99496	27.58810
2004	8.5	0.00067	0.99933	0.99428	27.56950
2003	9.5	0.00067	0.99933	0.99361	27.55092
2002	10.5	0.00067	0.99933	0.99294	27.53235
2001	11.5	0.00067	0.99933	0.99228	27.51379
2000	12.5	0.00067	0.99933	0.99161	27.49524
1999	13.5	0.00067	0.99933	0.99094	27.47671
1998	14.5	0.00067	0.99933	0.99027	27.45818
1997	15.5	0.00067	0.99933	0.98960	27.43968
1996	16.5	0.00067	0.99933	0.98894	27.42118
1995	17.5	0.00067	0.99933	0.98827	27.40269
1994	18.5	0.00067	0.99933	0.98760	27.38422
1993	19.5	0.00067	0.99933	0.98694	27.36576
1992	20.5	0.00067	0.99933	0.98627	27.34732
1991	21.5	0.00067	0.99933	0.98561	27.32888
1990	22.5	0.00067	0.99933	0.98494	27.31046
1989	23.5	0.00067	0.99933	0.98428	27.29205
1988	24.5	0.00067	0.99933	0.98362	27.27365
1987	25.5	0.00067	0.99933	0.98295	27.25527
1986	26.5	0.00067	0.99933	0.98229	27.23690
1985	27.5	0.00067	0.99933	0.98163	27.21854
1984	28.5	0.00067	0.99933	0.98097	27.20019
1983	29.5	0.00067	0.99933	0.98030	27.18185
1982	30.5	0.00067	0.99933	0.97964	27.16353
1981	31.5	0.00067	0.99933	0.97898	27.14522
1980	32.5	0.00067	0.99933	0.97832	26.16690
1979	33.5	0.00067	0.99933	0.97766	25.18923
1978	34.5	0.00067	0.99933	0.97700	24.21223
1977	35.5	0.00067	0.99933	0.97635	23.23588
1976	36.5	0.00067	0.99933	0.97569	22.26019
1975	37.5	0.00067	0.99933	0.97503	21.28516
1974	38.5	0.00067	0.99933	0.97437	20.31079
1973	39.5	0.00067	0.99933	0.97372	19.33707
1972	40.5	0.00067	0.99933	0.97306	18.36401
1971	41.5	0.00067	0.99933	0.97240	17.39161
1970	42.5	0.00067	0.99933	0.97175	16.41986
1969	43.5	0.00067	0.99933	0.97109	15.44877
1968	44.5	0.00067	0.99933	0.97044	14.47833
1967	45.5	0.00067	0.99933	0.96976	13.50854
1966	46.5	0.00067	0.99933	0.96913	12.53941
1965	47.5	0.00067	0.99933	0.96848	11.57094
1964	48.5	0.00067	0.99933	0.96782	10.60311
1963	49.5	0.00067	0.99933	0.96717	9.63594
1962	50.5	0.00067	0.99933	0.96652	8.66942
1961	51.5	0.00067	0.99933	0.96587	7.70355
1960	52.5	0.00067	0.99933	0.96522	6.73833
1959	53.5	0.00067	0.99933	0.96457	5.77376
1958	54.5	0.00067	0.99933	0.96392	4.80985
1957	55.5	0.00067	0.99933	0.96327	3.84658
1956	56.5	0.00067	0.99933	0.96262	2.88396
1955	57.5	0.00067	0.99933	0.96197	1.92199
1954	58.5	0.00067	0.99933	0.96132	0.96067

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production Boiler Plant | Account: 312

Date of Retirement (Mid Year):	2038
Interim Retirement Rate:	0.00373
Study Date, Year-End:	2012
Future Life from Study Date:	26.3
Remaining Life (F/E + .5) =	26.1

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	3,916,288	0	29,615	$ 3,945,902	0.00000
1966	0	0	0	$ 3,945,902	0.00000
1967	0	0	0	$ 3,945,902	0.00000
1968	0	0	0	$ 3,945,902	0.00000
1969	7,858,376	6,000	190,953	$ 11,989,231	0.00050
1970	8,220,732	5,360	293,878	$ 18,498,461	0.00029
1971	9,980,100	0	159,041	$ 28,637,622	0.00000
1972	182,490	35,260	1,019	$ 28,785,671	0.00122
1973	84,361	47,785	0	$ 28,822,448	0.00166
1974	135,999	980	0	$ 28,957,466	0.00003
1975	40,000	72,300	0	$ 28,926,187	0.00250
1976	7,336	807	771	$ 28,932,467	0.00003
1977	1,095,499	193,134	0	$ 29,834,832	0.00647
1978	477,024	18,000	0	$ 30,293,856	0.00059
1979	66,406,550	2,559	23,021	$ 98,720,868	0.00003
1980	2,717,361	325,053	2,119	$ 99,115,315	0.00328
1981	67,373,001	41,201	235,173	$ 166,682,269	0.00025
1982	739,077	234,532	5,315	$ 167,192,149	0.00140
1983	1,102,532	110,071	3,604	$ 168,188,215	0.00065
1984	3,424,227	713,794	5,987	$ 170,904,638	0.00418
1985	566,092	345,044	700	$ 171,126,384	0.00202
1986	384,348,232	44,591	5,994	$ 555,438,019	0.00008
1987	776,001	449,385	11,952	$ 555,774,587	0.00081
1988	280,438	183,385	5,342	$ 555,896,982	0.00029
1989	1,396,815	853,365	360	$ 556,440,592	0.00153
1990	2,154,435	729,927	113	$ 557,865,213	0.00131
1991	839,541	430,079	160	$ 558,274,835	0.00077
1992	2,194,697	771,619	0	$ 559,697,713	0.00136
1993	170,138	2,547,906	0	$ 557,319,945	0.00457
1994	1,084,718	953,692	0	$ 557,450,769	0.00171
1995	914,144	455,049	0	$ 557,909,864	0.00082
1996	255,860	116,764	0	$ 558,048,960	0.00021
1997	427,596	1,098,445	0	$ 557,375,111	0.00197
1998	1,219,719	6,723,594	0	$ 551,872,236	0.01218
1999	2,031,435	2,387,306	0	$ 551,518,365	0.00433
2000	10,112,831	1,740,646	0	$ 559,888,350	0.00311
2001	9,846,079	4,009,239	0	$ 565,725,190	0.00709
2002	4,734,655	2,524,814	0	$ 567,935,031	0.00445
2003	7,219,552	6,319,165	0	$ 568,835,419	0.01111
2004	7,970,539	1,256,416	0	$ 575,549,541	0.00218
2005	7,816,847	1,901,316	0	$ 581,465,070	0.00327
2006	7,689,092	1,890,342	0	$ 587,263,821	0.00322
2007	11,599,504	986,959	0	$ 597,876,366	0.00165
2008	10,508,691	3,467,092	0	$ 604,917,965	0.00573
2009	22,475,295	1,987,827	0	$ 625,405,433	0.00316
2010	15,467,001	14,872,092	1,135,983	$ 627,136,325	0.02371
2011	10,984,838	1,997,775	596,660	$ 636,720,046	0.00314
TOTAL	$ 696,845,360	$ 62,833,072	$ 2,707,760	$ 16,845,707,703	0.00373

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00373	0.99627	0.99814	25.58682
2011	1.5	0.00373	0.99627	0.99441	25.49138
2010	2.5	0.00373	0.99627	0.99070	25.39630
2009	3.5	0.00373	0.99627	0.98701	25.30157
2008	4.5	0.00373	0.99627	0.98333	25.20720
2007	5.5	0.00373	0.99627	0.97966	25.11318
2006	6.5	0.00373	0.99627	0.97600	25.01951
2005	7.5	0.00373	0.99627	0.97236	24.92919
2004	8.5	0.00373	0.99627	0.96874	24.83322
2003	9.5	0.00373	0.99627	0.96512	24.74059
2002	10.5	0.00373	0.99627	0.96152	24.64831
2001	11.5	0.00373	0.99627	0.95794	24.55637
2000	12.5	0.00373	0.99627	0.95436	24.46478
1999	13.5	0.00373	0.99627	0.95081	24.37353
1998	14.5	0.00373	0.99627	0.94726	24.28262
1997	15.5	0.00373	0.99627	0.94373	24.19205
1996	16.5	0.00373	0.99627	0.94021	24.10181
1995	17.5	0.00373	0.99627	0.93670	24.01191
1994	18.5	0.00373	0.99627	0.93320	23.92235
1993	19.5	0.00373	0.99627	0.92972	23.83312
1992	20.5	0.00373	0.99627	0.92626	23.74423
1991	21.5	0.00373	0.99627	0.92280	23.65566
1990	22.5	0.00373	0.99627	0.91936	23.56743
1989	23.5	0.00373	0.99627	0.91593	23.47953
1988	24.5	0.00373	0.99627	0.91251	23.39195
1987	25.5	0.00373	0.99627	0.90911	23.30470
1986	26.5	0.00373	0.99627	0.90572	23.21777
1985	27.5	0.00373	0.99627	0.90234	23.13117
1984	28.5	0.00373	0.99627	0.89898	23.04490
1983	29.5	0.00373	0.99627	0.89562	22.95894
1982	30.5	0.00373	0.99627	0.89228	22.87331
1981	31.5	0.00373	0.99627	0.88895	22.78799
1980	32.5	0.00373	0.99627	0.88564	22.70299
1979	33.5	0.00373	0.99627	0.88233	21.82066
1978	34.5	0.00373	0.99627	0.87904	20.94162
1977	35.5	0.00373	0.99627	0.87576	20.06585
1976	36.5	0.00373	0.99627	0.87250	19.19335
1975	37.5	0.00373	0.99627	0.86924	18.32411
1974	38.5	0.00373	0.99627	0.86600	17.45811
1973	39.5	0.00373	0.99627	0.86277	16.59534
1972	40.5	0.00373	0.99627	0.85955	15.73578
1971	41.5	0.00373	0.99627	0.85635	14.87944
1970	42.5	0.00373	0.99627	0.85315	14.02628
1969	43.5	0.00373	0.99627	0.84997	13.17631
1968	44.5	0.00373	0.99627	0.84680	12.32951
1967	45.5	0.00373	0.99627	0.84364	11.48587
1966	46.5	0.00373	0.99627	0.84050	10.64537
1965	47.5	0.00373	0.99627	0.83736	9.80801
1964	48.5	0.00373	0.99627	0.83424	8.97377
1963	49.5	0.00373	0.99627	0.83113	8.14265
1962	50.5	0.00373	0.99627	0.82803	7.31462
1961	51.5	0.00373	0.99627	0.82494	6.48969
1960	52.5	0.00373	0.99627	0.82186	5.66783
1959	53.5	0.00373	0.99627	0.81879	4.84903
1958	54.5	0.00373	0.99627	0.81574	4.03329
1957	55.5	0.00373	0.99627	0.81270	3.22059
1956	56.5	0.00373	0.99627	0.80967	2.41093
1955	57.5	0.00373	0.99627	0.80665	1.60426
1954	58.5	0.00373	0.99627	0.80364	0.80064

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production Boiler Plant Env Comp   Account: 312 A-K

Date of Retirement (Mid Year):	2038
Interim Retirement Rate:	0.00252
Study Date, Year-End:	2012
Future Life from Study Date:	26 3
Remaining Life (F/E + .5) =	26.6

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	44,570	0	0	$ 44,570	0.00000
1966	0	0	0	$ 44,570	0.00000
1967	0	0	0	$ 44,570	0.00000
1968	0	0	0	$ 44,570	0.00000
1969	700,674	0	0	$ 745,444	0.00000
1970	771,874	0	0	$ 1,517,318	0.00000
1971	528,902	0	0	$ 2,046,220	0.00000
1972	1,374	0	0	$ 2,047,595	0.00000
1973	380,587	0	0	$ 2,428,182	0.00000
1974	0	0	0	$ 2,428,182	0.00000
1975	52,494	0	0	$ 2,480,676	0.00000
1976	0	0	0	$ 2,480,676	0.00000
1977	216,624	0	0	$ 2,697,300	0.00000
1978	93,337	0	0	$ 2,790,637	0.00000
1979	38,673,298	0	0	$ 41,663,935	0.00000
1980	3,378,499	0	0	$ 45,042,434	0.00000
1981	35,350,822	0	0	$ 80,393,255	0.00000
1982	247,347	0	0	$ 80,640,603	0.00000
1983	1,374,682	0	0	$ 82,015,285	0.00000
1984	660,393	0	0	$ 82,675,677	0.00000
1985	243,512	0	0	$ 82,919,169	0.00000
1986	187,168,630	0	0	$ 270,067,820	0.00000
1987	69,775	0	0	$ 270,167,594	0.00000
1988	68,549	0	0	$ 270,226,143	0.00000
1989	19,814	0	0	$ 270,245,958	0.00000
1990	1,075,429	0	0	$ 271,321,387	0.00000
1991	349,036	0	0	$ 271,670,425	0.00000
1992	79,882	0	0	$ 271,750,307	0.00000
1993	4,899,560	0	0	$ 276,649,866	0.00000
1994	895,543	61,250	0	$ 277,464,159	0.00029
1995	37,056,711	1,122,550	0	$ 313,396,320	0.00358
1996	3,656,557	694,795	0	$ 318,150,082	0.00283
1997	1,778,459	449,630	0	$ 317,488,911	0.00142
1998	263,573	714,153	0	$ 317,038,331	0.00225
1999	1,331,517	873,952	0	$ 317,495,695	0.00275
2000	497,198	351,164	0	$ 317,641,930	0.00111
2001	2,817,168	261,585	0	$ 320,197,531	0.00082
2002	1,582,029	295,920	0	$ 321,483,640	0.00092
2003	80,152,968	934,849	0	$ 400,701,756	0.00233
2004	53,198,911	2,021,299	0	$ 451,879,370	0.00447
2005	1,915,969	1,337,010	0	$ 452,458,330	0.00295
2006	1,038,027	270,526	0	$ 453,225,830	0.00060
2007	4,462,599	1,300,047	0	$ 456,388,381	0.00285
2008	3,268,623	1,044,642	0	$ 456,812,162	0.00226
2009	104,277,773	1,902,711	0	$ 560,987,224	0.00339
2010	18,639,616	9,986,810	5,326,308	$ 574,966,536	0.01737
2011	8,637,202	2,584,868	942,428	$ 579,961,300	0.00446
TOTAL	$ 618,759,941	$ 26,429,761	$ 6,270,736	$ 10,495,450,994	0.00252

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1 - C)	E	F
2012	0 5	0.00252	0.99748	0.99874	26.03574
2011	1.5	0.00252	0.99748	0.99623	25.97018
2010	2.5	0.00252	0.99748	0.99372	25.90478
2009	3.5	0.00252	0.99748	0.99121	25.83955
2008	4.5	0.00252	0.99748	0.98872	25.77448
2007	5.5	0.00252	0.99748	0.98623	25.70957
2006	6.5	0.00252	0.99748	0.98375	25.64483
2005	7.5	0.00252	0.99748	0.98127	25.58025
2004	8.5	0.00252	0.99748	0.97880	25.51584
2003	9.5	0.00252	0.99748	0.97633	25.45158
2002	10.5	0.00252	0.99748	0.97387	25.38749
2001	11.5	0.00252	0.99748	0.97142	25.32358
2000	12.5	0.00252	0.99748	0.96897	25.25979
1999	13.5	0.00252	0.99748	0.96653	25.19618
1998	14.5	0.00252	0.99748	0.96410	25.13273
1997	15.5	0.00252	0.99748	0.96167	25.06944
1996	16.5	0.00252	0.99748	0.95925	26.00631
1995	17.5	0.00252	0.99748	0.95684	24.94334
1994	18.5	0.00252	0.99748	0.95443	24.88053
1993	19.5	0.00252	0.99748	0.95202	24.81787
1992	20.6	0.00252	0.99748	0.94963	24.75538
1991	21.5	0.00252	0.99748	0.94723	24.69304
1990	22.5	0.00252	0.99748	0.94485	24.63085
1989	23.5	0.00252	0.99748	0.94247	24.56883
1988	24.5	0.00252	0.99748	0.94010	24.50696
1987	25.5	0.00252	0.99748	0.93773	24.44524
1986	26.5	0.00252	0.99748	0.93537	24.38369
1985	27.5	0.00252	0.99748	0.93301	24.32228
1984	28.5	0.00252	0.99748	0.93066	24.26103
1983	29.5	0.00252	0.99748	0.92832	24.19994
1982	30.5	0.00252	0.99748	0.92598	24.13900
1981	31.5	0.00252	0.99748	0.92385	24.07821
1980	32.5	0.00252	0.99748	0.92132	24.01758
1979	33.5	0.00252	0.99748	0.91900	23.09658
1978	34.5	0.00252	0.99748	0.91669	22.18189
1977	35.5	0.00252	0.99748	0.91438	21.26751
1976	36.5	0.00252	0.99748	0.91208	20.35543
1975	37.5	0.00252	0.99748	0.90978	19.44565
1974	38.5	0.00252	0.99748	0.90749	16.53818
1973	39.5	0.00252	0.99748	0.90520	17.63295
1972	40.5	0.00252	0.99748	0.90293	18.73003
1971	41.5	0.00252	0.99748	0.90065	15.82937
1970	42.5	0.00252	0.99748	0.89838	14.93099
1969	43.5	0.00252	0.99748	0.89612	14.03487
1968	44.5	0.00252	0.99748	0.89386	13.14101
1967	45.5	0.00252	0.99748	0.89161	12.24939
1966	46.5	0.00252	0.99748	0.88937	11.36002
1965	47.5	0.00252	0.99746	0.88713	10.47289
1964	48.6	0.00262	0.99748	0.88489	9.58800
1963	49.5	0.00252	0.99748	0.88267	8.70533
1962	50.5	0.00252	0.99748	0.88044	7.82489
1961	51.5	0.00252	0.99748	0.87823	6.94666
1960	52.5	0.00252	0.99748	0.87502	6.07065
1959	53.5	0.00252	0.99748	0.87381	5.19684
1958	54.5	0.00252	0.99748	0.87181	4.32523
1957	55.5	0.00252	0.99748	0.86941	3.45582
1956	56.5	0.00252	0.99748	0.86722	2.58859
1955	57.5	0.00252	0.99748	0.86504	1.72355
1954	58.5	0.00252	0.99748	0.86268	0.86069

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production Short-Life Production Plant -Envi Account: PROD 312 L-P

Date of Retirement (Mid Year):	2017
Interim Retirement Rate:	0.12252
Study Date, Year-End:	2012
Future Life from Study Date:	5.0
Remaining Life (F/E + .5) =	4.8

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1976	0	0	0	$ -	0.00000
1977	0	0	0	$ -	0.00000
1978	0	0	0	$ -	0.00000
1979	0	0	0	$ -	0.00000
1980	0	0	0	$ -	0.00000
1981	0	0	0	$ -	0.00000
1982	0	0	0	$ -	0.00000
1983	0	0	0	$ -	0.00000
1984	0	0	0	$ -	0.00000
1985	0	0	0	$ -	0.00000
1986	0	0	0	$ -	0.00000
1987	0	0	0	$ -	0.00000
1988	0	0	0	$ -	0.00000
1989	0	0	0	$ -	0.00000
1990	0	0	0	$ -	0.00000
1991	0	0	0	$ -	0.00000
1992	0	0	0	$ -	0.00000
1993	0	0	0	$ -	0.00000
1994	0	0	0	$ -	0.00000
1995	0	0	0	$ -	0.00000
1996	0	0	0	$ -	0.00000
1997	0	0	0	$ -	0.00000
1998	0	0	0	$ -	0.00000
1999	0	0	0	$ -	0.00000
2000	0	0	0	$ -	0.00000
2001	0	0	0	$ -	0.00000
2002	185,953	0	0	$ 185,953	0.00000
2003	394,231	0	0	$ 580,184	0.00000
2004	0	44,130	0	$ 536,054	0.08232
2005	246,373	124,232	0	$ 658,195	0.18875
2006	0	0	0	$ 658,195	0.00000
2007	413,100	414,060	0	$ 657,235	0.63000
2008	0	137,386	0	$ 519,849	0.26428
2009	0	0	0	$ 519,849	0.00000
2010	0	0	0	$ 519,849	0.00000
2011	0	0	0	$ 519,849	0.00000
TOTAL	$ 1,239,656	$ 719,807	$ -	$ 5,875,060	0.12252

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.12252	0.87748	0.93874	4.03021
2011	1.5	0.12252	0.87748	0.82373	3.53643
2010	2.5	0.12252	0.87748	0.72280	3.10315
2009	3.5	0.12252	0.87748	0.63425	2.72296
2008	4.5	0.12252	0.87748	0.55654	2.38934
2007	5.5	0.12252	0.87748	0.48835	2.09660
2006	6.5	0.12252	0.87748	0.42852	1.83973
2005	7.5	0.12252	0.87748	0.37602	1.61433
2004	8.5	0.12252	0.87748	0.32995	1.41654
2003	9.5	0.12252	0.87748	0.28952	1.24299
2002	10.5	0.12252	0.87748	0.25405	1.09070
2001	11.5	0.12252	0.87748	0.22293	0.95707
2000	12.5	0.12252	0.87748	0.19561	0.83981
1999	13.5	0.12252	0.87748	0.17165	0.73691
1998	14.5	0.12252	0.87748	0.15062	0.64663
1997	15.5	0.12252	0.87748	0.13216	0.56740
1996	16.5	0.12252	0.87748	0.11597	0.49789
1995	17.5	0.12252	0.87748	0.10176	0.43689
1994	18.5	0.12252	0.87748	0.08929	0.38336
1993	19.5	0.12252	0.87748	0.07835	0.33639
1992	20.5	0.12252	0.87748	0.06875	0.29518
1991	21.5	0.12252	0.87748	0.06033	0.25901
1990	22.5	0.12252	0.87748	0.05294	0.22728
1989	23.5	0.12252	0.87748	0.04645	0.19943
1988	24.5	0.12252	0.87748	0.04076	0.17500
1987	25.5	0.12252	0.87748	0.03577	0.15356
1966	26.5	0.12252	0.87748	0.03139	0.13474
1985	27.5	0.12252	0.87748	0.02754	0.11823
1984	28.5	0.12252	0.87748	0.02417	0.10375
1983	29.5	0.12252	0.87748	0.02120	0.09104
1982	30.5	0.12252	0.87748	0.01861	0.07988
1981	31.5	0.12252	0.87748	0.01633	0.07010
1980	32.5	0.12252	0.87748	0.01433	0.06151
1979	33.5	0.12252	0.87748	0.01257	0.05397
1978	34.5	0.12252	0.87748	0.01103	0.04736
1977	35.5	0.12252	0.87748	0.00968	0.04156
1976	36.5	0.12252	0.87748	0.00849	0.03647
1975	37.5	0.12252	0.87748	0.00745	0.03200
1974	36.5	0.12252	0.87748	0.00654	0.02808
1973	39.5	0.12252	0.87748	0.00574	0.02464
1972	40.5	0.12252	0.87748	0.00504	0.02162
1971	41.5	0.12252	0.87748	0.00442	0.01897
1970	42.5	0.12252	0.87748	0.00388	0.01665
1969	43.5	0.12252	0.87748	0.00340	0.01461
1968	44.5	0.12252	0.87748	0.00299	0.01282
1967	45.5	0.12252	0.87748	0.00262	0.01125
1966	46.5	0.12252	0.87748	0.00230	0.00987
1965	47.5	0.12252	0.87748	0.00202	0.00866
1964	48.5	0.12252	0.87748	0.00177	0.00760
1963	49.5	0.12252	0.67748	0.00155	0.00667
1982	50.5	0.12252	0.87748	0.00136	0.00565
1961	51.5	0.12252	0.87748	0.00120	0.00513
1960	52.5	0.12252	0.87748	0.00105	0.00450
1959	53.5	0.12252	0.87748	0.00092	0.00358
1958	54.5	0.12252	0.87748	0.00081	0.00278
1957	55.5	0.12252	0.87748	0.00071	0.00207
1956	56.5	0.12252	0.87748	0.00062	0.00145
1955	57.5	0.12252	0.87748	0.00055	0.00090
1954	58.5	0.12252	0.87748	0.00048	0.00042

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production Short-Life Production Plant -Oth   Account: PROD 312 V-Z

Date of Retirement (Mid Year):	2017
Interim Retirement Rate:	0.04135
Study Date, Year-End:	2012
Future Life from Study Date:	5.0
Remaining Life (F/E + .5) =	4.9

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	102,791	0	0	$ 102,791	0.00000
1976	0	0	0	$ 102,791	0.00000
1977	61,320	0	0	$ 184,111	0.00000
1978	0	0	0	$ 184,111	0.00000
1979	0	0	0	$ 184,111	0.00000
1980	0	0	0	$ 184,111	0.00000
1981	0	0	0	$ 184,111	0.00000
1982	0	0	0	$ 184,111	0.00000
1983	0	0	0	$ 184,111	0.00000
1984	0	0	0	$ 184,111	0.00000
1985	0	0	0	$ 184,111	0.00000
1986	0	0	0	$ 184,111	0.00000
1967	0	0	0	$ 184,111	0.00000
1968	0	0	0	$ 184,111	0.00000
1989	0	0	0	$ 184,111	0.00000
1990	0	0	0	$ 184,111	0.00000
1991	0	0	0	$ 184,111	0.00000
1992	0	0	0	$ 184,111	0.00000
1993	0	0	0	$ 184,111	0.00000
1994	0	0	0	$ 184,111	0.00000
1995	0	0	0	$ 184,111	0.00000
1996	0	0	0	$ 184,111	0.00000
1997	0	0	0	$ 184,111	0.00000
1998	0	0	0	$ 184,111	0.00000
1999	0	46,482	0	$ 137,628	0.33774
2000	0	0	0	$ 137,628	0.00000
2001	29,494	0	0	$ 187,122	0.00000
2002	0	0	0	$ 187,122	0.00000
2003	0	0	0	$ 167,122	0.00000
2004	135,678	0	0	$ 302,801	0.00000
2005	0	0	0	$ 302,801	0.00000
2006	195,609	29,494	0	$ 488,916	0.06290
2007	128,037	54,814	0	$ 542,138	0.10111
2008	132,958	0	0	$ 875,096	0.00000
2009	62,867	0	0	$ 737,963	0.00000
2010	0	0	0	$ 737,963	0.00000
2011	354,011	299,569	11,683	$ 604,088	0.37256
TOTAL	$ 1,222,766	$ 430,361	$ 11,683	$ 10,408,496	0.04135

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.04135	0.95865	0.97933	4.32171
2011	1.5	0.04135	0.95865	0.93883	4.14302
2010	2.5	0.04135	0.95865	0.90002	3.97172
2009	3.5	0.04135	0.95885	0.86280	3.80750
2008	4.5	0.04135	0.95865	0.82713	3.65007
2007	5.5	0.04135	0.95865	0.79293	3.49915
2006	6.5	0.04135	0.95865	0.78014	3.35447
2005	7.5	0.04135	0.95865	0.72871	3.21578
2004	8.5	0.04135	0.95865	0.69858	3.08281
2003	9.5	0.04135	0.95865	0.66970	2.95535
2002	10.5	0.04135	0.95865	0.84201	2.83315
2001	11.5	0.04135	0.95865	0.61546	2.71601
2000	12.5	0.04135	0.95865	0.59002	2.60371
1999	13.5	0.04135	0.95865	0.66562	2.49606
1998	14.5	0.04135	0.95865	0.54223	2.39285
1997	15.5	0.04135	0.95865	0.51961	2.29391
1996	16.5	0.04135	0.95865	0.49832	2.19907
1995	17.5	0.04135	0.95865	0.47772	2.10814
1994	18.5	0.04135	0.95865	0.45797	2.02098
1993	19.5	0.04135	0.95865	0.43903	1.93741
1992	20.5	0.04135	0.95865	0.42088	1.85731
1991	21.5	0.04135	0.95865	0.40348	1.78051
1990	22.5	0.04135	0.95885	0.38679	1.70690
1989	23.5	0.04135	0.95865	0.37080	1.63632
1988	24.5	0.04135	0.95865	0.35547	1.56866
1987	25.5	0.04135	0.95865	0.34077	1.50380
1986	28.5	0.04135	0.95865	0.32668	1.44183
1985	27.5	0.04135	0.95865	0.31317	1.38202
1984	26.5	0.04135	0.95865	0.30023	1.32488
1963	29.5	0.04135	0.95865	0.28781	1.27010
1962	30.5	0.04135	0.95865	0.27591	1.21758
1981	31.5	0.04135	0.95865	0.28450	1.16724
1960	32.5	0.04135	0.95865	0.25357	1.11896
1979	33.5	0.04135	0.95865	0.24308	1.07271
1976	34.5	0.04135	0.95865	0.23303	1.02836
1977	35.5	0.04135	0.95865	0.22340	0.98584
1976	36.5	0.04135	0.95865	0.21416	0.94508
1975	37.5	0.04135	0.95865	0.20531	0.90600
1974	38.5	0.04135	0.95865	0.19682	0.86854
1973	39.5	0.04135	0.95865	0.18868	0.83263
1972	40.5	0.04135	0.95865	0.18088	0.79820
1971	41.5	0.04135	0.95865	0.17340	0.76520
1970	42.5	0.04135	0.95865	0.16623	0.73356
1969	43.5	0.04135	0.95665	0.15936	0.70323
1968	44.5	0.04135	0.95865	0.15277	0.87415
1967	45.5	0.04135	0.95865	0.14645	0.64628
1966	46.5	0.04135	0.95865	0.14040	0.61956
1965	47.5	0.04135	0.95665	0.13459	0.59394
1964	48.5	0.04135	0.95865	0.12903	0.56938
1963	49.5	0.04135	0.95865	0.12369	0.54584
1962	50.5	0.04135	0.95665	0.11858	0.52327
1961	51.5	0.04135	0.95885	0.11387	0.50184
1960	52.5	0.04135	0.95885	0.10897	0.48089
1959	53.5	0.04135	0.95665	0.10447	0.46101
1958	54.5	0.04135	0.95865	0.10015	0.44195
1957	55.5	0.04135	0.95665	0.09601	0.34594
1956	58.5	0.04135	0.95865	0.09204	0.25390
1955	57.5	0.04135	0.95865	0.08823	0.16567
1954	58.5	0.04135	0.95865	0.08458	0.08109

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production Turbine   Account: 314

Date of Retirement (Mid Year):	2038
Interim Retirement Rate:	0.00261
Study Date, Year-End:	2012
Future Life from Study Date:	26.3
Remaining Life (F/E + .5) =	26.5

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	2,796,515	0	31,664	$ 2,828,179	0.00000
1966	0	0	0	$ 2,628,179	0.00000
1967	0	0	0	$ 2,828,179	0.00000
1968	0	0	0	$ 2,826,179	0.00000
1969	5,207,206	0	1,908	$ 8,037,293	0.00000
1970	5,109,447	0	111,046	$ 13,257,786	0.00000
1971	5,592,461	0	2,674	$ 18,653,121	0.00000
1972	1,342	0	0	$ 18,654,463	0.00000
1973	0	0	0	$ 18,654,463	0.00000
1974	4,504	0	0	$ 18,858,967	0.00000
1975	0	0	0	$ 18,858,967	0.00000
1978	2,333	0	26	$ 18,861,329	0.00000
1977	57,374	2,004	0	$ 18,918,696	0.00011
1976	11,010	1,844	0	$ 18,925,864	0.00010
1979	23,074,937	0	3,445	$ 42,004,246	0.00000
1980	7,990	0	0	$ 42,012,236	0.00000
1981	27,432,065	0	78,262	$ 69,522,583	0.00000
1982	26,800	0	0	$ 69,549,363	0.00000
1983	83,586	0	50	$ 69,633,019	0.00000
1984	499,185	69,117	341	$ 70,063,429	0.00099
1985	29,881	0	0	$ 70,093,310	0.00000
1986	122,282,418	0	100	$ 192,375,827	0.00000
1987	17,618	5,500	0	$ 192,388,146	0.00003
1988	429,682	0	0	$ 192,817,829	0.00000
1989	1,158,803	293,352	0	$ 193,693,279	0.00151
1990	37,733	0	0	$ 193,731,012	0.00000
1991	486,727	4,957	0	$ 194,212,781	0.00003
1992	3,121,467	1,124,186	0	$ 196,210,062	0.00573
1993	1,495,730	914,753	0	$ 196,791,060	0.00465
1994	294,144	8,633	0	$ 197,076,571	0.00004
1995	182,041	139,494	0	$ 197,119,119	0.00071
1996	0	0	0	$ 197,119,119	0.00000
1997	33,629	82,124	0	$ 197,070,624	0.00042
1998	41,814	100,106	0	$ 197,012,132	0.00061
1999	1,685,960	35	0	$ 198,698,057	0.00000
2000	336,847	625,847	0	$ 198,408,056	0.00316
2001	2,732,006	650,720	0	$ 200,489,344	0.00325
2002	1,777,170	2,332,032	0	$ 199,934,461	0.01168
2003	3,470,385	1,128,858	0	$ 202,276,009	0.00558
2004	2,901,597	566,547	0	$ 204,611,058	0.00277
2005	2,306,239	715,673	0	$ 206,201,524	0.00347
2006	698,755	202,380	0	$ 206,697,999	0.00098
2007	2,963,416	823,013	0	$ 208,838,403	0.00394
2008	1,940,927	1,296,832	0	$ 209,482,498	0.00619
2009	5,760,515	1,115,416	0	$ 214,127,597	0.00521
2010	4,005,723	1,627,596	147,931	$ 216,453,656	0.00844
2011	3,821,613	1,758,693	105,554	$ 218,622,130	0.00805
TOTAL	$ 233,929,818	$ 15,790,914	$ 483,226	$ 6,057,550,500	0.00261

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00261	0.99739	0.99870	26.00259
2011	1.5	0.00261	0.99739	0.99609	25.93481
2010	2.5	0.00261	0.99739	0.99350	25.86720
2009	3.5	0.00251	0.99739	0.99091	25.79977
2008	4.5	0.00261	0.99739	0.98832	25.73251
2007	5.5	0.00261	0.99739	0.98575	25.66543
2006	6.5	0.00261	0.99739	0.98318	25.59853
2005	7.5	0.00261	0.99739	0.98061	25.53180
2004	8.5	0.00261	0.99739	0.97806	25.46524
2003	9.5	0.00261	0.99739	0.97551	25.39886
2002	10.5	0.00261	0.99739	0.97297	25.33265
2001	11.5	0.00261	0.99739	0.97043	25.26661
2000	12.5	0.00261	0.99739	0.96790	25.20075
1999	13.5	0.00261	0.99739	0.96538	25.13505
1998	14.5	0.00261	0.99739	0.96288	25.06953
1997	15.5	0.00261	0.99739	0.96035	25.00418
1996	16.5	0.00261	0.99739	0.95785	24.93900
1995	17.5	0.00261	0.99739	0.95535	24.87399
1994	18.5	0.00261	0.99739	0.95286	24.80914
1993	19.5	0.00261	0.99739	0.95038	24.74447
1992	20.5	0.00261	0.99739	0.94790	24.67997
1991	21.5	0.00261	0.99739	0.94543	24.61563
1990	22.5	0.00261	0.99739	0.94296	24.55146
1989	23.5	0.00261	0.99739	0.94050	24.46746
1988	24.5	0.00261	0.99739	0.93805	24.42363
1987	25.5	0.00261	0.99739	0.93561	24.35996
1986	26.5	0.00261	0.99739	0.93317	24.29648
1985	27.5	0.00261	0.99739	0.93074	24.23312
1984	28.5	0.00261	0.99739	0.92831	24.16995
1983	29.5	0.00261	0.99739	0.92589	24.10694
1982	30.5	0.00261	0.99739	0.92348	24.04410
1981	31.5	0.00261	0.99739	0.92107	23.98142
1980	32.5	0.00261	0.99739	0.91867	23.91891
1979	33.5	0.00261	0.99739	0.91627	23.00263
1978	34.5	0.00251	0.99739	0.91388	22.08875
1977	35.5	0.00261	0.99739	0.91150	21.17725
1976	36.5	0.00261	0.99739	0.90913	20.26812
1975	37.5	0.00261	0.99739	0.90676	19.36137
1974	38.5	0.00261	0.99739	0.90439	18.45698
1973	39.5	0.00261	0.99739	0.90203	17.55494
1972	40.5	0.00261	0.99739	0.89968	16.65526
1971	41.5	0.00261	0.99739	0.89734	15.75792
1970	42.5	0.00261	0.99739	0.89500	14.86292
1969	43.5	0.00261	0.99739	0.89267	13.97026
1968	44.5	0.00261	0.99739	0.89034	13.07992
1967	45.5	0.00261	0.99739	0.88802	12.19190
1966	46.5	0.00261	0.99739	0.88570	11.30620
1965	47.5	0.00261	0.99739	0.88339	10.42281
1964	48.5	0.00261	0.99739	0.88109	9.54172
1963	49.5	0.00261	0.99739	0.87878	8.66292
1962	50.5	0.00251	0.99739	0.87650	7.78642
1961	51.6	0.00261	0.99739	0.87422	6.91220
1960	52.5	0.00261	0.99739	0.87194	6.04026
1959	53.5	0.00251	0.99739	0.86967	5.17060
1958	54.5	0.00261	0.99739	0.86740	4.30320
1957	55.5	0.00261	0.99739	0.86514	3.43806
1956	56.5	0.00261	0.99739	0.86288	2.57518
1955	57.5	0.00261	0.99739	0.86063	1.71454
1954	58.5	0.00261	0.99739	0.85839	0.85615

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production Electric Eqpt   Account: 315

Date of Retirement (Mid Year):	2030
Interim Retirement Rate:	0.00117
Study Date, Year-End:	2012
Future Life from Study Date:	17.7
Remaining Life (F/E + .5) =	18.3

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	806,672	0	4,197	$ 810,870	0.00000
1966	0	0	0	$ 810,870	0.00000
1967	0	0	0	$ 810,870	0.00000
1968	0	0	0	$ 810,870	0.00000
1969	1,657,054	0	429	$ 2,468,352	0.00000
1970	1,211,816	0	0	$ 3,680,188	0.00000
1971	2,214,896	0	0	$ 5,895,063	0.00000
1972	0	0	0	$ 5,895,063	0.00000
1973	0	0	0	$ 5,895,063	0.00000
1974	583	0	0	$ 5,895,627	0.00000
1975	1,109	1,104	0	$ 5,895,832	0.00019
1976	638	0	0	$ 5,896,270	0.00000
1977	9,784	0	0	$ 5,906,034	0.00000
1978	51,819	0	0	$ 5,957,853	0.00000
1979	6,001,493	0	0	$ 13,959,346	0.00000
1980	1,282	0	0	$ 13,960,626	0.00000
1981	7,135,784	0	4,685	$ 21,101,097	0.00000
1982	124,942	0	0	$ 21,226,039	0.00000
1983	35,591	119,116	0	$ 21,142,514	0.00563
1984	372,343	393,929	0	$ 21,120,928	0.01865
1985	0	0	0	$ 21,120,928	0.00000
1986	33,607,061	1,604	0	$ 54,726,405	0.00003
1987	2,963	11,228	872	$ 54,719,012	0.00021
1988	50,734	24,761	821	$ 54,745,806	0.00045
1989	12,496	2,516	0	$ 54,755,788	0.00005
1990	0	0	0	$ 54,755,788	0.00000
1991	26,492	0	0	$ 54,782,280	0.00000
1992	0	6,694	0	$ 54,773,586	0.00018
1993	0	758	0	$ 54,772,828	0.00001
1994	39,463	17,049	0	$ 54,795,241	0.00031
1995	13,012	0	0	$ 54,808,253	0.00000
1996	0	15,881	0	$ 54,792,592	0.00029
1997	0	0	0	$ 54,792,592	0.00000
1998	11,622	0	0	$ 54,804,414	0.00000
1999	0	0	0	$ 54,804,414	0.00000
2000	14,681	13,170	0	$ 54,805,825	0.00024
2001	144,537	77,933	0	$ 54,872,529	0.00142
2002	72,066	17,065	0	$ 54,927,530	0.00031
2003	54,916	37,206	0	$ 54,955,242	0.00068
2004	765,626	81,116	0	$ 55,639,752	0.00146
2005	539,116	142,019	0	$ 56,036,850	0.00253
2006	979,575	259,551	0	$ 56,758,874	0.00457
2007	589,965	166,701	0	$ 57,160,138	0.00292
2008	949,772	265,169	0	$ 57,844,721	0.00458
2009	885,908	38,946	0	$ 58,691,581	0.00066
2010	1,196,210	148,255	55,000	$ 59,794,636	0.00248
2011	362,044	145,755	19,013	$ 60,029,938	0.00243
TOTAL	$ 61,934,249	$ 1,989,328	$ 85,017	$ 1,698,634,835	0.00117

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00117	0.99883	0.99941	17.79064
2011	1.5	0.00117	0.99883	0.99824	17.76980
2010	2.5	0.00117	0.99883	0.99707	17.74899
2009	3.5	0.00117	0.99883	0.99591	17.72820
2008	4.5	0.00117	0.99883	0.99474	17.70744
2007	5.5	0.00117	0.99883	0.99358	17.68670
2006	6.5	0.00117	0.99883	0.99241	17.66599
2005	7.5	0.00117	0.99883	0.99125	17.64530
2004	6.5	0.00117	0.99883	0.99009	17.62464
2003	9.5	0.00117	0.99883	0.98893	17.60399
2002	10.5	0.00117	0.99883	0.99777	17.58338
2001	11.5	0.00117	0.99883	0.98661	17.56279
2000	12.5	0.00117	0.99883	0.98546	17.54222
1999	13.5	0.00117	0.99883	0.98431	17.52167
1998	14.5	0.00117	0.99883	0.98315	17.50115
1997	15.5	0.00117	0.99883	0.98200	17.48066
1996	16.5	0.00117	0.99883	0.98085	17.46018
1995	17.5	0.00117	0.99883	0.97970	17.43974
1994	18.5	0.00117	0.99883	0.97855	17.41931
1993	19.5	0.00117	0.99883	0.97741	17.39891
1992	20.5	0.00117	0.99883	0.97626	17.37853
1991	21.5	0.00117	0.99883	0.97512	17.35816
1990	22.5	0.00117	0.99883	0.97398	17.33785
1989	23.5	0.00117	0.99883	0.97284	17.31755
1988	24.5	0.00117	0.99883	0.97170	17.29727
1987	25.5	0.00117	0.99883	0.97056	17.27701
1986	26.5	0.00117	0.99883	0.96942	17.25678
1985	27.5	0.00117	0.99883	0.96829	17.23657
1984	26.5	0.00117	0.99883	0.96715	17.21638
1983	29.5	0.00117	0.99883	0.96602	17.19622
1982	30.5	0.00117	0.99883	0.96489	17.17608
1881	31.5	0.00117	0.99883	0.96378	17.15596
1980	32.5	0.00117	0.99883	0.96263	17.13587
1979	33.5	0.00117	0.99883	0.96150	17.11580
1978	34.5	0.00117	0.99883	0.96038	17.09576
1877	35.5	0.00117	0.99883	0.95925	17.07574
1976	36.5	0.00117	0.99883	0.95813	17.05574
1975	37.5	0.00117	0.99883	0.95701	17.03576
1974	38.5	0.00117	0.99883	0.95589	17.01581
1973	39.5	0.00117	0.99883	0.96477	16.99588
1972	40.5	0.00117	0.99883	0.95365	16.97598
1971	41.5	0.00117	0.99883	0.95253	16.95610
1970	42.5	0.00117	0.99883	0.95142	16.00468
1969	43.5	0.00117	0.99883	0.95030	15.05438
1968	44.5	0.00117	0.99883	0.94919	14.10519
1967	45.5	0.00117	0.99883	0.94808	13.15711
1966	46.5	0.00117	0.99883	0.94697	12.21014
1965	47.5	0.00117	0.99883	0.94586	11.26428
1964	46.5	0.00117	0.99883	0.94475	10.31953
1963	49.5	0.00117	0.99883	0.94365	9.37588
1962	50.6	0.00117	0.99883	0.94254	8.43334
1961	51.5	0.00117	0.99883	0.94144	7.49191
1960	52.5	0.00117	0.99883	0.94033	8.55157
1959	53.5	0.00117	0.99883	0.93923	5.81234
1958	54.5	0.00117	0.99883	0.93813	4.67421
1957	55.5	0.00117	0.99883	0.93703	3.73717
1956	56.5	0.00117	0.99883	0.93594	2.80124
1955	57.5	0.00117	0.99883	0.93484	1.86640
1954	58.5	0.00117	0.99883	0.93375	0.93265

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production Misc. Eqpt   Account: 316

Date of Retirement (Mid Year):	2036
Interim Retirement Rate:	0.71717
Study Date, Year-End:	2012
Future Life from Study Date:	24.3
Remaining Life (F/E + .5) =	0.9

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	30	$ 30	0.00000
1970	0	0	30	$ 59	0.00000
1971	0	0	0	$ 59	0.00000
1972	0	0	0	$ 59	0.00000
1973	0	0	0	$ 59	0.00000
1974	0	0	0	$ 59	0.00000
1975	0	124	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1977	0	0	0	$ -	0.00000
1976	0	1,112	0	$ -	0.00000
1979	0	20,679	621	$ -	0.00000
1980	0	16,751	0	$ -	0.00000
1981	0	51,746	1,137	$ -	0.00000
1982	0	18,445	0	$ -	0.00000
1983	0	18,310	0	$ -	0.00000
1984	0	25,377	261	$ -	0.00000
1985	0	7,983	0	$ -	0.00000
1986	0	64,031	0	$ -	0.00000
1987	0	57,750	0	$ -	0.00000
1988	0	71,125	0	$ -	0.00000
1989	0	69,253	0	$ -	0.00000
1990	0	9,590	0	$ -	0.00000
1991	0	80,545	0	$ -	0.00000
1992	0	61,279	0	$ -	0.00000
1993	0	160,956	0	$ -	0.00000
1994	0	473,344	0	$ -	0.00000
1995	0	11,860	0	$ -	0.00000
1996	0	10,815	0	$ -	0.00000
1997	0	8,359	0	$ -	0.00000
1998	0	9,863,366	0	$ -	0.00000
1999	0	0	0	$ -	0.00000
2000	0	0	0	$ -	0.00000
2001	0	0	0	$ -	0.00000
2002	0	0	0	$ -	0.00000
2003	0	0	0	$ -	0.00000
2004	0	0	0	$ -	0.00000
2005	0	0	0	$ -	0.00000
2006	0	0	0	$ -	0.00000
2007	0	0	0	$ -	0.00000
2008	0	0	0	$ -	0.00000
2009	3,031,173	0	0	$ 3,031,173	0.00000
2010	385,851	0	0	$ 3,417,023	0.00000
2011	1,304,173	143,213	53,000	$ 4,630,983	0.03093
TOTAL	$ 4,721,197	$ 11,267,022	$ 55,076	$ 15,710,486	0.71717

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.71717	0.28283	0.64	0.25
2011	1.5	0.71717	0.28283	0.18	0.07
2010	2.5	0.71717	0.28283	0.05	0.02
2009	3.5	0.71717	0.28283	0.01	0.01
2008	4.5	0.71717	0.28283	0	0.00
2007	5.5	0.71717	0.28283	0	0.00
2006	6.5	0.71717	0.28283	0	0.00
2005	7.5	0.71717	0.28283	0	0.00
2004	8.5	0.71717	0.28283	0	0.00
2003	9.5	0.71717	0.28283	0	0.00
2002	10.5	0.71717	0.28283	0	0.00
2001	11.5	0.71717	0.28283	0	0.00
2000	12.5	0.71717	0.28283	0	0.00
1999	13.5	0.71717	0.28283	0	0.00
1998	14.5	0.71717	0.28283	0	0.00
1997	15.5	0.71717	0.28283	0	0.00
1996	16.5	0.71717	0.28283	0	0.00
1995	17.5	0.71717	0.28283	0	0.00
1994	18.5	0.71717	0.28283	0	0.00
1993	19.5	0.71717	0.28283	0	0.00
1992	20.5	0.71717	0.28283	0	0.00
1991	21.5	0.71717	0.28283	1.95E-12	0.00
1990	22.5	0.71717	0.28283	5.51E-13	0.00
1989	23.5	0.71717	0.28283	1.56E-13	0.00
1988	24.5	0.71717	0.28283	4.40E-14	0.00
1987	25.5	0.71717	0.28283	1.25E-14	0.00
1986	26.5	0.71717	0.28283	3.52E-15	0.00
1985	27.5	0.71717	0.28283	9.97E-15	0.00
1984	28.5	0.71717	0.28283	2.82E-16	0.00
1983	29.5	0.71717	0.28283	7.97E-17	0.00
1982	30.5	0.71717	0.28283	2.25E-17	0.00
1981	31.5	0.71717	0.28283	6.38E-16	0.00
1980	32.5	0.71717	0.28283	1.80E-18	0.00
1979	33.5	0.71717	0.28283	5.10E-19	0.00
1978	34.5	0.71717	0.28283	1.44E-19	0.00
1977	35.5	0.71717	0.28283	4.08E-20	0.00
1976	36.5	0.71717	0.28283	1.15E-20	0.00
1975	37.5	0.71717	0.28283	3.28E-21	0.00
1974	38.5	0.71717	0.28283	9.23E-22	0.00
1973	39.5	0.71717	0.28283	2.61E-22	0.00
1972	40.5	0.71717	0.28283	7.39E-23	0.00
1971	41.5	0.71717	0.28283	2.09E-23	0.00
1970	42.5	0.71717	0.28283	5.91E-24	0.00
1969	43.5	0.71717	0.28283	1.67E-24	0.00
1968	44.5	0.71717	0.28283	4.73E-25	0.00
1967	45.5	0.71717	0.28283	1.34E-25	0.00
1966	46.5	0.71717	0.28283	3.78E-25	0.00
1965	47.5	0.71717	0.28283	1.07E-26	0.00
1964	48.5	0.71717	0.28283	3.02E-27	0.00
1963	49.5	0.71717	0.28283	8.55E-28	0.00
1962	50.5	0.71717	0.28283	2.42E-28	0.00
1961	51.5	0.71717	0.28283	5.64E-29	0.00
1960	52.5	0.71717	0.28283	1.94E-29	0.00
1959	53.5	0.71717	0.28283	5.47E-30	0.00
1958	54.5	0.71717	0.28283	1.55E-30	0.00
1957	55.5	0.71717	0.28283	4.38E-31	0.00
1956	56.5	0.71717	0.28283	1.24E-31	0.00
1955	57.5	0.71717	0.28283	3.50E-32	0.00
1954	58.5	0.71717	0.28283	9.91E-33	0.00

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Production CT - Structures Account: 341

Date of Retirement (Mid Year): 2031
Interim Retirement Rate: 0.00071
Study Date, Year-End: 2012
Future Life from Study Date: 19.3
Remaining Life (F/E + .5) = 19.4

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1978	108,617	0	0	$ 108,617	0.00000
1977	0	0	0	$ 108,617	0.00000
1978	0	0	0	$ 106,617	0.00000
1979	17,703	0	0	$ 126,320	0.00000
1980	0	0	0	$ 126,320	0.00000
1981	0	0	0	$ 126,320	0.00000
1982	0	0	0	$ 128,320	0.00000
1983	0	210	0	$ 126,110	0.00166
1984	0	0	0	$ 126,110	0.00000
1985	0	0	0	$ 128,110	0.00000
1986	0	525	0	$ 125,585	0.00418
1987	0	272	0	$ 125,313	0.00217
1966	0	0	0	$ 125,313	0.00000
1989	0	0	0	$ 125,313	0.00000
1990	0	0	0	$ 125,313	0.00000
1991	0	0	0	$ 125,313	0.00000
1992	0	0	0	$ 125,313	0.00000
1993	0	0	0	$ 125,313	0.00000
1994	0	1,080	0	$ 124,233	0.00870
1995	0	0	0	$ 124,233	0.00000
1996	0	0	0	$ 124,233	0.00000
1997	0	0	0	$ 124,233	0.00000
1996	0	0	0	$ 124,233	0.00000
1999	0	0	0	$ 124,233	0.00000
2000	0	0	0	$ 124,233	0.00000
2001	27,913	1,376	0	$ 150,788	0.00914
2002	0	0	0	$ 150,786	0.00000
2003	0	18	0	$ 150,750	0.00012
2004	0	0	0	$ 150,750	0.00000
2005	0	0	0	$ 150,750	0.00000
2006	0	0	0	$ 150,750	0.00000
2007	0	0	0	$ 150,750	0.00000
2008	0	0	0	$ 150,750	0.00000
2009	0	0	0	$ 150,750	0.00000
2010	0	0	0	$ 150,750	0.00000
2011	0	0	0	$ 150,750	0.00000
TOTAL	$ 154,233	$ 3,463	$ -	$ 4,890,907	0.00071

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00071	0.99929	0.99964	18.85856
2011	1.5	0.00071	0.99929	0.99893	18.84513
2010	2.5	0.00071	0.99929	0.99822	18.83171
2009	3.5	0.00071	0.99929	0.99751	18.81830
2008	4.5	0.00071	0.99929	0.99680	18.80490
2007	5.5	0.00071	0.99929	0.99609	18.79151
2006	6.5	0.00071	0.99929	0.99538	18.77812
2005	7.5	0.00071	0.99929	0.99467	18.76475
2004	8.5	0.00071	0.99929	0.99396	18.75139
2003	9.5	0.00071	0.99929	0.99326	18.73804
2002	10.5	0.00071	0.99929	0.99255	18.72469
2001	11.5	0.00071	0.99929	0.99184	18.71136
2000	12.5	0.00071	0.99929	0.99113	18.69803
1999	13.5	0.00071	0.99929	0.99043	18.68472
1998	14.5	0.00071	0.99929	0.98972	18.67141
1997	15.5	0.00071	0.99929	0.98902	18.65812
1996	16.5	0.00071	0.99929	0.98831	18.64483
1995	17.5	0.00071	0.99929	0.98781	18.63155
1994	18.5	0.00071	0.99929	0.98691	18.81828
1993	19.5	0.00071	0.99929	0.98620	18.60503
1992	20.5	0.00071	0.99929	0.98550	18.59176
1991	21.5	0.00071	0.99929	0.98480	18.57854
1990	22.5	0.00071	0.99929	0.98410	18.56531
1989	23.5	0.00071	0.99929	0.98340	18.55209
1988	24.5	0.00071	0.99929	0.98270	18.53888
1987	25.5	0.00071	0.99929	0.98200	18.52567
1986	26.5	0.00071	0.99929	0.98130	18.51248
1985	27.5	0.00071	0.99929	0.98060	18.49930
1984	26.5	0.00071	0.99929	0.97990	18.48612
1983	29.5	0.00071	0.99929	0.97920	18.47296
1982	30.5	0.00071	0.99929	0.97851	18.45981
1981	31.5	0.00071	0.99929	0.97781	18.44666
1980	32.5	0.00071	0.99929	0.97711	16.43352
1979	33.5	0.00071	0.99929	0.97642	18.42040
1978	34.5	0.00071	0.99929	0.97572	18.40728
1977	35.5	0.00071	0.99929	0.97503	18.39417
1978	36.5	0.00071	0.99929	0.97433	18.36107
1975	37.5	0.00071	0.99929	0.97364	18.36798
1974	38.5	0.00071	0.99929	0.97295	18.35490
1973	39.5	0.00071	0.99929	0.97225	18.34183
1972	40.5	0.00071	0.99929	0.97158	18.32877
1971	41.5	0.00071	0.99929	0.97087	17.35790
1970	42.5	0.00071	0.99929	0.97018	15.36772
1969	43.5	0.00071	0.99929	0.96949	15.41824
1968	44.5	0.00071	0.99929	0.96880	14.44944
1967	45.5	0.00071	0.99929	0.96811	13.48133
1966	46.5	0.00071	0.99929	0.96742	12.51392
1965	47.5	0.00071	0.99929	0.96673	11.54719
1964	48.5	0.00071	0.99929	0.96604	10.58115
1963	49.5	0.00071	0.99929	0.96535	9.61579
1962	50.5	0.00071	0.99929	0.96466	8.65113
1961	51.5	0.00071	0.99929	0.96398	7.68715
1960	52.5	0.00071	0.99929	0.96329	8.72386
1959	53.5	0.00071	0.99929	0.96261	5.75125
1958	54.5	0.00071	0.99929	0.98192	4.79933
1957	55.5	0.00071	0.99929	0.96123	3.83810
1958	58.5	0.00071	0.99929	0.96055	2.87755
1955	57.5	0.00071	0.99929	0.95987	1.91768
1954	58.5	0.00071	0.99929	0.95918	0.95850

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production CT - Fuel Holders & Access. Account: 342

Date of Retirement (Mid Year):	2031
Interim Retirement Rate:	0.00167
Study Date, Year-End:	2012
Future Life from Study Date:	19.3
Remaining Life (F/E + .5) =	19.2

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1975	399,772	0	2,192	$ 401,963	0.00000
1977	0	0	0	$ 401,963	0.00000
1976	30,299	0	0	$ 432,262	0.00000
1979	0	0	0	$ 432,262	0.00000
1980	0	0	0	$ 432,262	0.00000
1981	0	0	0	$ 432,252	0.00000
1982	0	0	0	$ 432,262	0.00000
1983	0	0	0	$ 432,252	0.00000
1984	0	0	0	$ 432,262	0.00000
1985	0	0	0	$ 432,262	0.00000
1986	0	0	0	$ 432,262	0.00000
1987	0	0	0	$ 432,262	0.00000
1988	0	0	0	$ 432,262	0.00000
1989	0	0	0	$ 432,262	0.00000
1990	0	0	0	$ 432,262	0.00000
1991	0	0	0	$ 432,262	0.00000
1992	0	0	0	$ 432,262	0.00000
1993	8,958	1,626	0	$ 439,594	0.00370
1994	0	0	0	$ 439,594	0.00000
1995	0	0	0	$ 439,594	0.00000
1996	0	0	0	$ 439,594	0.00000
1997	0	0	0	$ 439,594	0.00000
1998	0	0	0	$ 439,594	0.00000
1999	0	0	0	$ 439,594	0.00000
2000	0	0	0	$ 439,594	0.00000
2001	19,473	0	0	$ 459,067	0.00000
2002	976,410	0	0	$ 1,437,477	0.00000
2003	0	0	0	$ 1,437,477	0.00000
2004	0	0	0	$ 1,437,477	0.00000
2005	0	0	0	$ 1,437,477	0.00000
2006	0	0	0	$ 1,437,477	0.00000
2007	0	0	0	$ 1,437,477	0.00000
2008	0	0	0	$ 1,437,477	0.00000
2009	0	0	0	$ 1,437,477	0.00000
2010	0	0	0	$ 1,437,477	0.00000
2011	49,200	43,725	20,000	$ 1,462,953	0.02989
TOTAL	$ 1,486,112	$ 45,351	$ 22,192	$ 27,126,880	0.00167

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00167	0.99833	0.99916	18.66990
2011	1.5	0.00167	0.99833	0.99749	18.63869
2010	2.5	0.00167	0.99833	0.99583	18.60753
2009	3.5	0.00167	0.99833	0.99416	18.57842
2008	4.5	0.00167	0.99833	0.99250	18.54537
2007	5.5	0.00167	0.99833	0.99084	18.51436
2006	6.5	0.00167	0.99833	0.98918	18.48341
2005	7.5	0.00167	0.99833	0.98753	18.45251
2004	8.5	0.00167	0.99833	0.98588	18.42166
2003	9.5	0.00167	0.99833	0.98423	18.39087
2002	10.5	0.00167	0.99833	0.98259	18.36012
2001	11.5	0.00167	0.99833	0.98094	18.32943
2000	12.5	0.00167	0.99833	0.97930	18.29878
1999	13.5	0.00167	0.99833	0.97767	18.26819
1998	14.5	0.00167	0.99833	0.97603	18.23765
1997	15.5	0.00167	0.99833	0.97440	18.20716
1996	15.5	0.00167	0.99833	0.97277	18.17672
1995	17.5	0.00157	0.99833	0.97114	18.14633
1994	18.5	0.00167	0.99833	0.96952	18.11600
1993	19.5	0.00157	0.99833	0.96790	18.08571
1992	20.5	0.00167	0.99833	0.96628	16.05548
1991	21.5	0.00167	0.99833	0.96467	16.02529
1990	22.5	0.00167	0.99833	0.96305	17.99516
1989	23.5	0.00167	0.99833	0.96144	17.96507
1988	24.5	0.00167	0.99833	0.95984	17.93504
1987	25.5	0.00167	0.99833	0.95823	17.90505
1988	25.5	0.00167	0.99833	0.95663	17.67512
1985	27.5	0.00167	0.99833	0.95503	17.84524
1984	26.5	0.00167	0.99833	0.95343	17.81540
1983	29.5	0.00167	0.99833	0.95184	17.78562
1982	30.5	0.00167	0.99833	0.95025	17.75589
1981	31.5	0.00167	0.99833	0.94866	17.72620
1980	32.5	0.00167	0.99833	0.94707	17.69657
1979	33.5	0.00167	0.99833	0.94549	17.66698
1978	34.5	0.00167	0.99833	0.94391	17.63745
1977	35.5	0.00167	0.99833	0.94233	17.60796
1976	36.5	0.00167	0.99833	0.94076	17.57652
1975	37.5	0.00167	0.99833	0.93916	17.54914
1974	38.5	0.00167	0.99833	0.93761	17.51980
1973	39.5	0.00167	0.99833	0.93605	17.49051
1972	40.5	0.00157	0.99833	0.93448	17.46127
1971	41.5	0.00167	0.99833	0.93292	16.52835
1970	42.5	0.00167	0.99833	0.93136	15.59699
1969	43.5	0.00167	0.99833	0.92980	14.66719
1968	44.5	0.00167	0.99833	0.92825	13.73894
1967	45.5	0.00167	0.99833	0.92670	12.61224
1966	45.5	0.00167	0.99633	0.92515	11.88710
1965	47.5	0.00167	0.99833	0.92360	10.98350
1964	48.5	0.00167	0.99833	0.92206	10.04144
1963	49.5	0.00167	0.99833	0.92051	9.12093
1962	50.5	0.00167	0.99833	0.91898	8.20195
1961	51.5	0.00167	0.99833	0.91744	7.28451
1980	52.5	0.00167	0.99833	0.91591	8.36881
1959	53.5	0.00167	0.99833	0.91437	5.45423
1958	54.5	0.00167	0.99833	0.91285	4.54139
1957	55.5	0.00167	0.99833	0.91132	3.63007
1956	56.5	0.00167	0.99833	0.90980	2.72027
1955	57.5	0.00167	0.99833	0.90827	1.81200
1954	58.5	0.00167	0.99833	0.90676	0.90524

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production CT - Prime Movers Account: 343

Date of Retirement (Mid Year):	2031
Interim Retirement Rate:	0.00077
Study Date, Year-End:	2012
Future Life from Study Date:	19.3
Remaining Life (F/E + .5) =	19.4

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1870	0	0	0	$ -	0.00000
1871	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1976	0	0	0	$ -	0.00000
1878	3,778,442	0	45,438	$ 3,823,879	0.00000
1977	0	0	0	$ 3,823,879	0.00000
1978	0	0	0	$ 3,823,879	0.00000
1979	0	0	0	$ 3,823,879	0.00000
1980	0	0	0	$ 3,823,879	0.00000
1981	0	0	0	$ 3,823,879	0.00000
1982	0	0	0	$ 3,823,879	0.00000
1983	0	0	0	$ 3,823,879	0.00000
1984	0	0	0	$ 3,823,879	0.00000
1985	0	0	0	$ 3,823,879	0.00000
1986	0	0	0	$ 3,823,879	0.00000
1987	0	0	0	$ 3,823,879	0.00000
1988	0	0	0	$ 3,823,879	0.00000
1989	0	0	0	$ 3,823,879	0.00000
1990	0	0	0	$ 3,823,879	0.00000
1991	0	0	0	$ 3,823,879	0.00000
1992	0	0	0	$ 3,823,879	0.00000
1993	0	0	0	$ 3,823,879	0.00000
1994	0	0	0	$ 3,823,879	0.00000
1995	0	0	0	$ 3,823,879	0.00000
1996	287,722	118,571	0	$ 3,993,030	0.02969
1997	0	0	0	$ 3,993,030	0.00000
1998	0	0	0	$ 3,993,030	0.00000
1999	0	0	0	$ 3,993,030	0.00000
2000	0	0	0	$ 3,993,030	0.00000
2001	0	0	0	$ 3,993,030	0.00000
2002	818,466	0	0	$ 4,809,498	0.00000
2003	18,577	0	0	$ 4,828,073	0.00000
2004	0	0	0	$ 4,829,073	0.00000
2005	0	0	0	$ 4,828,073	0.00000
2006	0	0	0	$ 4,828,073	0.00000
2007	0	0	0	$ 4,828,073	0.00000
2008	14,679	0	0	$ 4,842,752	0.00000
2009	0	0	0	$ 4,842,752	0.00000
2010	0	0	0	$ 4,842,752	0.00000
2011	0	0	0	$ 4,842,752	0.00000
TOTAL	$ 4,915,886	$ 118,571	$ 45,438	$ 153,599,389	0.00077

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00077	0.99923	0.99961	18.84673
2011	1.5	0.00077	0.99923	0.99884	18.83218
2010	2.5	0.00077	0.99923	0.99807	18.81764
2009	3.5	0.00077	0.99923	0.99730	18.80312
2008	4.5	0.00077	0.99923	0.99653	18.78860
2007	5.5	0.00077	0.99923	0.99576	18.77410
2006	6.5	0.00077	0.99923	0.99499	18.75960
2005	7.5	0.00077	0.99923	0.99422	18.74512
2004	8.5	0.00077	0.99923	0.99346	18.73065
2003	9.5	0.00077	0.99923	0.99269	18.71619
2002	10.5	0.00077	0.99923	0.99192	18.70175
2001	11.5	0.00077	0.99923	0.99116	18.68731
2000	12.5	0.00077	0.99923	0.99039	18.67288
1999	13.5	0.00077	0.99923	0.98963	18.65847
1998	14.5	0.00077	0.99923	0.98886	18.64407
1997	15.5	0.00077	0.99923	0.98810	18.62967
1996	16.5	0.00077	0.99923	0.98734	18.61529
1995	17.5	0.00077	0.99923	0.98658	18.60092
1994	18.5	0.00077	0.99923	0.98582	18.58656
1993	19.5	0.00077	0.99923	0.98505	18.57221
1992	20.5	0.00077	0.99923	0.98429	18.55788
1991	21.5	0.00077	0.99923	0.98353	18.54355
1990	22.5	0.00077	0.99923	0.98277	18.52924
1989	23.5	0.00077	0.99923	0.98202	18.51493
1988	24.5	0.00077	0.99923	0.98126	18.50064
1987	25.5	0.00077	0.99923	0.98050	18.48638
1986	26.5	0.00077	0.99923	0.97974	18.47209
1985	27.5	0.00077	0.99923	0.97899	18.45783
1984	28.5	0.00077	0.99923	0.97823	18.44358
1983	29.5	0.00077	0.99923	0.97748	18.42934
1982	30.5	0.00077	0.99923	0.97672	18.41512
1981	31.5	0.00077	0.99923	0.97597	18.40090
1980	32.5	0.00077	0.99923	0.97521	18.38670
1979	33.5	0.00077	0.99923	0.97446	18.37250
1878	34.5	0.00077	0.99923	0.97371	18.35832
1977	35.5	0.00077	0.99923	0.97296	18.34415
1976	36.5	0.00077	0.99923	0.97221	18.32999
1975	37.5	0.00077	0.99923	0.97146	18.31584
1874	38.5	0.00077	0.99923	0.97071	18.30170
1973	39.5	0.00077	0.99923	0.96996	18.28757
1972	40.6	0.00077	0.99923	0.96921	18.27345
1971	41.5	0.00077	0.99923	0.96846	17.30499
1970	42.5	0.00077	0.99923	0.96771	18.33728
1969	43.5	0.00077	0.99923	0.96697	15.37032
1968	44.5	0.00077	0.99923	0.96622	14.40410
1967	45.5	0.00077	0.99923	0.96547	13.43882
1966	46.5	0.00077	0.99923	0.96473	12.47390
1965	47.5	0.00077	0.99923	0.96398	11.50991
1964	48.5	0.00077	0.99923	0.96324	10.54668
1963	48.5	0.00077	0.99923	0.96250	9.58418
1962	50.5	0.00077	0.99923	0.96175	8.62243
1961	51.5	0.00077	0.99923	0.96101	7.68142
1960	52.5	0.00077	0.99923	0.96027	6.70116
1959	53.5	0.00077	0.99923	0.95953	5.74182
1958	54.5	0.00077	0.99923	0.95879	4.78284
1957	55.5	0.00077	0.99923	0.95805	3.82479
1956	56.5	0.00077	0.99923	0.95731	2.86749
1955	57.5	0.00077	0.99923	0.95657	1.91092
1954	58.5	0.00077	0.99923	0.95583	0.95509

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Production CT - Generators Account: 344

Date of Retirement (Mid Year): 2031
Interim Retirement Rate: 0.00000
Study Date, Year-End: 2012
Future Life from Study Date: 18.3
Remaining Life (F/E + .5) = 19.5

Development of Interim Retirement Rate					
Activity Year	Additions	Retirements	Adjustments and Transfers	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1976	1,102,964	0	0	$ 1,102,964	0.00000
1977	0	0	0	$ 1,102,964	0.00000
1978	0	0	0	$ 1,102,964	0.00000
1979	0	0	0	$ 1,102,964	0.00000
1980	0	0	0	$ 1,102,964	0.00000
1981	0	0	0	$ 1,102,964	0.00000
1982	0	0	0	$ 1,102,964	0.00000
1983	0	0	0	$ 1,102,964	0.00000
1984	0	0	0	$ 1,102,964	0.00000
1985	0	0	0	$ 1,102,964	0.00000
1986	0	0	0	$ 1,102,964	0.00000
1987	0	0	0	$ 1,102,964	0.00000
1988	0	0	0	$ 1,102,964	0.00000
1989	0	0	0	$ 1,102,964	0.00000
1990	0	0	0	$ 1,102,964	0.00000
1991	0	0	0	$ 1,102,964	0.00000
1992	0	0	0	$ 1,102,964	0.00000
1993	0	0	0	$ 1,102,964	0.00000
1994	0	0	0	$ 1,102,964	0.00000
1995	0	0	0	$ 1,102,964	0.00000
1996	0	0	0	$ 1,102,964	0.00000
1997	0	0	0	$ 1,102,964	0.00000
1998	0	0	0	$ 1,102,964	0.00000
1999	0	0	0	$ 1,102,964	0.00000
2000	0	0	0	$ 1,102,964	0.00000
2001	0	0	0	$ 1,102,964	0.00000
2002	0	0	0	$ 1,102,964	0.00000
2003	0	0	0	$ 1,102,964	0.00000
2004	0	0	0	$ 1,102,964	0.00000
2005	0	0	0	$ 1,102,964	0.00000
2006	0	0	0	$ 1,102,964	0.00000
2007	0	0	0	$ 1,102,964	0.00000
2008	0	0	0	$ 1,102,964	0.00000
2009	0	0	0	$ 1,102,964	0.00000
2010	0	0	0	$ 1,102,964	0.00000
2011	0	0	0	$ 1,102,964	0.00000
TOTAL	$ 1,102,964	$ -	$ -	$ 40,809,656	0.00000

Interim Retirement Life Table					
Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	-	1.00000	1.00000	19.00000
2011	1.5	-	1.00000	1.00000	19.00000
2010	2.5	-	1.00000	1.00000	19.00000
2009	3.5	-	1.00000	1.00000	19.00000
2008	4.5	-	1.00000	1.00000	19.00000
2007	5.5	-	1.00000	1.00000	19.00000
2006	6.5	-	1.00000	1.00000	19.00000
2005	7.5	-	1.00000	1.00000	19.00000
2004	6.5	-	1.00000	1.00000	19.00000
2003	9.5	-	1.00000	1.00000	19.00000
2002	10.5	-	1.00000	1.00000	19.00000
2001	11.5	-	1.00000	1.00000	19.00000
2000	12.5	-	1.00000	1.00000	19.00000
1999	13.5	-	1.00000	1.00000	19.00000
1998	14.5	-	1.00000	1.00000	19.00000
1997	15.5	-	1.00000	1.00000	19.00000
1996	16.5	-	1.00000	1.00000	19.00000
1995	17.5	-	1.00000	1.00000	19.00000
1994	16.5	-	1.00000	1.00000	19.00000
1993	19.5	-	1.00000	1.00000	19.00000
1992	20.5	-	1.00000	1.00000	19.00000
1991	21.5	-	1.00000	1.00000	19.00000
1990	22.5	-	1.00000	1.00000	19.00000
1989	23.5	-	1.00000	1.00000	19.00000
1988	24.5	-	1.00000	1.00000	19.00000
1987	25.5	-	1.00000	1.00000	19.00000
1986	26.5	-	1.00000	1.00000	19.00000
1985	27.5	-	1.00000	1.00000	19.00000
1964	26.5	-	1.00000	1.00000	19.00000
1983	29.5	-	1.00000	1.00000	19.00000
1982	30.5	-	1.00000	1.00000	19.00000
1981	31.5	-	1.00000	1.00000	19.00000
1980	32.5	-	1.00000	1.00000	19.00000
1979	33.5	-	1.00000	1.00000	19.00000
1979	34.5	-	1.00000	1.00000	19.00000
1977	35.5	-	1.00000	1.00000	19.00000
1976	36.5	-	1.00000	1.00000	19.00000
1975	37.5	-	1.00000	1.00000	19.00000
1974	38.5	-	1.00000	1.00000	19.00000
1973	39.5	-	1.00000	1.00000	19.00000
1972	40.5	-	1.00000	1.00000	19.00000
1971	41.5	-	1.00000	1.00000	16.00000
1970	42.5	-	1.00000	1.00000	17.00000
1989	43.5	-	1.00000	1.00000	16.00000
1968	44.5	-	1.00000	1.00000	15.00000
1987	45.5	-	1.00000	1.00000	14.00000
1966	46.5	-	1.00000	1.00000	13.00000
1965	47.5	-	1.00000	1.00000	12.00000
1964	48.5	-	1.00000	1.00000	11.00000
1963	49.5	-	1.00000	1.00000	10.00000
1962	50.5	-	1.00000	1.00000	9.00000
1961	51.5	-	1.00000	1.00000	8.00000
1960	52.5	-	1.00000	1.00000	7.00000
1959	53.5	-	1.00000	1.00000	6.00000
1958	54.5	-	1.00000	1.00000	5.00000
1957	55.5	-	1.00000	1.00000	4.00000
1956	56.5	-	1.00000	1.00000	3.00000
1955	57.5	-	1.00000	1.00000	2.00000
1954	58.5	-	1.00000	1.00000	1.00000

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Production CT - Access. Elec. Eqpt. Account: 345

Date of Retirement (Mid Year):	2031
Interim Retirement Rate:	0.00318
Study Date, Year-End:	2012
Future Life from Study Date:	19.3
Remaining Life (F/E + .5) =	18.9

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1976	190,437	0	0	$ 190,437	0.00000
1977	0	0	0	$ 190,437	0.00000
1978	0	0	0	$ 190,437	0.00000
1979	0	0	0	$ 190,437	0.00000
1980	0	0	0	$ 190,437	0.00000
1881	0	0	0	$ 190,437	0.00000
1982	0	0	0	$ 190,437	0.00000
1983	0	0	0	$ 190,437	0.00000
1984	0	0	0	$ 190,437	0.00000
1985	0	0	0	$ 190,437	0.00000
1986	0	0	0	$ 190,437	0.00000
1987	0	0	0	$ 190,437	0.00000
1986	0	0	0	$ 190,437	0.00000
1989	0	0	0	$ 190,437	0.00000
1990	0	0	0	$ 190,437	0.00000
1991	0	0	0	$ 190,437	0.00000
1992	0	0	0	$ 190,437	0.00000
1993	0	0	0	$ 190,437	0.00000
1994	0	542	0	$ 189,894	0.00286
1995	0	0	0	$ 169,894	0.00000
1996	0	0	0	$ 189,894	0.00000
1997	0	0	0	$ 189,894	0.00000
1996	0	0	0	$ 189,894	0.00000
1999	0	0	0	$ 189,894	0.00000
2000	0	0	0	$ 189,694	0.00000
2001	0	1,274	0	$ 188,621	0.00675
2002	0	0	0	$ 188,621	0.00000
2003	16,445	0	0	$ 205,066	0.00000
2004	0	0	0	$ 205,066	0.00000
2005	58,789	8,020	0	$ 257,835	0.02335
2006	0	0	0	$ 257,835	0.00000
2007	52,055	0	0	$ 309,890	0.00000
2008	0	0	0	$ 309,890	0.00000
2009	0	0	0	$ 309,890	0.00000
2010	82,832	16,838	4,700	$ 380,383	0.04427
2011	15,754	0	0	$ 396,138	0.00000
TOTAL	$ 416,112	$ 24,675	$ 4,700	$ 7,766,354	0.00316

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00318	0.99682	0.99841	18.37846
2011	1.5	0.00318	0.99682	0.99524	18.32007
2010	2.5	0.00318	0.99682	0.99208	18.26187
2009	3.5	0.00318	0.99682	0.98893	18.20385
2008	4.5	0.00318	0.99682	0.98578	18.14601
2007	5.5	0.00318	0.99682	0.98265	18.08836
2006	8.5	0.00318	0.99682	0.97953	18.03089
2005	7.5	0.00318	0.99682	0.97642	17.97360
2004	8.5	0.00318	0.99682	0.97332	17.91650
2003	9.5	0.00318	0.99682	0.97022	17.85958
2002	10.5	0.00318	0.99682	0.96714	17.80284
2001	11.5	0.00316	0.99682	0.96407	17.74627
2000	12.5	0.00318	0.99682	0.96100	17.88989
1999	13.5	0.00318	0.99682	0.95795	17.63369
1998	14.5	0.00318	0.99682	0.95491	17.57766
1997	15.5	0.00318	0.99682	0.95187	17.52182
1996	16.5	0.00318	0.99682	0.94885	17.46615
1995	17.5	0.00318	0.99682	0.94584	17.41066
1994	18.5	0.00318	0.99682	0.94283	17.35534
1993	19.5	0.00318	0.99682	0.93983	17.30020
1992	20.5	0.00318	0.99682	0.93685	17.24524
1991	21.5	0.00318	0.99682	0.93387	17.19045
1990	22.5	0.00318	0.99682	0.93091	17.13583
1989	23.5	0.00318	0.99682	0.92795	17.08139
1988	24.5	0.00318	0.99682	0.92500	17.02712
1987	25.5	0.00318	0.99682	0.92206	18.97302
1988	26.5	0.00318	0.99682	0.91913	18.91910
1985	27.5	0.00318	0.99682	0.91621	18.86534
1984	28.5	0.00318	0.99682	0.91330	18.81178
1983	29.5	0.00318	0.99682	0.91040	16.75835
1982	30.5	0.00318	0.99682	0.90751	18.70511
1881	31.5	0.00318	0.99682	0.90462	18.65203
1980	32.5	0.00318	0.99682	0.90176	16.59913
1979	33.5	0.00318	0.99682	0.89888	18.54639
1978	34.5	0.00318	0.99682	0.89603	18.49382
1977	35.5	0.00318	0.99682	0.89318	18.44142
1978	38.5	0.00318	0.99682	0.89034	16.38918
1976	37.5	0.00318	0.99682	0.88751	18.33711
1974	38.5	0.00318	0.99682	0.88470	18.28521
1973	39.5	0.00318	0.99682	0.88188	16.23347
1972	40.5	0.00318	0.99682	0.87908	16.18169
1971	41.5	0.00318	0.99682	0.87629	15.30560
1970	42.5	0.00316	0.99682	0.87351	14.43210
1969	43.5	0.00318	0.99682	0.67073	13.56138
1968	44.5	0.00318	0.99682	0.86796	12.69340
1967	45.5	0.00316	0.99682	0.88521	11.82819
1968	46.5	0.00318	0.99682	0.88246	10.96574
1965	47.5	0.00318	0.99682	0.85972	10.10602
1964	46.5	0.00318	0.99682	0.85699	9.24903
1963	49.5	0.00318	0.99682	0.85426	8.39477
1962	50.5	0.00318	0.99682	0.85155	7.54322
1961	51.5	0.00316	0.99682	0.84884	8.69438
1960	52.5	0.00318	0.99682	0.84615	5.84823
1959	53.5	0.00318	0.99682	0.84346	6.00477
1958	54.5	0.00318	0.99682	0.84078	4.16399
1957	55.5	0.00318	0.99682	0.83811	3.32589
1958	56.5	0.00318	0.99682	0.83544	2.49044
1955	57.5	0.00318	0.99682	0.83279	1.65765
1954	58.5	0.00316	0.99682	0.83014	0.82751

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Transmission Structures Account: 352

Date of Retirement (Mid Year): 2036
Interim Retirement Rate: 0.00088
Study Date, Year-End: 2012
Future Life from Study Date: 23.8
Remaining Life (F/E + .5) = 23.3

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1981	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	20,160	0	27	$ 20,187	0.00000
1966	40,763	0	27	$ 60,977	0.00000
1957	0	0	121	$ 61,098	0.00000
1968	43,613	0	16	$ 104,727	0.00000
1969	259,815	0	1,139	$ 365,462	0.00000
1970	58,666	0	0	$ 424,146	0.00000
1971	4,943	651	63	$ 428,502	0.00152
1972	14,525	0	0	$ 443,028	0.00000
1973	610	294	1,194	$ 444,537	0.00066
1974	5,847	3,892	111	$ 446,602	0.00827
1975	235,954	1,395	934	$ 682,094	0.00205
1976	18,559	491	105	$ 700,268	0.00070
1977	209	667	33	$ 699,843	0.00095
1978	102,849	329	0	$ 802,362	0.00041
1979	405,482	1,485	0	$ 1,206,360	0.00123
1980	599,906	443	1	$ 1,805,624	0.00025
1981	79,726	870	63	$ 1,884,762	0.00046
1982	438,495	0	156	$ 2,323,413	0.00000
1983	18,555	482	0	$ 2,341,507	0.00020
1954	976,798	35,882	0	$ 3,284,620	0.01086
1985	222,378	0	0	$ 3,506,998	0.00000
1986	2,256,609	0	0	$ 5,763,608	0.00000
1887	0	1,876	0	$ 5,761,732	0.00033
1988	3,577	488	0	$ 5,764,841	0.00008
1989	767	746	0	$ 5,784,882	0.00013
1990	16,452	37,975	0	$ 5,743,360	0.00661
1991	605	0	0	$ 5,743,965	0.00000
1992	35,886	5,671	0	$ 5,773,179	0.00116
1993	2,244	3,465	0	$ 5,771,958	0.00060
1994	75,274	987	0	$ 5,846,245	0.00017
1995	0	14,474	0	$ 5,631,771	0.00248
1996	0	4,625	0	$ 5,627,146	0.00079
1997	77,151	0	0	$ 5,904,298	0.00000
1998	36,801	10,364	0	$ 5,930,734	0.00176
1999	671	5,379	0	$ 5,926,026	0.00091
2000	0	107	0	$ 5,925,920	0.00002
2001	6,031	10,116	0	$ 5,923,632	0.00171
2002	97,730	0	0	$ 6,021,562	0.00000
2003	49,786	5,545	0	$ 6,064,803	0.00108
2004	9,861	0	0	$ 6,074,664	0.00000
2005	0	0	0	$ 6,074,664	0.00000
2006	273,628	1,834	0	$ 6,346,458	0.00029
2007	0	0	0	$ 8,346,456	0.00000
2008	225,774	0	0	$ 6,572,231	0.00000
2009	5,029	1,432	0	$ 6,575,628	0.00022
2010	323,951	4,372	679	$ 6,896,086	0.00063
2011	12,469	0	0	$ 6,908,676	0.00000
TOTAL	$ 7,061,787	$ 157,899	$ 4,688	$ 179,122,164	0.00086

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00088	0.99912	0.99956	22.74824
2011	1.5	0.00088	0.99912	0.99868	22.72818
2010	2.5	0.00088	0.99912	0.99780	22.70815
2009	3.5	0.00088	0.99912	0.99692	22.68813
2008	4.5	0.00088	0.99912	0.99604	22.66813
2007	5.5	0.00088	0.99912	0.99516	22.64815
2006	6.5	0.00088	0.99912	0.99428	22.62818
2005	7.5	0.00088	0.99912	0.99341	22.60824
2004	8.5	0.00088	0.99912	0.99253	22.58831
2003	9.5	0.00088	0.99912	0.99166	22.56839
2002	10.5	0.00088	0.99912	0.99078	22.54850
2001	11.5	0.00088	0.99912	0.98991	22.52862
2000	12.5	0.00088	0.99912	0.98904	22.50876
1999	13.5	0.00088	0.99912	0.98816	22.48892
1998	14.5	0.00088	0.99912	0.98729	22.46910
1997	15.5	0.00088	0.99912	0.98642	22.44929
1996	18.5	0.00088	0.99912	0.98555	22.42950
1995	17.5	0.00088	0.99912	0.98469	22.40973
1994	18.5	0.00088	0.99912	0.98382	22.38997
1993	19.5	0.00088	0.99912	0.98295	22.37024
1992	20.5	0.00088	0.99912	0.98208	22.35052
1991	21.5	0.00088	0.99912	0.98122	22.33081
1990	22.5	0.00088	0.99912	0.98035	22.31113
1989	23.5	0.00088	0.99912	0.97949	22.29146
1988	24.5	0.00088	0.99912	0.97863	22.27181
1987	25.5	0.00088	0.99912	0.97776	22.25218
1988	26.5	0.00088	0.99912	0.97690	22.23256
1985	27.5	0.00088	0.99912	0.97604	22.21296
1984	28.5	0.00088	0.99912	0.97518	22.19338
1983	29.5	0.00088	0.99912	0.97432	22.17382
1982	30.5	0.00088	0.99912	0.97346	22.15427
1961	31.5	0.00088	0.99912	0.97260	22.13474
1980	32.5	0.00088	0.99912	0.97174	22.11523
1979	33.5	0.00088	0.99912	0.97089	22.09574
1978	34.5	0.00088	0.99912	0.97003	22.07628
1977	35.5	0.00088	0.99912	0.96918	22.05680
1976	36.5	0.00088	0.99912	0.96832	22.03735
1975	37.5	0.00088	0.99912	0.96747	21.06989
1974	38.5	0.00088	0.99912	0.96662	20.10327
1973	39.5	0.00088	0.99912	0.96576	19.13750
1972	40.5	0.00088	0.99912	0.96491	16.17259
1971	41.5	0.00088	0.99912	0.96406	17.20853
1970	42.5	0.00088	0.99912	0.96321	16.24532
1969	43.5	0.00088	0.99912	0.96236	15.28295
1968	44.5	0.00088	0.99912	0.96152	14.32144
1987	45.5	0.00088	0.99912	0.96067	13.36077
1966	46.5	0.00088	0.99912	0.95982	12.40095
1965	47.5	0.00088	0.99912	0.95897	11.44197
1964	46.5	0.00088	0.99912	0.95813	10.48384
1963	49.5	0.00088	0.99912	0.95728	9.52656
1962	50.5	0.00066	0.99912	0.95644	8.57012
1961	51.5	0.00088	0.99912	0.95560	7.61452
1960	52.5	0.00088	0.99912	0.95476	8.85976
1959	53.5	0.00088	0.99912	0.95391	5.70585
1958	54.5	0.00088	0.99912	0.95307	4.75278
1957	55.5	0.00088	0.99912	0.95223	3.80054
1956	56.5	0.00088	0.99912	0.95139	2.84915
1955	57.5	0.00088	0.99912	0.95055	1.69860
1954	58.5	0.00088	0.99912	0.94972	0.94888

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Transmission Station Eqpt   Account: 353

Date of Retirement (Mid Year):	2036
Interim Retirement Rate:	0.00692
Study Date, Year-End:	2012
Future Life from Study Date:	23.9
Remaining Life (F/E + .5) =	23.4

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	152	$ 152	0.00000
1956	0	0	105	$ 258	0.00000
1957	0	0	0	$ 258	0.00000
1958	0	0	122	$ 379	0.00000
1959	0	0	422	$ 800	0.00000
1960	0	0	0	$ 800	0.00000
1961	0	0	181	$ 981	0.00000
1962	0	0	234	$ 1,195	0.00000
1963	0	0	0	$ 1,195	0.00000
1964	0	0	0	$ 1,195	0.00000
1965	419,714	5,035	4,825	$ 420,699	0.01197
1966	1,221,762	0	1,841	$ 1,644,102	0.00000
1967	1,474	0	5,421	$ 1,650,997	0.00000
1968	945,381	0	7,024	$ 2,603,381	0.00000
1969	3,144,331	3,574	21,755	$ 5,765,693	0.00062
1970	934,369	1,556	4,020	$ 6,702,726	0.00023
1971	376,657	4,337	2,938	$ 7,077,984	0.00061
1972	271,870	6,243	1,011	$ 7,344,622	0.00085
1973	1,593,104	251,447	5,865	$ 8,692,144	0.02893
1974	199,178	24,004	1,244	$ 8,868,582	0.00271
1975	1,954,922	72,258	10,840	$ 10,761,865	0.00671
1976	666,720	13,284	610	$ 11,415,911	0.00116
1977	1,840,851	3,445	2,715	$ 13,256,032	0.00026
1978	2,073,381	9,421	1,194	$ 15,321,188	0.00061
1979	3,301,427	70,870	1,430	$ 18,553,174	0.00382
1980	984,231	23,149	1,678	$ 19,515,933	0.00119
1981	2,755,462	63,090	3,278	$ 22,211,583	0.00284
1982	3,757,786	328,826	1,369	$ 25,641,911	0.01282
1983	940,709	8,084	11,828	$ 28,586,364	0.00030
1984	9,650,017	780,185	4,514	$ 35,480,710	0.02200
1985	1,709,015	19,519	4,901	$ 37,155,108	0.00053
1986	42,240,181	253,465	6,594	$ 79,146,418	0.00320
1987	1,070,892	24,667	1,306	$ 80,195,728	0.00031
1988	160,672	41,780	252	$ 80,314,871	0.00052
1989	393,258	34,043	1,544	$ 80,875,631	0.00042
1990	2,389,258	410,741	1,820	$ 82,855,965	0.00497
1991	49,569	37,817	285	$ 82,668,002	0.00048
1992	732,313	129,609	655	$ 83,271,361	0.00166
1993	1,239,184	1,259,760	867	$ 83,251,632	0.01513
1994	881,759	239,668	80	$ 83,893,784	0.00286
1995	74,232	242,935	393	$ 83,725,474	0.00290
1996	508,704	34,148	1,456	$ 84,201,486	0.00041
1997	1,085,876	19,820	551	$ 85,268,093	0.00023
1998	123,115	182,053	839	$ 85,209,993	0.00214
1999	3,199,950	192,792	670	$ 88,217,822	0.00219
2000	2,487,663	339,531	58	$ 90,366,011	0.00378
2001	975,817	481,633	436	$ 90,860,630	0.00508
2002	1,028,798	124,490	84	$ 91,765,023	0.00138
2003	1,481,576	269,518	0	$ 92,997,083	0.00290
2004	2,792,932	7,785,182	19	$ 88,004,872	0.08846
2005	232,344	65,400	3	$ 88,171,820	0.00074
2006	5,571,841	1,165,164	275	$ 92,578,772	0.01259
2007	245,661	2,399,085	0	$ 90,425,347	0.02653
2008	7,444,270	43,008	0	$ 97,826,610	0.00044
2009	120,432	2,438	0	$ 97,944,604	0.00002
2010	14,350,069	310,037	28,388	$ 112,013,004	0.00277
2011	1,075,366	192,774	490	$ 112,898,086	0.00171
TOTAL	$ 130,697,671	$ 17,949,725	$ 148,140	$ 2,595,246,192	0.00692

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00692	0.99308	0.99654	22.79265
2011	1.5	0.00692	0.99308	0.98965	22.63501
2010	2.5	0.00692	0.99308	0.98280	22.47848
2009	3.5	0.00692	0.99308	0.97601	22.32299
2008	4.5	0.00692	0.99308	0.96928	22.16860
2007	6.5	0.00692	0.99308	0.96255	22.01527
2006	6.5	0.00692	0.99308	0.95590	21.86300
2005	7.5	0.00692	0.99308	0.94928	21.71179
2004	8.5	0.00692	0.99308	0.94272	21.58162
2003	9.5	0.00692	0.99308	0.93620	21.41249
2002	10.5	0.00692	0.99308	0.92972	21.26440
2001	11.5	0.00692	0.99308	0.92329	21.11732
2000	12.5	0.00692	0.99308	0.91691	20.97127
1999	13.5	0.00692	0.99308	0.91057	20.82622
1998	14.5	0.00692	0.99308	0.90427	20.68216
1997	15.5	0.00692	0.99308	0.89801	20.53914
1996	16.5	0.00692	0.99308	0.89180	20.39708
1995	17.5	0.00692	0.99308	0.88563	20.25600
1994	18.5	0.00692	0.99308	0.87951	20.11591
1993	19.5	0.00692	0.99308	0.87343	19.97678
1992	20.5	0.00692	0.99308	0.86738	19.83881
1991	21.5	0.00692	0.99308	0.86139	19.70140
1990	22.5	0.00692	0.99308	0.85543	19.56514
1989	23.5	0.00692	0.99308	0.84951	19.42982
1988	24.5	0.00692	0.99308	0.84364	19.29543
1987	25.6	0.00692	0.99308	0.83780	19.16198
1986	26.5	0.00692	0.99308	0.83201	19.02945
1985	27.5	0.00692	0.99308	0.82625	18.89783
1984	28.5	0.00692	0.99308	0.82054	18.76713
1983	29.5	0.00692	0.99308	0.81488	18.63732
1982	30.5	0.00692	0.99308	0.80923	18.50842
1981	31.5	0.00692	0.99308	0.80363	18.38041
1980	32.5	0.00692	0.99308	0.79807	18.25328
1979	33.5	0.00692	0.99308	0.79255	18.12704
1978	34.5	0.00692	0.99308	0.78707	18.00166
1977	35.5	0.00692	0.99308	0.78163	17.22004
1976	36.5	0.00692	0.99308	0.77622	16.44382
1975	37.5	0.00692	0.99308	0.77085	15.67297
1974	38.5	0.00692	0.99308	0.76552	14.90745
1973	39.5	0.00692	0.99308	0.76023	14.14722
1972	40.5	0.00692	0.99308	0.75497	13.39225
1971	41.5	0.00692	0.99308	0.74975	12.64251
1970	42.5	0.00692	0.99308	0.74456	11.89795
1969	43.5	0.00692	0.99308	0.73941	11.15854
1968	44.5	0.00692	0.99308	0.73430	10.42424
1967	45.5	0.00692	0.99308	0.72922	9.69502
1966	46.5	0.00692	0.99308	0.72417	8.97085
1965	47.5	0.00692	0.99308	0.71917	8.25168
1964	48.6	0.00692	0.99308	0.71419	7.53749
1963	49.5	0.00692	0.99308	0.70925	6.82824
1962	50.5	0.00692	0.99308	0.70435	6.12389
1961	51.5	0.00692	0.99308	0.69947	5.42442
1960	52.5	0.00692	0.99308	0.69464	4.72978
1959	53.5	0.00692	0.99308	0.68983	4.03995
1958	54.5	0.00692	0.99308	0.68506	3.35489
1957	55.5	0.00692	0.99308	0.68032	2.67456
1956	56.5	0.00692	0.99308	0.67562	1.99895
1955	57.5	0.00692	0.99308	0.67095	1.32800
1954	58.5	0.00692	0.99308	0.66630	0.66170

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Transmission Towers Account: 354

Date of Retirement (Mid Year):	2041
Interim Retirement Rate:	0.00002
Study Date, Year-End:	2012
Future Life from Study Date:	28.8
Remaining Life (F/E + .5) =	28.5

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	309,097	0	0	$ 309,097	0.00000
1968	139,879	0	0	$ 448,978	0.00000
1969	157,055	0	0	$ 606,032	0.00000
1970	0	0	0	$ 606,032	0.00000
1871	0	0	0	$ 606,032	0.00000
1972	0	0	0	$ 606,032	0.00000
1973	0	0	0	$ 606,032	0.00000
1974	0	0	0	$ 606,032	0.00000
1975	0	0	0	$ 606,032	0.00000
1976	380,892	0	0	$ 986,924	0.00000
1977	4,019	0	145	$ 991,089	0.00000
1978	3,721	0	0	$ 994,809	0.00000
1979	78,240	0	0	$ 1,073,049	0.00000
1960	80,487	0	0	$ 1,153,536	0.00000
1961	4,893	0	0	$ 1,158,429	0.00000
1962	86,103	0	0	$ 1,246,532	0.00000
1963	14,694	0	0	$ 1,261,228	0.00000
1964	460,143	0	0	$ 1,721,370	0.00000
1965	0	0	0	$ 1,721,370	0.00000
1986	5,595,769	0	0	$ 7,317,138	0.00000
1987	0	0	0	$ 7,317,138	0.00000
1988	0	0	0	$ 7,317,138	0.00000
1989	0	0	0	$ 7,317,138	0.00000
1990	10,759	0	0	$ 7,327,897	0.00000
1991	0	3,667	0	$ 7,324,231	0.00050
1992	0	0	0	$ 7,324,231	0.00000
1993	0	0	0	$ 7,324,231	0.00000
1994	0	0	0	$ 7,324,231	0.00000
1995	0	0	0	$ 7,324,231	0.00000
1996	0	0	0	$ 7,324,231	0.00000
1997	0	0	0	$ 7,324,231	0.00000
1998	0	0	0	$ 7,324,231	0.00000
1999	0	0	0	$ 7,324,231	0.00000
2000	0	0	0	$ 7,324,231	0.00000
2001	0	445	0	$ 7,323,786	0.00006
2002	0	0	0	$ 7,323,786	0.00000
2003	6,688	0	0	$ 7,330,474	0.00000
2004	0	0	0	$ 7,330,474	0.00000
2005	0	0	0	$ 7,330,474	0.00000
2006	0	0	0	$ 7,330,474	0.00000
2007	0	0	0	$ 7,330,474	0.00000
2008	1,259,104	0	0	$ 8,589,578	0.00000
2009	0	0	0	$ 8,589,578	0.00000
2010	1,259,104	0	0	$ 9,848,682	0.00000
2011	42,360	0	0	$ 9,891,042	0.00000
TOTAL	$ 9,895,009	$ 4,112	$ 145	$ 215,366,205	0.00002

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.00002	0.99998	0.99999	27.99198
2011	1.5	0.00002	0.99998	0.99997	27.99145
2010	2.5	0.00002	0.99998	0.99995	27.99091
2009	3.6	0.00002	0.99998	0.99993	27.99038
2008	4.5	0.00002	0.99998	0.99991	27.98985
2007	5.5	0.00002	0.99998	0.99989	27.98931
2006	8.5	0.00002	0.99998	0.99988	27.98878
2005	7.5	0.00002	0.99998	0.99986	27.98824
2004	8.5	0.00002	0.99998	0.99984	27.98771
2003	9.5	0.00002	0.99998	0.99982	27.98717
2002	10.5	0.00002	0.99998	0.99980	27.98664
2001	11.5	0.00002	0.99998	0.99978	27.98610
2000	12.5	0.00002	0.99998	0.99978	27.98557
1999	13.5	0.00002	0.99998	0.99974	27.98504
1998	14.5	0.00002	0.99998	0.99972	27.98450
1997	15.5	0.00002	0.99998	0.99970	27.98397
1996	16.5	0.00002	0.99998	0.99969	27.98343
1995	17.5	0.00002	0.99998	0.99967	27.98290
1994	16.5	0.00002	0.99998	0.99965	27.98236
1993	19.5	0.00002	0.99998	0.99963	27.98183
1992	20.5	0.00002	0.99998	0.99961	27.98130
1991	21.5	0.00002	0.99998	0.99959	27.98076
1990	22.5	0.00002	0.99998	0.99957	27.98023
1989	23.5	0.00002	0.99998	0.99955	27.97969
1988	24.5	0.00002	0.99998	0.99953	27.97916
1987	25.5	0.00002	0.99998	0.99951	27.97863
1986	26.5	0.00002	0.99998	0.99949	27.97809
1985	27.5	0.00002	0.99998	0.99948	27.97756
1984	28.5	0.00002	0.99998	0.99948	27.97702
1983	29.5	0.00002	0.99998	0.99944	27.97649
1982	30.5	0.00002	0.99998	0.99942	27.97595
1981	31.5	0.00002	0.99998	0.99940	27.97542
1980	32.5	0.00002	0.99998	0.99938	26.97604
1979	33.5	0.00002	0.99998	0.99938	25.97668
1978	34.5	0.00002	0.99998	0.99934	24.97734
1977	35.5	0.00002	0.99998	0.99932	23.97802
1978	38.5	0.00002	0.99998	0.99930	22.97871
1975	37.5	0.00002	0.99998	0.99926	21.97943
1974	38.5	0.00002	0.99998	0.99927	20.98016
1973	39.5	0.00002	0.99998	0.99925	19.98092
1972	40.5	0.00002	0.99998	0.99923	18.98169
1971	41.6	0.00002	0.99998	0.99921	17.98248
1970	42.5	0.00002	0.99998	0.99919	18.98329
1969	43.5	0.00002	0.99998	0.99917	15.98412
1968	44.6	0.00002	0.99998	0.99915	14.98497
1967	45.5	0.00002	0.99998	0.99913	13.98584
1966	48.5	0.00002	0.99998	0.99911	12.98673
1965	47.5	0.00002	0.99998	0.99909	11.98763
1964	48.5	0.00002	0.99998	0.99907	10.98856
1963	49.5	0.00002	0.99998	0.99906	9.98950
1962	50.5	0.00002	0.99998	0.99904	8.99047
1961	51.5	0.00002	0.99998	0.99902	7.99145
1960	52.5	0.00002	0.99998	0.99900	8.99245
1959	53.5	0.00002	0.99998	0.99898	5.99347
1958	54.5	0.00002	0.99998	0.99896	4.99451
1957	55.5	0.00002	0.99998	0.99894	3.99557
1956	56.5	0.00002	0.99998	0.99892	2.99666
1955	57.5	0.00002	0.99998	0.99890	1.99775
1954	56.5	0.00002	0.99998	0.99888	0.99886

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Burns & McDonnell SINCE 1898

Transmission	Poles	Account:	355
Date of Retirement (Mid Year):			2033
Interim Retirement Rate:			0.00000
Study Date, Year-End:			2012
Future Life from Study Date:			20.8
Remaining Life (F/E + .5) =			20.5

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Adjustments and Transfers	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	57,283	0	0	$ 57,283	0.00000
1968	0	0	0	$ 57,283	0.00000
1969	24,190	0	0	$ 81,473	0.00000
1970	0	0	0	$ 81,473	0.00000
1971	0	0	0	$ 81,473	0.00000
1972	0	0	0	$ 81,473	0.00000
1973	0	0	0	$ 81,473	0.00000
1974	0	0	0	$ 81,473	0.00000
1975	0	0	0	$ 81,473	0.00000
1976	152,841	0	0	$ 234,314	0.00000
1977	0	0	0	$ 234,314	0.00000
1978	0	0	0	$ 234,314	0.00000
1979	0	0	0	$ 234,314	0.00000
1980	0	0	0	$ 234,314	0.00000
1981	0	0	0	$ 234,314	0.00000
1982	0	0	0	$ 234,314	0.00000
1983	0	0	0	$ 234,314	0.00000
1984	0	0	0	$ 234,314	0.00000
1985	0	0	0	$ 234,314	0.00000
1986	0	0	0	$ 234,314	0.00000
1987	0	0	0	$ 234,314	0.00000
1988	0	0	0	$ 234,314	0.00000
1989	0	0	0	$ 234,314	0.00000
1990	0	0	0	$ 234,314	0.00000
1991	0	0	0	$ 234,314	0.00000
1992	0	0	0	$ 234,314	0.00000
1993	0	0	0	$ 234,314	0.00000
1994	0	0	0	$ 234,314	0.00000
1995	0	0	0	$ 234,314	0.00000
1996	0	0	0	$ 234,314	0.00000
1997	0	0	0	$ 234,314	0.00000
1998	0	0	0	$ 234,314	0.00000
1999	0	0	0	$ 234,314	0.00000
2000	0	0	0	$ 234,314	0.00000
2001	0	0	0	$ 234,314	0.00000
2002	0	0	0	$ 234,314	0.00000
2003	0	0	0	$ 234,314	0.00000
2004	0	0	0	$ 234,314	0.00000
2005	0	0	0	$ 234,314	0.00000
2006	0	0	0	$ 234,314	0.00000
2007	0	0	0	$ 234,314	0.00000
2008	0	0	0	$ 234,314	0.00000
2009	0	0	0	$ 234,314	0.00000
2010	0	0	0	$ 234,314	0.00000
2011	0	0	0	$ 234,314	0.00000
TOTAL	$ 234,314	$ -	$ -	$ 9,354,502	0.00000

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1 - C)	E	F
2012	0.5	-	1.00000	1.00000	20.00000
2011	1.5	-	1.00000	1.00000	20.00000
2010	2.5	-	1.00000	1.00000	20.00000
2009	3.5	-	1.00000	1.00000	20.00000
2008	4.5	-	1.00000	1.00000	20.00000
2007	5.5	-	1.00000	1.00000	20.00000
2006	6.5	-	1.00000	1.00000	20.00000
2005	7.5	-	1.00000	1.00000	20.00000
2004	8.5	-	1.00000	1.00000	20.00000
2003	9.5	-	1.00000	1.00000	20.00000
2002	10.5	-	1.00000	1.00000	20.00000
2001	11.5	-	1.00000	1.00000	20.00000
2000	12.5	-	1.00000	1.00000	20.00000
1999	13.5	-	1.00000	1.00000	20.00000
1998	14.5	-	1.00000	1.00000	20.00000
1997	15.5	-	1.00000	1.00000	20.00000
1996	16.5	-	1.00000	1.00000	20.00000
1995	17.5	-	1.00000	1.00000	20.00000
1994	18.5	-	1.00000	1.00000	20.00000
1993	19.5	-	1.00000	1.00000	20.00000
1992	20.5	-	1.00000	1.00000	20.00000
1991	21.5	-	1.00000	1.00000	20.00000
1990	22.5	-	1.00000	1.00000	20.00000
1989	23.5	-	1.00000	1.00000	20.00000
1988	24.5	-	1.00000	1.00000	20.00000
1987	25.5	-	1.00000	1.00000	20.00000
1986	26.5	-	1.00000	1.00000	20.00000
1985	27.5	-	1.00000	1.00000	20.00000
1984	28.5	-	1.00000	1.00000	20.00000
1983	29.5	-	1.00000	1.00000	20.00000
1982	30.5	-	1.00000	1.00000	20.00000
1981	31.5	-	1.00000	1.00000	20.00000
1980	32.5	-	1.00000	1.00000	20.00000
1979	33.5	-	1.00000	1.00000	20.00000
1978	34.5	-	1.00000	1.00000	20.00000
1977	35.5	-	1.00000	1.00000	20.00000
1976	36.5	-	1.00000	1.00000	20.00000
1975	37.5	-	1.00000	1.00000	20.00000
1974	38.5	-	1.00000	1.00000	20.00000
1973	39.5	-	1.00000	1.00000	20.00000
1972	40.5	-	1.00000	1.00000	19.00000
1971	41.5	-	1.00000	1.00000	18.00000
1970	42.5	-	1.00000	1.00000	17.00000
1969	43.5	-	1.00000	1.00000	16.00000
1968	44.5	-	1.00000	1.00000	15.00000
1967	45.5	-	1.00000	1.00000	14.00000
1966	46.5	-	1.00000	1.00000	13.00000
1965	47.5	-	1.00000	1.00000	12.00000
1964	48.5	-	1.00000	1.00000	11.00000
1963	49.5	-	1.00000	1.00000	10.00000
1962	50.5	-	1.00000	1.00000	9.00000
1961	51.5	-	1.00000	1.00000	8.00000
1960	52.5	-	1.00000	1.00000	7.00000
1959	53.5	-	1.00000	1.00000	6.00000
1958	54.5	-	1.00000	1.00000	5.00000
1957	55.5	-	1.00000	1.00000	4.00000
1956	56.5	-	1.00000	1.00000	3.00000
1955	57.5	-	1.00000	1.00000	2.00000
1954	58.5	-	1.00000	1.00000	1.00000

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

Transmission Lines | Account: 356

Date of Retirement (Mid Year):	2036
Interim Retirement Rate:	0.00000
Study Date, Year-End:	2012
Future Life from Study Date:	23.8
Remaining Life (F/E + .5) =	23.5

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Adjustments and Transfers	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	39,131	0	0	$ 39,131	0.00000
1968	0	0	0	$ 39,131	0.00000
1969	23,026	0	0	$ 62,157	0.00000
1970	0	0	0	$ 52,157	0.00000
1971	0	0	0	$ 62,157	0.00000
1972	0	0	0	$ 62,157	0.00000
1973	0	0	0	$ 62,157	0.00000
1974	0	0	0	$ 62,157	0.00000
1975	0	0	0	$ 62,157	0.00000
1976	24,744	0	0	$ 86,901	0.00000
1977	0	0	0	$ 86,901	0.00000
1978	0	0	0	$ 86,901	0.00000
1979	0	0	0	$ 86,901	0.00000
1980	0	0	0	$ 86,901	0.00000
1981	5,876,547	0	0	$ 5,763,446	0.00000
1982	937,498	0	0	$ 6,700,944	0.00000
1983	210,765	0	0	$ 6,911,708	0.00000
1984	2,612,421	0	0	$ 9,724,129	0.00000
1985	45,223	0	0	$ 9,769,352	0.00000
1986	19,197,453	0	0	$ 28,966,805	0.00000
1987	180,019	0	0	$ 29,146,824	0.00000
1988	431,211	0	0	$ 29,576,035	0.00000
1989	265,513	0	0	$ 29,833,548	0.00000
1990	396,302	0	0	$ 30,229,849	0.00000
1991	68,804	0	0	$ 30,298,553	0.00000
1992	20,895	0	0	$ 30,319,549	0.00000
1993	77,924	0	0	$ 30,397,473	0.00000
1994	817,484	0	0	$ 31,214,957	0.00000
1995	74,339	0	0	$ 31,289,296	0.00000
1996	69,079	0	0	$ 31,376,375	0.00000
1997	1,179,392	0	0	$ 32,557,756	0.00000
1998	111,806	0	0	$ 32,569,574	0.00000
1999	672,219	0	0	$ 33,341,792	0.00000
2000	184,561	0	0	$ 33,526,354	0.00000
2001	699,346	0	0	$ 34,225,700	0.00000
2002	616,626	0	0	$ 35,042,326	0.00000
2003	432,410	0	0	$ 35,474,735	0.00000
2004	602,337	0	0	$ 36,077,073	0.00000
2005	242,723	0	0	$ 36,319,795	0.00000
2006	684,680	0	0	$ 37,004,455	0.00000
2007	137,405	0	0	$ 37,141,860	0.00000
2008	2,692,857	0	0	$ 40,034,717	0.00000
2009	0	0	0	$ 40,034,717	0.00000
2010	0	0	0	$ 40,034,717	0.00000
2011	0	0	0	$ 40,034,717	0.00000
TOTAL	$ 40,034,717	$ -	$ -	$ 915,991,114	0.00000

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	-	1.00000	1.00000	23.00000
2011	1.5	-	1.00000	1.00000	23.00000
2010	2.5	-	1.00000	1.00000	23.00000
2009	3.5	-	1.00000	1.00000	23.00000
2008	4.5	-	1.00000	1.00000	23.00000
2007	5.5	-	1.00000	1.00000	23.00000
2006	6.5	-	1.00000	1.00000	23.00000
2005	7.5	-	1.00000	1.00000	23.00000
2004	8.5	-	1.00000	1.00000	23.00000
2003	9.5	-	1.00000	1.00000	23.00000
2002	10.5	-	1.00000	1.00000	23.00000
2001	11.5	-	1.00000	1.00000	23.00000
2000	12.5	-	1.00000	1.00000	23.00000
1999	13.5	-	1.00000	1.00000	23.00000
1998	14.5	-	1.00000	1.00000	23.00000
1997	15.5	-	1.00000	1.00000	23.00000
1996	16.5	-	1.00000	1.00000	23.00000
1995	17.5	-	1.00000	1.00000	23.00000
1994	18.5	-	1.00000	1.00000	23.00000
1993	19.5	-	1.00000	1.00000	23.00000
1992	20.5	-	1.00000	1.00000	23.00000
1991	21.5	-	1.00000	1.00000	23.00000
1990	22.5	-	1.00000	1.00000	23.00000
1989	23.5	-	1.00000	1.00000	23.00000
1988	24.5	-	1.00000	1.00000	23.00000
1987	25.5	-	1.00000	1.00000	23.00000
1986	26.5	-	1.00000	1.00000	23.00000
1985	27.5	-	1.00000	1.00000	23.00000
1984	28.5	-	1.00000	1.00000	23.00000
1983	29.5	-	1.00000	1.00000	23.00000
1982	30.5	-	1.00000	1.00000	23.00000
1981	31.5	-	1.00000	1.00000	23.00000
1980	32.5	-	1.00000	1.00000	23.00000
1979	33.5	-	1.00000	1.00000	23.00000
1978	34.5	-	1.00000	1.00000	23.00000
1977	35.5	-	1.00000	1.00000	23.00000
1976	36.5	-	1.00000	1.00000	23.00000
1975	37.5	-	1.00000	1.00000	22.00000
1974	38.5	-	1.00000	1.00000	21.00000
1973	39.5	-	1.00000	1.00000	20.00000
1972	40.5	-	1.00000	1.00000	19.00000
1971	41.5	-	1.00000	1.00000	18.00000
1970	42.5	-	1.00000	1.00000	17.00000
1969	43.5	-	1.00000	1.00000	16.00000
1968	44.5	-	1.00000	1.00000	15.00000
1967	45.5	-	1.00000	1.00000	14.00000
1966	46.5	-	1.00000	1.00000	13.00000
1965	47.5	-	1.00000	1.00000	12.00000
1964	48.5	-	1.00000	1.00000	11.00000
1963	49.5	-	1.00000	1.00000	10.00000
1962	50.5	-	1.00000	1.00000	9.00000
1961	51.5	-	1.00000	1.00000	8.00000
1960	52.5	-	1.00000	1.00000	7.00000
1959	53.5	-	1.00000	1.00000	6.00000
1958	54.5	-	1.00000	1.00000	5.00000
1957	55.5	-	1.00000	1.00000	4.00000
1956	56.5	-	1.00000	1.00000	3.00000
1955	57.5	-	1.00000	1.00000	2.00000
1954	58.5	-	1.00000	1.00000	1.00000

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

General Plant Structures | Account: 390

Date of Retirement (Mid Year):	2024
Interim Retirement Rate:	0.01388
Study Date, Year-End:	2012
Future Life from Study Date:	11.5
Remaining Life (F/E + .5) =	11.5

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	213,961	0	0	$ 213,961	0.00000
1967	0	0	0	$ 213,961	0.00000
1958	2,483	0	0	$ 216,444	0.00000
1969	0	0	0	$ 215,444	0.00000
1970	267,258	0	0	$ 483,702	0.00000
1971	43,966	0	269	$ 527,959	0.00000
1972	0	4,598	0	$ 523,362	0.00878
1973	21,835	0	0	$ 545,197	0.00000
1974	37,731	2,500	0	$ 580,428	0.00431
1975	592	0	0	$ 581,020	0.00000
1978	1,704	0	208	$ 582,932	0.00000
1977	3,783	0	0	$ 586,715	0.00000
1978	4,808	0	0	$ 591,523	0.00000
1979	29,345	3,718	0	$ 817,153	0.00602
1980	1,269	0	0	$ 618,422	0.00000
1961	2,270,658	0	15,858	$ 2,904,737	0.00000
1962	190,818	0	0	$ 3,095,553	0.00000
1983	0	81,332	0	$ 3,034,221	0.02021
1984	0	0	0	$ 3,034,221	0.00000
1985	148,462	0	0	$ 3,182,684	0.00000
1966	0	0	0	$ 3,182,684	0.00000
1987	0	0	0	$ 3,182,684	0.00000
1988	24,337	0	0	$ 3,207,020	0.00000
1989	0	0	0	$ 3,207,020	0.00000
1990	1,995	0	0	$ 3,209,015	0.00000
1991	10,168	0	0	$ 3,219,183	0.00000
1992	0	0	0	$ 3,219,183	0.00000
1993	0	0	0	$ 3,219,183	0.00000
1994	126,550	5,098	0	$ 3,340,646	0.00152
1995	0	0	0	$ 3,340,646	0.00000
1996	0	0	0	$ 3,340,646	0.00000
1997	0	0	0	$ 3,340,646	0.00000
1998	10,667	18,258	0	$ 3,333,255	0.00548
1999	4,389	0	0	$ 3,337,644	0.00000
2000	0	984,851	0	$ 2,352,793	0.41859
2001	3,972	1,737	0	$ 2,355,027	0.00074
2002	31,276	1,099	0	$ 2,385,204	0.00048
2003	0	0	0	$ 2,385,204	0.00000
2004	3,785	3,761	0	$ 2,385,228	0.00158
2005	199,739	35,488	0	$ 2,548,479	0.01432
2006	10,205	2,514	0	$ 2,558,170	0.00098
2007	10,972	2,873	0	$ 2,564,269	0.00112
2008	4,742	-120	0	$ 2,569,131	-0.00005
2009	283,205	0	0	$ 2,832,336	0.00000
2010	4,039	0	0	$ 2,836,375	0.00000
2011	1,680,508	258,221	0	$ 4,138,662	0.08239
TOTAL	$ 5,509,442	$ 1,386,914	$ 16,134	$ 99,938,974	0.01388

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.01388	0.98612	0.99306	10.89464
2011	1.5	0.01388	0.98612	0.97928	10.74345
2010	2.5	0.01388	0.98612	0.96569	10.59435
2009	3.5	0.01388	0.98612	0.95229	10.44733
2008	4.5	0.01388	0.98612	0.93907	10.30235
2007	5.5	0.01388	0.98612	0.92604	10.15937
2006	8.5	0.01388	0.98612	0.91319	10.01839
2005	7.5	0.01388	0.98612	0.90052	9.87935
2004	8.5	0.01388	0.98612	0.88802	9.74225
2003	9.5	0.01388	0.98612	0.87570	9.60705
2002	10.5	0.01388	0.98612	0.86354	9.47373
2001	11.5	0.01388	0.98612	0.85156	9.34226
2000	12.5	0.01388	0.98612	0.83974	9.21261
1999	13.5	0.01388	0.98612	0.82809	9.08476
1998	14.5	0.01388	0.98612	0.81660	8.95869
1997	15.5	0.01388	0.98612	0.80526	8.83436
1996	16.5	0.01388	0.98612	0.79409	8.71178
1995	17.5	0.01388	0.98612	0.78307	6.59086
1994	18.5	0.01388	0.98612	0.77220	8.47164
1993	19.5	0.01388	0.98612	0.78149	8.35408
1992	20.5	0.01388	0.98612	0.75092	8.23814
1991	21.5	0.01388	0.98612	0.74050	8.12382
1990	22.5	0.01388	0.98612	0.73022	8.01108
1989	23.5	0.01388	0.98612	0.72009	7.69990
1988	24.5	0.01388	0.98612	0.71009	7.79027
1987	25.5	0.01388	0.98612	0.70024	7.68218
1986	26.5	0.01388	0.98612	0.69052	7.57555
1985	27.5	0.01388	0.98612	0.68094	7.47042
1984	28.5	0.01388	0.98612	0.87149	7.36875
1983	28.5	0.01388	0.98612	0.66217	7.26452
1982	30.5	0.01388	0.98612	0.65298	7.16370
1981	31.5	0.01388	0.98612	0.64392	7.08429
1980	32.5	0.01388	0.98612	0.63498	8.96625
1979	33.5	0.01388	0.98612	0.52517	8.86958
1978	34.5	0.01388	0.98812	0.81748	6.77424
1977	35.5	0.01388	0.98612	0.60891	8.68023
1976	36.5	0.01388	0.98612	0.60046	6.58753
1975	37.5	0.01388	0.98612	0.59213	8.49611
1974	38.5	0.01388	0.98612	0.58391	6.40596
1973	39.5	0.01388	0.98612	0.57581	6.31708
1972	40.5	0.01388	0.98612	0.56782	8.22939
1971	41.5	0.01388	0.98612	0.55994	8.14294
1970	42.5	0.01388	0.98612	0.55217	8.05769
1969	43.5	0.01388	0.98612	0.54450	5.97363
1968	44.5	0.01388	0.98612	0.53695	5.89073
1967	45.5	0.01388	0.98612	0.52950	5.80898
1966	46.5	0.01388	0.98612	0.52215	5.72838
1965	47.5	0.01388	0.98612	0.51490	5.64887
1964	48.5	0.01388	0.98612	0.50776	5.14111
1963	49.5	0.01388	0.98612	0.50071	4.64040
1962	50.5	0.01388	0.98612	0.49376	4.14664
1961	51.5	0.01388	0.98612	0.48691	3.65973
1960	52.5	0.01388	0.98612	0.48015	3.17958
1959	53.5	0.01388	0.98612	0.47349	2.70609
1958	54.5	0.01388	0.98612	0.46692	2.23917
1957	55.5	0.01388	0.98612	0.46044	1.77873
1956	56.6	0.01388	0.98612	0.45405	1.32469
1955	57.5	0.01388	0.98612	0.44775	0.87694
1954	58.5	0.01388	0.98612	0.44153	0.43541

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

General Plant   Office Furniture & Equipment   Account: 391.0, 391.6, 391.7

Date of Retirement (Mid Year):	2016
Interim Retirement Rate:	2.43677
Study Date, Year-End:	2012
Future Life from Study Date:	6.0
Remaining Life (F/E + .5) =	2.42

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	1,873	0	0	$ 1,873	0.00000
1872	0	0	0	$ 1,873	0.00000
1873	0	0	0	$ 1,873	0.00000
1874	3,825	0	0	$ 5,699	0.00000
1875	0	0	0	$ 5,699	0.00000
1976	0	0	0	$ 5,699	0.00000
1977	502	0	80	$ 6,281	0.00000
1978	10,533	1,444	664	$ 16,034	0.09004
1979	3,276	8,879	0	$ 12,431	0.65343
1980	4,635	3,291	0	$ 13,775	0.23892
1981	18,913	2,175	0	$ 30,512	0.07128
1982	32,904	11,112	0	$ 52,305	0.21244
1983	14,814	12,216	0	$ 54,902	0.22251
1984	52,080	12,836	63	$ 94,208	0.13626
1985	817	9,631	0	$ 85,193	0.11305
1986	5,651	38,293	0	$ 52,551	0.72868
1987	44,954	18,352	0	$ 79,153	0.23186
1988	15,044	58,299	0	$ 35,896	1.82403
1989	7,003	48,703	0	$ -	0.00000
1990	41,091	74,156	0	$ -	0.00000
1991	43,869	86,235	0	$ -	0.00000
1992	18,617	79,202	0	$ -	0.00000
1993	23,789	9,177	0	$ 14,612	0.82804
1994	1,865	84,556	0	$ -	0.00000
1995	15,609	7,290	0	$ 8,316	0.87639
1996	1,360	32,731	0	$ -	0.00000
1997	5,099	5,122	0	$ -	0.00000
1998	5,434	823,912	0	$ -	0.00000
1999	1,882	810,952	0	$ -	0.00000
2000	5,735	263,451	0	$ -	0.00000
2001	970	154,948	0	$ -	0.00000
2002	7,514	98,450	0	$ -	0.00000
2003	5,377	22,360	0	$ -	0.00000
2004	36,804	59,696	0	$ -	0.00000
2005	5,163	80,703	0	$ -	0.00000
2006	9,433	5,129	0	$ 4,304	1.19158
2007	36,882	22,689	0	$ 18,498	1.22657
2008	35,410	25,457	0	$ 28,450	0.89482
2009	96,149	4,748	0	$ 119,851	0.03981
2010	57,224	47,688	0	$ 129,367	0.36857
2011	173,132	22,733	0	$ 279,786	0.08125
TOTAL	$ 846,491	$ 2,824,621	$ 806	$ 1,159,165	2.43677

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	2.43677	(1.43677)	(0)	(0)
2011	1.5	2.43677	(1.43677)	0	1
2010	2.5	2.43677	(1.43677)	(0)	(1)
2009	3.5	2.43677	(1.43677)	1	1
2008	4.5	2.43677	(1.43677)	(1)	(2)
2007	5.5	2.43677	(1.43677)	1	3
2006	6.5	2.43677	(1.43677)	(2)	(4)
2005	7.5	2.43677	(1.43677)	3	5
2004	8.5	2.43677	(1.43677)	(4)	(8)
2003	9.5	2.43677	(1.43677)	6	11
2002	10.5	2.43677	(1.43677)	(6)	(16)
2001	11.5	2.43677	(1.43677)	12	23
2000	12.5	2.43677	(1.43677)	(17)	(32)
1999	13.5	2.43677	(1.43677)	24	47
1998	14.5	2.43677	(1.43677)	(35)	(67)
1997	15.5	2.43677	(1.43677)	50	96
1996	18.5	2.43677	(1.43677)	(72)	(136)
1995	17.5	2.43677	(1.43677)	103	199
1994	18.5	2.43677	(1.43677)	(149)	(286)
1993	19.5	2.43677	(1.43677)	214	411
1992	20.5	2.43677	(1.43577)	(307)	(590)
1991	21.5	2.43677	(1.43677)	441	848
1990	22.5	2.43677	(1.43677)	(634)	(1,218)
1989	23.5	2.43677	(1.43677)	9.10E+02	1,750
1988	24.5	2.43677	(1.43677)	-1.31E+03	(2,515)
1987	25.5	2.43677	(1.43677)	1.88E+03	3,613
1986	26.5	2.43677	(1.43677)	-2.70E+03	(5,181)
1985	27.5	2.43677	(1.43677)	3.88E+03	7,459
1984	28.5	2.43677	(1.43677)	-5.57E+03	(10,717)
1983	29.5	2.43677	(1.43677)	8.01E+03	15,398
1982	30.5	2.43677	(1.43677)	-1.15E+04	(22,123)
1981	31.5	2.43677	(1.43677)	1.65E+04	31,786
1980	32.5	2.43677	(1.43677)	-2.37E+04	(45,669)
1979	33.5	2.43677	(1.43677)	3.41E+04	65,816
1978	34.5	2.43677	(1.43677)	-4.90E+04	(94,275)
1977	35.5	2.43677	(1.43677)	7.04E+04	135,452
1976	36.5	2.43677	(1.43677)	-1.01E+05	(194,614)
1975	37.5	2.43677	(1.43677)	1.45E+05	279,616
1974	36.5	2.43677	(1.43677)	-2.09E+05	(401,744)
1973	39.5	2.43677	(1.43677)	3.00E+05	577,215
1972	40.5	2.43677	(1.43677)	-4.31E+05	(829,327)
1971	41.5	2.43677	(1.43677)	6.20E+05	1,191,554
1970	42.5	2.43677	(1.43677)	-8.90E+05	(1,711,993)
1969	43.5	2.43677	(1.43677)	1.28E+06	2,459,744
1968	44.5	2.43677	(1.43677)	-1.84E+06	(3,534,093)
1967	45.5	2.43677	(1.43677)	2.84E+06	5,077,889
1966	46.5	2.43677	(1.43677)	-3.79E+06	(7,295,485)
1965	47.5	2.43677	(1.43677)	5.45E+06	10,481,954
1964	48.5	2.43677	(1.43677)	-7.63E+06	(15,060,186)
1963	48.5	2.43677	(1.43677)	1.13E+07	21,836,065
1962	50.5	2.43677	(1.43677)	-1.62E+07	(31,088,982)
1961	51.5	2.43577	(1.43877)	2.32E+07	44,667,801
1960	52.5	2.43677	(1.43677)	-3.34E+07	(84,177,476)
1959	53.5	2.43677	(1.43677)	4.80E+07	92,208,451
1958	54.5	2.43677	(1.43677)	-6.89E+07	(132,482,588)
1957	55.5	2.43677	(1.43677)	9.90E+07	190,347,370
1956	56.5	2.43677	(1.43677)	-1.42E+08	332,566,439
1955	57.5	2.43677	(1.43677)	2.04E+06	128,229,959
1954	56.5	2.43677	(1.43677)	-2.94E+08	421,815,041

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

General Plant Computer System 34 Account: 391.2

Date of Retirement (Mid Year):	2019
Interim Retirement Rate:	0.15077
Study Date, Year-End:	2012
Future Life from Study Date:	7.0
Remaining Life (F/E + .5) =	4.8

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1976	0	0	0	$ -	0.00000
1977	0	0	0	$ -	0.00000
1978	0	0	0	$ -	0.00000
1979	0	0	0	$ -	0.00000
1980	0	0	0	$ -	0.00000
1981	0	0	0	$ -	0.00000
1982	0	0	0	$ -	0.00000
1983	20,178	0	0	$ 20,178	0.00000
1984	11,301	0	0	$ 31,478	0.00000
1985	566	0	0	$ 32,045	0.00000
1986	10,031	6,339	0	$ 35,736	0.17740
1987	10,070	102,442	0	$ -	0.00000
1988	2,044	348,449	0	$ -	0.00000
1989	88,513	96,391	0	$ -	0.00000
1990	10,095	584,760	0	$ -	0.00000
1991	152,299	26,119	0	$ 126,180	0.20700
1992	29,619	185,213	0	$ -	0.00000
1993	35,184	192,662	0	$ -	0.00000
1994	38,803	124,780	0	$ -	0.00000
1995	12,868	36,495	0	$ -	0.00000
1996	24,760	50,801	0	$ -	0.00000
1997	69,444	0	0	$ 69,444	0.00000
1998	104,512	826,943	0	$ -	0.00000
1999	6,579	921,279	0	$ -	0.00000
2000	161,462	239,043	0	$ -	0.00000
2001	171,377	632,084	0	$ -	0.00000
2002	280,680	35,782	0	$ 244,899	0.14611
2003	195,951	17,817	0	$ 423,032	0.04212
2004	1,868,261	503,288	0	$ 1,788,007	0.28179
2005	1,235,236	542,314	0	$ 2,478,929	0.21877
2006	709,512	80,829	0	$ 3,107,513	0.02601
2007	417,952	333,455	0	$ 3,192,110	0.10446
2008	943,959	205,735	0	$ 3,930,334	0.05235
2009	371,495	125,711	0	$ 4,178,118	0.03010
2010	452,166	88,697	0	$ 4,539,587	0.01954
2011	13,099,021	0	0	$ 17,638,508	0.00000
TOTAL	$ 20,511,837	$ 6,307,204	$ -	$ 41,832,299	0.15077

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.15077	0.84923	0.92461	4.01147
2011	1.5	0.15077	0.84923	0.78521	3.40864
2010	2.5	0.15077	0.84923	0.66682	2.89301
2009	3.5	0.15077	0.84923	0.56628	2.45682
2008	4.5	0.15077	0.84923	0.48090	2.08640
2007	5.5	0.15077	0.84923	0.40839	1.77183
2006	6.5	0.15077	0.84923	0.34682	1.50468
2005	7.5	0.15077	0.84923	0.29453	1.27781
2004	8.5	0.15077	0.84923	0.25012	1.08515
2003	9.5	0.15077	0.84923	0.21241	0.92154
2002	10.5	0.15077	0.84923	0.18036	0.78250
2001	11.5	0.15077	0.84923	0.15319	0.66460
2000	12.5	0.15077	0.84923	0.13009	0.56440
1999	13.5	0.15077	0.84923	0.11048	0.47930
1998	14.5	0.15077	0.84923	0.09382	0.40704
1997	15.5	0.15077	0.84923	0.07967	0.34567
1996	16.5	0.15077	0.84923	0.06766	0.29355
1995	17.5	0.15077	0.84923	0.05746	0.24929
1994	18.5	0.15077	0.84923	0.04880	0.21170
1993	19.5	0.15077	0.84923	0.04144	0.17978
1992	20.5	0.15077	0.84923	0.03519	0.15268
1991	21.5	0.15077	0.84923	0.02989	0.12966
1990	22.5	0.15077	0.84923	0.02538	0.11011
1989	23.5	0.15077	0.84923	0.02155	0.09351
1988	24.5	0.15077	0.84923	0.01830	0.07941
1987	25.5	0.15077	0.84923	0.01554	0.06744
1986	26.5	0.15077	0.84923	0.01320	0.05727
1985	27.5	0.15077	0.84923	0.01121	0.04863
1984	28.5	0.15077	0.84923	0.00952	0.04130
1983	29.5	0.15077	0.84923	0.00808	0.03507
1982	30.5	0.15077	0.84923	0.00687	0.02979
1981	31.5	0.15077	0.84923	0.00583	0.02529
1980	32.5	0.15077	0.84923	0.00495	0.02146
1979	33.5	0.15077	0.84923	0.00420	0.01824
1978	34.5	0.15077	0.84923	0.00357	0.01549
1977	35.5	0.15077	0.84923	0.00303	0.01316
1976	36.5	0.15077	0.84923	0.00258	0.01117
1975	37.5	0.15077	0.84923	0.00219	0.00949
1974	38.5	0.15077	0.84923	0.00186	0.00806
1973	39.5	0.15077	0.84923	0.00158	0.00684
1972	40.5	0.15077	0.84923	0.00134	0.00581
1971	41.5	0.15077	0.84923	0.00114	0.00493
1970	42.5	0.15077	0.84923	0.00097	0.00419
1969	43.5	0.15077	0.84923	0.00082	0.00356
1968	44.5	0.15077	0.84923	0.00070	0.00302
1967	45.5	0.15077	0.84923	0.00059	0.00257
1966	46.5	0.15077	0.84923	0.00050	0.00218
1965	47.5	0.15077	0.84923	0.00043	0.00185
1964	48.5	0.15077	0.84923	0.00036	0.00157
1963	49.5	0.15077	0.84923	0.00031	0.00133
1962	50.5	0.15077	0.84923	0.00025	0.00113
1961	51.5	0.15077	0.84923	0.00022	0.00091
1960	52.5	0.15077	0.84923	0.00019	0.00072
1959	53.5	0.15077	0.84923	0.00015	0.00056
1958	54.5	0.15077	0.84923	0.00014	0.00043
1957	55.5	0.15077	0.84923	0.00012	0.00031
1956	56.5	0.15077	0.84923	0.00010	0.00021
1955	57.5	0.15077	0.84923	0.00008	0.00013
1954	58.5	0.15077	0.84923	0.00007	0.00006

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

General Plant Vehicles General   Account: 392.2

Date of Retirement (Mid Year):	2015
Interim Retirement Rate:	1.13891
Study Date, Year-End:	2012
Future Life from Study Date:	3.0
Remaining Life (F/E + .5) =	0.4

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Adjustments and Transfers	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	5,547	0	0	$ 5,547	0.00000
1974	0	0	0	$ 5,547	0.00000
1975	0	0	0	$ 5,547	0.00000
1976	0	3,816	0	$ 1,731	2.20427
1877	0	20,858	0	$ -	0.00000
1978	5,200	25,542	0	$ -	0.00000
1979	4,459	50,625	0	$ -	0.00000
1980	0	67,299	0	$ -	0.00000
1961	6,670	29,321	0	$ -	0.00000
1962	3,075	50,194	0	$ -	0.00000
1983	3,716	67,323	0	$ -	0.00000
1984	0	69,038	0	$ -	0.00000
1986	0	156,989	0	$ -	0.00000
1986	0	156,898	0	$ -	0.00000
1987	1,727	31,901	0	$ -	0.00000
1988	0	103,137	0	$ -	0.00000
1989	0	107,488	0	$ -	0.00000
1990	0	197,186	0	$ -	0.00000
1991	11,036	265,309	0	$ -	0.00000
1992	0	204,469	0	$ -	0.00000
1993	8,201	59,955	0	$ -	0.00000
1994	2,953	130,235	0	$ -	0.00000
1995	0	85,465	0	$ -	0.00000
1996	32,532	50,415	0	$ -	0.00000
1997	0	77,751	0	$ -	0.00000
1998	148,830	1,361,164	0	$ -	0.00000
1999	3,065	32,959	0	$ -	0.00000
2000	83,659	66,492	0	$ 17,167	3.87322
2001	92,501	66,715	0	$ 42,953	1.55321
2002	174,304	196,182	0	$ 21,076	9.30847
2003	96,439	86,515	0	$ 31,000	2.79085
2004	120,127	17,128	0	$ 133,998	0.12762
2005	114,895	46,658	0	$ 202,235	0.23071
2006	86,265	67,321	0	$ 221,179	0.30437
2007	102,370	125,647	0	$ 197,902	0.83489
2008	213,902	72,235	0	$ 339,569	0.21272
2009	317,874	36,696	0	$ 620,748	0.05912
2010	217,961	19,629	0	$ 619,076	0.02396
2011	217,912	0	0	$ 1,036,990	0.00000
TOTAL	$ 2,073,419	$ 4,216,554	$ -	$ 3,702,266	1.13891

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	1.13891	(0.13891)	0.43054	(0.05249)
2011	1.5	1.13891	(0.13891)	(0.05981)	0.00729
2010	2.5	1.13891	(0.13891)	0.00831	(0.00101)
2009	3.5	1.13891	(0.13891)	(0.00115)	0.00014
2008	4.5	1.13891	(0.13891)	0.00016	(0.00002)
2007	5.5	1.13891	(0.13891)	(0.00002)	0.00000
2006	6.5	1.13891	(0.13891)	0.00000	(0.00000)
2005	7.5	1.13891	(0.13891)	(0.00000)	0.00000
2004	6.5	1.13891	(0.13891)	0.00000	(0.00000)
2003	9.5	1.13891	(0.13891)	(0.00000)	0.00000
2002	10.5	1.13891	(0.13891)	0.00000	(0.00000)
2001	11.5	1.13891	(0.13891)	(0.00000)	0.00000
2000	12.5	1.13891	(0.13891)	0.00000	(0.00000)
1999	13.5	1.13891	(0.13891)	(0.00000)	0.00000
1998	14.5	1.13891	(0.13891)	0.00000	(0.00000)
1997	15.5	1.13891	(0.13891)	(0.00000)	0.00000
1996	16.5	1.13891	(0.13891)	0.00000	(0.00000)
1995	17.5	1.13891	(0.13891)	(0.00000)	0.00000
1994	16.5	1.13891	(0.13891)	0.00000	(0.00000)
1993	19.5	1.13891	(0.13891)	(0.00000)	0.00000
1992	20.5	1.13891	(0.13891)	0.00000	(0.00000)
1991	21.5	1.13891	(0.13891)	(0.00000)	0.00000
1990	22.5	1.13891	(0.13891)	0.00000	(0.00000)
1989	23.5	1.13881	(0.13891)	(0.00000)	0.00000
1988	24.5	1.13891	(0.13891)	0.00000	(0.00000)
1987	25.5	1.13891	(0.13891)	(0.00000)	0.00000
1986	26.5	1.13891	(0.13891)	0.00000	(0.00000)
1985	27.5	1.13891	(0.13891)	(0.00000)	0.00000
1984	28.5	1.13891	(0.13891)	0.00000	(0.00000)
1983	29.5	1.13891	(0.13891)	(0.00000)	0.00000
1982	30.5	1.13891	(0.13891)	0.00000	(0.00000)
1981	31.5	1.13891	(0.13891)	(0.00000)	0.00000
1980	32.5	1.13891	(0.13891)	0.00000	(0.00000)
1979	33.5	1.13891	(0.13891)	(0.00000)	0.00000
1978	34.5	1.13891	(0.13891)	0.00	(0.00000)
1977	35.5	1.13891	(0.13891)	(0.00)	0.00000
1976	36.5	1.13891	(0.13891)	0.00	(0.00000)
1975	37.5	1.13891	(0.13891)	(0.00)	0.00000
1974	38.5	1.13891	(0.13891)	0.00	(0.00000)
1973	39.5	1.13891	(0.13891)	(0.00)	0.00000
1972	40.5	1.13891	(0.13891)	0.00	(0.00000)
1971	41.5	1.13891	(0.13891)	(0.00)	0.00000
1970	42.5	1.13891	(0.13891)	0.00	(0.00000)
1969	43.5	1.13891	(0.13891)	(0.00)	0.00000
1968	44.5	1.13891	(0.13891)	0.00	(0.00000)
1967	45.5	1.13891	(0.13891)	(0.00)	0.00000
1966	46.5	1.13891	(0.13891)	0.00	(0.00000)
1965	47.5	1.13891	(0.13891)	(0.00)	0.00000
1964	48.5	1.13891	(0.13891)	0.00	(0.00000)
1963	49.5	1.13891	(0.13891)	(0.00)	0.00000
1962	50.5	1.13891	(0.13891)	0.00	(0.00000)
1961	51.5	1.13891	(0.13891)	(0.00)	0.00000
1960	52.5	1.13891	(0.13891)	0	(0.00000)
1959	53.5	1.13891	(0.13891)	(0)	0.00000
1956	54.5	1.13891	(0.13891)	0	(0.00000)
1957	55.5	1.13891	(0.13891)	(0)	0.00000
1956	56.5	1.13891	(0.13891)	0	(0.00000)
1955	57.5	1.13891	(0.13891)	(0)	0.00000
1954	58.5	1.13891	(0.13891)	0	(0.00000)

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

General Plant Vehicles Transmission	Account:	392.3
Date of Retirement (Mid Year):		2017
Interim Retirement Rate:		0.10108
Study Date, Year-End:		2012
Future Life from Study Date:		5.0
Remaining Life (F/E + .5) =		4.7

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Adjustments and Transfers	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1981	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	13,937	0	0	$ 13,937	0.00000
1974	0	0	0	$ 13,937	0.00000
1975	0	0	0	$ 13,937	0.00000
1975	0	0	0	$ 13,937	0.00000
1977	0	0	0	$ 13,937	0.00000
1978	0	0	0	$ 13,937	0.00000
1979	0	0	0	$ 13,937	0.00000
1980	0	0	0	$ 13,937	0.00000
1981	3,000	0	0	$ 16,937	0.00000
1962	0	0	0	$ 16,937	0.00000
1993	0	49,539	0	$ -	0.00000
1984	0	0	0	$ -	0.00000
1985	0	0	0	$ -	0.00000
1986	0	0	0	$ -	0.00000
1987	0	0	0	$ -	0.00000
1988	0	0	0	$ -	0.00000
1989	105,435	0	0	$ 105,435	0.00000
1990	124,090	67,679	0	$ 151,846	0.41617
1991	30,236	6,226	0	$ 185,854	0.03351
1992	0	121,703	0	$ 64,151	1.89712
1993	29,592	5,000	0	$ 88,743	0.05634
1994	41,086	23,388	0	$ 106,442	0.21972
1995	0	12,865	0	$ 93,576	0.13749
1996	72,462	34,768	0	$ 131,270	0.26486
1997	0	0	0	$ 131,270	0.00000
1998	275,403	186,258	0	$ 220,415	0.84503
1999	0	0	0	$ 220,415	0.00000
2000	0	0	0	$ 220,415	0.00000
2001	32,404	0	0	$ 252,816	0.00000
2002	251,699	21,313	0	$ 483,204	0.04411
2003	0	150,672	0	$ 332,532	0.45311
2004	0	0	0	$ 332,532	0.00000
2005	2,268	0	0	$ 334,800	0.00000
2006	0	0	0	$ 334,800	0.00000
2007	0	0	0	$ 334,800	0.00000
2008	275,629	0	0	$ 610,430	0.00000
2009	0	0	0	$ 610,430	0.00000
2010	0	0	0	$ 610,430	0.00000
2011	0	0	0	$ 610,430	0.00000
TOTAL	$ 1,257,240	$ 679,512	$ -	$ 6,722,404	0.10108

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.10108	0.89892	0.94946	3.98855
2011	1.5	0.10108	0.89892	0.85349	3.58538
2010	2.5	0.10108	0.89892	0.76721	3.22297
2009	3.5	0.10108	0.89892	0.68966	2.89718
2008	4.5	0.10108	0.89892	0.61995	2.60433
2007	5.5	0.10108	0.89892	0.55729	2.34108
2006	6.5	0.10108	0.89892	0.50095	2.10444
2005	7.5	0.10108	0.89892	0.45032	1.89172
2004	8.5	0.10108	0.89892	0.40480	1.70050
2003	9.5	0.10108	0.89892	0.36388	1.52861
2002	10.5	0.10108	0.89892	0.32710	1.37410
2001	11.5	0.10108	0.89892	0.29403	1.23520
2000	12.5	0.10108	0.89892	0.26431	1.11035
1999	13.5	0.10108	0.89892	0.23760	0.99811
1998	14.5	0.10108	0.89892	0.21358	0.89722
1997	15.5	0.10108	0.89892	0.19199	0.80653
1998	16.5	0.10108	0.89892	0.17258	0.72500
1995	17.5	0.10108	0.89892	0.15514	0.65172
1994	18.5	0.10108	0.89892	0.13946	0.58584
1993	19.5	0.10108	0.89892	0.12536	0.52662
1992	20.5	0.10108	0.89892	0.11269	0.47339
1991	21.5	0.10108	0.89892	0.10130	0.42554
1990	22.5	0.10108	0.89892	0.09106	0.38253
1989	23.5	0.10108	0.89892	0.08185	0.34386
1988	24.5	0.10108	0.89892	0.07358	0.30910
1987	25.5	0.10108	0.89892	0.06614	0.27786
1986	26.5	0.10108	0.89892	0.05946	0.24977
1985	27.5	0.10108	0.89892	0.05345	0.22452
1984	28.5	0.10108	0.89892	0.04804	0.20193
1983	29.5	0.10108	0.89892	0.04319	0.18143
1982	30.5	0.10108	0.89892	0.03882	0.16309
1981	31.5	0.10108	0.89892	0.03490	0.14660
1980	32.5	0.10108	0.89892	0.03137	0.13178
1979	33.5	0.10108	0.89892	0.02820	0.11846
1976	34.5	0.10108	0.89892	0.02535	0.10649
1977	35.5	0.10108	0.89892	0.02279	0.09572
1978	36.5	0.10108	0.89892	0.02048	0.08605
1975	37.5	0.10108	0.89892	0.01841	0.07735
1974	38.5	0.10108	0.89892	0.01655	0.06953
1973	39.5	0.10108	0.89892	0.01488	0.06250
1972	40.5	0.10108	0.89892	0.01337	0.05619
1971	41.5	0.10108	0.89892	0.01202	0.05051
1970	42.5	0.10108	0.89892	0.01081	0.04540
1969	43.5	0.10108	0.89892	0.00972	0.04081
1968	44.5	0.10108	0.89892	0.00873	0.03669
1967	45.5	0.10108	0.89892	0.00785	0.03298
1966	46.5	0.10108	0.89892	0.00706	0.02964
1965	47.5	0.10108	0.89892	0.00634	0.02665
1964	48.5	0.10108	0.89892	0.00570	0.02395
1963	49.5	0.10108	0.89892	0.00513	0.02153
1962	50.5	0.10108	0.89892	0.00461	0.01936
1961	51.5	0.10108	0.89892	0.00414	0.01740
1960	52.5	0.10108	0.89892	0.00372	0.01564
1959	53.5	0.10108	0.89892	0.00335	0.01406
1958	54.5	0.10108	0.89892	0.00301	0.01105
1957	55.5	0.10108	0.89892	0.00270	0.00835
1956	56.5	0.10108	0.89892	0.00243	0.00592
1955	57.5	0.10108	0.89892	0.00219	0.00373
1954	58.5	0.10108	0.89892	0.00196	0.00177

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

General Plant Stores Equipment   Account: 393

Date of Retirement (Mid Year): 2020
Interim Retirement Rate: 0.13235
Study Date, Year-End: 2012
Future Life from Study Date: 8.0
Remaining Life (F/E + .5) = 5.2

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1976	0	0	0	$ -	0.00000
1977	0	0	0	$ -	0.00000
1978	0	0	0	$ -	0.00000
1979	15,170	0	0	$ 15,170	0.00000
1980	2,649	0	0	$ 17,818	0.00000
1981	1,481	0	0	$ 19,299	0.00000
1982	0	0	0	$ 19,299	0.00000
1983	1,449	0	0	$ 20,748	0.00000
1984	1,345	0	0	$ 22,093	0.00000
1985	15,937	0	0	$ 38,030	0.00000
1986	1,941	0	0	$ 39,970	0.00000
1987	509	0	0	$ 40,480	0.00000
1988	0	0	0	$ 40,480	0.00000
1989	0	0	0	$ 40,480	0.00000
1990	6,710	0	0	$ 47,190	0.00000
1991	6,603	0	0	$ 52,793	0.00000
1992	1,879	821	0	$ 54,052	0.01148
1993	0	0	0	$ 54,052	0.00000
1994	0	491	0	$ 53,561	0.00916
1995	0	0	0	$ 53,561	0.00000
1996	0	0	0	$ 53,561	0.00000
1997	3,677	0	0	$ 57,239	0.00000
1998	0	92,770	0	$ -	0.00000
1999	1,831	0	0	$ 1,831	0.00000
2000	36,692	24,692	0	$ 13,831	1.78532
2001	0	1,245	0	$ 12,586	0.09890
2002	0	0	0	$ 12,586	0.00000
2003	0	0	0	$ 12,586	0.00000
2004	0	0	0	$ 12,586	0.00000
2005	0	0	0	$ 12,586	0.00000
2006	1,893	0	0	$ 14,479	0.00000
2007	0	0	0	$ 14,479	0.00000
2008	0	0	0	$ 14,479	0.00000
2009	0	0	0	$ 14,479	0.00000
2010	0	0	0	$ 14,479	0.00000
2011	0	0	0	$ 14,479	0.00000
TOTAL	$ 98,766	$ 119,619	$ -	$ 905,341	0.13235

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.13235	0.86765	0.93383	4.41594
2011	1.5	0.13235	0.86765	0.81024	3.83151
2010	2.5	0.13235	0.86765	0.70301	3.32442
2009	3.5	0.13235	0.86765	0.60997	2.88445
2008	4.5	0.13235	0.86765	0.52924	2.50270
2007	5.5	0.13235	0.86765	0.45920	2.17148
2006	6.5	0.13235	0.86765	0.39842	1.88409
2005	7.5	0.13235	0.86765	0.34569	1.63473
2004	8.5	0.13235	0.86765	0.29994	1.41838
2003	9.5	0.13235	0.86765	0.26025	1.23067
2002	10.5	0.13235	0.86765	0.22580	1.06779
2001	11.5	0.13235	0.86765	0.19592	0.92647
2000	12.5	0.13235	0.86765	0.16999	0.80386
1999	13.5	0.13235	0.86765	0.14749	0.69747
1998	14.5	0.13235	0.86765	0.12797	0.60516
1997	15.5	0.13235	0.86765	0.11104	0.52507
1996	16.5	0.13235	0.86765	0.09634	0.45558
1995	17.5	0.13235	0.86765	0.08359	0.39528
1994	18.5	0.13235	0.86765	0.07253	0.34297
1993	19.5	0.13235	0.86765	0.06293	0.29758
1992	20.5	0.13235	0.86765	0.05460	0.25820
1991	21.5	0.13235	0.86765	0.04737	0.22402
1990	22.5	0.13235	0.86765	0.04110	0.19438
1989	23.5	0.13235	0.86765	0.03566	0.16865
1988	24.5	0.13235	0.86765	0.03094	0.14633
1987	25.5	0.13235	0.86765	0.02685	0.12696
1986	26.5	0.13235	0.86765	0.02330	0.11016
1985	27.5	0.13235	0.86765	0.02021	0.09558
1984	28.5	0.13235	0.86765	0.01754	0.08293
1983	29.5	0.13235	0.86765	0.01522	0.07196
1982	30.5	0.13235	0.86765	0.01320	0.06243
1981	31.5	0.13235	0.86765	0.01148	0.05417
1980	32.5	0.13235	0.86765	0.00994	0.04700
1979	33.5	0.13235	0.86765	0.00862	0.04078
1978	34.5	0.13235	0.86765	0.00748	0.03538
1977	35.5	0.13235	0.86765	0.00649	0.03070
1976	36.5	0.13235	0.86765	0.00563	0.02664
1975	37.5	0.13235	0.86765	0.00489	0.02311
1974	38.5	0.13235	0.86765	0.00424	0.02005
1973	39.5	0.13235	0.86765	0.00368	0.01740
1972	40.5	0.13235	0.86765	0.00319	0.01510
1971	41.5	0.13235	0.86765	0.00277	0.01310
1970	42.5	0.13235	0.86765	0.00240	0.01136
1969	43.5	0.13235	0.86765	0.00209	0.00985
1968	44.5	0.13235	0.86765	0.00181	0.00858
1967	45.5	0.13235	0.86765	0.00157	0.00742
1966	46.5	0.13235	0.86765	0.00136	0.00644
1965	47.5	0.13235	0.86765	0.00118	0.00559
1964	48.5	0.13235	0.86765	0.00103	0.00485
1963	49.5	0.13235	0.86765	0.00089	0.00421
1962	50.5	0.13235	0.86765	0.00077	0.00365
1961	51.5	0.13235	0.86765	0.00067	0.00298
1960	52.5	0.13235	0.86765	0.00058	0.00240
1959	53.5	0.13235	0.86765	0.00050	0.00190
1958	54.5	0.13235	0.86765	0.00044	0.00146
1957	55.5	0.13235	0.86765	0.00038	0.00108
1956	56.5	0.13235	0.86765	0.00033	0.00075
1955	57.5	0.13235	0.86765	0.00029	0.00046
1954	58.5	0.13235	0.86765	0.00025	0.00022

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

General Plant Tools Account: 394

Date of Retirement (Mid Year):	2020
Interim Retirement Rate:	0.03107
Study Date, Year-End:	2012
Future Life from Study Date:	8.0
Remaining Life (F/E + .5) =	8.2

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	2,350	0	0	$ 2,350	0.00000
1968	555	0	0	$ 2,905	0.00000
1969	0	0	0	$ 2,905	0.00000
1970	4,742	0	0	$ 7,847	0.00000
1971	3,825	475	0	$ 10,996	0.04323
1972	0	0	0	$ 10,996	0.00000
1973	601	0	0	$ 11,598	0.00000
1974	1,347	0	0	$ 12,945	0.00000
1975	0	0	0	$ 12,945	0.00000
1976	0	0	0	$ 12,945	0.00000
1977	3,148	0	0	$ 16,093	0.00000
1978	82,823	0	0	$ 98,916	0.00000
1979	6,795	232	0	$ 105,478	0.00220
1980	35,977	0	0	$ 141,456	0.00000
1981	16,713	425	0	$ 157,744	0.00269
1982	11,694	0	0	$ 169,437	0.00000
1983	2,687	3,735	0	$ 168,390	0.02218
1984	29,870	1,809	0	$ 196,451	0.00921
1985	5,993	2,334	0	$ 200,110	0.01166
1986	5,411	239	0	$ 205,282	0.00117
1987	0	568	0	$ 204,714	0.00277
1988	27,022	3,788	0	$ 227,948	0.01662
1989	6,594	577	0	$ 233,965	0.00247
1990	10,719	446	0	$ 244,238	0.00183
1991	4,753	29,508	0	$ 219,484	0.13444
1992	19,516	16,406	0	$ 220,594	0.08344
1993	6,322	6,085	0	$ 220,831	0.02755
1994	7,847	27,018	0	$ 201,660	0.13398
1995	5,453	3,774	0	$ 203,340	0.01856
1996	14,754	1,224	0	$ 216,869	0.00564
1997	30,127	513	0	$ 246,484	0.00208
1998	9,111	80,060	0	$ 175,534	0.45609
1999	4,843	4,340	0	$ 176,037	0.02466
2000	13,163	8,063	0	$ 181,158	0.04451
2001	12,247	31,571	0	$ 161,833	0.19508
2002	8,375	0	0	$ 170,208	0.00000
2003	6,007	537	0	$ 175,679	0.00305
2004	9,238	0	0	$ 184,917	0.00000
2005	5,911	1,299	0	$ 189,529	0.00685
2006	2,300	3,357	0	$ 188,473	0.01781
2007	14,993	7,646	0	$ 195,819	0.03905
2008	275,416	625	0	$ 470,610	0.00133
2009	7,349	0	0	$ 477,959	0.00000
2010	6,216	753	0	$ 483,423	0.00156
2011	2,439	0	0	$ 485,862	0.00000
TOTAL	$ 725,269	$ 239,407	$ -	$ 7,704,758	0.03107

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.03107	0.96893	0.98446	7.59171
2011	1.5	0.03107	0.96893	0.95387	7.35582
2010	2.5	0.03107	0.96893	0.92423	7.12725
2009	3.5	0.03107	0.96893	0.89552	6.90579
2008	4.5	0.03107	0.96893	0.86769	6.69121
2007	5.5	0.03107	0.96893	0.84073	6.48330
2006	6.5	0.03107	0.96893	0.81461	6.28184
2005	7.5	0.03107	0.96893	0.78929	6.08665
2004	8.5	0.03107	0.96893	0.76477	5.89752
2003	9.5	0.03107	0.96893	0.74100	5.71427
2002	10.5	0.03107	0.96893	0.71798	5.53671
2001	11.5	0.03107	0.96893	0.69567	5.36467
2000	12.5	0.03107	0.96893	0.67405	5.19798
1999	13.5	0.03107	0.96893	0.65311	5.03646
1998	14.5	0.03107	0.96893	0.63282	4.87997
1997	15.5	0.03107	0.96893	0.61315	4.72833
1996	16.5	0.03107	0.96893	0.59410	4.58141
1995	17.5	0.03107	0.96893	0.57564	4.43908
1994	18.5	0.03107	0.96893	0.55775	4.30112
1993	19.5	0.03107	0.96893	0.54042	4.16746
1992	20.5	0.03107	0.96893	0.52363	4.03798
1991	21.5	0.03107	0.96893	0.50736	3.91251
1990	22.5	0.03107	0.96893	0.49159	3.79094
1989	23.5	0.03107	0.96893	0.47632	3.67314
1988	24.5	0.03107	0.96893	0.46152	3.55901
1987	25.5	0.03107	0.96893	0.44718	3.44842
1986	26.5	0.03107	0.96893	0.43328	3.34127
1985	27.5	0.03107	0.96893	0.41982	3.23745
1984	28.5	0.03107	0.96893	0.40677	3.13685
1983	29.6	0.03107	0.96893	0.39414	3.03938
1982	30.5	0.03107	0.96893	0.38169	2.94494
1981	31.5	0.03107	0.96893	0.37002	2.85343
1980	32.5	0.03107	0.96893	0.35852	2.76477
1979	33.5	0.03107	0.96893	0.34738	2.67886
1978	34.5	0.03107	0.96893	0.33659	2.59562
1977	35.5	0.03107	0.96893	0.32613	2.51497
1976	36.5	0.03107	0.96893	0.31600	2.43682
1975	37.5	0.03107	0.96893	0.30618	2.36110
1974	38.5	0.03107	0.96893	0.29667	2.28774
1973	39.5	0.03107	0.96893	0.28745	2.21665
1972	40.6	0.03107	0.96893	0.27852	2.14776
1971	41.5	0.03107	0.96893	0.26986	2.08104
1970	42.5	0.03107	0.96893	0.26148	2.01638
1969	43.5	0.03107	0.96893	0.25335	1.95372
1968	44.5	0.03107	0.96893	0.24548	1.89301
1967	45.5	0.03107	0.96893	0.23785	1.83419
1966	46.5	0.03107	0.96893	0.23048	1.77720
1965	47.5	0.03107	0.96893	0.22330	1.72198
1964	48.5	0.03107	0.96893	0.21636	1.66847
1963	49.5	0.03107	0.96893	0.20964	1.61663
1962	50.5	0.03107	0.96893	0.20312	1.56639
1961	51.5	0.03107	0.96893	0.19681	1.36958
1960	52.5	0.03107	0.96893	0.19070	1.17689
1959	53.5	0.03107	0.96893	0.18477	0.99411
1958	54.5	0.03107	0.96893	0.17903	0.81508
1957	55.5	0.03107	0.96893	0.17347	0.64162
1956	56.5	0.03107	0.96893	0.16808	0.47354
1955	57.5	0.03107	0.96893	0.16285	0.31069
1954	58.5	0.03107	0.96893	0.15779	0.15289

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Burns & McDonnell SINCE 1898

General Plant Lab Equipment Account: 395

Date of Retirement (Mid Year):	2020
Interim Retirement Rate:	0.12220
Study Date, Year-End:	2012
Future Life from Study Date:	8.0
Remaining Life (F/E + .5) =	5.7

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	762	0	0	$ 782	0.00000
1967	9,649	0	0	$ 10,411	0.00000
1968	4,998	0	0	$ 15,409	0.00000
1969	0	0	0	$ 15,409	0.00000
1970	4,382	0	0	$ 19,791	0.00000
1971	2,361	0	0	$ 22,172	0.00000
1972	1,822	0	0	$ 23,994	0.00000
1973	921	0	0	$ 24,915	0.00000
1974	7,646	252	0	$ 32,308	0.00781
1975	8,189	0	0	$ 38,497	0.00000
1976	0	0	0	$ 38,497	0.00000
1977	977	0	0	$ 39,474	0.00000
1978	1,304	0	0	$ 40,778	0.00000
1979	13,537	0	0	$ 54,314	0.00000
1980	593	0	0	$ 54,908	0.00000
1981	5,084	0	0	$ 59,991	0.00000
1982	13,273	875	0	$ 72,590	0.00930
1983	7,025	0	0	$ 79,814	0.00000
1984	0	0	0	$ 79,614	0.00000
1985	0	0	0	$ 79,614	0.00000
1986	0	0	0	$ 79,614	0.00000
1987	0	0	0	$ 79,614	0.00000
1988	0	694	0	$ 78,920	0.00879
1989	14,936	0	0	$ 93,856	0.00000
1990	5,191	0	0	$ 99,047	0.00000
1991	35,538	0	0	$ 134,585	0.00000
1992	5,548	0	0	$ 140,134	0.00000
1993	4,918	14,118	0	$ 130,936	0.10781
1994	0	17,089	0	$ 113,847	0.15011
1995	0	0	0	$ 113,847	0.00000
1996	3,517	646	0	$ 118,718	0.00553
1997	4,915	2,817	0	$ 118,816	0.02371
1998	0	136,121	0	$ -	0.00000
1999	0	132,253	0	$ -	0.00000
2000	0	0	0	$ -	0.00000
2001	0	20,237	0	$ -	0.00000
2002	32,841	1,015	0	$ 31,826	0.03189
2003	0	-7,912	0	$ 39,736	-0.19910
2004	0	0	0	$ 39,738	0.00000
2005	0	0	0	$ 39,736	0.00000
2006	33,333	5,205	0	$ 67,865	0.07670
2007	0	0	0	$ 87,865	0.00000
2008	0	0	0	$ 67,865	0.00000
2009	0	0	0	$ 67,865	0.00000
2010	0	0	0	$ 67,865	0.00000
2011	0	0	0	$ 87,885	0.00000
TOTAL	$ 221,279	$ 325,207	$ -	$ 2,661,229	0.12220

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.12220	0.87780	0.93890	4.91246
2011	1.5	0.12220	0.87780	0.82416	4.31215
2010	2.5	0.12220	0.87780	0.72345	3.78520
2009	3.5	0.12220	0.87780	0.63604	3.32264
2008	4.5	0.12220	0.87780	0.55744	2.91661
2007	5.5	0.12220	0.87780	0.48932	2.56019
2006	6.5	0.12220	0.87780	0.42952	2.24733
2005	7.5	0.12220	0.87780	0.37703	1.97270
2004	8.5	0.12220	0.87780	0.33096	1.73184
2003	9.5	0.12220	0.87780	0.29052	1.52003
2002	10.5	0.12220	0.87780	0.25501	1.33428
2001	11.5	0.12220	0.87780	0.22385	1.17123
2000	12.5	0.12220	0.87780	0.19650	1.02810
1999	13.5	0.12220	0.87780	0.17248	0.90246
1998	14.5	0.12220	0.87780	0.15141	0.79218
1997	15.5	0.12220	0.87780	0.13290	0.69538
1996	16.5	0.12220	0.87780	0.11666	0.61040
1995	17.5	0.12220	0.87780	0.10241	0.53581
1994	18.5	0.12220	0.87780	0.08989	0.47033
1993	19.5	0.12220	0.87780	0.07891	0.41286
1992	20.5	0.12220	0.87780	0.06926	0.36240
1991	21.5	0.12220	0.87780	0.06080	0.31812
1990	22.5	0.12220	0.87780	0.05337	0.27924
1989	23.5	0.12220	0.87780	0.04685	0.24512
1988	24.5	0.12220	0.87780	0.04112	0.21518
1987	25.5	0.12220	0.87780	0.03610	0.18887
1986	26.5	0.12220	0.87780	0.03169	0.16579
1985	27.5	0.12220	0.87780	0.02781	0.14553
1984	28.5	0.12220	0.87780	0.02442	0.12775
1983	29.5	0.12220	0.87780	0.02143	0.11214
1982	30.5	0.12220	0.87780	0.01861	0.09843
1981	31.5	0.12220	0.87780	0.01651	0.08640
1980	32.5	0.12220	0.87780	0.01450	0.07585
1979	33.5	0.12220	0.87780	0.01272	0.06658
1978	34.5	0.12220	0.87780	0.01117	0.05844
1977	35.5	0.12220	0.87780	0.00980	0.05130
1976	36.5	0.12220	0.87780	0.00861	0.04503
1975	37.5	0.12220	0.87780	0.00755	0.03953
1974	38.5	0.12220	0.87780	0.00663	0.03470
1973	39.5	0.12220	0.87780	0.00582	0.03046
1972	40.5	0.12220	0.87780	0.00511	0.02674
1971	41.5	0.12220	0.87780	0.00449	0.02347
1970	42.5	0.12220	0.87780	0.00394	0.02060
1969	43.5	0.12220	0.87780	0.00346	0.01808
1968	44.5	0.12220	0.87780	0.00303	0.01567
1967	45.5	0.12220	0.87780	0.00285	0.01393
1966	46.6	0.12220	0.87780	0.00234	0.01223
1965	47.5	0.12220	0.87780	0.00205	0.01074
1964	48.5	0.12220	0.87780	0.00180	0.00942
1963	49.5	0.12220	0.87780	0.00156	0.00827
1962	50.5	0.12220	0.87780	0.00139	0.00688
1961	51.5	0.12220	0.87780	0.00122	0.00567
1960	52.5	0.12220	0.67780	0.00107	0.00460
1959	53.5	0.12220	0.87780	0.00094	0.00366
1958	54.5	0.12220	0.87780	0.00082	0.00283
1957	55.5	0.12220	0.87780	0.00072	0.00211
1956	56.5	0.12220	0.87780	0.00063	0.00148
1955	57.5	0.12220	0.87780	0.00056	0.00092
1954	56.5	0.12220	0.87780	0.00049	0.00043

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

General Plant Power Operated Eqpt Account: 396

Date of Retirement (Mid Year):	2021
Interim Retirement Rate:	0.13552
Study Date, Year-End:	2012
Future Life from Study Date:	9.0
Remaining Life (F/E + .5) =	5.6

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	0	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1976	0	0	0	$ -	0.00000
1977	0	0	0	$ -	0.00000
1978	0	0	0	$ -	0.00000
1979	561	0	0	$ 561	0.00000
1980	0	37,557	0	$ -	0.00000
1961	117,498	0	0	$ 117,498	0.00000
1982	14,401	0	0	$ 131,899	0.00000
1983	0	0	0	$ 131,899	0.00000
1984	0	0	0	$ 131,899	0.00000
1985	0	0	0	$ 131,899	0.00000
1986	0	0	0	$ 131,899	0.00000
1987	85,838	29,478	0	$ 186,259	0.15658
1968	0	38,931	0	$ 149,328	0.26071
1989	2,063	6,017	0	$ 145,374	0.04139
1990	0	0	0	$ 145,374	0.00000
1991	0	44,939	0	$ 100,435	0.44744
1992	17,923	12,898	0	$ 105,462	0.12228
1993	0	0	0	$ 105,462	0.00000
1994	57,527	25,413	0	$ 137,577	0.18472
1995	0	0	0	$ 137,577	0.00000
1996	7,036	6,314	0	$ 139,298	0.03815
1997	19,536	124,795	0	$ 34,040	3.66616
1998	84,553	62,951	0	$ 35,841	1.76625
1999	4,277	0	0	$ 39,919	0.00000
2000	0	530	0	$ 39,389	0.01346
2001	7,192	388	0	$ 46,192	0.00841
2002	0	0	0	$ 46,192	0.00000
2003	19,528	7,084	0	$ 58,636	0.12082
2004	44,979	32,447	0	$ 71,168	0.45592
2005	19,804	11,613	0	$ 79,359	0.14633
2006	0	0	0	$ 79,359	0.00000
2007	9,909	0	0	$ 89,268	0.00000
2008	12,114	0	0	$ 101,363	0.00000
2009	0	0	0	$ 101,383	0.00000
2010	29,842	0	0	$ 131,225	0.00000
2011	33,294	0	0	$ 184,519	0.00000
TOTAL	$ 567,875	$ 440,353	$ -	$ 3,249,370	0.13552

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.13552	0.86448	0.93224	4.74841
2011	1.5	0.13552	0.86448	0.80590	4.10491
2010	2.5	0.13552	0.86448	0.69669	3.54861
2009	3.5	0.13552	0.86448	0.60227	3.06771
2008	4.5	0.13552	0.86448	0.52065	2.65197
2007	5.5	0.13552	0.86448	0.45009	2.29258
2006	6.5	0.13552	0.86448	0.38910	1.98189
2005	7.5	0.13552	0.86448	0.33637	1.71331
2004	8.5	0.13552	0.86448	0.29078	1.48112
2003	9.5	0.13552	0.86448	0.25138	1.28040
2002	10.5	0.13552	0.86448	0.21731	1.10688
2001	11.5	0.13552	0.86448	0.18786	0.95688
2000	12.5	0.13552	0.86448	0.16240	0.62720
1999	13.5	0.13552	0.86448	0.14039	0.71510
1998	14.5	0.13552	0.86448	0.12137	0.61919
1997	15.5	0.13552	0.86448	0.10492	0.53441
1996	16.5	0.13552	0.86448	0.09070	0.46199
1985	17.5	0.13552	0.86449	0.07841	0.39938
1994	18.5	0.13552	0.86448	0.06778	0.34526
1993	19.5	0.13552	0.86448	0.05860	0.29847
1992	20.5	0.13552	0.86448	0.05066	0.25802
1991	21.5	0.13552	0.86448	0.04379	0.22305
1990	22.5	0.13552	0.86448	0.03786	0.19282
1989	23.5	0.13552	0.86448	0.03273	0.16669
1988	24.5	0.13552	0.86448	0.02829	0.14410
1987	25.5	0.13552	0.86448	0.02446	0.12457
1966	26.5	0.13552	0.86448	0.02114	0.10769
1985	27.5	0.13552	0.86448	0.01828	0.09310
1964	26.5	0.13552	0.86448	0.01580	0.08048
1963	29.5	0.13552	0.86448	0.01366	0.06957
1982	30.5	0.13552	0.86448	0.01181	0.06015
1981	31.5	0.13552	0.86448	0.01021	0.05199
1980	32.5	0.13552	0.86446	0.00882	0.04496
1979	33.5	0.13552	0.86448	0.00763	0.03886
1976	34.5	0.13552	0.86448	0.00659	0.03359
1977	35.5	0.13552	0.86448	0.00570	0.02904
1976	36.5	0.13552	0.86448	0.00493	0.02510
1975	37.5	0.13552	0.86448	0.00426	0.02170
1974	38.5	0.13552	0.86448	0.00368	0.01878
1973	39.5	0.13552	0.86448	0.00318	0.01622
1972	40.5	0.13552	0.86448	0.00275	0.01402
1971	41.5	0.13552	0.86448	0.00238	0.01212
1970	42.5	0.13552	0.86448	0.00206	0.01048
1969	43.5	0.13552	0.86448	0.00178	0.00906
1988	44.5	0.13552	0.86448	0.00154	0.00783
1987	45.5	0.13552	0.86448	0.00133	0.00677
1968	46.5	0.13552	0.86446	0.00115	0.00585
1965	47.5	0.13552	0.86448	0.00099	0.00508
1964	48.5	0.13552	0.86448	0.00086	0.00437
1963	49.5	0.13552	0.86446	0.00074	0.00363
1962	50.5	0.13552	0.86448	0.00064	0.00289
1961	51.5	0.13552	0.86448	0.00055	0.00243
1960	52.5	0.13552	0.86448	0.00048	0.00198
1959	53.5	0.13552	0.86448	0.00041	0.00154
1958	54.5	0.13552	0.86448	0.00036	0.00118
1957	55.5	0.13552	0.86448	0.00031	0.00087
1956	58.5	0.13552	0.86448	0.00027	0.00060
1955	57.6	0.13552	0.86448	0.00023	0.00037
1954	58.5	0.13552	0.86446	0.00020	0.00017

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

General Plant Communication Eqpt Account: 397

Date of Retirement (Mid Year):	2013
Interim Retirement Rate:	0.08490
Study Date, Year-End:	2012
Future Life from Study Date:	1.0
Remaining Life (F/E + .5) =	2.3

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	2,048	$ 2,048	0.00000
1969	3,371	0	0	$ 5,419	0.00000
1970	1,877	0	0	$ 7,297	0.00000
1971	0	0	0	$ 7,297	0.00000
1972	0	0	0	$ 7,297	0.00000
1973	4,032	0	0	$ 11,328	0.00000
1974	0	0	0	$ 11,328	0.00000
1975	0	71	0	$ 11,258	0.00628
1976	2,894	0	0	$ 14,151	0.00000
1977	0	0	0	$ 14,151	0.00000
1978	0	0	0	$ 14,151	0.00000
1979	912	0	224	$ 15,287	0.00000
1980	0	0	664	$ 15,952	0.00000
1981	849	0	0	$ 16,800	0.00000
1982	2,691	0	38	$ 19,529	0.00000
1983	50,210	14,240	0	$ 55,499	0.25659
1984	4,045	3,170	0	$ 56,374	0.05624
1985	1,015,588	56,760	10,300	$ 1,025,501	0.05535
1986	26,172	4,629	0	$ 1,047,045	0.00442
1987	10,746	0	0	$ 1,057,790	0.00000
1988	27,796	2,626	0	$ 1,082,960	0.00242
1989	22,530	7,684	0	$ 1,097,806	0.00700
1990	12,921	11,575	0	$ 1,099,152	0.01053
1991	27,050	0	0	$ 1,126,202	0.00000
1992	23,027	1,313	0	$ 1,147,916	0.00114
1993	3,284	5,719	0	$ 1,145,461	0.00499
1994	167,081	227,774	0	$ 1,084,768	0.20997
1995	1,694	0	0	$ 1,086,462	0.00000
1996	7,030	3,443	0	$ 1,090,048	0.00315
1997	387	0	0	$ 1,090,435	0.00000
1998	23,421	784,830	0	$ 329,026	2.38531
1999	0	1,129	0	$ 327,897	0.00344
2000	0	58,972	0	$ 270,925	0.21029
2001	0	32,785	0	$ 238,159	0.13758
2002	0	2,933	0	$ 235,227	0.01247
2003	3,864	0	0	$ 239,091	0.00000
2004	3,888	0	0	$ 242,979	0.00000
2005	30,946	26,936	0	$ 246,989	0.10906
2006	167,096	57,985	0	$ 346,101	0.16754
2007	2,950	50,509	0	$ 298,542	0.16919
2008	1,106	0	0	$ 299,648	0.00000
2009	0	0	0	$ 299,648	0.00000
2010	682	0	0	$ 300,330	0.00000
2011	245,695	215,283	0	$ 330,782	0.85081
TOTAL	$ 1,885,814	$ 1,568,327	$ 13,274	$ 18,472,037	0.08490

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.08490	0.91510	0.95755	1.67810
2011	1.5	0.08490	0.91510	0.87625	1.53563
2010	2.5	0.08490	0.91510	0.80185	1.40525
2009	3.5	0.08490	0.91510	0.73377	1.28594
2008	4.5	0.08490	0.91510	0.67148	1.17676
2007	5.5	0.08490	0.91510	0.61446	1.07685
2006	6.5	0.08490	0.91510	0.56230	0.98542
2005	7.5	0.08490	0.91510	0.51455	0.90176
2004	8.5	0.08490	0.91510	0.47087	0.82520
2003	9.5	0.08490	0.91510	0.43089	0.75513
2002	10.5	0.08490	0.91510	0.39431	0.69102
2001	11.5	0.08490	0.91510	0.36083	0.63235
2000	12.5	0.08490	0.91510	0.33019	0.57866
1999	13.5	0.08490	0.91510	0.30216	0.52953
1998	14.5	0.08490	0.91510	0.27650	0.48457
1997	15.5	0.08490	0.91510	0.25303	0.44343
1996	16.5	0.08490	0.91510	0.23155	0.40578
1995	17.5	0.08490	0.91510	0.21199	0.37133
1994	18.5	0.08490	0.91510	0.19390	0.33980
1993	19.5	0.08490	0.91510	0.17743	0.31095
1992	20.5	0.08490	0.91510	0.16237	0.28455
1991	21.5	0.08490	0.91510	0.14856	0.26039
1990	22.5	0.08490	0.91510	0.13597	0.23829
1989	23.5	0.08490	0.91510	0.12443	0.21805
1988	24.5	0.08490	0.91510	0.11386	0.19954
1987	25.5	0.08490	0.91510	0.10419	0.18260
1986	26.5	0.08490	0.91510	0.09535	0.16710
1985	27.5	0.08490	0.91510	0.08725	0.15291
1984	28.5	0.08490	0.91510	0.07984	0.13993
1983	29.5	0.08490	0.91510	0.07307	0.12805
1982	30.5	0.08490	0.91510	0.06686	0.11718
1981	31.5	0.08490	0.91510	0.06119	0.10723
1980	32.5	0.08490	0.91510	0.05599	0.09812
1979	33.5	0.08490	0.91510	0.05124	0.08979
1978	34.5	0.08490	0.91510	0.04689	0.08217
1977	35.5	0.08490	0.91510	0.04291	0.07519
1976	36.5	0.08490	0.91510	0.03926	0.06881
1975	37.5	0.08490	0.91510	0.03593	0.06297
1974	38.5	0.08490	0.91510	0.03288	0.05762
1973	39.5	0.08490	0.91510	0.03009	0.05273
1972	40.5	0.08490	0.91510	0.02753	0.04825
1971	41.5	0.08490	0.91510	0.02520	0.04415
1970	42.5	0.08490	0.91510	0.02306	0.04041
1969	43.5	0.08490	0.91510	0.02110	0.03698
1968	44.5	0.08490	0.91510	0.01931	0.03384
1967	45.5	0.08490	0.91510	0.01767	0.03096
1966	46.5	0.08490	0.91510	0.01617	0.02833
1965	47.5	0.08490	0.91510	0.01480	0.02593
1964	48.5	0.08490	0.91510	0.01354	0.02373
1963	49.5	0.08490	0.91510	0.01239	0.02171
1962	50.5	0.08490	0.91510	0.01134	0.01987
1961	51.5	0.08490	0.91510	0.01038	0.01818
1960	52.5	0.08490	0.91510	0.00949	0.01664
1959	53.5	0.08490	0.91510	0.00869	0.01523
1958	54.5	0.08490	0.91510	0.00795	0.01393
1957	55.5	0.08490	0.91510	0.00728	0.01275
1956	56.5	0.08490	0.91510	0.00666	0.01167
1955	57.5	0.08490	0.91510	0.00609	0.01068
1954	58.5	0.08490	0.91510	0.00558	0.00510

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

Big Rivers Electric Corporation
2012 Depreciation Rate Study - Interim Retirement Rate Analysis

Burns & McDonnell SINCE 1898

General Plant Miscellaneous Eqpt | Account: 398

Date of Retirement (Mid Year): 2021
Interim Retirement Rate: 0.24198
Study Date, Year-End: 2012
Future Life from Study Date: 9.0
Remaining Life (F/E + .5) = 3.5

Development of Interim Retirement Rate

Activity Year	Additions	Retirements	Removal Costs	Yr-End Plant Balance	Interim Retirement Rate
A	B	C	D	E	F = C / E
1953	0	0	0	$ -	0.00000
1954	0	0	0	$ -	0.00000
1955	0	0	0	$ -	0.00000
1956	0	0	0	$ -	0.00000
1957	0	0	0	$ -	0.00000
1958	0	0	0	$ -	0.00000
1959	0	0	0	$ -	0.00000
1960	0	0	0	$ -	0.00000
1961	0	0	0	$ -	0.00000
1962	0	0	0	$ -	0.00000
1963	0	0	0	$ -	0.00000
1964	0	0	0	$ -	0.00000
1965	0	0	0	$ -	0.00000
1966	0	0	0	$ -	0.00000
1967	0	0	0	$ -	0.00000
1968	0	0	0	$ -	0.00000
1969	0	0	0	$ -	0.00000
1970	0	0	0	$ -	0.00000
1971	0	0	0	$ -	0.00000
1972	0	0	0	$ -	0.00000
1973	0	0	0	$ -	0.00000
1974	0	2,056	0	$ -	0.00000
1975	0	0	0	$ -	0.00000
1976	0	232	0	$ -	0.00000
1977	0	0	0	$ -	0.00000
1978	0	0	0	$ -	0.00000
1979	8,745	1,619	0	$ 5,127	0.31571
1980	0	0	0	$ 5,127	0.00000
1981	3,777	3,120	171	$ 5,955	0.52361
1982	0	358	0	$ 5,597	0.06394
1983	629	10,640	0	$ -	0.00000
1984	0	0	0	$ -	0.00000
1985	0	27,611	0	$ -	0.00000
1986	0	10,942	0	$ -	0.00000
1987	0	7,671	0	$ -	0.00000
1988	0	6,016	0	$ -	0.00000
1989	0	9,363	0	$ -	0.00000
1990	2,568	936	0	$ 1,632	0.57334
1991	2,763	365	0	$ 4,031	0.09059
1992	0	210	0	$ 3,821	0.05495
1993	0	7,490	0	$ -	0.00000
1994	0	7,987	0	$ -	0.00000
1995	1,902	1,267	0	$ 635	1.99413
1996	583	2,505	0	$ -	0.00000
1997	1,134	702	0	$ 432	1.62280
1998	3,116	126,975	0	$ -	0.00000
1999	4,917	6,320	0	$ -	0.00000
2000	4,242	11,097	0	$ -	0.00000
2001	2,788	6,176	0	$ -	0.00000
2002	27,460	0	0	$ 27,460	0.00000
2003	3,454	1,851	0	$ 26,983	0.06737
2004	1,632	641	0	$ 29,954	0.02141
2005	12,233	633	0	$ 41,555	0.01522
2006	48,299	3,136	0	$ 88,717	0.03617
2007	1,824	1,195	0	$ 87,347	0.01368
2008	18,103	1,577	0	$ 103,873	0.01518
2009	13,475	0	0	$ 117,348	0.00000
2010	5,070	713	0	$ 121,704	0.00586
2011	84,559	0	0	$ 206,263	0.00000
TOTAL	$ 251,254	$ 263,602	$ 171	$ 1,089,803	0.24188

Interim Retirement Life Table

Year Placed	Age at 12/31/2009	Annual Retirement Rate	Annual Survival Ratio	Life Table	Unrealized Life of Original Plant [1]
A	B	C	D = (1- C)	E	F
2012	0.5	0.24188	0.75812	0.87906	2.62422
2011	1.5	0.24188	0.75812	0.66643	1.98947
2010	2.5	0.24188	0.75812	0.50524	1.50826
2009	3.5	0.24188	0.75812	0.38303	1.14344
2008	4.5	0.24188	0.75812	0.29038	0.86686
2007	5.5	0.24188	0.75812	0.22014	0.65719
2006	6.5	0.24188	0.75812	0.16690	0.49823
2005	7.5	0.24188	0.75812	0.12653	0.37771
2004	8.5	0.24188	0.75812	0.09592	0.28635
2003	9.5	0.24188	0.75812	0.07272	0.21709
2002	10.5	0.24188	0.75812	0.05513	0.16458
2001	11.5	0.24188	0.75812	0.04180	0.12477
2000	12.5	0.24188	0.75812	0.03169	0.09459
1999	13.5	0.24188	0.75812	0.02402	0.07171
1998	14.5	0.24188	0.75812	0.01821	0.05437
1997	15.5	0.24188	0.75812	0.01381	0.04122
1996	16.5	0.24188	0.75812	0.01047	0.03125
1995	17.5	0.24188	0.75812	0.00794	0.02369
1994	18.5	0.24188	0.75812	0.00602	0.01796
1993	19.5	0.24188	0.75812	0.00456	0.01361
1992	20.5	0.24188	0.75812	0.00346	0.01032
1991	21.5	0.24188	0.75812	0.00262	0.00783
1990	22.5	0.24188	0.75812	0.00199	0.00593
1989	23.5	0.24188	0.75812	0.00151	0.00450
1988	24.5	0.24188	0.75812	0.00114	0.00341
1987	25.5	0.24188	0.75812	0.00087	0.00258
1986	26.5	0.24188	0.75812	0.00066	0.00198
1985	27.5	0.24188	0.75812	0.00050	0.00149
1984	28.5	0.24188	0.75812	0.00038	0.00113
1983	29.5	0.24188	0.75812	0.00029	0.00085
1982	30.5	0.24188	0.75812	0.00022	0.00065
1981	31.5	0.24188	0.75812	0.00016	0.00049
1980	32.5	0.24188	0.75812	0.00012	0.00037
1979	33.5	0.24188	0.75812	0.00009	0.00028
1978	34.5	0.24188	0.75812	0.00007	0.00021
1977	35.5	0.24188	0.75812	0.00005	0.00016
1976	36.5	0.24188	0.75812	0.00004	0.00012
1975	37.5	0.24188	0.75812	0.00003	0.00009
1974	38.5	0.24188	0.75812	0.00002	0.00007
1973	39.5	0.24188	0.75812	0.00002	0.00005
1972	40.5	0.24188	0.75812	0.00001	0.00004
1971	41.5	0.24188	0.75812	0.00001	0.00003
1970	42.5	0.24188	0.75812	0.00001	0.00002
1969	43.5	0.24188	0.75812	0.00001	0.00002
1968	44.5	0.24188	0.75812	0.00000	0.00001
1967	45.5	0.24188	0.75812	0.00000	0.00001
1966	46.5	0.24188	0.75812	0.00000	0.00001
1965	47.5	0.24188	0.75812	0.00000	0.00001
1964	48.5	0.24188	0.75812	0.00000	0.00000
1963	49.5	0.24188	0.75812	0.00000	0.00000
1962	50.5	0.24188	0.75812	0.00000	0.00000
1961	51.5	0.24188	0.75812	0.00000	0.00000
1960	52.5	0.24188	0.75812	0.00000	0.00000
1959	53.5	0.24188	0.75812	0.00000	0.00000
1958	54.5	0.24188	0.75812	0.00000	0.00000
1957	55.5	0.24188	0.75812	0.00000	0.00000
1956	56.5	0.24188	0.75812	0.00000	0.00000
1955	57.5	0.24188	0.75812	0.00000	0.00000
1954	58.5	0.24188	0.75812	0.00000	0.00000

[1] Unrealized Life = Sum Life Table from (n-1) for (Future Life - .5) values

United States Bankruptcy Court,
D. Utah,
Central Division.

In re BONNEVILLE PACIFIC CORP., Debtor.

Bankruptcy No. 91A–27701.
May 22, 1996.

Counsel for Chapter 11 debtor-in-possession (DIP) applied for allowance of interim compensation and reimbursement of expenses. The Bankruptcy Court, 147 B.R. 803, denied application. Movants filed motions to alter or amend fee application denial. The Bankruptcy Court, John H. Allen, J., held that findings supported denial of fees and disgorgement of previously awarded fees.

Motions denied.

West Headnotes

[1] Bankruptcy 51 ⚿3501

51 Bankruptcy
51XIV Reorganization
51XIV(A) In General
51k3501 k. In General; Nature and Purpose. Most Cited Cases

Chapter 11 is remedy for debtor with considerable debts who does not wish to surrender all nonexempt assets to creditors and abandon all efforts to handle debt problems.

[2] Bankruptcy 51 ⚿2391

51 Bankruptcy
51IV Effect of Bankruptcy Relief; Injunction and Stay
51IV(B) Automatic Stay
51k2391 k. In General. Most Cited Cases

Automatic stay gives debtor breathing spell from hostile litigation in order to reorganize using such methods as selling assets, borrowing money, or changing methods of operation. Bankr.Code, 11 U.S.C.A. § 362.

[3] Bankruptcy 51 ⚿2187

51 Bankruptcy
51II Courts; Proceedings in General
51II(C) Costs and Fees
51k2182 Grounds and Circumstances
51k2187 k. Frivolity or Bad Faith; Sanctions. Most Cited Cases

Attorney who signs pleading, motion, or application certifies that attorney has read paper and to best of attorney's knowledge, information, and belief (formed after reasonable inquiry), there exists sufficient basis to support such filing, and that it is not filed for delay or any other improper purpose. Fed.Rules Bankr.Proc.Rule 9011, 11 U.S.C.A.

[4] Bankruptcy 51 ⚿2187

51 Bankruptcy
51II Courts; Proceedings in General
51II(C) Costs and Fees
51k2182 Grounds and Circumstances
51k2187 k. Frivolity or Bad Faith; Sanctions. Most Cited Cases

Disciplinary action is to be imposed for willful violation of rule requiring all pleadings and motions filed for party represented by attorney to be signed by that attorney. Fed.Rules Bankr.Proc.Rule 9011, 11 U.S.C.A.

[5] Bankruptcy 51 ⚿3030

51 Bankruptcy
51IX Administration
51IX(A) In General
51k3029 Employment of Professional Persons or Debtor's Officers
51k3030 k. Attorneys. Most Cited Cases

SC EXHIBIT 6

When representing debtor-in-possession (DIP), DIP's attorney has duty to look to interests of estate, not to interests of DIP's principals, shareholders, officers, or directors.

[6] Bankruptcy 51 ⚷3029.1

51 Bankruptcy
51IX Administration
51IX(A) In General
51k3029 Employment of Professional Persons or Debtor's Officers
51k3029.1 k. In General. Most Cited Cases

Bankruptcy 51 ⚷3622

51 Bankruptcy
51XIV Reorganization
51XIV(D) Administration
51k3622 k. Debtor in Possession, in General. Most Cited Cases

In Chapter 11 cases, debtors-in-possession (DIPs) act as "trustees" of estates in bankruptcy and, accordingly, may hire professionals, with court approval. Bankr.Code, 11 U.S.C.A. §§ 327, 541.

[7] Bankruptcy 51 ⚷3622

51 Bankruptcy
51XIV Reorganization
51XIV(D) Administration
51k3622 k. Debtor in Possession, in General. Most Cited Cases

Debtor-in-possession is statutory fiduciary of its own estate. Bankr.Code, 11 U.S.C.A. §§ 1106, 1107(a).

[8] Attorney and Client 45 ⚷21.5(6)

45 Attorney and Client
45I The Office of Attorney
45I(B) Privileges, Disabilities, and Liabilities
45k20 Representing Adverse Interests
45k21.5 Particular Cases and Problems
45k21.5(6) k. Bankruptcy. Most Cited Cases

Chapter 11 trustee representing estate must receive independent counsel, regardless of estate's relationship to other entities prepetition.

[9] Attorney and Client 45 ⚷21.5(6)

45 Attorney and Client
45I The Office of Attorney
45I(B) Privileges, Disabilities, and Liabilities
45k20 Representing Adverse Interests
45k21.5 Particular Cases and Problems
45k21.5(6) k. Bankruptcy. Most Cited Cases

Bankruptcy 51 ⚷3029.1

51 Bankruptcy
51IX Administration
51IX(A) In General
51k3029 Employment of Professional Persons or Debtor's Officers
51k3029.1 k. In General. Most Cited Cases

Inability to fulfill role of independent professional on behalf of fiduciary of estate constitutes impermissible conflict.

[10] Bankruptcy 51 ⚷3177

51 Bankruptcy
51IX Administration
51IX(E) Compensation of Officers and Others
51IX(E)3 Attorneys
51k3177 k. Conflict of Interest. Most Cited Cases

When counsel for debtor-in-possession undertakes representation of principal of debtor, counsel has abandoned counsel's fiduciary obligations as counsel for debtor, and it is proper exercise of bankruptcy court's authority to deny all fees. Bankr.Code, 11 U.S.C.A. § 328(c).

[11] Bankruptcy 51 ⚷3177

51 Bankruptcy
51IX Administration

51IX(E) Compensation of Officers and Others
51IX(E)3 Attorneys
51k3177 k. Conflict of Interest. Most Cited Cases

Bankruptcy attorney who fails in fiduciary capacity, who fails to remain free of conflicts, and who fails to refrain from serving conflicting interest during case must be denied all compensation.

[12] Bankruptcy 51 🔑3177

51 Bankruptcy
51IX Administration
51IX(E) Compensation of Officers and Others
51IX(E)3 Attorneys
51k3177 k. Conflict of Interest. Most Cited Cases

Findings that attorney for Chapter 11 debtor-in-possession (DIP) represented interests of principals of debtor to detriment of estate, and that attorney engaged in activities designed to sabotage efforts to ascertain truth concerning financial picture of debtor supported denial of fees and disgorgement of previously awarded fees, even though it was claimed that attorney's services were beneficial to estate. Bankr.Code, 11 U.S.C.A. § 330 .

[13] Bankruptcy 51 🔑3155

51 Bankruptcy
51IX Administration
51IX(E) Compensation of Officers and Others
51IX(E)2 Professional Persons in General
51k3155 k. In General. Most Cited Cases

Bankruptcy 51 🔑3170

51 Bankruptcy
51IX Administration
51IX(E) Compensation of Officers and Others
51IX(E)3 Attorneys
51k3170 k. In General. Most Cited Cases

Professionals who violate their fundamental ethical obligations to estates in their charge do not provide "valuable services" to those same estates. Bankr.Code, 11 U.S.C.A. § 330(a)(1).

***869** Robert L. Stolebarger, Greggory J. Savage, Haley & Stolebarger, Salt Lake City, UT.

Richard A. Rappaport, Vernon L. Hopkinson, Cohne Rappaport & Segal, Salt Lake City, UT, for trustee.

Clark Waddoups, Robert B. Lochhead, Kimball Parr Waddoups Brown & Gee, Salt Lake City, UT.

David K. Watkiss, David B. Watkiss, Watkiss Dunning & Watkiss, Salt Lake City, UT.

MEMORANDUM OPINION AND DECISION

JOHN H. ALLEN, Bankruptcy Judge.

The Court has before it Motions to Alter or Amend its December 2, 1992, Memorandum Opinion and Decision on the fee applications of Hansen, Jones & Leta and Snell & Wilmer. The Court has considered all the evidence and testimony, the entire record in this case and its related adversaries, has heard argument of counsel and being fully advised issues this Memorandum Opinion and Decision.

HISTORY

In its earlier decision, the Court found that counsel for the debtor, David E. Leta [FN1], represented the interests of the principals of the debtor to the detriment of the estate and engaged in activities designed to "sabotage efforts to ascertain the truth concerning the financial picture of this debtor." The activities included filing and noticing for hearing a wholly inappropriate and misleading plan and disclosure statement. *In re Bonneville Pacific Corp.*, 147 B.R. 803, 805–07 (Bankr.D.Utah 1992). As a result of these findings, the Court denied all compensation sought in the applications before it and ordered disgorgement of all previously awarded fees.

FN1. During the time periods covered by the various fee applications, counsel for the debtor in possession, David E. Leta was first, a shareholder in the law firm of Hansen, Jones & Leta and later, a shareholder in the law firm of Snell & Wilmer.

***870** Ever mindful of the far-reaching implications of its decision, the Court allowed movants the opportunity to prove that David E. Leta, attorney for the debtor, had indeed fulfilled his fiduciary responsibility to act in the best interest of this estate. The movants also requested the Court to vacate its decision and restore and award all compensation prayed for in the fee applications that were denied. The Court then spent ten days listening to the evidence presented pursuant to the motions.

NATURE OF THE DEBTOR

It would be an understatement to label this debtor, with all its underpinnings, complex. Indeed, it began so shrouded in mystery and secrecy the Court was forced on several occasions to remark on the record, "all I know about this case is that I don't know anything" and thereafter embark on a "lonely quest" for the truth. Because what occurred is so shameful, it is important to tell the story as completely as possible. Let it serve as a reminder to all who might be tempted to shirk fiduciary responsibility, beware.

INTRODUCTION

It took much time, effort and energy and this Court's sua sponte appointment of an examiner for the following information about the debtor and its business dealings to come to light. The result of all the effort reveals that the nature of the debtor was nothing more than a not-very-sophisticated variation of the classic "land flips" that brought the savings and loan industry to its knees.[FN2]

FN2. See Examiner's Report presentation in chambers, June 3, 1992, page 49, line 13 through page 56, line 15.

BACKGROUND

Although the exact public posture of the debtor was not revealed until several months after filing, for the sake of clarity, it is appropriate to begin this narrative with a brief description.

Bonneville Pacific Corporation ("Bonneville"), a publicly owned company, filed a voluntary petition under Chapter 11 of the United States Bankruptcy Code on December 5, 1991. At that time, Bonneville was the managing member of an assortment of entities which were intricately tied together by a coterie of individuals. These individuals collectively dominated what ultimately became a multifarious and perplexing operation. The coterie began in 1977 when a Utah corporation known as the Bonneville Group was formed by Raymond L. Hixson ("Hixson"), L. Wynn Johnson ("Johnson"), Robert L. Wood ("Wood"), Carl T. Peterson ("Peterson"), John T. Dunlop ("Dunlop") and Deedee Corradini ("Corradini"), (collectively, "the principals").[FN3]

FN3. To date, one of the principals of the debtor, Dunlop, has pleaded guilty to three felony counts and served a period of time in a federal penitentiary. On June 1, 1995, others of the debtor's principals, Wood, Johnson, and Hixson were indicted by a federal grand jury on 59 counts, including securities fraud, conspiracy, bank fraud and mail fraud all relating to their insider involvement with Bonneville. On July 28, 1995, Peterson pleaded guilty to two criminal counts (including a felony count related to the Dinuba transaction) and was sentenced to a period of time in federal prison and a substantial fine. Peterson must also pay the debtor's estate a criminal restitution of $500,000.

These principals then proceeded to put together the series of entities, the exact interrelationships between which are still not clear to this day.

On March 28, 1980, Hixson & Company, Inc., was incorporated in the State of Utah. On August 6, 1981, its name was changed to Bonneville Utah. Several modifications occurred in June and July 1986. First, Delaware Bonneville was incorporated in the State of Delaware; next, Bonneville Utah and Bonneville Delaware merged, Bonneville Delaware being the surviving corporation. Thereafter, Bonneville Delaware filed a Restated Certificate of Incorporation and changed its name to Bonneville Pacific Corporation ("Bonneville").

As described, Bonneville's operation was multi-faceted. Included in its operation was the buying, selling, development, and operation of small and medium sized energy projects. Between the years 1982 and 1985 Bonneville was involved in numerous hydroelectric***871** plants. Such systems were known as "cogeneration" facilities. In theory, these alternative energy facilities generated electricity and made commercial use of the heat produced as a byproduct of generating the electricity.

The supposed energy projects included Magic Valley, Steamboat, American Atlas, Dinuba, TET/ Recomp, BWETA, Pacific Hydro 11, Bonneville Nevada Corporation, Yuma Project, Island Park Project, Koyle Ranch Project, Recomp, Inc., Alpac/ Ecocure, Tamarack Project, as well as others whose identities and exact relationships were never adequately explained.

In addition to the energy project entities, others were created for more specific purposes such as Bonneville Management to operate the facilities and Bonneville Fuels and Bonneville Foods to sell products.

On September 30, 1985, the principals incorporated a new entity in the Republic of Panama, called Sallah International, Inc. ("Sallah"). Sallah was intended to be an offshore version of Bonneville Group. Other offshore entities were formed including Lio Cam and L & D [FN4].

FN4. See Examiner's Report presentation in chambers, June 3, 1992, page 43, line 18 through page 49, line 12.

These offshore entities had no employees, transacted no business and had no corporate existence apart from their use as repositories of funds utilized in transactions effected by the principals. In other words, all of these created entities were front or straw companies.[FN5]

FN5. The entities discussed in this opinion do not begin to fully complete the picture of all of Bonneville's financial interrelationships with other entities similarly created. For example, in Exhibits D and E to the disclosure statement submitted on behalf of the debtor in possession by David E. Leta, he lists numerous related subsidiaries and partnership interests. As noted from the bench, this Court doubts that the full extent of Bonneville's involvement with all these creations, including partnerships, will ever come to light.

Until 1986, Bonneville was privately held. In 1986, it initiated a public offering of its stock. The public offering was based upon the grossly exaggerated and ever-increasing paper value of the non-existent assets continually transferred between Bonneville and its related entities.[FN6]

FN6. An example of the inflated values of Bonneville's interests in these paper companies is Recomp. The insiders caused Bonneville to invest nearly $50 million in Recomp, $37 million of which was a direct cash payment in a period of just over two years. In the Fall of 1992, the trustee sold Bonneville's interest for approximately $700,000. John T. Dunlop was the President of Recomp, Inc.

It is important to note that beginning in 1984, two years before Bonneville's initial public offering, legal services were provided to Bonneville and its related entities by Mayer, Brown & Platt. The principals worked closely with this law firm. Evidence suggests these lawyers and principals met to outline universal company policy, virtually ignoring technical lines that divided the specific entities.

The relationship between Bonneville and Mayer, Brown & Platt continued through April 1992, approximately five months after Bonneville filed its petition in bankruptcy.

APPLICATIONS FOR EMPLOYMENT OF PROFESSIONALS

Concurrent with the filing of the bankruptcy petition, on December 5, 1991, Bonneville, operating as debtor in possession, filed an application to employ the law firm of Mayer, Brown & Platt as its general counsel, an application to employ Hansen, Jones & Leta as its local counsel and an application to employ Buccino & Associates, Inc. as its financial consultant.

Mayer, Brown & Platt

Accompanying the application to employ Mayer, Brown & Platt as general counsel was an affidavit of disinterestedness filed by one of its partners, Lawrence K. Snider. That affidavit stated:

> 3. To the best of my knowledge and belief, MB & P has no direct or indirect relationship to, connection with or interest in the Debtor, any creditors, or any party in interest, their respective attorneys and ***872** accounts [sic], the United States Trustee, or any person employed in the office of the United States Trustee, except as stated herein.
>
> 4. MB & P is a partnership which employs over 500 attorneys, and some attorney may have represented or may continue to represent certain of the Debtor's creditors or other parties in interest herein, or interests adverse to such creditors or parties in interest herein, in matters unrelated to this Case.
>
> 5. MB & P has, for some time prior to the filing of this case, represented the Debtor in connection with various specific matters. Such prior representation does not disqualify MB & P from representing the Debtor in this case.
>
> 6. The Debtor has several subsidiaries which have a debtor-creditor relationship with the Debtor. Such subsidiaries also have requested that MB & P represent them in connection with certain of their financial affairs as a result of the filing of the Case. MB & P believes that no actual conflict nor appearance of impropriety exists in connection with MB & P's proposed dual representation of the Debtor and its subsidiaries. MB. & P believes that at the present time differing interests are not present and that a unity of interests exists between the Debtor and its subsidiaries. In addition, the economic benefits to be gained by both the Debtor and its subsidiaries from such multiple representation, and attendant cost savings as a result of the economies of scale, would be significant and in the best interest of the Debtor and its subsidiaries. However, MB & P does not and will not represent any interest adverse to the Debtor or its estate during the pendency of this Case.

Based on the lack of disinterestedness and the conflicts of interest that were apparent on the face of the affidavit, and after notice and hearing, the Court denied the application. On December 24, 1991, Mayer, Brown & Platt appealed the order of denial. The United States District Court consolidated that appeal with several other pending appeals dealing with the same issue of law—denial of approval of employment of debtor in possession's choice of attorney on the basis of actual conflict of interest. On June 19, 1992, United States District Court Judge Dee Benson upheld the Bankruptcy Court's ruling stating:

> Bonneville is a holding company which does not

in most instances directly operate any businesses. Its businesses are operated through a complex corporate structure which delegates control and ownership of the operating facilities to more than 25 subsidiaries of Bonneville. Bonneville owns in whole or in part each of the subsidiaries, and exercises in some cases direct and in other cases indirect control over the subsidiaries.

Bonneville chose as its legal counsel Mayer, Brown & Platt ("MB & P") because of MB & P's extensive experience in bankruptcy law and Chapter 11 proceedings involving business entities. Bonneville chose Hansen Jones & Leta ("HJ & L") as its local counsel because of their expertise in the bankruptcy law and Chapter 11 Business reorganizations in the United States Bankruptcy Court for the District of Utah and its familiarity with the Local Rules of Practice in this District. Buccino & Associates ("Buccino") was chosen as Bonneville's financial consultants because of its considerable experience in dealing with and resolving business difficulties of troubled companies.

Each of the professionals have been asked by some of the subsidiaries who have a debtor/creditor relationship with Bonneville to represent them in connection with certain of their financial affairs as a result of the filing of Bonneville's bankruptcy case. Believing no conflict exists, the professionals agreed to the representation.

At the hearing regarding the professionals' applications the United States Trustee did not object to the applications. None of the creditors objected; two of the largest creditors of Bonneville—Chase Manhattan Bank and Portland General Holding, Inc.—supported approval of the applications. The United States Trustee only stated his concern that the applications may not satisfy the standards of the Bankruptcy Court's decision in *Green Street.* ***873** The Bankruptcy Court denied the applications based on the law stated in *Green Street.* Because the bankruptcy court based its decision in the *Bonneville* case on *Green Street,* this court will consider both appeals together....

While the court appreciates that the bankruptcies involved in these cases are complicated, especially the Bonneville bankruptcy, the court holds that dual representation would present significant conflicts of interest. Accordingly, the *Bonneville* and *Green Street* appeals are AFFIRMED [FN7].

FN7. Exh. K is a letter from David E. Leta to Lawrence K. Snider dated July 14, 1992. The letter discusses Judge Benson's Memorandum Decision and Order of June 22, 1992, affirming the Court's order precluding Bonneville's professionals from simultaneously representing the debtor and Bonneville's affiliates. The letter states, in part "[I] ... find it to be uniquely unsatisfying in addressing the important questions raised by the appeal ... raises more questions than it answers and in particular, creates meaningless non-legislative distinctions between 'big companies' and 'small businesses' ... is so poorly reasoned that up until the final conclusion, I thought Judge Benson was laying a framework for reversing Judge Allen.... I would like to know whether Mayer, Brown & Platt intends to appeal the Decision to the Tenth Circuit and, if not, whether it would join in such an appeal if we initiated one...."

Exh. L is a letter from Lawrence K. Snider to David E. Leta dated July 15, 1992. It states "I was very surprised by Judge Benson's decision which I found to be totally without any thought or analysis ... After a considerable discussion here, we have concluded that our energies are best served in other matters. I have written to Mark Rinehart to secure his consent for a further appeal but I have received no response. Should you decide to appeal, because of the importance of the issue, we would certainly provide some assistance to you and might consider joining with you but at this time we will defer...."

Exh. M is a letter dated July 17, 1992, from Vernon L. Hopkinson, attorney for trustee, to David E. Leta. It states: "[T]he Trustee has concluded that an appeal of Judge Benson's decision would not be appropriate and therefore we will not be joining with you or supporting an appeal of that decision...."

David E. Leta did appeal Judge Benson's decision to the Tenth Circuit in order to preserve Bonneville's rights until it could give a definitive answer as to whether it wanted to proceed. Bonneville's appeal was subsequently dismissed. The other appellants persisted and, as noted below, were unsuccessful.

[FN8] *In re Interwest Business Equipment, Inc.*, et al., Civ. No. 91–C–1062B (D.Utah, June 22, 1992).

FN8. The debtors in possession involved in the consolidated appeals were *Interwest Business Equipment, Green Street, Retail Systems,* and *Bonneville.* This Court's decision was called *Green Street,* the District Court's and later the Circuit Court's opinion in the consolidated appeals are under the title *In re Interwest.*

The other debtors in possession appealed the District Court's decision. However, by then, the trustee had been appointed in Bonneville [FN9] and that trustee chose not to expend estate assets on the matter. Without Bonneville, the issue of the Court's responsibility to deny appointment of counsel who also represented interests that conflicted with the bankruptcy estate proceeded to the Tenth Circuit. In a stinging opinion, the Tenth Circuit affirmed this Court's and the District Court's refusal to approve appointment of counsel with interests that conflict with the estate. *In re Interwest, Inc.*, 23 F.3d 311 (10th Cir.1994).

FN9. As discussed below, an independent trustee, Roger Segal, was appointed, on June 12, 1992, to take control of this Chapter 11 estate.

In these appeals from three related Chapter 11 cases we are asked to second-guess the bankruptcy court's decision to deny approval of employment of each debtor in possession's choice of attorney on the basis of actual conflict of interest. *Id.* at 313.

The reasons why counsel to a debtor in possession must meet the high standards of undivided loyalty established in § 327(a) are explained in *In re McKinney Ranch Assoc.*, 62 B.R. 249 (Bankr.C.D.Cal.1986).

It is the duty of counsel for the debtor in possession to survey the landscape in search of property of the estate, defenses to claims, preferential transfers, fraudulent conveyances and other causes of action that may yield a recovery to the estate. The jaundiced eye and scowling mien that counsel for the debtor is required to cast upon everyone in sight will likely not fall upon the party with whom he has a potential conflict.... *Id.* at 254.

Id. at 316.

On December 12, 1991, pursuant to a second application to employ Mayer, Brown & ***874** Platt as special counsel, the Court did authorize, for very limited purposes, such employment. [FN10] Pursuant to its role as special counsel, Mayer, Brown & Platt filed three interim applications, totaling $300,603.59, for fees and costs. Prior to filing, the debtor had given Mayer, Brown & Platt a total of $177,157.62, presumably as a retainer pursuant to the contemplated bankruptcy proceedings.[FN11]

FN10. On February 4, 1992, the Court authorized Mayer, Brown & Platt to act as special counsel for additional specific purposes. One was to allow it to defend the debtor and its estate against the Motion for Relief from Stay filed by American Atlas # 1, Ltd. Another was to assert appropriate causes of action on the part of the debtor against American Atlas # 1, Ltd.

FN11. In August, 1993, the trustee initiated suit against Mayer, Brown & Platt. In 1995, he also filed, in the Bankruptcy Court, a detailed objection to its fee application. Finally, he sought to have it disgorge at least $177,000 in funds that had been paid to it by the debtor on December 4, 1991, one day before filing. On May 3, 1996, the trustee filed with the Court a settlement agreement which requires Mayer, Brown & Platt to pay the trustee $30 million by June 30, 1996. Additionally, it shall pay up to an additional $3.5 million if certain conditions are met. Mayer, Brown & Platt will also release all claims to the $177,000 which is being held in the trustee's trust account. A hearing on Court approval of the settlement is set for May 24, 1996.

Hansen, Jones & Leta

Hansen, Jones & Leta was first approached by Mayer, Brown & Platt on November 18, 1991. The reason for the selection of Hansen, Jones & Leta to serve as local counsel for Bonneville was that one of its partners, David E. Leta, had been recommended by a partner of Mayer, Brown & Platt. Hansen, Jones & Leta agreed to the representation. During this period of time, Hansen, Jones & Leta had fourteen attorneys, five specifically engaged in bankruptcy practice, but the attorney responsible for the local representation was to be David E. Leta.

After the Mayer, Brown & Platt application to serve as general counsel was denied by the Court, an application was made to employ Hansen, Jones & Leta as general bankruptcy counsel for Bonneville. Based on the fact that the application indicated further involvement of Mayer, Brown & Platt as general counsel, it was denied.

A second application and order, which deleted all reference to Mayer, Brown & Platt, was subsequently signed on December 12, 1991. Thereafter, it was supposed that Hansen, Jones & Leta would be engaged with Bonneville, devoting its full fidelity to the debtor. This supposition was based on the statutory requirement that the attorney so engaged be disinterested and free of conflicts required by the fiduciary position occupied by such an attorney in a bankruptcy proceeding. 11 U.S.C. § 327(a).

From this point forward, Hansen, Jones & Leta was to function as general counsel in the stead of Mayer, Brown & Platt since the Court had found that Mayer, Brown & Platt was unfit to occupy a fiduciary relationship with the debtor. In making such a finding, the Court emphasized its firmly held and continuing belief that on the launching of a case through the deep and hazardous waters of Chapter 11, when experienced counsel is requested to represent a corporation as a debtor in possession, counsel is expected to advise shareholders and insiders that there can be only representation of the corporation itself. Shareholders and insiders must obtain separate representation. No professional is entitled to be paid through a bankruptcy court where there exists an opportunity for divided loyalty. If such manifests itself, the professional will ultimately be a volunteer, for no money will be paid from the estate in such a situation. *In re Dasom, Inc.*, 27 B.C.D. 137, 180 B.R. 430 (Bankr.W.D.Pa.1995).

COURSE OF THE CASE

For a substantial period, there was no significant activity in the case except for general housekeeping matters such as applications to sell insignificant assets, some compromises, orders limiting notice, an application to employ Deloitte & Touche [FN12] as ***875** accountants for the debtor, application for appointment of counsel for the unsecured creditors' committee, stipulations terminating stay, notices of appearances, requests for continuances and so on.

> FN12. The trustee commenced an action against Deloitte & Touche and related entities asserting damages caused by these defendants as a result of participation in or failing to disclose sham transactions. On May 2, 1996, the Court approved a settlement with Deloitte & Touche in the amount of $65 million payable on or before June 1, 1996.

Then, on January 14, 1992, a Motion for Relief From the Stay was filed by creditor American Atlas # 1, Ltd. A notice of hearing for February 20, 1992, was filed January 24, 1992. After the motion was filed but before the hearing, other housekeeping filings occurred such as motions to pay certain prepetition employee benefit plan obligations, an application to employ Parsons, Behle & Latimer as special counsel for the debtor, [FN13] an application to employ appraisers, application by the creditors' committee to employ Ernst & Young as accountants, an ex parte motion to extend time to assume or reject nonresidential real property lease, motions to pay employee expenses, motions for authority to lend money to affiliates and related entities, motions for special procedures for interim fee applications, and motions for expanded responsibilities for Mayer, Brown & Platt and Parsons, Behle & Latimer.

> FN13. The trustee brought an action alleging that Parsons, Behle & Latimer intimately participated in the ongoing fraud perpetuated by insiders of the debtor. Ultimately, a settlement between the trustee and Parsons, Behle & Latimer was approved by the Court on February 9, 1996, for $6.9 million.

American Atlas # 1 Ltd. Hearing

The American Atlas # 1, Ltd. relief from stay hearing proved to be a very important watermark. It was during this hearing that the Court finally, for the first time, heard details, albeit limited, concerning the business operations of the debtor, the activities of its principals and its relationship to its subsidiaries. During closing argument, counsel for the movant stated "We believe these people are thieves, that they have done us wrong, and that they have put a valuable asset in jeopardy." Ultimately, the Court concluded that what had been argued to have been a valuable asset of the debtor was not an asset, was a liability, was not needed for an effective reorganization and involved some very questionable transactions by principals of the debtors including evidence of prepetition mismanagement and wrongdoing. [FN14]

> FN14. In acquiring this asset, the principals paid $1,000. In a matter of days, they flipped it several times through various entities which they controlled and they ultimately pocketed $4.5 million for their efforts. This ill-gotten increase was divided among Dunlop, Johnson, Hixson and Corradini. Simply put, the American Atlas # 1, Ltd. project was structured through the commonly controlled entities, including Sallah, as a sham paper transaction.

Motion for Temporary Restraining Order and Preliminary Injunction

On February 26, 1992, hard on the heels of the American Atlas # 1, Ltd. matter, in Adversary Proceeding No. 92PA–2057, *Bonneville Pacific Corporation v. Portland General Holdings, Inc.*, the debtor filed a Motion for Temporary Restraining Order and Preliminary Injunction. The motion stated:

> Pursuant to 11 U.S.C. § 105(a) and this Court's general equity powers, Plaintiff, Bonneville Pacific Corporation ("Bonneville"), moves this Court for an order temporarily staying and

preliminarily enjoining prosecution of the action filed by Portland General Holdings, Inc. in the Third Judicial District Court of Salt Lake County, Utah entitled *Portland General Holdings, Inc. v. Deloitte & Touche, et al.*, Civil No. 920900386CV, as against the individual and "John Doe" defendants named therein, during the pendency of Bonneville's Chapter 11 case. This motion is supported by the memorandum of points and authorities filed herewith, the affidavit of Clark Mower and by plaintiff's Verified Complaint.

The individual defendants were principals of the debtor including Wood, Johnson, Dunlop and Gerald C. Monson ("Monson"). In the accompanying memorandum they were described thus:

2. On and prior to December 5, 1991, Wood was the Chief Executive Officer and President of Bonneville, a member of Bonneville's Board of Directors and Chairman of the Board of Directors. At the present time, Wood serves as a member of ***876** Bonneville's Board of Directors and as Chairman of the Board.

3. At the present time, Johnson serves Bonneville as an active member of its Board of Directors and, from time to time, assists Bonneville's management on specific projects.

4. At the present time, Dunlop serves Bonneville as a Vice President and as an active member of its Board of Directors and also serves as an officer and director of Recomp, Inc., which is a major subsidiary of Bonneville.[FN15]

FN15. Trustee's Report filed July 22, 1993, indicated that although the debtor had invested more than $27 million in Recomp, including a $500,000 postpetition loan, the trustee, utilizing unrelenting efforts in disposing of what proved to a questionable asset, was only able to realize cash of $500,000 and a Promissory Note in the amount of $189,000.

5. At the present time, Monson is employed by Bonneville as a Vice President in charge of accounting....

10. At the present time, the Individual Defendants devote substantial time, energy and attention to operating Bonneville's business, developing a plan of reorganization for Bonneville, consummating transactions in anticipation of a plan of reorganization, and operating numerous key subsidiaries and projects which will form the foundation for a plan of reorganization. The continued uninterrupted service of the Individual Defendants to Bonneville is essential to the successful completion of Bonneville's reorganization.[FN16]

FN16. The Trustee's Report filed July 22, 1993, stated that by the time the trustee was appointed, June 12, 1992, top level management had "literally headed for the hills (to their homes in the foothills surrounding the Salt Lake valley) and were no longer involved in the management or operations of the debtor or its subsidiaries." "The Trustee has found that, with few exceptions, every project in which the debtor is involved is tainted in some manner by the business practices of the Debtor's prior management."

"The Debtor's interests in many of the projects are or were of little or no value as a result of over-leveraging of the projects ... or the use of other methods by which the Debtor extracted cash from the projects in their early stages or by which the Debtor facilitated false earnings transactions."

(Internal citations omitted).

On March 2, 1992, the debtor filed an Amended Motion for Preliminary Injunction asking that the requested injunction be "through and including August 31, 1992, or entry of a final, non-appealable order confirming a plan of reorganization proposed by Bonneville Pacific Corporation ("Bonneville") in its pending Chapter 11 case, whichever occurs first, in lieu of a preliminary injunction during the pendency of Bonneville's Chapter 11 case."

The motion was heard on March 5, 1992, and was denied by order signed April 1, 1992.

On March 23, 1992, the debtor filed a Motion for Order Extending Exclusive Periods. Citing the difficulty inherent in proposing a meaningful plan of reorganization while attempting to deal with contingent, unliquidated or disputed claims, the debtor, after a hearing based on shortened notice, held March 31, 1992, obtained an Order Extending Exclusive Periods For Filing Plan and Obtaining Acceptances, through and including July 17, 1992.

On April 3, 1992, a Notice of Substitution of Counsel, effective April 1, 1992, stated the debtor's intention to substitute the firm of Snell & Wilmer as its general bankruptcy counsel in place of Hansen, Jones & Leta. David E. Leta had changed firms. The Order granting the motion was signed May 4, 1992.

Sua Sponte Appointment of Examiner

Several fee and cost applications had been noticed for April 6, 1992, including applications for Hansen, Jones & Leta, Buccino & Associates, the unsecured creditors' committee and Parsons, Behle & Latimer. The application for Mayer, Brown & Platt, originally noticed for this day, had been continued but not before several objections had been filed. After hearing arguments for and against the particular applications, the Court expressed some grave concerns.

> The Court has reviewed each of the applications in great detail and has heard with ***877** great interest the arguments in opposition to the same and in defense of the same and I have compared the evidence and argument with other evidence that this Court has heard in prior proceedings in this particular case. And in comparing the two, I am shocked at the inconsistencies of the information the Court is getting today and in the past. The Court has heard in prior hearings information from the representatives of Buccino & Associates that the matter was proceeding smoothly, the plan would be prepared by first, April 15th, and now, by May 18th. Today, counsel for Buccino describes in argument that the debtor is in chaos and has been in chaos, was at the time that Buccino took over, that it was a company adrift, that there was no one in charge, that the company was hemorrhaging and that Buccino & Associates had to train management and handle the day-to-day management and affairs of the company....
>
> While the fee application of Mayer, Brown & Platt is not being considered today for approval and has been continued, the Court has reviewed it and I discern from a review of that fee application that Mayer, Brown & Platt is advising the debtor in more areas than the appointment allows. I recognize that the initial applications of Mayer, Brown & Platt for approval as general counsel is now on appeal, but they are not now general counsel....
>
> At the American Atlas hearing on a motion for relief from the stay, this Court heard evidence of unexplained disposition of somewhere between 5 and $13 million. The debtor's own financial officer who testified on that day didn't know the details of that. These circumstances, together with the information that the Court received today, suggests that the Court knows one thing, that it doesn't know who's in control of this debtor. I'm not in the least way being critical of counsel for the debtor in this case because I wonder if general counsel for the debtor is being fully informed by the debtor and being asked to advise concerning all relevant matters.
>
> The exclusive time to file a plan of

reorganization has been enlarged at the request of the debtor. Everything seems to be on hold for some unexplained reason. There was an indication on the record last week that there would be a change of counsel or an addition to general counsel and a change of special counsel with no explanation and no information having been submitted to the Court subsequent. This information has so shocked me and so impressed me that it is obvious that the Court needs some independent information concerning this debtor and who is in control. I am, therefore, ordering an immediate appointment of an examiner pursuant to the authority of Section 105(a) to be effective immediately.

Thereafter, the Court requested answers to specific queries:

1. Who are the officers of the debtor?

2. What role Buccino & Associates played within the management of the company?

3. A determination of the assets and liabilities of the debtor.

4. Who is currently managing, advising and controlling the debtor?

5. Improprieties concerning Recomp.

6. Investigate all transfers in excess of $100,000 within the last three years.

7. An analysis of the subsidiaries of the debtor and all relationships thereto.

a. Report on transfers between the debtor and the subsidiaries.

b. Information concerning transfers between subsidiaries.

c. Information concerning management and control of the subsidiaries by the debtor.

d. The debtor's interest in various partnerships.

e. Identify transfers of debtor assets to partnerships.

8. Identify who has been counsel for the debtor and the subsidiaries in the past three years.

a. What funds have been paid to attorneys for the debtor?

b. What funds paid to counsel for subsidiaries by the debtor?

c. Has debtor's counsel been paid by the subsidiaries?

***878** 9. The annual income of the debtor's officers and directors for the past three years.

10. The source of debtor's income.

11. Identify all commitments that the debtor has to its subsidiaries and partnerships.

12. Disclose any evidence of fraud or mismanagement within the company.

13. Identify preferential transfers.

14. Identify any improper post-petition transfers.

It is a tragedy that counsel for Bonneville, David E. Leta, and the counsel for the official unsecured creditors' committee, Ralph R. Mabey, had not, by this point, begun to conduct a proper investigation with an eye to bringing the true facts before the Court. According to the evidence, they had been exposed to certain indications, such as the Buccino Report and the Portland General Complaint, that would serve to put any professional, serving in their capacity, on extra alert. David E. Leta testified that he was not in a position to know that the information in the plan and disclosure statement was misleading. However, if this Court, with no inside information, suspected enough to sua sponte appoint first an examiner and then an independent trustee, it is inconceivable these sophisticated attorneys, with all the information at their fingertips, could remain completely oblivious to reality.

The order appointing Alan V. Funk, as examiner, was signed on April 9, 1992, and specifically directed that the duties of the examiner included each area of concern identified by the Court in its ruling on April 6, 1992.

After the appointment of the examiner, but before his report, there was continued, tumultuous activity in the case including motions to assume real property leases, to pay certain employee expense obligations, to reject executory contracts, authority to enter into postpetition leases, approve stipulations, monthly financial reports, fee applications, an application to employ Ray, Quinney & Nebeker as new counsel for the debtor, motions to sell property, an application for order expanding the scope of Parsons Behle & Latimer's employment as special counsel, and, on May 18, 1992, a Disclosure Statement and Plan of Reorganization was filed by the debtor.

Joint Motion of Debtor and Official Unsecured Creditors' Committee for Order Extending Exclusive Periods

On May 14, 1992, the Court heard the Joint Motion of Debtor and Official Unsecured Creditors' Committee for Order Extending Exclusive Periods. The Joint Motion detailed the appointment of the examiner on April 6, 1992, and the examiner's report which was to be filed with the Court "on or about May 27, 1992." On April 14, 1992, the Court had entered the first order extending the exclusive periods for filing a plan of reorganization and obtaining acceptances of a plan of reorganization to May 18, 1992, and July 17, 1992. This Joint Motion asked for a time extension of 23 days each, up to and including June 10, 1992, and August 10, 1992.

The Joint Motion indicated the debtor had asked for the committee's consideration and advice on many issues "raised in a reorganization of the Debtor, including alternative plan structures and classification and treatment of various priorities of debt". It went on to say, "Notwithstanding that certain of the Debtor's past transactions are under investigation by the Examiner, the Committee understands the Examiner's preliminary investigation has found no wrongdoing on the part of current management—and specifically Mr. Clark Mower, the Debtor's President—in connection with any of the transactions which are the focus of the examiner's investigation. Affidavit of Alan V. Funk, filed herewith, at §§ 6 and 7 (hereinafter, "Funk Affidavit")." In addition to the affidavit of Alan V. Funk, examiner, there was an affidavit of Irving J. Thau, partner of Ernst & Young; the declaration of L. LeGrand Price, the chairman of the official unsecured creditors' committee; and Clark M. Mower, the president of the debtor. The pleadings and affidavits addressed two themes:

(1) What an outstanding job Clark M. Mower is doing running the debtor—he is forthcoming,***879** cooperative, very much in control, he has instituted an independent examination of business activities of RECOMP, Inc., and (2) Given the appropriate extension of time, the debtor, the official unsecured creditors' committee and the examiner, under the control and guidance of Mr. Mower, (helped by financial consultants on all sides) could put together a disclosure statement and plan of reorganization that would meet everyone's needs—no problem. According to the argument and testimony, the future for the debtor looked bleak without this extension. After hearing all the evidence and listening to the argument, the Court took a brief recess, then returned to rule:

> Notwithstanding no objections this is still a difficult decision. The evidence today is basically the same evidence that the Court received at the time of the last request for an extension of the exclusive period. The record before the Court shows there are enough professionals involved in working on the plan, or a least there should be, to have had that plan filed within the time that the Court has already authorized. My impression [was] that Buccino & Associates was developing the plan. And I hear today that Ernst & Young is

also working on the development of the plan.

I hear today, also, that Mr. Cattau was president of this company for a day, and that Buccino & Company ran the company for a month and a half.

I hear today that Mr. Mower welcomes the examiner because the examiner will find assets. If assets are to be located it would seem to me that there have been sufficient professionals on board and they are abundant that should have located assets.

The bottom line is the Court will welcome a plan from anyone who files a plan. I don't think the Debtor is entitled to an extension of the exclusive period. I don't think that there is a risk of competing plans, or if there is a competing plan filed, that isn't risk to creditors.

There is no forcing the Debtor to file a plan on Monday. A plan that is incomplete and unconfirmable. If such a plan is filed just to protect the period, and it isn't a good faith plan, I'd have concerns about that. So, I deny the motion to extend the exclusive period.

Four days later, on May 18, 1992, the debtor filed a plan and disclosure statement.

The order pursuant to the motion for extension of exclusive periods was signed May 21, 1992.

It is helpful to scan the events in chronological order.

March 2, 1992—debtor filed amended motion for preliminary injunction, insiders expertise needed for reorganization purposes.

March 5, 1992—hearing on motion for preliminary injunction—motion denied.

March 23, 1992—debtor files motion for extending exclusive periods.

April 6, 1992—Court orders appointment of examiner, sua sponte.

May 7, 1992—Supplemental Disclosure filed by LeBoeuf—had information from examiner.

May 11, 1992—Joint motion for extension of exclusive periods filed—Joint Motion supported by affidavit from examiner.

May 14, 1992—hearing on joint motion for second extension of exclusive period—motion denied.

May 18, 1992—debtor files plan and disclosure statement—very general—mostly boilerplate.

May 28, 1992—Examiner's Report filed under seal.

June 1, 1992—notice of hearing on adequacy of disclosure statement, June 17.

June 3, 1992—examiner presents report to Court—Court unseals report.

June 10, 1992—application to withdraw as counsel filed by LeBoeuf, Lamb, Leiby & MacRae.

June 10, 1992—Court signs order allowing withdrawal of counsel—effective June 17, 1992.

June 11, 1992—Court sua sponte orders appointment of trustee.

***880** June 15, 1992—Creditors' committee files very general objections to debtor's disclosure statement.

This bewildering chain of events would be inexplicable unless it is viewed in the context of the debtor's attorney, David E. Leta, working in conjunction with the attorney for the official unsecured creditors' committee, Ralph R. Mabey, to protect insiders to the detriment of the estate. The filing of the plan and disclosure statement, four days after spurious pleas for more time, was grasping at straws in a vain attempt to continue the obfuscation. The plan and disclosure statement are incomprehensible if one attempts to ascertain the true operation of the debtor, the true value of the debtor's estate or its plan and method of reorganization. The objection is a soft lob that reveals nothing about the factual deficiencies of the documents. Yet, on May 14, 1992, it was argued to the Court, during the hearing on the Joint Motion for extension of exclusive periods, that within 23 days a confirmable, consensual plan and disclosure statement could be filed by the movants.

What subsequently occurred is that by June 11, 1992, the Court had read the Examiner's Report and, had been so alarmed by its contents, was forced to sua sponte appoint a trustee. But there was more, as explained in greater detail below, [FN17] between the time of the examiner's appointment and the Examiner's Report *in camera.* The Court had been signing documents which protected the integrity of the examiner's work product. It had believed the examiner was laboring on behalf of the Court and would report, in timely fashion, directly to the Court. Instead, the examiner seems to have expended time and effort on behalf of David E. Leta, counsel for debtor, and Ralph R. Mabey, counsel for the official unsecured creditors' committee, providing them with services and expertise, i.e., affidavits, information and solutions. The Court was forced to conclude that the examiner's recommendation had been compromised as it pertained to the need for the appointment of a trustee.

FN17. See footnote 19.

Withdrawal of Counsel For Official Unsecured Creditors' Committee

On May 7, 1992, filed with the Court was a "Supplemental Disclosure of LeBoeuf, Lamb, Leiby & MacRae in accordance with Bankruptcy Code Section 1103 and Bankruptcy Rule 2014 in Connection with Application of the Official Unsecured Creditors' Committee for Authority to Retain LeBoeuf, Lamb, Leiby & MacRae as Counsel."

The Supplemental Disclosure detailed a mutual relationship between LeBoeuf, Lamb, Leiby & MacRae and the debtor. It revealed that Yan M. Ross, married to Deedee Corradini, served as "Of Counsel" to LeBoeuf, Lamb, Leiby & MacRae and held 10,953 shares of stock of the debtor. In addition, Corradini was a 25% owner of L & D Enterprise Limited, Isle of Man Corporation, [FN18] and was involved, in a minor role, with Hallas, Inc. or Sallah International, Inc. which may have had certain, unspecified transactions with the debtor. The Supplemental Disclosure also indicated that Corradini resigned from her positions with Bonneville Associates which did business with, but was separate from, Bonneville.

FN18. Harris Report dated April 10, 1992.

According to the Supplemental Disclosure, LeBoeuf, Lamb, Leiby & MacRae had been informed, by the examiner, of the connections. [FN19]

FN19. The Supplemental Disclosure, filed with the Court on May 7, 1992, stated:

> 2. Representatives of the Debtor and the Examiner recently informed LeBoeuf that it appears that the Debtor in the past has entered into business transactions with Sallah International, Inc. and with related entities which were owned in part by Hallas, Inc. The Examiner and representatives of the Debtor further informed LeBoeuf that Ms. Corradini may have had an ownership interest in Sallah International, Inc. or Hallas, Inc.
>
> 3. After receiving this information, LeBoeuf requested the Examiner's assistance in determining as promptly as possible whether and in what form supplemental disclosure was appropriate. The Examiner has cooperated by interviewing Ms. Corradini and Mr. Ross and by reviewing relevant matters. LeBoeuf believes that the following disclosure is accurate and consistent

with the Examiner's present knowledge and information.

The Court had ruled, by order signed May 5, 1992, that the debtor, creditors or other parties in interest shall not have the right to appear in person or by counsel at examinations conducted by the examiner. When the Examiner's Report was filed with the Court on May 28, 1992, all volumes were filed under seal. An order was signed on June 2, 1992, providing that all volumes as well as appendix volumes to be so filed. On June 2, 1992, the Court rejected a motion brought by the United States Trustee for an order permitting attendance at the examiner's presentation and for delivery of the Examiner's Report. "The Examiner's Report is to be to the Court only." After the examiner's presentation, *in camera* to the Court, an order was signed on June 3, 1992, unsealing all sealed volumes and making available transcripts of the oral presentation to the Court, which also took place on June 3, 1992, available to the public.

The relevant dates are thus: April 6, 1992, Court orders from the bench the immediate appointment of an examiner; April 8, 1992, notice of approval by the Court of the appointment of Alan V. Funk as the examiner; April 9, 1992, Court signs Order for the Appointment of Examiner; May 5, 1992, Court bars everyone but the examiner and his counsel from attending any examinations by the examiner; May 7, 1992, Supplemental Disclosure filed with the court outlining knowledge obtained by counsel for official unsecured committee and the debtor from the examiner; May 28, 1992, Examiner's Report filed under seal; June 2, 1992, Court refuses to allow attendance by any other entities at the oral presentation except the Court. The query is, how and why did LeBoeuf, Lamb, Leiby and MacRae and the debtor receive the information concerning Corradini and why did the examiner conduct special examinations at their behest and impart to them his findings?

In the Court's view, the breach of the duty of confidence on the part of the examiner has never been fully explained. The Court further believes this unexplained interaction between Ralph R. Mabey and the examiner compromised the examiner's opinion regarding the appointment of a trustee. Having stated, elsewhere, that management was doing a good job, the examiner could not have been expected to then do a complete turnaround shortly thereafter. However, the exhaustive array of alarmingly fraudulent facts and figures contained in the report proved to be an adequate basis for the Court's ultimate appointment of the trustee.

***881** After receiving the information, LeBoeuf, Lamb, Leiby & MacRae requested the examiner's assistance in determining in what form disclosure of the newly found facts should occur. The examiner cooperated by interviewing Corradini and Ross and reassuring counsel that the involvement was of little concern. In the past, Corradini and Ross had borrowed funds from Sallah International, Inc. and paid interest on such loans. After Corradini's election as Mayor of Salt Lake City, the loans had been transferred to a corporation owned by the couple.[FN20]

FN20. The corporation created by Corradini and Ross was Rossadini which became a vehicle for the collection of funds. From the Examiner's Report Dated May 28, 1992, page 93. "It is, however,

> clear from the Examiner's investigation that one of the purposes of transactions involving Bonneville Pacific and the off-shore companies was to provide an economic benefit to Ms. Corradini rather than simply those principals of Bonneville Group directly involved with Bonneville Pacific which would have excluded Ms. Corradini." As mentioned above, the trustee settled with Corradini and Ross early in the beginning of the massive litigation, for $860,000. This Court approved the settlement by Order signed September 16, 1993.

LeBoeuf, Lamb, Leiby & MacRae promised a wall of confidentiality would surround all materials involved with the case and Ross would have no access to such. Thereafter, the Supplemental Disclosure was noticed for hearing on June 16, 1992.

Before the hearing could take place, the examiner's oral report was given *in camera* to the Court and the transcript of that oral report, as well as the written report itself, had been unsealed and made available to all interested parties.

On June 10, 1992, filed with the Court and signed by lead counsel, Ralph R. Mabey, was the Application of LeBoeuf, Lamb, Leiby & MacRae to Withdraw as Counsel for the Official Unsecured Creditors' Committee Pursuant to Bankr.D.Ut.Rule 542(a)(1), Motion to Strike a Hearing Scheduled for June 16, 1992, on the Supplemental Disclosure of LeBoeuf, Lamb, Leiby & MacRae in Accordance with Bankruptcy Code Section 1103 and Bankruptcy Rule 2014 in Connection with Application of the Official Unsecured Creditors' Committee for Authority to Retain LeBoeuf, Lamb, Leiby & MacRae, and Motion to Continue without Date the Hearing Scheduled for June 16, 1992, on the Second Application by LeBoeuf, Lamb, Leiby & MacRae for Interim Compensation and Reimbursement of Fees and Expenses.

The Application to Withdraw states:

> ***882** 3. On May 28, 1992, the Examiner filed with the court his preliminary report which includes several statements concerning connections with Deedee Corradini, the spouse of Yan M. Ross an attorney who is of counsel at LeBoeuf, with entities that may be related to the debtor.
>
> 4. In light of the Examiner's report, LeBoeuf has decided that it cannot continue to effectively represent the committee. This decision is not based on that fact that LeBoeuf is not a "disinterested person" within the meaning of section 101(34) of the Bankruptcy Code or that it has an interest adverse to the estate. Rather, under the "appearance of impropriety" standard set forth in *In re Roberts,* 75 B.R. 402, 405 (D.Utah 1987), LeBoeuf believes it should withdraw....
>
> 8. In addition, LeBoeuf moves to continue the hearing on its Fee Application without date because it desires additional time to prepare.

On June 10, 1992, the Court signed an order granting the Application to Withdraw, effective no later than June 17, 1992, at 5:00 P.M. or the date of the committee's retention, with court approval, of substitute counsel. The Motion to Strike and the Motion to Continue were also granted. To this date, no hearings have been noticed pursuant to those motions.

The puzzling aspect of the surprise, indicated by the Motion to Withdraw and the naivete of the Supplemental Declaration, is the evidence presented to the Court during the ten-day hearing on these motions to alter or amend. *See In re Joseph A. Calabrese,* 173 B.R. 61 (Bank.D.Conn.1994).

The Order Granting Application of The Official Unsecured Creditors' Committee, To Employ LeBoeuf, Lamb, Leiby & MacRae was signed January 6, 1992, designated effective as of January 3, 1992.

During the employment period, Ralph Mabey and LeBoeuf, Lamb, Leiby & MacRae billed the estate $208,696.21 for services performed and costs incurred.

Ralph R. Mabey and others of LeBoeuf, Lamb, Leiby & MacRae were in close and intimate contact with the officers and directors of Bonneville Pacific and at times, according to the testimony, seemed to be "running the show". They vigorously participated in and supported many of the efforts to protect the insiders that had the potential to inflict real harm on the estate. These included some of the very activities which so alarmed the Court that ultimately an examiner and a trustee were appointed. These included, at the request of the debtor, signing a confidentiality agreement and requiring a confidentiality agreement from all members of the official unsecured creditors' committee—ignoring the fact that counsel's client was the official unsecured creditors' committee. It is incumbent on counsel to never forget who the client is, and it is not the debtor and/or its principals, officers or directors.

The March 5, 1992, injunction hearing clearly had the active support of the committee. The support for injunctive relief occurred even though testimony and evidence suggests that Ralph R. Mabey and LeBoeuf, Lamb, Leiby & MacRae should certainly have been put on investigative alert from the information presented on January 28, 1992, when several members of the firm attended the Buccino Report meeting. Buccino reported values of the estate as having fallen by $200 million, almost 80% loss. Later, Ralph R. Mabey was given the information generated by the efforts of Dale Harris ("the Harris Report").[FN21]

FN21. See Harris Report below.

Subsequently, Ralph R. Mabey met *in camera* with the Court, an unusual Saturday morning meeting, where he took the lead in presenting to the Court the "just discovered" defalcation of Dunlop. He was involved in the Magic Valley Settlement which paid not only $70,000 to various limited partners who were Mayer, Brown & Platt insiders but also protected them as well—at the same time allowing Mayer, Brown & Platt attorneys to be paid fees from the estate even though the services performed were to shield their own. This was affirmative and direct participation by counsel for the official unsecured creditors' committee. A member of LeBoeuf, ***883** Lamb, Leiby & MacRae participated in the American Atlas # 1, Ltd. hearing. So much evidence has emerged concerning the individuals involved in those endeavors, the Court is convinced that Ralph R. Mabey and David E. Leta walked in tandem down the ugly road of cover up and deceit, completely ignoring their statutory duties to protect creditors even at the expense of principals and insiders.

There is no question that the fees of the counsel for the official unsecured creditors' committee are not before the Court in these motions, nor were they part and parcel of the original opinion, nor is the Court in any way ruling on them today. However, the activities of Ralph R. Mabey and LeBoeuf, Lamb, Leiby & MacRae were fully documented by the evidence that was presented during this ten-day hearing. What has emerged illustrates the dangerous snowball effect of dereliction of duty.[FN22]

FN22. The official unsecured creditors' committee employed Ernst & Young as their accountants and financial advisors, approved by the Court, January 27, 1992. Partner, Irving Thau, was the liaison. From the date of its appointment through the date of its final entry on its final fee application, August 31, 1992, it billed the debtor, via four fee applications, a total of $316,987 for fees and costs. It continued to work for the official unsecured creditors' committee after the appointment, on June

12, 1992, of the trustee. In the meantime, the Court had declined to appoint new counsel for the committee (after the withdrawal of LeBoeuf, Lamb, Leiby & MacRae on June 17, 1992.) The Court refused to appoint new counsel for the committee based on its belief that after the trustee was appointed he was statutorily bound to perform the duties formerly assigned to the committee and from that point forward, the committee had no official function. It continues to amaze the Court that the massive fraud and cover-up, first outlined in the Portland General Report, alluded to in the Buccino Report and supported by the facts and figures contained in the Harris Report, completely escaped the notice of accountants and financial advisors.

Appointment of the Trustee

On June 11, 1992, during the hearing on the fee application for Buccino & Associates, continued from April 6, 1992, the Court made the following oral ruling:

Everyone knows that an examiner's report has been filed with this Court. The Court has read it. And that examiner's report, as well as what the Court has observed since the filing of this case, has left the Court with no confidence in the debtor and its ability to accurately report facts to the Court or reorganize solely with the efforts of the debtor....

Right now at least two of the officers and employees of the debtor, as pointed out in the examiner's report, Mr. Rinehart and Mr. Monson, are influenced by Mr. Wood, former president and CEO. This appears to me to have an influence on the debtor, on what the debtor does or does not do. And in my judgment, as I recited before results in counsel for the debtor getting less than complete information. Trustee could act independent of the outside influence, and, if necessary, terminate the services of those in the company who are not loyal to the present operation.

Right now, with the exception of counsel for the debtor, all counsel have apparent conflicts. Counsel for the creditors committee has the problem giving rise to—I assume giving rise to its withdrawal [sic] the matter of the Corradini matter. Mayer, Brown & Platt has had a conflict from the beginning in that as reflected in the examiner's report it took payment of substantial fees the day before filing, December 4, 1991, which is an obvious preference, and has represented subsidiaries all along and has failed to disclose those facts.

Parsons, Behle & Latimer, who's special counsel, failed to disclose and hasn't yet disclosed that it received an agreed reduced payment on its fees the day before filing, an obvious preference. Its fee application shows conferences with Mr. Wood, who the Court was of the opinion from evidence wasn't involved in any way, also with a Mr. Saperstein, who's not been approved as counsel. Neither counsel nor present management of the debtor, nor the creditors committee, can be expected to take any action to investigate and pursue, if appropriate, actions against former officers and directors who took advantage of corporate opportunities, or who took high signing and termination bonuses, or who made profits through inflated sales to the corporation. These people include Wood, Johnson, Nadauld, Hixson, Dunlop, Corradini ***884** and others.[FN23] Neither present management nor the creditors committee can be expected to investigate, and; if appropriate, pursue the attorneys who received preferential or post-petition payment, since management is responsible for those payments.

FN23. Settlements have occurred with the trustee as follows: Wood, $915,000; Johnson, $1.65 million; Nadauld, $260,000; Corradini and Ross, $860,000.

It appears that management, including present management, have taken the attitude that it is business as usual without regard to the limitations of being in Chapter 11.

[D]uring [the] May 14, 1992, hearing on the motion to extend the exclusive period, Mr. Mabey argued, Mr. Leta concurred, that a complete plan was not yet ready, that if the Court denied the motion, a plan would be filed, even though it would not be a confirmable plan and would have to be modified. His exact words were that they don't want to file a plan which is unacceptable. The Court told those present that if a complete and confirmable plan could not be filed, there should be no plan filed just to meet the deadline, that the Court may consider such a filing a bad faith plan, if that's why it was filed. That's just what happened. The plan and disclosure statement that were filed are incomplete and will have to be modified in major proportions, especially in light of the examiner's report. In light of that report, the plan is woefully inadequate.

This raises the question again in the mind of the Court whether the debtor's counsel could ever get from the debtor's principals enough information to present a confirmable plan.

The appeal by Mayer, Brown & Platt from the order denying their approval as general bankruptcy counsel is still pending. Should that order be reversed, Mayer, Brown & Platt may be general bankruptcy counsel, even though some representatives of the debtors have said no. Appointment of a trustee would resolve that problem.

As evidence of the fact that present management does not know all of the assets, liabilities and circumstances of the case, is the testimony of Mr. Mower on May 14, 1992, that the examiner's report would be helpful in uncovering claims as assets. That made it clear that neither he nor any person in present management have done any work to uncover potential claims, such as preferences or fraudulent conveyances as assets.

The same day, May 14th, Mr. Mower testified that Mr. Wood had not been involved in the company operations since January 15, 1992. That was contrary to the testimony we received today. Yet the examiner's report indicates that Mr. Wood still has an influence on Mr. Rinehart and Mr. Monson, would suggest he still gives and gets information. This is evidenced by the examiner's report which reports that Mr. Rinehart, contrary to his assurances concerning a confidential memo of all the parties, gave a copy of that confidential memo to Mr. Wood and let him carry it off.... Under the circumstances, I believe, and it's my order, that a trustee should be appointed forthwith.

On June 12, 1992, Roger Segal was appointed the Chapter 11 trustee for the debtor, thereby removing Bonneville as debtor in possession.

APPLICABLE LAW

Standard on Motion to Alter or Amend

Pursuant to Fed.R.Civ.P. 59(e), movants seek to have this Court vacate its earlier decision and award all fees sought to date. Rule 59(e) provides no standard for when a district court may grant alteration or amendment of its earlier judgment. However, courts have recognized three grounds for amending an earlier judgment: (1) to correct an intervening change of controlling law; (2) the availability of new evidence; (3) the need to correct a clear error of fact or law; or (4) to prevent manifest injustice. *Firestone v. Firestone,* 76 F.3d 1205, 1208 (D.C.Cir.1996).

The Tenth Circuit appears to follow a more restrictive interpretation of Rule 59(e). ***885** "The purpose of such a motion is to correct manifest errors of law or to present newly discovered evidence." *Committee for the First Amendment v. Campbell,* 962 F.2d 1517, 1524 (10th Cir.1992) (proffered evidence did not warrant reconsideration because it had not been discovered subsequent to the order granting summary judgment).

Debtor in Possession's Attorney as Fiduciary

[1][2] Chapter 11 is a remedy for a debtor with considerable debts who does not wish to surrender all non-exempt assets to creditors and abandon all efforts to handle debt problems. The concept of a debtor doing its best to work out problems is termed rehabilitation and has been regarded favorably by the courts and Congress. The automatic stay of 11 U.S.C. § 362 gives the debtor a breathing spell free from hostile litigation in order to reorganize utilizing such methods as selling assets, borrowing money or changing methods of operation. The Court protects debtors within limits. The design of Chapter 11, to provide the debtor with some respite in order to regroup, is intended in general to be effectuated by the automatic restraint. But it was never intended to be used as a vehicle for debtors to deplete collateral in hopeless efforts to reorganize or to buy time for those who have used the corporation as vehicle for fraudulent conduct.

The function of Chapter 11 should be to segregate out the hopeless and pointless cases from the ones with some prospect. The court cannot be too much moved by an unrealistic debtor unable or unwilling to face facts and even less so by a fraudulent one. Courts have the independent duty to see that no one makes a mockery of the bankruptcy system by misusing it. One of the most important duties is to oversee professionals involved in a bankruptcy case.

> Examination of the surrounding Bankruptcy Code section on professionals shows a consistent statutory scheme to give the bankruptcy judge discretion and power to ensure professionals are disinterested and do not represent interests adverse to the estate regardless of objection by party in interest. *See* 11 U.S.C.A. § 328(c) (bankruptcy judge has discretion to deny compensation to professionals if at any time during employment 'such professional ... represents or holds an interest adverse to the estate'); 11 U.S.C.A. § 329 (bankruptcy judge may cancel fee agreements or recoup payments made to attorneys in the year prior to the petition filing, to the extent payments exceed the reasonable value of services). Thus, §§ 327(a), 328 and 329 are alike as they give the bankruptcy judge the responsibility and power to oversee professionals involved in a bankruptcy case without any requirement that the issues be raised by party in interest.

In re Interwest, 23 F.3d at 317.

[3][4] Under Federal Rules of Bankruptcy Procedure 9011, all pleadings and motions filed for a party represented by an attorney must be signed by that attorney. An attorney who signs a pleading, motion or application certifies that he or she has read the paper and to the best of his or her knowledge, information and belief (formed after reasonable inquiry) there exists sufficient basis to support such a filing, that it is not filed for delay or any other improper purpose. Disciplinary action is to be imposed for a willful violation.

[5] Because of the unique nature of a bankruptcy estate and the concept that the debtor in possession is a fiduciary for that estate, courts have imposed a fiduciary duty upon counsel for a debtor. *In re Wilde Horse Enterprises*, 136 B.R. 830, 840 (Bankr.C.D.Cal.1991). When representing the debtor in possession, its attorney has a duty to look to the interests of the estate and not to the interests of its principals, shareholders, officers or directors. This purpose can only be realized when all who labor within the confines of the Bankruptcy Code would never countenance fraudulent behavior and greedy gain, all attempts to delay and deny, all motives dictated by hidden agenda.

[6][7][8][9] Under 11 U.S.C. § 541 of the Bankruptcy Code, each estate is a separate and distinct entity. In these Chapter 11 cases, the debtors in possession act as "trustees" of the estates in bankruptcy and accordingly***886** they may hire

professionals, with court approval, pursuant to § 327. *See* 11 U.S.C. § 1107. Thus, a debtor in possession is a statutory fiduciary of its own estate. 11 U.S.C.A. §§ 1106, 1107(a). A trustee representing an estate in bankruptcy must receive independent counsel, regardless of the estate's relationship to other entities prior to filing. *In re Amdura Corp.*, 121 B.R. 862, 868–69 (Bankr.D.Colo.1990). The inability to fulfill the role of independent professional on behalf of the fiduciary of the estate constitutes an impermissible conflict. *See In re Adam Furniture Indus., Inc.*, 158 B.R. 291, 302 (Bankr.S.D.Ga.1993); *In re Prudent Holding Corp.*, 153 B.R. 629, 631 (Bankr.E.D.N.Y.1993) (§ 327(a) is prophylactic "to insure that the undivided loyalty and exclusive allegiance required of a fiduciary to an estate in bankruptcy is not compromised"). *Interwest*, 23 F.3d at 316 n. 9. *accord; In re Sky Valley, Inc.*, 135 B.R. 925, 939 (Bankr.N.D.Ga.1992) (Because counsel for debtor in possession has fiduciary duty, counsel may be placed in the "unusual position of sometimes owing a higher duty to the estate and the bankruptcy court than to his client.").

[10] When counsel for a debtor in possession undertakes representation of a principal of the debtor, he or she has "abandoned his fiduciary obligations as counsel for the Debtor corporation" and it is a proper exercise of the bankruptcy court's authority under § 328(c) to deny all fees. *Fellheimer, Eichen & Braverman, P.C., v. Charter Technologies, Inc.*, 57 F.3d 1215, 1229 (3rd Cir.1995).

The duty of counsel to fully disclose possible conflicts and fee arrangements is thoroughly explained in the Bankruptcy Code and Rules and the many cases denying fees for the failure to comply with these duties. *See* 11 U.S.C. sect. 327 and 329; Fed.R.Bank.P. 2016 and 2014; *Interwest*, 23 F.3d 311; *In re Guard Force Management. Inc.*, 27 B.C.D. 883, 887–88, 185 B.R. 656, 662–63 (Bankr.D.Mass.,1995); *Rome v. Braunstein*, 19 F.3d 54 (1st Cir.1994); *In re Park–Helena Corp.*, 63 F.3d 877 (9th Cir.1995).

Long before the enactment of the current Bankruptcy Code and Rules, which impose upon counsel strict disclosure requirements and fiduciary obligations and impose upon the bankruptcy judges independent duties of oversight, the Supreme Court of the United States noted that the "only way to assure that professionals maintain the requisite standards of fiduciary conduct is to strictly enforce compliance with the conflict of interest rules by denial of compensation." *Woods v. City National Bank & Trust Co.*, 312 U.S. 262, 269, 61 S.Ct. 493, 497–98, 85 L.Ed. 820, *reh'g denied*, 312 U.S. 715, 61 S.Ct. 736, 85 L.Ed. 1145 (1941).

[11] It is for this reason that a bankruptcy attorney who fails in this fiduciary capacity, who fails to remain free of conflicts, who fails to refrain from serving conflicting interest during a case may, nay must, be denied all compensation.

DISCUSSION AND CONCLUSIONS

[12] Although movants contend that it erred in its findings, this Court is very satisfied that the evidence presented by all sides fully supports its conclusions.

As a preliminary matter, movants contend that this Court erred in denying all compensation because David E. Leta's services were reasonable and necessary within the meaning of 11 U.S.C.A. § 330(a)(1). Thus, movants contend that even if conflicts or improper actions were determined to have occurred, the appropriate sanction would merely be reduction in fees because the services were beneficial to the estate. In support of this position, movants cite *In re Kendavis Industries International, Inc.*, 91 B.R. 742 (Bankr.N.D.Tex.1988).

The record does not support movant's position that David E. Leta rendered a year's worth of valuable services to this estate. During the time this case was being handled by him, money was hemorrhaging out and valuable time was wasted.

No effort was made to determine the accurate financial picture of the debtor, no effort was made to ascertain the true value of all assets, no effort was made to investigate the right of the estate to recover damages from professionals and insiders who, by their actual fraud or disregard of truth and honesty, ***887** caused Bonneville to lose hundreds of millions of dollars. FN24

FN24. To date, according to documents in the Court files, the Trustee has recovered $141,637,883.78, the majority from professionals such as accountants and attorneys as well as insiders.

Further, in light of David E. Leta's testimony that he chose to undertake no investigation to determine what had actually happened to bring Bonneville to this pass, that he viewed his role as merely passing out forms or concentrating on ... "present tense, preserving the assets, avoiding loss of value, avoiding liabilities, not dwelling on historical events which were static and fixed in time and weren't going to change. We were dealing with events that were very dynamic and very fluid and were changing all the time ...", it would be impossible for any court to conclude that the services were valuable. How can a responsible debtor's attorney ignore the past in finding the true value of assets, in discovering if the estate has claims against insiders or claims for preferential transfers? How can a responsible debtor's attorney even begin to put together a plan and disclosure statement that meets statutory requirements when there is blanket refusal to perform any investigation? The explanation, of the worthlessness of "historical events," was used to justify David E. Leta's lack of inquiry regarding the downsized worth shown in the Buccino Report, pursue any query to ascertain the truth of the allegations contained in the Portland General Complaint, even read or ask questions concerning the Harris Report.

The Harris Report FN25 is a series of charts showing various transactions with Bonneville and its insider-owned entities. The insiders are Hixson, Johnson, Wood, Peterson and Dunlop. There are Sallah International Cash Accounts in the name of Dunlop, Corradini, Hixson, Johnson, Wood. On the day it was completed it was initially presented to the examiner and Ralph R. Mabey. A meeting to which David E. Leta was not invited. He was given the report on May 8, 1992.

FN25. The Harris Report is Exhibit 23 and is dated April 10, 1992.

The Harris Report joined comfortably with the Buccino Report and the Portland General Complaint in laying out an insidious pattern of serious, fraudulent conduct on the part of insiders of the debtor. Testimony is given which proves all three were almost completely ignored by David E. Leta. He continued to be unconcerned about "historical events". For example, towards the end of January 1992, the subject of amending the schedules in light of the Buccino Report had not been discussed with anyone. It never occurred to him to amend the schedules to reflect the Buccino values. David E. Leta testified that the Report was not an appraisal, it was an education tool and a planning tool and didn't compel an amendment to the schedules.

No one is more aware than this Court that being counsel for a debtor in possession and trying to shepherd a Chapter 11 case through the bankruptcy system is a tough, demanding, time-consuming job. As a result, this Court is generous in its views of hourly rates and supportive of those who labor accordingly. *In re Jensen-Farley Pictures, Inc.*, 47 B.R. 557 (Bankr.D.Utah 1985). However, when counsel is charging $173 an hour, a debtor in possession is entitled to more than just "handing out forms."

This Court has always followed the spirit as well as the letter of the Bankruptcy Code and Rules and has always required professionals, employed on behalf of the estates in their charge, to conform to the highest ethical standards. *In re Green Street,* 132 B.R. 460 (Bankr.D.Utah, 1991). These are standards imposed not only by the Code and Rules, but are also a minimum requirement for the privilege to practice law in the State of Utah. *See* Professional Rules of Responsibility.

[13] It would make a mockery of the Code and Rules, the Professional Code of Responsibility and would fatally undermine the public's already shaky confidence in the Chapter 11 process to adopt a position that lawyers abandoning their fiduciary duty to the estate may nonetheless recover huge hourly fees. This Court draws a bright line—professionals who violate their fundamental ethical obligations to the estates in their charge do not provide "valuable services"***888** to those same estates. To give just one small example, if the plan, proposed by David E. Leta had proceeded to confirmation there is every likelihood that the misdeeds of the insiders would have been covered over forever and the millions, which have since been recovered by the trustee, would have been gone with the wind.

Movants contend that this Court's findings were erroneous and do not support the denial of fees and the disgorgement of previously awarded fees. Somewhat inaccurately, they characterize the prior findings as follows:

1. The plan and disclosure statement were "wholly inappropriate" and contained information inconsistent with the Examiner's Report and with the Statement of Affairs and the Monthly Financial Reports.

2. Debtor's counsel engaged in unnecessary litigation and in "tactics that lead to excesses [and] delay of the case."

3. Debtor's counsel represented the interests of Bonneville's principals to the detriment of the estate.

More accurately, this Court's actual findings were that:

A. David E. Leta, while counsel for the debtor in possession, represented the interests of the principals of the debtor to the detriment of the estate.

B. David E. Leta engaged in activities designed to "sabotage efforts to ascertain the truth concerning the financial picture of this debtor." The activities included (1) filing and (2) noticing for hearing a plan and disclosure statement that were (3) wholly inappropriate and (4) misleading.

The Court addresses its prior findings as follows:

Representation of the Interests of the Principals to the Detriment of the Estate and Engaging in Activities Designed to Sabotage Efforts to Ascertain the Debtor's True Financial Picture

1. Failure to outline, in the disclosure statement, the potential liability to the estate of the insiders of Bonneville for fraudulent transfers, self-dealing, embezzlement and stock fraud. With the settlements produced by the trustee to date, the value to the estate of such actions against the Bonneville insiders totals more than $6,000,000.00.

2. The filing of a plan of reorganization that provided that claims be brought only by the reorganized debtor under the control of an advisory committee controlled by creditor designees. However, a condition precedent to the effectiveness of the plan was the entry of a final order equitably subordinating all claims of Portland General. In essence, this plan would have preserved the Bonneville insiders' control over litigation until the Portland General litigation is finally resolved—potentially, years later. At present, the Portland General litigation has not been resolved, and, during this time period, the trustee has recovered more than $1.5 million from the very individuals who would have controlled the litigation under the terms of the proposed plan.

3. Attempting to utilize the protection of the bankruptcy court for the personal benefit of

Bonneville insiders by seeking a § 105 injunction to enjoin legal actions against such insiders who had little or no involvement with the debtor at the time of the hearing.

4. Filing an amended schedule of assets on April 10, 1992, indicating that the value of Bonneville assets totals $256,887,291.41. The amended schedules overstate the value of Bonneville assets by more than $200 million when compared to the valuation of Bonneville assets reported by Buccino & Associates on January 28, 1992.

5. Drafting and arguing a motion for authority to compromise disputed claims of Magic Valley Limited Partners. Here, David E. Leta failed to disclose two important facts to the court: (1) Some partners of Mayer, Brown & Platt were limited partners of the Magic Valley Partnership. David E. Leta knew prior to the hearing of February 27, 1992, that some Mayer, Brown & Platt partners were financially involved with Magic Valley and that some held limited partnership interests in the project; (2) David E. Leta agreed to and did prepare an opinion letter for the Mayer, Brown & Platt partners who held limited partnership interests in the Magic Valley project. For this work, David ***889** E. Leta was paid by his client Mayer, Brown & Platt.

CONCLUSION

Movants have failed to meet their burden of showing that this Court's previous findings were incorrect. Instead, the record fully supports the findings. In the prior decision, this Court attempted to avoid specifics that would embarrass David E. Leta anymore than necessary to explain its findings and conclusions. It is indeed a sad day, for any court, when its duties imposed by the Bankruptcy Code and Rules require that it find dereliction of fiduciary duty that mandate denial of fees and disgorgement of previously allowed fees. Notwithstanding the unpleasantness of its duty, this Court cannot, and will not, shirk its own obligations to supervise the professionals entrusted with bankruptcy estates.

Accordingly, Hansen, Jones & Leta and Snell & Wilmer's Motion to Alter or Amend the December 2, 1992, Memorandum Opinion and Decision is DENIED.

Bkrtcy.D.Utah,1996.
In re Bonneville Pacific Corp.
196 B.R. 868, 29 Bankr.Ct.Dec. 99, Bankr. L. Rep. P 77,066

END OF DOCUMENT

SC EXHIBIT 7

(CONFIDENTIAL)

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Or

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SC EXHIBIT 8

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

Or

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SC EXHIBIT 9

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Or

In the Confidential File Materials at PSC

Exhibit - 7

MISO

Michael L. Kessler
Assistant General Counsel
Direct Dial: 317-249-5290
E-mail: mkessler@misoenergy.org

September 3, 2013

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20246

Re: Filing of Midcontinent Independent System Operator, Inc. Regarding LRZ CONE Calculation; FERC Docket No. ER13-____-000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, Part 35 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, 18 C.F.R. § 35, et. seq., and in compliance with Section 69A.8 of the Midcontinent Independent System Operator, Inc.'s ("MISO") Open Access Transmission, Energy and Operating Reserves Markets Tariff ("Tariff"), MISO respectfully files the annual calculation of the Cost of New Entry value ("CONE")[1] for each Local Resource Zone ("LRZ") in the MISO Region.

I. BACKGROUND

On April 21, 2010, the Commission issued an "Order on Compliance Filing" directing MISO to file a permanent solution to ensure the deliverability of Load Modifying Resources in MISO's voluntary capacity auction.[2] On June 8, 2010, the Commission issued a Market Mechanisms Order which required, in part, that MISO and its stakeholders develop a plan that details the steps that will be taken to incorporate locational capacity market mechanisms into the Resource Adequacy Plan and to submit its plan and a discussion of stakeholder perspectives to the Commission.[3]

On July 20, 2011, MISO filed proposed revisions to its resource adequacy construct with the Commission by proposing a permanent solution to ensure the deliverability of Load Modifying Resources in MISO's voluntary capacity auction and to incorporate locational capacity market mechanisms, as contained in proposed new Module E-1 to the Tariff. The Commission conditionally accepted in part, and rejected in part, MISO's July 20, 2011 filing and required MISO to submit a compliance filing on various issues. MISO submitted a proposed

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1 Capitalized terms not otherwise defined herein have the meanings ascribed thereto in Section 1 of the Tariff.

2 *Midwest Indep. Transmission Sys. Operator, Inc.*, 131 FERC ¶ 61,057 at P 19 (2010).

3 *Midwest Indep. Transmission Sys. Operator, Inc.*, 131 FERC ¶ 61,228 at P 24 (2010).

SC EXHIBIT 10

compliance filing on July 11, 2012 in Docket No. ER11-4081-002, which is currently pending before the Commission.

On August 16, 2013, MISO submitted proposed CONE values for the MISO Southern Region[4] to enable New LSEs to participate in a Transitional Planning Resource Auction, in accordance with Section 69A.11.9 of the Tariff. That filing is currently pending with the Commission in Docket No. ER13-2187-000.[5]

II. CONE for Each Local Resource Zone

MISO has calculated and is filing CONE values on an LRZ basis. Section 69A.8.a of Module E-1 of the Tariff requires, in part, that MISO and the IMM determine the CONE value for each LRZ, as follows:

> [C]onsider factors, including, but not limited to: (1) physical factors (such as, the type of Generation Resource that could reasonably be constructed to provide Planning Resources, costs associated with locating the Generation Resource within the Transmission Provider Region, the estimated costs of fuel for the Generation Resource); (2) financial factors (such as, the hypothetical debt/equity ratio for the Generation Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and maintenance expenses). In calculating the CONE, the Transmission Provider and the IMM shall not consider the anticipated net revenue from the sale of capacity, Energy or Ancillary Services. CONE values will be calculated for each LRZ. The Transmission Provider shall arrange for CONE values to be calculated annually in concert with the IMM no later than September 1 beginning on September 1, 2012 and filed with the Commission.

In addition, Section 69A.10 of the Tariff provides that MISO "will impose a Capacity Deficiency Charge on an [Load Serving Entity] that has not demonstrated, at the close of the Planning Resource Auction, to the Transmission Provider, through the MECT, that it has arranged sufficient zonal capacity resources to meets it PRMR. The annual Capacity Deficiency Charge will be calculated as follows: The CONE value for the LRZ where the LSE has not arranged through the MECT sufficient ZRCs will be multiplied by 2.748 times the number of Zonal Resource Credits that the LSE is deficient."

Thus, MISO is required to calculate and submit for Commission approval a CONE value for each of the LRZs in the MISO Region.

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4 On July 22, 2013, MISO submitted with the Commission a filing to establish two new LRZs in the MISO Southern Region, to be designated as LRZ 8 and LRZ 9. That filing is currently pending with the Commission in Docket No. ER13-1999-000.

5 MISO notes that the calculations in the MISO South region CONE filing were based upon 2010 dollars, rather than 2014 dollars. The instant filing is based upon 2014 dollars.

III. CONE CALCULATION PROCESS

A. Approach Followed by MISO

MISO analyzed the appropriate CONE value in each LRZ[6] based upon the costs associated with an advanced combustion turbine ("CT").[7] MISO used the following approach: First, MISO began with an estimate of a CONE value not specific to local zone. Next, MISO used "the law of one price" where applicable (*e.g.*, turbines that are sold competitively). Next, MISO developed zonal differences to reflect different locational costs (*e.g.*, labor, technical enhancements and others) using a recent United States Energy Information Administration ("EIA") document. Finally, MISO used the Net Present Value ("NPV") algorithm to calculate locational CONE values for each of the LRZs.

MISO estimates its most recent CONE value for the entire MISO Region to be $90,750/MW. This number was developed in concert with the IMM and serves as the basis for developing regional values.

Next, based upon the economic principle known as the "law of one price,"[8] MISO allowed factors such as the weighted average cost of capital, escalation rates (and others factors where global competition drives prices to have no locational differences) to be constant.

In order to determine the appropriate CONE value for each of the LRZs, MISO relied upon the most recent EIA report on Updated Capital Cost Estimates for Utility Scale Electricity Generation Plant ("EIA Report").[9] The EIA Report contains detailed specifications for a

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6 On July 22, 2013, MISO made a compliance filing in Docket No. ER13-1999-000 which included, among other things, Attachment VV, which is a map of the nine (9) LRZ boundaries and a description of the states that are in each of the LRZs. MISO is basing the subject LRZ CONE values on the LRZ boundaries described in the July 22, 2013 compliance filing, which is pending Commission approval.

7 Combustion turbines have been used as the basis for determining the cost of new entry in other RTOs and ISOs. *See PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275 at P 39 (2009); *New York Indep. Sys. Operator Inc.*, 123 FERC ¶ 61,206, P 24 (2008). The subject LRZ CONE values were based upon data for advanced CTs because such facilities are more likely to actually be constructed in the MISO Region, due to the more economic capital requirements and fuel costs of advanced CTs, which are more efficient and have a lower heat rate than conventional CTs.

8 The law of one price states, in essence, that in an efficient market, all identical goods must have only one price.

9 *See* Energy Information Administration, *Updated Capital Cost Estimates for Utility Scale Electricity Generation Plants* (April 2013) (*available at:* http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf).

hypothetical advanced CT,[10] including information regarding the differences in project costs for an advanced CT with a nominal capacity of 210 MW, based upon the state where the facility is constructed.[11]

MISO used a NPV analysis to determine an appropriate CONE value for hypothetical advanced CTs located in each of the LRZs. In accordance with Section 69A.8.a of the Tariff, MISO considered many factors in its calculation of the CONE value, including the following: (1) physical factors (such as, the type of Generation Resource that could reasonably be constructed to provide Planning Resources, costs associated with locating the Generation Resource within the Transmission Provider Region, the estimated costs of fuel for the Generation Resource); (2) financial factors (such as, the hypothetical debt/equity ratio for the Generation Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and maintenance expenses). MISO did not consider the anticipated net revenue from the sale of capacity, Energy or Ancillary Services.

The results shown on enclosed Attachment B were derived by MISO and comport with calculations made by the IMM. Attachment B was based, in part, upon data supplied by the EIA in year 2012 dollars, which were adjusted using the implicit price deflator from the Bureau of Economic analysis in order to convert EIA cost data from 2012 dollars into 2014 dollars.[12] In order to produce the annualized CONE value for each of the LRZs from these cost numbers, MISO assumed: a 50/50 debt to equity ratio; a 20-year project life and loan term; a 5.32 percent debt interest rate;[13] a 2.5 percent Operation and Maintenance escalation factor; a 2.2 percent GDP deflator; a 43 percent combined effective federal and state tax rate; property tax and insurance costs of 1.5 percent of the capital costs; a calculated weighted average cost of capital of 7.52 percent; and a 12 percent after tax internal rate of return on equity. None of these factors vary by LRZ to any significant degree that is discernible in available data. MISO will continue to examine these factors in the future in order to determine if any LRZ-specific modifications are indicated. These factors and assumptions are comparable to those used by other RTOs in the development of CONE estimates.

The most recent estimate of CONE for each LRZ in the MISO Region are consistent with the CONE calculation provided by the IMM in the 2012 State of the Market Report for the entire

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[10] *See* EIA Report at 9-1 through 9-3.

[11] *See* EIA Report Table 9-2. (The Total Location Project Costs for the states that comprise the nine (9) LRZs are shown in enclosed Attachment A, as well as the average Project Costs for each of the LRZs).

[12] The IMM's calculation was performed using the implicit price deflators from 2012 and 2013.

[13] This figure was developed based upon current information regarding interest rates on 20-year bonds.

MISO Region.[14] In that Report, the IMM presented information regarding the annual costs associated with two types of Generation Resources: gas combined-cycle Generation Resources and gas combustion turbine Generation Resources. The IMM concluded, for example, that the Estimated Annual Cost of a new combustion turbine Generation Resource in the MISO Region was approximately $90,750/MW.[15]

MISO believes that establishing the LRZ CONE values shown in enclosed Attachment B for the 2014/2015 Planning Year are just and reasonable, for use in the annual resource adequacy construct. The calculations are based on the same principles as those previously used to determine CONE values for the entire MISO footprint, but have been modified to include specifically estimated costs that vary by location. Other costs included in the determination of CONE are not believed to vary by location at this time.

B. Result

MISO, in concert with the IMM, proposes that the LRZ CONE values for the next Planning Year (June 1, 2014 through May 31, 2015) should be set at the values shown on Attachment B.

IV. EFFECTIVE DATE

MISO respectfully requests an effective date of December 4, 2013 for the subject LRZ CONE values. It is important for MISO's LSEs to know the CONE value for each of the LRZs well in advance of the April 2014 Planning Resource Auction that will be conducted in May of 2014. MISO requests waiver of any applicable provisions of the Commission's rules and regulations to effectuate such a date.

V. NOTICE AND SERVICE

MISO has served a copy of this filing electronically, including attachments, upon all Tariff Customers under the EMT, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, the MISO Advisory Committee participants, as well as, state commissions within the Region. In addition, the filing has been posted electronically on MISO's website at www.misoenergy.org, which is accessible from the homepage through the "Library" tab under the "FERC Filings" link, for other interested parties in this matter.[16]

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14 *See* David B. Patton, Ph.D., IMM for MISO, 2012 State of the Market Report (June 2013) (*available at*: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/Markets%20Committee/2013/20130724/20130724%20Markets%20Committee%20of%20the%20BOD%20Item%2005%202012%20SOM%20Report.pdf).

15 *Id.*

16 *See* MISO FERC Filings *available at*: https://www.misoenergy.org/Library/FERCFilingsOrders/Pages/FERCFilings.aspx

VI. CONCLUSION

For the foregoing reasons, MISO respectfully requests that the Commission find that MISO has complied with the requirements in Section 69A.8 of the Tariff and approve the LRZ CONE values as described on Attachment B for each of the LRZs in the MISO Region, for the Planning Year that will commence on June 1, 2014.

Respectfully submitted,

/s/ Michael L. Kessler
Michael L. Kessler
Assistant General Counsel
Midwest Independent Transmission
System Operator, Inc.
720 City Center Drive
Carmel, Indiana 46032
Telephone: (317) 249-5400
Fax: (317) 249-5912
mkessler@misoenergy.org

Richard A. Drom
Christian D. McMurray
Andrews Kurth LLP
1350 I Street, N.W.
Suite 1100
Washington, D.C. 20005
Telephone: (202) 662-2701
Fax: (202) 662-2739
rdrom@adrewskurth.com
cmcmurray@andrewskurth.com

Attorneys for MISO

September 3, 2013

ATTACHMENT A

Total Location Project Cost (2014 $/kW) Values for Local Resource Zones Reflecting the Energy Information Administration's *Updated Capital Cost Estimates for Electricity Generation Plants*

Local Resource Zone 1 -	Minnesota	$ 740	
	North Dakota	$ 690	
Average		$ 715.00	
Local Resource Zone 2 -	Wisconsin	$ 723	
Local Resource Zone 3 -	Iowa	$ 712	(Davenport)
	Iowa	$ 697	(Waterloo)
Average		$ 704.50	
Local Resource Zone 4[17] -	Indiana	$ 717	
	Iowa	$ 705	
	Missouri	$ 735	
Average		$ 718.83	
Local Resource Zone 5 -	Missouri	$ 735	(St. Louis)
Local Resource Zone 6 -	Indiana	$ 717	
Local Resource Zone 7 -	Michigan	$ 735	(Detroit)
	Michigan	$ 706	(Grand Rapids)
Average		$ 720.50	
Local Resource Zone 8 -	Arkansas	$ 681	
Local Resource Zone 9 -	Mississippi	$ 675	
	Louisiana	$ 724	
	Texas	$ 661	
Average		$ 686.67	

[17] The EIA Report only included data for Chicago, Illinois, which is not located within LRZ 4 (it is in the PJM Interconnection, L.L.C. region). Accordingly, MISO used EIA Report data from the 3 states bordering the non-Chicago area of Illinois to calculate the Total Location Project Cost for LRZ 4, which is located in Illinois.

ATTACHMENT B

CONE VALUES ($/MW/yr.) FOR LOCAL RESOURCE ZONES

Local Resource Zone 1	$ 89,500
Local Resource Zone 2	$ 90,320
Local Resource Zone 3	$ 88,450
Local Resource Zone 4	$ 89,890
Local Resource Zone 5	$ 91,610
Local Resource Zone 6	$ 89,670
Local Resource Zone 7	$ 90,100
Local Resource Zone 8	$ 85,990
Local Resource Zone 9	$ 86,530

Certificate of Service

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 3rd day of September, 2013.

/s/ Michael L. Kessler
Michael L. Kessler

SC EXHIBIT 11

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In the Confidential File Materials at PSC

SC EXHIBIT 12

(CONFIDENTIAL)

Maintained on the Confidential Materials DVD

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In the Confidential File Materials at PSC

Exhibit -

Big Rivers Electric Corporation Comments on the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

78 Federal Register 34432 dated June 7, 2013

Respectfully Submitted to the United States Environmental Protection Agency

USEPA Docket Number: EPA-HQ-OW-2009-0819
USEPA Docket Number: EPA-HQ-RCRA-2013-0209

September 20, 2013

SC EXHIBIT 13

Big Rivers Electric Corporation (BREC) submits these comments in response to the United States Environmental Protection Agency's (USEPA) proposed revisions to its Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (ELGs). These guidelines are located within 78 Federal Register 34432 (June 7, 2013).

BREC is a not-for-profit energy company which is located in Western Kentucky. Our regulated power generation assets currently have a total generating capacity of 1,444 megawatts and serve nearly 115,000 residential customers via our three member cooperatives. BREC fully supports responsible environmental regulation aimed at protecting human health, the public, and the environment in a cost-effective manner. Further, BREC supports the economic well-being of the communities that we serve.

BREC urges USEPA to take all appropriate steps to ensure that new and modified rules applicable to the power generation industry – specifically including the ELGs – are set within a sound level of accepted science and with an understanding of the significant challenges facing the power generation industry within the United States. The power generation industry has been made subject to an unprecedented number of new and modified environmental rules under the Clean Air Act, Clean Water Act, and various waste programs. These new and modified environmental regulations present unique challenges to our industry and ultimately to the customers that pay their electric bill each month – challenges that we do not believe have been considered within the establishment of this proposed rule. The overall cost and operational implications that have been set forth are difficult to meet from both a technical feasibility standpoint as well as an economic standpoint.

The currently proposed ELGs have a significant potential to impose additional unnecessary costs and operational restrictions with little or no corresponding benefit to human health and the environment to an industry that has faced varying significant additional environmental regulations over the past 5 years. BREC sincerely appreciates the opportunity to provide the following specific comments on the proposed rule.

1. **Clarification should be made to options for continued operation of surface impoundments containing wastewater**

   The proposed ELGs include provisions prohibiting the discharge of ash transport waters but do not clearly spell out requirements applicable to existing surface impoundments containing wastewaters generated from existing operating facilities. EPA should understand that operational infeasibility exists to dry out existing impoundments. BREC wishes for EPA to consider alternative mechanisms to allow for the conversion of existing impoundments or for the authorization for discharge from said existing surface impoundments until legacy wastewaters have been fully eliminated.

2. **ELGs should avoid duplicative regulatory involvement with the Coal Combustion Residuals (CCR) rule.**

   In the ultimate adoption of final ELGs, we request that EPA avoid duplicative requirements across both the water and waste realms contained within these two directives.

3. **Proposed Selenium and Mercury discharge standards are impractical.**

   The standards proposed by the ELGs provide near impracticality with regards to various constituents that are found in the water discharges from a steam electrical generation facility. Selenium standards to be set at a limit of 5 parts per billion (ppb or microgram per liter) are at the edge of existing technology for the detection of such a parameter. Additionally, the standard of mercury to a limit of 242 nanograms per litter – a standard which is two times less than the allowable maximum contamination limit (MCL) established by the Clean Drinking Water Act – is simply unnecessary, impractical and offers little benefit to human health and the environment. With an established MCL of 2 ppb and the notion that no one will be directly consuming effluent from a steam-fired plant, a limitation of 242 ng/l is simply nonsensical and provides little in the way of protecting the environment. Additionally, a 'one size fits all' approach is nearly impossible from the standpoint of grounded and accepted science in that the effluent that would need to meet the aforementioned goals will be ever changing depending on fuel quality and/or operational aspects of the facility. BREC feels strongly that these particular aspects lack just reason for implementation to such a nearly unachievable level of removal of these particular constituents.

In addition to the above comments, BREC supports the comments submitted by the Utility Water Act Group and the Edison Electric Institute. We urge EPA to conduct additional evaluation of the proposed rules and to collect additional data that is more reflective of the steam electric power generation industry in order to develop final ELGs. We believe that the proposed ELGs lack sound science and present operational impracticalities that many not be met by many utilities and thus cause a significant increase in the expenditures incurred by an utility – and thus resulting in additional and unnecessary costs being passed on to the end users.

BREC appreciates the opportunity to comment on the proposed ELGs and looks forward to continued participation in the rulemaking process.

Exhibit -

BIG RIVERS ELECTRIC CORPORATION

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

Response to Ben Taylor and Sierra Club's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 20) ***Refer to BREC's response to SC 1-37(d). State whether BREC is taking any steps to evaluate or estimate costs for potential compliance with Clean Water Act Effluent Limitation Guidelines.***

a. If so, explain such steps and identify by when BREC expects to have a cost estimate.

b. If not, explain why not.

Response)

a. Big Rivers has engaged Burns and McDonnell to review the proposed Clean Water Act Effluent Limitation Guidelines to determine compliance options and estimated costs. Big Rivers anticipates this study will be complete around November 1, 2013.

b. See Big Rivers' response to subpart a.

Witness) Robert W. Berry

SC EXHIBIT 14

BIG RIVERS ELECTRIC CORPORATION

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

Response to Ben Taylor and Sierra Club's Second Request for Information dated September 16, 2013

September 30, 2013

Item 21) ***Refer to BREC's response to KIUC 1-48.***

a. Explain why BREC is running a modeling sensitivity evaluating a fuel switch from coal to natural gas at the R.D. Green plant.

b. Produce all modeling files, including all inputs and outputs, in machine-readable format with formulas intact, and any other documents or analyses regarding a potential fuel switch from coal to natural gas at the R.D. Green plant. If such modeling is not yet complete, produce it when it becomes complete.

Response)

a. This production cost model sensitivity run evaluating the fuel switch from coal to natural gas at the R.D. Green Station is being performed to determine whether it is cost effective.

b. The production cost model sensitivity run has not been completed; however it will be provided when it has been completed.

Witness) Robert W. Berry

SC EXHIBIT 15

SC EXHIBIT 16

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Exhibit -

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

December 11, 2013

Lance Hedquist
City Administrator - South Sioux City
1615 1st Avenue
South Sioux City, NE 68776

Dear Lance,

Thanks so much for allowing Big Rivers to again come and visit with your City Council. We certainly appreciate all of the effort you have put in to investigating the best energy solution for your city.
I wanted to clarify a few items from our meeting on Monday, and remind you of the benefits of our proposal for your city and citizens.

I understand NPPD has been the only provider you've known, but times are different now: Federal energy laws require open access of all high voltage power lines so that competition can exist. You are leading the way in Nebraska, and are proving that bidding for power supply is possible....that it is possible for good business deals where a supplier like Big Rivers and a purchaser like South Sioux City can strike a deal to meet their unique needs. This is the purpose of our national energy policy, and of the orders issued by the Federal Energy Regulatory Commission and the creation of the Southwest Power Pool. These entities were formed to ensure reliable delivery of power to cities like South Sioux City regardless of where the power was generated.

Even your own power contract with NPPD envisioned that this kind of competition was going to be a reality when NPPD offered in 2001 to let South Sioux City reduce its supply from NPPD and get partial supply from other competitive providers, like Big Rivers. South Sioux is both proving that the purposes of the Federal Energy Regulatory Commission and the Southwest Power Pool can be realized, while acting completely within the mutually agreed to rights of your existing NPPD power contract.

I also wanted to clarify for you. Mr. Pope made a few comments about reliability. I want to ensure you understand that regardless of who you purchase your capacity and energy from, NPPD has the OBLIGATION to supply you with reliable transmission service. Transmission service is not something they choose to provide you with, they are OBLIGATED by the Federal Energy Regulatory Commission to provide you with access to reliable transmission. Your transmission service from NPPD will in no way be different whether we supply your capacity and energy or whether they do. Also, his comments about their investments in transmission will continue to benefit South Sioux, and you will continue contributing to the cost of maintaining those assets through your transmission payments in the future. Again, your transmission will be the same regardless of whether Big Rivers supplies your power or NPPD---same transmission, same reliability, and same cost.

SC EXHIBIT 17

When I first met you in July we began a process of being evaluated as a company by Todd Hegwer. In the following months we began negotiations, listening to your demands and developing ways to meet your community's needs. The deal before you is not a 'cookie cutter –one size fits all' contract. We've provided you with a plethora of OPTIONS that are written in black and white. We haven't said that we'd consider options....we're offering them to you in the contract we reviewed last week.

I think it is obvious that our price is unbeatable by NPPD. We are saying that we will provide SSC with capacity and energy for a guaranteed 13% less than NPPD starting in 2017 through at least 2026 and possibly beyond. Just to clarify, your savings will not be based on any projection, your savings will be based on NPPD's actual tariff prices as the time. We are going to charge you 90% of the GFPS Blend rate in effect at the time. I think Todd has informed you that he estimates the savings to be roughly $16 million dollars (assuming NPPD's new lower rate projections....it would be even more if their rates grow higher than their projections). That is money you can keep in the pockets of South Sioux City citizens either by lowering electric bills or offsetting taxes for another project. I've seen your city motto in a number of places throughout City Hall, and I think it's a great motto—*Where quality of life is a cardinal rule*. I think this cost savings will help you and your City Council deliver on that motto.

While this started out as a bid process, it also involves other terms. NPPD has shared that they expect South Sioux to sign an exclusive contract for 20 years or longer. While Big Rivers would like to have your business for 20 years we are permitting you to reevaluate us at 10 years. If both of us still like this deal we can keep it in place. If not, you can do another RFP and compare suppliers again. And since the contract has a known end date, you can begin evaluating new suppliers at any time between now and 2026. Big Rivers is even offering you an option to transition to a rate equivalent to 110% of our cost-based Member rates if NPPD's rate grows too much and it is more favorable for your citizens to be on our rate.

Also, Mr. Pope pointed out the carbon option on our proposal. We view that as a tremendous positive for your organization. What we are providing you is an opportunity to have the flexibility to choose the best option for your city in a "carbon" world. We certainly believe we will be able to find creative solutions for minimizing carbon costs; however, if your city feels you can find a better deal elsewhere, You have an OPTION.

Big Rivers also proposes investing in SSC as a place to grow local businesses starting in 2014. We have offered you access to our Economic Development rate to attract business to locate and grow in SSC. This is in addition to your option to provide the proposal rate to attract new customers. And while that is important remember that our offer to you includes a discount to each and every one of your ***existing*** electric customers.

Also important is the opportunity to offset up to 15% of your energy purchases from Big Rivers and use the money you would have paid for our energy to purchase renewable energy of your choosing. If you can leverage that with the opportunities to put in local generation and create new investment like you heard from Southwest, then you have an opportunity with our proposal you likely can't get anywhere else. I understood Mr. Pope to say he'd allow you to build a generator, but I didn't hear him say anything about offsetting your energy with renewable purchases. As I understood him, he said he would market the output into the market and give you the benefit or loss. That is very different from our offer to allow you to offset a full 15% of your energy with renewables.

I'm sure your council has asked, "who is Big Rivers and why can a company from Kentucky do all of this for a town in Nebraska?" To provide some context, Big Rivers recently had two large industrial customers break their contract with us in bad faith leaving us with available capacity. Those customers wanted to access market power, which is currently very inexpensive. Big Rivers agreed to allow those two customers to purchase power at market prices, in an effort to save jobs in Western Kentucky. As a result of our agreement, we are working to replace that load—hence, why we are here in Nebraska.

South Sioux City and the other RFP participants just happened to put out the RFP at the right time to catch our attention. Our offer to you is roughly the same price as was paid by our two former large industrial customers, thus this proposal is a good fit for Big Rivers, and I hope after further consideration you and your Council will vote it is a good fit for South Sioux City as well.

As you and I have discussed, as a result of losing our two largest customers (850MW combined load), Big Rivers was downgraded by the three rating agencies. The rating agencies have indicated that we need to 1) receive approval to increase our rates to our remaining Members to cover our costs and 2) start working to replace the load that was once consumed by those two customers so we can lower our Member rates at some point in the future. We filed two rate cases (one for each lost customer) with the Kentucky Public Service Commission (who has jurisdiction over our business). The first rate case was ruled upon favorably by the PSC in October and we anticipate the results of the second case in March or April. As you are acutely aware, we have certainly began working to replace the load and are negotiating with other entities looking for power as well.

As I'm sure you are aware, having an investment grade credit rating is only necessary when you want to borrow money in the capital markets. Big Rivers currently has roughly $100 million in cash and has more than $400 million worth of positive equity on our Balance Sheet. Our Balance Sheet is one of the strongest among Generation and Transmission Cooperatives throughout the country. Big Rivers is a strong organization and we feel the downgrade is a short-term setback that we will overcome. Diversifying our load will be a significant positive for our organization, and we'd appreciate the opportunity to serve your load.

I received your request earlier today, requesting a three month extension. We are willing to give you a three month extension; however, we will only be able to offer you the 90% discount on the Generation Station Rate as a result of the contract terms we've negotiated with the other Nebraska parties. Based on Todd's analysis of $16,000,000 savings, your city will forgo an estimated $3.5 Million over the life of the contract as a result of the extension.

As I've discussed, the tailored proposal we are offering meets the needs of your city. Through numerous discussions, we have addressed your wants and needs to develop a contract that provides your city with a plethora of options. These options will prove valuable to your city in the future, enabling you with the flexibility to choose the best options for your city, not only today, but well into the future. Big Rivers is ready and willing to partner with you. We appreciate all of the time you've invested in us and look forward to the opportunity to continue our discussions.

Sincerely,

Lindsay

Lindsay Barron, CPA
VP Energy Services

Exhibit -

Mixing variability with reliability

NPPD constructed Nebraska's first wind-energy generation facility in 1998 west of Springview. Since then, we've been active in the state's wind development and supportive of wind development legislation.

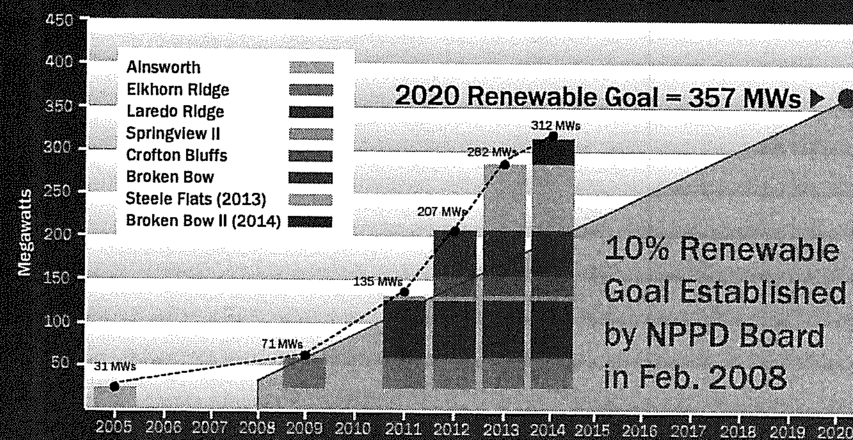
While it doesn't generate power all the time, wind energy is an important part of NPPD's diverse generation mix, and we've currently crossed the half-way point on meeting our Board's goal of having 10 percent of our power generation come from new renewable resources by 2020.

WIND ENERGY FACILITIES

Ainsworth Wind Energy Facility

Location: Ainsworth
Capacity: 60 MW
Units: 36, 1.65 MW each
Employs: 5
In-service: October 1, 2005
Participants: Nebraska Public Power District - 32 MW
Omaha Public Power District - 10 MW
JEA of Jacksonville (Fla.) - 10 MW
Municipal Energy Agency of Nebraska - 7 MW
City of Grand Island - 1 MW

TOTAL WIND ENERGY RESOURCES TO DATE



Power Purchase Agreements

NPPD purchases 100 percent of the output from these wind generating facilities and re-sells it to other utilities, less NPPD's share:

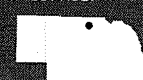
Broken Bow
Location: Broken Bow
Purchased MW: 80 MW
NPPD Share: 51 MW
In-service: 2012

Crofton Bluffs
Location: Crofton
Purchased MW: 42 MW
NPPD Share: 21 MW
In-service: 2012

Elkhorn Ridge
Location: Bloomfield
Purchased MW: 80 MW
NPPD Share: 40 MW
In-service: 2009

Laredo Ridge
Location: Petersburg
Purchased MW: 80 MW
NPPD Share: 61 MW
In-service: 2011

Springview II
Location: Springview
Purchased MW: 3 MW
NPPD Share: 3 MW
In-service: 2011



DENIED Admittance
SC EXHIBIT 18

BIG RIVERS ELECTRIC CORPORATION

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

Response to Ben Taylor and Sierra Club's
Initial Request for Information
dated August 19, 2013

September 3, 2013

Item 20) *Refer to page 12 of the Direct Testimony of Lindsey Barron Direct Testimony on page 12.*

a. Identify and produce the regression analyses that Big Rivers used to determine price elasticities of demand for rural customers.

b. For purposes of Big Rivers' long-term financial forecast, has Big Rivers performed any analyses of the difference between short-run and long-run price elasticity for its customers?

i. If so, please provide those analyses.

ii. If not, explain why not.

c. Identify and produce any studies or other documents that Big Rivers reviewed or relied upon in determining the price elasticities of demand for rural customers.

d. Explain why the price elasticities of demand identified in this proceeding are different than the values reported by Big Rivers in response to KIUC DR 1-35 in the Century rate case.

Response)

a. Regression models were developed for each of Big Rivers' three member distribution cooperatives to project average electricity consumption per

SC EXHIBIT 19

customer. Price elasticity coefficients were derived through the modeling process. The model specifications, data used to estimate the models, model statistics, and associated outputs are provided electronically under petition for confidential treatment as Exhibit-SC-1-20a-Kenergy.xlsx, Exhibit-SC-1-20a-JPEC.xlsx, and Exhibit-SC-1-20a-MCRECC.xlsx. Refer to sheet "ELAS" in each file for the price elasticity coefficient.

b. Big Rivers has not performed any analyses of the difference between short-run and long-run price elasticity. The regression models identified in item (a) above are used to compute the short-run price elasticity. While a specific analysis of the long-run price elasticity has not been performed, the models reflect changes in the market shares and operating efficiencies of electric heating and air conditioning, which indirectly capture long-run price elasticity (e.g., customers purchasing more efficient appliances or switching fuel sources).

c. Big Rivers' consultant compared the price elasticities derived in its forecasting models to those published in reports by the Energy Information Administration and the National Renewable Energy Laboratory. These reports are provided electronically as Exhibit-SC-1-20c-EIA.pdf and Exhibit-SC-1-20c-NREL.pdf.

d. The price elasticity of demand provided in response to KIUC DR 1-35 corresponds to the models developed in Big Rivers' 2011 Load Forecast. The elasticities of demand presented in the current proceeding are based on models from Big Rivers' 2013 Load Forecast. The price elasticities of demand from both studies are very similar and indicate that the impacts of price on consumption are essentially the same in both forecasts.

Witness) Lindsay N. Barron

U.S. Energy Information Administration - Average Retail Price of Electricity in 2011

RESIDENTIAL

#	Entity	State	Class of Ownership	Avg. ¢/kWh
1	Henderson City Utility Comm	KY	Public	6.13
2	Jackson Purchase Energy Corporation	KY	Cooperative	7.07
3	City of Benham	KY	Public	7.28
4	City of Falmouth	KY	Public	7.35
5	Kenergy Corp	KY	Cooperative	7.46
6	City of Nicholasville	KY	Public	7.50
7	Meade County Rural E C C	KY	Cooperative	7.53
8	City of Frankfort - (KY)	KY	Public	7.62
9	City of Berea Municipal Utility	KY	Public	7.73
10	City of Bardstown	KY	Public	7.75
11	City of Bardwell	KY	Public	7.89
12	Kentucky Utilities Co	KY	Investor Owned	8.02
13	Duke Energy Kentucky	KY	Investor Owned	8.39
14	Barbourville Utility Comm	KY	Public	8.58
15	Louisville Gas & Electric Co	KY	Investor Owned	8.60
16	Corbin City Utilities Comm	KY	Public	8.75
17	Madisonville Municipal Utils	KY	Public	8.83
18	City of Paris - (KY)	KY	Public	8.89
19	City of Olive Hill - (KY)	KY	Public	9.32
20	Salt River Electric Coop Corp	KY	Cooperative	9.39
21	Taylor County Rural E C C	KY	Cooperative	9.50
22	City of Providence - (KY)	KY	Public	9.51
23	City of Franklin - (KY)	KY	Public	9.53
	Big Rivers Total: Rural - NET of MRSM	KY	Cooperative	9.56
24	City of Paducah - (KY)	KY	Public	9.66
25	Kentucky Power Co	KY	Investor Owned	9.66
26	City of Russellville - (KY)	KY	Public	9.81
27	City of Owensboro - (KY)	KY	Public	9.84
28	City of Hopkinsville	KY	Public	9.85
29	Cumberland Valley Electric, Inc.	KY	Cooperative	9.92
30	Williamstown Utility Comm	KY	Public	10.01
31	City of Jellico	KY	Public	10.03
32	Nolin Rural Electric Coop Corp	KY	Cooperative	10.16
33	City of Glasgow	KY	Public	10.17
34	South Kentucky Rural E C C	KY	Cooperative	10.24
35	City of Murray - (KY)	KY	Public	10.31
36	Warren Rural Elec Coop Corp	KY	Cooperative	10.32
37	Tri-County Elec Member Corp	KY	Cooperative	10.33
38	Farmers Rural Electric Coop Corp	KY	Cooperative	10.35
39	Shelby Energy Co-op, Inc	KY	Cooperative	10.42
40	Owen Electric Coop Inc	KY	Cooperative	10.52
41	Blue Grass Energy Coop Corp	KY	Cooperative	10.62
42	Pennyrile Rural Electric Coop	KY	Cooperative	10.69
43	City of Fulton - (KY)	KY	Public	10.71
44	Big Sandy Rural Elec Coop Corp	KY	Cooperative	10.72
45	Fleming-Mason Energy Coop Inc	KY	Cooperative	10.75
46	City of Bowling Green - (KY)	KY	Public	10.84
47	City of Benton - (KY)	KY	Public	10.95
48	Clark Energy Coop Inc - (KY)	KY	Cooperative	11.00
49	Inter County Energy Coop Corp	KY	Cooperative	11.00
50	Licking Valley Rural E C C	KY	Cooperative	11.21
51	City of Mayfield Plant Board	KY	Public	11.29
52	City of Vanceburg	KY	Public	11.58
53	West Kentucky Rural E C C	KY	Cooperative	11.62
54	City of Princeton - (KY)	KY	Public	11.66
55	Jackson Energy Coop Corp - (KY)	KY	Cooperative	11.66
56	City of Hickman	KY	Public	11.67
57	Grayson Rural Electric Coop Corp	KY	Cooperative	12.37
58	Hickman-Fulton Counties RECC	KY	Cooperative	13.01
	Big Rivers Total: Rural - GROSS of MRSM	KY	Cooperative	13.46

Source: http://www.eia.gov/electricity/data.cfm#sales

Case No. 2013-00199
Exhibit Wolfram-8
Page 1 of 4

SC EXHIBIT 20

U.S. Energy Information Administration: Average Retail Price of Electricity in 2011

INDUSTRIAL

#	Entity	State	Class of Ownership	Avg. ¢/kWh
1	**Kenergy Corp**	**KY**	**Cooperative**	**4.14**
2	Electric Energy Inc	KY	Investor Owned	4.27
3	Corbin City Utilities Comm	KY	Public	4.62
4	Tennessee Valley Authority	KY	Federal	4.76
	Big Rivers Total: Large Industrial - NET of MRSM	**KY**	**Cooperative**	**4.96**
5	City of Bardstown	KY	Public	5.07
6	Henderson City Utility Comm	KY	Public	5.08
7	Owen Electric Coop Inc	KY	Cooperative	5.28
8	Williamstown Utility Comm	KY	Public	5.52
9	Kentucky Utilities Co	KY	Investor Owned	5.66
10	**Jackson Purchase Energy Corporation**	**KY**	**Cooperative**	**5.89**
11	Louisville Gas & Electric Co	KY	Investor Owned	5.98
12	City of Hopkinsville	KY	Public	5.99
13	Kentucky Power Co	KY	Investor Owned	6.03
14	Fleming-Mason Energy Coop Inc	KY	Cooperative	6.16
15	Nolin Rural Electric Coop Corp	KY	Cooperative	6.18
16	City of Nicholasville	KY	Public	6.41
17	Grayson Rural Electric Coop Corp	KY	Cooperative	6.47
18	City of Frankfort - (KY)	KY	Public	6.64
19	Blue Grass Energy Coop Corp	KY	Cooperative	6.68
20	Duke Energy Kentucky	KY	Investor Owned	6.70
21	Shelby Energy Co-op, Inc	KY	Cooperative	6.71
22	Salt River Electric Coop Corp	KY	Cooperative	6.77
23	City of Berea Municipal Utility	KY	Public	6.78
24	Big Sandy Rural Elec Coop Corp	KY	Cooperative	6.84
25	Barbourville Utility Comm	KY	Public	6.91
26	City of Franklin - (KY)	KY	Public	7.13
27	Inter County Energy Coop Corp	KY	Cooperative	7.13
28	City of Owensboro - (KY)	KY	Public	7.19
29	Jackson Energy Coop Corp - (KY)	KY	Cooperative	7.30
30	Farmers Rural Electric Coop Corp	KY	Cooperative	7.43
31	City of Murray - (KY)	KY	Public	7.61
32	West Kentucky Rural E C C	KY	Cooperative	7.81
33	Licking Valley Rural E C C	KY	Cooperative	7.90
	Big Rivers Total: Large Industrial - GROSS of MRSM	**KY**	**Cooperative**	**7.91**
34	Tri-County Elec Member Corp	KY	Cooperative	7.98
35	City of Glasgow	KY	Public	8.01
36	Cumberland Valley Electric, Inc.	KY	Cooperative	8.02
37	Pennyrile Rural Electric Coop	KY	Cooperative	8.15
38	Warren Rural Elec Coop Corp	KY	Cooperative	8.19
39	City of Bowling Green - (KY)	KY	Public	8.23
40	South Kentucky Rural E C C	KY	Cooperative	8.35
41	Clark Energy Coop Inc - (KY)	KY	Cooperative	8.57
42	City of Paris - (KY)	KY	Public	8.61
43	City of Russellville - (KY)	KY	Public	9.01
44	City of Fulton - (KY)	KY	Public	9.16
45	City of Vanceburg	KY	Public	9.27
46	Taylor County Rural E C C	KY	Cooperative	9.42
47	City of Benton - (KY)	KY	Public	9.45
48	City of Mayfield Plant Board	KY	Public	9.57
49	City of Paducah - (KY)	KY	Public	9.63
50	City of Princeton - (KY)	KY	Public	10.75
51	Hickman-Fulton Counties RECC	KY	Cooperative	12.67

ia.gov/electricity/data.cfm#sales

U.S. Energy Information Administration - Average Retail Price of Electricity in 2011

RESIDENTIAL

#	State	Avg. ¢/kWh
1	Idaho	7.87
2	Washington	8.28
3	North Dakota	8.58
4	Louisiana	8.98
5	Utah	8.98
8	Arkansas	9.02
7	Wyoming	9.11
8	**Kentucky**	**9.20**
9	Nebraska	9.32
	Kentucky with Big Rivers NET Increase	**9.33**
10	South Dakota	9.35
11	West Virginia	9.39
12	Oklahoma	9.47
13	Oregon	9.54
	Kentucky with Big Rivers GROSS Increase	**9.55**
14	Missouri	9.75
15	Montana	9.75
16	Tennessee	9.98
17	Indiana	10.08
18	Mississippi	10.17
19	North Carolina	10.28
20	Iowa	10.48
21	Virginia	10.84
22	Kansas	10.65
23	Minnesota	10.98
24	New Mexico	11.00
25	Georgia	11.05
28	South Carolina	11.05
27	Texas	11.08
28	Arizona	11.08
29	Alabama	11.09
30	Colorado	11.27
31	Ohio	11.42
32	Florida	11.51
33	Nevada	11.61
34	Illinois	11.78
35	Wisconsin	13.02
38	Pennsylvania	13.28
37	Michigan	13.27
38	Maryland	13.31
39	District of Columbia	13.40
40	Delaware	13.70
41	Rhode Island	14.33
42	Massachusetts	14.67
43	California	14.78
44	Maine	15.38
45	New Jersey	16.23
46	Vermont	18.26
47	New Hampshire	16.52
48	Alaska	17.62
49	Connecticut	18.11
50	New York	18.28
51	Hawaii	34.68

Source: http://www.eia.gov/electricity/data.cfm#sales

U.S. Energy Information Administration - Average Retail Price of Electricity in 2011

INDUSTRIAL

#	State	Avg. ¢/kWh
1	Washington	4.09
2	Idaho	5.10
3	Utah	5.10
4	Iowa	5.21
5	Montana	5.27
6	**Kentucky**	**5.33**
7	Wyoming	5.41
8	Oklahoma	5.46
9	Oregon	5.47
	Kentucky with Big Rivers NET Increase	5.49
10	Arkansas	5.63
11	Louisiana	5.69
12	Missouri	5.85
13	South Carolina	5.94
14	North Carolina	6.01
	Kentucky with Big Rivers GROSS Increase	6.05
15	New Mexico	6.06
16	Ohio	6.12
17	Indiana	6.17
18	West Virginia	6.18
19	South Dakota	6.20
20	North Dakota	6.24
21	Texas	6.24
22	Alabama	6.25
23	Illinois	6.42
24	Nebraska	6.43
25	Minnesota	6.47
26	Virginia	6.49
27	Mississippi	6.53
28	Arizona	6.55
29	Georgia	6.60
30	Nevada	6.65
31	Kansas	6.71
32	District of Columbia	6.89
33	Colorado	7.06
34	Tennessee	7.23
35	Michigan	7.32
36	Wisconsin	7.33
37	Pennsylvania	7.73
38	New York	7.83
39	Florida	8.55
40	Maryland	8.76
41	Maine	8.88
42	Delaware	8.91
43	Vermont	9.83
44	California	10.11
45	Rhode Island	11.27
46	New Jersey	11.43
47	New Hampshire	12.27
48	Connecticut	13.24
49	Massachusetts	13.38
50	Alaska	15.71
51	Hawaii	28.40

Source: http://www.eia.gov/electricity/data.cfm#sales

BIG RIVERS ELECTRIC CORPORATION

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

**Response to Ben Taylor and Sierra Club's
Second Request for Information
dated September 16, 2013**

September 30, 2013

Item 14) *Refer to BREC's response to PSC 2-20.*

a. Identify and produce any studies, analyses, reports, or empirical evidence supporting the statement that "Large industrial customers have less ability to react to price signals than do rural class customers."

b. Identify and produce any studies, analyses, or reports of price elasticity of demand that estimate a smaller (in absolute value) elasticity for industrial demand than for residential demand.

c. Provide any studies, analyses, or reports supporting BREC's assumption in this proceeding that the price elasticity of demand is zero (i.e., quantity of electricity demanded is unaffected by price) for Big Rivers' industrial customers.

d. Produce any communications that BREC has had with large industrial customers regarding what impact the rate increases reflected in the Century and Alcan rate cases would have on electricity consumption by large industrial customers.

e. Describe any effort BREC has taken to determine the impact that the rate increases reflected in the Century and Alcan rate cases would have on electricity consumption by large industrial customers

Response)

SC EXHIBIT 21

a. For the statement in PSC 2-20, Big Rivers relied upon its understanding of the industrial customers that are served by its members, including the views expressed by three large industrial customers in Case No. 2012-00535 and information from Big Rivers' members, who communicate regularly with their large industrial customers. These large industrial customers are sophisticated in their approach to energy management. They have a strong profit motive and incentive to minimize costs in order to maximize margins. In the normal course of business, they place significant emphasis on consumption optimization and energy cost reduction. Big Rivers expects that these customers have already taken steps to minimize their consumption and energy bills.

When developing the load forecast analysis for Big Rivers, GDS did not recommend or perform an analysis of price elasticity of demand for the large industrial customer segment. This has been the case for Big Rivers' load forecast and IRP process for many years. This is consistent with standard practices and supports the assumption described in the response to PSC 2-20.

In the load forecast analysis, energy sales projections for the large industrials were developed on an individual basis, based on historical trends and known changes. None of the entities taking service under Big Rivers' LIC tariff has notified Big

Rivers or its members of a plan or proposal to reduce the minimum billing demand in its contract as a result of rate adjustments proposed in either Case No. 2012-00535 or the instant case. This also supports the assumption described in the response to PSC 2-20.

b. Please see the response to part (a).

c. Please see the response to part (a).

d. Big Rivers has had conversations with its members on the potential impacts of rate increases on large industrial customers; Big Rivers' members communicate directly with the large industrial customers. Please see the response to part (a).

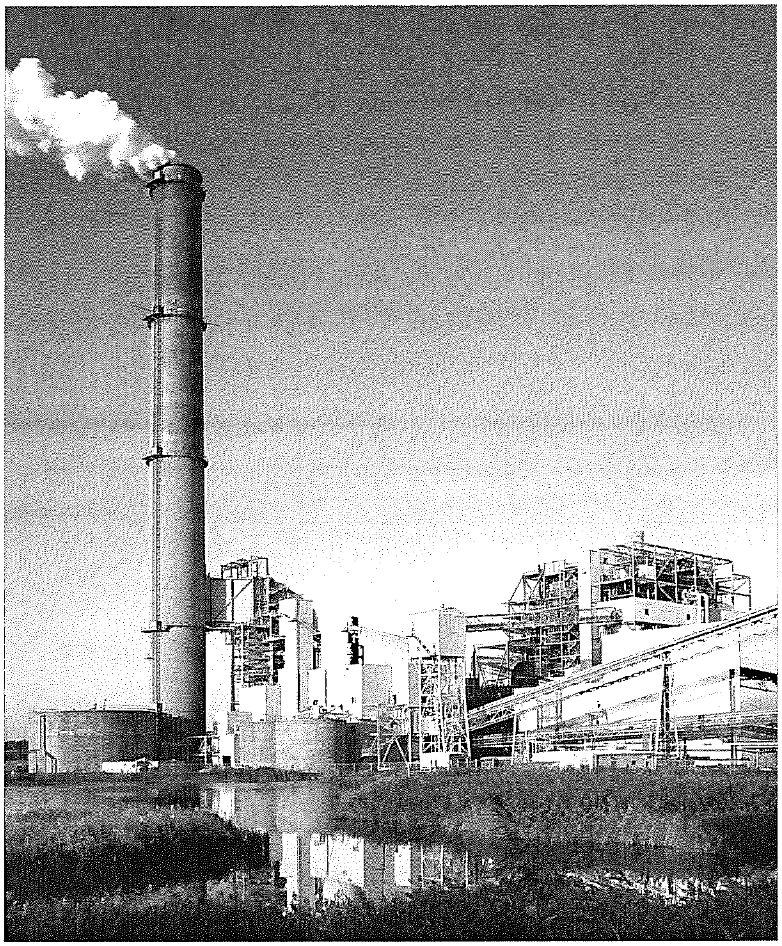
e. Please see the response to parts (a) and (d).

Witness) Lindsay N. Barron

Received
November 1, 2011
Indiana Utility Regulatory Commission

Exhibit -

2011 INTEGRATED RESOURCE PLAN



By
Southern Indiana Gas and Electric Company
d/b/a Vectren Energy Delivery of Indiana, Incorporated

November 1, 2011

VECTREN
Live Smart

SC EXHIBIT _ 22

Table 5-9 Large Energy Sales (GWh)

Year	Actual	Forecasts (Large) 2009	2007	2005	2004	2001	1999	Deviation from most recent forecast, %
2001	2,428					2,506		-3.2%
2002	2,444					2,522		-3.2%
2003	2,494					2,539		-1.8%
2004	2,346				2,568			-9.5%
2005	2,389			2,404				-0.6%
2006	2,376			2,379				-0.1%
2007	2,538		2,573					-1.4%
2008	2,655		2,567					3.3%
2009	2,251	2,247						0.2%
2010	2,601	2,281						12.3%
Compound Annual Growth Rate, 2001-2010	0.77%							

Table 5-10 Other Sales, Wholesale Contract Sales, and Losses (GWh)

Year	Actual	Forecasts (Other, Wholesale & Losses) 2009	2007	2005	2004	2001	1999	Deviation from most recent forecast, %
2001	863						949	-10.0%
2002	1,152					904		21.5%
2003	1,047					914		12.7%
2004	953				959			-0.6%
2005	992			967				2.5%
2006	986			1,014				-2.9%
2007	946		954					-0.9%
2008	309		636*					5.3%
2009	600	598						0.3%
2010	661	585						11.6%
Compound Annual Growth Rate, 2001-2010	-2.91%							

*Adjusted to include wholesale sales

Exhibit -

U.S. Energy Information Administration - Average Retail Price of Electricity in 2011

RESIDENTIAL

#	Entity	State	Class of Ownership	Avg. ¢/kWh
1	Henderson City Utility Comm	KY	Public	6.13
2	**Jackson Purchase Energy Corporation**	KY	Cooperative	7.07
3	City of Benham	KY	Public	7.28
4	City of Falmouth	KY	Public	7.35
5	**Kenergy Corp**	KY	Cooperative	7.46
6	City of Nicholasville	KY	Public	7.50
7	**Meade County Rural E C C**	KY	Cooperative	7.53
8	City of Frankfort - (KY)	KY	Public	7.62
9	City of Berea Municipal Utility	KY	Public	7.73
10	City of Bardstown	KY	Public	7.75
11	City of Bardwell	KY	Public	7.89
12	Kentucky Utilities Co	KY	Investor Owned	8.02
13	Duke Energy Kentucky	KY	Investor Owned	8.39
14	Barbourville Utility Comm	KY	Public	8.58
15	Louisville Gas & Electric Co	KY	Investor Owned	8.60
16	Corbin City Utilities Comm	KY	Public	8.75
17	Madisonville Municipal Utils	KY	Public	8.83
18	City of Paris - (KY)	KY	Public	8.89
19	City of Olive Hill - (KY)	KY	Public	9.32
20	Salt River Electric Coop Corp	KY	Cooperative	9.39
21	Taylor County Rural E C C	KY	Cooperative	9.50
22	City of Providence - (KY)	KY	Public	9.51
23	City of Franklin - (KY)	KY	Public	9.53
	Big Rivers Total: Rural ~ NET of MRSM	**KY**	**Cooperative**	**9.56**
24	City of Paducah - (KY)	KY	Public	9.66
25	Kentucky Power Co	KY	Investor Owned	9.66
26	City of Russellville - (KY)	KY	Public	9.81
27	City of Owensboro - (KY)	KY	Public	9.84
28	City of Hopkinsville	KY	Public	9.85
29	Cumberland Valley Electric, Inc.	KY	Cooperative	9.92
30	Williamstown Utility Comm	KY	Public	10.01
31	City of Jellico	KY	Public	10.03
32	Nolin Rural Electric Coop Corp	KY	Cooperative	10.16
33	City of Glasgow	KY	Public	10.17
34	South Kentucky Rural E C C	KY	Cooperative	10.24
35	City of Murray - (KY)	KY	Public	10.31
36	Warren Rural Elec Coop Corp	KY	Cooperative	10.32
37	Tri-County Elec Member Corp	KY	Cooperative	10.33
38	Farmers Rural Electric Coop Corp	KY	Cooperative	10.35
39	Shelby Energy Co-op, Inc	KY	Cooperative	10.42
40	Owen Electric Coop Inc	KY	Cooperative	10.52
41	Blue Grass Energy Coop Corp	KY	Cooperative	10.62
42	Pennyrile Rural Electric Coop	KY	Cooperative	10.69
43	City of Fulton - (KY)	KY	Public	10.71
44	Big Sandy Rural Elec Coop Corp	KY	Cooperative	10.72
45	Fleming-Mason Energy Coop Inc	KY	Cooperative	10.75
46	City of Bowling Green - (KY)	KY	Public	10.84
47	City of Benton - (KY)	KY	Public	10.95
48	Clark Energy Coop Inc - (KY)	KY	Cooperative	11.00
49	Inter County Energy Coop Corp	KY	Cooperative	11.00
50	Licking Valley Rural E C C	KY	Cooperative	11.21
51	City of Mayfield Plant Board	KY	Public	11.29
52	City of Vanceburg	KY	Public	11.58
53	West Kentucky Rural E C C	KY	Cooperative	11.62
54	City of Princeton - (KY)	KY	Public	11.66
55	Jackson Energy Coop Corp - (KY)	KY	Cooperative	11.66
56	City of Hickman	KY	Public	11.67
57	Grayson Rural Electric Coop Corp	KY	Cooperative	12.37
58	Hickman-Fulton Counties RECC	KY	Cooperative	13.01
	Big Rivers Total: Rural ~ GROSS of MRSM	**KY**	**Cooperative**	**13.46**

Source: http://www.eia.gov/electricity/data.cfm#sales

Case No. 2013-00199
Exhibit Wolfram-8
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SC EXHIBIT 23

U.S. Energy Information Administration: Average Retail Price of Electricity in 2011

INDUSTRIAL

#	Entity	State	Class of Ownership	Avg. ¢/kWh
1	**Kenergy Corp**	**KY**	**Cooperative**	**4.14**
2	Electric Energy Inc	KY	Investor Owned	4.27
3	Corbin City Utilities Comm	KY	Public	4.62
4	Tennessee Valley Authority	KY	Federal	4.76
	Big Rivers Total: Large Industrial ~NET of MRSM	**KY**	**Cooperative**	**4.96**
5	City of Bardstown	KY	Public	5.07
6	Henderson City Utility Comm	KY	Public	5.08
7	Owen Electric Coop Inc	KY	Cooperative	5.28
8	Williamstown Utility Comm	KY	Public	5.52
9	Kentucky Utilities Co	KY	Investor Owned	5.66
10	**Jackson Purchase Energy Corporation**	**KY**	**Cooperative**	**5.89**
11	Louisville Gas & Electric Co	KY	Investor Owned	5.98
12	City of Hopkinsville	KY	Public	5.99
13	Kentucky Power Co	KY	Investor Owned	6.03
14	Fleming-Mason Energy Coop Inc	KY	Cooperative	6.16
15	Nolin Rural Electric Coop Corp	KY	Cooperative	6.18
16	City of Nicholasville	KY	Public	6.41
17	Grayson Rural Electric Coop Corp	KY	Cooperative	6.47
18	City of Frankfort - (KY)	KY	Public	6.64
19	Blue Grass Energy Coop Corp	KY	Cooperative	6.68
20	Duke Energy Kentucky	KY	Investor Owned	6.70
21	Shelby Energy Co-op, Inc	KY	Cooperative	6.71
22	Salt River Electric Coop Corp	KY	Cooperative	6.77
23	City of Berea Municipal Utility	KY	Public	6.78
24	Big Sandy Rural Elec Coop Corp	KY	Cooperative	6.84
25	Barbourville Utility Comm	KY	Public	6.91
26	City of Franklin - (KY)	KY	Public	7.13
27	Inter County Energy Coop Corp	KY	Cooperative	7.13
28	City of Owensboro - (KY)	KY	Public	7.19
29	Jackson Energy Coop Corp - (KY)	KY	Cooperative	7.30
30	Farmers Rural Electric Coop Corp	KY	Cooperative	7.43
31	City of Murray - (KY)	KY	Public	7.61
32	West Kentucky Rural E C C	KY	Cooperative	7.81
33	Licking Valley Rural E C C	KY	Cooperative	7.90
	Big Rivers Total: Large Industrial ~GROSS of MRSM	**KY**	**Cooperative**	**7.91**
34	Tri-County Elec Member Corp	KY	Cooperative	7.98
35	City of Glasgow	KY	Public	8.01
36	Cumberland Valley Electric, Inc.	KY	Cooperative	8.02
37	Pennyrile Rural Electric Coop	KY	Cooperative	8.15
38	Warren Rural Elec Coop Corp	KY	Cooperative	8.19
39	City of Bowling Green - (KY)	KY	Public	8.23
40	South Kentucky Rural E C C	KY	Cooperative	8.35
41	Clark Energy Coop Inc - (KY)	KY	Cooperative	8.57
42	City of Paris - (KY)	KY	Public	8.61
43	City of Russellville - (KY)	KY	Public	9.01
44	City of Fulton - (KY)	KY	Public	9.16
45	City of Vanceburg	KY	Public	9.27
46	Taylor County Rural E C C	KY	Cooperative	9.42
47	City of Benton - (KY)	KY	Public	9.45
48	City of Mayfield Plant Board	KY	Public	9.57
49	City of Paducah - (KY)	KY	Public	9.63
50	City of Princeton - (KY)	KY	Public	10.75
51	Hickman-Fulton Counties RECC	KY	Cooperative	12.67

:ia.gov/electricity/data.cfm#sales

U.S. Energy Information Administration - Average Retail Price of Electricity in 2011

RESIDENTIAL

#	State	Avg. ¢/kWh
1	Idaho	7.87
2	Washington	8.28
3	North Dakota	8.58
4	Louisiana	8.96
5	Utah	8.96
6	Arkansas	9.02
7	Wyoming	9.11
8	**Kentucky**	**9.20**
9	Nebraska	9.32
	Kentucky with Big Rivers NET Increase	**9.33**
10	South Dakota	9.35
11	West Virginia	9.39
12	Oklahoma	9.47
13	Oregon	9.54
	Kentucky with Big Rivers GROSS Increase	**9.55**
14	Missouri	9.75
15	Montana	9.75
16	Tennessee	9.98
17	Indiana	10.06
18	Mississippi	10.17
19	North Carolina	10.26
20	Iowa	10.46
21	Virginia	10.64
22	Kansas	10.65
23	Minnesota	10.96
24	New Mexico	11.00
25	Georgia	11.05
26	South Carolina	11.05
27	Texas	11.08
28	Arizona	11.08
29	Alabama	11.09
30	Colorado	11.27
31	Ohio	11.42
32	Florida	11.51
33	Nevada	11.61
34	Illinois	11.78
35	Wisconsin	13.02
36	Pennsylvania	13.26
37	Michigan	13.27
38	Maryland	13.31
39	District of Columbia	13.40
40	Delaware	13.70
41	Rhode Island	14.33
42	Massachusetts	14.67
43	California	14.78
44	Maine	15.38
45	New Jersey	16.23
46	Vermont	16.26
47	New Hampshire	16.52
48	Alaska	17.62
49	Connecticut	18.11
50	New York	18.26
51	Hawaii	34.68

BREC Net of MRSM

BREC Gross of MRSM

Source: http://www.eia.gov/electricity/data.cfm#sales

U.S. Energy Information Administration - Average Retail Price of Electricity in 2011

INDUSTRIAL

#	State	Avg. ¢/kWh	
1	Washington	4.09	BREC Net of MRSM
2	Idaho	5.10	
3	Utah	5.10	
4	Iowa	5.21	
5	Montana	5.27	
6	**Kentucky**	**5.33**	
7	Wyoming	5.41	
8	Oklahoma	5.46	
9	Oregon	5.47	
	Kentucky with Big Rivers NET Increase	**5.49**	
10	Arkansas	5.63	
11	Louisiana	5.69	
12	Missouri	5.85	
13	South Carolina	5.94	
14	North Carolina	6.01	
	Kentucky with Big Rivers GROSS Increase	**6.05**	
15	New Mexico	6.06	
16	Ohio	6.12	
17	Indiana	6.17	
18	West Virginia	6.18	
19	South Dakota	6.20	
20	North Dakota	6.24	
21	Texas	6.24	
22	Alabama	6.25	
23	Illinois	6.42	
24	Nebraska	6.43	
25	Minnesota	6.47	
26	Virginia	6.49	
27	Mississippi	6.53	
28	Arizona	6.55	
29	Georgia	6.60	
30	Nevada	6.65	
31	Kansas	6.71	
32	District of Columbia	6.89	
33	Colorado	7.06	
34	Tennessee	7.23	
35	Michigan	7.32	
36	Wisconsin	7.33	
37	Pennsylvania	7.73	
38	New York	7.83	BREC Gross of MRSM
39	Florida	8.55	
40	Maryland	8.76	
41	Maine	8.88	
42	Delaware	8.91	
43	Vermont	9.83	
44	California	10.11	
45	Rhode Island	11.27	
46	New Jersey	11.43	
47	New Hampshire	12.27	
48	Connecticut	13.24	
49	Massachusetts	13.38	
50	Alaska	15.71	
51	Hawaii	28.40	

Source: http://www.eia.gov/electricity/data.cfm#sales