Big Rivers
ELECTRIC CORPORATION

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
270-827-2561
www.bigrivers.com

July 17, 2019

VIA FedEx OVERNIGHT DELIVERY

Ms. Gwen R. Pinson
Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
Frankfort, KY 40601

Re: *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*

Dear Ms. Pinson:

On June 18, 2019, the Public Service Commission (the Commission") issued two Orders directing Big Rivers Electric Corporation ("Big Rivers") to "*file revised pages reflecting as unredacted*" materials from Big Rivers' responses to certain information requests in the aforementioned docket. Specifically, the Commission directed Big Rivers to file unredacted pages for the following information:

1. Responses to Commission Staff's ("Staff's") Initial Request for Information, Item Nos. 13(a), 17, 29(b), and 57 originally filed July 12, 2013;
2. Responses to the Office of the Attorney General's ("AG's") Initial Request for Information, Item Nos. 196 and 202 originally filed September 3, 2013, and revised October 22, 2013;
3. Responses to the AG's Supplemental Request for Information, Item No. 59 originally filed September 30, 2013, and revised October 22, 2013;
4. Responses to the Kentucky Industrial Utility Customers, Inc.'s ("KIUC's") First Request for Information, Item Nos. 21 and 22 originally filed September 3, 2013, and revised October 22, 2013;
5. Responses to Ben Taylor and the Sierra Club's ("Sierra Club's") Supplemental Request for Information, Item No. 9 originally filed September 30, 2013, and revised October 22, 2013;
6. Rebuttal Testimony Documents originally filed December 17, 2013;
7. Responses to Requests for Information from the January 9, 2014, Hearing, Item Nos. 4, 5, 6, 7, 16, 17, and 20 originally filed January 24, 2014;
8. Responses to Staff's Third Request for Information, Item Nos. 5, 8, and 9 originally filed September 30, 2013
9. Responses to the AG's Supplemental Request for Information, Item Nos. 2, 7, 8, 9, 13–20, 28, 29, 31, 32, 34–37, 43, 47, 53, 54, 57, 58, 59, 67, 74, 81, and 83 originally filed September 30, 2013;

10. Responses to the KIUC's Second Request for Information, Item Nos. 1, 3, 4, 9, 10, 11, 15, 17, 18, 20, 23, 25, 26, 36, 37, 42, 43, and 48 originally filed September 3, 2013;
11. Responses to the Sierra Club's Supplemental Request for Information, Item Nos. 7, 9, 10, 11, 15, 23, 25, 26, 29, 30, 31, and 32 originally filed September 30, 2013.

Big Rivers hereby provides an original and ten (10) copies of the relevant unredacted pages from the items listed above. In some cases, the information request required an electronic version of files, supporting information which was best provided electronically, and voluminous documents which were best provided electronically. In those cases, that unredacted information is being provided on a CD accompanying this filing.

Please confirm your receipt of this information by placing the Commission's file stamp, with date received, on the enclosed additional copy of this letter and returning it to Big Rivers in the self-addressed, postage-paid envelop provided.

I certify that, on this date, a copy of this filing has been served on the persons listed on the attached service list by first class U.S. Postal Service.

Sincerely,

Tyson Kamuf
Corporate Attorney,
Big Rivers Electric Corporation
tyson.kamuf@bigrivers.com

cc: Service List
Roger D. Hickman

BIG RIVERS ELECTRIC CORPORATION

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

Service List

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BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
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BIG RIVERS ELECTRIC CORPORATION

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ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

Response to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to:

1. Commission Staff's Initial and Third Requests for Information;
2. Office of the Attorney General's Initial and Supplemental Requests for Information;
3. Kentucky Industrial Utility Customers, Inc.'s First and Second Requests for Information;
4. Ben Taylor and the Sierra Club's Supplemental Requests for Information; and
5. Responses to Requests for Information from the January 9, 2014, Hearing. *plus*

Designated Rebuttal Testimony Documents

FILED: July 18, 2019

ORIGINAL

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to Commission Staff's Initial Requests for Information, Responses to the Office of the Attorney General's Initial and Supplemental Requests for Information, Responses to the Kentucky Industrial Utility Customers, Inc.'s First and Second Requests for Information, Responses to Ben Taylor and the Sierra Club's Supplemental Requests for Information, and Responses to Requests for Information from the January 9, 2014, Hearing
FILED: July 18, 2019

Files Provided on CD [*Continued*]

AG 1-196 (JRW Att) - Wilson Plant Info by RUS Acct RVD - 2013-10-22

AG 1-202 (JRW Att) - Coleman Plant Info by RUS Acct RVD SC - 2012-10-22

AG 2-13 (BJR Att) - CFC G&T Benchmark Data

AG 2-28ac (JRW CAW Att) - Re AG 1-86 and AG 1-86(a) Att

AG 2-28d AG 2-29c (JRW CAW Att) - Coleman and Wilson Costs

AG 2-29ab (JRW CAW Att) - Re AG 1-86 and AG 1-86(a) Att

AG 2-34bcd (BJR Att) - Re PSC 2-15, NBV, etc., of Coleman and Wilson

AG 2-43b ((MAB, BJR, RWB, and TWD Att) - Re AG 1-53, BR Mngment Rpts to Board

KIUC 2-1a (RWB Att) - PCM Run (May-13 to Dec-28) Hourly Load Data

KIUC 2-1b (RWB Att) - PCM Run (May-13 to Dec-28) Hourly Data

KIUC 2-3 (RWB Att) - SEPA Charges Summary

KIUC 2-9 (RWB Att) - ACES Pwr Price Forecast

KIUC 2-15 (JRW Att) - Coleman and Wilson Rev Req

KIUC 2-17 (CAW Att) - Coleman RUS Loan Application Scenario V2

KIUC 2-17 (CAW Att) - Wilson RUS Loan Application Scenario V2

KIUC 2-18 (CAW Att) - Coleman Scenario V2

KIUC 2-18 (CAW Att) - Wilson Scenario V2

KIUC 2-20 (CAW Att) - Financial Forecast (3 + 9) 05-7-13

KIUC 2-25 (RWB Att) - Coleman and Wilson Tables, FDE Savings

KIUC 2-26 (RWB Att) - Coleman and Wilson Cost Table

PHDR-16 (RWB Att) - Re SC 2-21, Green Coal to NG Conversion Sensitivity Analysis

PHDR-20 (CAW Att1) - Exhibit Warren-2.2

PHDR-20 (CAW Att2) - Financial Forecast

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

APPLICATION OF BIG RIVERS	)	
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FILED: July 18, 2019

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In the Matter of:

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

Responses to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to Commission Staff's Initial Request for Information, Item No. 13(a) originally filed July 12, 2013

Information submitted on CD accompanying responses

Big Rivers Electric Corporation
Case No. 2013-00199
Construction Projects

For the 12 Months Preceding the Base Period
(10/1/2011 - 09/30/2012)

Type of Filing: Original - __X__; Updated - ______; Revised - ______

Schedule 2

Line No. (A)	Project No. (B)	Description of Project (C)	Accumulated Costs: Construction Amount (D)	AFUDC Capitalized (E)	Indirect Costs Other (F)[1]	Total Costs (G = D+E+F)	Estimated Physical % Completed (H)
1	2010 POLES	Pole Change Outs 2010	$ (127)	$ -	$ -	**$ (127)**	100%
2	2010 Projects	Bucket for Puts & Takes 2010	$ 333	$ -	$ -	**$ 333**	100%
3	2011 POLES	Pole Change Outs	$ 62,060	$ -	$ -	**$ 62,060**	100%
4	2012 POLES	Pole Change Outs	$ 257,631	$ -	$ -	**$ 257,631**	81%
5	BA11X033B	ENV - Replace Van	$ 28,926	$ -	$ -	**$ 28,926**	100%
6	BA11X044B	TRAN - Rpl #257 - Extended Cab 4x4 '	$ 25,045	$ -	$ -	**$ 25,045**	100%
7	BA11X045B	TRAN - Rpl #238 Heavy Duty Reg Cab	$ 42,749	$ -	$ -	**$ 42,749**	100%
8	BA11X048B	Operator Training Simulator	$ 889,242	$ -	$ -	**$ 889,242**	100%
9	BA11X051F	Groundwater Sampling Equipment	$ 5,297	$ -	$ -	**$ 5,297**	100%
10	BA11X054F	Power Surge for Central Lab	$ 7,554	$ -	$ -	**$ 7,554**	100%
11	BA11X056F	Operations Training Simulator - Green	$ 224,617	$ -	$ -	**$ 224,617**	100%
12	BA11X057F	Operations Training Simulator - Hende	$ 163,664	$ -	$ -	**$ 163,664**	100%
13	BA11X058F	HQ - Chevy Volt	$ 47,334	$ -	$ -	**$ 47,334**	100%
14	BA11X060F	ET&S 2012 Chevy Silverado	$ 28,189	$ -	$ -	**$ 28,189**	100%
15	BA12X002B	Replace Bomb Calorimeter	$ 33,683	$ -	$ -	**$ 33,683**	100%
16	BA12X003B	Replace AA Analyzer	$ 84,932	$ -	$ -	**$ 84,932**	100%
17	BA12X009B	Microfilm Viewer/Scanner/Printer	$ 5,671	$ -	$ -	**$ 5,671**	100%
18	BA12X017B	Copier (pushed from 2011)	$ 14,568	$ -	$ -	**$ 14,568**	100%
19	BA12X022B	TRAN - Rpl #300 - Extended Cab 4x4 '	$ 28,991	$ -	$ -	**$ 28,991**	100%

Big Rivers Electric Corporation
Case No. 2013-00199
Construction Projects

For the 12 Months Preceding the Base Period
(10/1/2011 - 09/30/2012)

Type of Filing: Original - __X__; Updated - _____; Revised - _____

Schedule 2

Line No. (A)	Project No. (B)	Description of Project (C)	Accumulated Costs: Construction Amount (D)	AFUDC Capitalized (E)	Indirect Costs Other (F)[1]	Total Costs (G = D+E+F)	Estimated Physical % Completed (H)
20	BA12X026B	SAFETY - Rpl #303 Truck (pushed fro	$ 34,126	$ -	$ -	**$ 34,126**	100%
21	BA12X030B	ENV - Rpl Environmental Jeep	$ 27,459	$ -	$ -	**$ 27,459**	100%
22	BA12X032B	ENV - Truck	$ 27,459	$ -	$ -	**$ 27,459**	100%
23	BA12X033B	IT - Rpl '99 White Dodge Van	$ 22,685	$ -	$ -	**$ 22,685**	100%
24	BA12X039F	Numbering System for fuel truck ticket	$ 1,200	$ -	$ -	**$ 1,200**	100%
25	BA12X040F	CD Duplicator	$ 712	$ -	$ -	**$ 712**	100%
26	BA12X041F	Environmental RoTep replacement	$ 2,271	$ -	$ -	**$ 2,271**	100%
27	BI11X001B	Tier-C replacement PC's, Laptops, Print	$ 43,183	$ -	$ -	**$ 43,183**	100%
28	BI11X002B	Tier-C replacement Data Centers Serve	$ 37,859	$ -	$ -	**$ 37,859**	100%
29	BI11X005B	Purchase spare network switches	$ 2,285	$ -	$ -	**$ 2,285**	100%
30	BI11X009B	Replace Monarch 1200 baud modems w	$ 1,301	$ -	$ -	**$ 1,301**	100%
31	BI11X010B	Capital Items - Coop/BREC hardware/s	$ 67,606	$ -	$ -	**$ 67,606**	100%
32	BI11X013B	Backup system for NERC	$ 61,585	$ -	$ -	**$ 61,585**	100%
33	BI12X001B	EMS Hardware Software upgrade	$ 547,045	$ -	$ -	**$ 547,045**	100%
34	BI12X002B	Replace PC's, Laptops, Printers	$ 102,202	$ -	$ -	**$ 102,202**	100%
35	BI12X003B	Replace - Data Centers Servers at HQ a	$ 70,017	$ -	$ -	**$ 70,017**	48%
36	BI12X004B	Oracle extensions -- eAM Scheduler	$ 127,857	$ -	$ -	**$ 127,857**	100%
37	BI12X006B	Compliance with NERC CIP Cyber Sec	$ 18,727	$ -	$ -	**$ 18,727**	78%
38	BI12X008B	Replace 4-C4006 Cisco network switch	$ 45,375	$ -	$ -	**$ 45,375**	100%

Big Rivers Electric Corporation
Case No. 2013-00199
Construction Projects

For the 12 Months Preceding the Base Period
(10/1/2011 - 09/30/2012)

Type of Filing: Original - X ; Updated - ______; Revised - ______

Schedule 2

Line No. (A)	Project No. (B)	Description of Project (C)	Accumulated Costs: Construction Amount (D)	AFUDC Capitalized (E)	Indirect Costs Other (F)[1]	Total Costs (G = D+E+F)	Estimated Physical % Completed (H)
39	BI12X009B	Replace 8-C3548 Cisco switches with 2	$ 15,150	$ -	$ -	**$ 15,150**	100%
40	BI12X011B	Replace Coop/BREC hardware/softwar	$ 7,630	$ -	$ -	**$ 7,630**	6%
41	BI12X017B	Replace Coop LaserFiche, Audiotel	$ 3,197	$ -	$ -	**$ 3,197**	53%
42	BI12X018F	Oracle License fees for payroll and HR	$ 46,513	$ -	$ -	**$ 46,513**	100%
43	BI12X019F	PER-005 training software	$ 16,960	$ -	$ -	**$ 16,960**	100%
44	BI12X020F	STR - AventX Oracle Attachments Prin	$ 31,250	$ -	$ -	**$ 31,250**	85%
45	BI12X021F	AC for Computer Room	$ 697	$ -	$ -	**$ 697**	100%
46	BI12X022F	eAM upgrade	$ 138,931	$ -	$ -	**$ 138,931**	100%
47	BP10C022B	CL Ready Pile Escape Tunnel	$ (300)	$ -	$ -	**$ (300)**	100%
48	BP10C047B	C-2 Boiler Feed Water Start Up Regula	$ (3,570)	$ -	$ -	**$ (3,570)**	100%
49	BP10C058B	C-2 Weld Overlay	$ (40)	$ -	$ -	**$ (40)**	100%
50	BP10G017B	GN - Landfill Downdrains	$ (4,277)	$ -	$ -	**$ (4,277)**	100%
51	BP10G019B	G2 - Upgrade SOE Migrate to DCS	$ 28,734	$ -	$ -	**$ 28,734**	100%
52	BP10G032F	GN - Barge Unloader Dust Collector	$ 303,653	$ -	$ -	**$ 303,653**	100%
53	BP10G041F	GN - Paint Boiler & Precip	$ 2,048,989	$ -	$ -	**$ 2,048,989**	75%
54	BP10G046F	CMS - Shop Expansion	$ 2,986	$ -	$ -	**$ 2,986**	100%
55	BP10S003B	H0 - Scrubber Stack Probes & Umbilic	$ 22,028	$ -	$ -	**$ 22,028**	100%
56	BP10S006B	H1 - Cooling Tower Controls	$ 15,367	$ -	$ -	**$ 15,367**	100%
57	BP10S007B	H1 - Feedwater Heater Level Controls (	$ (84)	$ -	$ -	**$ (84)**	100%

Big Rivers Electric Corporation
Case No. 2013-00199
Construction Projects

For the 12 Months Preceding the Base Period
(10/1/2011 - 09/30/2012)

Type of Filing: Original - __X__; Updated - ______; Revised - ______

Schedule 2

Line No. (A)	Project No. (B)	Description of Project (C)	Accumulated Costs: Construction Amount (D)	AFUDC Capitalized (E)	Indirect Costs Other (F)[1]	Total Costs (G = D+E+F)	Estimated Physical % Completed (H)
77	BP11C026B	CL 4160 to 480 step down transformer	$ 62,669	$ -	$ -	**$ 62,669**	100%
78	BP11C028B	CL Piezometer - Ashpond Geotechnical	$ 27,573	$ -	$ -	**$ 27,573**	100%
79	BP11C032B	CL Remote Racking and Relays (ARC I	$ 98,276	$ -	$ -	**$ 98,276**	100%
80	BP11C033B	C-1 Auxillary Transformer & Containm	$ 344,354	$ -	$ -	**$ 344,354**	66%
81	BP11C046F	CL Drying Agent Equipment	$ 84,323	$ -	$ -	**$ 84,323**	100%
82	BP11C047F	CL Sewage Line	$ 76,174	$ -	$ -	**$ 76,174**	7%
83	BP11C050F	C3 Excitation Transformer	$ 288,487	$ -	$ -	**$ 288,487**	60%
84	BP11C051F	C2 Upper Spray Regulator Isolation Va	$ 346	$ -	$ -	**$ 346**	100%
85	BP11C052F	CL Server & Client Replacement	$ 251,631	$ -	$ -	**$ 251,631**	100%
86	BP11C053F	CL Vent Fan GDE Bldg Hydroclone Rc	$ 12,309	$ -	$ -	**$ 12,309**	100%
87	BP11C054F	CL Absolute Pressure Calibrator	$ 14,551	$ -	$ -	**$ 14,551**	100%
88	BP11C055F	CL Bump Stations for Control Room M	$ 2,438	$ -	$ -	**$ 2,438**	100%
89	BP11C056F	CL GDE Building Bathroom/Breakroor	$ 90,637	$ -	$ -	**$ 90,637**	100%
90	BP11C057F	CL Install three (3) Silica Analyzers	$ 44,869	$ -	$ -	**$ 44,869**	100%
91	BP11C058F	CL Electrical Shop Tool Box	$ 2,300	$ -	$ -	**$ 2,300**	100%
92	BP11C059F	CL Veripro Hearing Protection Fit Test	$ 2,875	$ -	$ -	**$ 2,875**	100%
93	BP11G007B	G1 - # 3 LP Heater Retube	$ 129,353	$ -	$ -	**$ 129,353**	100%
94	BP11G008B	G1 - Air Heater Baskets	$ 260,992	$ -	$ -	**$ 260,992**	100%
95	BP11G009B	G1 - C/T Cell Structure and Fill Replac	$ 604,514	$ -	$ -	**$ 604,514**	100%

Big Rivers Electric Corporation
Case No. 2013-00199
Construction Projects

For the 12 Months Preceding the Base Period
(10/1/2011 - 09/30/2012)

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Schedule 2

			Accumulated Costs				
Line No. (A)	**Project No. (B)**	**Description of Project (C)**	**Construction Amount (D)**	**AFUDC Capitalized (E)**	**Indirect Costs Other (F)[1]**	**Total Costs (G = D+E+F)**	**Estimated Physical % Completed (H)**
96	BP11G012B	G1 - Economizer Outlet Exp Joints	$ 86,831	$ -	$ -	**$ 86,831**	100%
97	BP11G014B	GN - River Water Makeup Pump 1 of 3	$ 9,213	$ -	$ -	**$ 9,213**	100%
98	BP11G015B	GN - 1 & 2 FGD Consolidation - Loop	$ 13,967	$ -	$ -	**$ 13,967**	100%
99	BP11G018B	G1 - Precip Repair	$ 539,379	$ -	$ -	**$ 539,379**	100%
100	BP11G019B	GN - Precipitator AVCs	$ 5,827	$ -	$ -	**$ 5,827**	100%
101	BP11G020B	GN - Rpl 4160v Breakers	$ 49,000	$ -	$ -	**$ 49,000**	100%
102	BP11G021B	GN - Rpl 480v Breakers	$ 48,000	$ -	$ -	**$ 48,000**	100%
103	BP11G022B	G1 - Cold Reheat hangers (3 Sets)	$ 10,345	$ -	$ -	**$ 10,345**	100%
104	BP11G023B	G1 - Hot Reheat hangers (3 Sets)	$ 33,030	$ -	$ -	**$ 33,030**	100%
105	BP11G024B	G1 - Main Steam hangers (3 Sets)	$ 12,337	$ -	$ -	**$ 12,337**	100%
106	BP11G026B	G2 - Bottom Ash Dog House (1st of 4)	$ 16,681	$ -	$ -	**$ 16,681**	100%
107	BP11G027B	G2 - Replace Steam Coil Drain Tank	$ 22,136	$ -	$ -	**$ 22,136**	100%
108	BP11G031B	GN - B Coal Handling Transfer Tower	$ 43,307	$ -	$ -	**$ 43,307**	100%
109	BP11G033B	GN - Lime Silo Dust Collector	$ 56,603	$ -	$ -	**$ 56,603**	100%
110	BP11G035B	GN - Valve Operator Limitorque Type I	$ 543	$ -	$ -	**$ 543**	100%
111	BP11G037B	GN - Landfill Downdrains	$ 18,583	$ -	$ -	**$ 18,583**	100%
112	BP11G038B	GN - Landfill Expansion	$ 88,041	$ -	$ -	**$ 88,041**	100%
113	BP11G039B	GN - #2 Clarifier Coating	$ 86,600	$ -	$ -	**$ 86,600**	100%
114	BP11G042B	GN - Lab Sample and Analyzers	$ 93,269	$ -	$ -	**$ 93,269**	90%

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115	BP11G043B	G1 - Generator Rectifier Replacement	$ 165,089	$ -	$ -	**$ 165,089**	100%
116	BP11G044B	G1 - Generator Voltage Regulator	$ 111,227	$ -	$ -	**$ 111,227**	100%
117	BP11G045B	GN - (SW) USS Transformer	$ 13,689	$ -	$ -	**$ 13,689**	100%
118	BP11G046B	GN - Barge Unloader Battery	$ (416)	$ -	$ -	**$ (416)**	100%
119	BP11G051B	G2 - Remote Racking and Relays (ARC	$ 5,537	$ -	$ -	**$ 5,537**	100%
120	BP11G053B	G1 - Drum Camera Replacement	$ 38,872	$ -	$ -	**$ 38,872**	100%
121	BP11G054B	G1 - O2 Probe Additions	$ 26,707	$ -	$ -	**$ 26,707**	100%
122	BP11G055B	G2 - Drum Camera Replacement	$ 38,582	$ -	$ -	**$ 38,582**	100%
123	BP11G057B	G1 - D Coal Conveyor Drive Gearbox	$ 80,763	$ -	$ -	**$ 80,763**	100%
124	BP11G059B	GN - Additive Feed Pump 1of 4	$ 12,644	$ -	$ -	**$ 12,644**	100%
125	BP11G060B	GN - Additive Supply Pump 1 of 4	$ 8,051	$ -	$ -	**$ 8,051**	100%
126	BP11G061B	GN - Bleed Pump (2) 7 & 8 of 8	$ 797	$ -	$ -	**$ 797**	100%
127	BP11G064B	GN - Rpl Lime Silo Screws	$ 3,765	$ -	$ -	**$ 3,765**	100%
128	BP11G067B	GN - IUCS Controls	$ 128,982	$ -	$ -	**$ 128,982**	100%
129	BP11G077B	GN - FGD Rehab	$ 3,055,258	$ -	$ -	**$ 3,055,258**	71%
130	BP11G078F	G1 - Conditioner Monitor Replacement	$ 11,328	$ -	$ -	**$ 11,328**	100%
131	BP11G081B	G1 - Hot Reheat Safety	$ 788	$ -	$ -	**$ 788**	30%
132	BP11G082F	GN - Network Infrustructure Expansion	$ 3,522	$ -	$ -	**$ 3,522**	41%
133	BP11G083F	G1 - Precipitator A side Inlet Diffuser F	$ 172,402	$ -	$ -	**$ 172,402**	100%

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153	BP11H022B	H2 - DCS Cooling Tower Controls	$ 104	$ -	$ -	**$ 104**	80%
154	BP11H023B	H2 - Feedwater Heater Level Controls	$ 55,489	$ -	$ -	**$ 55,489**	100%
155	BP11H024B	H2 - Precipitator Controls	$ 83,922	$ -	$ -	**$ 83,922**	100%
156	BP11H025B	H2 -Turbine Trip Block Upgrade	$ 149,604	$ -	$ -	**$ 149,604**	100%
157	BP11H029B	H1 - Burner Replacement Study	$ 18,970	$ -	$ -	**$ 18,970**	100%
158	BP11H030F	H2 - 480V MCC at Cooling Tower (O)	$ 248,711	$ -	$ -	**$ 248,711**	11%
159	BP11H038F	H1 - NEMS Analyzers & Probes	$ 68,193	$ -	$ -	**$ 68,193**	100%
160	BP11H039F	H1 - Damper to SCR West Expansion J	$ 39,937	$ -	$ -	**$ 39,937**	100%
161	BP11H040F	H0 - Scrubber Mist Eliminator Regulati	$ 6,535	$ -	$ -	**$ 6,535**	100%
162	BP11H041F	H2 - "A" Pulverizer Gearbox	$ 2,647	$ -	$ -	**$ 2,647**	100%
163	BP11H042F	H1 - Boiler Access Door	$ 19,385	$ -	$ -	**$ 19,385**	100%
164	BP11H043F	H2 - "B" Condensate Drain Tank Pump	$ 5,798	$ -	$ -	**$ 5,798**	100%
165	BP11H044F	H0 - East/West Lower Terminal Tubes	$ 3,845	$ -	$ -	**$ 3,845**	100%
166	BP11H045F	H0 - Monitor Air Dryers	$ 8,424	$ -	$ -	**$ 8,424**	100%
167	BP11H046F	H0 - 7A Conveyor Belt	$ 3,022	$ -	$ -	**$ 3,022**	100%
168	BP11M007F	CMS - Ingersol-Rand CNC Water Jet T	$ 16,460	$ -	$ -	**$ 16,460**	100%
169	BP11Q002B	RH - Barge Unloader Drives	$ 57,678	$ -	$ -	**$ 57,678**	100%
170	BP11Q021B	RH - Caustic Pump	$ 6,136	$ -	$ -	**$ 6,136**	100%
171	BP11Q022B	RH - Acid Regeneration Pump	$ 6,420	$ -	$ -	**$ 6,420**	100%

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172	BP11Q023B	RH - De-Mineralizer Pump	$	4,948	$	-	$	-	**$**	**4,948**	100%
173	BP11Q024F	RH - Dry Flyash Equalizing Valves	$	26,409	$	-	$	-	**$**	**26,409**	100%
174	BP11Q025F	RH - Copy Machine	$	5,863	$	-	$	-	**$**	**5,863**	100%
175	BP11Q026F	RH - "B" Silo Sump Pump	$	40,303	$	-	$	-	**$**	**40,303**	100%
176	BP11Q027F	RH - 4A Conveyor Belt	$	10,140	$	-	$	-	**$**	**10,140**	100%
177	BP11Q028F	RH - Genie 34' Aerial Platform	$	15,018	$	-	$	-	**$**	**15,018**	100%
178	BP11Q029F	RH - Portable Welding Machine	$	2,407	$	-	$	-	**$**	**2,407**	100%
179	BP11Q031F	RH - 5A Conveyor Belt	$	11,946	$	-	$	-	**$**	**11,946**	100%
180	BP11R001F	R1 - "B" Mill Trunnion Bearing Housin	$	(106,652)	$	-	$	-	**$**	**(106,652)**	100%
181	BP11R003B	R1 - A2 & B2 Coal Valves	$	(868)	$	-	$	-	**$**	**(868)**	100%
182	BP11R004F	R1 - "A" Basement Sump Pump	$	9,750	$	-	$	-	**$**	**9,750**	100%
183	BP11R005F	GT - Purge Valves (2)	$	14,391	$	-	$	-	**$**	**14,391**	100%
184	BP11S002B	RGH - River Intake 480 Volt MCC	$	31,610	$	-	$	-	**$**	**31,610**	100%
185	BP11S006F	RGH - Magnetic Sweeper	$	8,023	$	-	$	-	**$**	**8,023**	100%
186	BP11S007F	RGH - Hydraulic Wrench	$	13,707	$	-	$	-	**$**	**13,707**	100%
187	BP11W006B	Replace #2 Polisher Liner	$	9,488	$	-	$	-	**$**	**9,488**	100%
188	BP11W010B	Replace WWP 5 & WWP 20 Impoundn	$	53,555	$	-	$	-	**$**	**53,555**	100%
189	BP11W012B	Fuels Area Service Bldg HVAC Replac	$	18,334	$	-	$	-	**$**	**18,334**	100%
190	BP11W014B	Finishing Superheater milestone pmt	$	891,349	$	-	$	-	**$**	**891,349**	24%

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191	BP11W018B	Waste Water Clarifier Refurbishment P	$ 216,329	$ -	$ -	**$ 216,329**	100%
192	BP11W021B	Remote Racking & Relays (ARC Flash)	$ 10,873	$ -	$ -	**$ 10,873**	100%
193	BP11W022B	Replace Barge Unloader Controls	$ 184,079	$ -	$ -	**$ 184,079**	100%
194	BP11W025B	Barge Unloader, Car Dumper, Sample T	$ 104,142	$ -	$ -	**$ 104,142**	100%
195	BP11W026B	Secondary Air Heater Milestone pmt	$ 2,382,850	$ -	$ -	**$ 2,382,850**	28%
196	BP11W029F	Rotary Parts cleaning for Mobile Fuels	$ 2,768	$ -	$ -	**$ 2,768**	100%
197	BP11W030F	Pressure Washer for Mtce (BURDEN)	$ 119	$ -	$ -	**$ 119**	100%
198	BP11W036B	6A conveyor belt	$ 42,507	$ -	$ -	**$ 42,507**	100%
199	BP11W037B	7-3 conveyor belt	$ 12,266	$ -	$ -	**$ 12,266**	100%
200	BP11W038B	8-1 conveyor belt	$ 249,342	$ -	$ -	**$ 249,342**	100%
201	BP11W040F	Nox monitoring system	$ 8,950	$ -	$ -	**$ 8,950**	100%
202	BP11W042F	Acid Pumps	$ 2,131	$ -	$ -	**$ 2,131**	100%
203	BP11W044F	Clam Shell Strainer	$ 878	$ -	$ -	**$ 878**	100%
204	BP11W046F	Steam header isolation vavle on SCR	$ 7,964	$ -	$ -	**$ 7,964**	100%
205	BP11W047F	Blow down sump pump VFD	$ 18,000	$ -	$ -	**$ 18,000**	100%
206	BP11W049F	Portable Diesel Pump	$ 1,795	$ -	$ -	**$ 1,795**	100%
207	BP11W050F	Veripro Hearing System	$ 3,048	$ -	$ -	**$ 3,048**	100%
208	BP11W051F	Surviair Respirators	$ 6,891	$ -	$ -	**$ 6,891**	100%
209	BP11W052F	Ambulance bldg roof	$ 8,720	$ -	$ -	**$ 8,720**	100%

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210	BP11W053F	B&R warehouse bldg roof	$ 47,360	$ -	$ -	**$ 47,360**	100%
211	BP11W054F	Crusher/MCC bldg roof	$ 8,720	$ -	$ -	**$ 8,720**	100%
212	BP11W057F	SCR UPS (CRUME)	$ 851	$ -	$ -	**$ 851**	100%
213	BP11W058F	Density Meter (CAMPBELL)	$ 12,380	$ -	$ -	**$ 12,380**	100%
214	BP11W059F	Fencing for new Inventory laydown are	$ 28,165	$ -	$ -	**$ 28,165**	100%
215	BP11W060F	Soft Start Motor control starters 5A and	$ 90,499	$ -	$ -	**$ 90,499**	100%
216	BP11W061F	landfill drainage ditch	$ 122,246	$ -	$ -	**$ 122,246**	100%
217	BP11W062F	Surface Grinder	$ 24,502	$ -	$ -	**$ 24,502**	100%
218	BP11W063F	Coal Scales Processing System	$ 36,275	$ -	$ -	**$ 36,275**	100%
219	BP11W064F	TIG Welding Machine	$ 4,156	$ -	$ -	**$ 4,156**	100%
220	BP11W065F	Flyash blower	$ 40,260	$ -	$ -	**$ 40,260**	100%
221	BP11W066F	Flyash blower	$ 20,756	$ -	$ -	**$ 20,756**	100%
222	BP11X014B	AED Replacements (8 units)	$ 8,946	$ -	$ -	**$ 8,946**	100%
223	BP11X023B	New roof (Four-story side of building)	$ 45,157	$ -	$ -	**$ 45,157**	100%
224	BP12C007B	CL Barge Unloader Controls	$ 109,654	$ -	$ -	**$ 109,654**	100%
225	BP12C009B	CL DCS Fuel handling power supplies ı	$ 66,158	$ -	$ -	**$ 66,158**	99%
226	BP12C011B	CL Barge Unloader Bucket	$ 95,096	$ -	$ -	**$ 95,096**	100%
227	BP12C012B	CL 4160 to 480 step down transformer	$ 58,834	$ -	$ -	**$ 58,834**	100%
228	BP12C018B	CL Outboard Motor Flatboat	$ 9,540	$ -	$ -	**$ 9,540**	100%

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229	BP12C020B	C-3 B Circulating Water Pump	$ 258,091	$ -	$ -	**$ 258,091**	100%
230	BP12C021B	C-3 B Circulating Water Pump Column	$ 177,887	$ -	$ -	**$ 177,887**	100%
231	BP12C022B	C-1 A Traveling Water Screen Replace	$ 95,454	$ -	$ -	**$ 95,454**	100%
232	BP12C024B	C-3 B Mill Liner Replacement with inle	$ 130,480	$ -	$ -	**$ 130,480**	39%
233	BP12C040B	C-3 DCS controller repl BRC 300	$ 266,658	$ -	$ -	**$ 266,658**	100%
234	BP12C047B	C-1 Booster Fan Blades	$ 174	$ -	$ -	**$ 174**	100%
235	BP12C049B	C-1 3 New Boiler Safety Valves, 1 Colo	$ 64,184	$ -	$ -	**$ 64,184**	50%
236	BP12C050B	C-1 Boiler Expansion Joint Replacemer	$ 172,757	$ -	$ -	**$ 172,757**	81%
237	BP12C055B	C-1 Tube Replacement Hot Reheat Sect	$ 880,033	$ -	$ -	**$ 880,033**	53%
238	BP12C057B	C-1 Hot/Cold/Rating Drive Replacemer	$ 189,066	$ -	$ -	**$ 189,066**	88%
239	BP12C058B	C-1 MCC Replacement	$ 37,304	$ -	$ -	**$ 37,304**	21%
240	BP12C059B	C-1 DCS controller repl BRC 300	$ 152,709	$ -	$ -	**$ 152,709**	100%
241	BP12C060B	C-1 Vacuum Pump Replacement	$ 82,081	$ -	$ -	**$ 82,081**	61%
242	BP12C061B	C-1 FD fan housings, silencers & hoods	$ 259,305	$ -	$ -	**$ 259,305**	41%
243	BP12C062B	C-1 CEM Duct Gas Analysers Replacer	$ 80,349	$ -	$ -	**$ 80,349**	89%
244	BP12C064B	C-1 Start Up Regulator	$ 57,948	$ -	$ -	**$ 57,948**	48%
245	BP12C067B	C-1 PA flow measurement CAMMS, A	$ 56,101	$ -	$ -	**$ 56,101**	67%
246	BP12C073F	CL Instrument & Electrical Tool Boxes	$ 4,861	$ -	$ -	**$ 4,861**	100%
247	BP12C074F	CL Beamex MultiFunctional Calibrator	$ 4,964	$ -	$ -	**$ 4,964**	100%

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248	BP12C075F	CL Replace A & B WWT Sludge/Agita	$ 36,217	$ -	$ -	$ 36,217	100%
249	BP12C077F	C-2 C Mill Gear Reducer Replacement	$ 337,618	$ -	$ -	$ 337,618	100%
250	BP12C078F	CL Radial Arm Drill Press for M/M shc	$ 13,256	$ -	$ -	$ 13,256	100%
251	BP12C079F	CL Lab Benchtop Photospectrometer	$ 3,278	$ -	$ -	$ 3,278	100%
252	BP12C080F	CL Men's Restroom Air Conditioner	$ 11,276	$ -	$ -	$ 11,276	100%
253	BP12C081F	CL B Dewatering Sump Pump	$ 19,132	$ -	$ -	$ 19,132	100%
254	BP12C082F	CL A Reagent Area Sump Pump	$ 19,256	$ -	$ -	$ 19,256	100%
255	BP12C083F	CL Resin Trap	$ 3,329	$ -	$ -	$ 3,329	100%
256	BP12C084F	C-1 ROFA system expansion joints repl	$ 21,830	$ -	$ -	$ 21,830	38%
257	BP12C085F	C-1 & C2 Computer Room A/C Unit	$ 15,145	$ -	$ -	$ 15,145	100%
258	BP12C086F	CL Safety shower at Bulk acid tank	$ 17,545	$ -	$ -	$ 17,545	100%
259	BP12C090F	C-3 "B" Ball Mill Pinion Replacement	$ 21,620	$ -	$ -	$ 21,620	100%
260	BP12C091F	C-2 Booster Fan Blades	$ 177,937	$ -	$ -	$ 177,937	100%
261	BP12C092F	C-3 Booster Fan Blades	$ 178,726	$ -	$ -	$ 178,726	100%
262	BP12C093F	C-3 Ash Overflow Sump Pump	$ 19,405	$ -	$ -	$ 19,405	100%
263	BP12G014B	GN - Valve Operator Limitorque SMB '	$ 8,282	$ -	$ -	$ 8,282	100%
264	BP12G016B	G2 - Air Heater Baskets	$ 294,648	$ -	$ -	$ 294,648	100%
265	BP12G018B	GN - Landfill Downdrains	$ 1,802	$ -	$ -	$ 1,802	91%
266	BP12G020B	G2 - Battery Charger (2 of 2)	$ 48,856	$ -	$ -	$ 48,856	100%

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324	BP12H021B	H2 - "B" PA Fan Duct Expansion Joint	$ 23,264	$ -	$ -	$ 23,264	100%
325	BP12H022B	H1 - Classifier Reject Valves (2)	$ 47,231	$ -	$ -	$ 47,231	100%
326	BP12H023B	H2 - Classifier Reject Valves (2)	$ 7,161	$ -	$ -	$ 7,161	38%
327	BP12H025B	H1 - Boiler Access Door (West Side)	$ 19,728	$ -	$ -	$ 19,728	100%
328	BP12H026B	H0 - Cooling Tower Acid Pumps (2)	$ 5,637	$ -	$ -	$ 5,637	100%
329	BP12H027B	H1 - Remote Racking Devices	$ 10,878	$ -	$ -	$ 10,878	100%
330	BP12H028B	H2 - Rpl "B" Cooling Water Pump	$ 5,030	$ -	$ -	$ 5,030	100%
331	BP12H029B	H2 - "A" Condensate Pump	$ 35,928	$ -	$ -	$ 35,928	100%
332	BP12H030B	H1 - Steam Seal Root Valve	$ 4,648	$ -	$ -	$ 4,648	100%
333	BP12H031F	H0 - Drum Enclosure Ventilation	$ 94,100	$ -	$ -	$ 94,100	100%
334	BP12H033B	H2 - "A" Condensate Drain Tank Pump	$ 6,166	$ -	$ -	$ 6,166	100%
335	BP12H034F	H0 - NEMS HMI Computer	$ 9,392	$ -	$ -	$ 9,392	100%
336	BP12H035F	H0 - Additive Surge Tank Agitator	$ 4,404	$ -	$ -	$ 4,404	100%
337	BP12H036F	H1 - SCR Seal Air Fan Discharge Valv	$ 9,124	$ -	$ -	$ 9,124	100%
338	BP12H037F	H0 - Cooling Tower Makeup Regulator	$ 5,132	$ -	$ -	$ 5,132	100%
339	BP12M001B	15"X50" Engine Lathe	$ 17,908	$ -	$ -	$ 17,908	100%
340	BP12M002B	4'X4' Sandblasting Cabinet	$ 5,667	$ -	$ -	$ 5,667	100%
341	BP12M003B	15X50 CNC Tool Room Lathe	$ 67,057	$ -	$ -	$ 67,057	78%
342	BP12M005B	Compressed Air Dryer	$ 8,673	$ -	$ -	$ 8,673	100%

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343	BP12M008F	Scotchman Ironworker	$ 26,623	$ -	$ -	$ 26,623	100%
344	BP12Q006B	RH - Boothe Flyash System	$ 184,315	$ -	$ -	$ 184,315	100%
345	BP12Q011B	RH - Infrared Camera	$ 9,665	$ -	$ -	$ 9,665	100%
346	BP12Q012B	RH - Control Room Air Conditioner	$ 25,238	$ -	$ -	$ 25,238	100%
347	BP12Q013F	RH - #3 Circulating Water Pump	$ 194,799	$ -	$ -	$ 194,799	24%
348	BP12R001B	GT - Hydrogen Purity Meter	$ 17,316	$ -	$ -	$ 17,316	100%
349	BP12R003F	R1 - Load Ctr Breakers (4 Main & 2 Ti	$ 38,383	$ -	$ -	$ 38,383	100%
350	BP12W014B	#3 Fly Ash Blower - 1st and 2nd Stage	$ 3,300	$ -	$ -	$ 3,300	100%
351	BP12W015B	Barge Unloader Split System HVAC Re	$ 31,780	$ -	$ -	$ 31,780	100%
352	BP12W017B	DCS Server Replacement	$ 61,850	$ -	$ -	$ 61,850	100%
353	BP12W018B	2012 IT controls projects prepayments	$ 104,824	$ -	$ -	$ 104,824	100%
354	BP12W020B	Sootblower IK Replacement (IK6 & IK	$ 52,186	$ -	$ -	$ 52,186	100%
355	BP12W021B	Replace 6.9KV480v Switchgear breake	$ 1,162	$ -	$ -	$ 1,162	100%
356	BP12W023B	2012 IT controls projects prepayments	$ 248,062	$ -	$ -	$ 248,062	100%
357	BP12W027B	Supervisory instruments, ID, FD and PA	$ 229,170	$ -	$ -	$ 229,170	100%
358	BP12W028B	125 Volt Station Batteries and Charger	$ 158,706	$ -	$ -	$ 158,706	100%
359	BP12W029B	expansion joints	$ 317,167	$ -	$ -	$ 317,167	100%
360	BP12W030B	Conveyor belts (#4,6B,8-2, Boom Conv	$ 137,729	$ -	$ -	$ 137,729	100%
361	BP12W032B	Wilson Stack Cone Replacement	$ 480,033	$ -	$ -	$ 480,033	100%

Big Rivers Electric Corporation
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Construction Projects

For the 12 Months Preceding the Base Period
(10/1/2011 - 09/30/2012)

Type of Filing: Original - __X__; Updated - ______; Revised - ______

Schedule 2

Line No. (A)	Project No. (B)	Description of Project (C)	Accumulated Costs: Construction Amount (D)	AFUDC Capitalized (E)	Indirect Costs Other (F)[1]	Total Costs (G = D+E+F)	Estimated Physical % Completed (H)
362	BP12W034B	Burner Replacement 13 of 25*	$ 366,972	$ -	$ -	$ 366,972	100%
363	BP12W035B	Catalyst Regeneration	$ 1,271,512	$ -	$ -	$ 1,271,512	100%
364	BP12W036B	Waterwall Tube Replacement	$ 333,559	$ -	$ -	$ 333,559	37%
365	BP12W039B	B&R Warehouse Roof (Service Bldg R	$ 74,374	$ -	$ -	$ 74,374	100%
366	BP12W040F	Regulating valve on turbine lube oil coc	$ 6,923	$ -	$ -	$ 6,923	100%
367	BP12W041F	Hydrogen seal oil coolers	$ 101,667	$ -	$ -	$ 101,667	100%
368	BP12W042F	ID inlet fan dampers	$ 231,529	$ -	$ -	$ 231,529	100%
369	BP12W043F	Acid Pumps	$ 24,764	$ -	$ -	$ 24,764	100%
370	BP12W044F	ME Hoist	$ 15,145	$ -	$ -	$ 15,145	100%
371	BP12W045F	Primary Air Steam Coils	$ 55,431	$ -	$ -	$ 55,431	100%
372	BP12W046F	ALE20 Gate valve	$ 8,807	$ -	$ -	$ 8,807	100%
373	BP12W047F	Ground Fault Detection Equipment	$ 10,180	$ -	$ -	$ 10,180	100%
374	BP12W048F	Fuel Handling building Ice machine	$ 3,343	$ -	$ -	$ 3,343	100%
375	BP12W049F	Survey Meter	$ 3,059	$ -	$ -	$ 3,059	100%
376	BP12W050F	Auto Transfer Switches	$ 30,208	$ -	$ -	$ 30,208	100%
377	BP12W051F	Ash Sump pump (Hollander)	$ 35,517	$ -	$ -	$ 35,517	100%
378	BP12W052F	Polisher Liners (Hickman)	$ 40,384	$ -	$ -	$ 40,384	100%
379	BP12W053F	#1 Bunker gate replacement project	$ 19,278	$ -	$ -	$ 19,278	100%
380	BP12W054F	Replace primary air heater gas outlet ex	$ 46,058	$ -	$ -	$ 46,058	100%

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Schedule 2

Line No. (A)	Project No. (B)	Description of Project (C)	Accumulated Costs: Construction Amount (D)	AFUDC Capitalized (E)	Indirect Costs Other (F)[1]	Total Costs (G = D+E+F)	Estimated Physical % Completed (H)
381	BP12W055F	Replace #6 Cooling Tower Fan Gear Re	$ 73,452	$ -	$ -	$ 73,452	100%
382	BP12W056F	#12 Conveyor Belt Replacement	$ 7,900	$ -	$ -	$ 7,900	100%
383	BP12W057F	Level gauges for acid and caustic day ta	$ 8,278	$ -	$ -	$ 8,278	100%
384	BP12W058F	Plant two way communication repeater	$ 21,076	$ -	$ -	$ 21,076	100%
385	BP12W060F	WL Resin Traps	$ 49,680	$ -	$ -	$ 49,680	90%
386	BP12W061F	WL Replacement of Turbine Building \	$ 68,916	$ -	$ -	$ 68,916	87%
387	BP12W062F	WL Replacement of 110-LL32 #2 Ball	$ 18,149	$ -	$ -	$ 18,149	100%
388	BP12W063F	WL SO3 Blower Replacement	$ 12,284	$ -	$ -	$ 12,284	100%
389	BP12W065F	14000lb Four Post Vehicle Lift	$ 8,605	$ -	$ -	$ 8,605	100%
390	BP13C021B	C-1 A Circulating Water Pump	$ 111,116	$ -	$ -	$ 111,116	33%
391	BP13H018B	H2 - Voltage Regulator	$ 53,824	$ -	$ -	$ 53,824	63%
392	BT11X009B	Substation Gravel at Meade	$ 17,246	$ -	$ -	$ 17,246	100%
393	BT11X011B	Replace TC Blocking Carriers (9)	$ 87,796	$ -	$ -	$ 87,796	73%
394	BT11X013B	Replace Disconnects at Coleman (10)	$ 88,848	$ -	$ -	$ 88,848	95%
395	BT11X019B	On-line DGA Monitoring for Green GS	$ 73,015	$ -	$ -	$ 73,015	100%
396	BT11X022B	LTC online filter Hancock County #2	$ 4,603	$ -	$ -	$ 4,603	100%
397	BT11X023B	Ledbetter 69 kV Switching Structure	$ 15,790	$ -	$ -	$ 15,790	100%
398	BT11X025B	Hoist, Rope and Grips Replacements	$ 5,928	$ -	$ -	$ 5,928	100%
399	BT11X026B	Hancock Co 69 kV Capacitor Bank	$ 4,500	$ -	$ -	$ 4,500	96%

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Schedule 2

Line No. (A)	Project No. (B)	Description of Project (C)	Accumulated Costs: Construction Amount (D)	AFUDC Capitalized (E)	Indirect Costs Other (F)[1]	Total Costs (G = D+E+F)	Estimated Physical % Completed (H)
400	BT11X027B	Fax Machine Replacement	$ 525	$ -	$ -	**$ 525**	100%
401	BT11X029B	Capital Tool Replacements	$ 1,723	$ -	$ -	**$ 1,723**	100%
402	BT11X030B	All-Terrain Vehicle (Line Crew)	$ 15,649	$ -	$ -	**$ 15,649**	100%
403	BT11X033B	Armstrong Lewis Creek Mine	$ 106,210	$ -	$ -	**$ 106,210**	100%
404	BT11X035F	Model 512A Lift	$ 1,367	$ -	$ -	**$ 1,367**	100%
405	BT11X036F	Fordsville Tie Switching Structure	$ 38,884	$ -	$ -	**$ 38,884**	100%
406	BT11X037F	Communication Tower Corrosion Prote	$ 352,517	$ -	$ -	**$ 352,517**	100%
407	BT11X038F	Jofra Temp Calibrator	$ 3,830	$ -	$ -	**$ 3,830**	100%
408	BT11X039F	On-line Tap Changer Filter for Henders	$ 4,603	$ -	$ -	**$ 4,603**	100%
409	BT11X041F	Skillman Battery, Rack, Charger	$ 21,084	$ -	$ -	**$ 21,084**	100%
410	BT11X042F	Raise 69KV Line 5F over Tradewater	$ 10,018	$ -	$ -	**$ 10,018**	56%
411	BT11X043F	Hopkins Co. MW Battery & Rack	$ 7,462	$ -	$ -	**$ 7,462**	100%
412	BT11X044F	Corydon Sub Batteries	$ 13,461	$ -	$ -	**$ 13,461**	100%
413	BT11X045F	Morganfield Sub Batteries	$ 11,185	$ -	$ -	**$ 11,185**	100%
414	BT11X046F	Polaris trailer	$ 3,657	$ -	$ -	**$ 3,657**	100%
415	BT11X047F	Safety equipment trailer	$ 4,823	$ -	$ -	**$ 4,823**	100%
416	BT11X048F	Utility Trailer for Gator	$ 2,597	$ -	$ -	**$ 2,597**	100%
417	BT11X049F	McCracken Shell Line C Phase PT	$ 5,276	$ -	$ -	**$ 5,276**	100%
418	BT11X050F	McCracken Kevil Line B Phase PT	$ 5,276	$ -	$ -	**$ 5,276**	100%

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Schedule 2

Line No. (A)	Project No. (B)	Description of Project (C)	Accumulated Costs: Construction Amount (D)	AFUDC Capitalized (E)	Indirect Costs Other (F)[1]	Total Costs (G = D+E+F)	Estimated Physical % Completed (H)
419	BT11X051F	Aeroflex Power and Frequency Meter a	$ 16,294	$ -	$ -	$ 16,294	100%
420	BT11X052F	TR fence for martin marietta substation	$ 17,840	$ -	$ -	$ 17,840	100%
421	BT11X053F	Transmission ASE test set	$ 3,325	$ -	$ -	$ 3,325	100%
422	BT12X001B	Martin Marietta T3	$ 119,837	$ -	$ -	$ 119,837	53%
423	BT12X009B	Horse Fork Tap 69 KV switch	$ 64,188	$ -	$ -	$ 64,188	100%
424	BT12X011B	Oil drum transfer pump	$ 597	$ -	$ -	$ 597	100%
425	BT12X012B	On-line DGA Monitoring for HMPL G	$ 154,988	$ -	$ -	$ 154,988	100%
426	BT12X016B	Replace repair roof at Wilson Substatio	$ 30,179	$ -	$ -	$ 30,179	100%
427	BT12X017B	Replace Substation Battery and Charge	$ 15,566	$ -	$ -	$ 15,566	15%
428	BT12X023B	Two (2) spare 161 kv CCVT's	$ 25,158	$ -	$ -	$ 25,158	100%
429	BT12X025B	Cumberland-Caldwell Springs Tap 69 k	$ 126,359	$ -	$ -	$ 126,359	50%
430	BT12X026B	Garrett-Flaherty 3 Mi 69 KV Line	$ 214,606	$ -	$ -	$ 214,606	26%
431	BT12X027B	Meade to Garrett 69 kV Reconductor	$ 207,508	$ -	$ -	$ 207,508	43%
432	BT12X029B	South Dermont - RCS	$ 8,134	$ -	$ -	$ 8,134	100%
433	BT12X030F	Work Platforms	$ 2,093	$ -	$ -	$ 2,093	100%
434	BT12X031F	Online Tap Changer Filter for Reid #1	$ 6,694	$ -	$ -	$ 6,694	100%
435	BT12X032F	CT Henderson	$ 12,612	$ -	$ -	$ 12,612	100%
436	BT12X033F	Metering Transformers	$ 5	$ -	$ -	$ 5	0%
437	BT12X035F	Reid Capacitor Bank	$ 17,532	$ -	$ -	$ 17,532	100%

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Schedule 2

			Accumulated Costs				
Line No. (A)	**Project No. (B)**	**Description of Project (C)**	**Construction Amount (D)**	**AFUDC Capitalized (E)**	**Indirect Costs Other (F)[1]**	**Total Costs (G = D+E+F)**	**Estimated Physical % Completed (H)**
438	BT12X036F	ELK Creek 69 kv service	$ 2,430	$ -	$ -	**$ 2,430**	100%
439	BT12X038F	Hancock County Transformer 1	$ 8,471	$ -	$ -	**$ 8,471**	1%
440	BT12X039F	Habit MW battery charger	$ 3,516	$ -	$ -	**$ 3,516**	100%
441	BT12X040F	Morganfield Battery charger	$ 3,873	$ -	$ -	**$ 3,873**	100%
442	BT12X041F	Maxon 69 kv T-line	$ 8,303	$ -	$ -	**$ 8,303**	44%
443	BT12X042F	CCVT Hopkins Co Substation	$ 6,837	$ -	$ -	**$ 6,837**	100%
444	BT12X046F	Dixon Tap Culvert	$ 2,127	$ -	$ -	**$ 2,127**	100%
445	BT12X047F	CCVT at Hopkins Co. Substation	$ 933	$ -	$ -	**$ 933**	100%
446	Various Old	CL Carry Over Projects	$ 1,222	$ -	$ -	**$ 1,222**	100%
447	W0010000	R1 & R2 161 KV Lines Teleprotection	$ 2,354	$ -	$ -	**$ 2,354**	18%
448	W9010000	Wilson EHV 161 KV Line Terminal foı	$ 736,426	$ -	$ -	**$ 736,426**	95%
449	W9100000	Daviess Co Airport Line Reroute - Rein	$ 1,689	$ -	$ -	**$ 1,689**	100%
450	W9190000	Wilson 161 KV Line 19F Addition	$ 676,038	$ -	$ -	**$ 676,038**	100%
451	W9230000	2-Way Radio Replacement	$ 4,163,461	$ -	$ -	**$ 4,163,461**	99%
452	W9300000	White Oak - 50 MVA Substation	$ (96,157)	$ -	$ -	**$ (96,157)**	8%
453	W9330000	Switches - Const 933	$ (567)	$ -	$ -	**$ (567)**	100%
454	W9340000	Wilson EHV 161-69 KV Substation Ad	$ 1,862,643	$ -	$ -	**$ 1,862,643**	100%
455	W9350000	Wilson 69 KV Line to Centertown Add	$ 716,104	$ -	$ -	**$ 716,104**	97%
456	W9450000	Livingston Co Autotransformer-Ice Stoı	$ (442,480)	$ -	$ -	**$ (442,480)**	100%

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Schedule 2

Line No. (A)	Project No. (B)	Description of Project (C)	Accumulated Costs: Construction Amount (D)	AFUDC Capitalized (E)	Indirect Costs Other (F)[1]	Total Costs (G = D+E+F)	Estimated Physical % Completed (H)
457	W9510000	REID BREAKER	$ (62,515)	$ -	$ -	**$ (62,515)**	100%
458	W9520000	MW Upgrade with Additional OC-3 to	$ 57,936	$ -	$ -	**$ 57,936**	100%
459	W9560000	Paradise to 7B Tap 161 KV Line Recon	$ 154,948	$ -	$ -	**$ 154,948**	37%
460	W9600000	Oracle Install	$ (67,500)	$ -	$ -	**$ (67,500)**	100%
461	W9650000	Paradise 161 KV Line Terminal Upgrac	$ 385,406	$ -	$ -	**$ 385,406**	63%

[1] Explanations of all other indirect costs.

Expenditures are for date range indicated above

Estimated Physical % completion for all projects for each date range indicated above is based on spending from project inception during period listed divided by the project budget estimate during period.

Capitalized Interest included in construction projects $250k and greater unless specifically identified

Excludes City's Share

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Construction Projects

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(10/1/2012 - 9/30/2013)

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Schedule 2

Line No.	Project No.	Description of Project	Accumulated Costs: Construction Amount	AFUDC Capitalized	Indirect Costs Other	Total Costs	Estimated Physical % Completed
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
1	2012 POLES	Pole Change Outs	$ 72,555	$ -	$ -	**$ 72,555**	72%
2	2013 POLES	Pole Change Outs	$ 442,041	$ -	$ -	**$ 442,041**	6%
3	BA11X048B	Operator Training Simulator	$ 218,420	$ -	$ -	**$ 218,420**	
4	BA12X001B	Miscellaneous Air Monitoring Replacer	$ 44,955	$ -	$ -	**$ 44,955**	
5	BA12X005B	Black lateral files ($1,200/ea) (pushed f	$ 4,639	$ -	$ -	**$ 4,639**	
6	BA12X018B	ENV - Rpl Environmental Truck (Tom	$ 35,220	$ -	$ -	**$ 35,220**	
7	BA12X034B	Black Vert & Lateral Files ($1,200/ea) (	$ 7,852	$ -	$ -	**$ 7,852**	
8	BA12X042F	Coper for Central lab	$ 1,025	$ -	$ -	**$ 1,025**	
9	BA13X001B	Miscellaneous Air Monitoring Replacer	$ 50,000	$ -	$ -	**$ 50,000**	31%
10	BA13X002B	Replace Mercury Analyzer	$ 50,000	$ -	$ -	**$ 50,000**	
11	BA13X003B	Replace Microwave Digestor	$ 45,000	$ -	$ -	**$ 45,000**	
12	BA13X004B	Replace CHN Analyzer	$ 100,000	$ -	$ -	**$ 100,000**	
13	BA13X005B	Reid Gas Conversion	$ 550,000	$ -	$ -	**$ 550,000**	
14	BA13X008B	Replacement Office Furniture	$ 2,500	$ -	$ -	**$ 2,500**	
15	BA13X009B	Drawing Scanner	$ 10,000	$ -	$ -	**$ 10,000**	58%
16	BA13X010B	CD Duplicator	$ 2,000	$ -	$ -	**$ 2,000**	
17	BA13X011B	High Angle Rescue Equipment	$ 2,000	$ -	$ -	**$ 2,000**	

For the Base Period
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Schedule 2

Line No.	Project No.	Description of Project	Accumulated Costs: Construction Amount	AFUDC Capitalized	Indirect Costs Other	Total Costs	Estimated Physical % Completed
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
18	BA13X012B	Rescue Manikin	$ 1,500	$ -	$ -	**$ 1,500**	
19	BA13X013B	Copy Machine	$ 17,000	$ -	$ -	**$ 17,000**	
20	BA13X014B	PROD - Rpl #422 - VP Production Veh	$ 40,000	$ -	$ -	**$ 40,000**	
21	BA13X016B	TRAN - Rpl #248 - 70' Bucket Truck	$ 300,000	$ -	$ -	**$ 300,000**	
22	BA13X017B	TRAN - Rpl #270 - Truck (diesel, crew	$ 60,000	$ -	$ -	**$ 60,000**	88%
23	BA13X018B	TRAN - Rpl #294 - Truck (diesel, ext c:	$ 50,000	$ -	$ -	**$ 50,000**	
24	BA13X019B	TRAN - Rpl #315 - Truck (ext cab, 1/2	$ 33,000	$ -	$ -	**$ 33,000**	
25	BA13X020B	TRAN - Rpl #318 - Truck (ext cab, 1/2	$ 35,000	$ -	$ -	**$ 35,000**	
26	BA13X021B	ENG - Rpl #326 - Truck (ext cab, 1/2 tc	$ 33,000	$ -	$ -	**$ 33,000**	
27	BI12X001B	OSI EMS software	$ 80,618	$ -	$ -	**$ 80,618**	100%
28	BI12X002B	Replace PC's, Laptops, Printers	$ 46,437	$ -	$ -	**$ 46,437**	100%
29	BI12X003B	Replace - Data Centers Servers at HQ a	$ 93,930	$ -	$ -	**$ 93,930**	
30	BI12X004B	Oracle extensions -- eAM Scheduler	$ 22,662	$ -	$ -	**$ 22,662**	
31	BI12X006B	Compliance with NERC CIP Cyber Sec	$ 200	$ -	$ -	**$ 200**	
32	BI12X007B	Replace BEST UPS at Headquarters	$ 40,888	$ -	$ -	**$ 40,888**	
33	BI12X011B	Replace Coop/BREC hardware/softwar	$ 127,325	$ -	$ -	**$ 127,325**	71%
34	BI12X019F	PER-005 training software	$ (822)	$ -	$ -	**$ (822)**	100%
35	BI12X020F	STR - AventX Oracle Attachments Prin	$ 5,442	$ -	$ -	**$ 5,442**	91%
36	BI12X021F	AC for Computer Room	$ 30,301	$ -	$ -	**$ 30,301**	100%
37	BI12X022F	eAM upgrade	$ 65,348	$ -	$ -	**$ 65,348**	100%
38	BI13X001B	Replacement PC's, Laptops, Printers	$ 190,000	$ -	$ -	**$ 190,000**	15%

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39	BI13X002B	Replacement Data Centers Servers (HQ	$ 125,000	$ -	$ -	**$ 125,000**	9%
40	BI13X003B	Replacement network switches (Plants)	$ 70,000	$ -	$ -	**$ 70,000**	
41	BI13X004B	Additional disk storage (SAN's)	$ 70,000	$ -	$ -	**$ 70,000**	
42	BI13X005B	Replace Palo Alto Server	$ 70,000	$ -	$ -	**$ 70,000**	
43	BI13X006B	Replace Firewalls in CIP's/Electronic P:	$ 25,000	$ -	$ -	**$ 25,000**	
44	BI13X007B	Replace Inverter on the Harris Diesel U	$ 70,000	$ -	$ -	**$ 70,000**	100%
45	BI13X008B	Replace Chart Recorders in Energy Cor	$ 60,000	$ -	$ -	**$ 60,000**	
46	BI13X009B	Replace Coop/BREC hardware/softwar	$ 305,000	$ -	$ -	**$ 305,000**	
47	BI13X010B	Software Tools	$ 10,000	$ -	$ -	**$ 10,000**	
48	BI13X011B	iSeries Software Replacement CIS/BIS	$ 60,000	$ -	$ -	**$ 60,000**	
49	BI13X012B	Corporate Analytics (BI) and Reporting	$ 400,000	$ -	$ -	**$ 400,000**	
50	BI13X013B	Upgrade Hyperion Rel 11.1.1.3 to 11.1.	$ 130,000	$ -	$ -	**$ 130,000**	
51	BI13X014B	Upgrade Oracle R12 from Rel 12.1.2 to	$ 445,000	$ -	$ -	**$ 445,000**	13%
52	BI13X015B	Replace Kenergy's Billing and Account	$ 274,380	$ -	$ -	**$ 274,380**	23%
53	BP10G019B	G2 - Upgrade SOE Migrate to DCS	$ 24,569	$ -	$ -	**$ 24,569**	100%
54	BP10G041F	GN - Paint Boiler & Precip	$ 1,585,062	$ -	$ -	**$ 1,585,062**	75%
55	BP10S008B	H1 - Precipitator Controls	$ (27)	$ -	$ -	**$ (27)**	100%
56	BP10S076F	H1 - Cooling Tower MCC	$ 731	$ -	$ -	**$ 731**	100%
57	BP10S087F	GT - Expansion Joints (6 ea.)	$ (11)	$ -	$ -	**$ (11)**	
58	BP11C033B	C-1 Auxillary Transformer & Containm	$ 175,000	$ -	$ -	**$ 175,000**	66%
59	BP11C047F	CL Sewage Line	$ 255,674	$ -	$ -	**$ 255,674**	

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(10/1/2012 - 9/30/2013)

Type of Filing: Original - ___X___; Updated - ______; Revised - ______

Schedule 2

Line No. (A)	Project No. (B)	Description of Project (C)	Accumulated Costs: Construction Amount (D)	AFUDC Capitalized (E)	Indirect Costs Other (F)[1]	Total Costs (G = D+E+F)	Estimated Physical % Completed (H)
60	BP11C048F	C-3 High Pressure Heater #5 Replacem	$ 265,794	$ -	$ -	**$ 265,794**	95%
61	BP11C050F	C-3 Excitation Transformer	$ 16,300	$ -	$ -	**$ 16,300**	60%
62	BP11G008B	G1 - Air Heater Baskets	$ 18,644	$ -	$ -	**$ 18,644**	100%
63	BP11G014B	G2 - B River Water Make Up Pump	$ 6,916	$ -	$ -	**$ 6,916**	100%
64	BP11G015B	GN - 1 & 2 FGD Consolidation - Loop	$ 14,275	$ -	$ -	**$ 14,275**	94%
65	BP11G016B	G2 - BRC 100 DCS Controller Upgrade	$ 7,896	$ -	$ -	**$ 7,896**	
66	BP11G017B	G2 - DCS Power Supply Upgrade	$ 20,585	$ -	$ -	**$ 20,585**	99%
67	BP11G031B	GN - B Coal Handling Transfer Tower	$ (1,923)	$ -	$ -	**$ (1,923)**	100%
68	BP11G051B	G2 - Remote Racking and Relays	$ 25,477	$ -	$ -	**$ 25,477**	100%
69	BP11G060B	GN - Bleed Pump (2) 7 & 8 of 8	$ (279)	$ -	$ -	**$ (279)**	100%
70	BP11G062B	GN - Reclaim Hopper (2 of 8)	$ (18,947)	$ -	$ -	**$ (18,947)**	
71	BP11G067B	GN - IUCS Controls	$ (13,423)	$ -	$ -	**$ (13,423)**	100%
72	BP11G077B	G1 & G2 FGD Rehab	$ 1,052,390	$ -	$ -	**$ 1,052,390**	71%
73	BP11G084B	G2 - Cold RH Drain Valves	$ 2,199	$ -	$ -	**$ 2,199**	
74	BP11G087F	G2 - O2 Probe Additions	$ 44,707	$ -	$ -	**$ 44,707**	100%
75	BP11H019B	H1 - AH Steam Coils (Qty 4) (SW#2)	$ (7,484)	$ -	$ -	**$ (7,484)**	100%
76	BP11H022B	H2 - DCS Cooling Tower Controls	$ 78,786	$ -	$ -	**$ 78,786**	62%
77	BP11H029B	H1 - Burner Replacement Study	$ (90,999)	$ -	$ -	**$ (90,999)**	
78	BP11H030F	H2 - Cooling Tower MCC	$ 61,951	$ -	$ -	**$ 61,951**	11%
79	BP11H042F	H1 - Boiler Access Door (East Side)	$ (18,906)	$ -	$ -	**$ (18,906)**	
80	BP11R005F	GT - Purge Valves (2)	$ 2,670	$ -	$ -	**$ 2,670**	
81	BP11W014B	Finishing Superheater replacement	$ 216,523	$ -	$ -	**$ 216,523**	40%

For the Base Period
(10/1/2012 - 9/30/2013)

Type of Filing: Original - ___X___; Updated - ______; Revised - ______

Schedule 2

Line No.	Project No.	Description of Project	Accumulated Costs				Estimated Physical % Completed
			Construction Amount	AFUDC Capitalized	Indirect Costs Other	Total Costs	
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
82	BP11W025B	Barge Unloader, Car Dumper, Sample 1	$ 25,352	$ -	$ -	**$ 25,352**	100%
83	BP11W026B	Secondary Air Heater Replacement	$ 207,471	$ -	$ -	**$ 207,471**	93%
84	BP11W040F	Nox analysis system	$ -	$ -	$ -	**$ -**	100%
85	BP12C007B	CL Barge Unloader Controls	$ 3,954	$ -	$ -	**$ 3,954**	100%
86	BP12C009B	CL DCS Fuel handling power supplies 1	$ (9,769)	$ -	$ -	**$ (9,769)**	98%
87	BP12C010B	CL Conveyor Belt Replacement	$ 12,972	$ -	$ -	**$ 12,972**	
88	BP12C020B	C-3 B Circulating Water Pump	$ 1,208	$ -	$ -	**$ 1,208**	100%
89	BP12C022B	C-1 A Traveling Water Screen Replace	$ (1,362)	$ -	$ -	**$ (1,362)**	100%
90	BP12C023B	C-3 Rpl 4160 V Motors (3A BFP & 3A	$ 114,879	$ -	$ -	**$ 114,879**	51%
91	BP12C024B	C-3 B Mill Liner Replacement with inle	$ 7,770	$ -	$ -	**$ 7,770**	39%
92	BP12C040B	C-3 DCS controller repl BRC 300 & Cc	$ 8,840	$ -	$ -	**$ 8,840**	100%
93	BP12C047B	C-1 Booster Fan Blades	$ 184,714	$ -	$ -	**$ 184,714**	100%
94	BP12C049B	C-1 3 New Boiler Safety Valves, 1 Colc	$ 40,000	$ -	$ -	**$ 40,000**	98%
95	BP12C050B	C-1 Boiler Expansion Joint Replacemer	$ 97,525	$ -	$ -	**$ 97,525**	33%
96	BP12C052B	C-1 Slag Grinder Replacement	$ 60,000	$ -	$ -	**$ 60,000**	
97	BP12C055B	C-1 Tube Replacement Hot Reheat Sect	$ 936,800	$ -	$ -	**$ 936,800**	22%
98	BP12C057B	C-1 Hot/Cold/Rating Drive Replacemer	$ 20,000	$ -	$ -	**$ 20,000**	90%
99	BP12C058B	C-1 "A" MCC Replacement	$ 5,615	$ -	$ -	**$ 5,615**	28%
100	BP12C060B	C-1 Vacuum Pump Replacement	$ 2,267	$ -	$ -	**$ 2,267**	40%
101	BP12C061B	C-1 FD fan housings, silencers & hoods	$ 250,000	$ -	$ -	**$ 250,000**	69%
102	BP12C062B	C-1 CEM Duct Gas Analysers Replacer	$ 11,364	$ -	$ -	**$ 11,364**	100%
103	BP12C063B	C-1 Precipitator Inlet duct replacement	$ 200,000	$ -	$ -	**$ 200,000**	23%

For the Base Period
(10/1/2012 - 9/30/2013)

Type of Filing: Original - ___X___; Updated - ______; Revised - ______

Schedule 2

Line No.	Project No.	Description of Project	Accumulated Costs: Construction Amount	AFUDC Capitalized	Indirect Costs Other	Total Costs	Estimated Physical % Completed
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
104	BP12C064B	C-1 Start Up Regulator	$ 1,090	$ -	$ -	**$ 1,090**	63%
105	BP12C065B	C-1 Cold End Air Heater Basket	$ 411,077	$ -	$ -	**$ 411,077**	45%
106	BP12C066B	C-1 ROFA Fan Dampers (Isolation Gat	$ 200,000	$ -	$ -	**$ 200,000**	41%
107	BP12C070B	C-1 Mill Coal Valves	$ 175,000	$ -	$ -	**$ 175,000**	49%
108	BP12C085F	C-1 & C2 Computer Room A/C Unit	$ 43	$ -	$ -	**$ 43**	100%
109	BP12C086F	CL Safety shower at Bulk acid tank	$ 2,553	$ -	$ -	**$ 2,553**	100%
110	BP12C087F	C-1 Sootblowing Regulator	$ 13,370	$ -	$ -	**$ 13,370**	
111	BP12C088F	C-2 Sootblowing Regulator	$ 8,775	$ -	$ -	**$ 8,775**	
112	BP12C089F	CL Hold and Close Drum on Barge Unl	$ 91,735	$ -	$ -	**$ 91,735**	
113	BP12C092F	C-3 Booster Fan Blades	$ 7,324	$ -	$ -	**$ 7,324**	100%
114	BP12C094B	C-3 Ash Sluice Pump	$ 66,789	$ -	$ -	**$ 66,789**	
115	BP12C095F	C-3 A Primary Air Fan Wheel Repl	$ 80,462	$ -	$ -	**$ 80,462**	
116	BP12C096F	CL 2 Tool Boxes 2012	$ 4,693	$ -	$ -	**$ 4,693**	100%
117	BP12C097F	C1 Retractable Sootblowers (5)	$ 94,414	$ -	$ -	**$ 94,414**	86%
118	BP12C098F	CL Purchase 120' JLG	$ 54,277	$ -	$ -	**$ 54,277**	100%
119	BP12C099F	CL Conveyor Belt Replacement #12	$ 18,388	$ -	$ -	**$ 18,388**	
120	BP12G008B	G2 - C/T Water Deck Replacement (3 C	$ 721,910	$ -	$ -	**$ 721,910**	
121	BP12G015B	GN - Valve Operator Limitorque Type I	$ 5,554	$ -	$ -	**$ 5,554**	
122	BP12G016B	G2 - Air Heater Baskets	$ 371,995	$ -	$ -	**$ 371,995**	100%
123	BP12G018B	GN - Landfill Downdrains	$ 16,477	$ -	$ -	**$ 16,477**	91%
124	BP12G020B	G2 - Battery Charger (2 of 2)	$ 18,043	$ -	$ -	**$ 18,043**	100%
125	BP12G021B	G2 - Precip Repair	$ 589,929	$ -	$ -	**$ 589,929**	68%

For the Base Period
(10/1/2012 - 9/30/2013)

Type of Filing: Original - ___X___; Updated - ______; Revised - ______

Schedule 2

Line No.	Project No.	Description of Project	Accumulated Costs: Construction Amount		AFUDC Capitalized		Indirect Costs Other		Total Costs		Estimated Physical % Completed
(A)	(B)	(C)	(D)		(E)		(F)[1]		(G = D+E+F)		(H)
126	BP12G024B	G2 - Voltage Regulator	$	5,548	$	-	$	-	$	5,548	95%
127	BP12G025B	GN - Precipitator AVCs	$	3,502	$	-	$	-	$	3,502	100%
128	BP12G029B	G2 - ID Fan Inlet Dampers	$	318,501	$	-	$	-	$	318,501	100%
129	BP12G030B	G2 - Additive Feed Pump 1 of 4	$	1,354	$	-	$	-	$	1,354	100%
130	BP12G031B	G2 - Additive Supply Pump 1 of 4	$	1,398	$	-	$	-	$	1,398	100%
131	BP12G038B	G2 - Ash Clinker Grinder (2)	$	8,538	$	-	$	-	$	8,538	100%
132	BP12G039B	G2 - Bottom Ash Dog House (1st of 4)	$	17,142	$	-	$	-	$	17,142	100%
133	BP12G042B	G2 - Replace Steam Coil Drain Tank	$	18,999	$	-	$	-	$	18,999	100%
134	BP12G046B	GN - Replace Fire Water Piping	$	330	$	-	$	-	$	330	100%
135	BP12G047B	GN - River Water Makeup Pump (2 of :	$	13,038	$	-	$	-	$	13,038	100%
136	BP12G048B	G1 - Rpl Bottom Ash Lines	$	428	$	-	$	-	$	428	100%
137	BP12G059B	G1 - A and B Ash Sluice Pump Dischar	$	20,351	$	-	$	-	$	20,351	100%
138	BP12G060F	G1 - Coal Feeder Upgrade	$	1,723	$	-	$	-	$	1,723	100%
139	BP12G061F	G2 - Coal Feeder Upgrade	$	5,570	$	-	$	-	$	5,570	100%
140	BP12G063F	G1 - 1A3 Unit Substation Transformer	$	35,363	$	-	$	-	$	35,363	100%
141	BP12G064F	G1 - A & B 1D Fan Inlet Dampers Rota	$	5,818	$	-	$	-	$	5,818	100%
142	BP12G070F	GN - CO-1B Conveyor Replacement	$	107,814	$	-	$	-	$	107,814	100%
143	BP12G071F	G2 - O2 Probe Platform	$	3,309	$	-	$	-	$	3,309	100%
144	BP12G072F	GN - Flyash Silo Stair Tower	$	236,866	$	-	$	-	$	236,866	100%
145	BP12G074F	GN - Telecom Room UPS	$	2,387	$	-	$	-	$	2,387	100%
146	BP12G075F	GN - Crusher Tower Glycol Tank	$	601	$	-	$	-	$	601	100%
147	BP12G076F	G2 - Rpl Bottom Ash Lines	$	70,956	$	-	$	-	$	70,956	

For the Base Period
(10/1/2012 - 9/30/2013)

Type of Filing: Original - __X__; Updated - _____; Revised - _____

Schedule 2

Line No. (A)	Project No. (B)	Description of Project (C)	Accumulated Costs: Construction Amount (D)	AFUDC Capitalized (E)	Indirect Costs Other (F)[1]	Total Costs (G = D+E+F)	Estimated Physical % Completed (H)
148	BP12G080F	G2 - FGD outage work	$ 548,366	$ -	$ -	**$ 548,366**	100%
149	BP12G081F	GN - Ultra Filtration Unit	$ 88,685	$ -	$ -	**$ 88,685**	100%
150	BP12G082F	G2 - BFP Discharge Valves (B and C)	$ 72,879	$ -	$ -	**$ 72,879**	
151	BP12G083F	GN - Sodium Analyzers	$ 23,188	$ -	$ -	**$ 23,188**	100%
152	BP12G084F	G1 - 1C Mill Gearbox	$ 356,652	$ -	$ -	**$ 356,652**	
153	BP12H003B	H1 - Burner Replacement (CCV-DAZ)	$ 113,067	$ -	$ -	**$ 113,067**	100%
154	BP12H023B	H2 - Classifier Reject Valves (Qty 2)	$ 12,533	$ -	$ -	**$ 12,533**	
155	BP12H024F	H1 - "A" NEM Inlet Probe	$ 16,889	$ -	$ -	**$ 16,889**	
156	BP12H025B	H1 - Boiler Access Door (West Side)	$ 15	$ -	$ -	**$ 15**	100%
157	BP12H031F	H0 - Drum Enclosure Ventilation	$ 3,431	$ -	$ -	**$ 3,431**	100%
158	BP12H034F	H0 - NEMS HMI Computer	$ (36)	$ -	$ -	**$ (36)**	100%
159	BP12H036F	H1 - SCR Seal Air Fan Discharge Valv	$ 7,783	$ -	$ -	**$ 7,783**	100%
160	BP12M003B	CMS - 24" CNC Lathe	$ 14,467	$ -	$ -	**$ 14,467**	78%
161	BP12Q006B	RH - Boothe Flyash System	$ 180,618	$ -	$ -	**$ 180,618**	100%
162	BP12Q007B	RH - Portable Gas Welding Machine	$ 3,184	$ -	$ -	**$ 3,184**	
163	BP12Q008B	RH - Wire Feed Welder	$ 3,648	$ -	$ -	**$ 3,648**	
164	BP12Q009B	RH - Clients/Servers (PLC&DCS)	$ 28,474	$ -	$ -	**$ 28,474**	
165	BP12Q013F	RH - #1 & #3 Circ Water Pump	$ 534,243	$ -	$ -	**$ 534,243**	24%
166	BP12R001B	GT - Hydrogen Purity Meter	$ 1,860	$ -	$ -	**$ 1,860**	100%
167	BP12R003F	R1 - Load Center Breakers	$ 65,265	$ -	$ -	**$ 65,265**	100%
168	BP12S003B	RGH - Rpl 2-Way Radio System	$ 50,645	$ -	$ -	**$ 50,645**	
169	BP12W009B	Tennant Floor Cleaning Machine	$ 29,414	$ -	$ -	**$ 29,414**	

For the Base Period
(10/1/2012 - 9/30/2013)

Type of Filing: Original - ___X___; Updated - ______; Revised - ______

Schedule 2

Line No.	**Project No.**	**Description of Project**	**Accumulated Costs**								**Estimated Physical % Completed**
			Construction Amount		**AFUDC Capitalized**		**Indirect Costs Other**		**Total Costs**		
(A)	**(B)**	**(C)**	**(D)**		**(E)**		**(F)[1]**		**(G = D+E+F)**		**(H)**
170	BP12W012B	Process Control System Replacement	$	32,328	$	-	$	-	**$**	**32,328**	
171	BP12W014B	#3 Fly Ash Blower - 1st and 2nd Stage	$	12,167	$	-	$	-	**$**	**12,167**	100%
172	BP12W020B	CARRYOVER WL Sootblower IK6 an	$	33,328	$	-	$	-	**$**	**33,328**	100%
173	BP12W021B	CARRYOVER Switchgear breakers	$	101,008	$	-	$	-	**$**	**101,008**	100%
174	BP12W024B	PLC Flyash Control System Replaceme	$	15,000	$	-	$	-	**$**	**15,000**	
175	BP12W025B	Rotating Element on #1 BFP	$	200,000	$	-	$	-	**$**	**200,000**	
176	BP12W027B	Supervisory instruments, ID, FD and PA	$	7,255	$	-	$	-	**$**	**7,255**	100%
177	BP12W030B	Conveyor belts (#4,6B,8-2, Boom Conv	$	102,903	$	-	$	-	**$**	**102,903**	100%
178	BP12W031B	Tube Weld Overlay	$	47,500	$	-	$	-	**$**	**47,500**	
179	BP12W036B	Waterwall Tube Replacement	$	134,557	$	-	$	-	**$**	**134,557**	72%
180	BP12W041F	Hydrogen seal oil coolers	$	(1)	$	-	$	-	**$**	**(1)**	100%
181	BP12W053F	#1 Bunker gate replacement project	$	3,093	$	-	$	-	**$**	**3,093**	100%
182	BP12W057F	Level gauges for acid and caustic day ta	$	672	$	-	$	-	**$**	**672**	100%
183	BP12W058F	Plant two way communication repeater	$	1,435	$	-	$	-	**$**	**1,435**	100%
184	BP12W059F	WL Replacement of #2 ID Fan Oil Coo	$	78,916	$	-	$	-	**$**	**78,916**	100%
185	BP12W060F	WL Resin Traps	$	5,596	$	-	$	-	**$**	**5,596**	90%
186	BP12W061F	WL Replacement of Turbine Building \	$	48,247	$	-	$	-	**$**	**48,247**	87%
187	BP12W062F	WL Replacement of 110-LL32 #2 Ball	$	(1,350)	$	-	$	-	**$**	**(1,350)**	100%
188	BP12W064F	125V Battery/charger replacement at Ri	$	32,966	$	-	$	-	**$**	**32,966**	
189	BP12W065F	14000lb Four Post Vehicle Lift	$	(545)	$	-	$	-	**$**	**(545)**	100%
190	BP12W066F	#6 Flyash Silo Vent Fan Valve Replace	$	10,072	$	-	$	-	**$**	**10,072**	
191	BP12W067F	C-122 Cake Blower Replacement	$	5,687	$	-	$	-	**$**	**5,687**	

For the Base Period
(10/1/2012 - 9/30/2013)

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Schedule 2

Line No.	Project No.	Description of Project	Accumulated Costs: Construction Amount	AFUDC Capitalized	Indirect Costs Other	Total Costs	Estimated Physical % Completed
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
192	BP12W068F	Halon Control Panel	$ 64,378	$ -	$ -	**$ 64,378**	
193	BP12W069F	1E,3E & 4B Oil Gun Assemblies	$ 58,052	$ -	$ -	**$ 58,052**	63%
194	BP12W070F	#3 Flyash Blower 1st Stage Replacemer	$ 37,744	$ -	$ -	**$ 37,744**	
195	BP12W071F	Security Improvements	$ 101,743	$ -	$ -	**$ 101,743**	100%
196	BP12W072F	WL Sewage Plant Controls	$ 27,045	$ -	$ -	**$ 27,045**	100%
197	BP12W073F	WL Transformer Rectifier	$ 30,499	$ -	$ -	**$ 30,499**	
198	BP12W074F	WL Replace Wetbottom drag chain	$ 113,940	$ -	$ -	**$ 113,940**	
199	BP12W075F	WL Automatic External Defibrillator (A	$ 5,737	$ -	$ -	**$ 5,737**	
200	BP12W076F	Coal Handling Service Building Fire Pa	$ 49,114	$ -	$ -	**$ 49,114**	100%
201	BP12W077F	Stand Alone Safety Shower	$ 17,945	$ -	$ -	**$ 17,945**	
202	BP13C003B	CL Misc. Tools and Equipment	$ 4,238	$ -	$ -	**$ 4,238**	
203	BP13C004B	CL Misc. Safety Equipment	$ 20,000	$ -	$ -	**$ 20,000**	
204	BP13C005B	CL Misc. Capital Projects	$ 41,180	$ -	$ -	**$ 41,180**	
205	BP13C006B	CL Capital Valve Replacement	$ 29,720	$ -	$ -	**$ 29,720**	
206	BP13C007B	CL Coleman FGD Misc. Pumps & Valv	$ 3,000	$ -	$ -	**$ 3,000**	
207	BP13C011B	CL 2013 Belts LS-5 and LS-6	$ 57,000	$ -	$ -	**$ 57,000**	51%
208	BP13C012B	CL tAnalyst Server PC Replacement	$ 25,000	$ -	$ -	**$ 25,000**	
209	BP13C014B	CL Increase number of PI tags	$ 40,000	$ -	$ -	**$ 40,000**	
210	BP13C015B	CL Truck Scales - hardware and softwa	$ 20,000	$ -	$ -	**$ 20,000**	
211	BP13C016B	CL FGD Townley Recycle Pump 1 of 5	$ 75,000	$ -	$ -	**$ 75,000**	
212	BP13C017B	CL 4160 to 480 step down transformer	$ 78,000	$ -	$ -	**$ 78,000**	
213	BP13C020B	C-1 A Circulating Water Pump Column	$ 225,000	$ -	$ -	**$ 225,000**	55%

For the Base Period
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Schedule 2

Line No.	Project No.	Description of Project	Accumulated Costs: Construction Amount	AFUDC Capitalized	Indirect Costs Other	Total Costs	Estimated Physical % Completed
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
214	BP13C021B	C-1 A Circulating Water Pump	$ 230,000	$ -	$ -	$ 230,000	33%
215	BP13C039B	CL FGD DCS UPS replacement	$ 7,558	$ -	$ -	$ 7,558	70%
216	BP13C042B	CL FGD CEMs Analyzer & Umbilical (	$ 79,316	$ -	$ -	$ 79,316	93%
217	BP13C066B	C-1 Drum Enclosure replacement	$ 76,293	$ -	$ -	$ 76,293	6%
218	BP13C068B	C-1 Boiler Insulation	$ 200,000	$ -	$ -	$ 200,000	
219	BP13C069B	C-1 Boiler penthouse casing	$ 100,000	$ -	$ -	$ 100,000	36%
220	BP13C082B	C-1 Burners	$ 700,000	$ -	$ -	$ 700,000	73%
221	BP13C083B	C-1 Air Register Drives	$ 159,014	$ -	$ -	$ 159,014	34%
222	BP13C084F	CL 2 New Instrumentation Tool Boxes	$ 5,062	$ -	$ -	$ 5,062	100%
223	BP13C085F	CL Emerson 475 Field Communicator	$ 5,890	$ -	$ -	$ 5,890	98%
224	BP13C086F	CL Ash Disposal Cleaning Equipment	$ 38,428	$ -	$ -	$ 38,428	
225	BP13C087F	C-3 B Mill Bull Gear Replacement	$ 388,000	$ -	$ -	$ 388,000	
226	BP13C088F	C-1 C Mill Gear Reducer Replacement	$ 281,572	$ -	$ -	$ 281,572	100%
227	BP13C089F	CL A and B WWT Sludge Pumps	$ 42,259	$ -	$ -	$ 42,259	100%
228	BP13C090F	CL Hydraulic Tools and Electric Pump	$ 24,620	$ -	$ -	$ 24,620	100%
229	BP13C091F	C-3 Rectifier / Inverter UPS System	$ 90,000	$ -	$ -	$ 90,000	87%
230	BP13C092F	C-2 A BFP Discharge & Check Valve	$ 70,280	$ -	$ -	$ 70,280	44%
231	BP13C093F	C-2 DA & Inching Regulators	$ 28,200	$ -	$ -	$ 28,200	
232	BP13C094F	C-1 Dust Valve Replacement	$ 50,000	$ -	$ -	$ 50,000	74%
233	BP13C095F	C-1 Air Heater Hopper Replacement	$ 70,000	$ -	$ -	$ 70,000	30%
234	BP13C096F	CL FGD Weigh Feeders A & B	$ 18,820	$ -	$ -	$ 18,820	64%
235	BP13G001B	GN - Capital Valves	$ 39,042	$ -	$ -	$ 39,042	

For the Base Period
(10/1/2012 - 9/30/2013)

Type of Filing: Original - ___X___; Updated - ______; Revised - ______

Schedule 2

Line No.	Project No.	Description of Project	Accumulated Costs: Construction Amount	AFUDC Capitalized	Indirect Costs Other	Total Costs	Estimated Physical % Completed
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
236	BP13G002B	GN - Miscellaneous Capital Projects	$ 78,320	$ -	$ -	**$ 78,320**	
237	BP13G003B	GN - Miscellaneous Safety	$ 20,000	$ -	$ -	**$ 20,000**	
238	BP13G004B	GN - Plant Tools & Equipment	$ 21,316	$ -	$ -	**$ 21,316**	
239	BP13G005B	GN - 6,000 lb Fork Truck	$ 95,000	$ -	$ -	**$ 95,000**	100%
240	BP13G006B	GN - Replace Slaker (1st of 8)	$ 200,000	$ -	$ -	**$ 200,000**	
241	BP13G007B	GN - Valve Operator Limitorque SMB '	$ 6,000	$ -	$ -	**$ 6,000**	
242	BP13G008B	GN - Valve Operator Limitorque Type]	$ 6,000	$ -	$ -	**$ 6,000**	
243	BP13G009B	GN - Control Room Chiller	$ 150,000	$ -	$ -	**$ 150,000**	
244	BP13G010B	GN - Control Room Lighting	$ 50,000	$ -	$ -	**$ 50,000**	
245	BP13G011B	GN - Gaitronic Phone System	$ 660,900	$ -	$ -	**$ 660,900**	
246	BP13G012B	GN - IK IR Sootblower Starter Panels	$ 175,000	$ -	$ -	**$ 175,000**	
247	BP13G013B	GN - Office Bldg Chiller	$ 275,000	$ -	$ -	**$ 275,000**	
248	BP13G014B	GN - 1 & 2 Slaker Controls	$ 200,000	$ -	$ -	**$ 200,000**	
249	BP13G016B	G1 - Secondary Air Damper Controls	$ 30,000	$ -	$ -	**$ 30,000**	
250	BP13G017B	GN - Calibration Equipment	$ 12,000	$ -	$ -	**$ 12,000**	
251	BP13G018B	GN - CO3A & CO3B Filter Cake Scale	$ 20,000	$ -	$ -	**$ 20,000**	
252	BP13G019B	GN - Additive Feed Pump 2 of 4	$ 50,000	$ -	$ -	**$ 50,000**	
253	BP13G020B	GN - Additive Supply Pump 2 of 4	$ 50,000	$ -	$ -	**$ 50,000**	
254	BP13G021B	GN - IU Filtrate Feed Pump 1 of 3	$ 45,000	$ -	$ -	**$ 45,000**	
255	BP13G022B	GN - IU Filtrate Return Pump 1 of 2	$ 15,000	$ -	$ -	**$ 15,000**	
256	BP13G023B	GN - 1D Coal Chute impact areas	$ 202,000	$ -	$ -	**$ 202,000**	
257	BP13G024B	GN - 2D Coal Chute impact areas	$ 202,000	$ -	$ -	**$ 202,000**	

For the Base Period
(10/1/2012 - 9/30/2013)

Type of Filing: Original - ___X___; Updated - ______; Revised - ______

Schedule 2

Line No.	Project No.	Description of Project	Accumulated Costs: Construction Amount	AFUDC Capitalized	Indirect Costs Other	Total Costs	Estimated Physical % Completed
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
258	BP13G025B	GN - Conveyor Belts	$ 90,000	$ -	$ -	$ 90,000	
259	BP13G026B	GN - Reclaim Feeder (3 & 4 of 8)	$ 400,000	$ -	$ -	$ 400,000	
260	BP13G027B	G1 - Service Water Line Underground r	$ 150,000	$ -	$ -	$ 150,000	
261	BP13G028B	G1 - B Reaction Tank Agitator Gearbox	$ 45,000	$ -	$ -	$ 45,000	
262	BP13G029B	GN - Crusher Tower Hoist	$ 25,000	$ -	$ -	$ 25,000	
263	BP13G030B	GN - Fire Water Deluges (12 - 6" CT)	$ 60,000	$ -	$ -	$ 60,000	50%
264	BP13G031B	G2 - Recycle Pumphouse Sump Pumps	$ 7,500	$ -	$ -	$ 7,500	87%
265	BP13G032B	GN - Replace Fire Water Piping	$ 100,000	$ -	$ -	$ 100,000	
266	BP13G033B	GN - River Water Makeup Pump 3 of 3	$ 185,000	$ -	$ -	$ 185,000	
267	BP13G034B	G1 - OFA Jordan Drives (20 per Unit)	$ 200,000	$ -	$ -	$ 200,000	
268	BP13G035B	GN - Replace G1 CCW heat Exchanger	$ 250,000	$ -	$ -	$ 250,000	
269	BP13G036B	GN - Steam Purity Analyzers (G1 and C	$ 20,000	$ -	$ -	$ 20,000	
270	BP13G037B	GN - Network Test Equipment	$ 40,000	$ -	$ -	$ 40,000	
271	BP13G038B	GN - Upgrade Control Room HMI Soft	$ 145,000	$ -	$ -	$ 145,000	
272	BP13G039B	GN - Rpl 4160v Breakers (4)	$ 60,000	$ -	$ -	$ 60,000	
273	BP13G040B	GN - Rpl 480v Breakers (8)	$ 60,000	$ -	$ -	$ 60,000	
274	BP13G041B	GN - Office Bldg Hot Water Boiler	$ 300,000	$ -	$ -	$ 300,000	
275	BP13G042B	GN - Conductor NT Client Licenses	$ 16,000	$ -	$ -	$ 16,000	
276	BP13G043B	GN - DCS Large Screen Monitors LCD	$ 10,000	$ -	$ -	$ 10,000	
277	BP13G044B	GN - DCS Servers/Client Computer & I	$ 20,000	$ -	$ -	$ 20,000	
278	BP13G045B	G2 - DCS Firmware Upgrade	$ 75,000	$ -	$ -	$ 75,000	
279	BP13G046B	G2 - Control Room Consoles	$ 125,000	$ -	$ -	$ 125,000	

For the Base Period
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Schedule 2

Line No. (A)	Project No. (B)	Description of Project (C)	Accumulated Costs: Construction Amount (D)	AFUDC Capitalized (E)	Indirect Costs Other (F)[1]	Total Costs (G = D+E+F)	Estimated Physical % Completed (H)
280	BP13G047B	G2 - Communication Controller Upgrac	$ 75,000	$ -	$ -	$ 75,000	
281	BP13G048B	GN - Drager Air Monitor	$ 15,000	$ -	$ -	$ 15,000	
282	BP13G049B	GN - M.S.A. Ammonia Monitor (Detec	$ 6,000	$ -	$ -	$ 6,000	
283	BP13G050B	GN - Portable Gas Analyzer	$ 12,500	$ -	$ -	$ 12,500	
284	BP13G051B	GN - 6" Diesel Pump	$ 50,000	$ -	$ -	$ 50,000	
285	BP13G052B	GN - Clarifier Sludge Pumps (2)	$ 35,000	$ -	$ -	$ 35,000	
286	BP13G053B	GN - Rpl Caustic Pumping System	$ 196,100	$ -	$ -	$ 196,100	
287	BP13G054B	GN - Landfill Downdrains	$ 30,000	$ -	$ -	$ 30,000	
288	BP13G055B	GN - Automatic Electronic Defibrillatoı	$ 3,000	$ -	$ -	$ 3,000	
289	BP13G056B	GN - Fire extinguisher- Roll Cart type	$ 2,500	$ -	$ -	$ 2,500	
290	BP13G057B	G2 - USS Transformer	$ 150,000	$ -	$ -	$ 150,000	
291	BP13G058F	GN - P-1A Filter Feed Pump	$ 35,100	$ -	$ -	$ 35,100	76%
292	BP13G059F	G2 - 2B Recycle Pump Discharge Valv	$ 52,000	$ -	$ -	$ 52,000	92%
293	BP13G060F	GN - Copy Machine	$ 12,000	$ -	$ -	$ 12,000	98%
294	BP13G061F	GN - Barge Unloader Hoist	$ 21,680	$ -	$ -	$ 21,680	88%
295	BP13G062F	G1 - Low Pressure Heater Shell Side Sa	$ 11,900	$ -	$ -	$ 11,900	83%
296	BP13G063F	GN - Spectrophotometer	$ 3,900	$ -	$ -	$ 3,900	100%
297	BP13H002B	H2 - NEMS NOx Analyzers	$ 16,943	$ -	$ -	$ 16,943	100%
298	BP13H003B	H0 - Roof Over 3rd Floor DA Tank, He	$ 50,513	$ -	$ -	$ 50,513	
299	BP13H004B	H0 - HC3 Slakers (Qty 2)	$ 189,424	$ -	$ -	$ 189,424	
300	BP13H005B	H0 - Steam Purity Analyzer (H1&H2 -	$ 12,628	$ -	$ -	$ 12,628	
301	BP13H006B	H0 - Cooling Tower Partition Walls (N	$ 78,926	$ -	$ -	$ 78,926	

For the Base Period
(10/1/2012 - 9/30/2013)

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Schedule 2

			Accumulated Costs				
Line No.	**Project No.**	**Description of Project**	**Construction Amount**	**AFUDC Capitalized**	**Indirect Costs Other**	**Total Costs**	**Estimated Physical % Completed**
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
302	BP13H007B	H2 - Rpl Cold End Airheater Baskets	$ 297,330	$ -	$ -	**$ 297,330**	100%
303	BP13H008B	H2 - Expansion Joints	$ 53,670	$ -	$ -	**$ 53,670**	100%
304	BP13H009B	H2 - Feedwater Heater Extraction MOV	$ 25,260	$ -	$ -	**$ 25,260**	100%
305	BP13H010B	H2 - High Energy Piping Hangers	$ 63,141	$ -	$ -	**$ 63,141**	99%
306	BP13H011B	H2 - Rpl Cooling Tower D & E Cell Fil	$ 304,655	$ -	$ -	**$ 304,655**	100%
307	BP13H012B	H2 - P.A. Damper Drives (Qty 2)	$ 19,889	$ -	$ -	**$ 19,889**	100%
308	BP13H013B	H2 - Precipitator False Floor	$ 196,369	$ -	$ -	**$ 196,369**	100%
309	BP13H014B	H2 - "A" Mill Trunnion Bearing	$ 254,459	$ -	$ -	**$ 254,459**	100%
310	BP13H015B	H2 - Pulverizer Mill Liners	$ 441,987	$ -	$ -	**$ 441,987**	100%
311	BP13H016B	H2 - Scanner Cooling Air Fans (Qty 2)	$ 37,885	$ -	$ -	**$ 37,885**	100%
312	BP13H017B	H2 - SCR Catalyst Layer	$ 284,135	$ -	$ -	**$ 284,135**	100%
313	BP13H018B	H2 - Voltage Regulator	$ 110,244	$ -	$ -	**$ 110,244**	100%
314	BP13H019B	H2 - Turbine Blading Replacement L-0	$ 631,410	$ -	$ -	**$ 631,410**	100%
315	BP13H020B	H2 - Turbine Nozzle Overlay	$ 31,949	$ -	$ -	**$ 31,949**	42%
316	BP13H021B	H2 - Turbine Packing HP-IP Rows	$ 126,282	$ -	$ -	**$ 126,282**	100%
317	BP13H023B	H2 - Refractory Cooling Water System	$ 25,256	$ -	$ -	**$ 25,256**	100%
318	BP13H024B	H2 - Rpl Wet Bottom Refractory	$ 59,984	$ -	$ -	**$ 59,984**	87%
319	BP13H025B	H2 - Rpl Wet Bottom Seal Skirt & Trou	$ 262,034	$ -	$ -	**$ 262,034**	100%
320	BP13H026B	H2 - Insulation & Lagging	$ 189,423	$ -	$ -	**$ 189,423**	100%
321	BP13H027B	H2 - Rpl Slag Grinders (Qty 2)	$ 40,789	$ -	$ -	**$ 40,789**	100%
322	BP13H028B	H2 - Rpl AH Steam Coils (Qty 2)	$ 13,891	$ -	$ -	**$ 13,891**	100%
323	BP13H030B	H2 - Rpl Sootblowers (28, 33, & 36) 3 t	$ 94,711	$ -	$ -	**$ 94,711**	100%

For the Base Period
(10/1/2012 - 9/30/2013)

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Schedule 2

Line No. (A)	Project No. (B)	Description of Project (C)	Accumulated Costs: Construction Amount (D)	AFUDC Capitalized (E)	Indirect Costs Other (F)[1]	Total Costs (G = D+E+F)	Estimated Physical % Completed (H)
324	BP13H031B	H1 - "A" 4160V Switchgear	$ 236,779	$ -	$ -	$ 236,779	
325	BP13H032B	H0 - Cooling Tower Chlorinator Equipr	$ 3,473	$ -	$ -	$ 3,473	
326	BP13H034F	H2 - NEMs Air Dryer	$ 4,360	$ -	$ -	$ 4,360	
327	BP13H035F	H1 - Scrubber Stack Particulate Monito:	$ 86,883	$ -	$ -	$ 86,883	100%
328	BP13H036F	H2 - Cooling Tower Circ Water Pump	$ 63,141	$ -	$ -	$ 63,141	
329	BP13H037F	H0 - Rpl Seal Air Fan Piping (H1&H2)	$ 63,141	$ -	$ -	$ 63,141	
330	BP13H038F	H0 - Rpl SCR 24" Vent Valve (H1&H2	$ 31,571	$ -	$ -	$ 31,571	
331	BP13H039F	H2 - NEMS Probe Upgrade	$ 37,190	$ -	$ -	$ 37,190	100%
332	BP13H040F	H1 - "A" & "B" Bleed Pump Suction V:	$ 7,641	$ -	$ -	$ 7,641	100%
333	BP13H041F	H2 - Boiler Water Wall Overlay	$ 135,753	$ -	$ -	$ 135,753	100%
334	BP13H042F	H0 - Scrubber Transformer	$ 14,144	$ -	$ -	$ 14,144	68%
335	BP13M001B	75 Ton Press	$ 15,000	$ -	$ -	$ 15,000	
336	BP13M002B	36" Vertical Band Saw	$ 10,000	$ -	$ -	$ 10,000	
337	BP13M003B	36" 4-Jaw Independent Chuck	$ 8,500	$ -	$ -	$ 8,500	
338	BP13M004B	External-Internal Tool Post Grinder	$ 4,500	$ -	$ -	$ 4,500	
339	BP13M005B	Bridgeport Series #1 Milling Machine	$ 6,320	$ -	$ -	$ 6,320	
340	BP13M008F	Bridgeport Series #2 Milling Machine F	$ 18,680	$ -	$ -	$ 18,680	
341	BP13M009F	New 21" Lathe to replace 19" lathe	$ 38,287	$ -	$ -	$ 38,287	
342	BP13M010F	19" Lathe Refurbish	$ 28,620	$ -	$ -	$ 28,620	3%
343	BP13Q003B	RH - Misc Conveyor Belts	$ 31,273	$ -	$ -	$ 31,273	
344	BP13Q004B	RH - Misc Safety	$ 6,950	$ -	$ -	$ 6,950	
345	BP13Q005B	RH - Misc Tools & Equipment	$ 1,737	$ -	$ -	$ 1,737	

For the Base Period
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Schedule 2

Line No. (A)	Project No. (B)	Description of Project (C)	Accumulated Costs: Construction Amount (D)	AFUDC Capitalized (E)	Indirect Costs Other (F)[1]	Total Costs (G = D+E+F)	Estimated Physical % Completed (H)
346	BP13Q006B	RH - 3rd Floor Lab Air Conditioner	$ 34,748	$ -	$ -	$ 34,748	
347	BP13Q007B	RH - Computer Room Air Conditioner	$ 48,647	$ -	$ -	$ 48,647	
348	BP13Q010B	RH - Barge Unloader Bucket	$ 69,496	$ -	$ -	$ 69,496	
349	BP13Q013B	RH - Vent Fans (Svc Bldg/Mtc Shop) -	$ 48,647	$ -	$ -	$ 48,647	
350	BP13Q014B	RH - Electric Conduit Bender	$ 5,560	$ -	$ -	$ 5,560	
351	BP13Q015B	RH - Client & Monitors (PLC & DCS)	$ 27,798	$ -	$ -	$ 27,798	
352	BP13Q016B	RH - #1 Flyash Vacuum Pump	$ 14,316	$ -	$ -	$ 14,316	91%
353	BP13Q017B	RH - Reid Svc Bldg Roof	$ 48,647	$ -	$ -	$ 48,647	
354	BP13Q019B	RH - Bldg. Steam Water Unit Heaters	$ 13,899	$ -	$ -	$ 13,899	
355	BP13Q020F	RH - #2 Flyash Vacuum Pump	$ 9,799	$ -	$ -	$ 9,799	
356	BP13Q021F	RH - Office Air Conditioner	$ 50,802	$ -	$ -	$ 50,802	100%
357	BP13Q023F	RH - Replace "C" Ash Sluice Pump on	$ 34,748	$ -	$ -	$ 34,748	
358	BP13R001B	R1 - Battery Room Air Conditioner	$ 50,000	$ -	$ -	$ 50,000	
359	BP13R002B	R1 - Turbine DCS Control Upgrade	$ 400,000	$ -	$ -	$ 400,000	
360	BP13S001B	RGH - Fiber Cable Test Equipment	$ 34,465	$ -	$ -	$ 34,465	
361	BP13S002B	RGH - Heavy Equip Bldg Air Compres	$ 12,924	$ -	$ -	$ 12,924	
362	BP13S003B	RGH - HEPA Air Machines (Qty 2)	$ 4,308	$ -	$ -	$ 4,308	
363	BP13S004B	RGH - Auger Sampler	$ 344,645	$ -	$ -	$ 344,645	
364	BP13S005B	RGH - Coal Pile Runoff Pumps & Discl	$ 229,189	$ -	$ -	$ 229,189	
365	BP13S006B	RGH - Self Contained Breathing Appr (	$ 12,924	$ -	$ -	$ 12,924	
366	BP13S009F	RGH - Copy Machine (B&R Bldg)	$ 10,167	$ -	$ -	$ 10,167	100%
367	BP13W005B	DCS Client Computer Replacement	$ 15,040	$ -	$ -	$ 15,040	72%

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Schedule 2

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(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
368	BP13W008B	Riser Duct Expansion Joint	$ 25,000	$ -	$ -	**$ 25,000**	
369	BP13W011B	Landfill Drainage Control	$ 150,000	$ -	$ -	**$ 150,000**	
370	BP13W021F	Hand Wash Basin	$ 7,916	$ -	$ -	**$ 7,916**	100%
371	BP13W022F	Stacker/Reclaimer HMI (Human Machi	$ 13,159	$ -	$ -	**$ 13,159**	100%
372	BP13W023F	Replacement of (4) Flyash Inlet Gate V	$ 24,200	$ -	$ -	**$ 24,200**	45%
373	BP13W024B	Boom Conveyor Replacement	$ 50,000	$ -	$ -	**$ 50,000**	100%
374	BP13W024F	Unit Layup Equipment	$ 750,000	$ -	$ -	**$ 750,000**	
375	BP13W025B	Expansion Joints	$ 150,000	$ -	$ -	**$ 150,000**	
376	BP13W026F	WL - SO3 System MCC	$ 20,600	$ -	$ -	**$ 20,600**	47%
377	BP13W027F	WL - Main SO3 Blower Replacement	$ 16,520	$ -	$ -	**$ 16,520**	100%
378	BP13W028B	#2 Fly Ash Blower Replacement	$ 75,000	$ -	$ -	**$ 75,000**	
379	BP13W029B	Rpl MFP's w/ BRC 400 Controllers (Cc	$ 15,000	$ -	$ -	**$ 15,000**	
380	BP13W030B	ID Fan Oil Cooler Replacement (2 of 4)	$ 10,000	$ -	$ -	**$ 10,000**	
381	BP13W031B	Replace Liner in #2 Make Up Clarifier	$ 200,000	$ -	$ -	**$ 200,000**	
382	BP13W032B	East and West Precipitator HVAC Repl	$ 50,000	$ -	$ -	**$ 50,000**	
383	BP13W033B	Drag Chain Replacement	$ 15,500	$ -	$ -	**$ 15,500**	
384	BP13W034B	Sewage Treatment Liner	$ 120,000	$ -	$ -	**$ 120,000**	
385	BP13W036B	Ronan System Integration into the DCS	$ 10,000	$ -	$ -		
386	BP13W037B	Replace Primary AH Baskets	$ 48,000	$ -	$ -		
387	BP13W038B	Burner Replacement 9 of 25	$ 40,000	$ -	$ -		
388	BP13W039B	Fire Panel Replacement & Smoke detec	$ 150,000	$ -	$ -		
389	BP13W040F	WL - Row 2 West Flyash Outlet Gate V	$ 15,200	$ -	$ -		100%

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Schedule 2

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(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
390	BT11X011B	Replace (9) TC Blocking Carriers with	$ (4,970)	$ -	$ -		73%
391	BT11X013B	Replace Disconnects at CLMN	$ 24,667	$ -	$ -		95%
392	BT11X026B	HANCOCK CO 69KV CAP BANK	$ 485,095	$ -	$ -		74%
393	BT11X033B	Armstrong Lewis Creek Mine	$ 938	$ -	$ -		100%
394	BT11X037F	Communication Tower Corrosion Prote	$ 6,689	$ -	$ -		100%
395	BT12X001B	Martin-marietta Transformer 3	$ 293,925	$ -	$ -		84%
396	BT12X002B	Add Shelter for Compressed Gas Storag	$ 11,969	$ -	$ -		
397	BT12X003B	BUCKET TRUCK #76	$ 279,127	$ -	$ -		93%
398	BT12X004B	Caldwell emergency gen	$ 6,952	$ -	$ -		
399	BT12X006B	DEHV generator	$ 7,959	$ -	$ -		
400	BT12X007B	Dry air package	$ 32,303	$ -	$ -		
401	BT12X009B	Horse Fork Tap 69KV switch	$ 4,921	$ -	$ -		100%
402	BT12X012B	On-line DGA Monitoring for HMPL G	$ 2,131	$ -	$ -		
403	BT12X015B	Reid switch replacement	$ 173,340	$ -	$ -		70%
404	BT12X016B	Replace repair roof at Wilson Substatio	$ 957	$ -	$ -		
405	BT12X017B	REHV and CEHV batteries	$ 99,294	$ -	$ -		15%
406	BT12X019B	Reid Switchyard fence	$ 40,676	$ -	$ -		
407	BT12X023B	Two (2) spare 161 kv CCVT's	$ 16,051	$ -	$ -		
408	BT12X025B	Cumberland to Caldwell Line	$ 431,385	$ -	$ -		50%
409	BT12X026B	Garrett-Flaherty Tap 3 mi 69 kV Line	$ 895,784	$ -	$ -		44%
410	BT12X027B	Meade Co to Garrett Line	$ 290,682	$ -	$ -		73%
411	BT12X029B	South Dermont - RCS	$ 35,696	$ -	$ -		100%

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Schedule 2

Line No. (A)	Project No. (B)	Description of Project (C)	Accumulated Costs: Construction Amount (D)	AFUDC Capitalized (E)	Indirect Costs Other (F)[1]	Total Costs (G = D+E+F)	Estimated Physical % Completed (H)
412	BT12X030F	Work Platforms	$ 126	$ -	$ -		100%
413	BT12X031F	Online Tap Changer Filter for Reid #1 '	$ (306)	$ -	$ -		100%
414	BT12X033F	Metering Transformers	$ 16,711	$ -	$ -		0%
415	BT12X034F	CCVT national aluminum	$ 10,000	$ -	$ -		
416	BT12X035F	Reid Capacitor Bank	$ 45,697	$ -	$ -		100%
417	BT12X036F	Elk Creek 69 kV Service	$ 64,487	$ -	$ -		100%
418	BT12X037F	Portable Battery Charger	$ 9,568	$ -	$ -		
419	BT12X038F	Hancock County Transformer #1	$ 671,329	$ -	$ -		1%
420	BT12X041F	JP Maxon Substation 0.3 mi. 69 kV T-L	$ 180,650	$ -	$ -		77%
421	BT12X043F	Wilson data fault recorder	$ 62,692	$ -	$ -		
422	BT12X044F	Coleman data fault recorder	$ 96,468	$ -	$ -		
423	BT12X045F	Reid data fault recorder	$ 141,304	$ -	$ -		
424	BT12X046F	Dixon Tap Culvert	$ 300	$ -	$ -		100%
425	BT12X048F	Copier at ET&S	$ 5,221	$ -	$ -		
426	BT12X049F	Mobile repeaters	$ 26,321	$ -	$ -		
427	BT13X002B	Replace Voice Recorder at DRC	$ 30,000	$ -	$ -		
428	BT13X003B	Replace 2 Energy Control Chairs	$ 1,100	$ -	$ -		99%
429	BT13X005B	Buttermilk Falls 69 kV line	$ 594,457	$ -	$ -		8%
430	BT13X007B	All Terrain Vehicle (Line Crew)	$ 17,000	$ -	$ -		
431	BT13X008B	All Terrain Vehicle (ROW Crew)	$ 15,000	$ -	$ -		
432	BT13X009B	All Terrain Vehicle Trailer (Line Crew)	$ 4,000	$ -	$ -		
433	BT13X010B	All Terrain Vehicle Trailer (ROW Crew	$ 3,500	$ -	$ -		

For the Base Period
(10/1/2012 - 9/30/2013)

Type of Filing: Original - ___X___; Updated - ______; Revised - ______

Schedule 2

Line No. (A)	Project No. (B)	Description of Project (C)	Accumulated Costs: Construction Amount (D)	AFUDC Capitalized (E)	Indirect Costs Other (F)[1]	Total Costs (G = D+E+F)	Estimated Physical % Completed (H)
434	BT13X011B	Capital Tool Replacements	$ 2,000	$ -	$ -		
435	BT13X012B	Hoist, Rope and Grips Replacements	$ 5,000	$ -	$ -		
436	BT13X013B	Hydraulic Pump and Press Replacemen	$ 3,500	$ -	$ -	**$ 3,500**	
437	BT13X014B	On-line DGA Monitoring for CEHV Tr	$ 84,000	$ -	$ -	**$ 84,000**	97%
438	BT13X015B	Portable Generator Replacements	$ 1,800	$ -	$ -	**$ 1,800**	
439	BT13X016B	Replace Disconnects at Coleman (10)	$ 207,140	$ -	$ -	**$ 207,140**	
440	BT13X017B	Replace Megger Transformer Ohm Met	$ 5,000	$ -	$ -	**$ 5,000**	
441	BT13X018B	Replace Miller welder and generator	$ 8,000	$ -	$ -	**$ 8,000**	
442	BT13X019B	Replace Substation Battery and Charger	$ 45,181	$ -	$ -	**$ 45,181**	
443	BT13X020B	Replace Substation Battery and Charger	$ 45,181	$ -	$ -	**$ 45,181**	
444	BT13X021B	Replace Substation Security Fence	$ 25,011	$ -	$ -	**$ 25,011**	
445	BT13X022B	Replacement A/C Units	$ 16,000	$ -	$ -	**$ 16,000**	
446	BT13X024B	Skid steer (Bobcat)	$ 43,000	$ -	$ -	**$ 43,000**	
447	BT13X025F	Dobie Domino CK Calibration Unit	$ 997	$ -	$ -	**$ 997**	100%
448	BT13X026F	Hancock Battery Charger (Substation)	$ 4,924	$ -	$ -	**$ 4,924**	100%
449	BT13X027F	Riveredge 69 kV Transmission Service	$ 77,593	$ -	$ -	**$ 77,593**	68%
450	BT13X028F	Niagara Portal 69kv T-Line	$ 11,000	$ -	$ -	**$ 11,000**	17%
451	BT13X029F	Removal of Steel Switch Structure at Pe	$ 8,900	$ -	$ -	**$ 8,900**	84%
452	Unassigned	Capitalized Interest	$ -	$ 261,874	$ -	**$ 261,874**	
453	Unassigned	Carry Over Projects	$ 12,948	$ -	$ -	**$ 12,948**	
454	Unassigned	Misc. Safety Equipment	$ 20,000	$ -	$ -	**$ 20,000**	
455	Unassigned	Misc. Capital	$ 4,507	$ -	$ -	**$ 4,507**	

For the Base Period
(10/1/2012 - 9/30/2013)

Type of Filing: Original - ___X___; Updated - ______; Revised - ______

Schedule 2

Line No.	Project No.	Description of Project	Accumulated Costs: Construction Amount	AFUDC Capitalized	Indirect Costs Other	Total Costs	Estimated Physical % Completed
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
456	Unassigned	Capital Valves	$ 10,000	$ -	$ -	$ 10,000	
457	Unassigned	HAPS/MATS - Capitalized Interest	$ -	$ 93,122	$ -	$ 93,122	
458	Unassigned	HAPS/MATS Project	$ 10,200,000	$ -	$ -	$ 10,200,000	
459	Various Old	CL Carry Over Projects	$ 45,541	$ -	$ -	$ 45,541	100%
460	W0050000	S-Station Battery and Charger	$ 4,119	$ -	$ -	$ 4,119	
461	W0190000	CL to CL EHV C1 & C2 Tele	$ 190,440	$ -	$ -	$ 190,440	100%
462	W9010000	Wilson EHV - 161 kV Line Terminal fc	$ 72,337	$ -	$ -	$ 72,337	95%
463	W9100000	T-line relocation Airport	$ 655	$ -	$ -	$ 655	100%
464	W9190000	Wilson 19F line	$ 37,902	$ -	$ -	$ 37,902	100%
465	W9230000	Two-Way Radio	$ 1,356,408	$ -	$ -	$ 1,356,408	99%
466	W9300000	White Oak - 50 MVA Substation	$ 338,559	$ -	$ -	$ 338,559	7%
467	W9340000	Wilson EHV Substation Addition	$ 448,785	$ -	$ -	$ 448,785	100%
468	W9350000	Wilson/Centertown 69 kV Line	$ 11,114	$ -	$ -	$ 11,114	97%
469	W9450000	Livingston Transformer	$ (8,370)	$ -	$ -	$ (8,370)	100%
470	W9560000	7-B Tap to Paradise 161 kV Line Recor	$ 304,548	$ -	$ -	$ 304,548	37%
471	W9650000	Paradise 161 kV Line Terminal Upgrad	$ 333,406	$ -	$ -	$ 333,406	100%
472	W9750000	Cannelton Hydroelectric	$ 135	$ -	$ -	$ 135	
473	WK08W020B	Install Stack Lightning Elimination Sys	$ 21,081	$ -	$ -	$ 21,081	100%

Big Rivers Electric Corporation
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For the Forecasted Test Period
(2/1/2014 - 1/31/2015)

Type of Filing: Original - __X__; Updated - _____; Revised - _____

Schedule 2

Line No.	Project No.	Description of Project	Accumulated Costs: Construction Amount	AFUDC Capitalized	Indirect Costs Other	Total Costs	Estimated Physical % Completed
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
1	Unassigned	Miscellaneous Air Monitoring Replacer	$ 50,000	$ -	$ -	**$ 50,000**	
2	Unassigned	Replace Mercury Analyzer	$ 50,000	$ -	$ -	**$ 50,000**	
3	Unassigned	Replace Microwave Digestor	$ 45,000	$ -	$ -	**$ 45,000**	
4	Unassigned	Replace CHN Analyzer	$ 100,000	$ -	$ -	**$ 100,000**	
5	Unassigned	TEM trailer	$ 100,000	$ -	$ -	**$ 100,000**	
6	Unassigned	Replacement Office Furniture	$ 2,500	$ -	$ -	**$ 2,500**	
7	Unassigned	TRAN - Rpl #293 - Truck (diesel, 3/4 t	$ 40,000	$ -	$ -	**$ 40,000**	
8	Unassigned	HR - Rpl #310 (Safety)	$ 35,000	$ -	$ -	**$ 35,000**	
9	Unassigned	HR - Rpl #312 - Pool Vehicle	$ 24,000	$ -	$ -	**$ 24,000**	
10	Unassigned	RGH - Rpl #431 - Plant Mgr Vehicle -	$ 27,268	$ -	$ -	**$ 27,268**	
11	Unassigned	WL - Rpl #430 - Plant Mgr Vehicle - 2(	$ 40,000	$ -	$ -	**$ 40,000**	
12	Unassigned	CL - Rpl #426 - Plant Mgr Vehicle - 20	$ 40,000	$ -	$ -	**$ 40,000**	
13	Unassigned	Replace PC's, Laptops, Printers	$ 220,000	$ -	$ -	**$ 220,000**	
14	Unassigned	Replace Data Centers Servers (HQ and	$ 325,000	$ -	$ -	**$ 325,000**	
15	Unassigned	Replacement network switches (Plants)	$ 70,000	$ -	$ -	**$ 70,000**	
16	Unassigned	CIP's Compliance - HMPL	$ 45,000	$ -	$ -	**$ 45,000**	

Big Rivers Electric Corporation
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For the Forecasted Test Period
(2/1/2014 - 1/31/2015)

Type of Filing: Original - ___X___; Updated - ______; Revised - ______

Schedule 2

Line No.	Project No.	Description of Project	Accumulated Costs: Construction Amount	Accumulated Costs: AFUDC Capitalized	Accumulated Costs: Indirect Costs Other	Total Costs	Estimated Physical % Completed
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
17	Unassigned	CIP's Compliance - Green	$ 45,000	$ -	$ -	**$ 45,000**	
18	Unassigned	CIP's Compliance - Coleman	$ 45,000	$ -	$ -	**$ 45,000**	
19	Unassigned	CIP's Compliance - Wilson	$ 45,000	$ -	$ -	**$ 45,000**	
20	Unassigned	Replace Energy Control's laser printer	$ 3,000	$ -	$ -	**$ 3,000**	
21	Unassigned	Replace UPS in DR center	$ 60,000	$ -	$ -	**$ 60,000**	
22	Unassigned	Replace Coop/BREC hardware/softwar	$ 165,000	$ -	$ -	**$ 165,000**	
23	Unassigned	Replace Coop laserFiche Audiotel	$ 2,000	$ -	$ -	**$ 2,000**	
24	Unassigned	Software Tools	$ 10,000	$ -	$ -	**$ 10,000**	
25	Unassigned	iSeries Software Replacement CIS/BIS	$ 405,000	$ -	$ -	**$ 405,000**	
26	Unassigned	AS400 Migration Plan - Phase 1	$ 200,000	$ -	$ -	**$ 200,000**	
27	W9010000	Wilson EHV - 161 kV Line Terminal fc	$ 16,000	$ -	$ -	**$ 16,000**	67%
28	W9560000	7-B Tap to Paradise 161 kV Line Recor	$ 33,000	$ -	$ -	**$ 33,000**	
29	W9650000	Paradise 161 kV Line Terminal Upgrad	$ 228,000	$ -	$ -	**$ 228,000**	48%
30	W9300000	White Oak - 50 MVA Substation	$ 200,061	$ -	$ -	**$ 200,061**	7%
31	W9000000	Hardinsburg - 161 kV Ring Bus Renov	$ 515,317	$ -	$ -	**$ 515,317**	
32	BT12X025B	Cumberland-Caldwell Springs Tap 69 k	$ 746,573	$ -	$ -	**$ 746,573**	50%
33	Unassigned	HMP&L 6 Tap Switching Structure	$ 70,130	$ -	$ -	**$ 70,130**	

Big Rivers Electric Corporation
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For the Forecasted Test Period
(2/1/2014 - 1/31/2015)

Type of Filing: Original - __X__; Updated - ______; Revised - ______

Schedule 2

Line No.	Project No.	Description of Project	Accumulated Costs: Construction Amount	AFUDC Capitalized	Indirect Costs Other	Total Costs	Estimated Physical % Completed
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
34	Unassigned	Replace Energy Control Chair	$ 550	$ -	$ -	$ 550	
35	BT11X011B	Replace (9) TC Blocking Carriers with	$ 71,453	$ -	$ -	$ 71,453	85%
36	BT12X028B	Skillman RTU Replacement	$ 31,238	$ -	$ -	$ 31,238	
37	W0190000	C1 & C2 161 kV Teleprotection Replac	$ 175,516	$ -	$ -	$ 175,516	
38	Unassigned	Buttermilk Falls 69 kV Line	$ 50,000	$ -	$ -	$ 50,000	
39	Unassigned	Irvington Substation	$ 110,000	$ -	$ -	$ 110,000	
40	2014 POLES	Pole Change Outs	$ 581,196	$ -	$ -	$ 581,196	
41	Unassigned	(5) RTU Replacements	$ 203,582	$ -	$ -	$ 203,582	
42	Unassigned	Capital Tool Replacements	$ 2,000	$ -	$ -	$ 2,000	
43	Unassigned	Caterpillar Dozer Replacement	$ 300,000	$ -	$ -	$ 300,000	
44	Unassigned	Go-Track Replacement	$ 500,000	$ -	$ -	$ 500,000	
45	Unassigned	Hoist, Rope and Grips Replacements	$ 5,000	$ -	$ -	$ 5,000	
46	Unassigned	Hydraulic Pump and Press Replacemen	$ 3,500	$ -	$ -	$ 3,500	
47	Unassigned	On-line DGA Monitoring for REHV Tı	$ 84,000	$ -	$ -	$ 84,000	
48	Unassigned	Portable Generator Replacements	$ 1,800	$ -	$ -	$ 1,800	
49	Unassigned	Replace Hopkins Co. Substation Batter	$ 28,000	$ -	$ -	$ 28,000	
50	Unassigned	Replace Skillman Substation Battery an	$ 28,000	$ -	$ -	$ 28,000	

Big Rivers Electric Corporation
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Construction Projects

For the Forecasted Test Period
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Type of Filing: Original - __X__; Updated - ______; Revised - ______

Schedule 2

			Accumulated Costs				
Line No.	Project No.	Description of Project	Construction Amount	AFUDC Capitalized	Indirect Costs Other	Total Costs	Estimated Physical % Completed
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
51	Unassigned	Replace Sub Disconnects Switches	$ 250,000	$ -	$ -	**$ 250,000**	
52	Unassigned	Replace Substation Security Fence	$ 27,830	$ -	$ -	**$ 27,830**	
53	Unassigned	Replacement A/C Units	$ 16,000	$ -	$ -	**$ 16,000**	
54	Unassigned	Substation Gravel	$ 22,000	$ -	$ -	**$ 22,000**	
55	Unassigned	Capitalized Interest	$ -	$ 285,827	$ -	**$ 285,827**	
56	Unassigned	CL Unforeseen Lay Up Costs	$ 100,000	$ -	$ -	**$ 100,000**	
57	Unassigned	New Water Jet Table	$ 88,000	$ -	$ -	**$ 88,000**	
58	Unassigned	2-Ton Gantry Crane Over Steel Area	$ 10,000	$ -	$ -	**$ 10,000**	
59	Unassigned	Large Hydraulic Bearing Puller	$ 13,000	$ -	$ -	**$ 13,000**	
60	Unassigned	New 21" Lathe to Replace 19" Lathe	$ 60,000	$ -	$ -	**$ 60,000**	
61	Unassigned	GN - Valve Operator Limitorque SMB '	$ 6,000	$ -	$ -	**$ 6,000**	
62	Unassigned	GN - Valve Operator Limitorque Type I	$ 3,000	$ -	$ -	**$ 3,000**	
63	Unassigned	G1 - B Service Water Pump	$ 40,000	$ -	$ -	**$ 40,000**	
64	Unassigned	GN - Ash Sluice Pump 3 of 3	$ 180,000	$ -	$ -	**$ 180,000**	
65	Unassigned	GN - Ash Seal Pump (3 of 3)	$ 125,000	$ -	$ -	**$ 125,000**	
66	Unassigned	GN - Rpl 4160v Breakers	$ 50,000	$ -	$ -	**$ 50,000**	
67	Unassigned	GN - Rpl 480v Breakers	$ 50,000	$ -	$ -	**$ 50,000**	
68	Unassigned	G1 - Scrubber Dupont SO2 Inlet and Ou	$ 200,000	$ -	$ -	**$ 200,000**	

Big Rivers Electric Corporation
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For the Forecasted Test Period
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Schedule 2

Line No.	Project No.	Description of Project	Accumulated Costs: Construction Amount	AFUDC Capitalized	Indirect Costs Other	Total Costs	Estimated Physical % Completed
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
69	Unassigned	FGD - USS Transformer	$ 150,000	$ -	$ -	**$ 150,000**	
70	Unassigned	GN - Fire Control Panel (Control Room	$ 500,000	$ -	$ -	**$ 500,000**	
71	Unassigned	GN - Upgrade CEMS Monitors	$ 200,000	$ -	$ -	**$ 200,000**	
72	BP11G077B	GN - FGD Rehab / Chemical Resistant	$ 1,403,020	$ -	$ -	**$ 1,403,020**	85%
73	Unassigned	GN - Portable DGA Monitor for Transf	$ 50,000	$ -	$ -	**$ 50,000**	
74	Unassigned	GN - Portable Online Oil Dryer for Tra	$ 30,000	$ -	$ -	**$ 30,000**	
75	Unassigned	G1 - Hot and Cold Air Damper Drives	$ 120,000	$ -	$ -	**$ 120,000**	
76	Unassigned	G1 - Secondary Air Damper Drives	$ 30,000	$ -	$ -	**$ 30,000**	
77	Unassigned	GN - DCS UPS Backup Upgrade	$ 90,000	$ -	$ -	**$ 90,000**	
78	Unassigned	GN - Conveyor Belts	$ 80,000	$ -	$ -	**$ 80,000**	
79	Unassigned	GN - Additive Feed Pump 3 of 4	$ 50,000	$ -	$ -	**$ 50,000**	
80	Unassigned	GN - Additive Supply Pump 3 of 4	$ 50,000	$ -	$ -	**$ 50,000**	
81	Unassigned	GN - Office Bldg HVAC System	$ 400,000	$ -	$ -	**$ 400,000**	
82	Unassigned	GN - Reclaim Feeder (5 & 6 of 8)	$ 400,000	$ -	$ -	**$ 400,000**	
83	Unassigned	GN - Replace Fire Water Piping	$ 65,000	$ -	$ -	**$ 65,000**	
84	Unassigned	G1- Rpl B Reaction Tank Agitator Gea	$ 45,000	$ -	$ -	**$ 45,000**	
85	Unassigned	GN - Recycle Pumphouse Sump Pumps	$ 5,000	$ -	$ -	**$ 5,000**	
86	Unassigned	GN - Fire Water Deluges	$ 60,000	$ -	$ -	**$ 60,000**	

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For the Forecasted Test Period
(2/1/2014 - 1/31/2015)

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Schedule 2

Line No. (A)	Project No. (B)	Description of Project (C)	Accumulated Costs: Construction Amount (D)	AFUDC Capitalized (E)	Indirect Costs Other (F)[1]	Total Costs (G = D+E+F)	Estimated Physical % Completed (H)
87	Unassigned	GN - IU Filtrate Feed Pump 2 of 3	$ 60,000	$ -	$ -	$ 60,000	
88	Unassigned	GN - IU Filtrate Return Pump 2 0f 2	$ 60,000	$ -	$ -	$ 60,000	
89	Unassigned	GN - DCS Servers/Client Computer & l	$ 30,000	$ -	$ -	$ 30,000	
90	Unassigned	GN - Conductor NT Client Licenses	$ 16,000	$ -	$ -	$ 16,000	
91	Unassigned	GN - DCS Large Screen Monitors LCD	$ 5,000	$ -	$ -	$ 5,000	
92	Unassigned	GN - Replace PI Server and API Node	$ 10,000	$ -	$ -	$ 10,000	
93	Unassigned	GN - Upgrde Control Room HMI Softw	$ 655,000	$ -	$ -	$ 655,000	
94	Unassigned	GN Communication Infrastructure	$ 40,000	$ -	$ -	$ 40,000	
95	Unassigned	GN - Drager Air Monitor	$ 15,000	$ -	$ -	$ 15,000	
96	Unassigned	GN - Portable Gas Analyzer	$ 12,500	$ -	$ -	$ 12,500	
97	Unassigned	GN - M.S.A. Ammonia Monitor (Detec	$ 6,000	$ -	$ -	$ 6,000	
98	Unassigned	GN - leco TGA-701 Sulfate/Carbonate/	$ 50,000	$ -	$ -	$ 50,000	
99	Unassigned	GN - Landfill Downdrains	$ 30,000	$ -	$ -	$ 30,000	
100	Unassigned	GN - Remote Racking	$ 7,500	$ -	$ -	$ 7,500	
101	Unassigned	G1 - Air Heater Baskets	$ 950,000	$ -	$ -	$ 950,000	
102	Unassigned	G1 - Replace Slaker (2nd of 8)	$ 220,000	$ -	$ -	$ 220,000	
103	Unassigned	G1 - Station Inverter	$ 100,000	$ -	$ -	$ 100,000	
104	Unassigned	G1 - Upgrade Ignitors	$ 1,250,000	$ -	$ -	$ 1,250,000	

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Schedule 2

Line No.	Project No.	Description of Project	Accumulated Costs: Construction Amount	AFUDC Capitalized	Indirect Costs Other	Total Costs	Estimated Physical % Completed
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
105	Unassigned	G1 - C/T Cell Structure and Fill Replac	$ 1,116,000	$ -	$ -	**$ 1,116,000**	
106	Unassigned	G1 Boiler Hanger Replacements, MSH,	$ 150,000	$ -	$ -	**$ 150,000**	
107	Unassigned	G1 - Air Heater Gas Outlet Exp Joints	$ 150,000	$ -	$ -	**$ 150,000**	
108	Unassigned	G1 - Precip Repair	$ 1,159,275	$ -	$ -	**$ 1,159,275**	
109	Unassigned	G1 - Bottom Ash Doghouses (2 & 3 of	$ 150,000	$ -	$ -	**$ 150,000**	
110	Unassigned	G1 - Precip Outlet Nozzle	$ 1,300,000	$ -	$ -	**$ 1,300,000**	
111	Unassigned	G1 - Ash Clinker Grinder (2)	$ 120,000	$ -	$ -	**$ 120,000**	
112	Unassigned	G1 - Condensor Dog Bone Expansion J	$ 100,000	$ -	$ -	**$ 100,000**	
113	Unassigned	G1 - CEM Umbilical	$ 60,000	$ -	$ -	**$ 60,000**	
114	Unassigned	G1 - ID Fan Inlet Dampers (Dampers, J	$ 400,000	$ -	$ -	**$ 400,000**	
115	Unassigned	GT - Enclosure Over Combustion Com	$ 200,000	$ -	$ -	**$ 200,000**	
116	Unassigned	GT - Replace Cooling Tower	$ 950,000	$ -	$ -	**$ 950,000**	
117	Unassigned	GT - Replace Silencers	$ 550,000	$ -	$ -	**$ 550,000**	
118	Unassigned	GT - Replace Stack Liner	$ 250,000	$ -	$ -	**$ 250,000**	
119	Unassigned	GT - Upgrade PLC and HMI	$ 160,000	$ -	$ -	**$ 160,000**	
120	Unassigned	RGH - AED's	$ 4,248	$ -	$ -	**$ 4,248**	
121	Unassigned	RGH - Communication Infrastructure	$ 33,983	$ -	$ -	**$ 33,983**	
122	Unassigned	RGH - Rpl PI Server API Node	$ 4,278	$ -	$ -	**$ 4,278**	

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Schedule 2

Line No.	Project No.	Description of Project	Accumulated Costs: Construction Amount	AFUDC Capitalized	Indirect Costs Other	Total Costs	Estimated Physical % Completed
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
123	Unassigned	RGH - Rpl Screen pumps (2)	$ 30,585	$ -	$ -	$ 30,585	
124	Unassigned	RH - 480 Volt Welder	$ 2,005	$ -	$ -	$ 2,005	
125	Unassigned	RH - Client & Monitors (PLC & DCS)	$ 26,737	$ -	$ -	$ 26,737	
126	Unassigned	RH - Gas Welder	$ 4,679	$ -	$ -	$ 4,679	
127	Unassigned	RH - Misc Capital Projects	$ 67,175	$ -	$ -	$ 67,175	
128	Unassigned	RH - Misc Capital Valves	$ 67,506	$ -	$ -	$ 67,506	
129	Unassigned	RH - Misc Conveyor Belts	$ 60,823	$ -	$ -	$ 60,823	
130	Unassigned	RH - Misc Safety	$ 13,501	$ -	$ -	$ 13,501	
131	Unassigned	RH - Misc Tools & Equipment	$ 33,753	$ -	$ -	$ 33,753	
132	Unassigned	RH - Operation Locker Room Air Cond	$ 20,053	$ -	$ -	$ 20,053	
133	Unassigned	RH - Replace Vent Fans	$ 46,790	$ -	$ -	$ 46,790	
134	Unassigned	RH - Rpl Bldg. Steam Water Unit Heat	$ 13,369	$ -	$ -	$ 13,369	
135	Unassigned	RH - Sluice Pump Recirc	$ 34,085	$ -	$ -	$ 34,085	
136	Unassigned	R1 - PI Server Replacement	$ 25,000	$ -	$ -	$ 25,000	
137	Unassigned	R1 - Replace Obsolete CEMs Equipme	$ 20,000	$ -	$ -	$ 20,000	
138	Unassigned	R1 - Turbine Roof Replacement	$ 162,000	$ -	$ -	$ 162,000	
139	Unassigned	H1 - Rpl Cooling Tower Top Deck	$ 61,538	$ -	$ -	$ 61,538	
140	Unassigned	H0 - Install New Service Elevator	$ 365,609	$ -	$ -	$ 365,609	

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Schedule 2

			Accumulated Costs				
Line No.	**Project No.**	**Description of Project**	**Construction Amount**	**AFUDC Capitalized**	**Indirect Costs Other**	**Total Costs**	**Estimated Physical % Completed**
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
141	Unassigned	H1 - "A" Mill Trunnion Bearing	$ 246,154	$ -	$ -	**$ 246,154**	
142	Unassigned	H1 - Bunker Gates (Qty 4)	$ 29,538	$ -	$ -	**$ 29,538**	
143	Unassigned	H1 - Coal Pipe Hangers	$ 36,923	$ -	$ -	**$ 36,923**	
144	Unassigned	H1 - DCS Communication Controls	$ 61,538	$ -	$ -	**$ 61,538**	
145	Unassigned	H1 - Ductwork Hangers	$ 36,923	$ -	$ -	**$ 36,923**	
146	Unassigned	H1 - Expansion Joints	$ 104,615	$ -	$ -	**$ 104,615**	
147	Unassigned	H1 - High Energy Pipe Hangers	$ 67,692	$ -	$ -	**$ 67,692**	
148	Unassigned	H1 - Insulation & Lagging	$ 184,615	$ -	$ -	**$ 184,615**	
149	Unassigned	H1 - Lined Coal Conduit	$ 369,230	$ -	$ -	**$ 369,230**	
150	Unassigned	H1 - Precipitator False Floor	$ 276,923	$ -	$ -	**$ 276,923**	
151	Unassigned	H1 - Pulverizer Liners	$ 430,769	$ -	$ -	**$ 430,769**	
152	Unassigned	H1 - Replace "B" Ash Sluice Pump	$ 30,769	$ -	$ -	**$ 30,769**	
153	Unassigned	H1 - Replace DCS Process Controllers	$ 73,846	$ -	$ -	**$ 73,846**	
154	Unassigned	H1 - Replace Generator Relay	$ 17,981	$ -	$ -	**$ 17,981**	
155	Unassigned	H1 - Replace Obsolete CEMs Equipme	$ 21,538	$ -	$ -	**$ 21,538**	
156	Unassigned	H1 - Rpl "A" 4160V switchgear	$ 923,077	$ -	$ -	**$ 923,077**	
157	Unassigned	H1 - Rpl AH Steam Coils (2)	$ 15,385	$ -	$ -	**$ 15,385**	
158	Unassigned	H1 - Rpl Cooling Tower A, B & C Cell	$ 369,231	$ -	$ -	**$ 369,231**	

Big Rivers Electric Corporation
Case No. 2013-00199
Construction Projects

For the Forecasted Test Period
(2/1/2014 - 1/31/2015)

Type of Filing: Original - __X__; Updated - _____; Revised - _____

Schedule 2

Line No.	Project No.	Description of Project	Accumulated Costs: Construction Amount	AFUDC Capitalized	Indirect Costs Other	Total Costs	Estimated Physical % Completed
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
159	Unassigned	H1 - Rpl Slag Grinders (2)	$ 46,154	$ -	$ -	**$ 46,154**	
160	Unassigned	H1 - Rpl Sootblowers (27 & 28) 2 total	$ 49,231	$ -	$ -	**$ 49,231**	
161	Unassigned	H1 - Rpl Wallblowers (12, 13 & 14) 3 t	$ 40,000	$ -	$ -	**$ 40,000**	
162	Unassigned	H1 - SCR Catalyst Layer	$ 603,077	$ -	$ -	**$ 603,077**	
163	Unassigned	H1 - Scrubber Stack Liner	$ 1,107,692	$ -	$ -	**$ 1,107,692**	
164	Unassigned	H1 - Network Switch Replacement	$ 6,154	$ -	$ -	**$ 6,154**	
165	Unassigned	H1 - Upgrade all ABB DCS Controls	$ 29,968	$ -	$ -	**$ 29,968**	
166	Unassigned	H2 - Upgrade all ABB DCS Controls	$ 29,968	$ -	$ -	**$ 29,968**	
167	Unassigned	Misc. Safety Equipment	$ 10,000	$ -	$ -	**$ 10,000**	
168	Unassigned	Misc. Capital	$ 100,000	$ -	$ -	**$ 100,000**	
169	Unassigned	Capital Valves	$ 20,000	$ -	$ -	**$ 20,000**	
170	Unassigned	Landfill Drainage Control	$ 150,000	$ -	$ -	**$ 150,000**	
171	Unassigned	Replace Liner in #1 Make Up Clarifier :	$ 200,000	$ -	$ -	**$ 200,000**	
172	Unassigned	HVAC Replacements	$ 50,000	$ -	$ -	**$ 50,000**	
173	Unassigned	HAPS/MATS - Capitalized Interest		$ 1,482,453	$ -	**$ 1,482,453**	
174	Unassigned	HAPS/MATS Project	$ 22,360,000	$ -	$ -	**$ 22,360,000**	
175	Unassigned	HAPS/MATS Project - HMPL	$ 292,499	$ -	$ -	**$ 292,499**	
176	Unassigned	GN - Plant Tools & Equipment	$ 50,000	$ -	$ -	**$ 50,000**	

Big Rivers Electric Corporation
Case No. 2013-00199
Construction Projects

For the Forecasted Test Period
(2/1/2014 - 1/31/2015)

Type of Filing: Original - __X__; Updated - ______; Revised - ______

Schedule 2

			Accumulated Costs				
Line No.	**Project No.**	**Description of Project**	**Construction Amount**	**AFUDC Capitalized**	**Indirect Costs Other**	**Total Costs**	**Estimated Physical % Completed**
(A)	(B)	(C)	(D)	(E)	(F)[1]	(G = D+E+F)	(H)
177	Unassigned	GN - Miscellaneous Capital Projects	$ 100,000	$ -	$ -	**$ 100,000**	
178	Unassigned	GN - Miscellaneous Safety	$ 20,000	$ -	$ -	**$ 20,000**	
179	Unassigned	GN - Capital Valves	$ 100,000	$ -	$ -	**$ 100,000**	
180	Unassigned	G1 - Control Room Consoles	$ 125,000	$ -	$ -	**$ 125,000**	
181	Unassigned	G1 - DCS Firmware Upgrade	$ 75,000	$ -	$ -	**$ 75,000**	
182	Unassigned	G1 - Communication Controller Upgrac	$ 75,000	$ -	$ -	**$ 75,000**	
183	Unassigned	GN - Pnuematic Air Wrench Right Ang	$ 6,000	$ -	$ -	**$ 6,000**	
184	Unassigned	GN - 4" Portable Heavy Sump Pump	$ 35,000	$ -	$ -	**$ 35,000**	
185	Unassigned	G1 - Replace G1 CCW heat Exchangers	$ 250,000	$ -	$ -	**$ 250,000**	
186	Unassigned	RH - Replace D8N with a D8T - Movec	$ 562,401	$ -	$ -	**$ 562,401**	
187	Unassigned	HAPS/MATS - Capitalized Interest	$ -	$ 166,355	$ -	**$ 166,355**	
188	Unassigned	HAPS/MATS Project	$ 5,000,000	$ -	$ -	**$ 5,000,000**	

Big Rivers Electric Corporation
Case No. 2013-00199
Comparison of Base Period and Three (3) Most Recent Calendar Years of Accounts
as Reported in KPSC Financial and Statistical Report (Annual Report)

Line No.	Account Number and Description	Base Period Ended 9/30/13	% Chg	2012	% Chg
1	POWER PRODUCTION EXPENSES				
2					
3	**Steam Power Generation**				
4	**Operation**				
5	500 Operation Supervison & Engineering	5,447,942	-2.72%	5,600,410	8.11%
6	501 Fuel	238,829,108	5.69%	225,977,816	0.30%
7	502 Steam Expenses	30,782,604	8.21%	28,446,807	-4.41%
8	503 Steam from Other Sources	-		-	
9	504 (Less) Steam Transferred	-		-	
10	505 Electric Expenses	7,279,346	6.09%	6,861,674	2.65%
11	506 Miscellaneous Steam Power Expenses	7,311,241	4.55%	6,992,913	-14.89%
12	507 Rents	-		-	
13	509 Allowances	97,242	-16.29%	116,162	-78.32%
14	**Total Operation**	**289,747,483**	**5.75%**	**273,995,782**	**-0.61%**
15					
16	**Maintenance**				
17	510 Maintenance Supervision & Engineering	5,127,224	6.78%	4,801,608	1.43%
18	511 Maintenance of Structures	3,389,432	-5.28%	3,578,281	-1.93%
19	512 Maintenance of Boiler Plant	23,815,746	-7.80%	25,831,130	-1.71%
20	513 Maintenance of Electric Plant	4,193,503	21.21%	3,459,701	-27.92%
21	514 Maintenance of Miscellaneous Steam Plant	3,043,620	-6.49%	3,254,923	-0.87%
22	**Total Maintenance**	**39,569,525**	**-3.31%**	**40,925,643**	**-4.26%**

Big Rivers Electric Corporation
Case No. 2013-00199
Comparison of Base Period and Three (3) Most Recent Calendar Years of Accounts
as Reported in KPSC Financial and Statistical Report (Annual Report)

Line No.	Account Number and Description	Base Period Ended 9/30/13	% Chg	2012	% Chg
23					
24	**Total Power Production Expenses-Steam Power**	**329,317,008**	**4.57%**	**314,921,425**	**-1.10%**
25					
26	**Other Power Generation**				
27	**Operation**				
28	546 Operation Supervison & Engineering	-		-	
29	547 Fuel	594,063	51.89%	391,106	-58.12%
30	548 Generation Expenses	35,814	-2.43%	36,705	8.22%
31	549 Miscellaneous Other Power Generation	-		-	
32	550 Rents	-		-	
33	**Total Operation**	**629,877**	**47.23%**	**427,811**	**-55.79%**
34					
35	**Maintenance**				
36	551 Maintenance Supervision & Engineering	-		-	
37	552 Maintenance of Structures	-		-	
38	553 Maintenance of Generating & Elec Plant	114,818	-52.99%	244,219	62.03%
39	554 Maintenance of Miscellaneous Other Power Generation Plant	-		-	
40	**Total Maintenance**	**114,818**	**-52.99%**	**244,219**	**62.03%**
41					
42	**Total Power Production Expenses-Other Power**	**744,695**	**10.81%**	**672,030**	**-39.92%**

Big Rivers Electric Corporation
Case No. 2013-00199
Comparison of Base Period and Three (3) Most Recent Calendar Years of Accounts
as Reported in KPSC Financial and Statistical Report (Annual Report)

Line No.	Account Number and Description	Base Period Ended 9/30/13	% Chg	2012	% Chg
43					
44					
45	**Other Power Supply Expenses**				
46	555 Purchased Power	99,538,601	-8.42%	108,690,784	3.73%
47	556 System control and Load Dispatching	-		-	-100.00%
48	557 Other Expenses	2,478,547	-10.67%	2,774,573	-62.69%
49	Total Other Power Supply Expenses	**102,017,148**	**-8.48%**	**111,465,357**	**-0.71%**
50					
51	Total Power Production Expenses (Lines 21,41,59,74,79)	**432,078,851**	**1.18%**	**427,058,812**	**-1.10%**
52					
53	**Transmission Expenses**				
54	**Operation**				
55	560 Operation Supervison & Engineering	763,386	21.98%	625,842	-6.21%
56	561 Load Dispatching	6,094,370	-2.16%	6,229,181	0.40%
57	562 Station Expenses	760,813	-1.58%	773,021	3.99%
58	563 Overhead Line Expenses	1,102,572	13.02%	975,573	-3.15%
59	564 Underground Lines Expenses	-		-	
60	565 Transmission of Electricity By Others	4,152,721	34.74%	3,082,093	27.98%
61	566 Miscellaneous Transmission Expenses	657,838	-1.93%	670,790	1.77%
62	567 Rents	38,829	57.20%	24,701	7.67%
63	**Total Operation**	**13,570,529**	**9.61%**	**12,381,201**	**5.71%**

Big Rivers Electric Corporation
Case No. 2013-00199
Comparison of Base Period and Three (3) Most Recent Calendar Years of Accounts
as Reported in KPSC Financial and Statistical Report (Annual Report)

Line No.	Account Number and Description	Base Period Ended 9/30/13	% Chg	2012	% Chg
64					
65	**Maintenance**				
66	568 Maintenance Supervision & Engineering	489,988	1.18%	484,274	-8.18%
67	569 Maintenance of Structures	(22,074)	-198.43%	22,426	35.04%
68	570 Maintenance of Station Equipment	1,482,291	-4.67%	1,554,891	-1.49%
69	571 Maintenance of Overhead Lines	1,809,779	0.26%	1,805,126	-5.77%
70	572 Maintenance of Underground Lines	-		-	
71	573 Maintenance of Miscellaneous Transmission Plant	716,015	-3.41%	741,281	15.38%
72	**Total Maintenance**	**4,475,999**	**-2.86%**	**4,607,998**	**-1.55%**
73					
74	**Total Transmission Expenes**	**18,046,528**	**6.22%**	**16,989,199**	**3.64%**
75					
76	**Customer Accounts Expense**				
77	**Operation**				
78	901 Supervision	-		-	
79	902 Meter Reading Expenses	-		-	
80	903 Customer Records and Collection Expenses	-		-	
81	904 Uncollectible Accounts	297,191	0.00%	297,191	
82	905 Miscellaneous Customer Accounts Expenses	-		-	
83	**Total Customer Accounts Expenses**	**297,191**		**297,191**	
84					

Big Rivers Electric Corporation
Case No. 2013-00199
Comparison of Base Period and Three (3) Most Recent Calendar Years of Accounts as Reported in KPSC Financial and Statistical Report (Annual Report)

Line No.	Account Number and Description	Base Period Ended 9/30/13	% Chg	2012	% Chg
106	923 Outside Services Employed	3,404,242	71.47%	1,985,347	25.06%
107	924 Property Insurance	-		-	
108	925 Injuries and Damages	114,956	-34.73%	176,132	-17.75%
109	926 Employee Pensions & Benefits	944,282	-4.64%	990,279	372.10%
110	927 Franchise Requirements	-		-	
111	928 Regulatory Commission Expenses	(735,134)	-164.53%	1,139,183	-55.28%
112	929 (Less) Duplicate Charges -- CR	-		-	
113	930.1 General Advertising Expenses	150,691	-7.13%	162,259	3.92%
114	930.2 Miscellaneous General Expenses	1,492,683	-22.95%	1,937,347	7.36%
115	931 Rents	1,933	0.00%	1,933	0.00%
116	**Total Operation**	**27,164,993**	**2.79%**	**26,428,745**	**-0.48%**
117					
118	**Maintenance**				
119	935 Maintenance of General Plant	**241,809**	**31.20%**	**184,301**	**31.14%**
120					
121	**Total Administrative and General Expenses**	**27,406,802**	**2.98%**	**26,613,046**	**-0.32%**
122					
123	**Total Electric Operation and Maintenance**	**479,449,556**	**1.57%**	**472,035,621**	**-0.77%**
124	(80,100,126,134,141,148,168)				

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

In the Matter of:

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

Responses to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to Commission Staff's Initial Request for Information, Item No. 57 originally filed July 12, 2013

Information submitted on CD accompanying responses

ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

Response to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Office of the Attorney General's Initial Request for Information, Item Nos. 196 and 202 originally filed September 3, 2013, and revised October 22, 2013

FILED: July 18, 2019

ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

In the Matter of:

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

Responses to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Office of the Attorney General's Initial Request for Information, Item No. 196 originally filed September 3, 2013, and revised October 22, 2013

Information submitted on CD accompanying responses

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

In the Matter of:

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

Responses to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Office of the Attorney General's Initial Request for Information, Item No. 202 originally filed September 3, 2013, and revised October 22, 2013

Information submitted on CD accompanying responses

ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

Response to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Office of the Attorney General's Supplemental Request for Information, Item No. 59 originally filed September 30, 2013, and revised October 22, 2013

FILED: July 18, 2019

ORIGINAL

Big Rivers Electric Corporation
Case No. 2013-00199
Wilson Plant Costs
Attachment 1 - *Revised*

Line No.	DESCRIPTION	2013	2014	2015	2016	2017	2018
1	Layup Capital	0	0	0	0	0	0
2	Layup Fixed Departmental Expense	961,000	0	0	0	0	0
3	Labor Expense	10,914,913	1,633,639	1,669,094	1,710,020	1,752,770	11,907,178
4	Ongoing Fixed Departmental Expense	6,139,952	610,576	612,205	613,807	738,055	12,843,980
5	Ongoing Capital	8,279,000	530,000	2,730,000	1,280,000	0	10,872,820
6	Property Tax Expense Base	1,048,464	1,081,241	1,093,163	1,107,493	1,136,043	1,165,526
7	Property Tax Expense ECR	14,169	14,417	22,956	21,773	21,454	20,909
8	Property Insurance Expense Base	1,127,161	1,240,971	1,289,128	1,354,001	1,387,745	1,422,328
9	Property Insurance Expense ECR	5,945	6,511	20,724	21,345	21,986	22,645
10	Interest Expense Base	22,160,093	20,658,667	20,621,730	20,509,890	21,037,823	21,578,989
11	Interest Expense ECR	66,636	273,794	329,984	329,984	323,048	315,904
12		50,717,333	26,049,817	28,388,984	26,948,314	26,418,925	60,150,280

Depreciation expense is not broken out by location in the financial model
Wilson is assumed to layup September 2013 and to come out of layup in 2018
Excludes startup cost in 2018

Big Rivers Electric Corporation
Case No. 2013-00199
Coleman Plant Costs
Attachment 2 - *Revised*

Line No.	DESCRIPTION	2013	2014	2015	2016	2017	2018	2019
1	Layup Capital	0	100,000	0	0	0	0	0
2	Layup Expense	0	2,000,000	0	0	0	0	0
3	*Labor Expense	12,059,190	5,063,365	1,384,331	1,419,971	1,455,470	3,292,354	13,580,606
4	*Ongoing Fixed Departmental Expense	14,389,026	1,981,289	1,230,305	1,253,805	1,285,151	1,317,279	3,333,449
5	Ongoing Capital	10,579,000	0	0	0	0	0	10,054,738
6	Property Tax Expense Base	438,274	468,898	479,268	482,978	495,429	508,288	521,461
7	Property Tax Expense ECR	5,936	6,266	10,020	9,509	9,370	9,132	8,893
8	Property Insurance Expense Base	658,951	725,628	753,789	791,722	811,453	831,675	852,400
9	Property Insurance Expense ECR	3,475	3,807	12,115	12,479	12,853	13,239	13,636
10	Interest Expense Base	6,782,569	6,099,296	5,967,836	5,931,664	6,117,166	6,307,391	6,502,458
11	Interest Expense ECR	163,284	670,901	808,588	808,588	791,592	774,086	756,055
12		45,079,705	17,119,450	10,646,252	10,710,716	10,978,484	13,053,443	35,623,698

Depreciation expense is not broken out by location in the financial model
Coleman is assumed to layup February 2014 and to come out of layup in 2019
Excludes startup cost in 2019
*Does not include pro-forma adjustments

Case No. 2013-00199
Attachment for *Revised* Response to AG 2-59
Witnesses: Jeffrey R. Williams and Christopher A. Warren

ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

**Response to the Commission's Orders, dated June 18, 2019,
withdrawing Confidential Treatment
of previously filed Confidential Documents**

**Responses to the Kentucky Industrial Utility Customers, Inc.'s
First Request for Information, Item Nos. 21 and 22
originally filed September 3, 2013, and revised October 22, 2013**

FILED: July 18, 2019

ORIGINAL

Big Rivers Electric Corporation
Case No. 2013-00199
Wilson Plant Costs
For the Forecasted Test Period

Type of Filing: Original - ______; Updated - ______; Revised - __X____

Line No.	DESCRIPTION	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15
1	Labor Expense	132,509	143,227	136,406	145,176	124,714	136,406	145,176	126,968	151,742	124,986	128,950	140,360
2	Fixed Departmental Expense	42,300	42,300	45,800	51,283	49,183	49,183	49,183	42,300	42,300	42,222	42,222	112,361
3	Property Tax Expense Base	90,103	90,103	90,103	90,103	90,103	90,103	90,103	90,103	90,103	90,103	90,103	91,097
4	Property Tax Expense ECR	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,913
5	Property Insurance Expense Base	103,414	103,414	103,414	103,414	103,414	103,414	103,414	103,414	103,414	103,414	103,414	107,427
6	Property Insurance Expense ECR	543	543	543	543	543	543	543	543	543	543	543	1,727
7	Depreciation Expense Base	1,671,036	1,671,036	1,671,106	1,671,238	1,671,395	1,671,517	1,671,517	1,672,175	1,672,450	1,672,474	1,672,474	1,672,505
8	Depreciation Expense ECR	0	0	0	0	0	0	0	23,288	23,288	23,288	23,288	23,288
9	Interest Expense Base	1,612,140	1,749,205	1,707,050	1,754,261	1,703,129	1,752,551	1,752,552	1,701,568	1,754,313	1,707,281	1,750,135	1,750,264
10	Interest Expense ECR	13,341	14,771	21,285	21,994	21,285	28,026	28,026	27,122	28,026	27,122	28,026	28,026
11		3,666,588	3,815,800	3,776,907	3,839,212	3,764,966	3,832,945	3,841,715	3,788,683	3,867,380	3,792,635	3,840,357	3,928,969

Case No. 2013-00199
Attachment for *Revised* Response to KIUC 1-21
Witness: Jeffrey R. Williams

Big Rivers Electric Corporation
Case No. 2013-00199
Coleman Plant Costs
For the Forecasted Test Period

Type of Filing: Original - _____; Updated - _____; Revised - __X___

Line No.	DESCRIPTION	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15
1	Labor Expense	973,074	1,048,002	1,100,936	148,174	104,141	114,019	121,427	106,368	127,355	104,689	108,047	116,321
2	Fixed Departmental Expense	1,773,641	53,049	58,591	65,601	220,054	79,317	71,554	68,811	72,274	83,253	231,753	131,628
3	Property Tax Expense Base	39,075	39,075	39,075	39,075	39,075	39,075	39,075	39,075	39,075	39,075	39,075	39,939
4	Property Tax Expense ECR	522	522	522	522	522	522	522	522	522	522	522	835
5	Property Insurance Expense Base	60,469	60,469	60,469	60,469	60,469	60,469	60,469	60,469	60,469	60,469	60,469	62,816
6	Property Insurance Expense ECR	317	317	317	317	317	317	317	317	317	317	317	1,010
7	Depreciation Expense Base	513,002	513,033	513,075	513,215	513,866	513,866	513,866	517,376	517,376	517,376	517,407	517,407
8	Depreciation Expense ECR	0	0	0	0	0	0	0	57,065	57,065	57,065	57,065	57,065
9	Interest Expense Base	493,039	534,330	506,841	520,601	505,573	507,218	507,219	492,652	507,788	494,500	506,437	506,479
10	Interest Expense ECR	32,691	36,194	52,155	53,894	52,155	68,675	68,675	66,459	68,675	66,459	68,675	68,675
11		3,885,831	2,284,990	2,331,981	1,401,868	1,496,172	1,383,478	1,383,123	1,409,115	1,450,917	1,423,726	1,589,767	1,502,175

ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

Response to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to Ben Taylor and the Sierra Club's Supplemental Request for Information, Item No. 9 originally filed September 30, 2013, and revised October 22, 2013

FILED: July 18, 2019

ORIGINAL

3. *Identify and produce any study or analysis supporting such carbon price projection.*

ii. *If not:*

1. *Explain why not.*
2. *Identify and produce any study or analysis supporting the assumption of no price on carbon emissions between now and 2027.*
3. *Identify any other utility that BREC is aware of that assumes in its long term financial forecasting that there will be no price on carbon emissions between now and 2027.*

c. *For the ACES market energy price forecasts, explain why:*

i. *The fall 2012 forecast used in the Century rate case projects significant prices increases (13.1% to 25.7% per year) in the [2019 to 2021 time frame.*

ii. *The August 19, 2013 forecast projects significant price increases (14.3%to 30.8% per year) in the 2021 to 2023 time frame, but increases of less than 4% per year in 2019 and 2020.*

iii. *The April 2013 forecast used in the Alcan rate case projects significantly lower market energy prices than were projected in the ACES fall 2012 forecast.*

iv. *There are large swings in successive ACES Indiana Hub electricity price forecasts.*

d. *State whether Big Rivers has considered the use of other market energy price forecasts in its long term forecasting in order to reduce dependence on the fluctuating ACES forecasts.*

i. *If not, explain why not.*

e. *Please clarify what role, if any, the IHS price forecast plays in Big Rivers' long-term forecasting.*

Response)

a. For the ACES market energy price forecasts, please see the attached letter from ACES to Big Rivers. For IHS, please see attached CONFIDENTIAL chart displaying the EPA's regulatory timeline under IHS CERA's planning scenario.

b. There is no change to the response filed September 30, 2013.

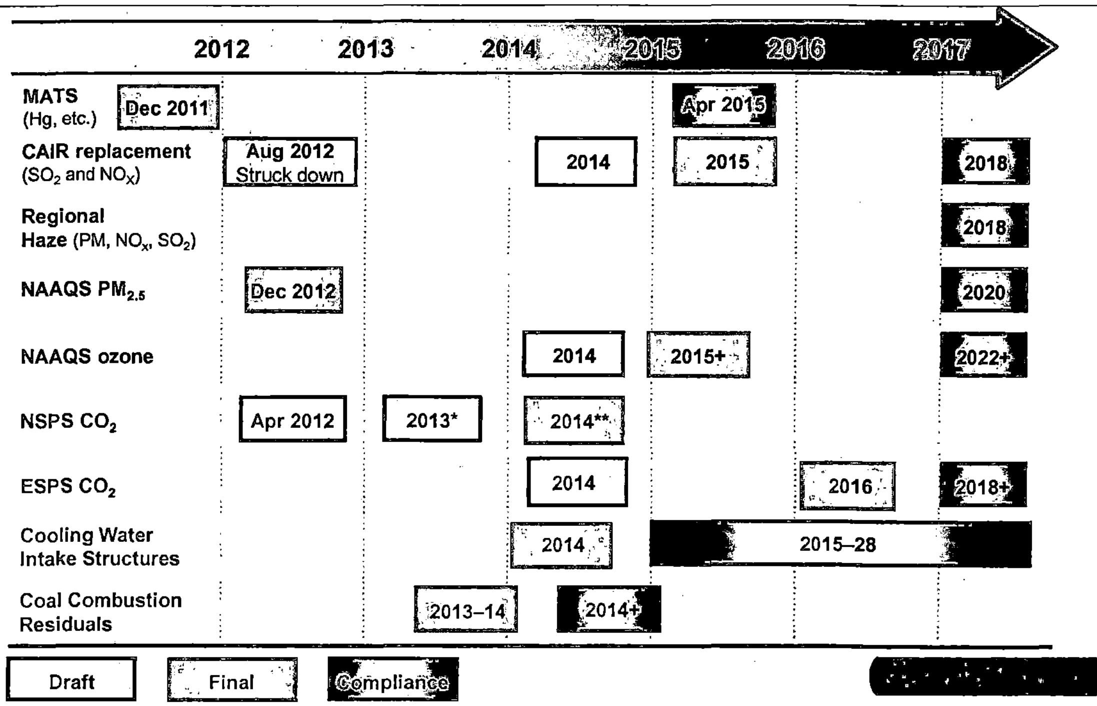
c. There is no change to the response filed September 30, 2013.

d. There is no change to the response filed September 30, 2013.

e. There is no change to the response filed September 30, 2013.

Witness) Robert W. Berry

EPA's regulatory timeline under IHS CERA's planning scenario



Source: IHS CERA. *EPA is expected to repropose its NSPS for CO_2 in the second half of 2013. **EPA's NSPS for CO_2 will apply to plants that begin construction 12 months after the reproposed rule is released.
30105-2

Case No. 2013-00199
Attachment 2 for Revised Response to SC 2-9a
Page 1 of 1

ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

Response to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Designated Rebuttal Testimony Documents originally filed December 17, 2013

FILED: July 18, 2019

ORIGINAL

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

	Wood-Mackenzie Projection		IHS Global Projection	
	MISO Capacity Value		MISO Capacity Value	
Year	$/kW-Month	482 MW Value	$/kW-Month	482 MW Value
2014	$1.68	$9,717,120	$0.19	$1,098,960
2015	$1.68	$9,717,120	$1.70	$9,832,800
2016	$5.82	$33,662,880	$4.68	$27,069,120
2017	$6.08	$35,166,720	$5.25	$30,366,000
2018	$6.52	$37,711,680	$6.26	$36,207,840
2019	$7.01	$40,545,840	$6.44	$37,248,960
2020	$7.54	$43,611,360	$6.48	$37,480,320
2021	$7.95	$45,982,800	$6.43	$37,191,120
2022	$8.29	$47,949,360	$7.11	$41,124,240
2023	$8.49	$49,106,160	$7.42	$42,917,280

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

ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

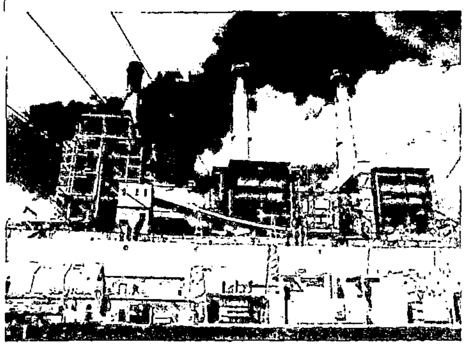
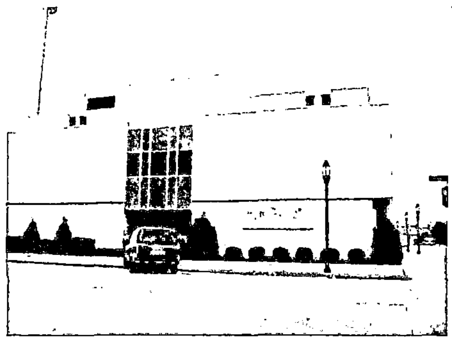
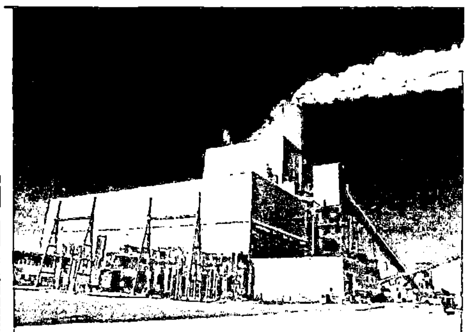
Response to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

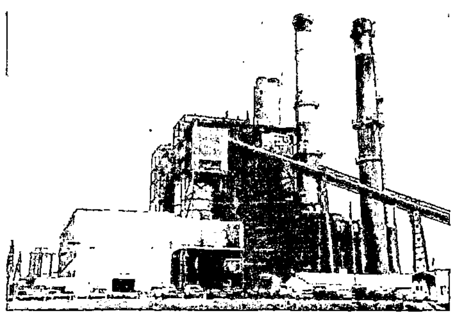
Responses to Requests for Information from the January 9, 2014, Hearing, Item Nos. 4, 5, 6, 7, 16, 17, and 20 originally filed January 24, 2014

FILED: July 18, 2019

ORIGINAL

Big Rivers
ELECTRIC CORPORATION



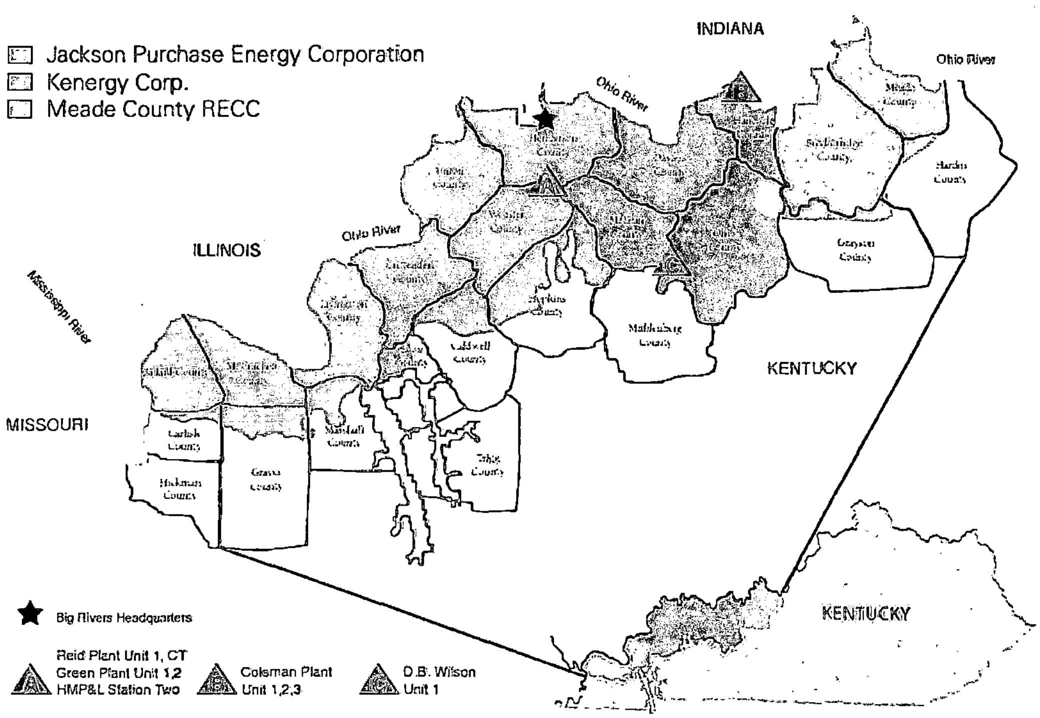

Load Concentration Analysis and Mitigation Plan

June 2012

INTRODUCTION

Big Rivers Electric Corporation is a member-owned, not-for-profit, generation and transmission (G&T) cooperative headquartered in Henderson, Kentucky. The company provides wholesale electric power and support services to three distribution cooperative members which serve portions of 22 counties in western Kentucky. In December 2010, Big Rivers became a transmission-owning member and market participant of Midwest ISO (MISO).

Big Rivers was formed to serve the needs of its member cooperatives (Members): Jackson Purchase Energy Corporation, headquartered in Paducah, KY; Kenergy Corp., headquartered in Henderson, KY; and Meade County Rural Electric Cooperative Corporation, headquartered in Brandenburg, KY. Together, the Members distribute retail electric power and provide other services to more than 114,000 homes, farms, businesses and industries.



Incorporated in June of 1961, the mission of Big Rivers is to safely deliver low cost, reliable wholesale power and cost-effective shared services desired by the Members. Business operations revolve around seven core values: safety, integrity, excellence, Member and community service, respect for the employee, teamwork, and environmental consciousness.

Big Rivers also serves, through Kenergy, two aluminum smelters located in Western Kentucky. The two aluminum smelters represent a significant portion of Big Rivers' total load. Approximately 68% of Big Rivers' energy sales are to the smelters. The smelters also account for approximately 57% of Big Rivers' system demand.

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

The Smelter Service Agreements were developed with recognition of the uncertainty in the world-wide aluminum commodity industry; the contracts allow a smelter to exit its electric service agreement on one year's notice. However, Big Rivers also recognizes that one-third of the Big Rivers system load cannot economically support the commercial viability of two large industrials that comprise the remaining two-thirds of the system load. Big Rivers will continue to support the smelters by operating in a prudent manner at the lowest reasonable cost, consistent with good utility practice. Also, Big Rivers recognizes the possibility that one or both smelters may one day discontinue their Kentucky operations and Big Rivers must be prepared for this possibility.

This analysis discusses numerous potential scenarios associated with the loss of one or both smelter operations and the resulting rate impacts. It serves as a road map to assist with decision-making given specific circumstances that exist at the time. Also, it recognizes that a myriad of potential circumstances may exist if, and when, a smelter closing may occur.

<u>Transmission Availability</u>

Due to the potential loss of smelter load, transmission projects were completed within and in proximity of Big Rivers' system to ensure the power the smelters consume could be transmitted off system should they close. These transmission construction projects were planned in two phases. Phase 1 of Big Rivers' internal transmission upgrades has been completed and will allow Big Rivers to transmit to its border all additional energy which would have been consumed by either one of the two smelters. Big Rivers has nearly completed its Phase 2 transmission projects, which will allow Big Rivers to transmit to its border all additional energy which would have been consumed by both smelters. Because the Smelter Service Agreements require one year's notice for termination, the Phase 2 transmission projects will be available in the event both smelters cease operations. Additionally, Vectren is in the process of constructing a 345 kV interconnection with Big Rivers as part of a MISO-approved project which will enhance Big Rivers' ability to import/export power when completed. Big Rivers has no cost responsibilities with this project.

Big Rivers requested a MISO assessment of transfer capability from the Big Rivers transmission zone into other MISO zones and TVA assuming the loss of all smelter load (850 MW). The July 11, 2011 MISO study results indicated the transmission grid has a transfer capacity in excess of the 850 MW currently provided to the smelters should the smelter operations cease. Thus, the transmission system, under normal or single contingency conditions, will permit Big Rivers to export all of the excess power from the loss of both smelters.

Wholesale Power Market

The average MISO real-time locational marginal price (LMP) during the 2011 summer season was 6.6% lower than the average price during the 2010 summer. The 2011 summer price averaged $35.13/MWh and the 2010 summer average was $37.63/MWh. The depressed economy, higher wind generation output and generally lower average fuel prices relative to the previous two summers impacted the real-time price in the summer of 2011.

As a standard practice, Big Rivers monitors market pricing forecasts in several ways. Big Rivers subscribes to numerous publications, monitors the InterContinental Exchange platform, receives market intelligence from ACES Power Marketing, and solicits the assistance of outside firms who specialize in market forecasting when modeling/planning needs warrant. In order to assist with the planning for Environmental Compliance, PACE Global was retained to provide Big Rivers with a market price forecast.

In order to ensure Big Rivers' analyses covered potential market changes, Big Rivers used both the PACE Global price curve discussed above and a more conservative (lower market pricing) ACES forward price curve. The use of this range of price sensitivities ensures a robust analysis of the potential impact of market pricing on the smelter loss scenarios included in this document.

Rates

Big Rivers regularly reviews its financial position to ensure compliance with loan covenants and corporate objectives. Big Rivers considers it a priority to work to minimize rate increases to Members; however, Big Rivers has and will continue to take a proactive approach to rate design and earnings requirements. Should Big Rivers project a revenue shortfall under any scenario; Big Rivers will petition the Kentucky Public Service Commission (PSC) for a rate increase to maintain financial viability.

Kentucky regulations offer Big Rivers the option to seek emergency rate relief should organizational needs warrant an expedited review from the PSC. While Big Rivers hopes to offset any needed rate increases to its Members in the short term by selling excess power in the wholesale market, Big Rivers is prepared to request needed increases to maintain financial viability should wholesale market conditions warrant.

At the Unwind Transaction closing, Big Rivers established a $35 million transition reserve account specifically to provide cash support in the event one or both smelters ceased operation on short notice. The funds in this account will be available to offset any temporary reduction in cash flow that could occur if one or both smelters cease operations.

Environmental Compliance Plan Summary

Big Rivers, like other utilities throughout the United States, has the obligation to ensure compliance with all environmental regulations. Most recently, the Cross State Air Pollution Rule (CSAPR) and Mercury and Air Toxics Standards (MATS) compliance deadlines have required Big Rivers to develop a new Environmental Compliance Plan (ECP). Big Rivers' ECP was filed with the Kentucky Public Service Commission (PSC) on April 2, 2012. The filing will be considered and ruled upon by the PSC through its normal process.

To comply with CSAPR, Big Rivers' 2012 ECP includes:

(1) installing a new scrubber on Big Rivers' Wilson Unit to increase sulfur dioxide (SO2) removal efficiency from 91% to 99%;
(2) installing a selective catalytic reduction (SCR) module on Big Rivers' Green Unit 2 to increase nitrous oxides (NOX) removal efficiency from 50% to 85%;
(3) modifying the scrubbers on HMP&L Station Two Units 1 and 2 to improve SO2 removal from 93.5% to 97%; and
(4) converting the existing equipment at Big Rivers' Reid Unit 1 to burn natural gas instead of coal, as necessary, to comply with the CSAPR rule.

To comply with the new MATS regulation, Big Rivers must install activated carbon injection (ACI) equipment for mercury (Hg) removal, dry sorbent injection (DSI) equipment for acid gas removal, and continuous emission compliance monitors on all three of Big Rivers' Coleman Units, the two Green Units and the Wilson Unit. Even though testing has proven the two HMP&L Units are low mercury emitters, continuous emission monitors must be installed to demonstrate continual compliance. Following its conversion, Reid Unit 1 and the Reid Combustion Turbine will both be natural gas fired units and not subject to MATS regulation.

The scenarios shown on pages 13 through 20 assume either that Big Rivers makes all necessary investments as described in its ECP filing to comply with both CSAPR and MATS or that Big Rivers makes the necessary investments to comply with MATS and purchases allowances and/or energy to comply with CSAPR.

Options for Mitigating Smelter Load Loss

Numerous internal strategic planning discussions have resulted in the development of a broad range of potential solutions for the organization to mitigate the loss of smelter load. The potential solutions are very diverse and each option has a varied impact on Big Rivers' future operations. While the options considered are complex with numerous variables, Big Rivers has both short-term and long-term approaches for mitigating the loss of smelter load. While these approaches summarize Big Rivers' overall strategy to mitigate this loss, Big Rivers will remain fluid in its analyses and work to ensure it has the flexibility to change course as conditions dictate and should unforeseen issues arise.

The scenarios highlighted in this report are options for mitigating the loss of one or both smelters. Numerous assumptions were considered, such as: the exit of one or both smelters; Big Rivers' environmental compliance strategy; market prices; and mitigation factors implemented to offset the loss of load. In those scenarios where only one smelter is modeled to cease operations, the remaining smelter is assumed in the model to shoulder their proportionate share of the price increase associated with the departure of the other smelter. Each scenario's assumptions and results are discussed later in this plan.

The rate impacts of these scenarios are shown in terms of average retail rates for rural and industrial customers, both net and gross of the Member Rate Stability Mechanism (MRSM) and Rural Economic Reserve (RER). Big Rivers' Members' rural customers' distribution adder fluctuates monthly, but averaged 3.3 cents per kWh in 2011. Industrial customers' distribution adder varies significantly between customers, but averaged 0.2 cents per kWh in 2011. The retail Member rate impacts were estimated by adding the current distribution adder to Big Rivers' projected wholesale rates in each of the scenarios. The distribution adders were assumed to remain constant throughout the analysis period.

The scenarios are provided in no particular order as to likelihood of occurrence.

HIGH-LEVEL STRATEGY

[redacted]

The scenarios included in this report (with the exception of Scenario 8) highlight potential circumstances that Big Rivers believes may exist if one or both of the smelters cease operations. The intelligence gained through these analyses has positioned Big Rivers to understand and effectively develop mitigation alternatives associated with the potential loss of one or both smelters; however, Big Rivers fully recognizes that the scenarios analyzed provide only general information. Ultimately, the approach to mitigating the loss of one or both smelters may include any number of mitigation strategies. Our general strategy is as follows:

Short-Term Approach

As discussed previously, Big Rivers will have adequate transmission capacity to transmit all its generating capacity to the MISO market or its TVA interface should both smelters terminate service. At Big Rivers' urging, the Kentucky General Assembly amended KRS 279.120 in 2006. The amendment enables Big Rivers and other cooperatives that experience a sudden, large drop in system load to remarket that power to non-members without endangering its cooperative status under state law.

In addition to petitioning the PSC for an emergency rate increase to help address any forecasted revenue shortfall, Big Rivers will market all excess power when the market price is greater than marginal generation cost. Benchmarking data indicates Big Rivers' generation costs currently rank better than more than half of similar utilities' costs, thus Big Rivers should be able to market a significant amount of its excess power. Big Rivers will idle or reduce generation when the market price does not support the cost of generating. Increased sales of power on the open market will cause Big Rivers' margins to be more heavily dependent on market prices. To reduce market risk, Big Rivers will evaluate the following options:

- Execute forward bilateral sales with counterparties
- Enter into wholesale sales agreements
- Participate in capacity markets
- Evaluate the opportunity to hedge market risk with options (i.e. puts, calls)
- Idle generation until new load is established or developed.

Big Rivers will evaluate implementation of a combination of the above options and will search for additional opportunities for mitigating the short-term risk of smelter loss. Each option is considered viable for short-term implementation and has the potential to stabilize Member rates.

Long-Term Approach

While selling power through short-term commitments in the wholesale market is a valid, viable outlet for Big Rivers' excess generation, a long-term sales commitment for power provides greater certainty and risk mitigation to the organization. As such, upon the announcement of a smelter closure, in addition to filing for an emergency rate increase, Big Rivers will immediately

[redacted]

begin working to procure long-term commitments from counterparties in need of generation. Several prospects have already indicated an interest in buying Big Rivers' power.

Big Rivers will concurrently investigate multiple counterparty opportunities, including but not limited to long-term wholesale agreements, existing load expansion, attracting new industrial load, and attracting new Members (cooperative, municipal, etc.). Each of these options could provide a stable revenue stream that would help to mitigate market risk to the organization and provide rate stabilization and potential relief to Member rates.

Entering into long-term wholesale agreement(s) to sell excess

Given the age of its generating capacity and its low variable cost of production, long-term wholesale sales agreements will likely be a valid outlet for all or a portion of Big Rivers' excess generation. Big Rivers has a plethora of potential counterparties for such a transaction. Because of Big Rivers' location within the MISO footprint, as well as Big Rivers' direct interconnection with other utilities not in the MISO footprint, Big Rivers has a number of opportunities to secure long-term wholesale agreements to sell excess power. Potential counterparties include, but are not limited to, Investor Owned Utilities (IOUs), power marketers, other G&T cooperatives, municipals, and distribution cooperatives. Many of these entities were short of generating capacity prior to the economic downturn and will likely return to the same situation when the economy strengthens. In addition, a number of utilities have announced coal-fired plant retirements to comply with EPA environmental requirements which will further increase sales opportunities and/or result in an increase in future wholesale market prices.

Existing load expansion

While some opportunity to assist and promote the expansion of existing load within the territory may exist, this load will likely be inconsequential to the overall sales portfolio of Big Rivers. These opportunities will be investigated, as prudent; however, they are not anticipated to be significant contributors to offsetting market risk for Big Rivers.

Attracting new industrial load

Attracting new industrial load to the Big Rivers system will be a key long-term strategic initiative for the organization to aid in minimizing market risk. Big Rivers has a cost competitive advantage over many of its peers because it has a lower cost generating fleet than most which has largely already been retrofitted with pollution controls. Likewise, Big Rivers' Members benefit from some of the lowest electricity rates in the country. Big Rivers' competitive advantage is not expected to deteriorate in the future as other neighboring utilities install pollution control equipment to comply with impending EPA regulations. This competitive advantage will make Big Rivers a leading contender for attracting new industrial load in the Midwest.

[redacted]

Attracting new Members (cooperative, municipal, etc.)

Contingent upon Member approval, Big Rivers will have the opportunity to offset market risk by securing new Members for the system. There are numerous opportunities for adding new distribution cooperatives and municipals within the state. Among these opportunities, Tennessee Valley Authority (TVA), the nation's largest government owned power provider, serves five Kentucky cooperatives near Big Rivers' service territory. Because TVA's member rates are much higher, the competitiveness of Big Rivers' rates should make attracting these cooperatives very feasible. Adding new Member cooperatives will provide Big Rivers future certainty; however, most cooperatives and municipals have multi-year notice power supply commitments that will impact the promptness of market risk mitigation.

TVA SERVICE AREA

The above options will be investigated and implemented, as appropriate, to reduce Big Rivers' market risk. Big Rivers will continue to seek additional opportunities and options to hedge market risk and provide reliable, low-cost power to its Member cooperatives.

<u>Additional Options</u>

While many of the previously described marketing and load growth options will be considered and pursued following the loss of smelter load, additional strategies can and will be considered. The following options merit consideration and are expected to be particularly attractive if market prices fall below generation costs.

If the following options are deemed necessary or desirable for the organization, they will be pursued in parallel with any ongoing marketing and load development efforts. While the final option(s) implemented and the timing of each will be dependent on factors that include the Big Rivers corporate strategy, environmental considerations, financial viability, financing availability, near-term power market, anticipated long-term power market, and the overall economic outlook, the following options will be fully evaluated and pursued as appropriate:

Lay-Up of Individual Generating Unit(s) and/or entire Generating Station(s)

This option has the potential to quickly and significantly reduce overall system costs while allowing Big Rivers to maintain ownership of valuable assets. The specific generating unit(s) and/or generating station(s) selected will be influenced by the individual unit costs, coal contracts, installed pollution control equipment or additional pollution control requirements, impact to the transmission system, as well as many other issues. Because of the timeliness and impact allowed by this option, it has been included in many of the scenarios analyzed heretofore.

Sale of Generating Station(s)

This option has the potential to reduce overall system operating costs and debt by liquidating existing asset(s). The specific generating station(s) targeted will be influenced by Big Rivers' corporate strategy, ability to find additional sales internally and externally, the individual unit costs, installed pollution control equipment, outside interest in the asset(s), as well as many other issues.

Merger

Under certain circumstances, a merger with another G&T cooperative or acquisition of Big Rivers by another G&T cooperative or an IOU could be beneficial to the Member cooperatives. With the significant low-variable-cost excess generation available under a loss of smelter situation, other entities, that are either currently short of generating capacity or expecting to be in the near future, may find value in either a merger with Big Rivers or the acquisition of some or all of Big Rivers' assets.

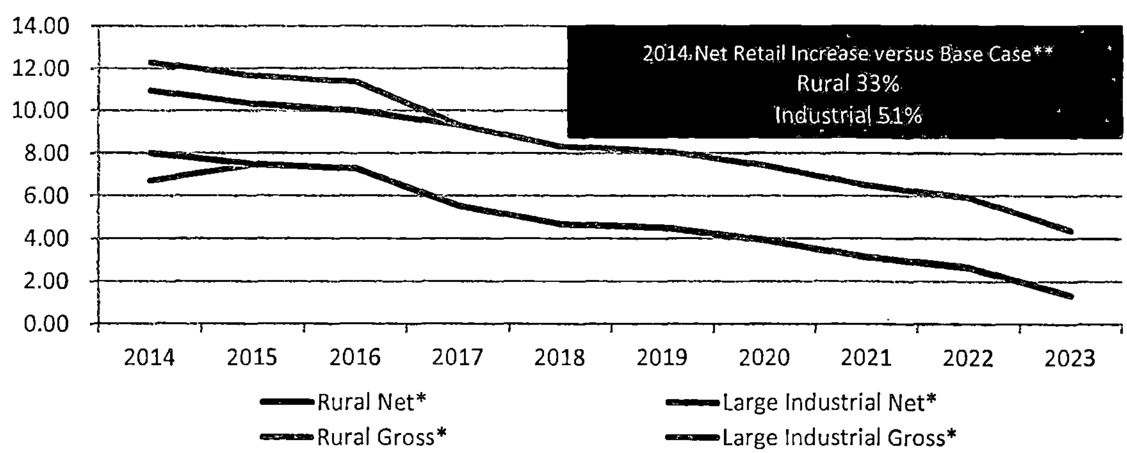
SCENARIOS

Scenario 1 Pollution Control Equipment Installed, Both Smelters Exit, Stronger Market Pricing

Scenario 1 analyzes Big Rivers' Member rates assuming Big Rivers installs all the pollution control equipment proposed in its Environmental Compliance Plan (ECP) filing, both smelters cease operation on 1/1/2014, and the PACE Global price forecast (more optimistic than ACES price curve) which Big Rivers procured for modeling purposes.

ASSUMPTIONS	
Generation	Load serving and wholesale sales
Smelters	Both exit 1/1/2014
Price Curve	PACE Global Market Price Curve
Pollution Control Equipment:	
CSAPR	Yes, as in ECP filing
MATS	Yes, as in ECP filing
Mitigation Efforts	Selling wholesale power in the market

ESTIMATED RESULTING AVERAGE MEMBER RETAIL* RATES (Cents per kWh)



*Member retail rate estimated by adding 3.3 and 0.2 cents per kWh to the residential and industrial projected wholesale rates, respectively.
**Base case assumes no Environmental Investment and both smelter in normal operation.
***Gross/Net of Member Rate Stability Mechanism & Rural Economic Reserve (RER)

DISCUSSION

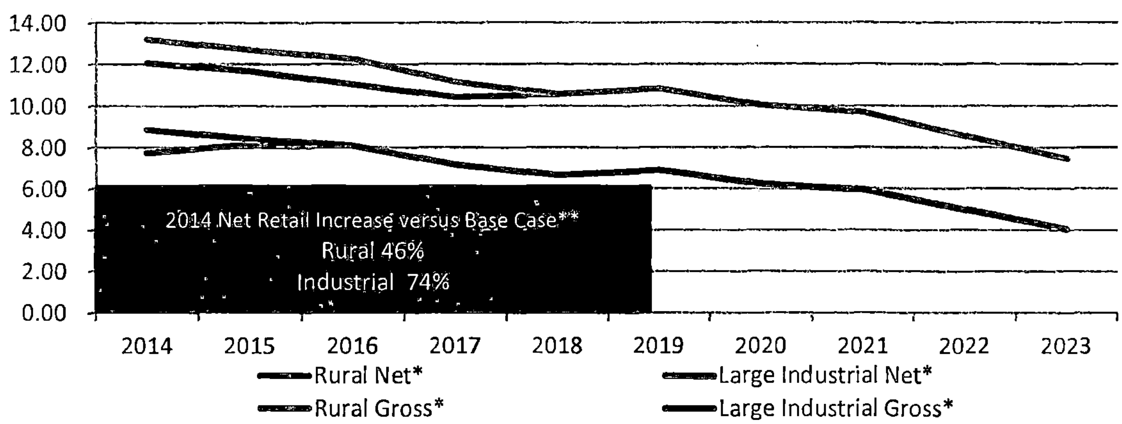
Scenario 1 projects Big Rivers' rates assuming the wholesale power market rebounds from current levels. The PACE Global price curve projects higher market prices than the other curves procured by Big Rivers, thus this scenario presents a very favorable outcome. As indicated in the chart above, if the wholesale market prices are as PACE projects and Big Rivers chooses to sell its excess power in the wholesale market, Big Rivers' Members could actually experience rate decreases (following the initial increase) through the end of the analysis period because the projected wholesale market pricing is stronger than the price expected to be paid by the aluminum smelters.

Scenario 2
MATS Pollution Control Equipment Only Installed, Both Smelters Exit, Stronger Market Pricing

Scenario 2 assumes Big Rivers does not make an investment in pollution control equipment for CSAPR. Big Rivers will instead purchase allowances and/or power to comply with the CSAPR standards. Big Rivers will still be required to make investments for compliance with MATS regulation. Scenario 2 assumes that both smelters exit 1/1/2014 and the analysis utilized the PACE Global market pricing (more optimistic).

ASSUMPTIONS	
Generation	Load serving and wholesale sales
Smelters	Both exit 1/1/2014
Price Curve	PACE Global Market Price Curve
Pollution Control Equipment:	
CSAPR	None, purchase allowances and/or energy to comply
MATS	Yes, as in ECP filing
Mitigation Efforts	Selling wholesale power in the market

ESTIMATED RESULTING AVERAGE MEMBER RETAIL* RATES (Cents per kWh)



*Member retail rate estimated by adding 3.3 and 0.2 cents per kWh to the residential and industrial projected wholesale rates, respectively.
**Base case assumes no Environmental Investment and both smelter in normal operation.
***Gross/Net of Member Rate Stability Mechanism & Rural Economic Reserve (RER)

DISCUSSION

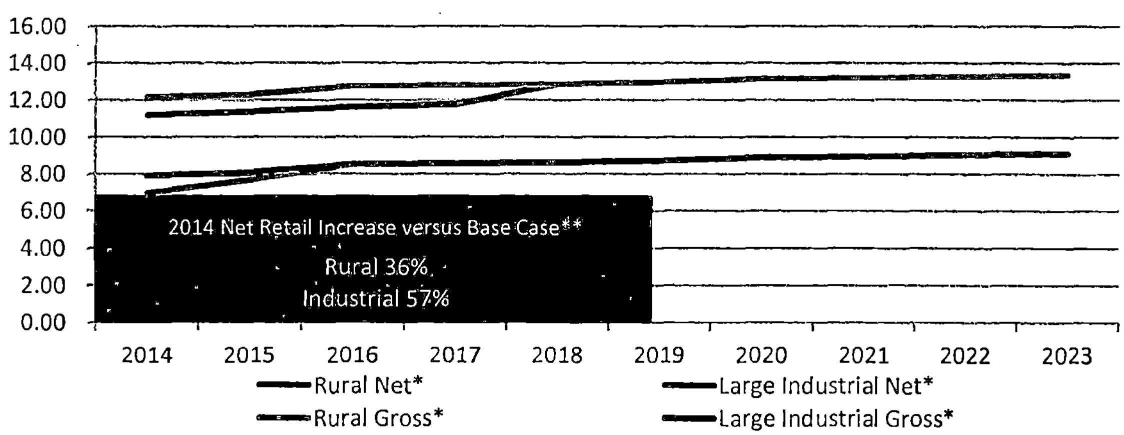
Scenario 2 is an alternate to Scenario 1 demonstrating the impact to Member rates of not making the investment in CSAPR equipment. While in Scenario 2 Big Rivers would avoid a large capital expenditure (for CSAPR investments), Big Rivers' Members would pay higher rates if the PACE market prices materialize. The decision to purchase allowances or power to maintain compliance reduces the amount of excess energy Big Rivers has to offer into the wholesale market. Given the strong price forecast given by PACE, this results in Big Rivers' Members paying more than Scenario 1 because less wholesale power is available to sell to offset the revenues required from Big Rivers' Members.

Scenario 3
MATS Pollution Control Equipment Only Installed, Both Smelters Exit, Conservative Market Pricing, Coleman & Wilson Offline

Scenario 3 assumes ACES' lower market price, assumes both smelters exit, and implements the mitigation efforts of station lay-up to offset the loss of smelter load. Scenario 3 assumes Big Rivers will purchase allowances or energy to comply with CSAPR regulations, but will install MATS equipment as shown in the Environmental Compliance Plan. Scenario 3 assumes the lay-up of both Wilson and Coleman plants to reduce fixed costs.

ASSUMPTIONS	
Generation	Sebree Station: load serving and wholesale sales Coleman and Wilson: "laid up" to reduce fixed costs
Smelters	Both exit 1/1/2014
Price Curve	ACES Power Marketing Market Price Curve
Pollution Control Equipment:	
CSAPR	None, purchase allowances and/or energy to comply
MATS	Yes, as in ECP filing
Mitigation Efforts	Selling excess wholesale power in the market, Coleman and Wilson "laid up" to reduce fixed costs

ESTIMATED RESULTING AVERAGE MEMBER RETAIL* RATES (Cents per kWh)



*Member retail rate estimated by adding 3.3 and 0.2 cents per kWh to the residential and industrial projected wholesale rates, respectively.
**Base case assumes no Environmental Investment and both smelter in normal operation.
***Gross/Net of Member Rate Stability Mechanism & Rural Economic Reserve (RER)

DISCUSSION

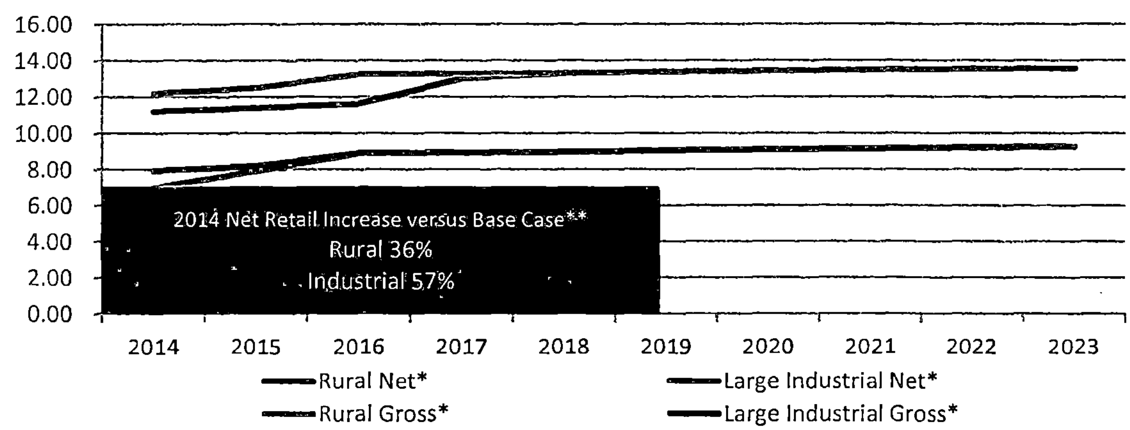
Scenario 3 provides a comparison to Scenario 2 using a lower market price. If the ACES price curve is accurate, Big Rivers will be able to lessen Member rate increases by laying up Wilson and Coleman, versus selling the excess from these units on the wholesale market. When comparing Scenario 3 to Scenario 2, Member rate impacts are initially less under Scenario 3 due to the savings gained by laying up the Coleman and Wilson units. However, in the later years, Scenario 2 is more favorable to member rates because of wholesale sales revenues driven by higher projected market prices and greater generation availability.

Scenario 4
Pollution Control Equipment Installed, Both Smelters Exit, Conservative Market Pricing , Coleman & Wilson Offline

Scenario 4 is similar to Scenario 3, but demonstrates the impact to Member rates if Big Rivers invests in CSAPR control equipment and ACES market prices are accurate. Scenario 4 analyzes Big Rivers' Member wholesale rates assuming that Big Rivers installs all the pollution control equipment proposed in its ECP filing, both smelters cease operation on 1/1/2014, the ACES Power Marketing price curve (conservative prices), and the lay-up of Wilson and Coleman stations to reduce fixed costs.

ASSUMPTIONS	
Generation	Sebree Station: load serving and wholesale sales Wilson and Coleman: "laid up" to reduce fixed costs
Smelters	Both exit 1/1/2014
Price Curve	ACES Power Marketing Market Price Curve
Pollution Control Equipment:	
CSAPR	Yes, as in ECP filing
MATS	Yes, as in ECP filing
Mitigation Efforts	Selling excess wholesale power in the market, Wilson and Coleman "laid up" to reduce fixed costs

ESTIMATED RESULTING AVERAGE MEMBER RETAIL* RATES (Cents per kWh)



*Member retail rate estimated by adding 3.3 and 0.2 cents per kWh to the residential and industrial projected wholesale rates, respectively.
**Base case assumes no Environmental Investment and both smelter in normal operation.
***Gross/Net of Member Rate Stability Mechanism & Rural Economic Reserve (RER)

DISCUSSION

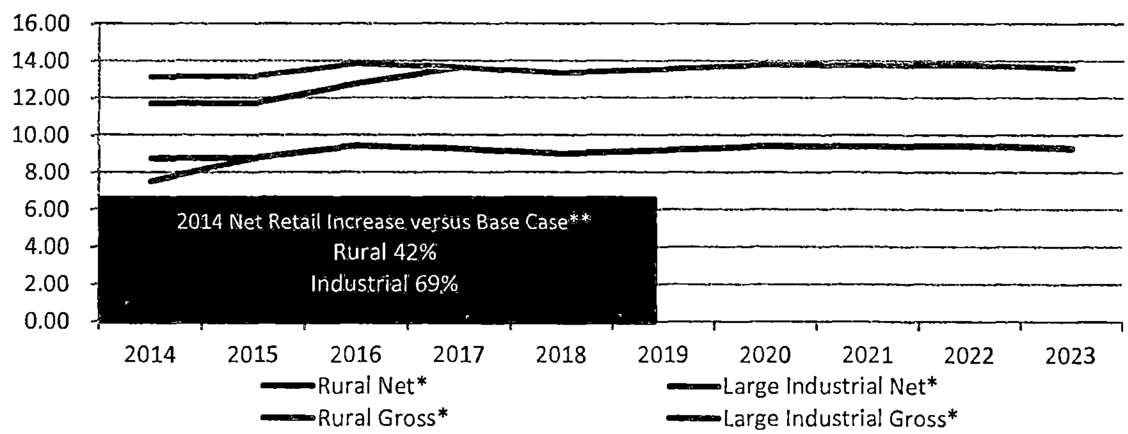
As in Scenario 3, Scenario 4 indicates the lay up of two stations to reduce fixed costs results in lower Member rates because market prices are soft enough that sales do not fully offset the fixed costs of operation. Scenario 4 results in slight savings to Member rates relative to Scenario 5 throughout the analysis period because the wholesale revenues generated using ACES market prices are not significant enough to offset the cost savings afforded by station lay up; however, these savings could be easily erased by stronger market pricing. Any decisions to lay up Big Rivers generating stations would be revisited regularly to ensure Member benefit is maximized.

Scenario 5 Pollution Control Equipment Installed, Both Smelters Exit, Conservative Market Pricing

Scenario 5 is identical to Scenario 1 except it uses a more conservative price curve for the wholesale energy market. Scenario 5 analyzes Big Rivers' Member rates assuming Big Rivers installs all the pollution control equipment proposed in its ECP filing, both smelters cease operation on 1/1/2014, and the ACES Power Marketing price curve (more conservative).

ASSUMPTIONS	
Generation	Load serving and wholesale sales
Smelters	Both exit 1/1/2014
Price Curve	ACES Power Marketing Market Price Curve
Pollution Control Equipment:	
CSAPR	Yes, as in ECP filing
MATS	Yes, as in ECP filing
Mitigation Efforts	Selling wholesale power in the market

ESTIMATED RESULTING AVERAGE MEMBER RETAIL* RATES (Cents per kWh)



*Member retail rate estimated by adding 3.3 and 0.2 cents per kWh to the residential and industrial projected wholesale rates, respectively.
**Base case assumes no Environmental Investment and both smelter in normal operation.
***Gross/Net of Member Rate Stability Mechanism & Rural Economic Reserve (RER)

DISCUSSION

Scenario 5 highlights the impact the market price of wholesale power has to mitigate price increases to Big Rivers' Members through off-system sales. In 2014, the impact of the price differential between the PACE Global and ACES' forward price curves cause a 9-18% increase in 2014 Member rates; the impact is much more significant in later years. Under the ACES price scenario, Big Rivers' rates are near constant from 2017 to 2023 due to the near constant market price. Assuming the PACE Global market price shown in Scenario 1, Big Rivers' Member rates decline annually from 2017 to 2023, resulting in prices that are less than current levels in 2020 and beyond. Comparing Scenario 5 to Scenario 4, shows the marginal benefit gained by unit lay-up assuming the ACES price curve.

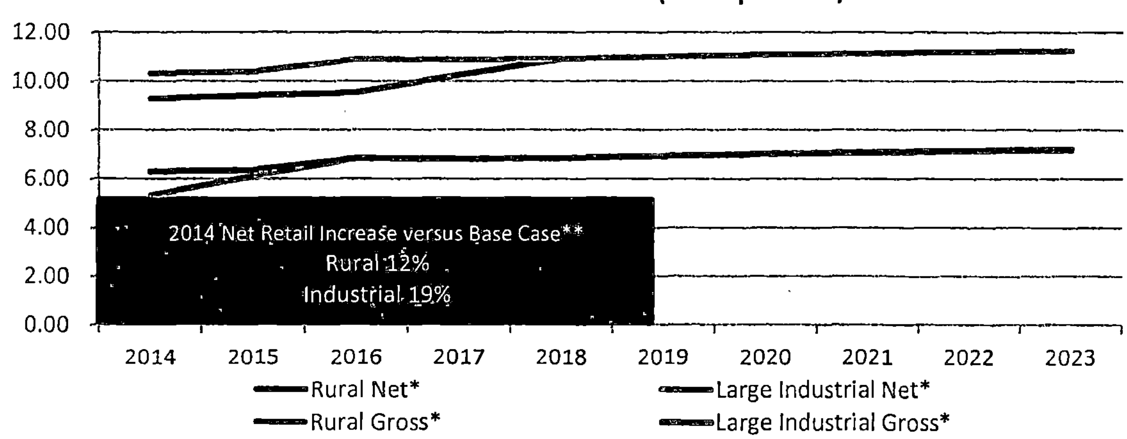
[redacted]

Scenario 6
Pollution Control Equipment Installed, Century Exits, Conservative Market Pricing, Coleman Offline

Scenario 6 is similar to Scenario 4; however, it assumes that only Century ceases operation and only the Coleman generation station is laid up. Scenario 6 assumes that all pollution control equipment proposed in the ECP is installed, uses ACES' conservative market pricing, and assumes that Big Rivers will lay up the Coleman plant to reduce fixed costs as a rate mitigation effort.

	ASSUMPTIONS
Generation	Sebree and Wilson Station: load serving and wholesale sales Coleman: "laid up" to reduce fixed costs
Smelters	Century exits 1/1/2014
Price Curve	ACES Power Marketing Market Price Curve
Pollution Control Equipment:	
CSAPR	Yes, as in ECP filing
MATS	Yes, as in ECP filing
Mitigation Efforts	Selling excess wholesale power in the market, Coleman "laid up" to reduce fixed costs

ESTIMATED RESULTING AVERAGE MEMBER RETAIL* RATES (Cents per kWh)



*Member retail rate estimated by adding 3.3 and 0.2 cents per kWh to the residential and industrial projected wholesale rates, respectively.
**Base case assumes no Environmental Investment and both smelter in normal operation.
***Gross/Net of Member Rate Stability Mechanism & Rural Economic Reserve (RER)

DISCUSSION

The results of Scenario 6 indicate the loss of one smelter has a lesser impact on the remaining Big Rivers' Member rates than the loss of two smelters. Scenario 6 again utilizes a rate mitigation effort of laying up the Coleman generation station to reduce fixed costs. Given the ACES pricing used in Scenario 6, unit lay-up is more cost effective for Big Rivers' Members; however, if market prices are closer to the PACE Global prices, unit lay-up would negatively affect Big Rivers' Members' rates because Big Rivers would be able to more than offset the fixed cost savings through market sales if the market price is strong.

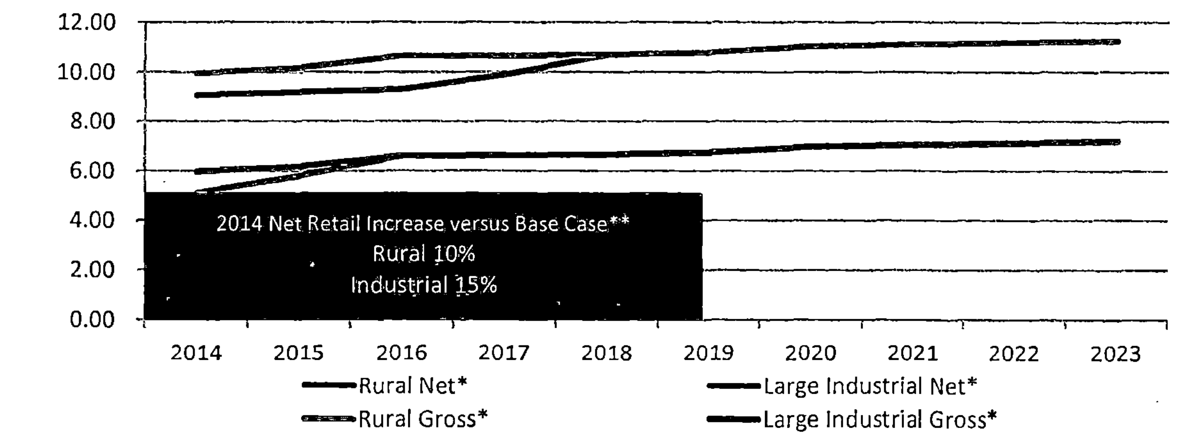
[redacted]

Scenario 7
Pollution Control Equipment Installed, Alcan Exits, Conservative Market Pricing, Wilson Offline

Scenario 7 is identical to scenario 6; however, it assumes that Alcan ceases operation while Century remains in business and Coleman generating station remains in service while Wilson generating station is laid up. Scenario 7 assumes that all pollution control equipment proposed in the ECP is installed, uses ACES' conservative market pricing, and assumes Wilson generating station is laid up to offset fixed costs as a rate mitigation effort.

ASSUMPTIONS	
Generation	Sebree and Coleman Station: load serving and wholesale sales Wilson: "laid up" to reduce fixed costs
Smelters	Alcan exits 1/1/2014
Price Curve	ACES Power Marketing Market Price Curve
Pollution Control Equipment:	
CSAPR	Yes, as in ECP filing
MATS	Yes, as in ECP filing
Mitigation Efforts	Selling excess wholesale power in the market, Wilson "laid up" to reduce fixed costs

ESTIMATED RESULTING AVERAGE MEMBER RETAIL* RATES (Cents per kWh)



*Member retail rate estimated by adding 3.3 and 0.2 cents per kWh to the residential and industrial projected wholesale rates, respectively.
**Base case assumes no Environmental Investment and both smelter in normal operation.
***Gross/Net of Member Rate Stability Mechanism & Rural Economic Reserve (RER)

DISCUSSION

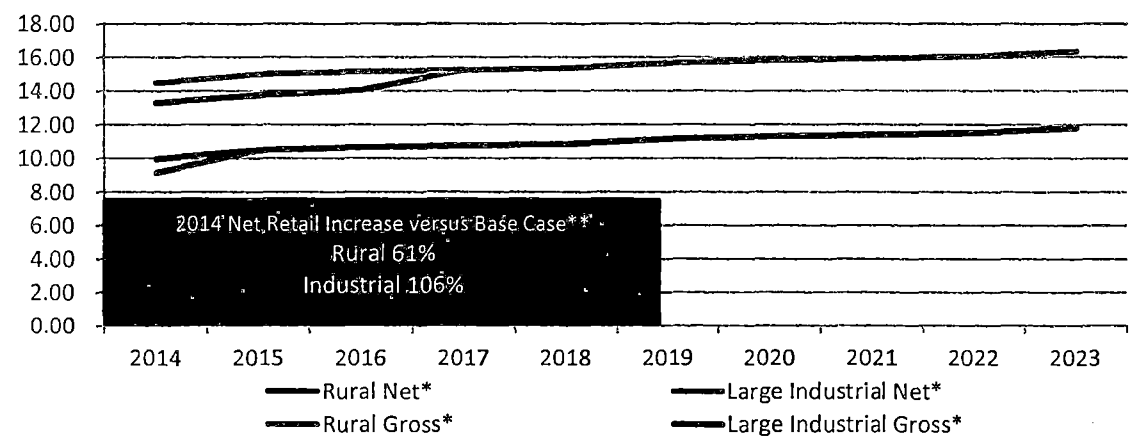
As previously discussed, the loss of one smelter has a lesser rate impact to Big Rivers' Members. Because Alcan's load is smaller than Century, the rate impact of Alcan leaving is slightly less than the rate impact of Century leaving. In Scenario 7, Wilson plant was laid up instead of the Coleman plant due to the proximity of the Coleman plant to the Century load. Again, market prices will dictate whether unit lay ups are cost effective for Big Rivers; however, assuming the ACES price curve, this mitigation factor appears to be a good option if the market actually turns out to be similar to the ACES curve.

Scenario 8 Worse than the Worst Case

Big Rivers chose to analyze Scenario 8 to determine a worst case scenario and ceiling of the potential impact the loss of smelter load could have on its operations and remaining Members' rates. This is a fictitious case and is not considered credible because it presumes Big Rivers would do nothing if the smelters exit. It provides an upper bound on the potential rate impact which is helpful in gaining internal understanding of the load concentration issue. Scenario 8 assumes both smelters will exit and Big Rivers will not implement any cost cutting measures. All of Big Rivers' fixed costs are assumed to remain and be paid by Big Rivers' remaining existing non-smelter Members. Also, it is presumed Big Rivers is unable to sell any power into the wholesale market due to market prices below generation costs.

ASSUMPTIONS	
Generation	Load Serving Only
Smelters	Both exit 1/1/2014
Price Curve	Not applicable, no off-system sales margins
Pollution Control Equipment:	
CSAPR	No
MATS	No
Mitigation Efforts	None

ESTIMATED RESULTING AVERAGE MEMBER RETAIL* RATES (Cents per kWh)



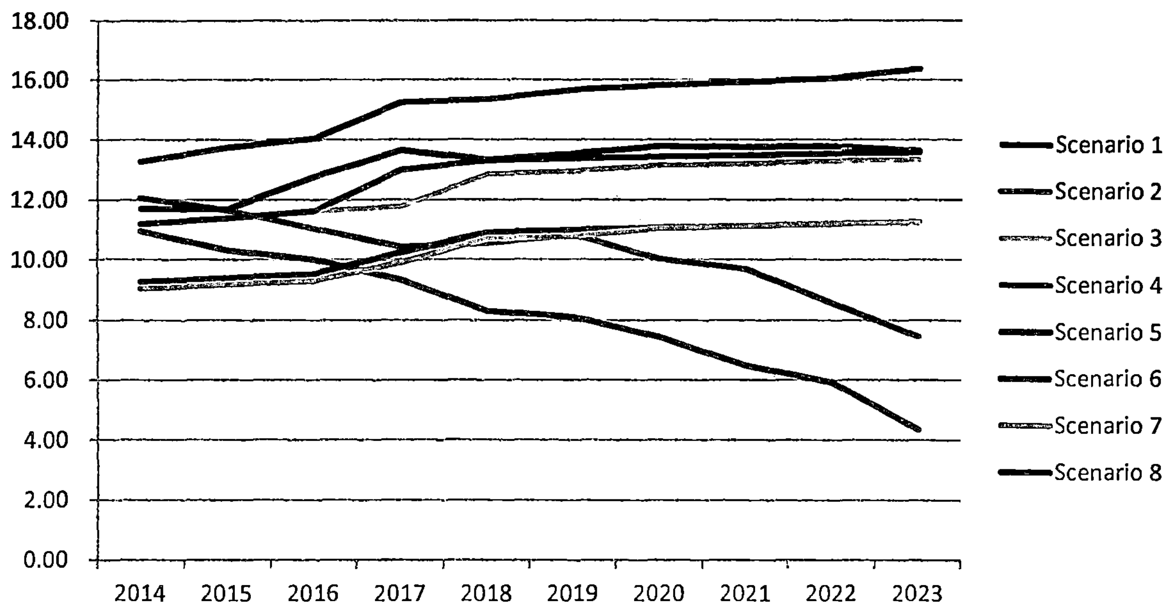
*Member retail rate estimated by adding 3.3 and 0.2 cents per kWh to the residential and industrial projected wholesale rates, respectively.
**Base case assumes no Environmental Investment and both smelter in normal operation.
***Gross/Net of Member Rate Stability Mechanism & Rural Economic Reserve (RER)

DISCUSSION

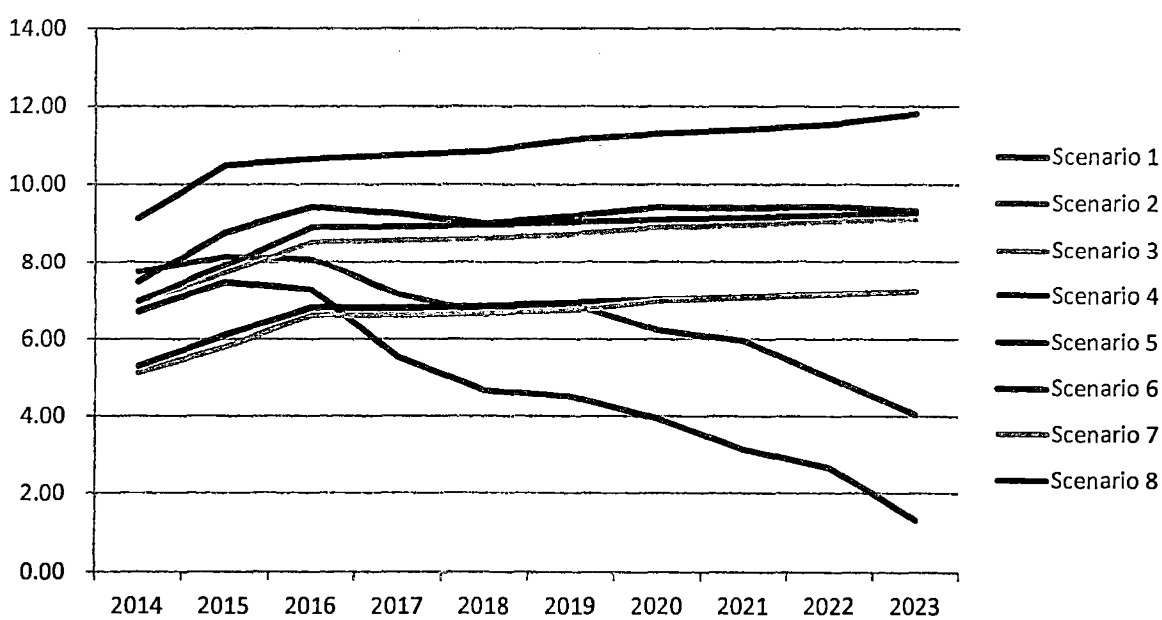
As discussed above, Scenario 8 assumes Big Rivers' existing Members will shoulder the entire burden caused by the loss of smelter load. It further assumes that there are no opportunities for mitigating the loss of smelter revenues other than raising remaining customers' rates. **Scenario 8 provides a worst case scenario that will never actually occur**; however, it does provide an upper bound to the potential impact of losing the smelter load on Big Rivers' system.

Scenario Comparison

PROJECTED AVERAGE RURAL RETAIL RATE*



PROJECTED AVERAGE INDUSTRIAL RETAIL RATE*



*Retail Rates Net of MSRM & RER

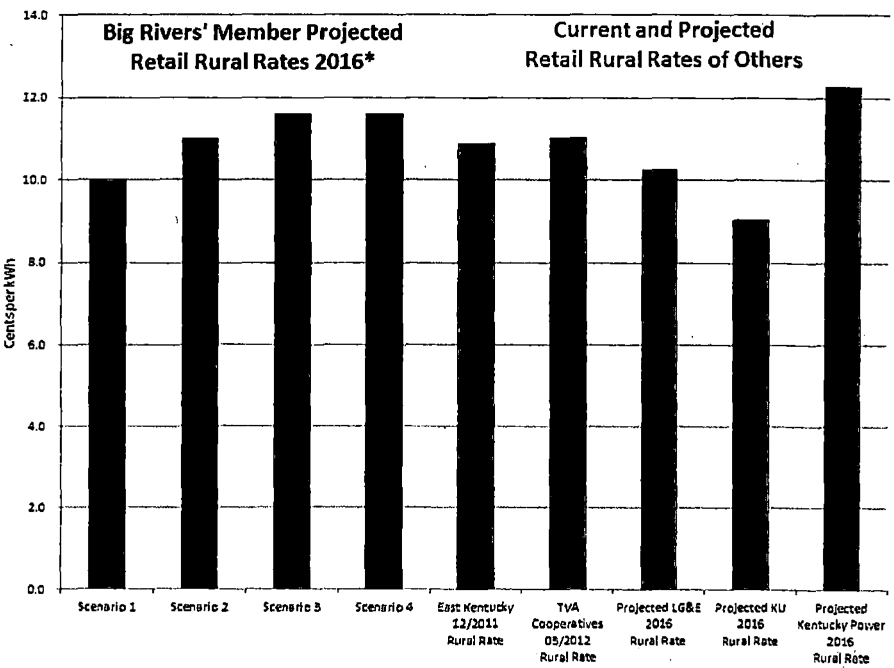
CONCLUSIONS

[redacted]

Big Rivers has completed significant analyses to evaluate the potential impact of smelter loss on Big Rivers' transmission system, revenues, and Member rates. While there is uncertainty surrounding future wholesale market prices, Big Rivers' analyses demonstrate that even in the unfortunate event of smelter load loss and a lack of wholesale market opportunities, options exist that enable Big Rivers to remain a viable organization.

If future wholesale market prices resemble the PACE Global price curve, Big Rivers' Member rates will see a short-term increase, followed by a significant, steady price decrease. If the ACES price curve materializes and Big Rivers is unable to obtain additional load to offset the loss of smelter load, Big Rivers will implement mitigation efforts to stabilize Member rates. Thus, if both smelters exit within the next several years, Scenarios 1, 2, 3 or 4 are believed to be the most likely for the organization.

As is shown in the chart below, Big Rivers Member's Rural Retail rates are projected to be reasonable compared to other utilities in the state even with the loss of both smelters' load. The chart compares Big Rivers' projected 2016 retail rates to the projected 2016 retail rate of other utilities if available. When the 2016 projection was unavailable, the utilities' recent rates are included for comparison purposes. As shown, Big Rivers' 2016 rate compares well to these current rates and it is reasonably assumed that their actual 2016 rates will be higher than today's rates due to pending environmental regulations and general cost escalations.



*Big Rivers' Member Retail rates estimated by adding a 3.3 cent per kWh adder for Member distribution services.

Big Rivers analyses will continue in an effort to refine our strategy for mitigating the loss of smelter load in the future. Big Rivers hopes that the smelter load remains in its system for the benefit of its Members, the smelters, and the community as a whole; however, Big Rivers is prepared to deal with the loss of smelter load and has plans to enable its continued viability.

LOAD REPLACEMENT ACTIVITIES
UPDATED January 17, 2014

***ITALICIZED FONT* = STILL ACTIVE**

RFP Activity

Submitted response to LGE/KU RFP

- Capacity/Energy/Ancillary Services of Wilson (up to 417MW), up to 15 years
- Priced at the Large Industrial Tariff equivalent
- Made the "short-list" –CONFIDENTIAL
- Supplied sales price for Wilson on March 1
- Supplied sales price for Coleman on May 22
- Supplied proposed Tolling Agreement for Coleman on June 5
- LGE has announced plans to build a 640 MW Combined Cycle Natural Gas facility and a 10 MW Solar Facility.
- *LGE/KU submitted a proposed term sheet requesting Capacity for the MISO 2016/2017 and 2017/2018 planning year and on-peak Energy for the summer months of 2016 and 2017. Discussions continue.*

Submitted an unsolicited proposal to East Kentucky

- Up to 400 MW, Up to 20 Years
- Priced at Large Industrial Tariff rate. EKPC looking for intermediate resource. East KY indicated we were uncompetitive in their RFP, likely due to deliverability in PJM.

Duke Kentucky has issued an RFP to purchase up to 200MW of PJM Capacity and Energy from 2014-2017

- Proposal submitted May 15, submitted proposal to sell Coleman, Wilson (or portion thereof) and offered a purchase power agreement.
- Received formal notification that we did not make their short-list for this RFP (lack of PJM deliverability likely cause)

AEP – Kentucky Power has issued an RFP to purchase up to 250MW of PJM Capacity and Energy for 15 years.

- Proposal submitted June 11, to sell Coleman, Wilson (or portion thereof) and offering a Tolling agreement.
- Received official response that they were executing their right to cancel the RFP. They are transferring existing assets into their KY portfolio from another state.

Duke Kentucky has issued an RFP to purchase up to 200MW of PJM Capacity and Energy starting in 2017 for 15-20 years.

- Proposal Due August 15, Notice of Intent to Bid sent June 10
- Duke followed up with questions regarding deliverability and pre-sold capacity in early September.

- Received formal notification that we were no longer being considered for this RFP (lack of PJM deliverability likely cause)

Duke Indiana has issued an RFP to purchase up to 300MW of MISO Capacity and Energy starting in 2016 for 5-10 years. They indicated they will not consider the purchase of coal plants, but will consider PPAs or Tolling Agreements from coal facilities.

- *Proposal submitted August 5. Proposed the Lease or Tolling of both Wilson and Coleman*
- *Big Rivers was notified that we had made the "short-list".*
- *Provided "refreshed" data as requested on November 1.*
- *Final decision expected in first quarter 2014.*

Northeast Nebraska Public Power District (and other NE municipals) issued an RFP on June 17 to purchase up to 110MW of Capacity and Energy starting in 2017. They indicated they were willing to consider power from MISO, although they are located in SPP. Big Rivers submitted a proposal on July 2, had a call on July 12 to discuss our proposal, and presented our proposal in Wayne, NE on July 23.

- *NeNPPD's consultant visited Big Rivers on September 19 to discuss alternatives that may make our proposal more attractive to NeNPPD.*
- *Traveled to Nebraska October 21-22. Gave to NeNPPD a draft term sheet for their Board to consider. Were informed that we were the top responder of 2.*
- *Contract negotiation is complete. NeNPPD (46MW) signed to begin 30% flow in 2018. Wakefield (8MW) has signed to begin 90% flow in 2019. Wayne (13MW) signed to begin 90% flow in 2019.*

Alcoa submitted an RFP for 20MW of energy for 7 years beginning July 1, 2014 to supply their eastern Tennessee Operations. Big Rivers submitted a proposal on September 12.

- Big Rivers did not make the short-list.
- Future discussions anticipated regarding other power needs.

Alcoa has issued another RFP for load following which was due November 8.

- Big Rivers submitted a proposal but did not make the shortlist.

East Texas Electric Cooperative, Inc. (joining MISO in December) and Tex-La Electric Cooperative of Texas, Inc. submitted an RFP for more than 100MW of capacity and energy beginning in 2018.

- *Proposal submitted October 21, 2013 for Sale or Lease of Wilson or Coleman or PPA/Tolling Agreement*

Midwest Energy, Inc. (central and western Kansas) submitted an RFP for 25MW to 175MW of SPP capacity beginning in 2017. Delivery will be an obstacle, but we are going to submit a proposal contingent on the availability of transmission.

- Proposals due October 18, 2013

- Proposal submitted for Sale or Lease of Wilson or Coleman or PPA/Tolling Agreement
- Notified that they would not be considering resources in MISO.

Burns and McDonnell has issued an RFP for an unnamed client located in SPP for 50-250MW of capacity and energy for a minimum of 5 years.

- *Proposal submitted November 1, 2013 for Sale or Lease of Wilson or Coleman or PPA/Tolling Agreement*

People's Electric Cooperative (PEC) has issued a request for proposal to solicit bids for up to 75 MW of firm capacity and/or energy in SPP.

- *Proposals submitted November 25, 2013*
- *People's Executives and Board were on site for plant tours on Friday, Dec. 20. Peoples has indicated a strong interest in 50MW which could flow in Summer 2014.*
- *Traveled to Ada, OK on January 13 and 14 for meetings with PEC.*
- *Strong interest from People's on both PPA as well as purchase of 50MW of Wilson Capacity. Term sheet in development.*

Received an RFP on behalf of the 12 Kentucky Municipals (Barbourville, Bardstown, Bardwell, Benham, Berea, Corbin, Falmouth, Frankfort, Madisonville, Nicholasville, Paris, Providence) served currently by Kentucky Utilities. Aggregate load nearly 400MW.

- *Proposals due January 20 for period commencing 2019 and extending at least 10 years. Earlier delivery potential mentioned (May 2015), but uncertain at this time.*

Received RFP from Wolverine Power Cooperative in Cadillac, Michigan for up to 100MW MISO Capacity and 100MW of energy.

- *Submitted a proposal for capacity and energy on December 31.*

Received RFP from Lafayette (LA) Utilities System for 50-200MW of capacity and energy beginning as early as June 2014. Proposals are due February 28, 2014.

Received RFP from Willmar Municipal Utilities for 10MW Capacity and Energy in MISO for up to 10 years. Proposal due January 21.

Economic Development

- *Continue to support Economic Development Strategy with Member CEOs by supplying price quotes. Continue working with Member CEOs, KY Economic Development Cabinet, KAED, and Kentucky United to develop economic development opportunities in our territories.*

Attracting Existing Load

- *Westlake has 188MW in Calvert City. Westlake continues their analysis. They are awaiting the outcome of our rate cases before interested in having further substantive discussions.*
- *CC Metals has roughly 95MW of load in Calvert City, they are awaiting the outcome of the rate case.*
- *Gerdau has a 6MW load in Calvert City, they are awaiting the outcome of our rate cases before interested in having further substantive discussions.*

Wholesale Sales Offers

- *Provided 3-year and 10-year proposal to Energy Consulting Group on March 22. Followed up with an additional 3-year and 17-year proposal on April 5. We have had numerous conversations and ECG continues investigating their transmission capabilities within Georgia.*
- *Had discussions with Prairie Power about their needs—they have followed up with a schedule of their needs (<100MW through 2024). Provided a quote on May 10. 10 year projection provided 5/22/13. They are currently evaluating.*
- *Vectren – Had a meeting with them on May 2 and May 9 to discuss possibility of selling capacity and energy long-term. Their needs are several years out.*
- *Gerdau - Gerdau has two mills in Tennessee, one in North Carolina, two in Michigan, one in Minnesota, and one in Iowa. The two Michigan mills have a combined load of 100-120MW. Provided a quote on June 5. They were interested in the outcome of our rate case.*
- *We have submitted a proposal to North Carolina EMC and they will be evaluating our proposal as part of their annual long-term forecast process. We would utilize our TVA transmission reservation to deliver.*
- *Mississippi Delta Energy Agency (MDEA) – Provided a proposal on June 14 to sell 20MW. MDEA will be integrating into MISO with Entergy in December. TVA transmission would not be required to deliver. We provided an updated quote to MDEA on September 11. MDEA now only needs 10MW. Senior Business Development Manager traveled to MDEA on September 19 to further discuss our proposal. MDEA continues review of our 10MW offer.*
- *Hoosier Energy has indicated they may have an interest in long-term power. We have supplied them with a capacity and energy price for the next several years. Awaiting their analysis.*
- *Conway Corp. Conway Arkansas: Is using GDS to review power options. Conway is evaluating long term (5 year) master contracts or the possibility of layering in multiyear shaped strips such as a 7x24, 5x16,. (Conway is concerned about coal pricing, they own parts of Independence and White Bluff Coal fired power plants) Conway plans to issue a RFP in early 2014.*
- *Kennett City Light, Gas and Water (a Missouri municipal) has a load of roughly 40MW. They are currently purchasing spot energy to supplement their own generation. Kennett has indicated they may have an interest in a long-term PPA for 5-10MW. Further discussions anticipated.*

- *Discussions with Kansas Municipal Energy Agency: (KMEA) indicates they are considering 20 to 40 MW in 2 blocks to spread supply risk. They have a recent purchase of Dogwood combined cycle plant and are looking at a nearby coal plant and are being courted on a Nuclear plant. Additional discussions expected.*
- *Executed a non-disclosure agreement with Public Power Energy Services. The owner of the organization is acting as agent for Nebraska group, but also has other clients that he feels could likely have an interest. We met with him on September 19 in connection with the NeNPPD deal and discussed other potential opportunities. We continue discussions with PPES about a consulting contract.*
- *Conversations occurred with NTE Solutions, a Florida based company that provides energy and infrastructure services, about potential outlets for our product. We plan to maintain a relationship with them and develop a relationship with other engineering and marketing firms that procure power supply for municipals, cooperatives, and investor-owned utilities.*
- *Had discussions with SWECI, an IL cooperative. They have been able to get out of their Plum Point contract and have an interest in capacity through 2021. They are also interested in a path to full membership.*
- *Had discussions with Norris Electric, a central IL cooperative, who currently has a contract with SIPC, but is not an SIPC Member. Norris has to give notice to SIPC within 1 year of their desire to continue the contract or move on. They have provided load data for us to provide them with a quote. They may have an interest in a contract or in membership.*
- *Had conversation with Energy Ventures Analysis, Inc. about analyzing Wilson and Coleman information for a client. We submitted a Non-Disclosure Agreement to them for review.*
- *Northeast Oklahoma Electric Cooperative is a 200MW load. Delivery may be an obstacle, but we are going to continue discussions with them contingent on the availability of transmission. We provided capacity and energy pricing to Northeast in early December and will be visiting their offices for discussions on January 14. They indicated an interest in 50MW.*

KY Coops and Municipals served by TVA

Big Rivers has been in contact with several Kentucky cooperatives and municipals, including Murray Electric System, Hopkinsville Electric System, Warren Rural Electric Cooperative Corporation, Pennyrile Electric, Tri-County Electric, West Kentucky RECC, and Hickman-Fulton Counties RECC. Because of the competitiveness of Big Rivers' tariff rates, these groups may have interest in obtaining power from Big Rivers; however, Big Rivers will likely be required to make transmission investments to serve these groups and they have a five-year termination notice requirement with TVA, making them long-term solutions. Big Rivers is awaiting the outcome of the rate cases to initiate further discussions with these entities. Their interest is long-term and the perceived uncertainty of our situation causes considerable unease—a positive rate case outcome will make success with these entities more likely.

PJM Membership

Big Rivers has also been evaluating the feasibility of joining PJM as a potential option to mitigate the loss of smelter load. As has been discussed before, PJM has a more mature capacity market that is currently yielding higher prices than the MISO market. Big Rivers estimates that it would be unnecessary to idle stations if it were able to procure the prices currently being experienced in the PJM Market. These prices would provide Member benefit through increased off-system sales, and it could offer a greater potential for long-term, cost-based power sales.

Big Rivers has had several discussions with PJM about the costs and benefits of joining PJM. A meeting was held with PJM senior staff on February 21, 2013 to discuss the transmission-feasibility of PJM integration. Big Rivers has the option to exit MISO in December 2014. Additional analysis of this solution will continue.

Parties we've spoken to and don't anticipate further discussions with:

- Discussions have occurred and are currently not expected to resume with Wabash Valley, Southern Illinois Power, Associated Electric, Indiana Municipal Power Agency, Illinois Municipal Electric Agency, Missouri Joint Municipal Electric Utility Commission, American Municipal Power of Ohio, North Carolina Eastern Municipal Power Agency, South Mississippi Electric Power Association, Southern Company, Integrys Energy Services, Morgan Stanley, Cargill, EDF, Oglethorpe, NextEra, Quantum Utility Generation, Southern Power Company, Powersouth, Noranda, USEC, Benton Arkansas, Clarksville Arkansas Light and Water, Poplar Bluff Missouri Municipals, City of West Memphis (AR), Morgan Stanley, TVA, and Kansas Power Pool.

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

Corrective Plan to Achieve Two Credit Ratings of Investment Grade

March 7, 2013

[Please note that Appendices A and B to this document contain **CONFIDENTIAL COMMERCIAL BUSINESS INFORMATION** relating to details of ongoing negotiations of credit documents and potential business transactions, the public disclosure of which would be highly prejudicial and damaging to Big Rivers Electric Corporation's commercial business interests.]

Contractual Covenant: Maintenance of Two Credit Ratings of Investment Grade

If Big Rivers fails to maintain two Credit Ratings of Investment Grade per Section 4.23 – Maintenance of Credit Ratings of the Amended and Consolidated Loan Contract dated as of July 16, 2009 (the Agreement) between Big Rivers Electric Corporation (Big Rivers) and United States of America acting by and through the Administrator of the Rural Utilities Service (RUS), Big Rivers must notify RUS in writing to that effect within five (5) days after becoming aware of such failure.

Big Rivers became aware of this failure to maintain two Credit Ratings of Investment Grade when Fitch Ratings downgraded its rating from BBB- to BB on February 6, 2013. Standard & Poor's previously downgraded Big Rivers from BBB- to BB- on February 4, 2013. Big Rivers notified RUS in writing on February 7, 2013 pursuant to Section 4.23 (b) of the Agreement.

In addition, pursuant to Section 4.23 (c) of the Agreement, within thirty (30) days of the date on which Big Rivers fails to maintain two Credit Ratings of Investment Grade, Big Rivers in consultation with the RUS shall provide a written plan satisfactory to the RUS setting forth the actions that shall be taken that are reasonably expected to achieve two Credit Ratings of Investment Grade. This document is submitted by Big Rivers to the RUS as a proposed written plan that is expected to be satisfactory to the RUS as is required under Section 4.23 (c).

Background

On August 20, 2012, Century Aluminum Company (Century) gave its one year contract termination notice to Kenergy Corp. and Big Rivers Electric Corporation. This notice indicated Century is ceasing all smelter operations at their Hawesville, Kentucky facility on August 20, 2013. Century is the source of approximately thirty-six (36%) of Big Rivers' wholesale revenues or approximately $205 million for the twelve months ending December 31, 2012.

On January 31, 2013, Alcan Primary Products Corporation (Alcan) gave its one year contract termination notice to Kenergy Corp. and Big Rivers. This notice indicated Alcan is ceasing all smelter operations at their Sebree smelter located in Robards, Kentucky on January 31, 2014. Alcan is the source of approximately twenty-eight (28%) of Big Rivers' wholesale revenues or approximately $155 million for the twelve months ending December 31, 2012.

As a result of Big Rivers receiving Alcan's notice of termination, all three rating agencies, Fitch Ratings (on February 6, 2013), Standard & Poor's (on February 4, 2013) and Moody's Investors Service (on February 6, 2013), downgraded the credit ratings on Big Rivers' $83.3 million County of Ohio, KY's Pollution Control Refunding Revenue Bonds, Series 2010A. In addition, Standard & Poor's downgraded its long term rating on Big Rivers. All three bond ratings are now below investment grade as shown in the following table:

Big Rivers Electric Corporation
Corrective Plan to Achieve Two Credit Ratings of Investment Grade
March 7, 2013

Big Rivers' Current Credit Ratings

Moody's	S&P	Fitch	
Aaa	AAA	AAA	
Aa1	AA+	AA+	
Aa2	AA	AA	
Aa3	AA-	AA-	
A1	A+	A+	Investment Grade
A2	A	A	
A3	A-	A-	
Baa1	BBB+	BBB+	
Baa2	BBB	BBB	
Baa3	BBB-	BBB-	↑
Ba1	BB+	BB+	↓
Ba2	BB	BB	
Ba3	BB-	BB-	Non-Investment Grade
B1	B+	B+	
B2	B	B	
B3	B-	B-	

= Big Rivers' credit ratings as of 2/6/2013

Big Rivers Electric Corporation
Corrective Plan to Achieve Two Credit Ratings of Investment Grade
March 7, 2013

Rating Agencies' Focus

Rating agencies focus on three areas of Big Rivers' business when issuing ratings on Big Rivers' $83.8m County of Ohio, Kentucky, Pollution Control Refunding Revenue Bonds. Primarily these three areas are:

1) Access to and maintenance of liquidity

2) Replacement load for Big Rivers' two largest customers who have given notice of termination, and

3) Increased Big Rivers' activity in off-system sales market

As part of Big Rivers' corrective plan to achieve two investment grade credit ratings Big Rivers' addresses each of these areas in this document.

Access to and Maintain Liquidity

Lines of Credit

Big Rivers has two $50 million lines of credit, one with CoBank, ACB, expiring July 2017, and the other with National Rural Utilities Cooperative Finance Corporation (CFC) that expires July 2014.

CFC Line of Credit

Under the current arrangement, the CFC line of credit will become unavailable to Big Rivers on August 20, 2013 upon the termination of a smelter wholesale agreement and this event is an Event of Default under Section 6.01 M of that facility.

Big Rivers and CFC have completed negotiations on a Term Sheet for the CFC line of credit with the major modifications that are listed on the attached **CONFIDENTIAL** Appendix A.

CoBank Line of Credit

Presently, Big Rivers is unable to make the representations and warranties necessary to draw on the CoBank line of credit as a result of Kenergy receiving the Notice of Termination from Century. Upon the termination of the Century retail agreement which occurs on August 20, 2013, there is an Event of Default which terminates CoBank's commitment to lend and accelerates payments. A default under this agreement can cause a default under the CoBank Secured Loan Agreement.

Big Rivers intends to restart negotiations with CoBank to attempt to restructure this line later in March 2013.

Environmental Compliance Plan for Mercury and Air Toxics Standards (MATS) Financing

Big Rivers plans to submit an application to RUS to obtain long-term financing for its MATS Environmental Compliance Plan. In the interim, Big Rivers will obtain short-term financing from the National Rural Utilities Cooperative Finance Corporation (CFC). This short-term or bridge financing will be in the form of a $60 million senior secured three-year credit facility. Big Rivers has received a Term Sheet from CFC which reflects the terms and conditions Big Rivers has negotiated with CFC. As requested by RUS, we are submitting a copy to RUS of this Term Sheet.

Big Rivers is updating its RUS application for long-term financing to reflect results of a revised load forecast based upon both Century and Alcan going to market and no longer buying their power from Big Rivers.

CFC requires submission of the RUS application prior to finalizing the short-term MATS financing. As such, Big Rivers is planning to submit its application to RUS by mid-April and file a financing application with the PSC for the CFC interim financing shortly thereafter.

Rate Case 2012-00535 – Century

On January 15, 2013, Big Rivers filed a general rate case with the PSC as a result of Century's contract termination, continued depressed off system sales margins, increased depreciation expense, and other costs not fully recovered in the 2011 general rate case. The total annual revenue deficiency, $74,476,120, is calculated as the annual incremental revenue needed to permit Big Rivers to achieve a 1.24 TIER during the fully forecasted test year (September 2013 – August 2014) while also achieving Margin for Interest Ratio (MFIR) of 1.10 in calendar year 2013. This total annual revenue deficiency represents a 21% wholesale revenue increase; 29% for the rurals; 18% for the large industrials; and 16% for the remaining smelter, Alcan. These rate increases would go into effect August 20, 2013.

Rate Case 2013-XXXXX – Alcan

Big Rivers has begun plans to file another general rate case in late June 2013 to address the annual revenue deficiency resulting from Alcan's contract termination. These rate increases would go into effect January 31, 2014.

$58.8 Million PCB Financing Case 2012-00492

On January 13, 2013, Big Rivers amended its application in the $58.8 million PCB financing case. The reason for amending this application is to seek PSC approval to repurpose the $60 million borrowed for capital expenditures from CoBank in 2012 to pay-off the $58.8 million pollution control bonds due June 1, 2013, and to use the $35 million Transition Reserve to pay for capital expenditures. Although it was Big Rivers' original intent to refund these bonds, it was determined market receptivity was minimal due to the uncertainty surrounding Big Rivers and the results of the two smelters giving notices of termination. By paying off these bonds, Big Rivers will realize an annual net cost savings of approximately $3.4 million in interest expense and issuance costs. The amendment filed in this financing case is intended also to preserve the capability of Big Rivers to issue, in part, tax-exempt pollution control bonds sometime in the future.

A hearing was held in Frankfort, Kentucky on February 28th, 2013. No briefs are being filed. Big Rivers is hopeful that the PSC will issue an order by March 31, 2013.

Replacement Load and Addressing Reliance on Off-System Sales

Load Concentration Mitigation Plan Activities Update

The **CONFIDENTIAL** Big Rivers Load Concentration Mitigation Plan Activities Update is attached as **CONFIDENTIAL** Appendix B.

Big Rivers Electric Corporation
Corrective Plan to Achieve Two Credit Ratings of Investment Grade
March 7, 2013

SUMMARY

Big Rivers is confident it can regain two investment grade ratings with the rate relief from the PSC along with the successful implementation of its Load Concentration Mitigation Plan and following the pay down of the $58.8 million PCB issue due June 1, 2013. Big Rivers' believes completion of the entire process will most likely take three to four years. Big Rivers financial metrics are good; it continues to meet all of the financial debt covenants associated with both long-term and short-term debt; and our projections for the 2013 – 2016 timeframe reflect ongoing compliance. We are ready to work closely with the RUS in developing a corrective plan which is acceptable to the RUS and to ensure Big Rivers achieves two credit ratings of investment grade within a reasonable period of time.

Big Rivers Electric Corporation
Corrective Plan to Achieve Two Credit Ratings of Investment Grade
March 7, 2013

APPENDIX A

The principal terms on the term sheet to amend the CFC revolving line of credit agreement are:

1) The line of credit will become secured under the indenture.

2) The maturity date will be extended to July 16, 2017.

3) Certification that Big Rivers' available cash is less than $35 million prior to draw-down.

4) A minimum Members' Equities' Balance (MEB) at each quarter end and each fiscal year-end of $325 million + 75% of positive net margins for the period. At the end of December 31, 2012, Big Rivers' MEB was $403 million compared with the required of $334 million; a positive excess of $69 million.

5) Big Rivers cannot use the CFC line of credit to pay off $58.8 million Pollution Control Bonds which are due June 1, 2013.

APPENDIX B

Century's Notice of Termination

Upon receipt of Century's one year notice of termination, Big Rivers immediately began implementing its formal Load Concentration Mitigation Plan (LCMP) which had been finalized in June 2012 and includes the following actions:

1) Timely filing of a general rate increase with the Kentucky Public Service Commission (PSC)
2) Pursuit of replacement load for Century's 482 MW
3) Development of a 2013 budget and 2014-2016 financial plan which include a temporary layup, beginning in August 2013, of our D.B. Wilson plant, which has a net capacity of 417 MW. This layup will continue until such time as replacement load is found or until such time the price of off-system sales improves.

Presently, Kenergy, Big Rivers and Century are discussing how Kenergy can purchase Century's power from the market after August 20, 2013. The Governor's office has endorsed this action.

Alcan's Notice of Termination

Upon receipt of Alcan's one year notice of termination, Big Rivers began implementing the LCMP scenario where both smelters go to market for their power and includes the following actions:

1) Completion of a new load forecast, production cost model and cost of service study with both smelters gone
2) Development of a 2014 budget and 2015-2017 financial plan which include a temporary layup of another plant with the approximate capacity of the Alcan load. This layup will continue until such time as replacement load is found or until such time as the price of off-system sales improves.
3) Filing for a general rate increase with the PSC in late June 2013 for rates to go into effect January 31, 2014 upon Alcan's departure.

APPENDIX B

4) Pursuit of replacement load for Alcan's 368 MW

Big Rivers, Kenergy and Alcan are initiating negotiations for Alcan to go to market to buy its power after January 31, 2014.

On-going Mitigation Efforts

Retail Activity

Big Rivers desires to find a long-term cost-based solution, either selling power to another entity or adding new customers. Big Rivers' marginal generation costs are extremely competitive making Big Rivers a strong choice for long-term supply options; however, many organizations with long-term needs are currently unwilling to commit to long-term contracts because of the current low cost market capacity and energy available. Because the average current wholesale market price is less than the total generation cost (fixed and variable) , Big Rivers' best short-term options for mitigating the loss of smelter load lies in attracting new all-requirements customers and/or Members and/or selling or leasing an asset.

Big Rivers is actively exploring options to find load replacement for the 850 MW currently being utilized by Century and Alcan. Big Rivers has been evaluating options to execute forward bilateral sales with counterparties, enter into wholesale power agreements, sell or lease assets, and/or gain access to developed capacity markets. Big Rivers is following a multi-pronged approach, with Big Rivers' three distribution Members focusing on economic development opportunities and Big Rivers' Energy Services Department working to find wholesale marketing opportunities for the power.

Big Rivers' Members (Kenergy Corp., Jackson Purchase Energy Corporation, and Meade County Rural Electric Cooperative Corporation) have been aggressively seeking new commercial and industrial loads within their territory. Big Rivers and each Member have resources dedicated to this task. The Members' staffs actively work with local, regional and state economic development officials to

APPENDIX B

identify and provide technical planning support and electricity pricing quotes to interested economic development prospects. Big Rivers' staff supports the Members' economic development efforts by attending economic development visits as requested by of its Members while providing timely transmission infrastructure cost projections and energy rate pricing estimates given the specific load parameters of the prospect. While Big Rivers' staff does not personally solicit new economic development prospects, it does provide solid support to assist our Members in their efforts to attract new businesses to Western Kentucky. Additionally, Big Rivers provides its three distribution Members with financial support to promote economic development initiatives within their cooperative communities. In 2012, Big Rivers supported its distribution Members with more than $100,000 in funding to encourage economic development efforts in western Kentucky. Big Rivers believes these efforts can have a positive impact in influencing industrial and commercial load growth within our distribution Members' service territories.

Wholesale Contract Activity

Big Rivers submitted a confidential proposal to provide firm capacity and energy in response to a Request for Proposal (RFP) from Louisville Gas and Electric Company/Kentucky Utilities Company (LGE/KU). Big Rivers also submitted an unsolicited proposal to East Kentucky Power Cooperative (EKPC) outside of their RFP process. EKPC's RFP process had deadlines which occurred prior to Big Rivers' receipt of Century's notice of closure, thus Big Rivers was unable to participate in their RFP due to its lack of capacity, but it was able to submit an unsolicited proposal. Big Rivers made two proposals to EKPC, the first being for 400 MW firm capacity and energy, subject to adequate available transmission, Big Rivers subsequently offered 100 MW firm capacity and energy which would be delivered using Big Rivers' existing TVA transmission reservation. Big Rivers has been verbally informed that its proposal to EKPC was not cost-effective for their organization.
Big Rivers proposed to sell LGE/KU up to 417 MW of capacity, associated unit contingent energy, and ancillary services from Big Rivers' Wilson Station generating facility for up to 20 years at a cost-based rate. Big Rivers was successful in making the shortlist in the LGE/KU RFP. Big Rivers met with

APPENDIX B

LGE/KU on January 11, 2013 to discuss the proposed purchase power agreement (PPA). During the meeting the parties discussed specific terms and potential options regarding the structure and costs of the PPA. Big Rivers anticipates further discussions with LGE/KU on the PPA. LGE/KU has proposed in its RFP to complete its evaluation by March 15, 2013.

During the January 11 meeting, Big Rivers also discussed its willingness to consider the sale of Wilson Station. LGE/KU indicated an interest in receiving pricing information and Big Rivers' staff has been working with outside consultants to determine a sales price for the asset. Because of the limitations in their RFP timeline, LGE/KU has indicated to Big Rivers that a potential Wilson acquisition will be considered outside of their existing RFP process. Big Rivers has secured Board approval for a specific sale price that was submitted to LGE/KU on March 1, 2013. The offer was made contingent on Big Rivers receiving approvals from RUS, the Kentucky Public Service Commission, and Big Rivers' lenders.

Wholesale Market Activity

Big Rivers has been also evaluating a number of avenues for placing its available capacity and energy in the market. Big Rivers has held discussions with numerous counterparties, including utilities, municipals, and power marketers. Big Rivers continues to have discussions with:

Tennessee Valley Authority – Discussions have occurred. Big Rivers has a meeting scheduled with TVA on March 12 to discuss the potential of providing TVA with long-term power at a cost-based rate.

Ameren – Big Rivers has been talking with Ameren about the opportunity to partner with them in serving an existing load. Big Rivers is awaiting the results of Ameren's evaluation of project feasibility.

APPENDIX B

Energy Consulting Group – This group procures power for 7 distribution cooperatives in Georgia. The group is looking to procure 100 MW from 2014-2016. Preliminary discussions have occurred. Big Rivers anticipate further conversations in the coming weeks.

Indianapolis Power and Light – Discussions have occurred. IPL currently has interest in 100-200 MW of MISO capacity from 2014-2016. Big Rivers is currently evaluating an appropriate price to offer IPL.

AEP Energy Partners – AEP Energy Partners has indicated an interest in purchasing 10 MW of MISO capacity from 2013-2016. Big Rivers is working to execute an EEI Agreement with AEP Energy Partners to facilitate this transaction.

Macquarie – Big Rivers is in the process of executing a confidentiality agreement with Macquarie. Discussions are expected to start after the confidentiality agreement is executed.
Discussions have occurred and are currently not expected to resume with **Wabash Valley, Hoosier Energy, Southern Illinois Power, Prairie Power, Associated Electric, Indiana Municipal Power Agency, Illinois Municipal Electric Agency, Missouri Joint Municipal Electric Utility Commission, American Municipal Power of Ohio, North Carolina Eastern Municipal Power Agency, North Carolina Electric Membership Corporation, South Mississippi Electric Power Association, Southern Company, Integrys Energy Services, Morgan Stanley, Cargill, EDF, Oglethorpe, NextEra, Quantum Utility Generation, Southern Power Company, Powersouth, and Noranda.**

APPENDIX B

Longer Term Prospects

Big Rivers has also been in contact with several Kentucky cooperatives and municipals, including **Murray Electric System, Hopkinsville Electric System, Madisonville Municipal Utilities, Warren Rural Electric Cooperative Corporation, Pennyrile Electric, Tri-County Electric, West Kentucky RECC, and Hickman-Fulton Counties RECC.** Because of the competitiveness of Big Rivers' tariff rates, these groups may have interest in obtaining power from Big Rivers; however, Big Rivers will likely be required to make transmission investments to serve these groups and they have up to a five-year termination notice requirement with TVA, making them long-term solutions.

Big Rivers believes one of its best solutions lies in Calvert City, Kentucky. Currently there are 16 TVA-served industrial plants located in Calvert City. These plants are located in the certified territory of Big Rivers' Member, Jackson Purchase Energy Corporation. Heretofore, Big Rivers has not had available capacity to serve these loads; however, due to the smelters' notices, Big Rivers now finds itself with available capacity. Big Rivers has been in discussions with one such industrial, Westlake Vinyls, Inc., for more than 12 months. Westlake currently utilizes 172 MW of power and has a 90% load factor. Big Rivers has a formal meeting with Westlake scheduled for April 2 to provide our current cost projections. Big Rivers rate projections are expected to be viewed favorably by Westlake, when compared to their current TVA cost. Big Rivers understands that these TVA-served industrials currently have contracts with one to three-year termination notices.

Big Rivers has also made contact with CC Metals and Alloys, another Calvert City industrial. Big Rivers' current approach has been to work on procuring Westlake as a customer to act as a catalyst for the other industrials located in the Calvert City area; however, Big Rivers intends to take a broader approach, by contacting more industrials simultaneously, in light of Alcan's recent notice of termination.

APPENDIX B

Potential PJM Membership

Big Rivers has also been evaluating the feasibility of joining PJM as a potential option to mitigate the loss of smelter load. PJM has a much more mature capacity market and is currently yielding higher prices than the MISO market. Big Rivers estimates that it would be unnecessary to idle generation stations if it were able to sell into the PJM Market. These prices would provide Member benefit through increased off-system sales, and PJM membership could offer a greater potential for long-term, cost-based power sales.

Big Rivers has had several discussions with PJM concerning the costs and benefits of joining PJM. A meeting was held with PJM senior staff on February 21 to discuss the transmission-feasibility of PJM integration. Big Rivers has the option to exit MISO in December 2014. Additional analysis of this solution will continue.

Going Forward

Going forward, Big Rivers will continue implementation of its load concentration mitigation plan, focusing on:

- Discussions with LGE/KU on the possibility of a long-term PPA or sale of Wilson Station,
- Targeting of the industrial loads in the Calvert City area,
- Supporting our Members' economic development efforts,
- Investigating long-term, cost-based purchase power agreements options,
- Attracting new Members, and
- Analysis of the feasibility, costs and benefits of PJM integration.

BIG RIVERS ELECTRIC CORPORATION

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

Response to Post-Hearing Request for Information
Dated January 9, 2014

January 24, 2014
Confidential Markings Removed – July 18, 2019

For the rate case revenue requirements Big Rivers began with the revenue that is lost when the smelters leave the system, reduced variable costs and labor and non-labor O&M expenses by the idling two of its plants, and determined the remaining revenue deficiency that would still need to be made up after the smelters exit the system. The table below provides a list of the cost reductions in the two cases in broad categories.

Expense Reductions (in $ Millions)		
Cases 2012-00535 and 2013-00199		
Smelter Revenue Loss		$ 360
Less:		
Variable Expenses*	$ (197)	
Coleman Plant Idling (Labor & Non-Labor)	$ (26)	
Wilson Plant Idling (Labor & Non-Labor)	$ (26)	
Other Margin/TIER Requirements	$ 11	
Total Reductions		$ (238)
Remaining Revenue Deficiency		$ 122

* System fuel, reagent and purchased power expenses (Page 8 of the December 2012 Financial Report).

Witness) Mark A. Bailey

Based on Burns & McDonnell's estimates the mid-range cost to decommission and retire the Coleman and Wilson units would be approximately $78.6 million.

	Units Idled			Units Retired	
			Asbestos Remediation	$	4,000,000
			Structural Demolition	$	19,000,000
			Other Remediation	$	1,150,000
			Landfill/Pond Closures	$	46,850,000
FDE Non-Labor	$	2,244,215	Scrap	$	(10,000,000)
FDE Labor	$	2,556,261	Contingency	$	17,600,000
Total Idled Cost, $	**$**	**4,800,476**	**Total Retirement Cost, $**	**$**	**78,600,000**

Witness) Robert W. Berry

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

In the Matter of:

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

Responses to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to Requests for Information from the January 9, 2014, Hearing, Item No. 16 originally filed January 24, 2014

Information submitted on CD accompanying responses

BIG RIVERS ELECTRIC CORPORATION
CASE NO. 2013-00199
Response to Post-Hearing Request for Information
Dated January 9, 2014
Wilson Production Cost

2014 Wilson Production Cost

Operation Data/Inputs	
Net Generation, MWH	2,942,960
Net Heat Rate, BTU/kWH	10,505
Fuel Cost, $/MMBtu	$ 2.0705
Variable Cost (Non Fuel - Reagent & Disposal), $/MWH	$ 2.5660

Fixed Costs	**$**	**$/MWH**
Non-Labor (Non Outage) O&M	$ 10,021,472	$ 3.41
Non-Labor (Outage) O&M	$ 4,490,452	$ 1.53
Labor	$ 12,041,808	$ 4.09
Total Fixed Costs (w/o Capital)	**$ 26,553,732**	**$ 9.02**

Variable Costs	**$**	**$/MWH**
Fuel Cost	$ 64,011,153	$ 21.75
Non Fuel (Reagent & Disposal) Cost	$ 7,551,635	$ 2.566
Total Variable Cost	**$ 71,562,788**	**$ 24.32**

	$	**$/MWH**
Total Production Cost (w/o Capital)	**$ 98,116,520**	**$ 33.34**

Capital Costs	**$ 10,954,000**

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

In the Matter of:

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

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Responses to Requests for Information from the January 9, 2014, Hearing, Item No. 20 originally filed January 24, 2014

Information submitted on CD accompanying responses

ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

Response to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to Commission Staff's Third Request for Information, Item Nos. 5, 8, and 9 originally filed September 30, 2013

FILED: July 18, 2019

ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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FILED: July 18, 2019

an extraordinary or nonrecurring expense that over time will result in a saving that fully offsets the cost."[1] Some examples include expenses related to storm damage, workforce reduction initiatives, write-offs for retired mechanical meters, and post-merger retirement/benefit packages.

It is appropriate for the Commission to allow Big Rivers to recover the amortized portion of the non-recurring, non-labor Coleman layup costs as an extraordinary expense "that over time will result in a saving that fully offsets the cost" because the one-time expense of $1,679,221 million for these costs in the test period is prudent, material, and results in over $25 million in annual savings for Big Rivers, for as long as the Coleman units are idled. As such, the Commission should allow Big Rivers to recover the amortized amount in its rates.

Witness) John Wolfram

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[1] *In the Matter of: The Application of East Kentucky Power Cooperative, Inc. for an Order Approving Accounting Practices to Establish a Regulatory Asset Related to Certain Replacement Power costs Resulting from Generation Forced Outages*, Order, P.S.C. Case No. 2008-00436 at p. 4 (Dec. 23, 2008).

Big Rivers Electric Corporation
Case No. 2013-00199

Off-System Sales Margins

			Test Period Feb-14 to Jan-15	
a.	Off-System Volumes (MWh)		1,825,807	
b.	Off-System Price ($/MWh)	$	31.76	
c.	Off-System Revenues ($)	$	57,983,831	a. times b.
d.	Off-System Variable Costs ($/MWh)	$	30.78	
e.	Off-System Variable Expense ($)	$	56,192,194	a. times d.
f.	Off-System Gross Margin ($)	$	1,791,638	c. minus e.

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Commission Staff's Third Request for Information dated September 16, 2013

September 30, 2013
Confidential Markings Removed – July 18, 2019

Item 9) ***Refer to the response to Item 14 of Kentucky Industrial Utility Customers, Inc.'s ("KIUC") first information request which was filed under petition for confidentiality. Explain the fluctuations in off-system sales revenues for the years 2015-2019.***

Response) Off-system revenues in the years 2015-2019 are driven by the available system generation for sale in the off-system market after native load requirements are satisfied. Two primary reasons for the fluctuations in off-system revenues during this period are the addition of replacement load and the restarting of idled plants. Replacement load recovery begins in 2016 and grows until 2021 in the following increments: 100 MW in 2016, 100 MW in 2017, 100 MW in 2018, 100 MW in 2019, 200 MW in 2020 and 200 MW in 2021 for a total load recovery of 800 MW. In addition to the load recovery, the Wilson station re-starts in 2018 and the Coleman facility re-starts in 2019.

Off-system sales revenues decrease 38% from 2015 to 2016 driven by a 39% decrease in off-system sales volumes due to projected replacement load in 2016 of 658,800 MWh. Off-system revenues decrease 44% in 2017 due to projected replacement load volumes of 1,314,000 MWh. In 2018, there is replacement load totaling 1,971,000 MWh, but off-system sales revenues increase 239% driven by increased generation with the re-start of the Wilson unit. In 2019, the projected off-system revenues increase 107% due to the increased generation related to the Coleman station re-start. In 2020, off-system sales revenues increase 7%, driven by 3% increase in volumes and 4% increase in the market price. The attachment to this response, which is being provided under a petition for confidential treatment, provides additional detail on the generation and load requirements for the system in each of the years.

Witness) Robert W. Berry

Big Rivers Electric Corporation
Case No. 2013-00199

Off-System Reconciliation

		2015		2016		2017		2018		2019		2020
Off-System MWh		1,784,457		1,091,279		628,382		1,971,771		3,641,079		3,757,133
Change over prior year				-39%		-42%		214%		85%		3%
Off-System $/MWh	$	33.91	$	34.40	$	33.62	$	36.37	$	40.67	$	42.20
Change over prior year				1%		-2%		8%		12%		4%
Off-System Revenues	$	60,510,863	$	37,537,264	$	21,127,528	$	71,707,993	$	148,084,666	$	158,567,824
Change over prior year				-38%		-44%		239%		107%		7%

MWh Sales	2015	2016	2017	2018	2019	2020
Rural	2,276,093	2,262,136	2,281,571	2,299,525	2,317,163	2,336,403
Large Industrial	985,813	985,324	982,555	982,555	982,555	982,555
Smelter	-	-	-	-	-	-
Replacement Load	-	658,800	1,314,000	1,971,000	2,628,000	3,952,800
Off-System	1,784,457	1,091,279	628,382	1,971,771	3,641,079	3,757,133
Total	5,048,378	4,999,555	5,208,525	7,226,869	9,570,817	11,030,911
MWh Reconciliation						
Generation	4,891,868	4,756,206	4,868,493	6,853,959	9,469,548	11,000,916
SEPA	266,980	266,980	266,980	266,980	266,980	266,980
Market	15,229	123,265	242,033	297,140	47,676	20,512
Available	5,174,077	5,146,451	5,377,506	7,418,079	9,784,204	11,288,408
Losses	(125,700)	(146,896)	(168,980)	(191,210)	(213,387)	(257,497)
Sales	5,048,378	4,999,555	5,208,525	7,226,869	9,570,817	11,030,911

ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

Response to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Office of the Attorney General's Supplemental Request for Information, Item Nos. 2, 7, 8, 9, 13–20, 28, 29, 31, 32, 34–37, 43, 47, 53, 54, 57, 58, 59, 67, 74, 81, and 83 originally filed September 30, 2013

FILED: July 18, 2019

ORIGINAL

Big Rivers
Electric Corporation
A Touchstone Energy Cooperative

BIG RIVERS ELECTRIC CORPORATION
BULK TRANSMISSION SYSTEM ASSESSMENT

Prepared by
Big Rivers Electric Corporation
June 28, 2007

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INTRODUCTION

Background

As Big Rivers regains operation of its generating stations, the ability to export this generation under a wide range of system conditions becomes critical to the long-term viability of Big Rivers Electric Corporation (Big Rivers or BREC). Consequently, a complete bulk transmission system evaluation, including load loss scenarios, was undertaken.

Specifically, two large industrial customers (aluminum smelters) served within the Big Rivers balancing area have loads that total approximately 850 MW. The loss of one or both of these loads would result in significant excess generation in the Big Rivers balancing area. In the absence of a large load addition, the ability to export this generation outside the Big Rivers control area would be critical. Various scenarios with the loss of these industrial loads were evaluated in the transmission assessment study.

As evaluations of load loss scenarios were beginning, Vectren contacted Big Rivers with a request to evaluate possible EHV interconnections. This request resulted from a Vectren long-range transmission plan completed in late 2006. This plan includes a 345 kV Vectren to Big Rivers interconnection. If constructed, this interconnection will connect AB Brown (Vectren) to Reid EHV (BREC). In addition, the Vectren plan includes a 345 kV interconnection in the eastern part of their system. If constructed, this eastern interconnection will connect Culley (Vectren) to Elmer Smith (Owensboro Municipal Utilities). An alternative to this eastern interconnection was also evaluated. This alternative is a 345 kV interconnection from Culley (Vectren) to Coleman EHV (BREC). These proposed interconnections were evaluated as part of the load loss scenarios to assess their effect on the ability to export excess generation off the Big Rivers system. These are the only know external bulk transmission projects which, if built, were deemed to have the potential to impact the study results.

Purpose

The purpose of this study was to prepare a complete analysis of the Big Rivers bulk transmission system with and without the loss of smelter load. The focus of the study was the Big Rivers transmission system, but consideration was given to external system conditions.

Various system improvement alternatives were evaluated with and without the loss of smelter load. In addition, to fully assess the Big Rivers transmission system and the improvement alternatives considered, the overall ability to import and export power during a variety of system conditions was studied.

Scope of Study

This study included steady-state power flow analyses and limited short-circuit analyses. The following transmission projects were considered in the study process:

<u>Transmission Additions Included in all Studies</u>

Daviess County EHV 345 kV Interconnection (BREC-KU)
Skillman to Meade County to New Hardinsburg 161 kV circuit
Francisco 345/138 kV substation (Vectren)
Dubois to Newtonville 138 kV circuit (Vectren)

<u>Transmission Additions Evaluated</u>

Reid to AB Brown 345 kV interconnection (BREC-Vectren)
Wilson to Paradise 161 kV interconnection (BREC-TVA)
Culley 345/138 kV transformer (Vectren)
Culley to Smith 345 kV interconnection (Vectren-KU)
Coleman EHV to Culley 345 kV interconnection (BREC-Vectren)
Culley to Duff 345 kV line (Vectren)
AB Brown 345/138 kV transformer (Vectren)
AB Brown to Gibson 345 kV interconnection (Vectren-Duke)

SUMMARY OF RESULTS AND CONCLUSIONS

At this time, it is not known whether any of the Vectren interconnection study improvements will be implemented. Therefore, the study results and conclusions are made in light of these results, but are not dependent upon any of the improvements. The following system enhancements were found to be necessary to reliably export all excess generation during the loss of both aluminum smelters:

IMPROVEMENT	MINIMUM REQUIRED RATING
Reid to Daviess Co. 161 kV Upgrade	1200 Amp
Coleman EHV to Coleman 161 kV 1 & 2 Upgrades	1200 Amp
Coleman to Newtonville 161 kV Upgrade	1200 Amp
Wilson to N.Hard/Paradise 161 kV 3 Terminal	2000 Amp
3 Terminal-Paradise 161 kV Upgrade	1600 Amp
Paradise 161 kV Terminal Upgrade	1600 Amp

Additional details regarding the study results and required improvements are included below:

- Modify the existing New Hardinsburg to Paradise 161 kV interconnection by constructing a 13 mile circuit from Wilson to the existing interconnection. This will create a New Hardinsburg/Wilson/Paradise three-terminal circuit.
- Upgrade the 8 mile 161 kV transmission circuit from the new three-terminal tap point to Paradise to allow for 1600 Amp operation.
- Upgrade the Paradise terminal (TVA) to allow for 1600 Amp operation.
- Upgrade the 22 mile Reid to Daviess County 161 kV circuit to allow for 1200 Amp operation.
- Upgrade the 6.4 mile Coleman to Newtonville 161 kV interconnection to allow for 1200 Amp operation.
- Upgrade both Coleman EHV to Coleman 161 kV circuits (the total combined circuit length is 2.8 miles) to allow for 1200 Amp operation.

MODELING ASSUMPTIONS AND STUDY SCENARIOS

Power Flow Base Case

A 2015 model created from a 2015 summer peak ECAR/MEM/VEM base case (created in 2005) was used to complete the system assessment. A detailed Big Rivers model was merged into the case. The loads modeled by Big Rivers are consistent with the 2005 corporate load forecast. In addition, facilities either planned or under consideration by Big Rivers were added to the model. From this 2015 summer peak model, four basic models were developed. These models are described as Case A, Case B, Case C, and Case D. A detailed discussion of each case is included later in this report. Additional models were also created to allow light load and other transfer scenarios to be evaluated. These scenarios are number 1 through 6 and are described later in this report.

Short-Circuit and Transient Stability Models

A regional short-circuit model was used to evaluate the fault duty impacts of the proposed construction. Stability analyses were not performed as part of the initial study. Instead, previously prepared stability studies were reviewed. If necessary, additional stability studies will be completed as part of a subsequent interconnection or system impact study.

Summer Peak Study Scenarios

The study was conducted in two phases. In the first phase, the following study scenarios were evaluated with the 2015 summer peak model. The second phase included an additional evaluation of the improvements proposed as a result of the first phase studies. The intent of the second phase was to provide a sensitivity analysis of the proposed facilities with power flow models that represent different system conditions. Four separate cases (A, B, C, and D) were created from the 2015 summer peak model. A description of the facilities included in each of these cases follows.

<u>Case A – 2015 Summer Model Without the Proposed Vectren Interconnections</u>

The Case A study results will serve as a benchmark for evaluating the interconnections proposed by Vectren. These study results will also provide an assessment of the impacts expected with the loss of smelter load.

Facilities included as in-service in the base model include:

Daviess County EHV 345 kV interconnection (BREC-KU)
Ensor 161/69 kV substation
30 MVAR Hancock County 69 kV capacitor

<u>Case B – 2015 Summer Model with the Proposed Vectren Interconnections</u>

The Case B study results will allow the proposed Vectren interconnections to be evaluated under various system conditions.

Facilities included as in-service in the base model include:

Francisco 345/138 kV substation
Dubois to Newtonville 138 kV circuit
Daviess County EHV 345 kV Interconnection (BREC-KU)
Reid to AB Brown 345 kV interconnection
Culley 345/138 kV station
Culley to Smith 345 kV interconnection
Culley to Duff 345 kV line
AB Brown 345/138 kV station
AB Brown to Gibson 345 kV interconnection
Ensor 161/69 kV substation
30 MVAR Hancock County 69 kV capacitor

<u>Case C – 2015 Summer Model with a Variation of the Proposed Vectren Interconnections</u>

The Case B study results will allow a modified Vectren interconnection plan to be evaluated under various system conditions. In this case, the proposed Culley to Smith 345 kV circuit is replaced with a Culley to Coleman EHV 345 kV circuit.

Facilities included as in-service in the base model include:

Francisco 345/138 kV substation
Dubois to Newtonville 138 kV circuit
Daviess County EHV 345 kV Interconnection (BREC-KU)
Reid to AB Brown 345 kV interconnection
Culley 345/138 kV station
Coleman EHV to Culley interconnection (BREC-Vectren)

Culley to Duff 345 kV line
AB Brown 345/138 kV station
AB Brown to Gibson 345 kV interconnection
Ensor 161/69 kV substation
30 MVAR Hancock County 69 kV capacitor

Case D – 2015 Summer Model Without an Eastern Vectren Interconnection

The case Case D study results will allow the Vectren 345 kV interconnection proposed from AB Brown to Reid to be evaluated. In this case, the proposed Culley to Smith 345 kV circuit (and the Culley to Coleman EHV 345 kV circuit) are removed from the model.

Facilities included as in-service in the base model include:

Francisco 345/138 kV substation
Dubois to Newtonville 138 kV circuit
Daviess County EHV 345 kV Interconnection (BREC-KU)
Reid to AB Brown 345 kV interconnection
Culley 345/138 kV station
Culley to Duff 345 kV line
AB Brown 345/138 kV station
AB Brown to Gibson 345 kV interconnection
Ensor 161/69 kV substation
30 MVAR Hancock County 69 kV capacitor

In addition, various scenarios were studied with each of the four cases. These scenarios are numbered 1 through 4. As description of these scenarios follows:

Scenario 1: Base model with the facilities included in the Case A, B, C or D description.

Scenario 2: Loss of both aluminum smelters with the excess generation exported (25% to the northeast, 25% to the northwest, 25% to the southeast, and 25% to the southwest).

Scenario 3: Loss of both aluminum smelters with the excess generation exported (25% to the northeast, 25% to the northwest, 25% to the southeast, and 25% to the southwest). Also included is a modification of the existing New Hardinsburg (BREC) to Paradise (TVA) 161 kV interconnection (the existing circuit is looped through Wilson).

Scenario 4: Loss of both aluminum smelters with the excess generation exported (25% to the northeast, 25% to the northwest, 25% to the southeast, and 25% to the southwest). Also included is new terrain Wilson to Paradise (TVA) 161 kV interconnection.

The Big Rivers system loads and excess generation included in both the 2015 summer peak model and a light load model (described later) are shown below:

Big Rivers Power Flow Model Loads (MW)

	2015 Summer Peak Model		2015 Off Peak Model	
	Scenario 1	Scenarios 2, 3, 4	Scenario 1	Scenario 2
Generation	1744	1744	1744	1744
System Load	1599	749	1360	510
HMP&L Take	100	100	100	100
Balancing Area Load	1699	849	1460	610
Excess Generation	45	895	284	1134

POWER FLOW ANALYSIS – SUMMER PEAK

Study Contingencies and Monitored Facilities

Big Rivers used the GE PSLF power flow and contingency processor program to automatically perform the power flow analysis. The contingencies studied included all transmission lines and transformers in the Big Rivers balancing area as well as select external outages. Each transmission line and transformer outage was evaluated alone and with the simultaneous outage of single generating units. This is consistent with the Big Rivers planning criteria described in Appendix A. In addition, select outages of multiple generating units with the outage of each transmission line or transformer were also studied.

The BREC, EKPC, Hoosier Energy, LGEE, TVA, and Vectren systems were monitored for overloads and voltage violations. Summary reports of the study results are included in Appendix B of this report. The table on the following page shows the maximum observed loading on each overloading facility for various scenarios. Additional details are included in later report sections.

MAXIMUM LOADING (% OF RATING)

LIMITING FACILITY	CASE A				CASE B				CASE C			CASE D		
	1	2	3	4	1	2	3	4	1	2	3	1	2	3
Reid to Daviess Co. 161 kV	102%	129%	123%	126%	100%	95%	92%	98%	98%	97%	97%	107%	107%	108%
Hancock to Coleman EHV 161 kV	95%				94%				93%			95%		
Hardin to Daviess Co EHV 345 kV		126%	102%	104%	102%	137%	116%	117%	101%	131%	118%	95%	129%	111%
Wilson to Green River 161 kV		106%				95%				97%			99%	
Coleman EHV to Coleman 161 kV		112%	104%	109%			93%	96%		91%	97%		98%	107%
Reid 345/161 kV Transformer		108%	99%	103%										
Smith to Daviess Co EHV 345 kV					101%									
Coleman to Newtonville 161 kV		132%	115%	118%		115%	99%	100%		106%	97%		122%	108%
Wilson to Reid EHV 345 kV					96%		93%	103%	95%	90%	108%	105%	95%	105%
Wilson to Paradise 161 kV			134%	157%			135%	169%			158%			169%

CASE A: Base 2015 summer peak model.
CASE B: 2015 summer peak model with the addition of all proposed Vectren interconnections.
CASE C: 2015 summer peak model with a modified Vectren interconnection plan (Culley to Coleman EHV 345 kV interconnection).
CASE D: 2015 summer peak model with only the AB Brown to Reid 345 kV interconnection added (the eastern Vectren-OMU or BREC interconnection was not included).

SCENARIO 1: Base model.
SCENARIO 2: Loss of both smelters.
SCENARIO 3: Loss of both smelters with the addition of a New Hardinsburg-Wilson-Paradise 161 kV loop.
SCENARIO 4: Loss of both smelters with the addition of a new Wilson to Paradise 161 kV circuit.

Case A – 2015 Summer Model without the Proposed Vectren-BREC Interconnections

Case A models include the Big Rivers system with planned system upgrades. The proposed Vectren interconnections with Big Rivers are not included. The study results are provided in Appendix B and discussed in this section.

As these studies show, a slight overload (102%) of the Reid to Daviess County 161 kV circuit is expected with a single contingency outage. System voltages in the Coleman-Hancock County-Daviess County area are below the criteria limit. In addition, import limitations have been experienced during multiple generating unit outages and heavy north to south transfers.

As described earlier, the loss of one or both smelter loads is a concern for Big Rivers. Studies completed with the loss of both smelter loads (with all excess generation exported off-system) indicate significant facility overloads should be expected. Overloads and/or heavy loadings are expected on the Reid to Daviess County 161 kV circuit (129%), the Coleman EHV to Hancock County 161 kV circuit (98%), the Wilson to Green River (KU) 161 kV interconnection (106%), the Coleman to Coleman EHV 161 kV circuits 1 and 2 (112%), the Daviess County EHV to Hardin County (LGEE) 345 kV circuit (126%), and the Coleman to Newtonville (Hoosier

Energy) 161 kV interconnection (132%). Additionally, a north to south transfers bias that can be reasonably expected to occur would result in increased loadings.

Since the existing Big Rivers bulk transmission system is primarily a 161 kV system with limited 138 kV and 345 kV facilities, the system is not capable of transferring large amounts of power to load outside the Big Rivers control area. Consequently, transmission enhancements that provide additional paths to either existing load centers or the EHV transmission system were found to be necessary to accommodate large power exports.

A previously prepared generator interconnection study identified the need for additional outlets (interconnections with neighboring utilities) during system conditions that include increased power exports from Big Rivers. More specifically, two interconnections were required to support the addition of 750 MW of generation to the Big Rivers transmission system. One of these upgrades (a 345 kV interconnection with KU) is already scheduled to be constructed in 2007. The second outlet is a new-terrain 161 kV Wilson to Paradise (TVA) interconnection. Since both interconnections were found to increase the ability to export power, the second interconnection was evaluated as part of the aluminum smelter load loss studies. In addition, two alternatives to this interconnection were also considered. Both alternatives include a modification of the existing New Hardinsburg to Paradise 161 kV interconnection. One alternative involves looping the existing line through the Wilson station. The second alternative involves creating a three-terminal circuit by constructing a new 161 kV circuit from Wilson to the existing New Hardinsburg to Paradise interconnection. Either alternative would minimize the necessary new right-of-way (ROW) required to interconnect Wilson with Paradise.

The addition of a Wilson to Paradise (TVA) 161 kV interconnection along with a loss of both smelters results in reduced loadings. However, overloads do remain. Overloads are expected on Reid to Daviess County 161 kV circuit (126%), the Coleman to Coleman EHV 161 kV circuits 1 and 2 (109%), the Coleman to Newtonville (Hoosier Energy) 161 kV interconnection (118%) and the Daviess County EHV to Hardin County 345 kV circuit (104%).

The modification of the existing New Hardinsburg to Paradise (TVA) 161 kV interconnection (loop through Wilson), along with a loss of both smelters, also results in reduced loadings. However, overloads again remain. Overloads are expected on Reid to Daviess County 161 kV circuit (123%), the Coleman to Coleman EHV 161 kV circuits 1 and 2 (104%), the Daviess County EHV to Hardin County (LGEE) 345 kV circuit (102%), and the Coleman to Newtonville (Hoosier Energy) 161 kV interconnection (115%).

With the heavy loadings on both internal Big Rivers facilities and external facilities, an addition outlet (interconnection) is required to provide required transfer capability improvement. Since the modification of the existing New Hardinsburg to Paradise (TVA) 161 kV interconnection (either creating a loop circuit or three-terminal circuit) results in reduced loadings on key facilities and requires less ROW when compared to a direct Wilson to Paradise interconnection, this improvement is preferred option for providing increased export capability. No other reasonable interconnection option was identified. The complete list of facilities needed to export all excess power during peak loads and the loss of both aluminum smelters follows:

- Modify the existing New Hardinsburg to Paradise 161 kV interconnection by constructing a 13 mile circuit from Wilson to the existing interconnection. This will create a New Hardinsburg/Wilson/Paradise three-terminal circuit.
- Upgrade the 8 mile 161 kV transmission circuit from the new three-terminal tap point to Paradise to allow for 1600 Amp operation.
- Upgrade the Paradise terminal (TVA) to allow for 1600 Amp operation.
- Upgrade the 22 mile Reid to Daviess County 161 kV circuit to allow for 1200 Amp operation.
- Upgrade the 6.4 mile Coleman to Newtonville 161 kV interconnection to allow for 1200 Amp operation.
- Upgrade both Coleman EHV to Coleman 161 kV circuits (the total combined circuit length is 2.8 miles) to allow for 1200 Amp operation.
- Upgrade the KU 345 kV circuit from Daviess County EHV to Hardin County to allow for 1200 Amp operation.

Additional study details follow:

<u>1. Normal System Observations (base model)</u>

No facility overloads or low voltages were identified.

<u>2. Normal System Observations (with loss of both smelters)</u>

No facility overloads or low voltages were identified.

<u>3. Normal System Observations (loss of both smelters, N. Hard/Paradise to Wilson)</u>

No facility overloads or low voltages were identified.

<u>4. Normal System Observations (loss of both smelters, Wilson to Paradise 16 kV Line Added)</u>

No facility overloads or low voltages were identified.

<u>1. Contingency Observations (base model)</u>

The following transmission facilities (100 kV and above) either exceeded their emergency ratings or experienced heavy loadings near their ratings.

BREC	Reid – Daviess County 161 kV	102%
BREC	Coleman EHV – Hancock Co. 161 kV	95%

Unacceptable single contingency voltages are expected on the 161 kV system at both the Hancock County substation (91%) and the Newman substation (91%).

When the planning criteria is expanded to include the outage of two generating units and a single transmission element, the following transmission facilities (100 kV and above) exceeded their emergency ratings:

BREC	Reid – Daviess County 161 kV	122%
BREC	Coleman EHV – Hancock Co. 161 kV	100%
BREC	Newtonville (HE) – Coleman EHV 161 kV	112%

With the expanded criteria, voltages as low as 83% are expected with an outage of two Coleman generating units with a simultaneous outage of the Coleman EHV to Daviess County EHV 345 kV circuit.

2. Contingency Observations (with loss of both smelters)

BREC	Reid – Daviess County 161 kV	129%
BREC	Wilson – Green River (LGEE) 161 kV	106%
BREC	Coleman – Newtonville (HE) 161 kV	132%
BREC	Coleman EHV – Coleman 161 kV	112%
KU	Hardin-Daviess County EHV 345 kV	126%
BREC	Reid EHV 345/161 kV Transformer	108%

3. Contingency Observations (loss of both smelters, N. Hard/Paradise to Wilson)

BREC	Reid – Daviess County 161 kV	123%
BREC	Coleman EHV – Coleman 161 kV	104%
BREC	Newtonville (HE) – Coleman 161 kV	115%
KU	Hardin-Daviess Co EHV 345 kV	102%

4. Contingency Observations (loss of both smelters, Wilson to Paradise 161 kV Line Added)

BREC	Reid – Daviess County 161 kV	126%
BREC	Coleman EHV – Coleman 161 kV	109%
BREC	Newtonville (HE) – Coleman 161 kV	118%
BREC	Hardin-Daviess Co. EHV 345 kV	104%

Case B – 2015 Summer Model with the Proposed Vectren-BREC Interconnections

Case B models include the Big Rivers system with planned system upgrades and the proposed Vectren interconnections. The study results are provided in Appendix B and discussed in this section.

The single contingency overload (102%) of the Reid to Daviess County 161 kV circuit found with Case A studies was reduced to 100% with the Vectren additions. However, the loading on the Smith (OMU) to Daviess County EHV (KU) 345 kV increased to 101%. The flow on the

Reid to Wilson 345 kV circuit was found to be 96%. Unacceptable system voltages in the Coleman-Hancock County-Daviess County area were improved from 91% to 92.5%.

Studies completed with the loss of both smelter loads (with all excess generation exported off-system) indicate facility overloads should be expected with the Vectren additions. Overloads and/or heavy loadings are expected on the Reid to Daviess County 161 kV circuit (95% with Vectren compared to 129% without), the Wilson to Green River (KU) 161 kV interconnection (95% with Vectren and 106% without), the Coleman to Newtonville (Hoosier Energy) 161 kV interconnection (115% with the Vectren addition and 132% without) and the Daviess County EHV to Hardin County (KU) 345 kV interconnection (137% with Vectren and 126% without).

While the Vectren additions improve system voltages, the Hardin to Daviess County EHV circuit overload is more severe with the Vectren interconnection. In order to export all excess generation during peak, off-peak, and times of heavier north to south flows, additional improvements are required. The addition of a Wilson to Paradise interconnection (through a modification of the existing New Hardinsburg to Paradise interconnection) or the reconductoring of the Coleman to Newtonville 161 kV line is necessary.

The complete list of facilities needed to export all excess power during peak loads and the loss of both aluminum smelters follows:

- Upgrade the 6.4 mile Coleman to Newtonville 161 kV interconnection to allow for 1200 Amp operation.
- Modify the existing New Hardinsburg to Paradise 161 kV interconnection by constructing a 13 mile circuit from Wilson to the existing interconnection. This will create a New Hardinsburg/Wilson/Paradise three-terminal circuit.
- Upgrade the 8 mile 161 kV transmission circuit from the new three-terminal tap point to Paradise to allow for 2000 Amp operation.
- Upgrade the Paradise terminal (TVA) to allow for 2000 Amp operation.
- Upgrade both Coleman EHV to Coleman 161 kV circuits (the total combined circuit length is 2.8 miles) to allow for 1200 Amp operation.
- Upgrade the KU 345 kV circuit from Daviess County EHV to Hardin County to allow for 1200 Amp operation.

Additional study details follow:

<u>1. Normal System Observations (base model)</u>

LGEE	Daviess Co. EHV – Hardin County 161 kV	93%

No unacceptable system voltages are expected.

<u>2. Normal System Observations (with loss of both smelters)</u>

LGEE	Daviess Co. EHV – Hardin County 161 kV	122%

No unacceptable system voltages are expected.

<u>3. Normal System Observations (loss of both smelters, N. Hard/Paradise to Wilson)</u>

LGEE	Daviess Co. EHV – Hardin County 161 kV	116%

No unacceptable system voltages are expected.

<u>1. Contingency Observations (base model)</u>

The following transmission facilities (100 kV and above) either exceeded their emergency ratings or experienced heavy loadings near their ratings.

BREC	Reid – Daviess County 161 kV	100%
BREC	Coleman EHV – Hancock Co. 161 kV	94%
LGEE	Daviess Co. EHV – Hardin County 161 kV	102%
LGEE	Daviess Co. EHV – Smith 161 kV	101%

No unacceptable system voltages are expected. The lowest observed bulk system voltage was 92.5% at the Newman substation (with an outage of the Reid to Daviess County 161 kV circuit with a simultaneous outage of 1 Coleman generating unit.

When the planning criteria is expanded to include the outage of two generating units and a single transmission element, the following transmission facilities (100 kV and above) exceeded their emergency ratings:

BREC	Reid – Daviess County 161 kV	126%
BREC	Coleman EHV – Hancock Co. 161 kV	99%
BREC	Newtonville (HE) – Coleman EHV 161 kV	109%
BREC	Coleman EHV – Coleman 161 kV 1 & 2	100%
LGEE	Daviess Co. EHV – Smith 161 kV	107%

With the expanded criteria, voltages as low as 85% are expected during various outage combinations.

<u>2. Contingency Observations (with loss of both smelters)</u>

LGEE	Daviess Co. EHV – Hardin County 161 kV	137%
BREC	Newtonville (HE) – Coleman EHV 161 kV	115%
BREC	Wilson – Green River (LGEE) 161 kV	95%
BREC	Reid – Daviess County 161 kV	95%

<u>3. Contingency Observations (loss of both smelters, N. Hard/Paradise to Wilson)</u>

BREC	Reid – Daviess County 161 kV	92%
BREC	Newtonville (HE) – Coleman EHV 161 kV	99%
BREC	Coleman EHV – Coleman 161 kV 1 & 2	93%
LGEE	Daviess Co. EHV – Hardin County 161 kV	116%
BREC	Wilson – Reid EHV 345 kV	93%

Case C – 2015 Summer Model with a variation of the Proposed Vectren-BREC Interconnections

Case C models include the BREC system with already planned system upgrades and the proposed Vectren interconnections. However, the Culley to Smith (OMU) 345 kV interconnection proposed by Vectren was replaced with a 345 kV Culley to Coleman interconnection. The study results are provided in Appendix B and discussed in this section.

The single contingency overload (102%) of the Reid to Daviess County 161 kV circuit found with Case A studies was reduced to 98% with the Vectren additions. However, the Daviess County to Hardin County 345 kV circuit was overloaded at 101%.

Studies completed with the loss of both smelter loads (with all excess generation exported off-system) indicate facility overloads or heavy system loadings should be expected with the Vectren additions. Overloads and/or heavy loadings are expected on the Reid to Daviess County 161 kV circuit (97% with Vectren compared to 129% without), the Wilson to Green River (KU) 161 kV interconnection (97% with Vectren and 106% without), the Coleman to Newtonville (Hoosier Energy) 161 kV interconnection (106% with the Vectren addition and 132% without) and the Daviess County EHV to Hardin County (KU) 345 kV interconnection (131% with Vectren and 126% without).

While the Vectren additions improve system voltages, the Hardin to Daviess County EHV circuit overload is more severe with the Vectren interconnection. In order to export all excess generation during various system conditions (the Wilson to Green River 161 kV line loading is 106% with additional north to south transfers modeled) additional improvements are required. The addition of a Wilson to Paradise 161 kV interconnection (through a modification of the existing New Hardinsburg to Paradise interconnection) eliminates the Wilson to Green River overload and reduces the contingency loading on the Coleman to Newtonville 161 kV interconnection to just below 100%.

The complete list of facilities needed to export all excess power during peak loads and the loss of both aluminum smelters follows:

- Modify the existing New Hardinsburg to Paradise 161 kV interconnection by constructing a 13 mile circuit from Wilson to the existing interconnection. This will create a New Hardinsburg/Wilson/Paradise three-terminal circuit.
- Upgrade the 8 mile 161 kV transmission circuit from the new three-terminal tap point to Paradise to allow for 2000 Amp operation.
- Upgrade the Paradise terminal (TVA) to allow for 2000 Amp operation.
- Upgrade the KU 345 kV circuit from Daviess County EHV to Hardin County to allow for 1600 Amp operation.

Additional study details follow:

1. Normal System Observations (base model)

LGEE	Daviess Co. EHV – Hardin County 161 kV	93%

2. Normal System Observations (with loss of both smelters)

LGEE	Daviess Co. EHV – Hardin County 161 kV	121%

3. Normal System Observations (loss of both smelters, N. Hard/Paradise to Wilson)

LGEE	Daviess Co. EHV – Hardin County 161 kV	115%

1. Contingency Observations (base model)

The following transmission facilities (100 kV and above) either exceeded their emergency ratings or experienced heavy loadings near their ratings.

BREC	Reid – Daviess County 161 kV	98%
BREC	Coleman EHV – Hancock Co. 161 kV	93%
LGEE	Daviess Co. EHV – Hardin County 161 kV	101%

No unacceptable system voltages are expected. The lowest observed bulk system voltage was 92.5% at the Hancock County substation (with an outage of the Coleman EHV to Hancock County 161 kV circuit with a simultaneous outage of the Wilson generating unit.

When the planning criteria is expanded to include the outage of two generating units and a single transmission element, the following transmission facilities (100 kV and above) exceeded their emergency ratings:

BREC	Reid – Daviess County 161 kV	104%
BREC	Coleman EHV – Hancock Co. 161 kV	97%
BREC	Coleman EHV – Coleman 161 kV 1 & 2	108%

With the expanded criteria, voltages as low as 91.6% are expected.

2. Contingency Observations (with loss of both smelters)

The following transmission facilities (100 kV and above) either exceeded their emergency ratings or experienced heavy loadings near their ratings.

BREC	Newtonville (HE) – Coleman EHV 161 kV	106%
BREC	Reid – Daviess County 161 kV	97%
LGEE	Daviess Co. EHV – Hardin County 161 kV	131%

3. Contingency Observations (loss of both smelters, N. Hard/Paradise to Wilson)

The following transmission facilities (100 kV and above) either exceeded their emergency ratings or experienced heavy loadings near their ratings.

BREC	Reid – Daviess County 161 kV	97%
BREC	Coleman EHV – Coleman 161 kV 1 & 2	97%
BREC	Wilson – Reid EHV 345 kV	108%
LGEE	Daviess Co. EHV – Hardin County 161 kV	118%

Case D – 2015 Summer Model with only the AB Brown to Reid Interconnection

Case D models include the Big Rivers planned system upgrades and the proposed 345 kV Vectren interconnections from AB Brown to Reid EHV. However, the Culley to Smith (OMU) 345 kV interconnection proposed by Vectren (and the 345 kV Culley to Coleman interconnection) was removed from the model. The study results are provided in Appendix B and discussed in this section.

The single contingency overload (102%) of the Reid to Daviess County 161 kV circuit found with Case A studies increased to 107% with the Vectren addition. In addition, the Reid EHV to Wilson 345 kV circuit was overloaded at 105% and the Coleman EHV to Hancock County 161 kV circuit was loaded at 95%. Similar to Case A, system voltages in the Coleman-Hancock County-Daviess County area are near the 92% criteria limit.

Studies completed with the loss of both smelter loads (with all excess generation exported off-system) indicate facility overloads or heavy system loadings should be expected with the Vectren addition. Overloads and/or heavy loadings are expected on the Reid to Daviess County 161 kV circuit (107% with Vectren compared to 129% without), the Wilson to Green River (KU) 161 kV interconnection (99% with Vectren and 106% without), the Coleman to Newtonville (Hoosier Energy) 161 kV interconnection (122% with the Vectren addition and 132% without) and the Daviess County EHV to Hardin County (KU) 345 kV interconnection (129% with Vectren and 126% without).

With the 345 kV AB Brown to Reid EHV circuit in-place, the following facilities are required to export all excess power during peak loads and the loss of both aluminum smelters follows:

- Upgrade the 22 mile Reid to Daviess County 161 kV circuit to allow for 1200 Amp operation.
- Upgrade the 6.4 mile Coleman to Newtonville 161 kV interconnection to allow for 1200 Amp operation.
- Modify the existing New Hardinsburg to Paradise 161 kV interconnection by constructing a 13 mile circuit from Wilson to the existing interconnection. This will create a New Hardinsburg/Wilson/Paradise three-terminal circuit.
- Upgrade the 8 mile 161 kV transmission circuit from the new three-terminal tap point to Paradise to allow for 2000 Amp operation.

- Upgrade the Paradise terminal (TVA) to allow for 2000 Amp operation.
- Upgrade both Coleman EHV to Coleman 161 kV circuits (the total combined circuit length is 2.8 miles) to allow for 1200 Amp operation.
- Upgrade the KU 345 kV circuit from Daviess County EHV to Hardin County to allow for 1200 Amp operation.
- Upgrade the KU 345 kV circuit from Daviess County EHV to Hardin County to allow for 1600 Amp operation.

Additional study details follow:

1. Normal System Observations (base model)

No facility overloads or low voltages were identified.

2. Normal System Observations (with loss of both smelters)

LGEE	Daviess Co. EHV – Hardin County 161 kV	118%

3. Normal System Observations (loss of both smelters, N. Hard/Paradise to Wilson)

LGEE	Daviess Co. EHV – Hardin County 161 kV	111%

1. Contingency Observations (base model)

The following transmission facilities (100 kV and above) either exceeded their emergency ratings or experienced heavy loadings near their ratings.

BREC	Reid EHV – Wilson 345 kV	105%
BREC	Reid – Daviess County 161 kV	107%
BREC	Coleman EHV – Hancock Co. 161 kV	95%
LGEE	Daviess Co. EHV – Hardin County 161 kV	95%

Single contingency voltages at the accepted low voltage limit are expected on the 161 kV system at the Newman substation (91.9%).

2. Contingency Observations (with loss of both smelters)

The following transmission facilities (100 kV and above) either exceeded their emergency ratings or experienced heavy loadings near their ratings.

BREC	Reid – Daviess County 161 kV	107%
BREC	Wilson – Green River (LGEE) 161 kV	99%
BREC	Coleman – Newtonville (HE) 161 kV	122%
BREC	Coleman EHV – Coleman 161 kV	98%
KU	Hardin-Daviess County EHV 345 kV	129%

3. Contingency Observations (loss of both smelters, N. Hard/Paradise to Wilson)

The following transmission facilities (100 kV and above) either exceeded their emergency ratings or experienced heavy loadings near their ratings.

BREC	Coleman – Newtonville (HE) 161 kV	108%
BREC	Reid – Daviess County 161 kV	108%
BREC	Coleman EHV – Coleman 161 kV 1 & 2	107%
BREC	Wilson – Reid EHV 345 kV	105%
LGEE	Daviess Co. EHV – Hardin County 161 kV	111%

POWER FLOW ANALYSIS – SENSITIVITY

In order to more fully evaluate the proposed system enhancements, the following sensitivity studies were completed. A complete N-1 analysis was completed with each model (Case E, F, G, and H). In addition, scenarios 1, 4, and 5b were analyzed with each case. Again, a complete N-1 analysis was performed.

Case E: 3000 MW north to south transfer and no system improvements.
Case F: 3000 MW north to south transfer with the AB Brown to Reid EHV 345 kV interconnection.
Case G: Off-peak model with no system improvements.
Case H: Off-peak model with the AB Brown to Reid EHV 345 kV interconnection.

Scenario 1: Base model (with smelters).
Scenario 4: No smelter.
Scenario 5b: No smelter with a Wilson to Paradise 161 kV interconnection (3-terminal from the existing New Hardinsburg to Paradise 161 kV interconnection).

Results

As expected, facility loadings during off-peak load levels (with all excess generation exported) can be higher than the loadings experienced during peak load conditions. The same is true for system conditions that include heavier north to south transfers (the study results are included as Appendix E).

These scenarios, as described above, were studied with the addition of a Wilson to Paradise 161 kV interconnection (3-terminal with the existing New Hardinsburg to Paradise interconnection connected to Wilson). The study results showed no additional improvements are necessary above those identified with the peak load studies.

IMPORT/EXPORT ANALYSES

The intent of these analyses was to determine the impact various system improvement options are expected to have on the overall ability to import and export power to and from the Big Rivers balancing area. The loadings on internal Big Rivers facilities and nearby external facilities were considered. These analyses are not coordinated ATC studies. The results do not guarantee or imply that firm transmission that will be available to the market.

Export capability studies were completed with and without the loss of the aluminum smelter load. Without the load loss, over-generating was necessary to reach facility limitations. Consequently, the study results may not accurately represent actual conditions. Since the Reid to Daviess County 161 kV circuit is already planned to be upgraded, limits found on this circuit were not considered. In addition, the Wilson to Reid EHV 345 kV circuit is limited by a CT ratio. Since this upgrade could be easily accomplished, this limit was also not considered.

Export: Existing System (no Vectren Interconnections)

With the existing system, the 2015 summer peak export capability was found to be 574 MW as limited by the Wilson to Green River 161 kV circuit. With the addition of the proposed Wilson to Paradise interconnection (modification of the existing New Hardinsburg to Paradise 161 kV circuit), the export capability increased to 1121 MW as limited by the Coleman to Newtonville 161 kV interconnection.

With loss of both smelters, the 2015 summer peak export capability was found to be 912 MW as limited by the Coleman to Newtonville 161 kV interconnection. With the addition of the proposed Wilson to Paradise interconnection (modification of the existing New Hardinsburg to Paradise 161 kV circuit), the export capability increased to 1098 MW as limited by the Coleman to Newtonville 161 kV interconnection. With an upgrade of the Coleman to Newtonville circuit, the next limit was found to be the Reid to Hopkins County 161 kV circuit at 1380 MW.

The Wilson to Paradise interconnection (modification of the existing New Hardinsburg to Paradise 161 kV circuit) was found to significantly increase the Big Rivers export capability. With the loss of smelters and an upgrade of the Coleman to Newtonville interconnection, the export capability (not considering external flow gates or other external facilities) was increased by 468 MW.

Export: With the Addition of the Brown to Reid EHV 345 kV Interconnection

With 2015 summer peak conditions, the export capability was found to be 632 MW as limited by Wilson to Green River 161 kV circuit. With the addition of the proposed Wilson to Paradise interconnection (modification of the existing New Hardinsburg to Paradise 161 kV circuit), the export capability increased to 972 MW as limited by the Reid to Hopkins County 161 kV circuit.

With loss of both smelters, the 2015 summer peak export capability was found to be 1040 MW as limited by the Coleman to Newtonville 161 kV interconnection. With the addition of the proposed Wilson to Paradise interconnection (modification of the existing New Hardinsburg to Paradise 161 kV circuit), the export capability increased to 1212 MW as limited by the Coleman to Newtonville 161 kV interconnection.

The interconnection addition is expected to increase flows into the Big Rivers system. However, when studied with 2015 summer peak load conditions, the interconnection did offer a modest increase in export capability (58 MW during normal peak conditions and 128 MW with the loss of both aluminum smelters).

<u>Export: With the Addition of the Brown to Reid EHV 345 kV and Culley to Coleman 345 kV Interconnection</u>

With 2015 summer peak conditions, the export capability was found to be 742 MW as limited by Wilson to Green River 161 kV circuit. With the addition of the proposed Wilson to Paradise interconnection (modification of the existing New Hardinsburg to Paradise 161 kV circuit), the export capability increased to 1294 MW as limited by the Reid to Hopkins County 161 kV circuit.

With loss of both smelters, the 2015 summer peak export capability was found to be 1259 MW as limited by the Wilson to Green River 161 kV interconnection. With the addition of the proposed Wilson to Paradise interconnection (modification of the existing New Hardinsburg to Paradise 161 kV circuit), the export capability increased to 1583 MW as limited by the Coleman to Newtonville 161 kV interconnection. With an upgrade of the Coleman to Newtonville circuit, the next limit was found to be the Reid to Hopkins County 161 kV circuit at 2048 MW.

The addition of both Vectren interconnections resulted in an export capability increase of 168 MW during normal peak load conditions and 347 MW with the loss of both smelter loads (as compared to export values with the addition of neither Vectren interconnection).

<u>Import Study Results</u>

2015 summer peak import studies were completed with the smelters load being served. The import was modeled as a transfer from the north (Duke). With the existing system, an import limit of 621 MW was found (limited by the Coleman to Newtonville 161 kV interconnection). With the addition of a Wilson to Paradise interconnection, an import limit of 626 MW was found (limited by the Coleman to Newtonville 161 kV interconnection). With an upgrade of the Coleman to Newtonville 161 kV circuit, the import limit increases to approximately 950 MW.

With the addition of the proposed AB Brown to Reid EHV 345 kV interconnection, the import capability increased to 895 MW. Again, the impact of the Wilson to Paradise interconnection was not significant (896 MW import capability). The limiting facility was found to be the Coleman to Newtonville 161 kV interconnection. An upgrade of the Coleman to Newtonville 161 kV circuit was found to increase the import limit to approximately 1200 MW. The overall import capability is expected to increase with the addition of the AB Brown to Reid EHV 345 kV interconnection.

With the addition of both of the proposed Vectren interconnections (AB Brown to Reid EHV 345 kV and Culley to Smith 345 kV) the import capability increased to 942 MW. Again, the impact of the Wilson to Paradise interconnection was not significant (941 MW import capability). The limiting facility was found to be the Coleman to Newtonville 161 kV interconnection. An upgrade of the Coleman to Newtonville 161 kV circuit is expected to increase the import limit. The overall import capability is expected to increase with the addition of these Vectren interconnections.

With the addition of both of the modified Vectren interconnection plan (AB Brown to Reid EHV 345 kV and Culley to Coleman EHV 345 kV) the import capability increased to 2000+MW (assuming the Coleman EHV to Coleman 161 kV circuits are upgraded). Again, the impact of the Wilson to Paradise interconnection was not significant (2000+ MW import capability).

LOSS COMPARISON

A comparison of system losses is provided below. The largest loss reduction is in the Vectren system. The LGEE system includes the only significant loss increase. The overall change in system losses does not appear significant.

MW LOSSES (NO NEW PARADISE INTERCONNECTION)				
System	**Case A Losses**	**Case B Losses**	**Case C Losses**	**Case D Losses**
BREC (214)	22	23	22	23
LGEE (211)	258	267	266	264
TVA (147)	797	799	799	799
VECTREN (210)	43	35	35	35
Total	**1120**	**1124**	**1122**	**1121**

MW LOSSES (WITH NEW PARADISE INTERCONNECTION)				
System	**Case A Losses**	**Case B Losses**	**Case C Losses**	**Case D Losses**
BREC (214)	22	23	23	24
LGEE (211)	257	266	265	263
TVA (147)	797	800	800	800
VECTREN (210)	43	35	35	35
Total	**1119**	**1124**	**1123**	**1122**

SHORT-CIRCUIT STUDY RESULTS

A short circuit analysis was completed. The intent of the analysis was to determine if the replacement of any circuit breakers would be required as a result of the proposed construction (line reconductors and the creation of a Wilson to Paradise interconnection). The study results are shown in Appendix D. Based on these results, no breaker replacement projects are proposed.

TRANSIENT STABILITY STUDY

Transient stability is a study conducted to investigate the dynamic response of generators due to a fault or some other type of system disturbance near a generator. Stability analyses were not completed as part of this study effort. However, a previously prepared stability study was reviewed.

The previously prepared stability study included a generation addition near the Wilson station and a new 161 kV Wilson to Paradise interconnection (in addition to the planned Daviess County EHV 345 kV switching station). Based on these study results, acceptable dynamic performance is expected with the addition of a Wilson to Paradise interconnection (either a new direct interconnection or through a modification of the existing New Hardinsburg to Paradise 161 kV interconnection).

RECOMMENDATION

The proposed facility upgrades described in the Summary of Results and Conclusions section of this report were found to be the most cost effective system improvements available to meet the system export needs. No other improvements were found to provide the robustness of the proposed facilities while limiting the need for new right-of-ways. The Vectren improvements were found to benefit the Big Rivers system and the regional transmission network. However, these improvements did not eliminate the need for the proposed Wilson to New Hardinsburg/Paradise Tap 161 kV circuit. Consequently, the Vectren interconnection alternatives were not selected due to the limited improvement provided to the Big Rivers export capability.

Three connection alternatives were considered for the 161 kV Wilson circuit. One alternative included a 21 mile new terrain Wilson to Paradise 161 kV interconnection. This alternative requires new 161 kV terminals at both Wilson and Paradise. Due to the additional miles of new-terrain right-of-way required (as compared to the selected alternative) and higher cost, this connection alternative was not selected. A second alternative included two 13 mile new terrain circuits on a common right-of-way to loop the Hardinsburg to Paradise 161 kV circuit through the Wilson switchyard. This alternative requires two new 161 kV terminals at Wilson. Due to the additional right-of-way and cost, this connection alternative was not selected. The selected alternative includes approximately 13 miles of new-terrain 161 kV construction from Wilson to a tap point in the existing Hardinsburg to Paradise 161 kV circuit. In addition, by creating a three-terminal circuit with an existing interconnection, only one new terminal (Wilson) is required. When cost, effectiveness, and necessary new right-of-way were considered, the proposed alternative was found to be the superior alternative.

APPENDIX A: BIG RIVERS PLANNING CRITERIA

Big Rivers Electric Corporation

Procedure Documentation

TRANSMISSION PLANNING CRITERIA AND GUIDELINES

PL-FAC-0001

Document Information		
Current Revision	**Review Cycle**	**Subject to External Audit**
Rev. 1.0	As needed (copy to RC)	Yes

Big Rivers Corporate Approvals		
Prepared By	Chris Bradley/Bob Warren	5/18/2007
Approval - Supervisor	N/A	
Approval - Dept. Manager	N/A	
Approval - Vice President		

Revision Information				
Number	**Date**	**Notes**	**Revised by**	**Approved**
Rev. 1.0	3/15/2007	New Document - Replaces original document.	Chris Bradley	Yes
Rev. 1.1	5/18/2007	Dynamic stability procedures were expanded.	Chris Bradley	Yes

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I. GENERAL SYSTEM PLANNING REQUIREMENTS

The Big Rivers transmission system consists of the physical equipment necessary to transmit power from its generating plants and interconnection points to all substations from which customers of its three member distribution cooperatives are served. Transmission planning embodies making investment decisions required to maintain this system so that it can reliably meet the power needs of the customers served. Transmission planning also includes the evaluation of transmission service requests, internal and external generator interconnection requests, internal and external transmission interconnection requests, and end-user connection requests. Justifications used in any transmission study are based on technical and economic evaluations of options that may be implemented to meet the specific need. The planning criteria described in this document are consistently utilized for all transmission studies.

The technical studies performed by the system planning section require the use of several software packages. The software package PSLF (Positive Sequence Load Flow) is a comprehensive set of transmission system planning programs supported by the General Electric Company. PSSE is a similar program supported by Siemens. Both software programs are used to complete AC and DC power flow studies, to create power flow equivalents, to prepare stability studies, and to complete other studies.

A software package for short-circuit calculations and relay coordination is also used. This package is known as CAPE (The Computer-Aided Power Engineering System) and is supported by Electrocon International Inc.

The above-described software programs are used in the preparation of seasonal assessments (for internal use and to meet NERC and/or SERC requirements) as well as short-term and long-term construction plans (as defined and required by RUS). Power flow studies for specific operating conditions are also performed to support system operations. Special power flow studies, generator, transmission, and end-user interconnection studies, and transfer capability studies are performed as needed.

II. POWER FLOW STUDIES

The most widely used software program for transmission system planning is the power flow program. In order to get consistent and meaningful results from power flow studies, specific criteria and procedures have been established and are followed. Succeeding sections of the document describe the contingency criteria, voltage criteria, line and transformer loading criteria, and modeling procedures established and consistently applied by Big Rivers for all transmission system planning study efforts.

1. Contingency Criteria

Big Rivers follows two RUS recommended criteria for analyzing the adequacy of its transmission system. The first criteria defines single contingency outages to be used in all system planning studies. This criteria serves as the basis for planning and justifying system improvements. The second criteria outlines double contingency outages that can be analyzed to determine the extent of problems encountered on the system under extreme outage or emergency situations. In most double contingency cases, system improvements would not be considered justifiable. However, the type and severity of the system problems encountered is useful information in planning those system improvements that are justifiable.

Single Contingency Criteria:

1. Outage of two generation units (any combination).
2. Outage of one generation unit and one transmission line.
3. Outage of one generating unit and one transformer.
4. Outage of one transmission line.

Double Contingency Criteria:

1. Outage of two transmission lines on the same right-of-way.
2. Outage of transmission lines due to outage of one bus.
3. Outage of three generation units.

In addition to the above-described criteria, Big Rivers also analyzes its transmission system to ensure compliance with NERC Planning Standards. The following describes the outages studied to ensure compliance with the NERC TPL standards:

NERC Category A (no contingencies)

As with all studies, base case conditions (no outages) are evaluated to ensure compliance with all planning criteria and standards. Base case models used for all studies should include appropriate loads that are consistent with the corporate load forecast, firm transactions, realistic generator dispatch based on historic data, and should include existing and planned facilities.

NERC Category B

1. Individual outage of all single elements in Big Rivers (including 3-terminal circuits), Hoosier Energy (HE), KU and LG&E (LGEE), Southern Illinois Power Cooperative (SIPC), TVA, and Vectren.

2. Single generating unit outages.

Seasonal assessments and other bulk system assessments performed by Big Rivers include the outage of each single element above 100 KV in the systems listed above with the bulk facilities in each of the above listed systems monitored.

NERC Category C (including NERC Category B with Generating Unit outage)

1. Single transmission element outage with simultaneous generating unit outage (including each of the following: Wilson, Green, Coleman, and Paradise).

2. Double transmission element outages including two circuits on a common tower (global Big Rivers outages and select external).

3. Substation bus or bus section outage.

Seasonal assessments include every combination of double contingencies in the Big Rivers system (above 100 KV). In addition, each Big Rivers single contingency is performed with the simultaneous outage of select individual generating units (listed above). Select bus section outages in Big Rivers are studied. While performing these outages, all bulk facilities (Big Rivers, HE, LGEE, SIPC, TVA, and Vectren) are monitored. However, the external facilities are monitored only for the potential to cascade (130% overload). Other transmission assessment studies may include only a subset of the above described outages.

NERC Category D

1. Coleman generating plant outaged.

2. Wilson generating plant outaged.

3. Green generating plant outaged.

4. Century Aluminum load outaged.

5. Alcan load outaged.

6. Outage of Reid 161 kV switchyard.

7. Outage of Coleman 161 kV switchyard.

8. Outage of all Green and HMP&L generating units.

Seasonal assessments include the above described Category D outages. While performing these outages, all bulk facilities (Big Rivers, HE, LGEE, SIPC, TVA, and Vectren) are monitored. However, the external facilities are monitored only for the potential to cascade (130% overload). Other transmission assessment studies may include only a subset of the above described outages.

When completing all bulk transmission studies, all internal facilities are monitored for voltage and loading violations. Either select external facilities or the complete list of external system previously described are also monitored. When completing seasonal assessments, the neighboring systems may only be monitored for the potential to cascade. When completing expansion studies or connection studies, any neighboring system violation will be compared against the base model to determine the impact of the proposed projects. Any violation made worse by the proposed system improvement will be investigated with the facility owner.

2. Voltage Criteria

As indicated in the following table, Big Rivers has adopted a voltage criteria for planning and assessing its transmission system. This criteria defines acceptable minimum and maximum voltage levels for the high-side buses. The criteria include a range of acceptable voltages for normal system conditions (all facilities in service) and during single contingency conditions. A more detailed description of the voltage criteria is included as Appendix A.

Transmission System Conditions	69 kV Bus Voltage		> 69 kV Bus Voltage	
	Minimum	Maximum	Minimum	Maximum
Range A: Normal System Operations	95.0%	105.0%	95.0%	105.0%
Range B: Single Contingency Conditions	91.7%	105.8%	92.0%	105.0%

3. Facility Rating Criteria

Big Rivers' transmission lines are rated according to limits determined by the most restrictive of either the conductor thermal ratings, the NESC minimum line to ground clearances, or the terminal equipment ratings. Big Rivers' transformer ratings are established according to their thermal design ratings as specified by the manufacturer. For normal and single contingency situations, all lines are to be loaded at or below their ratings and all transformers are to be loaded at or below their maximum 65°C ratings. Substation equipment ratings are based on manufacturer recommendations. Big Rivers does not derate high voltage air switches, line traps, or power circuit breakers based on weather conditions or previous loading conditions. Shunt capacitors are designed for a minimum of 1.05 p.u. voltage. Jumpers connecting these substation components to other elements of the transmission system are sized with current carrying capacity greater than the component itself. Additional rating details can be found later in this report.

4. Modeling Procedures

In order to perform a power flow study, a model of the electrical system is required. The power flow model requires line and transformer impedances, transformer tap settings, generation levels, load levels (MW and MVAR), scheduled voltages, line and transformer ratings, and inter-change schedules for Big Rivers' facilities as well as for other utilities.

To start the model development process, an MMWG power flow case for a desired year is obtained. This model includes information for neighboring utilities within SERC as well as other reliability areas. Neighboring utilities may be contacted directly in order to obtain more detailed system information. After the MMWG case is obtained, the Big Rivers model and any desired neighboring utility representations are removed and more detailed models are merged into the case.

After all detailed representations are merged into the MMWG case, fine-tuning of the case begins. The first step is to make sure Big Rivers' interchange is correct. The modeled interchange should typically reflect firm contract sales for the desired time period. Transactions that are consistent with firm transmission reservations confirmed on the OASIS may also be modeled as part of Big Rivers' scheduled interchange. Close attention is paid to HMP&L's allocation from Station 2 generation and HMP&L's loads (in the MMWG case, the HMP&L take is modeled as Big Rivers load. HMP&L load is modeled in a separate HMP&L area in the detailed case). After the interchange is modeled, the loads in Big Rivers' area are reviewed and revised. The distributed loads will match the forecast numbers found in the latest available Big Rivers load forecast for the desired year. Regression techniques or averages based on historical data are used to distribute the total rural load. The large industrial loads modeled in the power flow case will match the values given in the Big Rivers load forecast. Each distribution cooperative is consulted during this load distribution process. Additional details regarding this process are included in Appendix B. In most cases, the generation at Reid 1 and at the Reid CT is modeled off-line. All transmission or generation construction scheduled to be completed before the time period to be studied is added into the model. A final check of line and transformer impedances and ratings is performed prior to starting the desired power flow studies.

III. SHORT CIRCUIT STUDIES

System planning utilizes short circuit study results to evaluate the adequacy of the short time current or interrupting ratings of existing equipment, to determine the ratings of new equipment to be purchased, and to provide short circuit source data to its member cooperatives, their industrial customers, or for Big Rivers' own protection coordination studies. System planning currently performs these short circuit studies. Short circuit studies are performed using the CAPE software package.

In order to perform these short circuit studies, a database model including the positive and zero sequence impedances of each line, transformer, and generator is prepared for Big Rivers' system. Equivalent system impedances for each of Big Rivers' interconnections are also determined and modeled. Short circuit studies are then run to determine the magnitude of single phase to ground and three phase faults at each station or bus in Big Rivers' system. These fault levels are compared to the existing power circuit breaker ratings to determine if any equipment ratings are exceeded. If equipment ratings are exceeded, then upgrades in equipment are recommended.

IV. STABILITY STUDIES

Another concern of the system planning section is system stability. Stability refers to the ability of a generator to remain in synchronism with all other generators after a disturbance or fault. On an annual basis, seasonal assessments performed by Big Rivers will be reviewed to determine significant NERC Category B, C, and D outages that warrant near-term dynamic simulations. In general, any Category B, C, or D outage that has the potential to result in significant facility overloads, widespread low voltages, or cascading outages without operator action will be considered for inclusion in a dynamic analysis. Particular attention should be given to facilities or geographic areas that appear particularly vulnerable to frequent overloading or low voltage conditions (during various independent single or multiple contingencies). If no new significant facilities, outages, or areas of concerns are identified, previously prepared dynamic simulations may be sufficient. However, dynamic simulations should be performed if any of the following conditions or situations occur:

- Significant system changes have occurred since the last dynamic simulations were completed. This includes internal and nearby external changes (EHV additions, generator additions or retirements, interconnection additions, load loss or addition, etc.).

- Additional significant facilities or outages are identified through the seasonal assessment study process.

- The most recent dynamic simulations are found to be over 5 years old.

The criteria followed during stability studies follows:

- With one transmission element out-of-service, all generating units must remain stable with a subsequent single phase-to-ground fault.

- Under normal system peak load conditions with full generation output, all generating units must remain stable with a three phase-to ground fault at the most critical location.

- Under normal system peak load conditions with full generation output, all generating units must remain stable with a single phase-to-ground fault at the most critical location followed by a breaker failure.

- All circuit breakers should be capable of interrupting the maximum fault current duty imposed on the circuit breaker.

- All NERC standards and SERC Supplement requirements must be met.

V. CONSTRUCTION WORK PLANS

RUS requires that borrowers maintain an up-to-date short-range construction work plan (CWP). The CWP consists of a series of system studies, which covers a period of 2 to 3 years in the future and identifies required transmission facility improvements. The CWP is consistent with the long-range engineering plan. The CWP studies use the system load estimates found in the borrower's approved load forecast. A CWP, according to RUS, shall normally include studies of power flows, voltage regulation, and stability characteristics to demonstrate system performance and needs. These requirements, as well as additional requirements, are described in the Federal Register in 7 CFR Part 1710.

A CWP, as prepared by Big Rivers, covers a three year period beyond the year in which the study is being performed. For example, a CWP prepared in the summer of 1995 would cover the time frame from 1996 to 1998. New CWPs are typically prepared during the last year covered by an existing CWP.

Power flow studies make up the majority of a CWP as prepared by Big Rivers. A power flow database is prepared as previously described. Load levels that are consistent with the most current load forecast are modeled. Typically, the interchange is modeled according to firm contract sales and purchases. However, transactions that are consistent with firm transmission reservations that are confirmed on the OASIS may also be modeled as part of Big Rivers' scheduled interchange. Single contingency outages of each line of Big Rivers' system (excluding radial lines) are studied. Single contingencies, which yield unacceptable system results, are identified. Alternate systems switching arrangements or changes in transformer tap settings are evaluated as the first solution option. If operational changes will not correct the problem, then system improvement alternatives are defined, modeled, and studied to determine their merits in correcting the system problem. The system improvements that prove to be successful solutions for the system problem are then evaluated based on economics, reliability, practicality, possible system benefits, and consistency with long range engineering plans to determine their inclusion in the CWP recommendation. Both external and internal improvement options are considered. When external options are considered (or internal options that may impact external facilities), coordination with all neighboring systems (including MISO, SPP, and TVA RC) is necessary and will be initiated as soon as possible. Final construction plans should be provided to interested and potentially impacted entities for comment as soon as possible. Power flow studies are typically completed for summer and winter peak conditions. Power flow studies with extreme conditions (peak load forecast with extreme weather) are also performed and may be used to evaluate construction alternatives.

Maximum transfer capability studies may be included as a part of the CWP. A maximum transfer capability study typically includes multiple scenarios to evaluate potential transfers. Maximum power transfer studies from Big Rivers to TVA and MISO would be evaluated. The intent of these studies is to identify any system problems that may occur because of off-system sales or purchases.

Short circuit studies to evaluate the adequacy of system equipment ratings are also performed and their results analyzed. Stability studies accompany any study in which additional generation is being recommended or evaluated.

VI. LONG-RANGE ENGINEERING PLANS

RUS also requires that borrowers maintain up-to-date long-range engineering plans. These long-range engineering plans are prepared in a manner similar to the process of preparing a CWP. A long-range engineering plan is prepared immediately following each CWP. This allows the CWP to be reviewed in light of long-range plans. Reviewing and revising a long-range engineering plan is acceptable in place of preparing an entirely new study if system changes and load forecast changes have been minimal. Engineering judgement is used to decide if simply reviewing and revising the study is appropriate.

As with a CWP, the long-range engineering plan is predominantly driven by the results of system power flow studies. The power flow studies are again prepared with an MMWG database. This database represents all systems ten years in the future. A detailed representation of Big Rivers, and any desired neighbor, is merged into the MMWG database. The load level modeled for Big Rivers are consistent with the approved load forecast for the desired year. The power flow cases are modeled with summer peak and off-peak loads. The modeled interchange reflects what Big Rivers management believes is most probable for the study period. This interchange level may be equivalent to firm contract sales and purchases or may include transactions that are consistent with firm transmission reservations that are confirmed on the OASIS. Single contingency outages of each Big Rivers' line (excluding radial lines) are studied. These single contingency studies identify cases that yield unacceptable voltages or line loading conditions. Studies are then run to evaluate possible solutions for the problems identified. Operational changes such as switching or transformer tap changes are the first solution options studied. If operational changes proved to be unsuccessful, then various system improvement options are studied. All system improvements that are found to be successful solutions for the system problems are then evaluated based on economics, reliability, practicality, and other system benefits to determine the best solution. Additional system studies are run to evaluate the cumulative effects of multiple system improvements. The result is a transmission system that will allow Big Rivers to provide reliable and cost-effective electric service to its member cooperatives.

In addition to the ten-year study, a fifteen or twenty year study is performed. A procedure, similar to the ten-year study procedure, would be followed with a fifteen or twenty year power flow database. Any final conclusion is made using the results from both the ten-year study and the fifteen or twenty year study.

Maximum power transfer capability studies are also be prepared as part of a long-range engineering plan. These studies will help to identify any problems that may occur in the long run as a result of off-system transactions. Possible solutions to correct the deficiencies are identified and evaluated following normal power flow study procedures.

Short circuit studies are also performed as previously described. These studies help identify long-term problems associated with increasing fault duties. Stability studies accompany any study in which additional generation is being recommended or evaluated.

It should be noted that not every system addition or upgrade identified or proposed in the long-range engineering is implemented. As Big Rivers' system actually grows, it may become obvious that the problems identified in the long-range study may not develop or that problems may develop in other areas. The actual system development is continually reviewed and monitored to determine when a new long-range engineering plan is necessary. The long-range plan, when reviewed with the CWP, helps to identify any proposed short run solutions that may just be "band-aid" solutions for a major long-range problem. In some of these cases, investing in a facility that may only be a temporary solution may not be advisable. Instead, other alternatives may be more economical when the long-term system needs are considered.

VII. SHORT-TERM/OPERATIONAL PLANNING

Technical studies are performed by the system planning department to support near-term and real-time reliability efforts. These studies utilize both the OSI OpenNet application that provides a real-time state estimator and contingency analysis tool (EMS application) and the off-line power flow study tool (PSLF).

1. Planned System Outages

Both the on-line and off-line power flow programs are used to study planned outages and system events as necessary. The TVA RC studies all outages entered into the NERC SDX and coordinates this information with other reliability coordinators. Any action plans involving Henderson Municipal Power and Light (HMP&L), our member cooperatives, or any impacted customer are coordinated through Big Rivers System Supervisors with Engineering support provided as needed. Action plans involving adjacent reliability coordinators are coordinated through TVA.

2. Real-Time Contingency Analysis

The real-time contingency analysis tool is used on a continuous basis (once every two minutes) to study all bulk system single contingencies (single line, transformer, and generator outages). Also, all single line/transformer contingencies are run with simultaneous generator outages on a regular basis (generally on a daily basis). Several external outages that have a known impact on the Big Rivers' system are also run on a daily basis. In Addition, the TVA RC uses the AREVA state estimator/contingency analysis program to monitor and study the Big Rivers system as well as the regional transmission network.

3. Real-Time Contingency Analysis Alarming

As previously discussed, the real-time contingency analysis tool is part of the EMS and the results can be viewed by the System Supervisors. The thermal and voltage results can be viewed on two separate displays. Any line or transformer with normal or N-1 loadings at 90% or greater of its seasonal thermal rating are alarmed and displayed. Normal and N-1 system voltages outside of the range from 95% to 105% of nominal are also alarmed and displayed.

4. Off-Line Model

MMWG power flow models for the desired years are used as the basis for developing the power flow model for use in reliability and planning studies. Detailed models for Big Rivers and any desired neighboring utility are merged into the case. This model is then updated to reflect the system conditions that are to be studied. Actual system data from the EMS is used in the update process.

5. Real-Time Model

The real-time model was also created from a MMWG power flow model with the detailed Big Rivers model merged in. The model is updated manually with support from the engineering department and neighboring utilities as needed. Real-time data is brought into the model every time the state estimator executes (once per minute) through the Big Rivers SCADA system and the ICCP connection with the TVA.

VIII. MISCELLANEOUS PLANNING STUDIES

Other studies performed by Big Rivers include operational studies, system impact studies to evaluate transmission service requests, generator interconnection studies, transmission interconnection studies, end-user connection studies, and various other special studies. The study process and format will vary according to need. However, all studies should follow the same voltage and facility loading criteria and should be consistent with the procedures and methodologies outlined in this report (the alternative selection process is consistent with the process described in Section V). As with all studies, compliance with NERC standards is necessary.

In addition, transmission studies should be properly coordinated with neighboring transmission systems and reliability organizations. Specifically, all potentially impacted neighbors (E.ON. U.S., Hoosier Energy, MISO, SIPC, SPP, TVA, and Vectren) should be invited to participate in all generator interconnection studies and significant transmission interconnection or modification studies. Modeling information, study results, and proposed transmission plans should be communicated to these entities and any other interested transmission planning entity or transmission owner/provider. After all internal and external approvals (including regulatory approvals) are obtained, the proposed facilities will be included in the MMWG model building process and communicated to the TVA Reliability Coordinator. A log of communication (email history is acceptable) should be maintained as part of the study process.

On an annual basis, studies are prepared to evaluate all annual firm transmission requests (new or renewals). Other studies are performed to support the calculation of the ATC values that are posted to the OASIS. Details concerning these studies are included in a separate document.

Seasonal system assessments are also prepared on an annual basis. These seasonal assessments include (at a minimum) summer peak studies, winter peak studies, stress cases (heavy transfers or extreme loads), and long-range studies. Single, double, and extreme contingencies should be studied with the results compared against NERC planning standard requirements. Stability studies should also be reviewed as necessary.

Big Rivers also participates in SERC near-term and long-term assessments. In addition, Big Rivers participates in the quarterly OASIS studies prepared by SERC companies.

IX. RATING METHODOLOGIES

All transmission facility ratings are based on the most limiting element included in any circuit (switches, breakers, buses, traps, protective relaying systems and their trip settings, transformers, CTs, transmission lines, etc.). Unless otherwise stated, summer and winter ratings are based on the same methodology.

All transmission system ratings have been provided to the TVA reliability coordinator. Any rating changes are communicated to the TVA reliability coordinator and interested neighboring systems as the changes occur. In addition, up-to-date ratings are included in the MMWG models available to most interested parties. Additional rating details will be made available to neighboring utilities and other interested parties as needed. Interconnection ratings are coordinated once per year as part of the MMWG model building process. Additional coordination is completed via email as necessary.

Conductors

The calculations of transmission line ratings are consistent with IEEE Standard 738-1993 "IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors". The following assumptions are utilized in the calculations:

1. Minimum ground clearances (as defined by NESC) will be maintained during operations at the conductor's maximum operating temperature (typically 212° F).

2. Summer Normal and Summer Emergency ratings are calculated with 2 foot per second wind speed, full sun, and an ambient temperature of 100° F.

3. Winter Normal and Winter Emergency ratings are calculated with 2 foot per second wind speed, full sun, and an ambient temperature of 32° F.

4. In addition to the above ratings, temperature dependent ratings are used by system operations (actual temperatures are used in place of the assumed temperature when calculating the ratings).

Generators

Manufactures nameplate information (including reactive capability curves) is used to determine unit ratings when actual test data is unavailable. At this time, each generating unit is schedule to be field tested. The test will determine actual real and reactive capabilities and other data necessary to properly model the generating units for steady-state and dynamic analyses.

High Voltage Air Switches

Big Rivers purchases, operates and maintains transmission voltage (100 kV and above) High Voltage Air Switches in accordance with ANSI C37.32 *HV Air Switches – Preferred Ratings, Specifications and Application Guide*. Table 1 of C37.32 lists *Preferred Ratings for Outdoor Air Switches.* Big Rivers does not derate High Voltage Air Switches based on weather conditions or previous loading conditions. Jumpers connecting switches to other elements of the transmission facility are sized with current carrying capacity greater than the switch itself.

Shunt Capacitors

Big Rivers purchases, operates and maintains transmission voltage (100 kV and above) Shunt Capacitors in accordance with NEMA CP1 - Shunt Capacitors, and ANSI/IEEE C37.99 – Guide for Protection of Shunt Capacitor Banks, and IEEE 1036 Guide for the Application of

Shunt Power Capacitors. These capacitor banks are composed of capacitor can groups in series and connected in a grounded wye configuration. Since substation bus voltages run higher than 1.0 p.u., banks are designed for a minimum of 1.05 p.u. Jumpers connecting capacitor banks to other elements of the transmission system are sized with current carrying capacity greater than the capacitor bank itself.

<u>Line Traps</u>

Big Rivers purchases, operates and maintains transmission voltage (100 kV and above) Line Traps in accordance with ANSI C93.3 – *Requirements for Power-Line Carrier Line Traps*. Table 5 of C93.3 lists *Current Ratings*. Big Rivers does not derate Line Traps based on weather conditions or previous loading conditions. Jumpers connecting Line Traps to other elements of the transmission facility are sized with current carrying capacity greater than the Line Trap itself.

<u>Transformers</u>

Big Rivers purchases, operates and maintains transmission voltage (100 kV and above) Transformers in accordance with ANSI / IEEE C57.12.00 – 1987 *General Requirements for Liquid Immersed Power Transformers* and ANSI / IEEE C57.92 – 1981 *Loading Mineral Oil Immersed Power Transformers*. Big Rivers plans and operates power transformers on its system whose voltage ratings fall within the bulk transmission level (100 kV and above high side). Big Rivers has established that the normal and emergency rating for power transformers shall be the highest nameplate rating with all cooling equipment operating. For most of the Big Rivers transformers, this is the maximum FOA or FA (OFAF or ONAF) 65 degree Celsius nameplate rating with all cooling equipment operating. In the absence of any or all stages of cooling equipment, the rating is the maximum nameplate rating associated with that level of cooling. For the six 345/161 kV power transformers the rating is 420 MVA (a significant increase above the nameplate value as determined by the manufacturer, General Electric Company). However, if these units are operated in a step-up mode (direction of flow from 161 kV to 345 kV system), either the high side voltage must be limited to 345 kV (1.0 per unit) or the unit rating reverts back to the 336 MVA nameplate value.

<u>High Voltage Bus</u>

Big Rivers purchases, operates and maintains transmission voltage (100 kV and above) High Voltage Bus in accordance with ANSI / IEEE Standard 605 – 1987 *Guide for Design of Substation Rigid-Bus Structures*. Table B3 of Standard 605 Appendix B lists *Bus Conductor Ampacity - Aluminum Tubular Bus –Schedule 40 AC Ampacity (53% Conductivity)*. Big Rivers utilizes this table assuming a normal oxidized surface with emissivity of 0.50, with sun, in still but unconfined air, with a 30 degree C temperature rise over 40 degrees C ambient.

Power Circuit Breakers

Big Rivers purchases, operates and maintains transmission voltage (100 kV and above) Power Circuit Breakers in accordance with ANSI C37.06 *AC HV Circuit Breakers – Preferred Ratings and Related Required Capabilities.* Table 3 of C37.06 lists *Preferred Ratings for Outdoor Circuit Breakers 121 kV and Above.* Big Rivers does not derate PCBs based on weather conditions or previous loading conditions. PCBs on the Big Rivers transmission system are equipped with Bushing Current Transformers (BCTs). These BCTs are usually Multi-ratio and sometimes tapped at less than the full continuous current rating of the PCB. In these situations the PCB is derated to the Multi-Ratio BCT tap value. The Thermal Rating Factor of the BCT is used where applicable. Jumpers connecting PCBs to other elements of the transmission facility are sized with current carrying capacity greater than the PCB itself.

Protective Relaying

Big Rivers purchases, operates and maintains transmission facilities protective relays in accordance with IEEE C37 Guides and Standards for Protective Relaying Systems. The protective relaying schemes are specified and their settings are calculated such that neither limits the capacity of the transmission facility. For impedance relays of networked transmission facilities, 0.85 p.u. voltage is utilized in the rating calculation.

Current Transformers

Big Rivers purchases, operates, and maintains current transformers in accordance with ANSI/IEEE C57.13 – Standard Requirements for Instrument Transformers. Current transformers are operated up-to a maximum current level equal to the nameplate rating multiplied by any continuous-thermal-current rating factor (RF).

X. LINE SWITCH CRITERIA

The following documents the criteria applied in the planning, design, construction, and operation of line switches on Big Rivers' transmission system. The focus here is on the 69 kV system serving all of the rural and many of the dedicated (customer) delivery point substations of our three member cooperatives. The following functional objectives and standards define the 69 kV transmission line switching practices currently in effect.

For loop or dual feed line sections:

1. Line sectionalizing switches shall be employed at both ends of every line section.

2. Full load interrupting capability shall exist at a minimum on one end of every line section.

3. Load interrupting capability shall exist on the other end line sectionalizing switch of sufficient rating to safely de-energize the line (i.e. break the line charging current).

4. Remote control operational equipment shall be added to full load interrupting switches to solve service reliability problems and typically shall be applied at three-way junction points to provide alternate power supply switching arrangements for a number of distribution stations.

For radial line sections:

1. Line sectionalizing switches shall be applied for tap lines greater than 4.0 miles in length or where continuous service is essential to other stations supplied off the radial line section being tapped.

2. Line sectionalizing switches shall have sufficient load interrupting capability to safely de-energize the line (i.e. minimum capability equal to or greater than line charging current).

XI. CRITICAL FACILITIES

While no critical facilities have been identified, Big Rivers has internal flowgates that can limit the ability to import and export power. The state estimator/on-line power flow model is used to monitoring and study each flowgate as well as all other bulk system facilities. Big Rivers recognizes the IROL and SOL definitions and processes as documented in *Transmission Reliability Order of Curtailment* (attached as Appendix F).

XII. COORDINATION/COMMUNICATION

As stated previously, transmission studies should be properly coordinated with neighboring transmission systems and reliability organizations. Specifically, all potentially impacted neighbors (E.ON. U.S., Hoosier Energy, MISO, SIPC, SPP, TVA, and Vectren) should be invited to participate (or allowed to review and provide input regarding planned improvements) in all generator interconnection studies and significant transmission interconnection or modification studies. Modeling information, study assumptions, alternatives considered, study results, and proposed transmission plans should be communicated to these entities and any other interested transmission planning entity or transmission owner/provider. After all internal and external approvals (including regulatory approvals) are obtained, the proposed facilities will be included in the MMWG model building process and communicated to the TVA Reliability Coordinator. A log of communication (email history is acceptable) should be maintained as part of the study process. All documentation will be maintained for a minimum of five years.

As part of this communication/coordination effort, Big Rivers participates in near-term and long-term SERC study groups. Internal seasonal assessments will be made available to the reliability coordinator and others as requested.

In addition to study coordination and communication, facility ratings and methodologies must be properly coordinated and communicated. As previously stated, all transmission system ratings have been provided to the TVA reliability coordinator. Any rating changes are communicated to the TVA reliability coordinator and interested neighboring systems as the changes occur. In addition, up-to-date ratings are included in the MMWG models available to most interested parties. Additional rating details will be made available to neighboring utilities and other interested parties as needed. Interconnection ratings are coordinated once per year as part of the MMWG model building process. Additional coordination is completed via email as necessary.

As an additional communication and coordination effort, this document and Big Rivers documents relating to TTC/ATC/TRM/CBM will be provided to the reliability coordinator when any update is made (prior to effective date or implementation of any significant change). Upon request, or as appropriate, these documents will also be made available to neighboring utilities and other interested parties. Any comments or concerns received will be addressed in a written response within 45 calendar days of receipt.

XIII. TRANSFER CAPABILITY

Transfer capabilities are calculated, coordinated, and communicated to others through various means. The criteria described in this document are consistently applied in all transfer capability studies (near-term operating horizon and longer-term planning horizon). In all study processes, Big Rivers will respect all system operating limits (internal and external). Any variations from the criteria will be documented in the appropriate study report.

Big Rivers participates in SERC near-term, long-term, and OASIS study groups. These studies include all existing and planned facilities in the Big Rivers system. The Big Rivers loads will be consistent with the Big Rivers corporate load forecast for the study period. Only those transactions with a firm contract will be included in the model (after proper coordination with the other entity). Generation dispatch should reflect past experience. Reliability margins (CBM, TRM, etc.) are not included in these models. Appropriate summer and winter ratings will be modeled. Various import and export scenarios are studied. Currently, Big Rivers imports from TVA and SIPC as well as exports to LGEE, SIPC, and TVA are studied. Additional transfers will be added as necessary. Study results are available to all SERC members and other appropriate entities.

Internal studies also consider transfer capabilities. Internal seasonal assessments generally begin with all generation except Reid 1 and Reid CT dispatched. This net export base model gives an indication of expected system performance with most generation dispatched. Generation outages (single and multiple units) provide an indication of performance under import conditions. Summer assessments generally include a study of north to south transfers. The seasonal assessment study reports are provided internally to system operations and are also made available to the reliability coordinator. Additionally, the report will also be made available to neighboring utilities and other interested parties.

Big Rivers TTC, AFC, and ATC calculations are performed by TVA. These calculations are described in the Big Rivers document PL-MOD-0001 *AFC/ATC Calculation Procedures*. This document and resulting ATC values are available through the Big Rivers OASIS.

APPENDIX A:

Voltage Level Criteria Guideline

APPENDIX A: VOLTAGE LEVEL CRITERIA GUIDELINE

In 1989, Big Rivers adopted a voltage criteria for use as a guideline in planning for the design and operation of its transmission system. This criteria was based on service voltage requirements defined by the Kentucky Public Service Commission (PSC) and the Rural Utilities Service (RUS). This criteria was defined as the acceptable voltage level at the unregulated distribution and/or industrial substation low-voltage buses (served from Big Rivers' 69 kV transmission system). This criteria, summarized below, includes a Range A criteria which is applied during normal system operations (all transmission elements in service) and a Range B criteria that is applied during single contingencies.

Transmission System Conditions	Minimum Bus Voltage	Maximum Bus Voltage
Range A: Normal System Operations	95.0%	105.0%
Range B: Single Contingency Conditions	91.7%	105.8%

A second criteria, which applies to Big Rivers' 161 kV transmission system, has also been adopted. The development of this criteria also involved a review of PSC and RUS voltage requirements. This criteria was based on maintaining acceptable voltage levels on the low-side unregulated bus at all 161 kV delivery points. The Range A and Range B criteria apply to the same system conditions as defined for the 69 kV system. These criteria limits are defined below:

Transmission System Conditions	Minimum Bus Voltage	Maximum Bus Voltage
Range A: Normal System Operations	95.0%	105.0%
Range B: Single Contingency Conditions	90.0%	105.0%

Both criteria, as previously defined, were applied to the low-side unregulated buses. For transmission planning purposes, a voltage criteria that applies to the high side buses was developed. When reflecting the voltage criteria to the high side bus, transformer regulation (voltage drop across the transformer) and the boost supplied by the no load tap changers was considered. Low-side voltage regulators or load tap changers were not considered.

When developing the low voltage criteria limit for the 69 kV delivery points, it was assumed that the transformer would be set on their mid-tap. In most cases, the mid-tap is 67 kV. With a 67 kV nominal tap, the transformer regulation is offset. In the few instances that the transformer mid-tap is 69 kV, it is assumed that the fixed tap could be changed to a boost position (which would offset the transformer regulation). When calculating the transformer regulation, it was assumed that the transformer was two-thirds loaded with a 90% power factor.

When developing the low voltage criteria limit for the 161 kV delivery points, it was assumed that the transformer would be set with one fixed tap of boost. It was also assumed that the transformers would be two-thirds loaded (with the corresponding transformer regulation). If a customer taking service from the 161 kV system has special needs which a 90% to 105% voltage criteria fail to meet, an LTC may be used to maintain acceptable voltage levels under both normal and single-contingency conditions.

To protect against damage due to high voltages during off-peak times or instances when a transformer may be unloaded (little or no transformer regulation would be expected), the high voltage limits were not changed when the criteria was reflected to the high-side bus.

The high-side voltage ranges included below were found to be necessary to maintain the low-side voltage criteria. However, the operator should not wait until voltages fall outside of the accepted range to take action. System operators should take all available actions to maintain voltages between .95 P.U. and 1.05 P.U. This includes, but is not limited to, switching capacitors and reactors, changing the voltage schedules at the generator buses, and utilizing load tap changers.

Transmission System Conditions	**69kV Bus Voltage**		**161 kV Bus Voltage**	
	Minimum	**Maximum**	**Minimum**	**Maximum**
Range A: Normal System Operations	95.0%	105.0%	95.0%	105.0%
Range B: Single Contingency Conditions	91.7%	105.8%	92.0%	105.0%

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APPENDIX B:

Load Distribution and Modeling

LOAD DISTRIBUTION AND MODELING

A key part of the database development is load modeling. Big Rivers prepares a load forecast on an annual basis. This load forecast is built from individual member cooperative load forecast forecasts. The loads modeled in the power flow database should be consistent with the Big Rivers coincident peak load forecast with the loads distributed among all of the member cooperative substations.

Regression techniques have been used to help distribute the loads on an individual substation basis. Historical substation data is collected for each delivery point. The data series for each substation is regressed on time using a simple linear curve equation. In addition, the load at each substation is forecasted by applying the system average growth rate (from the cooperative forecast) to an average of the two most recent years coincident peak data. These two forecast values, along with input from each distribution cooperative and engineering judgment, are used to create a forecasted load for each delivery point. These forecasts are uniformly ratioed to match the overall Big Rivers coincident peak forecast. This method allows the historical trends to be reflected in the load distribution while consistency with the overall load forecast is maintained.

Industrial customers with dedicated delivery points are forecasted by the individual industries. As part of the load forecast preparation, all large industrial customers are contacted and asked to supply a forecast for their energy needs and expected peak demand. These forecasts are used to model these individual customers.

HMP&L personnel should provide HMP&L load. This load should be modeled in a separate area in the detailed power flow cases. However, in the MMWG models, the HMP&L take (HMP&L load supplied from Station 2) should be modeled as load at Henderson County, Reid 161 kV, and Reid 69 kV.

Power factors for each load are also based on historical data. The actual power factors at each delivery point during the most recent coincident peak for both summer and winter seasons are used. Since this historical power factor information is generally based on low-side meter data, adjustments are necessary when modeling loads on the high-side of the distribution transformers. This adjustment is typically accomplished by reducing the power factors by 98% to 99%. The percent adjustment is calculated on a seasonal basis for each distribution cooperative by modeling a distribution transformer loaded at 50% with a low-side power factor equal to the system average power factor during the most recent coincident peak. Loads metered on the high-side need no adjustment (this includes: Kimberly-Clark, Lodestar, P&M, Patriot Coal, Hopkins County Coal, ALCAN, and Century).

Appendix C:

Transformer Information

This information is available from a separate document.

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Appendix D:

Shunt Information

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This information is available from a separate document.

Appendix E:

Loadability Tables

Big Rivers Electric operates transmission voltage (100 kV and above) facilities according to the attached Loadability Table. The table identifies various limiting elements on each transmission line terminal. The lines are sorted in rows according to voltage with 345 kV lines listed first.

Equipment and conductor ratings exclusive of Current Transformer Ratio limitations are listed in the first set of columns. These columns indicate that the limiting component is usually the conductor. However, both 345 kV lines are limited by 1600 A line disconnect switches. Bryan Rd, Meade County and Newman 161 kV radial lines are limited by their transformation capacity. The Hardinsburg 138 kV Cloverport line is limited by a line trap.

Limiting Current Transformer Ratios are identified in the next set of columns. CTRs are only listed if they are set lower than the conductor would allow.

The next four columns check all components of the transmission facility and report the minimum rating. Listed are the Summer and Winter MVA and Amp ratings for each transmission line.

This information is available from a separate document.

Appendix F

Transmission Reliability Order of Curtailment

This information is available from the TVA document titled:

Transmission Reliability Order of Curtailment

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APPENDIX B: 2015 SUMMER PEAK STUDY RESULTS

Appendix B: Voltages

Base

Contingent Element	Monitored Facility	Case A Pre-Cont.	Case A Post-Cont.	Case B Pre-Cont.	Case B Post-Cont.	Case C Pre-Cont.	Case C Post-Cont.	Case D Pre-Cont.	Case D Post-Cont.
Hancock-Coleman EHV	Hancock Co	1.032	0.923	1.033	0.931	1.034	0.931	1.032	0.930
	Daviess Co	1.011	0.943	1.014	0.952	1.015	0.952	1.013	0.951
	Ensor	1.018	0.936	1.020	0.944	1.021	0.943	1.019	0.943
	Newman	0.999	0.930	1.002	0.939	1.003	0.939	1.001	0.938

Wilson Unit Outage

Contingent Element	Monitored Facility	Case A Pre-Cont.	Case A Post-Cont.	Case B Pre-Cont.	Case B Post-Cont.	Case C Pre-Cont.	Case C Post-Cont.	Case D Pre-Cont.	Case D Post-Cont.
Hancock-Coleman EHV	Hancock Co	1.026	0.910	1.030	0.925	1.031	0.925	1.028	0.923
	Daviess Co	1.005	0.930	1.010	0.945	1.011	0.945	1.008	0.943
	Ensor	1.012	0.923	1.017	0.938	1.018	0.938	1.015	0.936
	Newman	0.993	0.917	0.998	0.932	0.999	0.932	0.996	0.930
Reid-Daviess Co	Daviess Co	1.005	0.953						
	Newman	0.993	0.940					0.996	0.946

Coleman 1 Unit Outage

Contingent Element	Monitored Facility	Case A Pre-Cont.	Case A Post-Cont.	Case B Pre-Cont.	Case B Post-Cont.	Case C Pre-Cont.	Case C Post-Cont.	Case D Pre-Cont.	Case D Post-Cont.
Hancock-Coleman EHV	Hancock Co	1.018	0.921	1.022	0.930	1.025	0.930	1.020	0.929
	Daviess Co	1.002	0.940	1.006	0.950	1.008	0.950	1.004	0.949
	Ensor	1.007	0.934	1.011	0.943	1.013	0.943	1.009	0.942
	Newman	0.990	0.927	0.994	0.938	0.996	0.938	0.992	0.936
Reid-Daviess Co	Daviess Co	1.002	0.927	1.006	0.937	1.008	0.948	1.004	0.932
	Newman	0.990	0.914	0.994	0.925	0.996	0.935	0.992	0.919
Coleman-Daviess EHV	Newtonville	1.020	0.933					1.026	0.965
	Coleman 161	1.019	0.927	1.025	0.953			1.022	0.957
	Hancock Co	1.018	0.929	1.022	0.953			1.02	0.956
	National Aluminum	1.021	0.934	1.026	0.958			1.024	0.961
	Daviess Co	1.002	0.948						
	Ensor	1.007	0.941	1.011	0.959				
	Newman	0.990	0.935						

Appendix B: Voltages

Green 2 Unit Outage

Contingent Element	Monitored Facility	Case A Pre-Cont.	Case A Post-Cont.	Case B Pre-Cont.	Case B Post-Cont.	Case C Pre-Cont.	Case C Post-Cont.	Case D Pre-Cont.	Case D Post-Cont.
Hancock-Coleman EHV	Hancock Co	1.032	0.913	1.034	0.929	1.035	0.929	1.033	0.927
	Daviess Co	1.012	0.933	1.016	0.949	1.016	0.949	1.014	0.947
	Ensor	1.019	0.926	1.021	0.942	1.022	0.942	1.020	0.940
	Newman	1.000	0.920	1.004	0.936	1.005	0.936	1.003	0.934

Paradise 1 Unit Outage

Contingent Element	Monitored Facility	Case A Pre-Cont.	Case A Post-Cont.	Case B Pre-Cont.	Case B Post-Cont.	Case C Pre-Cont.	Case C Post-Cont.	Case D Pre-Cont.	Case D Post-Cont.
Hancock-Coleman EHV	Hancock Co	1.031	0.923	1.033	0.931	1.033	0.930	1.032	0.929
	Daviess Co	1.011	0.943	1.013	0.951	1.014	0.951	1.012	0.950
	Ensor	1.018	0.936	1.019	0.943	1.020	0.943	1.018	0.942
	Newman	0.999	0.930	1.001	0.938	1.002	0.938	1.000	0.937

Coleman 1 and 2 Unit Outage

Contingent Element	Monitored Facility	Case A Pre-Cont.	Case A Post-Cont.	Case B Pre-Cont.	Case B Post-Cont.	Case C Pre-Cont.	Case C Post-Cont.	Case D Pre-Cont.	Case D Post-Cont.
Hancock-Coleman EHV	Hancock Co	0.989	0.915	0.998	0.927	1.004	0.928	0.994	0.926
	Daviess Co	0.983	0.935	0.990	0.948	0.995	0.948	0.988	0.946
	Ensor	0.985	0.928	0.992	0.940	0.997	0.941	0.990	0.939
	Newman	0.971	0.922	0.978	0.935	0.983	0.935	0.975	0.933
Reid-Daviess Co	Daviess Co	0.983	0.888	0.990	0.902	0.995	0.916	0.988	0.893
	Ensor	0.985	0.919	0.992	0.933	0.997	0.947	0.990	0.924
	Newman	0.971	0.874	0.978	0.889	0.983	0.903	0.975	0.879
Coleman-Daviess EHV	Newtonville	0.990	0.851	1.003	0.871			1.000	0.871
	Coleman 161	0.987	0.829	0.997	0.849			0.993	0.849
	Hancock Co	0.989	0.835	0.998	0.854			0.994	0.854
	National Aluminum	0.993	0.84	1.001	0.859			0.998	0.859
	Daviess Co	0.983	0.886	0.99	0.898			0.988	0.899
	Ensor	0.985	0.862	0.992	0.877			0.990	0.878
	Newman	0.971	0.872	0.978	0.885			0.975	0.885

Appendix B: Voltages

Wilson and Green 2 Unit Outage

		Case A		Case B		Case C		Case D	
Contingent Element	**Monitored Facility**	**Pre-Cont.**	**Post-Cont.**	**Pre-Cont.**	**Post-Cont.**	**Pre-Cont.**	**Post-Cont.**	**Pre-Cont.**	**Post-Cont.**
Hancock-Coleman EHV	Hancock Co	1.024	0.890	1.031	0.920	1.032	0.919	1.029	0.917
	Daviess Co	1.002	0.912	1.012	0.939	1.013	0.939	1.010	0.936
	Ensor	1.010	0.903	1.018	0.933	1.019	0.932	1.016	0.929
	Newman	0.990	0.899	1.000	0.926	1.001	0.926	0.998	0.923
Reid-Daviess Co	Daviess Co	1.002	0.951						
	Newman	0.990	0.938					0.998	0.948

Base with CSN Load Addition

		Case A		Case B		Case C		Case D	
Contingent Element	**Monitored Facility**	**Pre-Cont.**	**Post-Cont.**	**Pre-Cont.**	**Post-Cont.**	**Pre-Cont.**	**Post-Cont.**	**Pre-Cont.**	**Post-Cont.**
Hancock-Coleman EHV	Case Diverged							No Issues	
Reid-Daviess Co	Daviess Co	1.006	0.944	1.008	0.952	1.010	0.957		
	Newman	0.994	0.931	0.996	0.939	0.998	0.944		

No Century

		Case A		Case B		Case C	
Contingent Element	**Monitored Facility**	**Pre-Cont.**	**Post-Cont.**	**Pre-Cont.**	**Post-Cont.**	**Pre-Cont.**	**Post-Cont.**
Hancock-Coleman EHV	Hancock Co	1.069	0.934	1.069	0.939	1.066	0.938
	Daviess Co	1.039	0.956	1.040	0.960	1.038	0.960
	Ensor	1.048	0.947	1.048	0.952	1.046	0.951
	Newman	1.027	0.943	1.028	0.948	1.027	0.947

No Smelters with New Hardinsburg-Paradise Looped through Wilson and CSN Load (Hancock Service)

		Case A		Case B		Case C	
Contingent Element	**Monitored Facility**	**Pre-Cont.**	**Post-Cont.**	**Pre-Cont.**	**Post-Cont.**	**Pre-Cont.**	**Post-Cont.**
Hancock-Coleman EHV	Hancock Co	1.065	0.784	1.064	0.793	1.062	0.792
	CSN	1.064	0.783	1.063	0.793	1.061	0.791
	Daviess Co	1.049	0.861	1.047	0.869	1.046	0.868
	Ensor	1.051	0.822	1.049	0.831	1.048	0.830
	Newman	1.038	0.847	1.036	0.855	1.035	0.854

Appendix B: Voltages

Case C Green 1 and 2 and HMPL 1 Outaged		W/Out AB Brown to Reid EHV			
Contingent Element	Monitored Element	Pre-Cont.	Post-Cont.	Pre-Cont.	Post-Cont.
Wilson-Reid EHV	Hopkins Co	1.002	0.912		
	Reid 161	1.002	0.877		
	Daviess Co	0.992	0.911		
	Henderson Co 161	0.986	0.885		
	Henderson Co 138	0.980	0.909		
	Newman	0.993	0.897		
Hancock-Coleman EHV	Hopkins Co	1.002	0.952		
	Reid 161	1.002	0.933		
	Hancock Co	1.027	0.781	1.033	0.873
	Daviess Co	0.992	0.814	1.005	0.897
	Ensor	1.007	0.797	1.016	0.887
	Henderson Co 161	0.986	0.932		
	Newman	0.993	0.799	0.993	0.883

APPENDIX C: PRESENT WORTH ANALYSES

PROPOSED WILSON TO HARDINSBURG/PARADISE 161 KV 3-TERMINAL (2008)

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-2

	YEAR	TRANS. INVESTMENT 2008 $'s	TRANS. $ INFLATED 3.00%	SUBSTATION INVESTMENT 2008 $'s	SUB $ INFLATED 3.00%	TRANS. DEPR 2.86%	SUBSTATION DEPR 2.22%	INTEREST 5.75%	TRANS. O&M 6.63%	STATION O&M 4.30%	ANNUAL COST IN NOM. $	PRESENT WORTH (2008)
1	2008	$5,800,000	$5,800,000	$1,800,000	$1,800,000	$0	$0	$437,000	$384,540	$77,400	$898,940	$898,940
2	2009	$0	$0	$0	$0	$165,880	$39,960	$437,000	$384,540	$77,400	$1,104,780	$1,044,709
3	2010	$0	$0	$0	$0	$165,880	$39,960	$425,164	$373,542	$75,682	$1,080,228	$965,950
4	2011	$0	$0	$0	$0	$165,880	$39,960	$413,328	$362,544	$73,963	$1,055,676	$892,667
5	2012	$0	$0	$0	$0	$165,880	$39,960	$401,493	$351,546	$72,245	$1,031,124	$824,498
6	2013	$0	$0	$0	$0	$165,880	$39,960	$389,657	$340,549	$70,527	$1,006,572	$761,102
7	2014	$0	$0	$0	$0	$165,880	$39,960	$377,821	$329,551	$68,809	$982,020	$702,163
8	2015	$0	$0	$0	$0	$165,880	$39,960	$365,985	$318,553	$67,090	$957,468	$647,384
9	2016	$0	$0	$0	$0	$165,880	$39,960	$354,149	$307,555	$65,372	$932,917	$596,485
10	2017	$0	$0	$0	$0	$165,880	$39,960	$342,314	$296,557	$63,654	$908,365	$549,208
11	2018	$0	$0	$0	$0	$165,880	$39,960	$330,478	$285,559	$61,935	$883,813	$505,308
12	2019	$0	$0	$0	$0	$165,880	$39,960	$318,642	$274,562	$60,217	$859,261	$464,559
13	2020	$0	$0	$0	$0	$165,880	$39,960	$306,806	$263,564	$58,499	$834,709	$426,747
14	2021	$0	$0	$0	$0	$165,880	$39,960	$294,970	$252,566	$56,781	$810,157	$391,674
15	2022	$0	$0	$0	$0	$165,880	$39,960	$283,135	$241,568	$55,062	$785,605	$359,153
16	2023	$0	$0	$0	$0	$165,880	$39,960	$271,299	$230,570	$53,344	$761,053	$329,010
17	2024	$0	$0	$0	$0	$165,880	$39,960	$259,463	$219,572	$51,626	$736,501	$301,084
18	2025	$0	$0	$0	$0	$165,880	$39,960	$247,627	$208,574	$49,908	$711,949	$275,222
19	2026	$0	$0	$0	$0	$165,880	$39,960	$235,791	$197,577	$48,189	$687,397	$251,282
20	2027	$0	$0	$0	$0	$165,880	$39,960	$223,956	$186,579	$46,471	$662,845	$229,132
21	2028	$0	$0	$0	$0	$165,880	$39,960	$212,120	$175,581	$44,753	$638,293	$208,647
22	2029	$0	$0	$0	$0	$165,880	$39,960	$200,284	$164,583	$43,034	$613,742	$189,713
23	2030	$0	$0	$0	$0	$165,880	$39,960	$188,448	$153,585	$41,316	$589,190	$172,221
24	2031	$0	$0	$0	$0	$165,880	$39,960	$176,612	$142,587	$39,598	$564,638	$156,071
25	2032	$0	$0	$0	$0	$165,880	$39,960	$164,777	$131,590	$37,880	$540,086	$141,167
26	2033	$0	$0	$0	$0	$165,880	$39,960	$152,941	$120,592	$36,161	$515,534	$127,423
27	2034	$0	$0	$0	$0	$165,880	$39,960	$141,105	$109,594	$34,443	$490,982	$114,756
28	2035	$0	$0	$0	$0	$165,880	$39,960	$129,269	$98,596	$32,725	$466,430	$103,090
29	2036	$0	$0	$0	$0	$165,880	$39,960	$117,433	$87,598	$31,006	$441,878	$92,353
30	2037	$0	$0	$0	$0	$165,880	$39,960	$105,598	$76,600	$29,288	$417,326	$82,479
30 YR.TOTAL		$5,800,000		$1,800,000		$4,810,520	$1,158,840	$8,304,665	$7,071,075	$1,624,378	$22,969,479	$12,804,198
AVERAGE YEARLY COST OVER 30 YEARS						$160,351	$38,628	$276,822	$235,703	$54,146	$765,649	$426,807

Timing of upgrades and intalled cost in 2006 dollars:

13 mile 161 kV Wilson to Hardinsburg/Paradise tap line (2008) - $4,700,000
161 kV transmission line upgrade from new tap point to Paradise (2008) - $1,100,000
161 kV Wilson terminal addition (2008) - $1,700,000
161 kV Paradise terminal upgrade (2008) - $100,000

Inflation: 3% per year.
Transmission depreciation: 2.86% calculated from an average of 3.24% for poles and 2.47% for lines from Big Rivers 1997 depreciation study.
Substation depreciation: 2.22% from Big Rivers 1997 depreciation study.
Interest: 5.75% RUS note (cost of debt).
O&M based on 5 year average (2001-2005): 6.63% for transmission and 4.30% for substation.
Present Worth calculated with 5.75% discount rate - RUS note.

21 MILE WILSON TO PARADISE (TVA) 161 KV INTERCONNECTION (2008)

YEAR		TRANS. INVESTMENT 2008 $'s	TRANS. $ INFLATED 3.00%	SUBSTATION INVESTMENT 2008 $'s	SUB $ INFLATED 3.00%	TRANS. DEPR 2.86%	SUBSTATION DEPR 2.22%	INTEREST 5.75%	TRANS. O&M 6.63%	STATION O&M 4.30%	ANNUAL COST IN NOM. $	PRESENT WORTH (2008)
1	2008	$7,400,000	$7,400,000	$3,200,000	$3,200,000	$0	$0	$609,500	$490,620	$51,600	$1,151,720	$1,151,720
2	2009	$0	$0	$0	$0	$211,640	$71,040	$609,500	$490,620	$51,600	$1,434,400	$1,356,407
3	2010	$0	$0	$0	$0	$211,640	$71,040	$593,246	$476,588	$50,454	$1,402,969	$1,254,548
4	2011	$0	$0	$0	$0	$211,640	$71,040	$576,992	$462,557	$49,309	$1,371,537	$1,159,756
5	2012	$0	$0	$0	$0	$211,640	$71,040	$560,738	$448,525	$48,163	$1,340,106	$1,071,563
6	2013	$0	$0	$0	$0	$211,640	$71,040	$544,484	$434,493	$47,018	$1,308,675	$989,532
7	2014	$0	$0	$0	$0	$211,640	$71,040	$528,230	$420,461	$45,872	$1,277,243	$913,254
8	2015	$0	$0	$0	$0	$211,640	$71,040	$511,975	$406,430	$44,727	$1,245,812	$842,345
9	2016	$0	$0	$0	$0	$211,640	$71,040	$495,721	$392,398	$43,581	$1,214,381	$776,447
10	2017	$0	$0	$0	$0	$211,640	$71,040	$479,467	$378,366	$42,436	$1,182,949	$715,225
11	2018	$0	$0	$0	$0	$211,640	$71,040	$463,213	$364,334	$41,290	$1,151,518	$658,365
12	2019	$0	$0	$0	$0	$211,640	$71,040	$446,959	$350,303	$40,145	$1,120,086	$605,574
13	2020	$0	$0	$0	$0	$211,640	$71,040	$430,705	$336,271	$38,999	$1,088,655	$556,578
14	2021	$0	$0	$0	$0	$211,640	$71,040	$414,451	$322,239	$37,854	$1,057,224	$511,119
15	2022	$0	$0	$0	$0	$211,640	$71,040	$398,197	$308,207	$36,708	$1,025,792	$468,958
16	2023	$0	$0	$0	$0	$211,640	$71,040	$381,943	$294,176	$35,563	$994,361	$429,871
17	2024	$0	$0	$0	$0	$211,640	$71,040	$365,689	$280,144	$34,417	$962,930	$393,648
18	2025	$0	$0	$0	$0	$211,640	$71,040	$349,434	$266,112	$33,272	$931,498	$360,094
19	2026	$0	$0	$0	$0	$211,640	$71,040	$333,180	$252,081	$32,126	$900,067	$329,024
20	2027	$0	$0	$0	$0	$211,640	$71,040	$316,926	$238,049	$30,981	$868,636	$300,269
21	2028	$0	$0	$0	$0	$211,640	$71,040	$300,672	$224,017	$29,835	$837,204	$273,668
22	2029	$0	$0	$0	$0	$211,640	$71,040	$284,418	$209,985	$28,690	$805,773	$249,072
23	2030	$0	$0	$0	$0	$211,640	$71,040	$268,164	$195,954	$27,544	$774,342	$226,342
24	2031	$0	$0	$0	$0	$211,640	$71,040	$251,910	$181,922	$26,399	$742,910	$205,347
25	2032	$0	$0	$0	$0	$211,640	$71,040	$235,656	$167,890	$25,253	$711,479	$185,966
26	2033	$0	$0	$0	$0	$211,640	$71,040	$219,402	$153,858	$24,108	$680,048	$168,085
27	2034	$0	$0	$0	$0	$211,640	$71,040	$203,148	$139,827	$22,962	$648,616	$151,600
28	2035	$0	$0	$0	$0	$211,640	$71,040	$186,893	$125,795	$21,816	$617,185	$136,410
29	2036	$0	$0	$0	$0	$211,640	$71,040	$170,639	$111,763	$20,671	$585,753	$122,423
30	2037	$0	$0	$0	$0	$211,640	$71,040	$154,385	$97,732	$19,525	$554,322	$109,555
30 YR.TOTAL		$7,400,000		$3,200,000		$6,137,560	$2,060,160	$11,685,835	$9,021,717	$1,082,919	$29,988,191	$16,672,763
AVERAGE YEARLY COST OVER 30 YEARS						$204,585	$68,672	$389,528	$300,724	$36,097	$999,606	$555,759

Timing of upgrades and intalled cost in 2006 dollars:
Wilson 161 kV line terminal (2008) - $1,200,000 (Based on Burns and McDonnell estimate for a Wilson 161 kV line terminal).
Paradise 161 kV line terminal (2008) - $2,000,000
21 mile Wilson to Paradise circuit (2008) - $7,400,000

Inflation: 3% per year.
Transmission depreciation: 2.86% calculated from an average of 3.24% for poles and 2.47% for lines from Big Rivers 1997 depreciation study.
Substation depreciation: 2.22% from Big Rivers 1997 depreciation study.
Interest: 5.75% RUS note (cost of debt).
O&M based on 5 year average (2001-2005): 6.63% for transmission and 4.30% for substation (not including Paradise terminal).
Present Worth calculated with 5.75% discount rate - RUS note.

APPENDIX D: SHORT CIRCUIT STUDY RESULTS

Short Circuit Study Results
2/5/2007
CSB

FAULT CURRENT (AMPS) AT EACH FAULT LOCATION

	ECAR Model without Improvements		ECAR Model with Improvements	
Fault Location	Three Phase	Single Line-to-Ground	Three Phase	Single Line-to-Ground
Wilson 345 kV	11,882	12,196	12,565	12,763
Coleman EHV 345 kV	10,233	10,190	10,318	10,249
Daviess Co. EHV 345 kV	13,070	12,188	13,360	12,374
Reid EHV 345 kV	9,432	9,961	9,645	10,128
Wilson 161 kV	20,096	22,359	24,212	26,217
Coleman EHV 161 kV	23,639	24,621	23,640	24,624
Reid 161 kV	24,907	29,386	25,114	29,580
Hancock County 161 kV	17,775	16,035	17,779	16,039
National Aluminum 161 kV	16,822	15,722	16,805	15,712
Daviess County 161 kV	7,833	6,603	7,850	6,611

APPENDIX E: SENSITIVITY STUDY RESULTS

Appendix E: Voltages

Base					
		Case E		Case F	
Contingent Element	Monitored Element	Pre-Cont.	Post-Cont.	Pre-Cont.	Post-Cont.
Hancock-Coleman EHV	Hancock Co	1.031	0.925	1.031	0.929
	Daviess Co	1.012	0.945	1.012	0.949
	Ensor	1.018	0.938	1.018	0.942
	Newman	1.000	0.932	1.000	0.937

Base					
Coleman 1 Outaged		Case E		Case F	
Contingent Element	Monitored Element	Pre-Cont.	Post-Cont.	Pre-Cont.	Post-Cont.
Coleman-Daviess EHV	Newtonville	1.018	0.923	1.024	0.955
	Skillman	1.024	0.947	1.025	0.970
	Hancock Co	1.016	0.922	1.018	0.948
	Coleman 161	1.018	0.919	1.021	0.947
	National Aluminum	1.020	0.927	1.022	0.953
	Daviess Co	1.002	0.945		
	Ensor	1.007	0.936	1.007	0.956
	Newman	0.990	0.932	0.991	0.948
Hancock-Coleman EHV	Daviess Co	1.002	0.942	1.003	0.948
	Ensor	1.007	0.936	1.007	0.940
	Newman	0.990	0.929	0.991	0.935
Reid-Daviess Co	Daviess Co	1.002	0.923	1.003	0.928
	Ensor	1.007	0.954		
	Newman	0.990	0.910	0.991	0.915

Appendix E: Voltages

Base Wilson Outaged Contingent Element	Monitored Element	Case E Pre-Cont.	Case E Post-Cont.	Case F Pre-Cont.	Case F Post-Cont.
Hancock-Coleman EHV	Hancock Co	1.025	0.915	1.027	0.923
	Daviess Co	1.006	0.934	1.008	0.943
	Ensor	1.012	0.927	1.013	0.935
	Newman	0.994	0.921	0.996	0.930
Reid-Daviess Co	Daviess Co	1.006	0.951		
	Newman	0.994	0.939	0.996	0.945

Base Green 2 Outaged Contingent Element	Monitored Element	Case E Pre-Cont.	Case E Post-Cont.	Case F Pre-Cont.	Case F Post-Cont.
Hancock-Coleman EHV	Hancock Co	1.032	0.916	1.032	0.926
	Daviess Co	1.012	0.936	1.014	0.946
	Ensor	1.019	0.929	1.020	0.939
	Newman	1.001	0.923	1.002	0.933

Appendix E: Voltages

Base Paradise 1 Outaged Contingent Element	Monitored Element	Case E Pre-Cont.	 Post-Cont.	Case F Pre-Cont.	 Post-Cont.
Hancock-Coleman EHV	Hancock Co	1.030	0.924	1.029	0.928
	Daviess Co	1.011	0.944	1.010	0.948
	Ensor	1.017	0.937	1.016	0.940
	Newman	0.999	0.931	0.998	0.936
Reid-Daviess Co	Daviess Co				
	Newman	0.999	0.949	0.998	0.949

Base Coleman 1 and 2 Outaged Contingent Element	Monitored Element	Case E Pre-Cont.	 Post-Cont.	Case F Pre-Cont.	 Post-Cont.
Coleman-Daviess EHV	Newtonville	0.986	0.849	0.996	0.868
	Meade Co	0.986	0.915	0.986	0.926
	Skillman	1.000	0.869	1.001	0.885
	Hancock Co	0.987	0.835	0.991	0.852
	Coleman 161	0.985	0.829	0.990	0.847
	National Aluminum	0.991	0.840	0.995	0.857
	Daviess Co	0.983	0.888	0.986	0.898
	Ensor	0.985	0.863	0.987	0.876
	Newman	0.971	0.874	0.973	0.884
Hancock-Coleman EHV	Hancock Co	0.987	0.918	0.991	0.925
	Daviess Co	0.983	0.937	0.986	0.945
	Ensor	0.985	0.930	0.987	0.938
	Newman	0.971	0.925	0.973	0.932
Reid-Daviess Co	Hancock Co	0.987	0.942	0.991	0.949
	Coleman 161	0.985	0.946		
	Daviess Co	0.983	0.883	0.986	0.889
	Ensor	0.985	0.913	0.987	0.919
	Newman	0.971	0.869	0.973	0.876
Wilson-Daviess EHV	Coleman 161			0.990	0.949
	Newman			0.973	0.946

Appendix E: Voltages

Base (MW loads ratioed at 60%; Mvar loads ratioed at 50%) Coleman 1 and 2 Outaged		Case G		Case H	
Contingent Element	Monitored Element	Pre-Cont.	Post-Cont.	Pre-Cont.	Post-Cont.
Coleman-Daviess EHV	Newtonville	1.014	0.891	1.021	0.899
	Meade Co	1.012	0.960		
	Skillman	1.024	0.919	1.026	0.926
	Hancock Co	1.013	0.889	1.016	0.896
	Coleman 161	1.010	0.880	1.014	0.888
	National Aluminum	1.016	0.891	1.018	0.899
	Daviess Co	1.017	0.939	1.019	0.945
	Ensor	1.015	0.920	1.017	0.926
	Newman	1.005	0.926	1.008	0.932

3 terminal to Wilson, New Hardinsburg, and Paradise		Case F	
Contingent Element	Monitored Element	Pre-Cont.	Post-Cont.
Hancock-Coleman EHV	Hancock Co	1.032	0.929
	Daviess Co	1.012	0.949
	Ensor	1.018	0.941
	Newman	1.000	0.936

3 terminal to Wilson, New Hardinsburg, and Paradise Coleman 1 Outaged		Case F	
Contingent Element	Monitored Element	Pre-Cont.	Post-Cont.
Coleman-Daviess EHV	Newtonville	1.025	0.960
	Skillman	1.026	0.975
	Hancock Co	1.019	0.953
	Coleman 161	1.021	0.953
	National Aluminum	1.022	0.958
Hancock-Coleman EHV	Hancock Co	1.019	0.927
	Daviess Co	1.003	0.948
	Ensor	1.008	0.940
	Newman	0.991	0.935
Reid-Daviess Co	Daviess Co	1.003	0.929
	Newman	0.991	0.916

Appendix E: Voltages

3 terminal to Wilson, New Hardinsburg, and Paradise
Wilson Outaged

		Case F	
Contingent Element	**Monitored Element**	**Pre-Cont.**	**Post-Cont.**
Hancock-Coleman EHV	Hancock Co	1.028	0.924
	Daviess Co	1.008	0.943
	Ensor	1.014	0.936
	Newman	0.996	0.931
Reid-Daviess Co	Daviess Co	1.008	0.958
	Newman	0.996	0.946

3 terminal to Wilson, New Hardinsburg, and Paradise
Green 2 Outaged

		Case F	
Contingent Element	**Monitored Element**	**Pre-Cont.**	**Post-Cont.**
Hancock-Coleman EHV	Hancock Co	1.033	0.926
	Daviess Co	1.014	0.945
	Ensor	1.020	0.938
	Newman	1.002	0.932

3 terminal to Wilson, New Hardinsburg, and Paradise
Paradise 1 Outaged

		Case F	
Contingent Element	**Monitored Element**	**Pre-Cont.**	**Post-Cont.**
Hancock-Coleman EHV	Hancock Co	1.030	0.926
	Daviess Co	1.010	0.947
	Ensor	1.016	0.939
	Newman	0.998	0.934

Appendix E: Voltages

3 terminal to Wilson, New Hardinsburg, and Paradise Green River 4 Outaged			
		Case F	
Contingent Element	Monitored Element	Pre-Cont.	Post-Cont.
Hancock-Coleman EHV	Hancock Co	1.031	0.927
	Daviess Co	1.011	0.948
	Ensor	1.019	0.940
	Newman	0.999	0.935

	Description	Type	Base Period 2013
1	FGD, Ductwork, Stack and Module Lay-Up	FDE	$ 180,000
2	Ductwork, Dead Air, Boiler/Boiler Aux. Equipment	FDE	181,000
3	Fans, ductwork, steam coils, trap systems	FDE	55,000
4	Buners, fuel oil system, pulverizer, ductwork	FDE	25,000
5	Turbine Generator	FDE	45,000
6	Cooling Tower fill, basin, acid skid	FDE	-
7	Total Base Period		486,000

There are no layup costs on an annual basis in the Forecast for Wilson Station during 2014-2018.

b. The financial model used in this rate application does not include Wilson Station layup costs because Wilson Station was originally planned to be idled September 2013.

Witness) Robert W. Berry

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 Second Request for Information dated September 16, 2013

September 30, 2013
Confidential Markings Removed – July 18, 2019

		Type	Forecasted Test Period
1	C1LAYUP	FDE	$ 500,000
2	C2LAYUP	FDE	500,000
3	C3LAYUP	FDE	500,000
4	FGDLAYUP	FDE	500,000
5	LAYUP EQUIPMENT	CAPITAL	100,000
6	**Total Forecasted Test Period**		**$ 2,100,000**

There are no layup costs for Coleman Station on an annual basis for years 2015 through 2018.

b. The Fixed Departmental Expenses (FDE) are provided in the Hyperion output files entitled "2014 Alcan.xlsx", "2015 Alcan.xlsx" (response to PSC 1-57) and "2016 Alcan.xlsx" (response to AG 1-227). The expenses for Coleman are loaded into the financial forecast in the response to PSC 1-57 on the O&M worksheet in rows 127-139. These expenses are included on rows 92, 93 and 104 of the Stmts RUS worksheet. The Capital Expenditures are included on the Capex & Depr worksheet in row 24.

Witness) Robert W. Berry

h. Provide a description of all necessary permits that will be required prior to restarting these units.

i. Provide a detailed breakdown of all costs related to achieving these permits and the year these costs will be incurred.

Response) Big Rivers objects that this request is unduly burdensome and not reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding these objections, and without waiving them, Big Rivers responds as follows.

a. Please see Big Rivers' CONFIDENTIAL attachment to this response.

b. Please see Big Rivers' CONFIDENTIAL attachment to this response.

c. Please see Big Rivers' CONFIDENTIAL attachment to this response.

d. Big Rivers currently plans on deferring installation of MATS equipment for Coleman and Wilson stations, which includes ACI and DSI injection equipment, until approximately one year prior to restarting these units. Big Rivers has not included any other environmental upgrades at this time.

e. The estimated costs to install MATS equipment at Wilson currently is $11.24 million. The estimated cost to install MATS equipment at Coleman currently is $28.44 million. These costs will be incurred approximately one year prior to restarting these units.

Activated Carbon Injection, Dry Sorbent Injection and Monitors	Coleman Unit 1	$ 9.48M
	Coleman Unit 2	$ 9.48M
	Coleman Unit 3	$ 9.48M
Activated Carbon Injection, Dry Sorbent Injection and Monitors	Wilson Unit 1	$ 11.24M

f. Please see Big Rivers' CONFIDENTIAL attachment to this response.

g. Please see Big Rivers' CONFIDENTIAL attachment to this response.

h. It is Big Rivers' intent to maintain its Title V permit for both units while they are idled.

i. The requested information is not currently available to Big Rivers. At this time, however, Big Rivers expects the cost to maintain its Title V permit to be relatively small.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION
Case No. 2013-00199
Attachment for Response to AG 2-9
Expected Restart Cost Summary

		Coleman Restoration	Wilson Restoration
O&M		$ 1,385,580	$ 1,574,330
Capital		$ 655,000	$ 330,000
	Total	**$ 2,040,580**	**$ 1,904,330**

BIG RIVERS ELECTRIC CORPORATION
Case No. 2013-00199
Attachment for Response to AG 2-9

Restoration Description	Cost	Year Expected	Capital	FDE	VOM
Replace Station Batteries	325,000	2019	X		
Transformer testing	22,000	2019		X	
Anion Resin for Mixed Beds	20,000	2019		X	
Cation Resin for Mixed Beds	9,000	2019		X	
RO membranes	15,000	2019		X	
Salt	5,000	2019		X	
Labor to load Resin	20,000	2019		X	
Media for Sand Filters	17,500	2019		X	
Labor to load sand filters	7,500	2019		X	
Acid and Caustic	112,000	2019		X	
Seed absorber	20,000	2019		X	
Dredge intake	75,000	2019		X	
Water Treatment Chemicals	65,000	2019		X	
Lab Analytical Reagents	5,000	2019		X	
Lab Operating Budget for equipment replacement	180,000	2019	X		
Diesel Fuel for fuel for initial fuel delivery	50,000	2019		X	
Handling Equipment /Barge Unloader Maintenance	88,000	2019		X	
Ball Mill Charge	110,880	2019		X	
Uniform Rental	33,000	2019		X	
Safety Supplies (S)	11,000	2019		X	
Operation Department Budget CO2/Hydrogen/Lube Oil/ EH oil /I	150,000	2019		X	
Consumables Instrument, Electrical and Mechancial	30,000	2019		X	
Contingency for restoration unknowns	200,000	2019		X	
Limestone 3,200 tons of Limestone to start the Unit	50,000	2019			X
Start-up fuel nat gas	187,200	2019			X
Environmental Instrunmentation replacement	150,000	2019	X		
Reverse lay-up equipment installation Contract Labor	82,500	2019		X	
Total Restart Cost $	**2,040,580**				
Less Capital	655,000				
O&M Expense $	**1,385,580**				

BIG RIVERS ELECTRIC CORPORATION
Case No. 2013-00199
Attachment for Response to AG 2-9

Restoration Description		Cost	Year Expected	Capital	FDE	VOM
Anion Resin for Anion Exchangers	$	80,000	2018		X	
Cation Resin for Cation Exchangers	$	45,000	2018		X	
Anion Resin for Mixed Beds	$	20,000	2018		X	
Cation Resin for Mixed Beds	$	9,000	2018		X	
Anion Resin for Condensate Polishers	$	75,000	2018		X	
Cation Resin for Condensate Polishers	$	70,000	2018		X	
Labor to load Resin	$	20,000	2018		X	
Media for Sand Filters and Carbon Filters	$	17,500	2018		X	
Labor to load sand filters and carbon filters	$	7,500	2018		X	
Acid and Caustic	$	112,000	2018		X	
DBA Reagent 4,000 gals	$	20,000	2018			X
SBS Reagent 4,000 gals	$	5,500	2018			X
Water Treatment Chemicals	$	65,000	2018		X	
Analytical Reagents	$	5,000	2018		X	
Operating Budget for equipment replacement	$	180,000	2018	X		
Equipment Fuel for fuel for initial fuel delivery	$	50,000	2018		X	
Fuel Handling Equipment /Barge Unloader Maintenance	$	88,000	2018		X	
Ball Mill Charge	$	110,880	2018		X	
Uniform Rental	$	33,000	2018		X	
Safety Supplies (S)	$	11,000	2018		X	
Operation Department Budget CO2/Hydrogen/Lube Oil /Filte	$	150,000	2018		X	
Consumables Instrument, Electrical and Mechancial	$	30,000	2018		X	
Contingency for restoration unknowns	$	200,000	2018		X	
Limestone 3,200 tons of Limestone to start the Unit	$	50,000	2018			X
Start Up Fuel Oil 60,000 gals	$	187,200	2018			X
Hydrated Lime	$	4,000	2018			X
Chlorine	$	1,250	2018			X
Ammonia	$	25,000	2018			X
Environmental Instrunmentation replacement	$	150,000	2018	X		
Reverse lay-up equipment installation Contract Labor	$	82,500	2018		X	
	$	**1,904,330**				
Less Capital	$	330,000				
O&M Expense	**$**	**1,574,330**				

	Coleman Outage	Wilson Outage
O&M	$ 5,913,462	$ 4,518,852
Capital	$ 7,638,000	$ 11,186,040
	$ 13,551,462	$ 15,704,892

BIG RIVERS ELECTRIC CORPORATION
Case No. 2013-00199
Attachment for Response to AG 2-9

Coleman Unit 1		FDE
Boiler Chemical Clean	$	248,230
Boiler Chemical Clean, temp piping	$	65,000
Boiler Chemical Clean, temp piping	$	10,000
PM-Outage Wetbottom Insp.	$	11,727
PM-Outage Wetbottom Insp.	$	10,405
PM-Dust Vlv Inspection	$	7,035
PM-Dust Vlv Inspection	$	18,389
Air Seperator Tank Inspeciton	$	6,254
Air Seperator Tank Inspeciton	$	1,950
Grinder Doghouse Inspection	$	3,126
Grinder Doghouse Inspection	$	5,853
Hydorjector Inspection & Repair	$	3,126
Hydorjector Inspection & Repair	$	7,153
Seal Skirt Replacement	$	82,476
Seal Skirt Replacement	$	171,297
Boiler Inspection & Repair	$	171,968
Boiler Inspection & Repair	$	11,705
Boiler Buckstay Inspection & Repair	$	12,260
Burner Inspection & Repair	$	28,141
Burner Inspection & Repair	$	28,614
Boiler Inspection Ports	$	12,689
Boiler Inspection Ports	$	3,678
Boiler Penthouse Inspection	$	11,725
Boiler Penthouse Inspection	$	5,894
Boiler Doors	$	6,254
Scaffold Furnace	$	656
Outage Contingencies	$	11,725
Outage Contingencies	$	1,248
PM-Sootblower Inspection	$	12,689
PM-Sootblower Inspection	$	27,915
Safety Valve Inspection	$	23,411
Safety Valve Inspection	$	24,519
Boiler Valves	$	15,226
Boiler Valves	$	12,689
Steam Drum Inspection	$	2,947
Steam Drum Inspection	$	656
Seal Air Line Inspection	$	44,410

Critical Pipe Inspection	$	92,241
Critical Pipe Inspection	$	18,389
Mob & Demob	$	37,520
Contractor Adminstration	$	98,491
Contractor Supervision	$	46,900
Hot Well Inspection & Repair	$	4,691
Hot Well Inspection & Repair	$	1,301
#4 Heater Inspection	$	11,725
#4 Heater Inspection	$	656
CBD Tank Inspection & Repair	$	1,563
CBD Tank Inspection & Repair	$	7,969
DA Storage Tank Inspection & Repair	$	9,380
DA Storage Tank Inspection & Repair	$	656
BFP Motor PM	$	12,689
BFP Motor PM	$	3,800
Wetbottom Refractory	$	79,687
Wetbottom Refractory	$	91,947
Economizer Inlet Check Valve	$	7,817
Economizer Inlet Check Valve	$	1,561
Feed Water Pipe Assessment	$	9,380
Feed Water Pipe Assessment	$	7,803
1-B Boiler Feed Pump Overhaul	$	103,052
PM-Outage Air Htr.Inspection	$	57,130
PM-Outage Air Htr.Inspection	$	39,231
FD Fan Inspection	$	12,689
Stack Liner repairs	$	3,800
FD Fan Motor PM	$	24,322
FD Fan Motor PM	$	13,006
ROFA Fan Motor PM	$	4,000
ROFA Fan Motor PM	$	1,000
Stack Breaching insp.& repairs	$	15,226
Stack Breaching insp.& repairs	$	6,130
PM-Outage Gas Leak repairs	$	63,443
PM-Outage Gas Leak repairs	$	12,689
Steam Coil Inspection & Repair	$	3,126
Asbestos Removal	$	11,725
Asbestos Removal	$	6,028
Piping Insulation Repairs	$	11,725

Dead Air Space Insulation Renewal	$	6,504
Condenser & Condenser Vavle Inspeciton	$	9,380
Condenser Inlet Line Inspection	$	4,691
Condenser Inlet Line Inspection	$	3,251
Heater Drain Regulator Inspection	$	3,126
Traveling Water Screen Inspection	$	50,809
Traveling Water Screen Inspection	$	9,755
Precipitator Inspection & Repair	$	12,260
Precipitator Inspection & Repair	$	6,130
Inspection & Repair	$	11,725
Mill Inspection & Repair	$	1,950
Coal Valve Inspection	$	25,013
Coal Valve Inspection	$	19,510
Mill Motor PM	$	6,130
PA Fan Motor PM	$	3,678
Mill Seal Air Fan Motor PM	$	8,582
DCS Controls maintenance	$	4,942
DCS Controls maintenance	$	7,969
Duct Inspection & Repair	$	21,350
Stock Feeder Inspection and Repair	$	6,344
Stock Feeder Inspection and Repair	$	6,504
Bunker & Bunker Piping Inspection	$	6,254
Routine Inspection & Repair	$	1,950
4160/480 V MCC Inspeciton & Repairs	$	14,632
4160/480 V MCC Inspeciton & Repairs	$	35,875
ECT fuel flow upgrade	$	12,689
ECT fuel flow upgrade	$	70,493
Generator Excitation Inspection & Repair	$	20,000
Transformer Inspection & Repairs	$	2,000
Transformer Inspection & Repairs	$	20,698
Turbine Valve Inspection & Repair	$	366,194
Turbine Valve Inspection & Repair	$	125,993
C1 Booster Fan Overhaul	$	53,000
C1 Booster Fan Overhaul	$	221,540
Vacuum work	$	20,000
Test 86 Protective Relays	$	3,105
Unit 1 Total	**$**	**3,261,548**

Coleman Unit 2		FDE
PM-Outage Wetbottom Insp.	$	12,801
PM-Outage Wetbottom Insp.	$	11,360
PM-Dust Vlv Inspection	$	7,680
PM-Dust Vlv Inspection	$	20,077
Air Separator Tank Inspection	$	6,828
Air Separator Tank Inspection	$	2,130
Grinder Doghouse Inspection	$	3,413
Grinder Doghouse Inspection	$	6,390
Hydorjector Inspection & Repair	$	3,413
Hydorjector Inspection & Repair	$	7,810
Boiler Inspection & Repair	$	187,752
Boiler Inspection & Repair	$	12,780
Boiler Buckstay Inspection & Repair	$	13,385
Burner Inspection & Repair	$	30,724
Burner Inspection & Repair	$	31,240
Boiler Inspection Ports	$	13,853
Boiler Inspection Ports	$	4,015
Boiler Penthouse Inspection	$	12,801
Boiler Penthouse Inspection	$	6,435
Boiler Doors	$	6,828
Boiler Doors	$	716
Outage Contingencies	$	12,801
Outage Contingencies	$	1,363
PM-Sootblower Inspection	$	13,853
PM-Sootblower Inspection	$	30,477
Safety Valve Inspection	$	25,560
Safety Valve Inspection	$	26,770
Boiler Valves	$	16,624
Boiler Valves	$	13,853
Steam Drum Inspection	$	3,218
Steam Drum Inspection	$	716
Seal Air Line Inspection	$	48,487
Critical Pipe Inspection	$	10,241
Critical Pipe Inspection	$	2,130
Mob & Demob	$	40,964
Contractor Adminstration	$	107,531
Contractor Supervision	$	51,205

Hot Well Inspection & Repair	$	5,121
Hot Well Inspection & Repair	$	1,420
#4 Heater Inspection	$	12,801
#4 Heater Inspection	$	716
CBD Tank Inspection & Repair	$	1,707
CBD Tank Inspection & Repair	$	8,700
DA Storage Tank Inspection & Repair	$	10,241
DA Storage Tank Inspection & Repair	$	716
PM-Outage Gas Leak repairs	$	69,267
PM-Outage Gas Leak repairs	$	13,853
Steam Coil Inspection & Repair	$	3,413
Piping Insulation Repairs	$	12,801
Piping Insulation Repairs	$	7,101
Hot Well Inspeciton	$	3,413
Precipitator Inspection & Repair	$	13,385
Precipitator Inspection & Repair	$	6,692
Inspection & Repair	$	12,801
Inspection & Repair	$	2,130
Coal Valve Inspection	$	27,309
Coal Valve Inspection	$	21,301
Duct Inspection & Reapir	$	20,780
Duct Inspection & Reapir	$	6,927
Stock Feeder Inspection and Reapir	$	7,101
Bunker & Bunker Piping Inspection	$	6,828
Bunker & Bunker Piping Inspection	$	2,130
4160/480 V MCC Inspeciton & Repairs	$	15,975
4160/480 V MCC Inspeciton & Repairs	$	39,168
Generator Excitation Inspection & Repair	$	20,000
Generator Excitation Inspection & Repair	$	2,000
Transformer Inspection & Reapirs	$	22,598
Test 86 Protective Relays	$	3,230
Unit 2 Total	**$**	**1,189,847**

Coleman Unit 3		**FDE**
PM-Outage Wetbottom Insp.	$	11,784
PM-Outage Wetbottom Insp.	$	10,455
PM-Dust Vlv Inspection	$	7,069
PM-Dust Vlv Inspection	$	18,479

Air Seperator Tank Inspeciton	$	6,284
Air Seperator Tank Inspeciton	$	1,960
Grinder Doghouse Inspection	$	3,141
Grinder Doghouse Inspection	$	5,881
Hydorjector Inspection & Repair	$	3,141
Hydorjector Inspection & Repair	$	7,188
Boiler Inspection & Repair	$	172,802
Boiler Inspection & Repair	$	11,762
Boiler Buckstay Inspection & Repair	$	12,319
Burner Inspection & Repair	$	28,277
Burner Inspection & Repair	$	28,754
Boiler Inspection Ports	$	12,750
Boiler Inspection Ports	$	3,696
Boiler Penthouse Inspection	$	110,782
Boiler Penthouse Inspection	$	15,923
Boiler Doors	$	6,284
Boiler Doors	$	659
Scaffolding Misc	$	75,000
Scaffolding Misc	$	25,000
Outage Contingencies	$	26,783
Outage Contingencies	$	17,254
PM-Sootblower Inspection	$	12,750
PM-Sootblower Inspection	$	28,051
Safety Valve Inspection	$	23,525
Safety Valve Inspection	$	24,638
Boiler Valves	$	75,300
Boiler Valves	$	12,750
Steam Drum Inspection	$	2,962
Steam Drum Inspection	$	659
Seal Air Line Inspection	$	44,626
Mob & Demob	$	37,702
Contractor Adminstration	$	98,969
Contractor Supervision	$	47,128
Hot Well Inspection & Repair	$	4,713
Hot Well Inspection & Repair	$	1,307
#4 Heater Inspection	$	11,782
#4 Heater Inspection	$	659
CBD Tank Inspection & Repair	$	1,571

CBD Tank Inspection & Repair	$	8,007
DA Storage Tank Inspection & Repair	$	9,425
DA Storage Tank Inspection & Repair	$	659
Stack Breaching insp.& repairs	$	15,300
Stack Breaching insp.& repairs	$	6,160
PM-Outage Gas Leak repairs	$	63,751
PM-Outage Gas Leak repairs	$	12,750
Steam Coil Inspection & Repair	$	3,141
Piping Insulation Repairs	$	11,782
Piping Insulation Repairs	$	6,535
Boiler Wall Insulation	$	30,000
Boiler Wall Insulation	$	5,000
Hot Well Inspeciton	$	3,141
Precipitator Inspection & Repair	$	12,319
Precipitator Inspection & Repair	$	6,160
Pipe Hanger Inspection & Repair	$	11,782
Pipe Hanger Inspection & Repair	$	1,960
Coal Valve Inspection	$	25,135
Coal Valve Inspection	$	19,606
Duct Inspection & Repair	$	19,125
Duct Inspection & Repair	$	6,375
Stock Feeder Inspection and Reapir	$	6,535
Bunker & Bunker Piping Inspection	$	6,284
Bunker & Bunker Piping Inspection	$	1,960
4160/480 V MCC Inspeciton & Repairs	$	14,703
4160/480 V MCC Inspeciton & Repairs	$	36,049
Generator Excitation Inspection & Repair	$	20,000
Generator Excitation Inspection & Repair	$	2,000
Transformer Inspection & Repairs	$	20,799
Inverter / Battery charger insp & repair	$	20,000
Test 86 Protective Relays	$	3,105
Unit 3 Total	**$**	**1,462,067**

Coleman		Capital
C-1 Auxillary Transformer & Containment	$	175,000
C-1 Boiler Insulation	$	400,000
C-1 Boiler penthouse casing	$	200,000
C-1 Tube Replacement Hot Reheat Section	$	1,675,000
C-1 Critical Pipe System Hanger Replacements	$	40,000
C-1 "A" MCC Replacement	$	140,000
C-1 FD fan housings, silencers & hoods	$	380,000
C-1 Precipitator Inlet duct replacement	$	350,000
C-1 Cold End Air Heater Basket	$	500,000
C-1 Boiler Tube Weld Overlay	$	1,250,000
C-1 Mill Coal Valves	$	275,000
C-1 Burners	$	1,353,000
C-1 Air Register Drives	$	200,000
C-1 Air Heater Hopper Replacement	$	70,000
CL Misc. Tools and Equipment	$	50,000
CL Misc. Safety Equipment	$	20,000
CL Misc. Capital Projects	$	100,000
CL Capital Valve Replacement	$	100,000
CL Coleman FGD Misc. Pumps & Valves	$	50,000
controls	$	150,000
CL Limitorque Drive Replacement	$	50,000
CL Conveyor Belt Replacement	$	110,000
Total Capital	**$**	**7,638,000**

BIG RIVERS ELECTRIC CORPORATION
Case No. 2013-00199
Attachment for Response to AG 2-9

		FDE
480V USS Breakers	$	24,519
Air System Ductwork Inspection	$	32,835
Ammonia Spool Pieces Remove & Replacement	$	1,993
Ash Handling System Repairs	$	95,639
Blow Down Tank Inspection	$	1,495
Boiler Building Elevator Attendant (Guard)	$	41,864
Boiler Castable Remove & Replace	$	14,952
Boiler Chemical Clean	$	469,120
Boiler Feed Pump Suction Strainer Inspection	$	1,246
Boiler Penthouse Inspection	$	6,230
Boiler Radiant & Convection Pass Inspection & Repair	$	174,624
Boiler Transition Radiation Tile Inspection	$	2,990
Boiler Tube Samples Remove & Replace	$	37,972
Boiler Tube Thermocouples Inspection	$	3,115
Boiler Water Wall Mapping	$	27,185
Boiler Wet Seal Cleaning & Inspect	$	5,437
Boiler Wet Seal Cleanout Door Remove and Replace	$	5,980
Boiler, Burner Hoods, Register	$	4,486
Boiler, DA Storage Tank, Open, inspect and close	$	7,476
Boiler, Dead Air Space, Boundary Air Ducts inspect and re	$	3,738
Boiler, Insulation General	$	173,147
Boiler, Over fire Air Duct, Inspections	$	6,230
Boiler, Safety Valves, Inspections	$	49,699
Boiler, Soot blower Nozzles, Inspection	$	6,230
Boiler; Doors; Open; Inspect and Repair	$	2,243
Bottom Ash Drag Chain Hydraulic Unit Inspection	$	2,990
Bottom Ash Surge Tank Inspection	$	9,345
Burner Repairs	$	158,212
Chimney & Flue Inspection	$	47,416
Circulating Water System Repairs	$	48,828
Circulating Water Tunnel Inspections	$	4,672
Coal Valve Inspections	$	29,485
Condensate Pump Suction Strainer Inspection	$	2,492
Condensate System Repair	$	26,575
Condenser Tube Cleaning	$	30,496
Condenser Water Box Anodes Replacement	$	4,050
Condenser Water Box Coating Repair	$	9,715

Contractor Mobilization & Demobilization	$	93,822
Contractor Outage Supervision & Planning	$	237,868
Cooling Tower Inspection & Repair	$	40,952
Cooling Water System Repairs	$	21,851
Critical Pipe Hanger Inspection & Repairs	$	20,117
Electrostatic Precipitator Repairs	$	305,829
Fans and Draft System Repair	$	103,312
Forced Draft Fan Overhaul	$	49,142
Feed Water System Repair	$	39,524
Flue Gas Desulfurization Module Circulating Pump Nozzle Inspection & Repair	$	97,325
Flue Gas Desulfurization Repair	$	96,733
Flyash System Remove & Replace Spools	$	997
Fuel Processing System Repair	$	65,348
Gas System Ductwork Inspect	$	54,261
Generator Exciter Cooler Head Remove and Replace	$	5,980
Generator Hydrogen Cooler Head Remove and Replace	$	5,980
Generator Seal Oil Cooler Head Remove and Replace	$	5,980
Guard at Contractor Gate	$	41,864
Heater Trays #5 Remove Inspect & Replace	$	24,920
Hot well Inspect & Repair Impact Plates	$	28,561
Induced Draft Fan Carbon Seal Replacement	$	7,878
Induced Draft Fan Wheel Clean Inspect & Repair	$	5,981
Critical Equipment Limitorques Open Clean Lubricate & (	$	18,690
Inspect Dibasic Acid Tank	$	1,133
Inspect Module Agitator Blades	$	4,984
Selected Catalytic Reduction Bypass Dampers Inspection	$	2,990
Selected Catalytic Reduction Soot blowers Inspection	$	2,990
Main Turbine EH System Filter Replacement	$	436
Main Turbine Reverse Current Valve Inspections	$	11,675
Main Turbine Valves, Inspect	$	453,082
Mill PASO Damper Inspection & Repair	$	31,149
Flue Gas Desulfurization Circulating Pump Headers Open Clean & Close	$	6,230
Module Overflow Loop Inspections	$	11,327
Non Destructive Examination Boiler Tubes	$	148,509
Outage Lubrication	$	45,796

	$	297,814
PM-Outage, Boiler, Flue Gas Desulfurization, Ductwork, Insulation and Valve Replacement Scaffolding		
PM-Outage, Economizer Ash Tank Inspections	$	1,496
Primary & Secondary Air Preheater Wash Nozzle Inspecti	$	2,492
Primary Air Preheater Inspection & Repair	$	16,947
Pulverizers Rating, Cold & Hot Air Damper Inspections	$	21,565
Recondition 1SC-C-1, #1 S.A.H. Drive Motor	$	4,821
Recondition 1TG-P-10 Air Side Seal Oil AC Pump Motor	$	8,249
Remove & Replace Outlet Duct Drains	$	15,575
Repack Boiler Feed Pump Steam Root Valves	$	45,534
Selective Catalytic Reduction Structural Repairs	$	12,634
Flue Gas Desulfurization Guillotine Damper Inspections	$	6,230
Flue Gas Desulfurization Module Brick Inspect & Replace	$	88,125
Flue Gas Desulfurization Outlet Duct Prekrete Inspection	$	15,575
Secondary & Primary Air Preheater Wash	$	11,327
Secondary Air Preheater Inspection & Repair	$	16,947
Soot Blower Seal Box and Sleeve Replacement	$	49,839
Soot blower Pressure Checks	$	4,984
Stack Drain Inspect & Clean	$	747
Stack Pan Cleaning	$	5,437
Steam Coil Trap Inspections	$	13,366
Steam Drum Inspection	$	2,492
Turbine Generator Repairs	$	53,085
Under fire Damper Inspections	$	24,920
Valve Repair	$	61,680
Valve Replacement	$	62,799
Wet Bottom Transition Chute Inspection & Repair	$	6,230
Total FDE	**$**	**4,518,852**

		Capital
Capital Valves	$	110,381
Primary AH Basket Replacement	$	529,830
Boiler Feed Pump #1 Rotating Element Replacement	$	77,267
Boiler Feed Pump #2 Rotating Element Replacement	$	77,267
Boiler Feed Pump Auxiliary Rotating Element Replaceme	$	77,267
Water Wall Tube Weld Overlay	$	524,311
Burner Replacement 18 of 25	$	883,050
Waterwall Tube Replacement	$	551,906
Superheater Secondary Tube Replacement	$	2,262,816
Air Preheater Secondary Basket Replacement	$	2,184,446
Selective Catalytic Reduction Catalyst Replacement (Low	$	2,759,532
Acid Tank Relining - East Tank	$	110,381
Acid Tank Relining - West Tank	$	82,786
Gas & Air Duct Epansion Joint Replacement	$	165,572
Riser Duct Expansion Joint	$	275,953
Wet Bottom Drag Chain Replacement	$	126,938
Primary Air Fan #2 Blade & Regulating Arm Replacement	$	386,335
Total Capital	**$**	**11,186,040**

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

In the Matter of:

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

Responses to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Office of the Attorney General's Supplemental Request for Information, Item No. 13 originally filed September 30, 2013

Information submitted on CD accompanying responses

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
Second Request for Information
dated September 16, 2013

September 30, 2013
Confidential Markings Removed – July 18, 2019

Item 14) ***Please refer to BREC's Response to AG 1-53, page 15(Confidential): Provide all documents, power point presentations, etc. associated with the extensive presentation and analysis of [BEGIN CONFIDENTIAL] "the actions management recommends in response to the Alcan Primary Products Corporation notice of termination….and the reasons for the recommendations" [END CONFIDENTIAL], both before the Board of Directors, and in any board work session.***

Response) Please see the response to AG 1-158.

Witness) Christopher A. Warren

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 Second Request for Information dated September 16, 2013

September 30, 2013
Confidential Markings Removed – July 18, 2019

Item 15) ***Please refer to BREC's Response to AG 1-53, page 16 (Confidential): Provide all documents, power point presentations, etc. associated with the presentation and analysis of [BEGIN CONFIDENTIAL] "the RUS Loan Application – Financing for the Environmental Compliance Plan" [END CONFIDENTIAL], both before the Board of Directors, and in any board work session.***

Response) See the attached RUS Loan Application – Financing for the Environmental Compliance Plan presentation made to the Board of Directors on May 17, 2013. This CONFIDENTIAL attachment is being provided pursuant to a petition for confidential treatment.

Witness) Billie J. Richert

Big Rivers
ELECTRIC CORPORATION
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Rural Utilities Service (RUS) Financing for the Environmental Compliance Plan

Board Meeting Date: May 17, 2013

Big Rivers ELECTRIC CORPORATION
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Approval for Obtaining RUS Long-Term Financing for Environmental Compliance Plan

The Environmental Compliance Plan (ECP) for Mercury and Air Toxic Standards (MATS) was approved by the Kentucky Public Service Commission (PSC) on October 1, 2012. Generation plant improvements and replacements as submitted in the Revised 2012 Environmental Compliance Plan portion of the Construction Work Plan for electric plant facilities are $58,440,000.

Our projected capital expenditures are approximately $30.8m for 2013 and $27.6 for 2014 with an in service date of August 2014.

Big Rivers' intent is to submit an application to the Rural Utilities Service (RUS) for long-term financing on May 28, 2013. The RUS approval process for this is anticipated to take two to three years.

Big Rivers ELECTRIC CORPORATION

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Terms of RUS Long-Term Financing

- Application to the RUS will be for a guaranteed Federal Financing Bank (FFB) loan for $58,440,000.
- This FFB loan shall bear a maturity date to cover an approximate period of thirty (30) years.
- Amortization of this loan will include quarterly principal and interest payments utilizing level-debt service.
- Interest rate is presently equal to Treasury's cost of money for debt instruments with similar maturities and options, plus one-eight of one percent (0.125 percent). Using a May 10, 2013 issue date, the FFB quarterly rate would be 2.52 percent for a thirty year loan.
- There is an annual loan servicing fee of one one-thousandth of one percent (0.001 percent) on the principal balance outstanding at the end of each calendar year.

Request for Board Approval

We are seeking Board approval to authorize management to execute and attest on behalf of Big Rivers all necessary papers, documents, and applications related to this RUS application.

This does not require the Public Service Commission's approval.

Counsel is researching to determine if the related supplemental indenture with US Bank, Trustee, will require approval.

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
Second Request for Information
dated September 16, 2013

September 30, 2013
Confidential Markings Removed – July 18, 2019

Item 16) *Please refer to BREC's Response to AG 1-53, page 20, (Confidential): Provide all documents, power point presentations, etc. associated with the extensive presentation and analysis of [BEGIN CONFIDENTIAL] "the term sheet that had been negotiated between and among Big Rivers, Kenergy Corp. and Century Aluminum of Kentucky" [END CONFIDENTIAL], both before the Board of Directors, and in any board work session.*

Response) Please find attached the CONFIDENTIAL PowerPoint labeled "Term Sheet" that was the basis for Mr. Berry's presentation to the Big Rivers Board of Directors on May 17, 2013.

Witness) Robert W. Berry

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

Century Term Sheet Summary

May 2013

[redacted]

Big Rivers ELECTRIC CORPORATION
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Principal Goals / Objectives

- **Negotiate a framework to allow Century to obtain its power supply from the wholesale market rather than cease operations.**
    - ➢ Once Century gains market access Big Rivers is no longer obligated to serve them.
    - ➢ The arrangement cannot increase the Members rates more than would be necessary if the smelter ceased operation.
    - ➢ Successfully accomplished both objectives

[redacted] 2

Term Sheet

- **The Term Sheet outlines the structure of the 7 Agreements associated with the transaction.**

1. **Electric Service Agreement -** A retail electric service agreement between Kenergy and Century for the sale of electricity, electric capacity and electricity-related ancillary services, including transmission services, by Kenergy to Century.

2. **Arrangement Agreement -** The power arrangement and procurement agreement between Big Rivers and Kenergy pursuant to which at least initially Big Rivers arranges and procures electricity, electric capacity and electricity-related ancillary services for Kenergy for resale to Century under the Electric Service Agreement.

[redacted]

Big Rivers ELECTRIC CORPORATION
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Term Sheet (Continued)

- **The Term Sheet outlines the structure of the 7 Agreements associated with the transaction.**

3. **Direct Agreement -** An agreement between Big Rivers and Century relating to direct, bilateral obligations to each other in connection with the Transaction.

4. **Capacitor Agreement -** An agreement entered into between and among Big Rivers, Kenergy, and Century relating to obligations for the design, development, purchase, installation, operation, maintenance and indemnification of risk regarding the Capacitor Additions at Century.

[redacted]

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Term Sheet (Continued)

- **The Term Sheet outlines the structure of the 7 Agreements associated with the transaction.**

5. **Protective Relay Agreement -** An agreement entered into between and among Big Rivers, Kenergy, and Century relating to obligations for the design, development, purchase, installation, operation, maintenance and indemnification of risk regarding the Protective Relay additions at Century.

6. **Tax Indemnity Agreement** – Agreement between Kenergy, and Century and Century Parent to indemnify Kenergy if this transaction were to jeopardize Kenergy's tax exempt status.

7. **Parent Guarantee of Century Parent** – Agreement between and among Big Rivers, Kenergy and Century Parent.

[redacted]

Big Rivers ELECTRIC CORPORATION
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Overview

- The term (Service Period) of the transaction is August 20, 2013 through December 31, 2023.
- Century may terminate the agreement upon 60 days prior written notice.
- Big Rivers will at least initially be the Market Participate for Kenergy to arrange and schedule the required electricity, capacity and associated services for Kenergy to sale to Century.
- Kenergy may elect, subject to the consent and approval of Century, to become the Market Participant.
- Century may designate an alternative Market Participant with a 120 day notice to Kenergy, and to Big Rivers, if the Arrangement Agreement is in effect.

[redacted]

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Overview (Continued)

- This transaction only applies to the Hawesville smelter.
- Century plans to purchase the maximum amount of energy (Base Load) that can be imported into the Hawesville smelter without the Coleman Plant operating. (Potentially 375 MW)
- This will require approximately 300 MVAR of Capacitors to be installed at Century / Hawesville, at Century's cost to maintain the appropriate system voltage support.
- Century is investigating the possibility of purchasing additional electricity on an interruptible basis (Curtailable Load) by utilizing protective relays, also at Century's cost, that can be activated to protect system stability in the event of an unplanned disturbance (i.e. loss of transmission, transformer failure or generating units).

[redacted]

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Overview (Continued)

- Installation of the Capacitors and approval for the Protective Relays cannot be accomplished before August 20, 2013.
- To avoid interruption in service, Big Rivers agreed to enter into a short term (9 months) System Support Resource (SSR) agreement with MISO to operate the Coleman Plant until the earlier of, the date when the Capacitors and Protective Relays are in place or June 1, 2014.
- Century has agreed to pay all of the operating cost of Coleman that is allocated to Big Rivers by MISO during this 9 month period.
- Big Rivers agreed to offset the SSR cost with the incremental transmission revenue it receives from Century. This only applies during the short term (Rider I SSR period).

[redacted]

Big Rivers
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Credit Support

- Century shall provide and maintain credit support, cash or letter of credit from a bank rated A+ or better for the following:
  - The amounts reasonably estimated by Kenergy and Big Rivers to be due with respect to Century's obligations under the Electric Service Agreement for a period not longer than the payment terms required by Kenergy's suppliers.
  - The amounts reasonably estimated by Big Rivers to be due with respect to Century's additional obligations to Big Rivers for a period of two months for amounts under the Direct Agreements.
  - The amounts estimated by Kenergy to be due with respect to Century's obligation under the Tax Indemnity Agreement.
  - All other amounts reasonably projected by Kenergy or Big Rivers to become payable to either or both of them by Century.

[redacted]

Big Rivers ELECTRIC CORPORATION
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Credit Support & Billing

- Century will provide and maintain credit support in the form and in the amount required by MISO with respect to the of electricity, capacity and ancillary services for resale to Century.
- Big Rivers will invoice Kenergy and Kenergy will invoice Century based on how Big Rivers is invoiced by MISO (weekly) for energy and related services.
- Big Rivers will invoice Kenergy and Kenergy will invoice Century based on how Big Rivers is invoiced by MISO (monthly) for all other ancillary services including transmission.
- Big Rivers will invoice Century monthly for all services associated with the Direct Agreement.

[redacted]

Big Rivers ELECTRIC CORPORATION
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Electric Service Agreement

- Agreement between Century and Kenergy that Century is obligated to pay for costs of electric services related to Hawesville's operation:
    - Electricity, capacity and ancillary services including transmission services
    - Kenergy's internal and direct cost including a nominal net margin (equivalent to current net margin).
    - Cost associated with any entity other than Big Rivers serving as the Market Participant.
    - Cost incurred by Kenergy to comply with state or federal renewable energy portfolio or similar standards.
    - Charges to Kenergy for MISO Transmission Expansion Plan (MTEP) or Multi-Value projects (MVP).

[redacted]

Big Rivers ELECTRIC CORPORATION
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Electric Service Agreement

- Agreement between Century and Kenergy that Century is obligated to pay for costs of electric services related to Hawesville's operation: (Continued)

  - Any cost to Kenergy arising out of any bilateral electrical supply contract that Century has approved.
  - Costs related to Century's operation incurred by Kenergy to comply with the Dodd-Frank Wall Street Reform and Consumer Protection Act.
  - Monthly charges with respect to items charged to Kenergy by Big Rivers under the Arrangement Agreement.
  - Excess reactive demand charges.
  - All other direct costs of Kenergy incurred or committed to by Kenergy related to Century's operation.

[redacted]

Big Rivers ELECTRIC CORPORATION
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Arrangement Agreement

- Agreement between Kenergy and Big Rivers under which Kenergy is obligated to pay Big Rivers for costs of procuring wholesale electric services related to Century's operation:
  - Electricity, capacity and ancillary services to serve Kenergy for resale to Century.
  - Costs incurred by Big Rivers to comply with state or federal renewable energy portfolio or similar standards.
  - MISO charges to establish and maintain the Hawesville Node.
  - Charges to Big Rivers for MISO Transmission Expansion Plan (MTEP) or Multi-Value projects (MVP).

[redacted]

Big Rivers ELECTRIC CORPORATION
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Arrangement Agreement

- Agreement between Kenergy and Big Rivers under which Kenergy is obligated to pay Big Rivers for costs of procuring wholesale electric services related to Century's operation: (Continued)
  - Costs related to Century's operation incurred by Big Rivers to comply with the Dodd-Frank Wall Street Reform and Consumer Protection Act.
  - Costs or charges of ACES, or similar service for scheduling , awards and settlements.
  - Costs of a 0.25 Full Time Equivalent (FTE) employee of Big Rivers if it is serving as the Market Participant.
  - Any other amounts due and owing to Big Rivers under the Definitive Documents, including applicable taxes.

[redacted]

Big Rivers ELECTRIC CORPORATION
Your Touchstone Energy® Cooperative

Direct Agreement

- Agreement between Big Rivers and Century under which Century is obligated to pay Big Rivers for direct, bilateral obligations related to Hawesville's operation:
  - All SSR (must run) costs of the Coleman generating station under the circumstances contemplated in Rider I, less any transmission revenue received by Big Rivers from Century.
  - All electrical transmission capital costs related to Century's operation allocated by MISO to the Century Node (Does not include costs allocated to Big Rivers Node for remaining load).
  - Other third-party out of pocket costs of Big Rivers incurred or committed to by Big Rivers related to Century's operation.
  - All SSR (must run) costs, including capital if Coleman is forced to restart due to Century's increase in load.

[redacted]

Big Rivers ELECTRIC CORPORATION
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Direct Agreement (Continued)

- Century will hold Big Rivers harmless from all direct costs, expenses, liabilities, claims or similar consequences relating to the following to the extent not recovered under the Electrical Service Agreement:
    - Purchasing and transmitting electricity, capacity and ancillary services for resale to Century under the transaction.
    - Claims of bilateral power suppliers under contracts to which Century has agreed for electricity, capacity and ancillary services.
    - Any other amounts due and owing to Big Rivers under the Definitive Documents.

[redacted]

Big Rivers
ELECTRIC CORPORATION
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Rider I

- SSR Agreement for Short Term Operation of Coleman
  - The purpose is to recover the cost associated with the MISO must run requirement of one or more of the Coleman units after August 20, 2013, until Century can install the Capacitors and Protective Relays.
  - The term ends on the earlier of June 1, 2014, or when Century completes the installation of the capacitors and protective relays.
  - Century will pay all costs allocated from MISO to Big Rivers under the SSR agreement. Big Rivers agrees not to spend any capital at Coleman other than what it would have spent if Century would have ceased operation.

[redacted]

Big Rivers ELECTRIC CORPORATION
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Rider I

- SSR Agreement for Short Term Operation of Coleman (continued)
  - If a major failure occurs at Coleman during the Rider I period, Century will pay the $1 million insurance deductible, or if less than 3 units are required to operate, Century will pay the costs to restart the idled unit.
  - Under the SSR agreement, Big Rivers' expenses are reimbursed by MISO, but it does not receive any revenue from sales from the plant.

[redacted]

Big Rivers ELECTRIC CORPORATION
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RTO Membership

- Big Rivers has the freedom to leave MISO and Century can remain in MISO, if MISO allows and as long as it does not inhibit Big Rivers' ability to leave.
- Century is responsible for any additional costs resulting from the Hawesville Node remaining in MISO.
- Big Rivers is required to provide Century with one year's notice before leaving MISO.
- Big Rivers agreed to provide Century notice if management recommends to the Board of Directors to terminate Big Rivers membership in MISO.
- Agreed to provide Century the annual MISO membership update given to the KPSC, if the update is publicly available.

[redacted]

Closing Summary

- Definitive documents need to be completed and filed at the KPSC by June 1, 2013
- Need Board approval based on the term sheet structure prior to the June 1 deadline.
- Asking the Board to approve prior to June 1, based on our management confirming these principal provisions remain substantively unchanged in the definitive agreements.

[redacted]

Big Rivers ELECTRIC CORPORATION
Your Touchstone Energy® Cooperative

Term Sheet

Questions

[redacted]

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 SecondRequest for Information dated September 16, 2013

September 30, 2013
Confidential Markings Removed – July 18, 2019

Item 17) *Please refer to BREC's Response to AG 1-53, page 21, (Confidential): Provide all documents, power point presentations, etc. associated with the presentation and analysis of [BEGIN CONFIDENTIAL] "the circumstances that may arise in the near term that would require Big Rivers ... to idle Coleman Generating Station to reduce the Corporation's expenses" [END CONFIDENTIAL], both before the Board of Directors, and in any board work session.*

Response) Please find the attached, CONFIDENTIAL PowerPoint labeled "Coleman Plant Idle Recommendation" that was the basis for Mr. Berry's presentation to the Big Rivers Board of Directors on May 17, 2013.

Witness) Robert W. Berry

Big Rivers
ELECTRIC CORPORATION

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Coleman Station Evaluation

May 17, 2013

1

Background

- On August 20, 2012, Century aluminum issued its one year notice to terminate its power supply contract.
- Big Rivers immediately began to implement it's Load Concentration Mitigation plan.
- The mitigation plan included the need to temporarily idle a generating plant if the wholesale power market did not support the total cost of production (variable and fixed) to operate the plant.
- MISO approval is required before Big Rivers can idle any of it's generating plants.
  - This approval is required to protect the system stability of the transmission grid.

Big Rivers ELECTRIC CORPORATION
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MISO Requirements

- To request the approval to idle a plant, the MISO member must file one of the following:
  - **Attachment Y** - a binding process where MISO will perform an analysis and determine if idling the specific plant will negatively affect the transmission system. (No cost to the member but it is binding)
  - **Attachment Y-2** - a non-binding process where MISO will perform an analysis and determine if idling the specific plant will negatively affect the transmission system. (Member pays the cost but results are non-binding)
- Both processes require a 26 week lead time before the utility can idle the plant in question.

3

Big Rivers ELECTRIC CORPORATION
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Request to MISO

- On December 18, 2012 Big Rivers submitted an Attachment Y-2 to MISO requesting them to perform an analysis to determine if Big Rivers could idle Coleman, considering the following two scenarios:
  - The Century Hawesville smelter continued operation (482 MW load) after August 20, 2013.
  - The Century Hawesville smelter ceased operation (0 MW load) after August 20, 2013.
- On December 26, 2012 Big Rivers submitted an Attachment Y-2 to MISO requesting them to perform the same analysis to determine if Big Rivers could idle the Wilson plant, considering the same scenarios listed above for Coleman.
- On April 22, 2013 Big Rivers submitted an Attachment Y-2 to MISO requesting them to perform an analysis to determine if Big Rivers could idle the Green plant assuming one or both smelters were operating or ceased to operate.

Results

- On May 2, 2013 Big Rivers received the results of the Attachment Y-2 regarding the potential to idle the Coleman plant. (Attachment Y-2 is not final, only an Attachment Y is final)
  - Coleman Station can be idled if the Century Hawesville smelter ceases operation.
  - There are transmission issues if Century continues to operate and Big Rivers idles the Coleman plant. High probability this scenario will create a must run condition for Coleman.
- To get a final answer regarding the ability to idle the Coleman plant before August 20, 2013 when the Century contract terminates, Big Rivers must convert the Attachment Y-2 into a Attachment Y at MISO.
- If we do not convert the Attachment Y-2 into an Attachment Y within 30 days from the time the Y-2 report was issued the 26 week time clock restarts.

Big Rivers ELECTRIC CORPORATION
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Recommendation

- Management is requesting Board approval to idle the Coleman generating facility if the wholesale power market is not sufficient to cover the total production cost of the Coleman units.

Big Rivers
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Data to Support Recommendation

- Idling the Coleman Plant will provide the largest fixed cost saving opportunities for Big Rivers and it Members.

2014 - 2016 Station O&M Fixed Cost Savings				
Station	**2014**	**2015**	**2016**	**Total**
Wilson	$ 28,412,857	$ 22,666,092	$ 21,572,545	[redacted]
Coleman	$ 26,247,125	$ 24,404,762	$ 25,515,726	[redacted]
Green	$ 22,658,180	$ 23,156,886	$ 27,353,464	[redacted]

Data to Support Recommendation

- Idling the Coleman Plant will provide the largest capital cost reduction opportunities for Big Rivers and it Members.

2014 - 2016 Station Capital Cost Savings				
Station	2014	2015	2016	Total
Wilson	$ 13,511,500	$ 4,012,500	$ 5,947,610	[redacted]
Coleman	$ 17,135,459	$ 17,946,000	$ 10,609,000	[redacted]
Green	$ 13,170,295	$ 16,012,986	$ 15,965,324	[redacted]

Big Rivers
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Data to Support Recommendation

Historical Data by Unit 2008 – 2012
Sorted Lowest Costs First

Big Rivers System - 2008 - 2012 Historical Data								
Unit	EAF	EFOR	NCF	Oper. w/o Fuel	Maint.	Fuel	Non-Fuel O&M $	O&M $ inc. Fuel
Green 1	94.30	2.59	86.00	$ 4.67	$ 7.43	$ 19.76	$ 12.10	$ 31.85
Wilson	88.29	4.13	85.03	$ 4.04	$ 9.80	$ 18.19	$ 13.83	$ 32.03
Green 2	92.99	1.51	82.71	$ 4.64	$ 8.84	$ 19.68	$ 13.48	$ 33.13
Coleman 3	93.31	2.94	79.47	$ 3.57	$ 6.07	$ 25.34	$ 9.64	$ 34.98
Coleman 1	88.65	5.28	73.50	$ 3.52	$ 8.10	$ 25.64	$ 11.62	$ 37.26
Coleman 2	93.69	2.89	76.37	$ 3.64	$ 6.08	$ 27.75	$ 9.72	$ 37.47
HMP'L 2	89.73	5.49	78.08	$ 5.73	$ 8.53	$ 24.16	$ 14.26	$ 38.42
HMP'L 1	85.50	9.71	78.67	$ 5.68	$ 10.38	$ 24.09	$ 16.06	$ 40.15

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Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy® Cooperative

Data to Support Recommendation

Historical Data by Plant 2008 – 2012
Sorted Lowest Costs First

Big Rivers System - 2008 - 2012 Historical Data								
Station	EAF	EFOR	NCF	Oper. w/o Fuel	Maint.	Fuel	Non-Fuel O&M $	O&M $ inc. Fuel
Wilson Station	88.29	4.13	85.03	$ 4.04	$ 9.80	$ 18.19	$ 13.83	$ 32.03
Green Station	93.65	2.05	84.36	$ 4.66	$ 8.14	$ 19.72	$ 12.79	$ 32.53
Coleman Station	91.88	3.70	76.45	$ 3.58	$ 6.75	$ 26.24	$ 10.33	$ 36.57

Big Rivers ELECTRIC CORPORATION
Your Touchstone Energy® Cooperative

Rate Case Comparison

Wilson Lay-Up Savings (2014-2015 Annual Average)		
FDE Non-Labor	$	15,213,931
FDE Labor	$	12,786,089
Total FDE Budget	**$**	**28,000,020**
Less Lay-Up cost	$	(611,391)
Less Retained Big Rivers Labor	$	(1,513,437)
Total FDE Budget Reduction	**$**	**25,875,193**

Coleman Lay-Up Savings (2014-2015 Annual Average)		
FDE Non-Labor	$	16,396,384
FDE Labor	$	12,172,987
Total FDE Budget	**$**	**28,569,371**
Less Lay-Up cost	$	(1,218,422)
Less Retained Big Rivers Labor	$	(1,513,434)
Total FDE Budget Reduction	**$**	**25,837,516**

Note: Idling a station does not eliminate all fixed costs. Items such as Depreciation, Interest, Property Tax, and Property Insurance remain.

Big Rivers ELECTRIC CORPORATION
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Intangibles

- The fuel cost for 2014 and 2015 is essentiality fixed due to Big Rivers being 100% hedged for those two years.
- The only difference in fuel cost would be based on unit specific heat rate.
- Green and Wilson is permitted to burn Pet Coke, Coleman is not.
- Green is designed to burn lower quality coal (10,800 btu vs. 11,500 at Coleman and Wilson). Lower quality can mean more supply options and lower cost.
- Coleman has limited space to install any new Environmental equipment.
- Will cost 33% more to install same Environmental equipment on Coleman vs. Green or Wilson (3 units at Coleman vs. 2 at Green and 1 at Wilson).
- Coleman is the oldest generating units in our system (except Reid 1).

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Big Rivers ELECTRIC CORPORATION
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Environmental Equipment

Environmental Equipment	Coleman	Green	Wilson
FGD (Scrubber)	95% Efficiency	98% Efficiency	92% Efficiency
Selective Catalyic Reduction (SCR)	No	No	90% Efficiency

Proposed Environmental Regualtions	Coleman	Green	Wilson
316 a&b	Requires Investment	Compliant	Compliant
Coal Combustion Residual (CCR)	Requires Investment	Requires Investment	Compliant

Discussion / Conclusion

- Based on the supporting information provided in this presentation, management is requesting Board approval to idle the Coleman generating facility if the wholesale power market is not sufficient to cover the total production cost of the Coleman units.
- Management will submit a request to MISO to convert the current Attachment Y-2 into an Attachment Y.

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
Second Request for Information
dated September 16, 2013**

**September 30, 2013
Confidential Markings Removed – July 18, 2019**

Item 18) *Please refer to BREC's response to AG 1-53, page 28, (Confidential): Provide all documents, power point presentations, etc. associated with the presentation and analysis of [BEGIN CONFIDENTIAL] "the Big Rivers' Electric Corporation Salaried Employees Retirement Plan and Bargaining Employees Retirement Savings Plan" [END CONFIDENTIAL], both before the Board of Directors, and in any board work session.*

Response) To the best of Big Rivers' knowledge, there are no responsive documents.

Witness) Thomas W. Davis

**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
Second Request for Information
dated September 16, 2013**

**September 30, 2013
Confidential Markings Removed – July 18, 2019**

Item 19) *Please refer to BREC's Response to AG 1-53, page 26, (Confidential): Provide all documents, power point presentations, etc. associated with the presentation and analysis of [BEGIN CONFIDENTIAL] the deferral "until 2014 the marketing of [property and casualty insurance] coverages to multiple brokers and direct writers as called for in Big Rivers' property and casualty insurance procurement procedures" [END CONFIDENTIAL], both before the Board of Directors, and in any board work session.*

a. Explain what are [BEGIN CONFIDENTIAL] "the expected changes in Big Rivers' operations over the next 6-12 months" [END CONFIDENTIAL], and,

b. Explain what is [BEGIN CONFIDENTIAL] "the impact of those changes on underwriting of [BREC's] property and casualty insurance" [END CONFIDENTIAL].

c. State why it is appropriate to not obtain [BEGIN CONFIDENTIAL] multiple bids for property and casualty insurance coverage, and defer obtaining multiple bids until 2014. [END CONFIDENTIAL]

d. Describe in detail how the management recommendation and Board action is consistent with BREC's response to KIUC-26.

Response)

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 Second Request for Information dated September 16, 2013

September 30, 2013
Confidential Markings Removed – July 18, 2019

Item 20) *Please refer to BREC's Response to AG 1-53 (Confidential): Provide minutes and/or notes from all executive sessions or any other non-Regular meeting of the Big Rivers' Board of Directors, from 1/1/13 to the present, specifically to include the session referenced at page 14, during the [BEGIN CONFIDENTIAL] April 19, 2013 [END CONFIDENTIAL] board meeting, as well as any others during that time period.*

Response) Please see the attached CONFIDENTIAL document. There are no other minutes of executive sessions or other non-regular meetings.

Witness) Mark A. Bailey

BIG RIVERS ELECTRIC CORPORATION
SPECIAL BOARD OF DIRECTORS MEETING
MARCH 21, 2013

A special meeting of the Board of Directors of Big Rivers Electric Corporation was called to order at 6:00 p.m., CDT, on Thursday, March 21, 2013, at Kenergy Corp., 6402 Old Corydon Road, Henderson, KY 42420.

James Sills, Chair, presided and Larry Elder, Secretary-Treasurer, acted as Secretary of the meeting.

Upon calling the roll, the Secretary-Treasurer reported that the following directors were present: Messrs. Sills, Butler, Elliott, Elder, Bearden, and Denton. Also present were Mark Bailey, president/CEO; James Miller, corporate counsel; Billie Richert, Eric Robeson, Lindsay Barron, and Dean Lawrence, Big Rivers' management; and Steve Thompson, vice president of accounting and finance, Kenergy Corp.

Billie Richert, Vice President Accounting, Rates/CFO, introduced Joe Charles and Kevin Lyons of KPMG who presented Big Rivers' 2012 annual financial audit results to the Board. At the conclusion of the presentation, members of management left the meeting room to allow the Board to have further discussions with the auditors.

The meeting adjourned at 7 p.m.

Larry Elder
Secretary-Treasurer

APPROVED:

Chair

row references at the Financial Model.

i. *Per Attachment AG 1-76(a), "Total Cost of Electric Service" showing a difference of BEGIN CONFIDENTIAL*** $63,699,352 END CONFIDENTIAL between costs in Case No. 00535 and Case No. 00199, explain if this is intended to be the same BEGIN CONFIDENTIAL $63 million ***END CONFIDENTIAL shown as the revenue requirement impact of the Century departure in Case No. 00535 (per Exhibit Berry-4), or explain if this amount is merely a coincidence. Provide all related explanations.*

Response) Big Rivers objects that this request is overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding these objections and without waiving them, Big Rivers responds as follows.

a. AG 1-86(a) did not request a working Excel version of the attachment. Nevertheless, please see the electronic attachment labeled 'AG 2-28 Elec. Att. CONFIDENTIAL.xlsx', worksheet 'AG 2-28(a)'.

b. Please see Big Rivers' response to subpart (a).

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

In the Matter of:

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

Responses to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Office of the Attorney General's Supplemental Request for Information, Item Nos. 28ac and 28d originally filed September 30, 2013

Information submitted on CD accompanying responses

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

In the Matter of:

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

Responses to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Office of the Attorney General's Supplemental Request for Information, Item Nos. 29ab and 29c originally filed September 30, 2013

Information submitted on CD accompanying responses

show where the $11 million of Wilson "Labor Reduction" and "Non-Recurring Labor" have been removed in this rate case and provide supporting documentation and calculations. Show amounts for all months and for the base period and forecasted test period, and reconcile these amounts to the same format used for removing Coleman non-recurring labor at Schedule 1.10. Explain the reasons for differences in assumptions and methods used in calculating Labor Reduction and Non-Recurring Labor costs for Wilson and Coleman. Also, provide a citation to where all amounts are reflected in the Financial Model, showing worksheet and row numbers.

*j. The response to AG 1-76 shows confidential "Non-Labor Expenses" related to the Wilson lay-up of BEGIN CONFIDENTIAL*** $15 million ***END CONFIDENTIAL. Also, Mr. Wolfram's testimony and exhibits (p. 18 and Schedule 1.13) in this rate case only show an adjustment to remove idled Coleman plant non-labor expenses. Explain and show where the Wilson "Non-Labor Expenses" have been removed in this rate case and provide supporting documentation and calculations (show amounts for all months and for the base period and forecasted test period), and reconcile these amounts to the same format used for removing Coleman non-labor expenses at Schedule 1.13.*

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(a)(iii)
Wilson Station Operating Costs for the Test Period

Line No.		Feb 14 CN 2013-00199	Mar 14 CN 2013-00199	Apr 14 CN 2013-00199	May 14 CN 2013-00199	Jun 14 CN 2013-00199	Jul 14 CN 2013-00199
	WILSON						
1	Non Labor Expenses	42,300	42,300	45,800	51,283	49,183	49,183
2	Labor Expenses	132,509	143,227	136,406	145,176	124,714	136,406
3	Variable Costs	-	-	-	-	-	-

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(a)(iii)
Wilson Station Operating Costs for the Test Period

Line No.		Aug 14 CN 2013-00199	Sep 14 CN 2013-00199	Oct 14 CN 2013-00199	Nov 14 CN 2013-00199	Dec 14 CN 2013-00199	Jan 15 CN 2013-00199
	WILSON						
1	Non Labor Expenses	49,183	42,300	42,300	42,222	42,222	112,361
2	Labor Expenses	145,176	126,968	151,742	124,986	128,950	140,360
3	Variable Costs	33,333	33,333	33,334	-	-	-

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(a)(iii)
Wilson Station Operating Costs for the Test Period

Line No.		Test Period Feb 14-Jan 15 CN 2013-00199	Worksheet and Row Reference In Financial Model	Reference to AG 1-86
	WILSON			
1	Non Labor Expenses	610,637	O&M, Rows 127-129, 131-132,135-139,142	Production Expense Non-Labor
2	Labor Expenses	1,636,619	O&M, Rows 149-179	Labor
3	Variable Costs	100,000	PCM, Rows 121-135, 140	Fuel, Reagent and Allowances

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(b)(iii)
Coleman Station Operating Costs for the Test Period

Line No.		Feb 14 CN 2013-00199	Mar 14 CN 2013-00199	Apr 14 CN 2013-00199	May 14 CN 2013-00199	Jun 14 CN 2013-00199
	COLEMAN					
5	Non Labor Expenses	430,264	53,049	58,591	65,601	220,054
6	Labor Expenses	140,347	151,154	158,789	148,174	104,141
7	Variable Costs	15,450	-	-	-	-

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(b)(iii)
Coleman Station Operating Costs for the Test Period

Line No.		Jul 14 CN 2013-00199	Aug 14 CN 2013-00199	Sep 14 CN 2013-00199	Oct 14 CN 2013-00199	Nov 14 CN 2013-00199
	COLEMAN					
5	Non Labor Expenses	79,317	71,554	68,811	72,274	83,253
6	Labor Expenses	114,019	121,427	106,368	127,355	104,689
7	Variable Costs	-	-	-	-	-

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(b)(iii)
Coleman Station Operating Costs for the Test Period

Line No.		Dec 14 CN 2013-00199	Jan 15 CN 2013-00199	Test Period Feb 14-Jan 15 CN 2013-00199
	COLEMAN			
5	Non Labor Expenses	231,753	131,628	1,566,150
6	Labor Expenses	108,047	116,321	1,500,832
7	Variable Costs	-	-	15,450

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(b)(iii)
Coleman Station Operating Costs for the Test Period

Line No.		Worksheet and Row Reference In Financial Model	Reference to AG 1-86
	COLEMAN		
5	Non Labor Expenses	O&M Rows 127-129, 131-132,135-139,142	Production Expense Non-labor
6	Labor Expenses	O&M, Rows 149-179	Labor
7	Variable Costs	PCM, Rows 121-135, 140	Fuel, Reagent and Allowances

Big Rivers Electric Corporation
Case No. 2013-00199

Attachment for Response to AG 2-31(f)
Attachment 1
($ millions)

		Century & Alcan
Revenue Loss	$	360
Variable Cost	$	196
Gross Sales Margin	$	164
Non Labor Expense	$	30
Labor Reduction	$	22
Addl. OSS Net Sales Margin	$	1
Reduction in MISO Administrative Fees	$	2
Net Revenue Deficiency	$	109

Big Rivers Electric Corporation
Case No. 2013-00199

Attachment for Response to AG 2-31(g)
Attachment 1
($ millions)

	Century & Alcan	Century	Alcan
Gross Sales Margin (Revenue less Variable cost)	$ 164	$ 92	$ 72
Non-Labor Expenses	$ 30	$ 15	$ 15
Labor Reduction	$ 22	$ 11	$ 11
Addl. OSS* Gross Sales Margin	$ 1	$ 1	$ -
Reduction in MISO* Administrative Fees	$ 2	$ 2	$ -
Net Revenue Deficiency	$ 109	$ 63	$ 46

*The two items, off-system sales ("OSS") and Midcontinent Independent Service Operator, Inc. ("MISO"), that were included on Exhibit-4 Berry provided in Case No. 2012-00535 were marginal in the Alcan case.

Item 32) *Regarding BREC's Confidential response to PSC 2-15 in regards to the PSC's request if BREC has offered to sell the Wilson and Coleman plants, address the following:*

*BEGIN CONFIDENTIAL****

a. Identify the counterparties to which the sale of Wilson and Coleman plants has been offered, provide a copy of the related offer to sale which was provided to all counterparties, and provide all correspondence with these parties to date.

b. Provide all supporting documentation, calculations and studies that BREC relied upon in arriving at the offered sales price of $500 million for Wilson and $200 million for Coleman.

c. If BREC would sell the Wilson and Coleman plants at the offered prices in this data request response, provide and describe the journal entry that would be recorded for the sale of these plants, and show amounts by account number with an explanation of all accounts impacted.

*END CONFIDENTIAL****

Response) Please see Big Rivers' responses to SC 2-29 and SC 2-30.

Item 34) *Regarding BREC's Confidential response to PSC 2-15, address the following:*

*BEGIN CONFIDENTIAL****

a. *Explain why the net book value (NBV) used in these calculations excluded construction work in progress (CWIP) at July 31, 2013, since these costs have already been incurred by BREC. Explain if the actual CWIP plant would be dissembled or not provided to the buyer, or if the buyer would be provided the CWIP at no additional charge.*

b. *Provide the NBV of Wilson and Coleman including the CWIP at July 31, 2013, and provide all related supporting documentation and calculations. Show the amount of CWIP by major project/work order, and reconcile to workpapers, documents, and the Financial Model provided in this rate case (and reconcile to all amounts included in the forecasted test period in this rate case).*

c. *Provide all documentation and calculations supporting the July 31, 2013, NBV of $448.3 m for Wilson and $180.1 mil. for Coleman, and provide all amounts by primary account number for gross plant, accumulated depreciation reserve, accumulated deferred income taxes, and all other accounts. Provide a reconciliation to workpapers, documents, and the*

Financial Model provided in this rate case (and reconcile to all amounts included in the forecasted test period in this rate case). Explain if any amounts were written down or written off in the calculation of NBV.

d. *Provide all documentation and calculations supporting the July 31, 2013, Long-Term Debt of $858.9 mil., and provide all amounts by primary account number. Provide a reconciliation to workpapers, documents, and the Financial Model provided in this rate case (and reconcile to all amounts included in the forecasted test period in this rate case).*

e. *If the Wilson and Coleman plants were sold for a combined $700 mil. (or some other amount), explain how much of this $700 mil. in proceeds (or the amount of proceeds received) would be used to pay-off and reduce the long-term debt balance of $858.9 mil., and how much of the proceeds would be used for other purposes such as capital expenditures, deferred maintenance, payroll bonuses/incentive payments, etc. (and explain the reasons for how the proceeds would be used).*

f. *Explain how much of the long-term debt that BREC would be contractually obligated to pay-off to lenders and provide a citation to related loan* *documents, or explain if there are no lender covenants or requirements for pay-off of debt when significant assets are sold.*

****END CONFIDENTIAL.*

Response) Big Rivers objects that this request is not reasonably calculated to lead to the discovery of admissible evidence. Big Rivers further objects to the extent that this request seeks a legal interpretation of documents that speak for themselves. Notwithstanding these objections, and without waiving them, Big Rivers responds as follows.

a. The Net Book Value ("NBV") calculated for each plant in response to PSC 2-15 excluded Construction Work-In-Progress ("CWIP") as the question requested "net" amounts. Accordingly, Big Rivers provided only net amounts for plant in service as no depreciation is taken on CWIP. In order to avoid potential confusion regarding what amounts were included in the response, Big Rivers explicitly stated that the amounts did not include CWIP within the response. If either the Wilson and/or Coleman plants were sold, the handling of actual CWIP would be based on the terms of the actual sales agreement.

b. Please see the electronic attachment to this response for the NBV of Wilson and Coleman, including CWIP, as of July 31, 2013 with supporting detail.

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

In the Matter of:

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

Responses to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Office of the Attorney General's Supplemental Request for Information, Item Nos. 34bcd originally filed September 30, 2013

Information submitted on CD accompanying responses

Item 35) *Regarding BREC's Confidential response to PSC 2-15 address the following:*

*BEGIN CONFIDENTIAL****

a. *BREC's response shows a NBV of $448.5 mil. for Wilson and $180.1 m for Coleman, and total long-term debt of $858.9 mil., but this is only the capital costs and debt impact. If Wilson and/or Coleman was sold, provide the total revenue requirement impact of Wilson and Coleman by showing all capital costs and all balance sheet amounts impacted (plant in service, CWIP, accumulated depreciation reserve, accumulated deferred taxes, other deferred balances, etc.) and all revenues, expense and operating income statement amounts impacted (depreciation, property taxes, insurance, interest expense on debt, labor expense, non-labor expense, administrative and general costs, etc.) and provide the amounts by account number and account description (and cite to such amounts included in the forecasted test period).*

b. *Regarding the amounts in (a) above, explain and show the amount of gain or loss that would result, assuming a sales price of $500 mil. for Wilson and $200 mil. for Coleman, and provide all supporting documentation and calculations.*

***END CONFIDENTIAL

Response) Big Rivers objects that this request is not reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding this objection, and without waiving it, Big Rivers responds as follows.

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

b. See Big Rivers' response to subpart (a), above.

Witness) Billie J. Richert

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
Second Request for Information
dated September 16, 2013

September 30, 2013
Confidential Markings Removed – July 18, 2019

Item 36) *Provide all supporting documentation Regarding BREC's Confidential response to PSC 2-15, and address the following: BEGIN CONFIDENTIAL****

a. *Explain if the sale of Wilson at $500 mil. and the sale of Coleman at $200 mil. will result in a gain or loss, and provide all supporting documentation and calculations.*

b. *Explain and provide a copy of all scenarios and cost versus benefit analysis prepared by BREC in considering whether to sale Wilson and Coleman at amounts above or below the $500 mil. for Wilson and $200 mil. for Coleman that is set forth in this response (and include the scenario of selling Wilson at $500 mil. and Coleman at $200 mil.). Show the resulting gain or loss that would be recorded by BREC under each scenario (including the sale of Wilson at $500 mil. and Coleman at $200 mil.) and provide related supporting documentation and calculations.*

c. *Explain and show the possible cost versus the benefit of selling Wilson and Coleman at a price less than $500 mil. and $200 mil. respectively, in order to sale these plants more quickly. For example, explain if BREC has considered scenarios of selling Wilson and Coleman at a loss, and then sharing this loss with customers by amortizing the loss over a ten-year* *period (or a different amortization period). Provide copies of such scenarios and explain the cost versus the benefit and provide supporting explanations, documentation, and calculations.*

d. *Regarding items (b) and (c) above, explain the cost versus the benefit of selling Wilson and Coleman at a loss of $100 million (or amounts under any and all other scenarios evaluated by BREC) to be amortized over 10 years (or some other amortization period evaluated by BREC), compared to customers continuing to pay at least $109 mil. per year just for Wilson operating costs (BREC response to AG 1-76), plus depreciation expense on Wilson plant of at least $448 mil. NBV and Coleman plant of $180 m NBV (the depreciation expense would actually be paid on amounts greater than these NBV amounts). In other words, won't it be more costly for customers to continue to pay for the on-going costs of Wilson and Coleman in the long-term (or over several more years), instead of selling Wilson and Coleman at some loss (with some reasonable limit to the loss). Explain and provide all scenarios that BREC has performed regarding these considerations and explain the cost versus the benefit, along and provide all supporting documentation and calculations.*

indicate the IRP would be completed over about 7 months ending June 21, 2013.

f. *Explain when actual costs will start being incurred for the IRP, Load Forecast, and Transient Study, and provide supporting documentation for this such as citations to bid documents and RFPs.*

g. *AG 1-285(b) requested copies of actual invoices for work performed to date on the IRP, Load Forecast, and Transient costs included in the test period, but it appears that invoices for only the months of February, March, April, and May 2013 have been provided (and these reflect a relatively small amount of costs). Explain why few costs have been billed and the IRP is not substantially complete, when the prior cited bid document indicated the IRP would be completed by June 21, 2013.*

h. *In BREC's response to AG 1-285, explain why the Load Forecast costs shown at 1-285a Attachment, along with 1-285d Attachment, do not reconcile to the total Load Forecast costs of $65,000 in Mr. Wolfram's testimony. Provide all reconciliations and supporting documents.*

i. *Explain why the Load Forecast and Transient Stability costs are not spread over 3 years, or are not amortized over 3 years.*

j. In BREC's response to AG 1-285(d), explain why the IRP budgeted costs of $445,000 are greater and different than the bid amounts.

k. In BREC's response to AG 1-285(d), explain why IRP budgeted costs of $445,000 are significantly greater than the actual IRP costs of $269,780 incurred in 2010 and 2011 as shown at 1-285d Attachment.

l. Explain why most of the actual costs of the prior IRP (shown at 1-285d Attachment) were incurred in one year, while the budgeted IRP costs included in this rate case have been spread randomly over three years.

m. Explain why IRP, Load, and Transient budgeted costs should be included in the test period when BREC does not provide actual updated cost for these services similar to updates provided for rate case expense.

Response) Big Rivers objects that this question is overly broad and unduly burdensome. Big Rivers further objects that the question is argumentative to the extent that it mischaracterizes Big Rivers as acting "randomly." Notwithstanding these objections, and without waiving them, Big Rivers responds as follows.

Big Rivers is not aware of any error in the IRP costs identified in this case. The question states that in the current case, Big Rivers "proposes recovery of $60,000 of these

b. IRP costs are ratably amortized over three years, but the question does not account for the amounts of IRP costs already included in the test period. Please see the response to subpart a.

c. The $271,500 shown in the response to AG 1-285(a) attachment does not reconcile to the $445,000 total IRP costs because the $271,500 includes only those amounts included in the base period and forecast test period. The total amount of $445,000 includes costs for months that are not included in either the base period or the test period. See attached. (Note that in Case No. 2013-00034 Big Rivers was granted an extension, until May 15, 2014 to file its next IRP. This extension of time is not reflected in the forecast of IRP expenses. This has no effect on the revenue requirement because the entire forecasted IRP cost is ratably amortized over three years, not over the test period.)

d. Please see the response to subpart c, above.

e. The estimate of costs over three years is provided because the IRP filing is due every three years. The vendor producing the IRP may do so over a seven month period, but the proceeding before the Commission will take additional time, and the entire process will be repeated every three years.

Item 43) *Regarding BREC's response to AG 1-53 and the related Confidential Board of Director Minutes (BODM), address the following: BEGIN CONFIDENTIAL****

a. *The March 14, 2013, BOD minutes refer to a "Oxford Mining lawsuit." Explain this lawsuit and identify costs by account number and outside attorney included in the base period and forecasted test period, and separately identify actual and forecasted costs. Explain why these costs should be recovered in this rate case.*

b. *The April 19, 2013 BOD minutes (p. 13), refer to "Management's Report." Explain if these are reports previously provided to the AG, or otherwise provide the Management's Report for all months of 2012 and 2013 year-to-date and describe the purpose of these reports.*

c. *The May 17, 2013 BOD minutes (p. 15), refer to presentations made to the BOD by Mr. Wolfram, Ms. Richert, Mr. Bailey, Mr. Warren, and others regarding actions recommended by management in response to the Alcan notice of termination. Provide a copy of this and all other written and oral presentations made to the BOD regarding both Alcan and Century in regards to their termination and subsequent actions.*

d. The May 17, 2013 BOD minutes (p. 23), refers to possible discontinuation of NRECA membership and reduction in NRECA member dues, explain the status of this membership, identify the NRECA costs included in the forecasted test period by account number, and identify all reductions in NRECA dues and if these are reflected in this rate case.

e. The July 19, 2013 BOD minutes (p. 28), refer to amendments/changes to the retirement and savings plans and the post-retirement medical insurance plans. Provide a copy of documentation describing these changes, identify the amount of cost savings from such changes, and explain if these cost reductions have been included in the forecasted test period of this rate case and provide all related calculations and documentation, or explain why these cost reductions have not been included in this rate case.

******END CONFIDENTIAL***

Response)

a. Oxford Mining Company - Kentucky, LLC ("Oxford") filed a civil action against Big Rivers on April 26, 2012, styled *Oxford Mining - Kentucky, LLC v. Big Rivers Electric Corporation*, Ohio Circuit Court Civil Action No. 12-

recently-approved Century contract was provided in response to AG 1-2(a) in Case No. 2013-00221.

d. Big Rivers renewed its membership with the NRECA in July 2013. Please refer to Big Rivers' response to TAB 49 of the Application for the amount of NRECA dues included in the forecasted test period. These dues are coded to major account 930. At the time of the application, any reduction in dues was not known. There was a $74,959 reduction in dues, as described in the attachment. Additionally, members' payment of their own CRN dues saved $14,976.

e. Please see the response to AG 2-18 for Board minutes regarding amendments/changes to the retirement and savings plans. Management's plan with regard to post-retirement medical insurance is still under review. No recommendation was made at the August board meeting.

Witnesses) Robert W. Berry, Mark A. Bailey, Billie J. Richert, Christopher A. Warren, John Wolfram, Thomas W. Davis

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

In the Matter of:

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

Responses to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Office of the Attorney General's Supplemental Request for Information, Item No. 43b originally filed September 30, 2013

Information submitted on CD accompanying responses

Item 47) *BREC's response to AG 1-57 states, BEGIN CONFIDENTIAL*** there is one company conducting due diligence of the Coleman plant associated with BREC's offer to sell that facility***END CONFIDENTIAL. Address the following:*

a. *Identify the name of the "company" performing the services mentioned above and provide a copy of the related contract, RFP, and engagement letter.*

b. *Provide the amount paid to the "company" by account number, and provide copies of all invoices.*

c. *Explain if the costs of this "company" have been included in the forecasted test period of this rate case and identify all costs for the base period and forecasted test period, separately show actual and forecasted amounts, and show amounts by account number. Explain why it is reasonable to recover these costs from BREC's customers.*

Response)

a. The name of that company is identified in the confidential portion of the Attorney General's information request number AG 2-53. Please understand

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
Second Request for Information
dated September 16, 2013

September 30, 2013
Confidential Markings Removed – July 18, 2019

Item 53) ***Referencing Big Rivers' response to PSC 2-15 that [BEGIN CONFIDENTIAL]"Big Rivers has also offered to sell the Coleman Station to Century Aluminum for $200 Million." Please explain in detail how the Century Agreement language would be affected regarding the offset of transmission costs through SSR operation of the Coleman unit. Is it possible that the Century Agreement and a subsequent sale of Coleman to Century would result in the Century Hawesville smelter never paying anything to Big Rivers for use of Big Rivers' transmission system? If so why would Big Rivers contemplate such a sale? If so why did Big Rivers enter into the Century Agreement? [END CONFIDENTIAL]***

Response) If Big Rivers sells the Coleman Station to Century,the SSR Agreement to which Big Rivers is a party will terminate. Century is required to pay transmission charges to Big Rivers whether or not there is a SSR Agreement.

Witness) Robert W. Berry

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 Second Request for Information dated September 16, 2013

September 30, 2013
Confidential Markings Removed – July 18, 2019

Item 54) *Referencing Big Rivers' response to KIUC 1-52 and the installation of MATS equipment at Wilson and Coleman, please provide the following:*

a. *Costs of installing this equipment for each unit.*

b. *Dates these costs will be incurred.*

c. *Net Plant for both all Coleman and Wilson accounts for the years of 2014 through 2020.*

Response)

a. The estimated costs to install MATS equipment at Wilson currently is $11.24 million. The estimated cost to install MATS equipment at Coleman currently is $28.44 million.

b. These costs will be not be incurred on a specific single date; they will be incurred over time, but Big Rivers expects that the vast majority of expenses will be incurred approximately one year prior to returning these plants to service.

c. Please see the attachment to this response for budgeted net plant values for Coleman and Wilson for the years 2014 through 2016 based on Big Rivers'

Big Rivers Forecasted Delivered Coal Prices, $/MMBtu

Year	Coleman		Green		HMP&L		Wilson	
	$/MMBtu	% Annual Increase	$/MMBtu	% Annual Increase	$/MMBtu	% Annual Increase	$/MMBtu	% Annual Increase
2013	$ 2.397		$ 1.993		$ 2.424		$ 1.973	
2014	$ 2.355	-1.8%	$ 2.180	9.4%	$ 2.300	-5.1%	$ 2.252	14.1%
2015	$ 2.506	6.4%	$ 2.375	8.9%	$ 2.553	11.0%	$ 2.404	6.7%
2016	$ 2.505	0.0%	$ 2.441	2.8%	$ 2.660	4.2%	$ 2.483	3.3%
2017	$ 2.687	7.3%	$ 2.660	9.0%	$ 2.739	3.0%	$ 2.687	8.2%
2018	$ 2.768	3.0%	$ 2.717	2.2%	$ 2.837	3.6%	$ 2.747	2.2%
2019	$ 2.880	4.1%	$ 2.830	4.2%	$ 2.949	3.9%	$ 2.860	4.1%
2020	$ 2.920	1.4%	$ 2.870	1.4%	$ 2.987	1.3%	$ 2.900	1.4%
2021	$ 2.969	1.7%	$ 2.919	1.7%	$ 3.037	1.7%	$ 2.950	1.7%
2022	$ 3.045	2.6%	$ 2.996	2.6%	$ 3.111	2.4%	$ 3.026	2.6%
2023	$ 3.120	2.5%	$ 3.071	2.5%	$ 3.183	2.3%	$ 3.101	2.5%
2024	$ 3.211	2.9%	$ 3.163	3.0%	$ 3.261	2.4%	$ 3.193	3.0%
2025	$ 3.268	1.8%	$ 3.219	1.8%	$ 3.318	1.8%	$ 3.250	1.8%
2026	$ 3.361	2.9%	$ 3.312	2.9%	$ 3.412	2.8%	$ 3.343	2.9%
2027	$ 3.364	0.1%	$ 3.315	0.1%	$ 3.415	0.1%	$ 3.346	0.1%
2028	$ 3.479	3.4%	$ 3.430	3.5%	$ 3.531	3.4%	$ 3.461	3.5%

	Prices based on All Running with existing coal contracts and spot purchases as required
	Prices escalated from 2017 by the average annual increase from ACES (Wood Mac) and JDE long term forecasts

Updated spot coal pricing for revised / updated model runs (Century / Alcan)

Synopsis/Avg

	2013	2014	2015	2016	2017	
[redacted]	$ 2.0053	$ 2.0780	$ 2.3703	$ 2.5004	$ 2.5750	
Transport	**$ 2.1536**	**$ 2.2301**	**$ 2.5262**	**$ 2.6601**	**$ 2.7386**	
[redacted]	$ 1.9334	$ 2.0067	$ 2.1550	$ 2.2784	$ 2.5878	
Transport	**$ 2.0856**	**$ 2.1628**	**$ 2.3150**	**$ 2.4423**	**$ 2.7556**	[redacted]
[redacted]	$ 1.7916	$ 1.9092	$ 2.1281	$ 2.2248	$ 2.4845	
	$ 1.9507	**$ 2.0724**	**$ 2.2954**	**$ 2.3962**	**$ 2.6600**	

Transport: Barging contract expires 12/31/13. Estimated $3.50/ton transport fee for delivery.
Escalation on transport fee 2.50% per year, to include fuel.

Updated spot coal pricing for revised / updated model runs (Century / Alcan)

13-Mar-13

Coal Outlook

	2013	2014
11,800 BTU	$ 1.7924	$ 1.7924
11,500 BTU	$ 2.0978	$ 2.0978
11,000 BTU	$ 1.7818	$ 1.7818

Coal Daily

	2013	2014	2015	2016
11,800 BTU	$ 2.1300	$ 2.2458	$ 2.4047	$ 2.5636
11,500 BTU	$ 1.9200	$ 2.0200	$ 2.1400	$ 2.2500
11,000 BTU	$ 1.8600	$ 1.9300	$ 2.0500	$ 2.1400

ACES Power Marketing

	2013	2014	2015	2016	2017
11,800 BTU	$ 2.0935	$ 2.1959	$ 2.3359	$ 2.4372	$ 2.5750
11,500 BTU	$ 1.7824	$ 1.9022	$ 2.1701	$ 2.3067	$ 2.5878
11,000 BTU	$ 1.7048	$ 1.8194	$ 2.0756	$ 2.2063	$ 2.5877

J. D. Energy

	2013	2014	2015	2016	2017
11,000 BTU	$40.03	$46.32	$49.69	$51.22	$52.39
	$ 1.8197	$ 2.1055	$ 2.2587	$ 2.3280	$ 2.3814

Synopsis/Avg

	2013	2014	2015	2016	2017
11,800 BTU	$ 2.0053	$ 2.0780	$ 2.3703	$ 2.5004	$ 2.5750
11,500 BTU	$ 1.9334	$ 2.0067	$ 2.1550	$ 2.2784	$ 2.5878
11,000 BTU	$ 1.7916	$ 1.9092	$ 2.1281	$ 2.2248	$ 2.4845

Attachment for Response to AG 2-57

Weekly Price Survey: Traditional Physical Market, week ending Mar 8

Origin/Product	Btu/lb	SO2 lb	Transport Mode	Prompt Quarter	Q3 2013	Q4 2013	Cal. Yr. 2014
Northern Appalachia							
Pittsburgh Seam	13,000	<3.0	RAIL	61.10	61.25	61.30	62.35
	13,000	4	RAIL	54.50	54.95	54.95	55.40
Upper Ohio River	12,500	6+	BARGE	45.55	46.55	46.55	47.00
Central Appalachia							
CAPP barge physical	12,000	1.67	BARGE	59.95	61.70	63.20	67.10
Big Sandy/Ohio River	12,000	1.2	BARGE	63.15	64.90	66.40	70.20
CAPP rail (CSX) physical	12,500	1.6	CSX	61.25*	63.25*	65.15*	69.20*
Big Sandy/Kanawha	12,500	1.2	CSX	64.10	66.25	68.10	71.95
Thacker/Kenova	12,500	1.5	NS	64.90	67.25	68.80	71.65
Thacker/Kenova	12,500	1.2	NS	66.75	69.20	70.85	73.55
Illinois Basin /MM BTU							
$1.7924	11,800	5	RAIL	42.20	42.30	42.40	42.30
$2.0978	11,500	2.5	RAIL	48.15	48.25	48.35	48.25
$1.7818	11,000	5	BARGE	39.10	39.20	39.30	39.20
	10,500	6+	RAIL	32.10	32.20	32.30	32.20
Powder River Basin							
	8,800	0.8	RAIL	10.35	10.65	10.90	12.50
	8,400	0.8	RAIL	9.55	9.85	10.00	11.65
Rocky Mountain							
Colorado	11,700	0.8	RAIL	41.00	41.00	41.00	41.00
	11,000	0.8	RAIL	32.00	32.00	32.00	32.00
Utah	11,500	0.8	RAIL	37.50	37.50	37.50	37.50

Two assessments in this table were renamed effective Dec. 20, 2010: CAPP barge physical was previously named NYMEX look-alike; CAPP rail (CSX) physical was Big Sandy/Kanawha with the same, unchanged specifications listed in the table. *Price change from previous week.

OTC Hedge Price Monitor, Friday-Thursday average of Platts Daily OTC Assessments

Delivery: Within Calendar Period Specified.

Region/Product	Btu/lb	Sulfur Lbs/ MMBtu	Sulfur Percent	Q2 2013	Q3 2013	Q4 2013	Cal. Yr. 2014
Central Appalachia							
CAPP barge OTC	12,000	1.67	1.00	59.00*	60.35*	62.30*	66.30*
CAPP rail (CSX) OTC	12,500	1.6	1.00	60.90*	62.25*	64.00*	68.50*
Powder River Basin							
PRB 8,800 OTC	8,800	0.8	0.35	9.75*	10.50*	10.70*	11.65*
PRB 8,400 OTC	8,400	0.8	0.35	9.05*	9.60*	9.75*	10.05*

The four assessments in this table were renamed effective Dec. 20, 2010; the underlying specifications and methodology were not changed. CAPP barge OTC was previously named NYMEX/barge; CAPP rail (CSX) OTC was CXS - Big Sandy/Kanawha; PRB 8,800 OTC was Wyoming/Rail 8,800; and PRB 8,400 OTC was Wyoming/Rail 8,400. Price change from previous week.

Weekly Coal Production Totals

	Week Ended 03/02/13	Week Ended 03/02/12	Year-to-Date 03/02/13	Year-to-Date 03/02/12
Bituminous and Lignite	19,335	20,294	164,921	187,214
Anthracite	47	42	400	386
U.S. Total	19,382	20,336	165,321	187,601
Railroad Cars Loaded	118,091	118,632	1,023,888	1,136,586

For state breakdowns, visit:

www.eia.doe.gov/cneaf/coal/weekly/weekly_html/wcppage.html.

Petcoke Spot Price Assessments

Origin	Sulfur	HGI	Current price range
US Gulf	6% - 6.5%	40	52.00-58.00
	5% - 6%	<50	56.00-64.00
	4% - 5.5%	50	58.00-68.00
US West Coast	4%	50	70.00-80.00
Venezuela	4%	45	60.00-70.00

Editor's Note: All petroleum coke prices are quoted in metric tons

Physical market assessments (continued)

Central Appalachia (continued)				$/st
Location	Btu/lb	lbs SO2	Price	Change
CSX rail	12,500	2.0		
Q2 2013			59.75	
Q3 2013			61.25	-0.50
Q4 2013			63.00	-0.50
2014			67.25	-0.50
2015			74.00	-0.50
2016			76.50	-1.00
Big Sandy barge	12,000	1.2		
Q2 2013			61.50	-0.50
Q3 2013			63.00	-0.50
Q4 2013			64.75	-0.50
2014			68.75	-0.50
2015			75.25	-0.50
2016			78.00	-0.50

Illinois Basin				$/st
West KY Ohio River barge	11,500	5.0		
Q2 2013			43.00	
Q3 2013 $1.92	$44.17		44.00	
Q4 2013			45.50	
2014 $2.02			46.50	
2015 $2.14			49.25	+0.25
2016 $2.25			51.75	+0.25
Illinois/Indiana mine	11,500	5.0		
Q2 2013			38.75	
Q3 2013			39.50	
Q4 2013			40.75	
2014			41.50	-0.40
2015			44.25	+0.25
2016			46.75	+0.25
West KY Ohio River barge	11,800	2.5-3.0		
Q2 2013			49.00	
Q3 2013		$50.50	50.50	
Q4 2013 $2.1398			52.00	
2014 $2.2458			53.00	
2015 $2.4047			56.75	
2016 $2.5636			60.50	+0.50
Illinois/Indiana mine	11,000	6.0		
Q2 2013			34.50	
Q3 2013			35.25	
Q4 2013			36.00	
2014			37.00	
2015			39.25	+0.25
2016			41.25	+0.25
West KY Ohio River barge	11,000	6.0		
Q2 2013			40.25	
Q3 2013	$41		41.00	
Q4 2013 $1.8636			41.75	
2014 $1.9318			42.50	
2015 $2.045			45.00	+0.25
2016 $2.1364			47.00	+0.50

fourth quarter," CSX chief financial officer Fredrik Eliasson said on 6 March at a conference hosted by JP Morgan.

Despite sharp supply cuts, Central Appalachian prices were flat to lower again this week. The approaching shoulder season has heightened the basin's demand pressures from plant retirements and gas displacement. Prompt-month Nymex gas settled 4.7¢ higher today at $3.629/mmBtu but is still too low for many generators to switch back to Central Appalachian coal. Producers are adjusting to the lower demand by cutting output. James River Coal said yesterday it trimmed 3mn st of production capacity from its Central Appalachian mines in light of the long-term demand destruction.

Note to subscribers: *Argus* is reviewing its US steam coal import assessments and proposes discontinuing its CIF Baltimore, Charleston and Mobile coal assessments on 28 March.

Argus also intends to revise the sulfur content of its Colorado-Utah weekly steam coal indexes to less than 1pc sulfur starting in April, reflecting the increasing alignment of this region with the international, seaborne markets.

Argus is also proposing revisions to its Puerto Bolivar assessment on 28 March 2013, when it will adjust standard heat and lot size. From that date, *Argus* will assess Puerto Bolivar coal at 6,000 kcal/kg with minimum net calorific value of 5,750 kcal/kg NAR. Standard lot size will be revised to 50,000 metric tonnes and sulphur content will remain up to 1pc. The assessment is priced FOB Puerto Bolivar, but transactions at other Caribbean terminals will be netted to Puerto Bolivar and incorporated into the assessment process. *Argus* will also introduce a weekly index of the daily Puerto Bolivar number, which will average the week's assessments and be published on Fridays.

Comments on these proposals can be addressed to Molly Christian at coaldaily@argusmedia.com or by telephone at +1 (202) 349-2883.

Coal Daily monthly indexes: February

Monthly indexes				$/st
Location	Btu/lb	Sulfur	Price	Change
Central Appalachia				
Nymex-spec Barge	12,000	<1%	59.25	-1.06
Big Sandy/CSX Rail	12,500	<1%	61.44	-1.88
Illinois Basin				
West KY Ohio River Barge	11,500	5.0lb	42.94	0.38
Illinois/Indiana Mine	11,500	5.0lb	38.69	0.38
Pittsburgh Seam				
FOB Mine	13,000	4.5lb	54.08	-0.04
Atlantic Basin				
Colombia (FOB Puerto Bolivar, $/mt)	11,300	<1%	80.66	1.55
USGC FOB New Orleans	11,300	0.03	58.77	0.25
Western bituminous				
UP-served CO, UT, WY	11,300	0.8lb	30.81	-1.40
Powder River Basin				
FOB Mine/Rail	8,800	0.8lb	10.35	0.15

Download from ACES Web-Site - Coal Forward Prices.
ACES Power Marketing Indices (to include ICAP and Wood/MacKenzie forecast)

Attachment for Response to AG 2-57

ACES	WKY 4.5 lb 11,800 BTU		WKY 6 lb 11,000 BTU		WKY 5.8 lb 11,500 BTU	
Apr-13	47.86		38.69		40.45	
May-13	47.86		38.69		40.45	
Jun-13	47.86		38.69		40.45	
Jul-13	49.66		40.49		42.33	
Aug-13	49.66		40.49		42.33	
Sep-13	49.66		40.49		42.33	
Oct-13	50.69		41.52		43.41	
Nov-13	50.69		41.52		43.41	
Dec-13	50.69	49.41	41.52	40.23	43.41	42.06
Jan-14	51.57	$ 2.0935	42.42	$ 1.7048	44.35	$ 1.7824
Feb-14	51.57		42.42		44.35	
Mar-14	51.57		42.42		44.35	
Apr-14	51.57		42.42		44.35	
May-14	51.57		42.42		44.35	
Jun-14	51.57		42.42		44.35	
Jul-14	52.08		43.45		45.43	
Aug-14	52.08		43.45		45.43	
Sep-14	52.08		43.45		45.43	
Oct-14	52.08		43.45		45.43	
Nov-14	52.08		43.45		45.43	
Dec-14	52.08	51.82	43.45	42.94	45.43	44.89
Jan-15	55.13	$ 2.1959	48.98	$ 1.8194	51.21	$ 1.9022
Feb-15	55.13		48.98		51.21	
Mar-15	55.13		48.98		51.21	
Apr-15	55.13		48.98		51.21	
May-15	55.13		48.98		51.21	
Jun-15	55.13		48.98		51.21	
Jul-15	55.13		48.98		51.21	
Aug-15	55.13		48.98		51.21	
Sep-15	55.13		48.98		51.21	
Oct-15	55.13		48.98		51.21	
Nov-15	55.13		48.98		51.21	
Dec-15	55.13	55.13	48.98	48.98	51.21	51.21
Jan-16	57.52	$ 2.3359	52.07	$ 2.0793	54.44	$ 2.1701
Feb-16	57.52		52.07		54.44	
Mar-16	57.52		52.07		54.44	
Apr-16	57.52		52.07		54.44	
May-16	57.52		52.07		54.44	
Jun-16	57.52		52.07		54.44	
Jul-16	57.52		52.07		54.44	
Aug-16	57.52		52.07		54.44	
Sep-16	57.52		52.07		54.44	
Oct-16	57.52		52.07		54.44	
Nov-16	57.52		52.07		54.44	
Dec-16	57.52	57.52	52.07	52.07	54.44	54.44
Jan-17	60.77	$ 2.4372	56.93	$ 2.2063	59.52	$ 2.3067
Feb-17	60.77		56.93		59.52	
Mar-17	60.77		56.93		59.52	
Apr-17	60.77		56.93		59.52	
May-17	60.77		56.93		59.52	
Jun-17	60.77		56.93		59.52	
Jul-17	60.77		56.93		59.52	
Aug-17	60.77		56.93		59.52	
Sep-17	60.77		56.93		59.52	
Oct-17	60.77		56.93		59.52	
Nov-17	60.77		56.93		59.52	
Dec-17	60.77	$ 2.5750	56.93	$ 2.5877	59.52	$ 2.5878

Attachment for Response to AG 2-57

J. D. Energy	WKY 5.[illegible] 11,000 BTU	
Jan 2013	$38.75	
Feb	$38.75	
Mar	$38.65	
Apr	$38.60	
May	$38.75	
Jun	$39.30	
Jul	$39.90	
Aug	$40.65	
Sep	$41.00	
Oct	$41.35	
Nov	$41.95	
Dec	$42.75	$40.03
Jan 2014	$43.85	
Feb	$44.20	
Mar	$44.40	
Apr	$44.65	
May	$44.95	
Jun	$45.90	
Jul	$46.85	
Aug	$48.00	
Sep	$48.05	
Oct	$48.15	
Nov	$48.30	
Dec	$48.55	$46.32
Jan 2015	$49.30	
Feb	$49.40	
Mar	$49.50	
Apr	$49.50	
May	$49.65	
Jun	$49.70	
Jul	$49.90	
Aug	$50.05	
Sep	$49.90	
Oct	$49.80	
Nov	$49.70	
Dec	$49.90	$49.69

COAL & PETCOKE MONTHLY SPREADSHEET
JD Energy, Inc.
March 14th, 2013

DIRECTORY

Cell	Item
B13	Price Tables for Coal and Petroleum Coke
V13	Coal Production
V30	Coal Demand

Region:	Central Appalachia	Central Appalachia	Central Appalachia	Central Appalachia	Northern Appalachia	Northern Appalachia	Northern App/Ohio	Illinois Basin (IL)	Illinois Basin (WKY)
Market:	Physical	Physical	Physical	NYMEX	Physical	Physical	Physical	Physical	Physical
SO2/mmBTU	1.2	1.6	2.3	1.6	2.5	3.0-4.0	6.4	5.45	5.45
Sulfur:	0.75%	1.00%	1.40%	1.00%	1.60%	2.30%	4.00%	3.00%	3.00%
BTU/lb:	12,500	12,500	12,500	12,000	13,000	13,000	12,500	11,000	11,000
Mode:	FOB Mine (CSX)	FOB Mine (CSX)	FOB Mine (CSX)	Barge-Big Sandy	FOB Mine	FOB Mine	FOB Mine	FOB Mine	FOB Mine
Price per:	Short ton	Short ton	Short ton	Short ton	Short ton	Short ton	Short ton	Short ton	Short ton
Jan 2011	$77.15	$74.65	$63.60	$76.20	$75.50	$68.05	$56.80	$44.00	$45.80
Feb	$77.75	$75.25	$64.15	$70.43	$75.85	$68.30	$57.05	$44.30	$46.10
Mar	$77.40	$74.85	$64.60	$73.94	$76.30	$68.75	$56.65	$45.60	$47.45
Apr	$77.40	$74.90	$66.00	$76.50	$77.20	$69.55	$56.95	$45.70	$47.55
May	$76.20	$73.85	$67.60	$75.19	$78.00	$70.35	$57.70	$44.65	$46.55
Jun	$76.40	$74.30	$68.45	$77.67	$78.00	$70.35	$57.75	$45.90	$47.75
Jul	$79.65	$77.80	$70.75	$77.07	$78.05	$70.45	$57.75	$47.40	$49.20
Aug	$80.25	$77.60	$70.55	$76.07	$77.95	$70.35	$57.65	$49.00	$50.75
Sep	$80.15	$77.70	$70.60	$74.87	$77.05	$68.85	$56.40	$48.70	$50.45
Oct	$80.60	$76.90	$67.45	$73.40	$77.05	$66.90	$56.35	$48.05	$49.85
Nov	$78.45	$74.75	$67.00	$70.54	$77.00	$66.85	$56.30	$47.90	$49.70
Dec	$73.85	$70.55	$63.75	$69.00	$73.90	$64.50	$55.10	$46.90	$48.65
Jan 2012	$69.00	$66.25	$60.85	$63.70	$68.45	$61.60	$52.30	$44.25	$46.00
Feb	$65.30	$62.50	$56.70	$59.54	$65.80	$59.00	$47.10	$41.10	$42.85
Mar	$63.10	$60.35	$54.35	$58.07	$64.05	$57.00	$46.45	$39.80	$41.60
Apr	$61.75	$59.55	$53.60	$57.31	$63.45	$56.80	$46.85	$37.85	$39.65
May	$59.25	$57.65	$50.95	$56.91	$60.95	$55.50	$46.90	$36.60	$38.45
Jun	$56.25	$55.15	$48.05	$54.89	$59.25	$53.55	$46.25	$36.25	$38.05
Jul	$57.70	$56.50	$49.25	$57.26	$59.53	$53.85	$46.70	$36.65	$38.40
Aug	$60.85	$59.60	$50.85	$59.26	$60.75	$55.05	$47.55	$36.80	$38.50
Sep	$64.70	$63.25	$52.50	$54.68	$62.30	$56.65	$48.50	$36.80	$38.50
Oct	$68.00	$65.30	$56.85	$56.26	$62.15	$56.50	$48.35	$36.65	$38.40
Nov	$68.85	$66.15	$57.60	$60.81	$62.25	$56.60	$48.40	$36.65	$38.40
Dec	$69.10	$66.35	$57.75	$59.89	$61.90	$56.35	$48.20	$36.70	$38.40
Jan 2013	$68.85	$66.15	$57.60	$57.45	$61.15	$55.40	$47.30	$36.95	$38.75
Feb	$68.05	$65.30	$56.85	$59.04	$61.05	$55.20	$47.10	$36.90	$38.70
Mar	$67.05	$64.25	$55.96	$58.08	$61.10	$55.95	$47.50	$36.85	$38.70
Apr	$66.96	$64.10	$55.86	$57.92	$61.18	$55.35	$46.75	$36.75	$38.60
May	$67.46	$64.55	$56.28	$58.39	$61.30	$54.80	$46.05	$36.85	$38.75
Jun	$67.76	$64.80	$56.53	$58.72	$62.83	$55.65	$46.53	$37.45	$39.30
Jul	$68.92	$65.90	$57.52	$60.53	$66.40	$58.55	$48.70	$38.10	$39.90
Aug	$69.52	$66.45	$58.03	$62.24	$68.73	$60.20	$49.82	$38.90	$40.65
Sep	$69.32	$66.20	$57.84	$63.04	$69.90	$60.70	$49.97	$39.25	$41.00
Oct	$69.13	$65.95	$57.65	$63.35	$71.13	$61.25	$50.16	$39.55	$41.35
Nov	$69.58	$66.35	$58.03	$63.76	$72.10	$61.55	$50.15	$40.15	$41.95
Dec	$70.08	$66.80	$58.46	$63.37	$74.70	$62.10	$50.33	$41.00	$42.75
Jan 2014	$70.53	$67.20	$58.84	$64.07	$74.95	$62.35	$50.26	$42.00	$43.85
Feb	$70.39	$67.00	$58.69	$63.46	$75.25	$62.65	$50.24	$42.35	$44.20
Mar	$70.29	$66.85	$58.59	$63.71	$75.45	$62.85	$50.13	$42.50	$44.40
Apr	$70.24	$66.75	$58.53	$63.76	$75.60	$63.00	$49.98	$42.75	$44.65
May	$70.25	$66.70	$58.52	$63.27	$75.75	$63.10	$49.79	$43.00	$44.95
Jun	$70.40	$66.80	$58.64	$62.97	$76.10	$63.45	$50.28	$44.00	$45.90
Jul	$70.78	$67.20	$59.08	$62.74	$76.55	$63.85	$50.82	$45.00	$46.85
Aug	$71.01	$67.45	$59.38	$64.85	$76.85	$64.15	$51.28	$46.20	$48.00
Sep	$70.64	$67.10	$59.16	$64.57	$76.70	$63.95	$51.35	$46.25	$48.05
Oct	$69.87	$66.35	$58.59	$63.74	$76.30	$63.55	$51.24	$46.30	$48.15
Nov	$69.14	$65.65	$58.06	$63.09	$76.45	$63.65	$51.55	$46.45	$48.30
Dec	$69.17	$65.70	$58.19	$62.32	$76.75	$63.95	$52.01	$46.75	$48.55
Jan 2015	$69.15	$65.70	$58.27	$62.64	$77.25	$64.35	$52.56	$47.40	$49.30
Feb	$69.08	$65.65	$58.32	$62.18	$77.75	$64.85	$53.19	$47.50	$49.40
Mar	$69.01	$65.60	$58.36	$62.52	$77.75	$64.80	$53.38	$47.55	$49.50
Apr	$68.89	$65.50	$58.35	$62.57	$77.70	$64.75	$53.56	$47.55	$49.50
May	$68.82	$65.45	$58.40	$62.09	$77.60	$64.60	$53.66	$47.65	$49.65
Jun	$68.85	$65.50	$58.53	$61.75	$78.25	$65.25	$54.43	$47.75	$49.70
Jul	$69.13	$65.80	$58.88	$61.43	$79.15	$66.10	$55.37	$48.00	$49.90
Aug	$69.25	$65.95	$59.10	$63.41	$80.00	$66.95	$56.31	$48.20	$50.05
Sep	$69.08	$65.80	$59.05	$63.32	$79.95	$66.85	$56.46	$48.05	$49.90
Oct	$68.96	$65.70	$59.05	$63.11	$79.85	$66.75	$56.61	$47.90	$49.80
Nov	$68.84	$65.60	$59.05	$63.04	$79.85	$66.70	$56.80	$47.80	$49.70
Dec	$68.77	$65.55	$59.09	$62.18	$80.00	$66.85	$57.16	$48.05	$49.90

LONG-TERM COAL FORECAST - 201302

JD Energy, Inc.

BASE CASE

February 2013

ANNUAL AVERAGE SPOT PRICES - NOMINAL DOLLARS PER TON

BASE CASE

Year:	2013	2014	2015	2016	2017
Northern Appalachia					
-1.6%, 13000 BTU	**$67.12**	**$76.06**	**$78.76**	**$82.26**	**$84.71**
-1.8%, 13000 BTU	**$59.94**	**$65.52**	**$67.92**	**$71.20**	**$73.40**
-2.3%, 13000 BTU	**$57.95**	**$63.38**	**$65.73**	**$68.95**	**$71.12**
Central Appalachia					
-.7%, 12500 BTU	**$68.64**	**$70.19**	**$68.99**	**$69.45**	**$70.73**
-1.0%, 12500 BTU	**$65.68**	**$66.73**	**$65.65**	**$66.79**	**$68.94**
-1.5%, 12500 BTU	**$57.34**	**$58.69**	**$58.70**	**$61.25**	**$64.67**
		$1.14	$1.12		
Ohio					
-4%, 12500 BTU	**$48.15**	**$50.73**	**$54.96**	**$59.16**	**$61.10**
Illinois Basin					
-3%, 11000 BTU (IL)	**$38.23**	**$44.46**	**$47.78**	**$49.24**	**$50.35**
-3%, 11000 BTU (KY)	**$40.03**	**$46.32**	**$49.69**	**$51.22**	**$52.39**

Item 58) *Referencing Big Rivers' response to PSC 2-14 and the Reid Steam unit, please provide the following information:*

a. *Explain why VOM, Heat Rate, Fuel Costs, generation, etc. are shown as [BEGIN CONFIDENTIAL] "#/DIV/0!" or "0" for many time periods [END CONFIDENTIAL] on the Annual and Monthly Resource Report tabs of the Big Rivers PCM Run 4-22-13 (2013-2017) spreadsheet.*

b. *Explain all work completed, or remaining to be completed, as well as completion or expected completion dates for conversion of the unit entirely to natural gas.*

c. *Provide a detailed breakdown of all costs incurred, when they have been incurred or are expected to be incurred to convert the unit to natural gas.*

Response)

a. The Reid Steam unit was not being dispatched to run by the PCM (0 MW of generation) which caused many of results to display "0" or "#/DIV/0!". Please recall in the PCM generation inputs, the Reid Steam unit fuel was switched from coal to natural gas in 2014.

b. To date Big Rivers has submitted a revision of its Title V Permit to KDAQ for approval. In addition, Big Rivers has solicited budgetary pricing for new burner management and turbine control systems. Remaining work includes actual purchase of the burner management and turbine control systems as well as purchase of replacement gas burners. This equipment must then be installed in the unit. The gas supply pipeline to this unit will also be replaced as part of this project. The expected completion date of this project will be the end of 2014 assuming timely issuance of the revised Title V Permit.

c. To date Big Rivers has incurred approximately $20,000 in preparation of the revised Title V permit application. Remaining costs, all of which are to be incurred in the second half of 2014, include:

Burner Management and Turbine Control Systems	$610,000
Replacement Burners	$920,000
Gas pipeline replacement	$50,000
Installation of above components	$250,000

Witness) Robert W. Berry

Big Rivers Electric Corporation
Case No. 2013-00199

Attachment 1 for Response to AG 2-59
Wilson Plant Costs

Line No.	DESCRIPTION	2013	2014	2015	2016	2017	2018
1	Layup Capital	0	0	0	0	0	0
2	Layup Fixed Departmental Expense	961,000	0	0	0	0	0
3	Labor Expense	10,914,913	1,633,639	1,669,094	1,710,020	1,752,770	11,907,178
4	Ongoing Fixed Departmental Expense	6,139,952	610,576	612,205	613,807	738,055	12,843,980
5	Ongoing Capital	8,279,000	530,000	2,730,000	1,280,000	0	10,872,820
6	Property Tax Expense Base	1,048,464	1,081,241	1,093,163	1,107,493	1,136,043	1,165,526
7	Property Tax Expense ECR	14,169	14,417	22,956	21,773	21,454	20,909
8	Property Insurance Expense Base	1,127,161	1,240,971	1,289,128	1,354,001	1,387,745	1,422,328
9	Property Insurance Expense ECR	5,945	6,511	20,724	21,345	21,986	22,645
10	Interest Expense Base	21,932,153	20,658,667	20,621,730	20,509,890	21,037,823	21,578,989
11	Interest Expense ECR	294,576	273,794	329,984	329,984	323,048	315,904
12		50,717,333	26,049,817	28,388,984	26,948,314	26,418,925	60,150,280

Depreciation expense is not broken out by location in the financial model
Wilson is assumed to layup September 2013 and to come out of layup in 2018
Excludes startup cost in 2018

Big Rivers Electric Corporation
Case No. 2013-00199

Attachment 2 for Response to AG 2-59
Coleman Plant Costs

Line No.	DESCRIPTION	2013	2014	2015	2016	2017	2018	2019
1	Layup Capital	0	100,000	0	0	0	0	0
2	Layup Expense	0	2,000,000	0	0	0	0	0
3	*Labor Expense	12,059,190	5,063,365	1,384,331	1,419,971	1,455,470	3,292,354	13,580,606
4	*Ongoing Fixed Departmental Expense	14,389,026	1,981,289	1,230,305	1,253,805	1,285,151	1,317,279	3,333,449
5	Ongoing Capital	10,579,000	0	0	0	0	0	10,054,738
6	Property Tax Expense Base	438,274	468,898	479,268	482,978	495,429	508,288	521,461
7	Property Tax Expense ECR	5,936	6,266	10,020	9,509	9,370	9,132	8,893
8	Property Insurance Expense Base	658,951	725,628	753,789	791,722	811,453	831,675	852,400
9	Property Insurance Expense ECR	3,475	3,807	12,115	12,479	12,853	13,239	13,636
10	Interest Expense Base	6,410,007	6,285,309	6,192,024	6,155,852	6,336,641	6,522,013	6,712,081
11	Interest Expense ECR	535,846	484,888	584,400	584,400	572,116	559,464	546,432
12		45,079,705	17,119,450	10,646,252	10,710,716	10,978,484	13,053,443	35,623,698

Depreciation expense is not broken out by location in the financial model
Coleman is assumed to layup February 2014 and to come out of layup in 2019
Excludes startup cost in 2019
*Does not include pro-forma adjustments

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-67(a)

O&M, Outside Professional Costs, and A&G Expenses

		FTP	Supporting Documentation
1	Green 1 Planned Outage	$ 3,666	Refer to KIUC 1-40e
2	HMPL 1 Planned Outage	2,865	Refer to KIUC 1-40e
3	Managed Information Systems Services	2,500	Invoice
4	Gas Turbine Outage	1,200	Refer to KIUC 1-40e
5	Demand Side Management (DSM)	1,096	Refer to Wolfram Testimony (page 17) and Schedule 1.12 (Exhibit Wolfram-2)
6	Right of Way Mtce	1,061	Proposal
7	Customer Billing Services	700	Award Recommendation
8	PSC Assessment	820	Invoice
9	NRECA Dues	355	Invoice
10	NERC	300	Invoice
	Total of Ten Largest Individual Line Items	**$ 14,563**	

a. Big Rivers' annual structure adjustments are based on numerous sources of information, including nationally published survey data, government indices, and any compensation study undertaken in an annual review. On page 9 of its Competitive Market Assessment, Towers Watson observed that Big Rivers' structure was 4.3% below market levels. It recommended that Big Rivers consider adjusting the structure by 3.0-4.0%. Rather than the 3.0-4.0% adjustment recommended, Big Rivers chose to adjust the structure January 2, 2012, by 2.6%, the amount management determined necessary – based on movement in the Consumer Price Index – to prevent an erosion of purchasing power for the non-bargaining employees since the Unwind closing. Consequently, the entire study is supportive, but not determinative.

b. Big Rivers objects that this request is overly broad and not reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding these objections, and without waiving them, Big Rivers responds as follows. Please refer to Big Rivers' response to subpart (a), above.

Witness) Thomas W. Davis

Big Rivers Electric Corporation
Case No. 2013-00199

Attachment for Response to AG 2-81(c)
Forecasted Transmission Expenses: Accounts 560 - 575

Line	Year	Transmission O&M
1	2014	$14,941,199
2	2015	$14,804,580
3	2016	$15,180,797
4	2017	$15,560,228
5	2018	$15,949,144
6	2019	$16,347,782
7	2020	$16,756,387
8	2021	$17,175,207
9	2022	$17,604,498
10	2023	$18,044,520
11	2024	$18,495,543
12	2025	$18,957,842
13	2026	$19,431,699
14	2027	$19,917,401
15	2028	$20,415,247

From Big Rivers Financial Model, Tab 'Trial Bal', Row 522, provided in PSC 1-57

GDS Associates, Inc.
Engineers and Consultants

2013 Load Forecast

Energy and Peak Demand Projections for 2013- 2027

Jackson Purchase Energy Corporation

Paducah, Kentucky

August 2013

In Cooperation with
Big Rivers Electric Corporation

GDS Associates, Inc.
1850 Parkway Place
Suite 800
Marietta, GA 30067
770.425.8100
www.gdsassociates.com

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APPENDICES

1. Executive Summary

Jackson Purchase Energy Corporation (JPEC) is a rural electric distribution system headquartered in Paducah, Kentucky. This 2013 Load Forecast was completed in August 2013 and updates the most recent forecast that was completed in May 2011. The forecast contains projections of energy and demand requirements for a forecast horizon spanning years 2013-2027. High and low range forecast scenarios were developed to address uncertainties regarding the factors expected to influence energy consumption in the future. In addition to the energy and demand projections, this report presents the assumptions upon which the forecast is based and the methodologies employed in development of the forecast.

1.1 Forecast Results

Total system energy and non-coincident peak demand requirements are projected to increase at average compound rates of 0.4% and 0.5%, respectively, from 2012 through 2027[1]. Rural system energy and demand requirements, which are represented as total system requirements less direct-serve customer loads, are projected to increase at average rates of 1.5% and 1.4%, respectively over the same period. With the exception of the projections presented in section 6, Table 6.2, all projections of energy and peak demand presented in this report exclude the potential impacts associated with new energy efficiency and demand-side management programs that JPEC plans to implement in the coming years.

The forecast is summarized in Tables 1.1 and 1.2. The primary influence on growth in the rural system requirements over the forecast period will continue to be growth in residential sales, which is primarily a function of growth in number of customers.

Table 1.1
Load Forecast Summary

		Total System		Rural System	
Year	Consumers	Energy Requirements (MWh)	Peak Demand (NCP kW)	Energy Requirements (MWh)	Peak Demand (CP kW)
2002	27,086	642,251	146,731	606,588	138,264
2007	28,747	718,915	164,605	696,665	158,540
2012a	29,241	668,864	160,040	663,607	159,750
2012n	29,294	668,272	155,798	663,016	155,508
2017	30,327	650,523	157,766	639,845	155,865
2022	31,635	679,830	163,450	664,753	161,549

[1] Growth rates for total system and rural system requirements are based on weather normalized values for 2012

2027	33,101	717,661	171,774	698,889	169,873

2012a represent actual values; 2012n represents weather adjusted values
Projected values reflect impacts of DSM and energy efficiency programs

Table 1.2
Load Forecast – Average Annual Growth Rates

	1997-2002	2002-2007	2007-2012	2012-2017	2012-2027
Total System Energy Requirements	1.2%	2.3%	-1.1%	-0.7%	0.4%
Total System Peak Demand (NCP)	0.0%	0.0%	-0.1%	0.3%	0.5%
Rural System Energy Requirements	2.0%	2.9%	-0.6%	-0.6%	0.4%
Rural System 1-Hour Peak Demand	1.7%	2.8%	0.6%	0.0%	0.6%
Residential Energy Sales	1.9%	2.3%	-0.5%	0.0%	0.7%
Residential Consumers	1.7%	0.9%	0.1%	0.7%	0.8%
Small Commercial Energy Sales	-0.2%	5.0%	1.1%	-1.1%	0.4%
Small Commercial Consumers	2.5%	3.9%	2.2%	0.8%	0.9%
Large Commercial Energy Sales	1.1%	-2.0%	-10.3%	-0.7%	-0.2%
Large Commercial Consumers	5.6%	-3.9%	3.3%	3.2%	1.0%
Irrigation Sales	-2.1%	-4.9%	-6.5%	0.0%	0.0%
Public Street Lighting Sales	5.8%	2.3%	0.9%	-0.6%	0.5%

Growth rates for Total System and Rural System requirements reflect DSM and energy efficiency program impacts.

Projected growth rates for the rural system are lower than in previous forecasts and the result of significant retail price increases over the near term. Due to increases wholesale power costs, retail electricity prices are projected to increase by approximately 40%, in aggregate, over years 2014-2016. As result, rural system sales are expected to decline by 4.1% over the course of these three years before reestablishing a positive trend of approximately 0.9% per year thereafter.

The primary influence on growth in the rural system requirements over the forecast period will continue to be growth in the number of customers. Following near term declines in average use per customer due to retail price increases, average use is expected to be relatively flat over the remainder of the forecast horizon, increasing by less than 1% per year. JPEC is projected to be a summer peaking system under normal peaking weather conditions; however, as in past years, the annual peak can occur during a winter month if peaking temperatures are colder than normal.

The projections of total system and rural system energy and peak demand presented in this report include the impacts associated with new energy efficiency and demand-side management programs that Big Rivers and JPEC plan to implement in the coming years.

Section 2 of the report presents a brief summary of the cooperative background and service area characteristics. Section 3 identifies the sources of the data used to prepare the forecast. Section 4 presents the assumptions made during the forecasting process. Sections 5 and 6 present the short and long-term base case forecasts. Section 7 presents four forecast scenarios, which address optimistic/pessimistic economic growth and extreme/mild weather conditions. Section 8 describes the forecasting methodologies incorporated in developing the forecasting models.

1.2 Forecast Assumptions

The forecast is based upon a number of assumptions regarding factors that impact energy consumption, including: demographics, economic activity, price of electricity and competing fuels, electric market share, and weather conditions. The assumptions were developed by GDS Associates and discussed with cooperative management prior to development of the final forecast. The economic outlook for the base case forecast was formulated using information collected from Moody's Economy.com.

- Number of households will increase at an average rate of 0.2% per year from 2012-2028.
- Employment will increase at an average rate of 0.5% per year from 2012-2028.
- Real gross regional product will increase at an average rate of 2.9% per year from 2012-2028.
- Real average income per household will increase at an average rate of 1.9% per year from 2012-2028.
- Real retail sales will increase at an average rate of 1.3% per year from 2012-2028.
- Inflation, as measured by the Gross Domestic Product Price Index, will increase at an average compound rate of 2.0% per year from 2012-2028.
- The average price of electricity to rural system customers will increase by 43% over 2014-2016 and then increase at the rate of inflation over the long term.
- Heating and cooling degree days for Paducah, Kentucky will be equal to averages based on the twenty years ending 2012.
- Impacts of existing energy efficiency programs will increase during the forecast horizon and will impact both energy and peak demand requirements..

1.3 Forecasting Process

A bottom-up approach was followed in developing Big Rivers' load forecast as projections were developed for each of three member cooperatives and aggregated to the Big Rivers level. Projections were developed for two customer classifications: rural system and direct serve. The rural system is comprised of all residential, commercial, and other customers that are served at the retail level by JPEC. The direct serve class includes all large commercial and industrial customers that are served directly by Big Rivers.

Econometric models were developed to project the number of rural system customers and average use per customer. Rural system peak demand was developed at the Big Rivers level and allocated to each member cooperative based on each cooperative's contribution to the Big Rivers peak. Direct serve demand and energy projections were developed using information provided by cooperative management regarding local industrial operations. Projections of total system NCP demand was computed as the sum of rural system one-hour peak demand and direct-serve NCP demand.

1.4 Changes from Prior Load Forecast

The 2013 load forecast is lower than the 2011 forecast, due primarily to sharp increases in the retail price of electricity through 2016.

Figure 1.1
Total Energy Requirements (GWh)

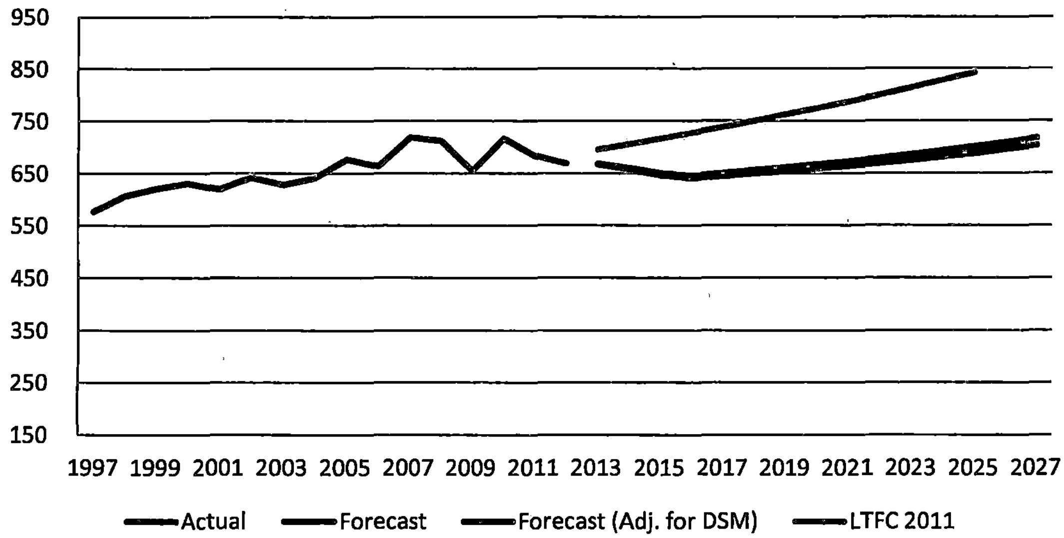
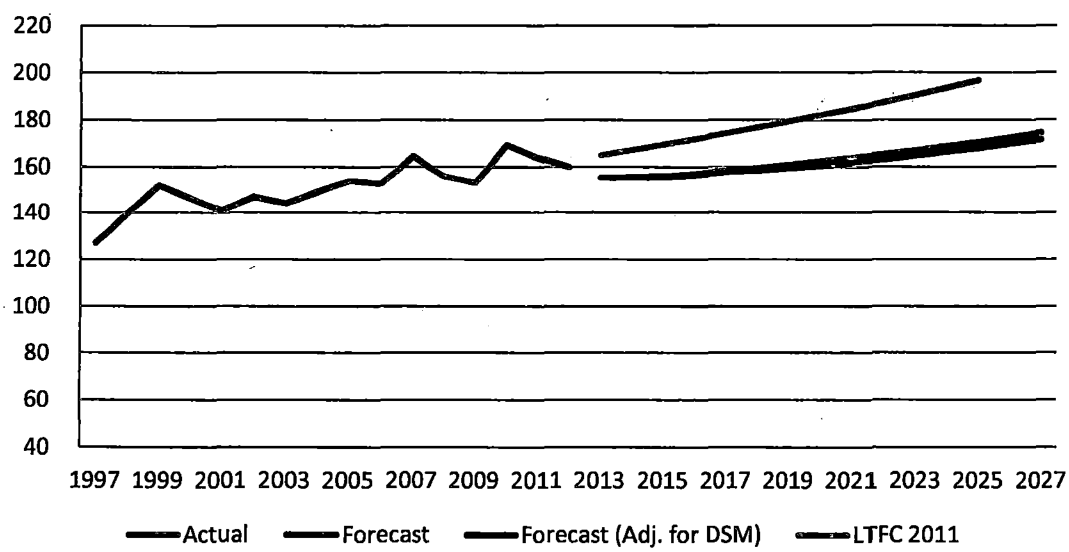


Figure 1.2
Peak Demand (MW)



Rural system energy requirements in the current forecast are lower than in the 2011 forecast, as the current forecast reflects lower long term customer growth and lower average consumption per customer, due primarily to increases in the retail price of electricity.

Figure 1.3
Rural System Energy Requirements (GWh)

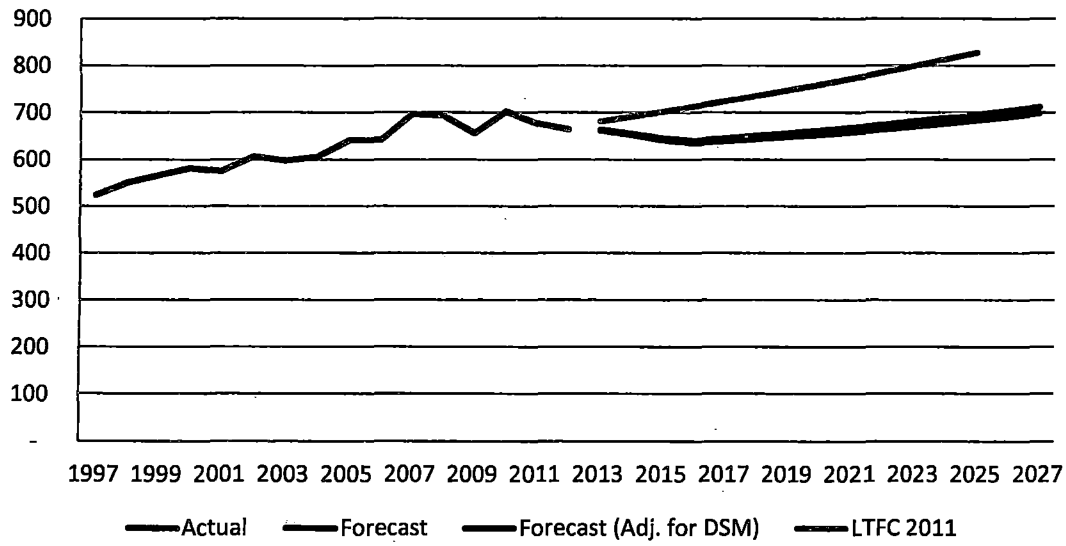
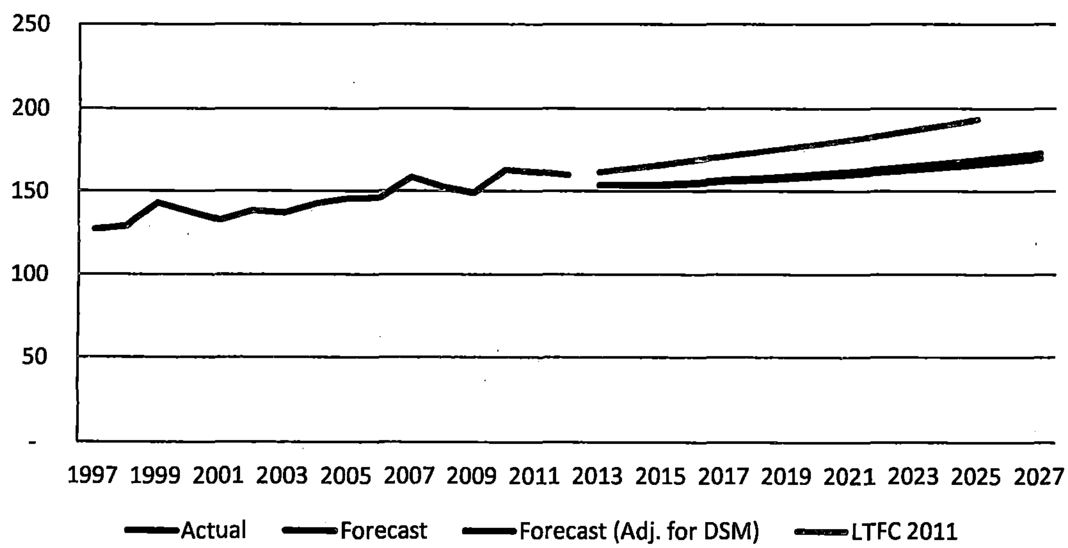


Figure 1.4
Rural System Peak Demand (MW)



1.5 Forecast Scenarios

The base case forecast was developed using the expected economic outlook and average weather conditions. Given the uncertainty with the forecast, four forecast scenarios were generated to evaluate varying economic and weather impacts from those contained in the base case forecast. Results from the four scenarios are presented graphically in Figures 1.5 through 1.8 and described in detail in Section 7.

Figure 1.5
Total Energy Requirements (GWh)

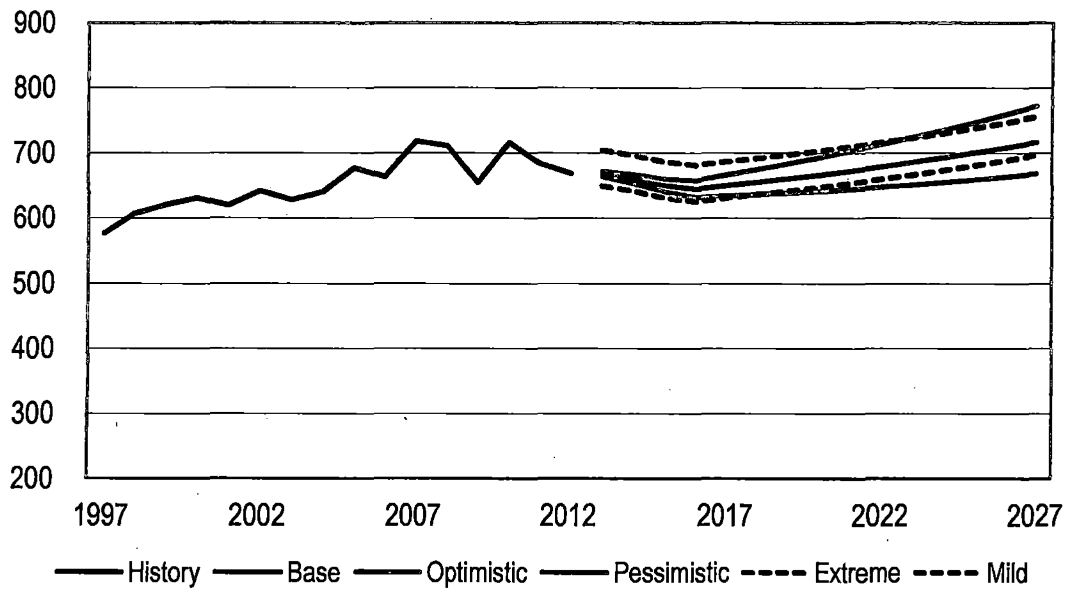


Figure 1.6
Peak Demand Requirements (MW)

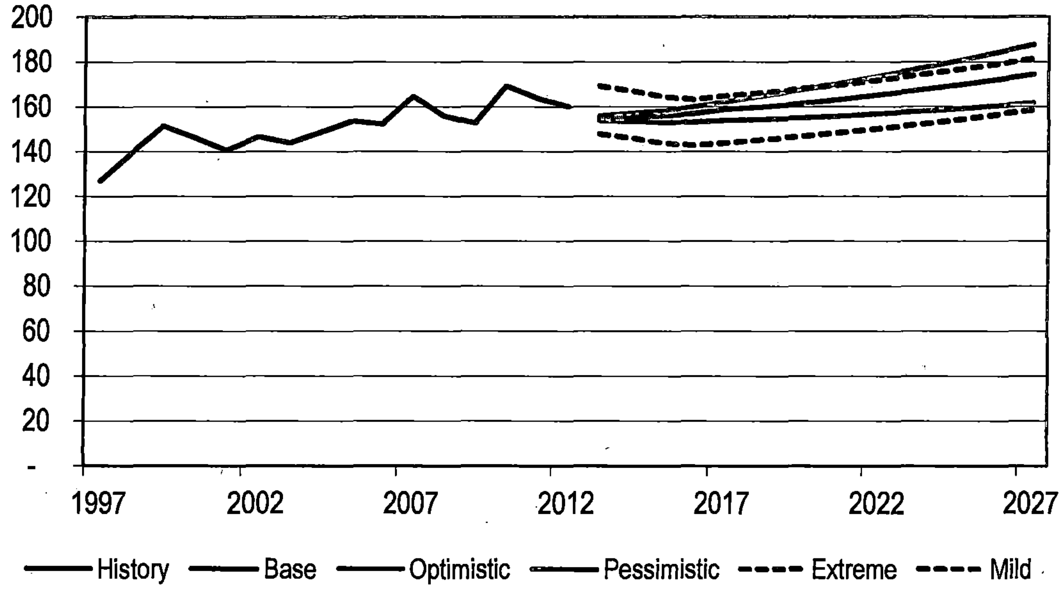


Figure 1.7
Rural System Energy Requirements (GWh)

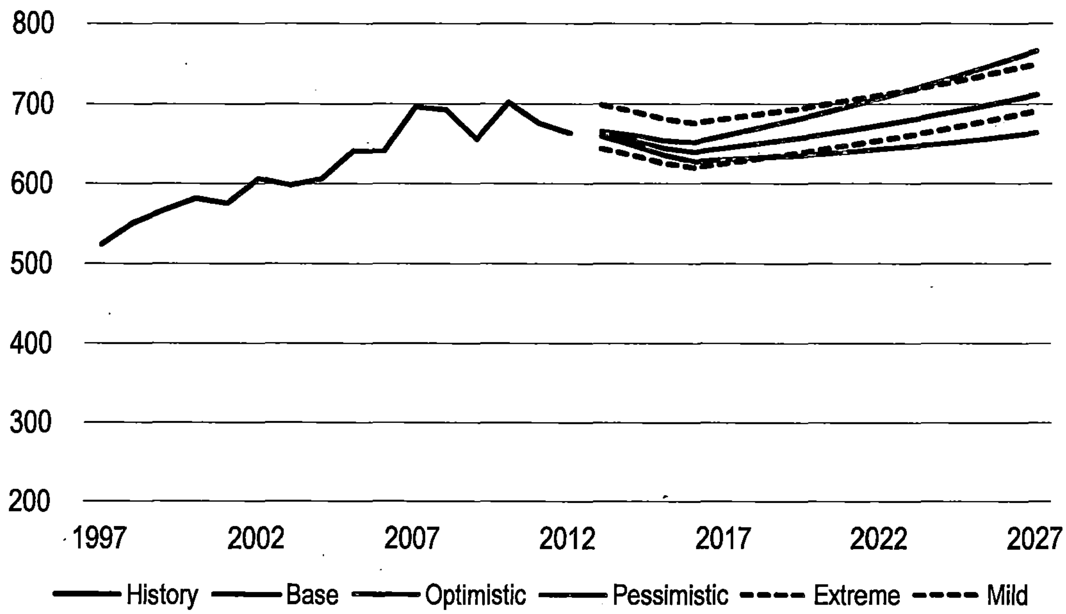
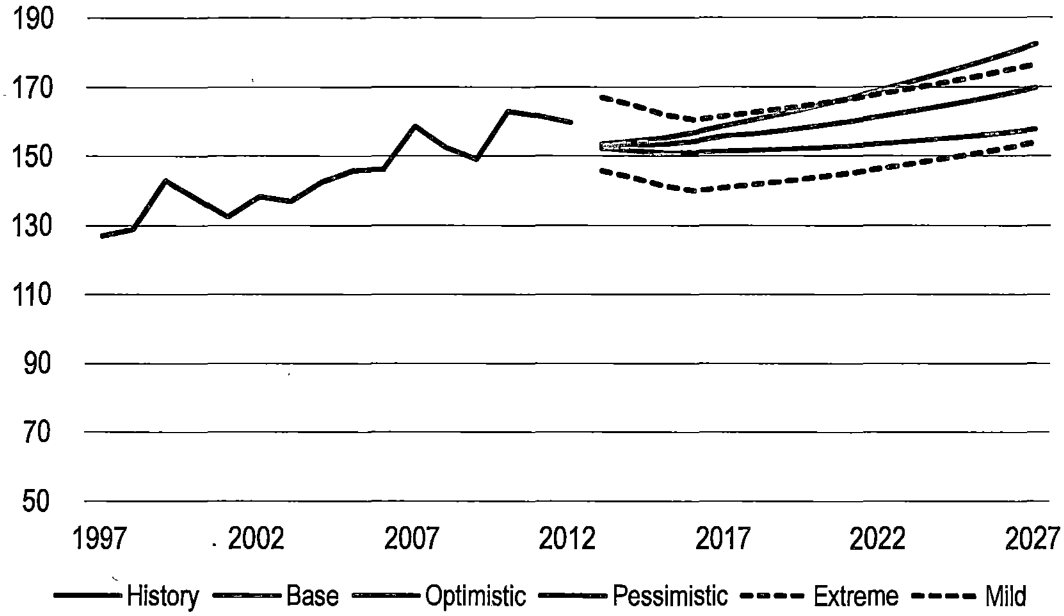


Figure 1.8
Rural System Peak Demand Requirements (MW)


190
170
150
130
110
90
70
50
1997
2002
2007
2012
2017
2022
2027
History
Base
Optimistic
Pessimistic
Extreme
Mild

2. Introduction

The 2013 Load Forecast was conducted by representatives from JPEC, Big Rivers Electric Corporation (Big Rivers), and GDS Associates, Inc.

2.1 Purpose

The purpose of the long-term load forecast is to provide reliable load projections for the Cooperative's resource, distribution, and financial planning functions. This forecast of system requirements includes the following:

- Number of consumers by customer classification
- Energy sales by customer classification
- Distribution losses
- Total system energy requirements
- Total system seasonal peak demand
- Rural system energy sales
- Rural system seasonal peak demand

Five forecast scenarios were developed in the forecast: a base case, which focuses on expected economic conditions and normal weather, and two sets of high-range and low-range projections, both of which consider deviations from expected economic conditions and deviations from normal weather conditions.

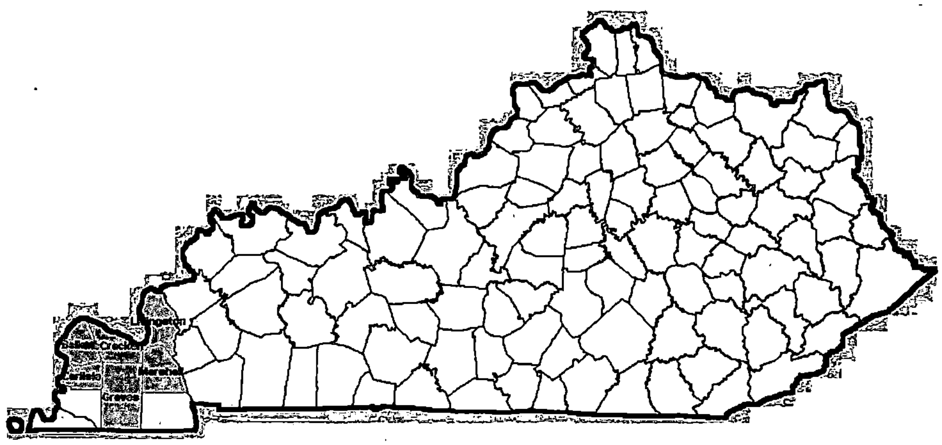
2.2 Cooperative Background

JPEC is headquartered in Paducah, Kentucky, with its service area in the western part of the state. Approximately 90% of the accounts the cooperative serves are residential. The data used in the modeling process was weighted based on the percentage of residential customers in each county that the cooperative services. This weighting system was used to better represent the growth in population, employment, and income of the cooperative's service area. The service area consists of the percentage of the following counties: Ballard, 81 percent; Carlisle, 23 percent; Graves, 15 percent; Livingston, 100 percent; Marshall, 35 percent, and McCracken, 43 percent.

2.3 Service Area

JPEC's service area is located in western Kentucky and includes six counties, which are presented in Figure 2.1. JPEC currently owns and maintains over 2,911 miles of line and 27 step-down sub-stations.

Figure 2.1
Service Area Counties



2.3.1 Geography

JPEC's service area topography ranges from a rolling, sandy embayment area to a flat plateau area with low relief and subterranean drainage. Typical elevations range from approximately 340 to 400 feet above sea level. The climate in the area is humid, temperate and continental.

2.3.2 Climate

Service area weather conditions are based on climate data measured at the Paducah, Kentucky airport. The climate in the area is humid, temperate and continental. Daily and seasonal changes in temperature, cloudiness, wind and precipitation may be sudden and extreme. The seasons are well defined, but changes between the seasons are gradual. Winters are harsh with sustained periods of very low temperatures, with the minimum monthly low temperature averaging 6 degrees Fahrenheit in January, over the last 20 years. Snowfall provides minimal precipitation, averaging 12 inches per year. The frequent thunderstorms that occur in the spring bring rainfall, which is beneficial to area crops. Annual rainfall averages 46 to 50 inches. The summer season is long, humid and hot, with the maximum monthly high temperature averaging 98 degrees Fahrenheit in July, over the last 20 years.

Heating and cooling degree days for Paducah, Kentucky were used in the forecasting models to quantify the impacts of weather on energy consumption. A degree day represents the difference between the average temperature for a given day and a base temperature. Positive differences represent cooling degree days, and negative differences represent heating degree days. For example, if the average temperature for a day is 80 degrees, and the base temperature used is 65 degrees, there would be 15 cooling degree days for that day. Cooling and heating degree days measured at the Paducah airport are presented in Table 2.1.

Table 2.1
Degree Days

Year	Heating Degree Days	Cooling Degree Days	Total Degree Days
1991	4,531	1,686	6,217
1992	3,911	1,409	5,320
1993	4,129	1,615	5,744
1994	4,573	1,390	5,963
1995	4,445	1,271	5,716
1996	3,535	1,798	5,333
1997	3,650	1,531	5,181
1998	4,273	1,566	5,839
1999	3,921	1,540	5,461
2000	4,099	1,877	5,976
2001	4,150	1,289	5,439
2002	3,885	1,394	5,279
2003	3,904	1,685	5,589
2004	3,672	1,512	5,184
2005	3,823	1,958	5,781
2006	4,274	1,508	5,782
2007	3,877	1,444	5,321
2008	4,377	2,013	6,390
2009	3,911	1,703	5,614
2010	3,342	1,978	5,320
Average	4,014	1,608	5,622

2.4 Power Supply

JPEC purchases power through twenty-seven (27) non-dedicated and one (1) dedicated metering point on the Big Rivers transmission system. The tariffs under which Big Rivers bills JPEC became effective September 1, 2011 upon approval by the Kentucky Public Service Commission.

2.5 Alternative Fuels

Electricity, natural gas, and propane are the primary heating fuels available in the service area. Some consumers use wood as a supplemental heating source as timber is readily available in western Kentucky. Refer to Big Rivers' End-Use and Energy Efficiency Survey (December 2007) for details regarding specific fuels used for heating, water heating, and air conditioning.

2.6 Economic Conditions

Energy consumption is influenced significantly over the long-term by economic conditions. As the local economy expands, population and employment increase, which translate into new cooperative consumers and additional energy sales and peak demand. The economy of western Kentucky depends primarily upon agriculture, manufacturing, services, and wholesale and retail trade. Coal mining and related operations are located throughout the state. Data used to represent economic activity for the service area was computed using county level information. Refer to section 4 for details regarding historical and projected growth in the economic variables included in this forecast.

3. Load Forecast Database

A load forecast database was created to house the data used in development of the load forecast. This section identifies the data collected and used in the study, sources from which the data were collected, and computations that were conducted. Four classes of data were collected for this study: (i) system data, (ii) price data, (iii) economic and demographic data, and (iv) meteorological data. The data elements collected under each category, as well as the source and time period, are presented in Table 3.1.

Table 3.1
Load Forecast Database

Class of Data	Source	Data Element	Units	Time Period
System	RUS Form 7	Number of Customers by RUS Classification	Meters	1970 – 2012
		Energy Sales by RUS Classification	kWh	1970 – 2012
		Revenue by RUS Classification	$	1970 – 2012
		Purchases	kWh	1970 – 2012
		Power Cost	$	1970 – 2012
		Peak Demand	NCP	1970 – 2012
Price Index	Moody's Analytics	Implicit Price Deflator, Gross National Product, 2004=100, Seasonally Adjusted	Index	1970.01 – 2012.12
Economic and Demographic	Moody's Analytics	Average Household Income	Real $	1970 – 2030
		Retail Sales	Real $	1970 – 2030
		Gross Regional Product (GRP)	Real $	1970 – 2030
		Total Population	Number of People	1970 – 2030
		Households	Number of Households	1970 – 2030
		Total Employment	Number of Employees	1970 – 2030
End-Use Data	Energy Information Administration	Unit Energy Consumption	kWh	2005-2030
	U.S. Census Big Rivers Surveys	Electric Market Share	Percent	1990, 2000, 2005 2007
Meteorological	National Oceanic and Atmospheric Administration	Heating and Cooling Degree Days	Base of 65°F	1970.01 – 2012.12
		Temperatures	Degrees F	1970.01 – 2012.12

3.1 Weather Data

Weather conditions recorded at Paducah, Kentucky were used to represent weather within the JPEC service territory. Heating and cooling degree days were used in projecting residential and small commercial energy sales. Data for years 1993-2012 are actual amounts, while data for 2013-2027 are equal to the average for the most recent 20 years.

3.2 End-Use Data

End-use energy data was obtained from the Department of Energy, Energy Information Administration (EIA). End-use market data is collected through customer surveys conducted periodically by Big Rivers.

4. Forecast Assumptions

4.1 Forecast Methodology

Econometrics was the forecasting methodology employed in developing the energy sales forecasting models for the rural system class. When using econometric techniques to forecast energy sales, it is assumed that the relationships between energy consumption and those influential factors included in the models remain the same in both the historical and forecast periods.

4.2 Economic Outlook

It is assumed that growth in peak demand and energy requirements over time has been strongly influenced by economic conditions, including number of households, employment, total personal income, and retail sales. It is assumed that the influences of these factors will continue over the next sixteen years. The economic outlook used in developing the base case forecast was based on information obtained from Moody's Analytics. The outlook presented in this forecast reflects a relatively slow recovery from the economic recession followed by moderate growth over the extended long term. Projections for key economic data used in this forecast are presented in Table 4.1.

4.2.1 Number of Households

Number of households is an excellent measure of number of residential cooperative customers. The number of households in the service area has increased, while population has flattened, indicating that the average household size has declined over time. Growth in the number of households is projected to increase at an average rate of 0.2% per year.

4.2.2 Employment

Employment is a measure of economic activity and, with respect to this forecast, captures growth in the number of commercial accounts over time. Employment is projected to increase at an average compound rate of 0.5% per year over the 15 year forecast horizon, which is higher than the growth over the most recent ten years. Employment projections are based on data obtained from Moody's Analytics.

4.2.3 Household Income

Household income, expressed in real dollars (adjusted for inflation using the GDP price index), represents income received from all sources. Household income provides a measure of consumer spending potential, including electricity. Household income is projected to increase at an average rate of 1.9% per year from 2012 to 2027. This rate of growth is higher than growth over the previous 10 years.

4.2.4 Gross Regional Output

Gross regional product (GRP) is expressed in real dollars and represents the monetary value of all the finished goods and services produced within the service area and includes private and public consumption, government outlays, investments and exports less imports. GRP is an indicator of commercial and industrial energy sales. GRP for the service area is estimated by allocating state GRP to counties on the proportion of total state earnings of employees originating in the respective counties. County GRP estimates are constrained to the state total for each year. GRP in the service area is projected to increase at an average rate of 2.9% per year from 2012 through 2027. Projected growth in GRP is higher than growth measured over the most recent 10 year period.

4.2.5 Retail Sales

Retail sales represent all sales dollars (adjusted for inflation using the personal consumption expenditures index), for all business establishments, including mail order and on-line sales. Retail sales provide a measure of commercial activity in the service area. Retail sales are projected to increase at an average rate of 1.3% over the forecast period.

4.3 Electric Appliance Market Shares

It is assumed that the market shares for major electric appliances (heating, cooling, water heating) will show minimal growth over the forecast horizon as the market shares for each are relatively high and have leveled in recent years. Electric markets shares are based on JPEC's 2007 End-Use and Energy Efficiency Study and data obtained from the Energy Information Administration's Residential Energy Consumption Surveys.

4.4 Appliance Efficiencies

The average operating efficiencies of electric heating, electric water heating, and air conditioning systems are expected to continue to increase at a decreasing rate over the next 20 years. Historical and projected average appliance efficiencies were collected from the Energy Information Administration's 2013 Annual Energy Outlook.

4.5 Weather Conditions

It is assumed that the weather conditions measured at the Paducah, Kentucky airport are representative of the member cooperative service area. Heating and cooling degree days were used to represent weather conditions, and values for each year of the forecast period are based on the average amounts computed for the 20 year period ending in 2012.

4.6 Retail Electricity Prices

The average price of electricity to rural system customers is expected to increase, in real terms, by 43% by 2016 and then remain flat from 2016-2027.

4.7 Alternative Fuel Prices

Natural gas and liquid propane are the two primary alternative heating fuels in the service area. This load forecast contains no direct impacts of changes in alternative fuel prices as it was assumed that the changes in alternative fuel prices will not be significant enough over the long term to impact electricity consumption.

Table 4.1
Key Economic Variables

	Population (Ths.)	Households (Ths.)	Real Average Household Income	Real Gross Regional Product (Mil. $)	Real Retail Sales (Mil. $)	Employment (Ths.)
1990	146.2	58.8	$55	$3,422	$1,598	58.6
1991	147.1	59.4	$55	$3,510	$1,578	58.7
1992	148.4	60.0	$58	$3,752	$1,618	61.0
1993	149.9	60.8	$58	$3,871	$1,742	62.4
1994	151.4	61.6	$59	$4,051	$1,843	63.6
1995	152.6	62.3	$60	$4,330	$1,934	66.1
1996	153.8	62.9	$62	$4,570	$2,019	67.4
1997	154.6	63.4	$63	$4,849	$2,035	68.3
1998	155.2	63.9	$66	$4,987	$2,106	70.3
1999	155.8	64.3	$66	$5,201	$2,251	72.7
2000	156.0	64.6	$69	$5,035	$2,283	73.5
2001	155.2	64.3	$68	$4,892	$2,164	71.4
2002	154.8	64.2	$68	$4,969	$2,222	70.6
2003	155.0	64.3	$68	$4,969	$2,305	69.4
2004	154.8	64.3	$69	$4,955	$2,392	69.4
2005	155.4	64.6	$70	$5,043	$2,440	69.5
2006	155.8	64.8	$70	$5,203	$2,434	69.8
2007	156.1	65.1	$71	$5,209	$2,452	71.1
2008	156.4	65.3	$74	$5,203	$2,356	70.3
2009	156.8	65.6	$72	$5,065	$2,206	66.9
2010	157.1	65.7	$72	$5,388	$2,344	67.2
2011	157.4	66.0	$74	$5,430	$2,468	68.4
2012	157.7	66.2	$75	$5,550	$2,549	69.3
2013	157.9	66.4	$75	$5,710	$2,570	70.5
2014	158.1	66.7	$78	$5,954	$2,629	71.6
2015	158.2	67.0	$80	$6,202	$2,679	72.8
2016	158.4	67.3	$82	$6,421	$2,715	73.9
2017	158.6	67.6	$83	$6,619	$2,759	74.4
2018	158.8	67.9	$85	$6,805	$2,795	74.6
2019	159.1	68.1	$86	$6,991	$2,833	74.7
2020	159.4	68.3	$87	$7,188	$2,867	74.9
2021	159.7	68.4	$89	$7,394	$2,904	75.0
2022	160.0	68.5	$90	$7,603	$2,942	75.0
2023	160.2	68.6	$92	$7,812	$2,981	75.0
2024	160.5	68.6	$94	$8,019	$3,019	75.0
2025	160.8	68.6	$96	$8,223	$3,055	75.0
2026	161.0	68.6	$97	$8,422	$3,089	74.9
2027	161.3	68.6	$99	$8,619	$3,121	74.8
2028	161.5	68.6	$101	$8,814	$3,155	74.6

5. Short-Term Energy Sales and Peak Demand Forecast

The short-term forecast contains energy and demand projections by month for years 2013-2016. A summary of projected growth rates is presented in Table 5.1. Projected energy sales and peak demand requirements are presented by month in Appendix A, Tables – Short-Term Forecast.

Table 5.1
Short-Term Forecast
Annual Average Growth Rates

Description	2013	2014	2015	2016
Residential Sales	2.7%	-1.3%	-1.6%	-0.8%
Small Commercial Sales	-3.4%	-1.1%	-1.4%	-0.7%
Large Commercial Sales	-0.9%	-0.9%	-0.9%	-0.9%
Irrigation Sales	-0.3%	0.0%	0.0%	0.0%
Street Lights Sales	-0.3%	-1.3%	-1.6%	-0.9%
Rural System Sales	0.5%	-1.2%	-1.5%	-0.8%
Rural System CP	-1.4%	0.2%	0.2%	0.7%
Total Energy Requirements	0.2%	-1.2%	-1.5%	-0.8%
Total NCP	-0.4%	0.2%	0.2%	0.7%

5.1 Monthly Energy Sales Forecast

Regression models were developed to project monthly energy consumption and number of customers for the rural system classification. Energy sales projections for the direct serve class were developed individually by customer based on historic trends, operating characteristics, and information made available to the cooperative by individual customers.

5.2 Monthly Peak Demand Forecast

Projections of Big Rivers rural system CP demand were developed on a monthly basis using an econometric model and then allocated to JPEC and the other member cooperatives based on historical contributions to the Big Rivers peak. JPEC's contribution to the Big Rivers rural system peak was increased by 0.2% to reflect JPEC's 1-hour rural system peak demand. Projections of direct serve peak demand were based on historic trends, operating characteristics, and information made available to the cooperatives by individual customers. Total system NCP is equal to the sum of rural system 1-hour peak for each month and direct-serve NCP.

6. Long-Term Energy Sales and Peak Demand Forecast

The load and energy projections presented in this section show that energy sales and peak demand requirements are expected to increase at average compound rates of 0.4% and 0.5%, respectively, from 2012 to 2027. Rural system energy sales and peak demand are projected to increase at average compound rates of 0.4% and 0.6%, respectively. The primary impact on growth in rural system sales will be increases in the number of consumers, which are expected to increase at a rate of 0.8% per year. Tables presenting the long-term energy sales and peak demand forecast are included in Appendix B, Tables - Long-Term Forecast.

Table 6.1
Long-Term Load Forecast
Average Annual Growth Rates

	2010 - 2015	2010 - 2025
Total System Energy Requirements	-0.7%	0.4%
Total System Peak Demand (NCP)	0.3%	0.5%
Rural System Energy Requirements	-0.6%	0.4%
Rural System 1-Hour Peak Demand	0.0%	0.6%
Residential Energy Sales	0.0%	0.7%
Residential Consumers	0.7%	0.8%
Small Commercial Energy Sales	-1.1%	0.4%
Small Commercial Consumers	0.8%	0.9%
Large Commercial Energy Sales	-0.7%	-0.2%
Large Commercial Consumers	3.2%	1.0%
Irrigation Sales	0.0%	0.0%
Public Street Lighting Sales	-0.6%	0.5%

6.1 Forecast Methodology

The forecast was developed using econometrics and informed judgment. Details on econometric modeling are presented in section 8 of this report. The econometric model specifications discussed in this section, including statistical outputs, are presented in Appendix D, Econometric Model Specifications.

Econometric models were used to project number of customers and average energy use per customer for the rural system class. Informed judgment was used to forecast energy sales of each large commercial customer included in the direct serve class. An econometric model was developed to project Big Rivers' rural system coincident peak demand for 2013-2017. Projections for these years were allocated to JPEC and the other member cooperatives based on historical contributions to Big Rivers' peak. Rural peak demand for years 2018-2027 was projected by applying the derived 2017 load factor to the rural system energy forecast. Demand was projected on a monthly basis and provided the means for developing projections of summer and winter peaks from one model. The summer season includes months June through September, and the winter season includes months January, February, and March of the current year and December from the prior year.

6.2 Forecast Results

6.2.1 Rural System

The rural system class consists of all customers receiving retail service from JPEC. In 2012, the rural system accounted for 99% of all accounts and total system energy. Weather normalized class sales over the past ten years increased at an average rate of 1.8% per year; however, growth in the most recent five years has been relatively flat. Sales are projected to increase at a rate of 0.4% per year from 2012 through 2027. Growth in average consumption per customer is expected to be low in future years due primarily to the vintaging of heating and cooling systems, energy conservation, and a slowing of increases in electric heating market share. Customer growth is projected at 0.8% per year. After declines in the near term due to sharp price increases, energy sales are projected to increase at an average rate of 0.9% per year from 2016-2027.

The rural system sales forecast is based on the product of number of customers and average use per customer. The customer forecast is based on an econometric model that specifies a relationship between number of customers and number of households. An autoregressive parameter was also included in the consumer model to correct for serial autocorrelation.

The average monthly energy consumption per customer forecast is based on an econometric model that specifies a relationship between average use, average household income, real price of electricity, heating degree days, cooling degree days, electric heating market share, air conditioning market share, and the appliance efficiencies of electric heating and cooling systems. Projections of average household income were obtained from Moody's Analytics. Projected retail prices were developed by Big Rivers. Heating and cooling degree days were collected from the National Oceanic and Atmospheric Administration, and projected values represent averages for the 20 years ending 2012. Appliance market shares are based on appliance saturation surveys. Projected appliance efficiencies were obtained from the Energy Information Administration's 2013 Annual Energy Outlook. Expected impacts on average use over the long term include:

- Leveling in electric heating, electric air conditioning, and electric water heating market share;
- Increases in average home size, which result in higher heating and cooling load as well as increases in "plug-in" loads;
- Increases in "plug-in" loads, regardless of home size;
- Growth in average household income, which increases disposable income available to purchase electric goods;
- Increased efficiencies in new electric appliances;
- Regulatory energy standards;
- Energy conservation.

6.2.2 Direct Serve Commercial & Industrial

The direct serve class includes all commercial and industrial customers that are served directly from a dedicated point of delivery. The class represents less than 1% of total system customers and energy sales. No new direct serve customers are projected over the next 15 years, and sales to the existing customer are expected to be flat.

6.3 Distribution Losses

Distribution losses on the rural system have averaged 5.1% over the most recent ten-year period and are projected to be 5.0% from 2012 through 2027. There are no losses associated with JPEC's direct serve customer.

6.4 Peak Demand

This forecast contains projections of rural system non-coincident peak (NCP) demand, rural system station NCP, and total system non-coincident peak demand. Rural system NCP represents the maximum 1-hour, aggregated, simultaneous load of all rural substations on the system. Rural system station NCP demand represents the sum of the maximum individual substation demands in a given month without respect to date or time. Peak demand projections were developed on a summer and winter seasonal basis.

Rural system NCP demand is projected to increase at an average rate of 0.6% over the forecast period, reaching 173 MW by 2027. Rural NCP is expected to continue a trend of occurring during the summer season. Rural station NCP is projected to reach 185 MW by 2027. Direct serve NCP is projected to remain flat at 2 MW through 2027. Total system NCP, represented as the sum of rural system NCP and direct serve NCP, is projected to fall to 155 MW in 2013 and increase to 172 MW by 2027.

The coincidence factor between JPEC's contribution to Big Rivers' 1-hour rural system peak and JPEC's 1-hour peak averaged 0.993 for 2007-2012. This average was applied to JPEC's projected load coincident with Big Rivers to computed JPEC's 1-hour rural system NCP. A diversity factor of 107% was applied to rural system NCP to compute rural system station NCP.

An econometric model was developed to project rural system peak demand at the Big Rivers level, which was then allocated to JPEC and the other member cooperatives based on historical contributions to the Big Rivers peak. The model specifies a relationship between peak demand, energy requirements, peak day degree days, degree days for the day prior to the peak day, and binary variables equal to 1 for the months of March, April, May, and October, and 0 in all other months.

6.5 Energy Efficiency Program Impacts

The Cooperative recently implemented energy efficiency programs that will impact energy sales and peak demand over the forecast horizon. A comprehensive energy efficiency and demand-side management study was conducted in 2010 by Big Rivers Electric Corporation[2], and the seven programs listed in Table 6.2 were concluded to be economically feasible. Details for each of the seven programs are described in that report.

Table 6.2
Energy Efficiency Programs

Residential Programs	Commercial Programs
Lighting	Lighting
Efficient Appliances	HVAC
Advanced Technologies	
Weatherization	
New Construction	

The portfolio of programs was designed at the Big Rivers level rather than at each of Big Rivers' three member cooperatives. Total program potential through 2020 is estimated at 1 percent of rural system energy sales and 1.4 percent of rural system peak demand (winter peak). Energy and peak savings are based on total funding by Big Rivers of $11.2 million, consisting of $1 million in 2011, followed by increases of 2.5 percent annually from 2012-2020.

The Big Rivers study examined over 200 energy efficiency measure permutations in the residential, commercial and industrial sectors combined. The findings suggest that Big Rivers could save up to 31.6%

[2] Demand-Side Management (DSM) Potential Report for Big Rivers Electric Corporation, October 2010.

of total energy sales and 40.1% of winter peak demand by pursuing "Economic Potential" energy efficient technologies. In the base case "Achievable Potential" scenario, savings of approximately 8.8% of total energy sales (311,744 MWh) and 11.6% of winter peak demand (79.5 MW) are possible by 2020.

The example programs analyzed in the "Program Potential" scenario achieve estimated savings in 2020 of 34,845 MWh and peak load reductions of 9.5 MW in the winter and 7.2 MW in the summer at the end-consumer level for all three Big Rivers member cooperatives in the aggregate. This represents approximately 1.0% of total energy sales, 1.4% of peak demand in the winter, and 1.0% of peak demand in the summer by 2020.

Table 6.3 presents JPEC's forecast of rural system energy and peak demand, estimated program impacts at JPEC, and projected rural system requirements adjusted for the programs.

Table 6.3
Energy Efficiency Programs

Year	Rural Energy Sales (MWh)	Energy Efficiency Program Impact (MWh)	Adjusted Energy Sales (MWh)	Rural Peak Demand (MW)	Energy Efficiency Program Impact (MW)	Adjusted Peak Demand (MW)
2013	663,016	1,139	661,876	153	0	153
2014	654,890	2,175	652,715	154	1	153
2015	644,964	3,233	641,731	154	1	153
2016	639,698	4,317	635,381	155	1	154
2017	645,266	5,422	639,845	157	1	156
2018	650,636	6,344	644,292	158	2	156
2019	655,992	7,314	648,678	159	2	157
2020	661,820	8,203	653,618	160	2	158
2021	668,015	9,044	658,972	162	2	160
2022	674,574	9,821	664,753	164	3	161
2023	681,399	10,585	670,814	165	3	162
2024	688,490	11,305	677,185	167	3	164
2025	695,967	12,041	683,926	169	3	165
2026	703,968	12,778	691,190	171	3	167
2027	712,405	13,516	698,889	173	4	169

Program Impact MWh includes distribution losses.

7. Range Forecasts

The base case projections reflect expected economic growth for the area as well as average weather conditions. To address the inherent uncertainty related to these factors, long-term high and low range projections were developed. The range forecasts reflect the energy and demand requirements corresponding to more optimistic or pessimistic economic growth and to mild or extreme weather conditions. Such forecast scenarios are useful for various planning functions. Four scenarios were generated: (i) base case economics and mild weather, (ii) base case economics and extreme weather, (iii) optimistic economics and normal weather, and (iv) pessimistic economics and normal weather.

The optimistic and pessimistic economy scenarios for rural system sales were developed by revising the economic inputs in the forecast models. The growth rate for number of households was adjusted to reflect the base case growth rate ±1 standard deviation of the historical growth rates. The growth rate for average household income was adjusted to reflect the base case growth rate ±1%.

The extreme and mild weather scenarios for rural system sales were developed by revising the heating and cooling degree day inputs in the forecasting models. The extreme and mild degree day values were set to the actual values from the historical years when total degree days established the highest and lowest totals. For the extreme case, degree days were set at the values in 1980; for the mild case, they were set at values in 1990.

The forecast for direct serve customers was developed using judgment; therefore, the forecast ranges for the class were developed using the same approach. Smelter load was assumed equal to the base case in each scenario. Energy sales and peak demand for the class, less smelters, were increased/decreased 15% from the base case to develop the optimistic/pessimistic economy scenarios. Energy sales and peak demand for the direct serve class were assumed equal to the base case for extreme and mild weather scenarios since consumption for direct serve customers is not weather sensitive.

The range forecasts are presented in table form in Appendix C, Range Forecasts.

8. Forecast Methodology

Econometric models were used to forecast the number of rural system customers and energy use per customer. Econometrics was also used to project rural system peak demand. Energy sales and peak demand for direct serve customers were developed individually for each customer using information available from JPEC.

8.1 Forecasting Process

Econometric models have the advantage of explicitly tracking the underlying causes of trends and patterns in historical data. They provide information that allows Cooperative management to estimate the impacts of certain factors on energy consumption. The methodology has proven very useful for simulation and "what-if" study. In addition, econometric models can be used to identify sources of forecasting error. On the other hand, econometric models require considerable amounts of data, and when used for forecasting, force the assumption that relationships developed during historical period will remain the same throughout the forecast horizon. Econometric models have been developed to project residential and small commercial requirements as these two consumer classifications account for the overwhelming majority of total system energy sales.

Expert opinion is used when other techniques are ineffective. This approach is utilized to project industrial requirements. Projections are made individually for each account and are based upon information collected from the account's management. The advantages of this method include simplicity and expert input. The major disadvantage is that forecasts based on expert opinion can be biased by one person's opinion.

8.2 Econometrics

Econometrics is a forecasting technique in which the relationship between a variable of interest and one or more influential factors is quantified. Econometrics is based on an area of statistical theory known as regression analysis. Regression analysis is a statistical technique for modeling and testing the relationship between two or more variables. The general form of an econometric model can be expressed as:

$$y_t = ß_0 + ß_1(x_{t1}) + ß_2(x_{t2}) + ß_3(x_{t3}) + \ldots ß_k(x_{tn}) + e_t$$

where:

t	= time element
y_t	= the dependent variable
$x_1, x_2, \ldots x_n$	= the set of independent variables
$ß_0, ß_1, \ldots ß_k$	= the set of parameter coefficients
e_t	= modeling error

8.2.1 Model Specification

In the context of this report, model specification refers to the process of defining: (i) the explanatory variables to incorporate in the model and (ii) the form of the model. Explanatory variables, also referred to as independent or exogenous variables, represent factors which are hypothesized to influence a change in the dependent, or endogenous variables. Definition of the explanatory variables should be based upon sound economic principles and assumptions. For example, it is reasonable to assume that local economic conditions produce significant impacts on energy consumption. Variables such as a gross state product and per capita income are often used as explanatory variables to represent, or indicate, the level of economic activity.

In the utility industry, an econometric model is usually developed using some combination of economic, demographic, price, and meteorological variables. It is desirable to also include specific information in the econometric model concerning the end-users, or consumers, of electricity; this information may be in the form of appliance saturation levels or indicators of consumer attitudes toward conservation. Inclusion of these types of explanatory variables in a model enables the forecaster to identify the major factors influencing periodic changes in a variable such as peak demand or energy sales. Inclusion of these variables also makes possible a better estimation of the impact these factors have on changes in consumption.

Models sometime include as an independent variable the lag of the dependent variable. Such models are commonly referred to as adaptive expectation or Koyck distributed lag models. L.M. Koyck demonstrated in 1954 that this specification is equivalent to an infinite geometric lag model. Under such a specification, the assumption is made that the impacts of the explanatory variables included in the model are significant over a period of years, with the current year weighted the heaviest, the previous year weighted less, and so on until the earliest year has no impact.

Econometric models can be specified in linear or log-linear form. When the model is specified in linear form, the assumption is made that elasticities are not constant, and that a unit change in a given explanatory variable will influence a change in the dependent variable equal to the unit change in the explanatory variable times the corresponding coefficient.

When the model variables are expressed in natural log form, it is assumed that elasticities are constant and that a percentage change in a given explanatory variable influences a constant percentage change in the dependent variable based upon the coefficient of the given explanatory variable. A second assumption made when specifying a log-linear model is that changes in the dependent variable are greater at lower levels of the explanatory variables than at higher levels. With respect to energy consumption, this assumption applies primarily to increases in income. Consumption increases rapidly when income increases from lower levels as consumers purchase electric goods and services; however, once income reaches a certain level, most high use electric end-uses have been purchased. As a result, additional increases in income tend to have less impact on consumption than the same level of increase from a lower level of income.

8.2.2 Model Estimation

Once a hypothesized relationship or model is specified, historical data are used to estimate the model parameters, $ß_0$, $ß_1$, $ß_2$,... $ß_k$ and quantify the empirical relationship that exists between the variable of interest and the chosen set of explanatory variables. Investigation of the relationship between the dependent variable, y, and an independent variable, x, leads to one of three conclusions: (i) a change in variable x impacts no change in variable y, and a change in variable y impacts no change in variable x, (ii) a change in variable x impacts a change in variable y, while a change in variable y impacts no change in variable x, and (iii) a change in variable x impacts a change in variable y, and a change in variable y impacts a change in variable x. Under conclusion (i), no relationship exits and the explanatory variable should be omitted from further analysis. Under conclusion (ii) variable x is said to be exogenous; its value is determined outside of the marketplace. Under conclusion (iii), both variables x and y are said to be endogenous; both are determined within the marketplace.

The appropriate regression technique to employ in estimating the model depends upon the relationship between the dependent and independent variables. When all explanatory variables are exogenous, ordinary least squares is appropriate. When one or more of the explanatory variables are endogenous, two-stage least squares is appropriate.

8.2.3 Ordinary Least Squares (OLS)

Regression analysis is a statistical procedure that quantifies the relationship between two or more variables. Based upon available input data, a regression equation provides a means of estimating values of a dependent variable. The difference between the actual value of the dependent variables and its regression based estimated value is the error term, generally referred to as the residual. Ordinary least squares is the technique employed which minimizes the sum of the squared errors. A tentative least square model for residential usage can be expressed as:

$$RUSE_t = ß_0 + ß_1(PCAP_t) - ß_2(RRPE_t) + ß_3(CDD_t) + ß_4(HDD_t) + e_t$$

$RUSE_t$	=	residential energy use in year t
$PCAP_t$	=	per capita income in year t
$RRPE_t$	=	price of electricity in year t
CDD_t	=	number of cooling degree days in year t
HDD_t	=	number of heating degree days in year t
e_t	=	represents the unexplained error in year t

8.2.4 Model Validation

In this study, the model validation process involved evaluation of the models for theoretical consistency, statistical validity, and estimating accuracy. From a theoretical standpoint, the model should be consistent with economic theory and specify a relationship that addresses those factors known to influence energy usage. For models that address customer growth, it is appropriate to include a demographic variable such as population, number of households, or employment to explain growth in the number of consumers. For models that address changes in energy sales, more types of variables are needed. An economic variable such as income explains customers' ability to purchase electric goods and services. Weather variables explain changes in consumption due to weather conditions. Price of electricity and price of electricity substitutes measure consumer conservation. Appliance saturation levels measure change in consumption due to changes in end-use equipment. Lagged dependent variables account for the lagged effect of all explanatory variables from previous periods.

The coefficients for each parameter included in the models were tested to insure the proper sign (+ or -). The number of customers increases with population or some other demographic variable; therefore, the sign of demographic variables in the customer model should be positive. There is a direct relationship between energy consumption and income; as income increases, consumption will increase as well. The sign on the income variable in the energy consumption model should be positive. The sign on the price of natural gas, or some other electricity substitute should be positive. Energy consumption increases as weather conditions, as measured by degree days, become more extreme; the sign of both the heating and cooling degree day variables should be positive. There is an indirect relationship between energy consumption and price of electricity. As price increases, consumers tend to conserve energy, and consumption decreases.

The statistical validity of each model is based on two criteria. One, each model was examined to determine the statistical significance of each explanatory variable. Two, tests were performed to identify problems resulting from autocorrelation and/or multicollinearity. An analysis of the models' residuals was performed to determine whether mathematical transformations of the independent variables were required.

Each model was evaluated with respect to its estimating accuracy. The standard error of regression, a statistic generated during the regression analysis, was used to measure accuracy. Tentative models that initially had low degrees of accuracy were tested using alternative specifications.

8.2.5 Model Building Process

The development of forecasts using econometric modeling is a multi-step process. A substantial portion of the effort involved in effective model building is the collection of reliable data for both the historical and projected periods. It is critical, in building models which explain changes in load growth, that the appropriate influential factors be considered, and that the correct explanatory variables be collected to quantify those influential factors.

There are many factors that influence consumers to change their usage levels of electricity. A partial list would include changes in the economy, new industry in an area, key industry leaving an area, population shifts, temperature, unemployment levels, attitudes toward conservation, precipitation amounts, improved appliance efficiencies, political events, inflation, and increases in the price of electricity. The relationship between these factors and energy usage is further complicated since most of these factors are interrelated; for example, when inflation is rampant, increases in the price of electricity may not significantly lower usage by the consumer.

After all necessary data are collected, the model building process begins. During this process, numerous models containing various combinations of candidate explanatory variables are estimated and tested. Each tentative model is examined to see if the explanatory variables included in that particular model specification contribute significantly to the "explanation" of the variable of interest. For those models that pass this preliminary examination, the appropriate regression diagnostic tools are used to test the validity of the underlying statistical assumptions. Included in this examination are tests for autocorrelation and multicollinearity.

The tentative models are tested, not only for statistical reliability, but also for reasonableness of practical interpretation. For example, the model should not show that the effect of extremely cold winter weather has been a reduction in usage. The potential performance of a tentative model for forecasting purposes is also investigated. A model that contained only one explanatory variable (one which measured only weather effects, for example) might not be a good predictive model.

If a tentative model is found to have significant statistical problems, or if the model is simply found to be misspecified, the model is discarded, and a new tentative model is specified. Analysis of the residuals (actual minus estimated values) from the discarded model is helpful in the reformulation of the model and might indicate whether some mathematical transformation of the existing set of explanatory variables is required. This process of specification, estimating, and reformulation continues until a model is found which is statistically sound and which has a sound practical interpretation as well.

8.2.6 Final Model Selection

If a model is found to be a good representation of the proposed relationship, and if it is also determined to be statistically sound, it can be used to estimate values of the variable of interest in future time periods. It is important to note that the forecaster makes the assumption that the modeled relationship between the response and explanatory variables remains the same in the forecast period as it was measured in the historical period. Forecasts are calculated by inserting projected values of the explanatory variables into the estimated model equation. Different forecast scenarios can also be considered by incorporating different values of forecasted explanatory variables. Managerial judgment, based on practical estimations of future trends, can then be used to select the most appropriate and reasonable forecast.

Appendix A
Tables – Short-Term Forecast

JACKSON PURCHASE ENERGY

2013 LOAD FORECAST - BASE CASE

TOTAL SYSTEM REQUIREMENTS

Year	Month	Consumers	Sales (MWh)	Purchases (MWh)	DSM Adj. Purchases (MWh)	NCP (kW)	DSM Adj. NCP (kW)	Load Factor
2012	Jan	29,215	58,075	61,163	61,163	127,249	127,249	64.6%
2012	Feb	29,169	49,843	52,290	52,290	115,062	115,062	61.1%
2012	Mar	29,185	44,375	44,620	44,620	92,690	92,690	64.7%
2012	Apr	29,140	39,672	43,507	43,507	104,485	104,485	56.0%
2012	May	29,197	53,383	56,596	56,596	129,159	129,159	58.9%
2012	Jun	29,229	56,975	62,134	62,134	160,040	160,040	52.2%
2012	Jul	29,291	76,903	77,948	77,948	155,944	155,944	67.2%
2012	Aug	29,284	63,071	66,360	66,360	152,824	152,824	58.4%
2012	Sep	29,312	49,593	50,112	50,112	132,765	132,765	50.7%
2012	Oct	29,280	40,976	44,998	44,998	89,453	89,453	67.6%
2012	Nov	29,291	49,207	51,445	51,445	110,765	110,765	62.4%
2012	Dec	29,301	52,902	57,689	57,689	115,594	115,594	67.1%
2013	Jan	29,288	61,023	64,215	-	137,586	137,303	0.0%
2013	Feb	29,291	51,600	54,301	-	120,604	120,321	0.0%
2013	Mar	29,283	48,403	50,937	-	110,376	110,093	0.0%
2013	Apr	29,259	41,715	43,880	-	95,828	95,545	0.0%
2013	May	29,258	46,813	49,247	-	115,686	115,485	0.0%
2013	Jun	29,269	56,701	59,669	-	143,782	143,582	0.0%
2013	Jul	29,285	65,567	69,008	-	155,234	155,033	0.0%
2013	Aug	29,300	63,904	67,245	-	148,829	148,628	0.0%
2013	Sep	29,313	48,918	51,464	-	133,212	133,011	0.0%
2013	Oct	29,321	43,331	45,581	-	95,783	95,582	0.0%
2013	Nov	29,321	47,286	49,747	-	113,222	112,939	0.0%
2013	Dec	29,348	59,859	62,978	-	130,249	129,966	0.0%
2014	Jan	29,525	60,284	63,437	-	137,922	137,357	0.0%
2014	Feb	29,504	50,827	53,487	-	120,937	120,371	0.0%
2014	Mar	29,517	47,688	50,184	-	110,721	110,155	0.0%
2014	Apr	29,475	40,940	43,064	-	96,183	95,617	0.0%
2014	May	29,530	46,154	48,552	-	116,053	115,653	0.0%
2014	Jun	29,549	56,114	59,050	-	144,153	143,752	0.0%
2014	Jul	29,591	65,102	68,518	-	155,604	155,203	0.0%
2014	Aug	29,579	63,378	66,692	-	149,195	148,794	0.0%
2014	Sep	29,582	48,296	50,810	-	133,573	133,172	0.0%
2014	Oct	29,548	42,637	44,850	-	96,133	95,733	0.0%
2014	Nov	29,572	46,665	49,094	-	113,565	113,000	0.0%
2014	Dec	29,587	59,316	62,407	-	130,592	130,026	0.0%
2015	Jan	29,768	59,654	62,773	-	138,203	137,383	0.0%
2015	Feb	29,750	50,120	52,743	-	121,214	120,395	0.0%
2015	Mar	29,767	46,946	49,403	-	111,008	110,188	0.0%
2015	Apr	29,728	40,117	42,198	-	96,478	95,659	0.0%
2015	May	29,786	45,305	47,659	-	116,360	115,754	0.0%
2015	Jun	29,808	55,230	58,120	-	144,462	143,856	0.0%
2015	Jul	29,851	64,227	67,597	-	155,912	155,306	0.0%
2015	Aug	29,841	62,514	65,782	-	149,500	148,894	0.0%
2015	Sep	29,845	47,441	49,910	-	133,873	133,268	0.0%
2015	Oct	29,813	41,825	43,996	-	96,426	95,820	0.0%
2015	Nov	29,837	45,913	48,302	-	113,851	113,032	0.0%
2015	Dec	29,852	58,680	61,737	-	130,877	130,058	0.0%
2016	Jan	30,033	59,402	62,508	-	139,174	138,073	0.0%
2016	Feb	30,015	49,782	52,387	-	122,175	121,075	0.0%
2016	Mar	30,032	46,571	49,008	-	112,003	110,902	0.0%
2016	Apr	29,993	39,659	41,716	-	97,501	96,401	0.0%
2016	May	30,051	44,831	47,160	-	117,421	116,605	0.0%
2016	Jun	30,071	54,739	57,603	-	145,531	144,715	0.0%
2016	Jul	30,115	63,750	67,095	-	156,979	156,163	0.0%
2016	Aug	30,104	62,038	65,281	-	150,556	149,740	0.0%
2016	Sep	30,108	46,950	49,393	-	134,915	134,100	0.0%
2016	Oct	30,075	41,362	43,508	-	97,437	96,622	0.0%
2016	Nov	30,100	45,504	47,872	-	114,842	113,742	0.0%
2016	Dec	30,114	58,382	61,424	-	131,867	130,767	0.0%

JACKSON PURCHASE ENERGY

2013 LOAD FORECAST - BASE CASE

RURAL SYSTEM REQUIREMENTS

Year	Month	Energy (MWh)	DSM Adj. Energy (MWh)	NCP (kW)	DSM Adj. NCP (kW)	Load Factor
2012	Jan	60,784	60,784	126,100	126,100	64.8%
2012	Feb	52,000	52,000	113,054	113,054	61.8%
2012	Mar	44,319	44,319	89,581	89,581	66.5%
2012	Apr	42,911	42,911	102,426	102,426	56.3%
2012	May	56,012	56,012	131,230	131,230	57.4%
2012	Jun	61,771	61,771	159,750	159,750	52.0%
2012	Jul	77,763	77,763	159,615	159,615	65.5%
2012	Aug	65,946	65,946	151,298	151,298	58.6%
2012	Sep	49,622	49,622	133,453	133,453	50.0%
2012	Oct	44,400	44,400	85,497	85,497	69.8%
2012	Nov	50,942	50,942	108,120	108,120	63.3%
2012	Dec	57,090	57,090	113,757	113,757	67.5%
2013	Jan	63,835	63,725	135,685	135,402	63.3%
2013	Feb	54,011	53,918	118,725	118,442	61.2%
2013	Mar	50,684	50,597	108,486	108,203	62.9%
2013	Apr	43,293	43,218	93,949	93,666	62.0%
2013	May	48,665	48,582	113,623	113,422	57.6%
2013	Jun	59,353	59,251	141,870	141,670	56.2%
2013	Jul	68,813	68,695	153,333	153,132	60.3%
2013	Aug	66,819	66,705	146,788	146,587	61.2%
2013	Sep	50,933	50,845	131,192	130,991	52.2%
2013	Oct	45,001	44,924	93,871	93,670	64.5%
2013	Nov	49,229	49,145	111,310	111,027	59.5%
2013	Dec	62,378	62,271	128,359	128,076	65.4%
2014	Jan	63,057	62,848	136,021	135,456	62.4%
2014	Feb	53,197	53,020	119,058	118,492	60.1%
2014	Mar	49,931	49,765	108,831	108,265	61.8%
2014	Apr	42,476	42,335	94,304	93,738	60.7%
2014	May	47,971	47,812	113,990	113,590	56.6%
2014	Jun	58,735	58,540	142,241	141,840	55.5%
2014	Jul	68,324	68,097	153,703	153,302	59.7%
2014	Aug	66,266	66,046	147,154	146,753	60.5%
2014	Sep	50,279	50,112	131,553	131,152	51.4%
2014	Oct	44,271	44,124	94,221	93,821	63.2%
2014	Nov	48,576	48,414	111,653	111,088	58.6%
2014	Dec	61,807	61,602	128,702	128,136	64.6%
2015	Jan	62,393	62,081	136,302	135,482	61.6%
2015	Feb	52,453	52,190	119,335	118,516	59.2%
2015	Mar	49,150	48,904	109,118	108,298	60.7%
2015	Apr	41,610	41,402	94,599	93,780	59.3%
2015	May	47,077	46,841	114,297	113,691	55.4%
2015	Jun	57,805	57,515	142,550	141,944	54.5%
2015	Jul	67,402	67,064	154,011	153,405	58.8%
2015	Aug	65,357	65,029	147,459	146,853	59.5%
2015	Sep	49,379	49,131	131,853	131,248	50.3%
2015	Oct	43,416	43,199	94,514	93,908	61.8%
2015	Nov	47,784	47,545	111,939	111,120	57.5%
2015	Dec	61,137	60,830	128,987	128,168	63.8%
2016	Jan	62,128	61,709	137,273	136,172	60.9%
2016	Feb	52,097	51,745	120,296	119,196	58.3%
2016	Mar	48,755	48,426	110,113	109,012	59.7%
2016	Apr	41,128	40,851	95,622	94,522	58.1%
2016	May	46,578	46,264	115,358	114,542	54.3%
2016	Jun	57,287	56,901	143,619	142,803	53.6%
2016	Jul	66,900	66,449	155,078	154,262	57.9%
2016	Aug	64,856	64,418	148,515	147,699	58.6%
2016	Sep	48,862	48,532	132,895	132,080	49.4%
2016	Oct	42,928	42,639	95,525	94,710	60.5%
2016	Nov	47,353	47,034	112,930	111,830	56.5%
2016	Dec	60,824	60,413	129,977	128,877	63.0%

JACKSON PURCHASE ENERGY

2013 LOAD FORECAST - BASE CASE

RESIDENTIAL CLASSIFICATION

Year	Month	Consumers	Energy Sales (MWh)	Average Use Per Month
2012	Jan	26,003	38,340	1,474
2012	Feb	25,969	31,899	1,228
2012	Mar	25,968	26,418	1,017
2012	Apr	25,913	22,892	883
2012	May	25,951	32,128	1,238
2012	Jun	25,954	35,151	1,354
2012	Jul	25,979	52,747	2,030
2012	Aug	25,952	40,421	1,558
2012	Sep	25,940	29,543	1,139
2012	Oct	25,893	22,512	869
2012	Nov	25,901	30,347	1,172
2012	Dec	25,900	33,471	1,292
2013	Jan	25,983	41,204	1,586
2013	Feb	25,986	34,060	1,311
2013	Mar	25,978	30,652	1,180
2013	Apr	25,957	24,686	951
2013	May	25,957	27,967	1,077
2013	Jun	25,966	36,141	1,392
2013	Jul	25,980	43,840	1,687
2013	Aug	25,994	41,770	1,607
2013	Sep	26,005	29,649	1,140
2013	Oct	26,012	24,895	957
2013	Nov	26,013	28,668	1,102
2013	Dec	26,036	40,209	1,544
2014	Jan	26,190	40,676	1,553
2014	Feb	26,172	33,516	1,281
2014	Mar	26,184	30,168	1,152
2014	Apr	26,146	24,180	925
2014	May	26,195	27,537	1,051
2014	Jun	26,212	35,745	1,364
2014	Jul	26,249	43,516	1,658
2014	Aug	26,238	41,409	1,578
2014	Sep	26,241	29,244	1,114
2014	Oct	26,211	24,457	933
2014	Nov	26,233	28,260	1,077
2014	Dec	26,246	39,825	1,517
2015	Jan	26,403	40,227	1,524
2015	Feb	26,387	33,020	1,251
2015	Mar	26,402	29,666	1,124
2015	Apr	26,368	23,642	897
2015	May	26,419	26,977	1,021
2015	Jun	26,438	35,139	1,329
2015	Jul	26,477	42,894	1,620
2015	Aug	26,468	40,808	1,542
2015	Sep	26,472	28,679	1,083
2015	Oct	26,443	23,941	905
2015	Nov	26,465	27,760	1,049
2015	Dec	26,478	39,372	1,487
2016	Jan	26,635	40,057	1,504
2016	Feb	26,620	32,789	1,232
2016	Mar	26,635	29,418	1,105
2016	Apr	26,600	23,351	878
2016	May	26,651	26,674	1,001
2016	Jun	26,670	34,811	1,305
2016	Jul	26,708	42,562	1,594
2016	Aug	26,698	40,483	1,516
2016	Sep	26,702	28,362	1,062
2016	Oct	26,673	23,655	887
2016	Nov	26,694	27,500	1,030
2016	Dec	26,707	39,169	1,467

JACKSON PURCHASE ENERGY

2013 LOAD FORECAST - BASE CASE

SMALL COMMERCIAL CLASSIFICATION

Year	Month	Consumers	Energy Sales (MWh)	Average Use Per Month
2012	Jan	3,194	15,664	4,904
2012	Feb	3,183	14,608	4,589
2012	Mar	3,200	14,816	4,630
2012	Apr	3,210	12,998	4,049
2012	May	3,229	16,799	5,203
2012	Jun	3,258	17,630	5,411
2012	Jul	3,295	20,031	6,079
2012	Aug	3,315	18,741	5,653
2012	Sep	3,355	16,043	4,782
2012	Oct	3,370	14,405	4,275
2012	Nov	3,371	14,280	4,236
2012	Dec	3,382	15,258	4,511
2013	Jan	3,286	15,782	4,803
2013	Feb	3,286	14,237	4,332
2013	Mar	3,285	14,635	4,455
2013	Apr	3,283	13,279	4,045
2013	May	3,283	14,435	4,397
2013	Jun	3,284	16,394	4,992
2013	Jul	3,286	17,647	5,371
2013	Aug	3,287	18,258	5,554
2013	Sep	3,289	15,296	4,651
2013	Oct	3,290	14,414	4,382
2013	Nov	3,290	14,078	4,279
2013	Dec	3,293	15,509	4,710
2014	Jan	3,316	15,608	4,708
2014	Feb	3,313	14,038	4,237
2014	Mar	3,315	14,433	4,354
2014	Apr	3,310	13,042	3,940
2014	May	3,316	14,244	4,295
2014	Jun	3,318	16,241	4,894
2014	Jul	3,323	17,542	5,279
2014	Aug	3,322	18,127	5,457
2014	Sep	3,322	15,115	4,550
2014	Oct	3,318	14,193	4,277
2014	Nov	3,321	13,905	4,187
2014	Dec	3,323	15,385	4,631
2015	Jan	3,346	15,463	4,622
2015	Feb	3,344	13,857	4,144
2015	Mar	3,346	14,222	4,251
2015	Apr	3,341	12,788	3,827
2015	May	3,348	13,992	4,180
2015	Jun	3,350	16,001	4,776
2015	Jul	3,355	17,326	5,164
2015	Aug	3,354	17,898	5,336
2015	Sep	3,354	14,859	4,430
2015	Oct	3,351	13,932	4,158
2015	Nov	3,354	13,693	4,083
2015	Dec	3,355	15,237	4,541
2016	Jan	3,379	15,416	4,563
2016	Feb	3,377	13,779	4,081
2016	Mar	3,379	14,122	4,180
2016	Apr	3,374	12,652	3,750
2016	May	3,381	13,858	4,099
2016	Jun	3,383	15,875	4,693
2016	Jul	3,388	17,217	5,082
2016	Aug	3,387	17,780	5,250
2016	Sep	3,387	14,718	4,345
2016	Oct	3,383	13,789	4,075
2016	Nov	3,386	13,584	4,012
2016	Dec	3,388	15,177	4,480

JACKSON PURCHASE ENERGY

2013 LOAD FORECAST - BASE CASE

LARGE COMMERCIAL RURAL CLASSIFICATION

Year	Month	Consumers	Energy Sales (MWh)	Average Use Per Month
2012	Jan	10	4,032	403,152
2012	Feb	9	3,283	364,831
2012	Mar	9	3,077	341,926
2012	Apr	9	3,683	409,220
2012	May	9	4,327	480,737
2012	Jun	9	4,132	459,109
2012	Jul	9	3,861	429,052
2012	Aug	9	3,812	423,531
2012	Sep	9	3,937	437,465
2012	Oct	9	3,998	444,200
2012	Nov	11	4,510	409,956
2012	Dec	11	4,125	375,005
2013	Jan	11	3,995	363,182
2013	Feb	11	3,254	295,776
2013	Mar	11	3,049	277,190
2013	Apr	11	3,652	332,002
2013	May	11	4,289	389,925
2013	Jun	11	4,094	372,165
2013	Jul	11	3,825	347,709
2013	Aug	11	3,778	343,447
2013	Sep	11	3,903	354,830
2013	Oct	11	3,964	360,329
2013	Nov	11	4,470	406,328
2013	Dec	11	4,090	371,800
2014	Jan	11	3,959	359,896
2014	Feb	11	3,224	293,082
2014	Mar	11	3,021	274,649
2014	Apr	11	3,621	329,216
2014	May	11	4,252	386,554
2014	Jun	11	4,056	368,730
2014	Jul	11	3,788	344,409
2014	Aug	11	3,744	340,399
2014	Sep	11	3,869	351,765
2014	Oct	11	3,930	357,252
2014	Nov	11	4,430	402,736
2014	Dec	11	4,055	368,627
2015	Jan	11	3,923	356,642
2015	Feb	11	3,195	290,415
2015	Mar	11	2,993	272,132
2015	Apr	11	3,591	326,458
2015	May	11	4,215	383,217
2015	Jun	11	4,019	365,330
2015	Jul	11	3,753	341,142
2015	Aug	11	3,711	337,382
2015	Sep	11	3,836	348,730
2015	Oct	11	3,896	354,207
2015	Nov	11	4,391	399,179
2015	Dec	11	4,020	365,486
2016	Jan	11	3,888	353,421
2016	Feb	11	3,166	287,774
2016	Mar	11	2,966	269,641
2016	Apr	11	3,561	323,728
2016	May	11	4,179	379,913
2016	Jun	11	3,982	361,963
2016	Jul	11	3,717	337,908
2016	Aug	11	3,678	334,394
2016	Sep	11	3,803	345,726
2016	Oct	11	3,863	351,192
2016	Nov	11	4,352	395,659
2016	Dec	11	3,986	362,377

JACKSON PURCHASE ENERGY

2013 LOAD FORECAST - BASE CASE

IRRIGATION CLASSIFICATION

Year	Month	Consumers	Energy Sales (MWh)	Average Use Per Month
2012	Jan	5	(1)	(269)
2012	Feb	5	0	1
2012	Mar	5	12	2,375
2012	Apr	5	46	9,142
2012	May	5	61	12,149
2012	Jun	5	25	4,981
2012	Jul	5	212	42,427
2012	Aug	5	51	10,281
2012	Sep	5	22	4,421
2012	Oct	5	1	131
2012	Nov	5	8	1,549
2012	Dec	5	4	868
2013	Jan	5	-	-
2013	Feb	5	-	-
2013	Mar	5	12	2,400
2013	Apr	5	46	9,200
2013	May	5	61	12,200
2013	Jun	5	25	5,000
2013	Jul	5	210	42,000
2013	Aug	5	50	10,000
2013	Sep	5	22	4,400
2013	Oct	5	1	200
2013	Nov	5	8	1,600
2013	Dec	5	4	800
2014	Jan	5	-	-
2014	Feb	5	-	-
2014	Mar	5	12	2,400
2014	Apr	5	46	9,200
2014	May	5	61	12,200
2014	Jun	5	25	5,000
2014	Jul	5	210	42,000
2014	Aug	5	50	10,000
2014	Sep	5	22	4,400
2014	Oct	5	1	200
2014	Nov	5	8	1,600
2014	Dec	5	4	800
2015	Jan	5	-	-
2015	Feb	5	-	-
2015	Mar	5	12	2,400
2015	Apr	5	46	9,200
2015	May	5	61	12,200
2015	Jun	5	25	5,000
2015	Jul	5	210	42,000
2015	Aug	5	50	10,000
2015	Sep	5	22	4,400
2015	Oct	5	1	200
2015	Nov	5	8	1,600
2015	Dec	5	4	800
2016	Jan	5	-	-
2016	Feb	5	-	-
2016	Mar	5	12	2,400
2016	Apr	5	46	9,200
2016	May	5	61	12,200
2016	Jun	5	25	5,000
2016	Jul	5	210	42,000
2016	Aug	5	50	10,000
2016	Sep	5	22	4,400
2016	Oct	5	1	200
2016	Nov	5	8	1,600
2016	Dec	5	4	800

JACKSON PURCHASE ENERGY

2013 LOAD FORECAST - BASE CASE

STREET LIGHTING CLASSIFICATION

Year	Month	Consumers	Energy Sales (MWh)	Average Use Per Month
2012	Jan	3	41	13,512
2012	Feb	3	53	17,645
2012	Mar	3	51	17,025
2012	Apr	3	53	17,661
2012	May	3	69	22,835
2012	Jun	3	37	12,465
2012	Jul	3	51	16,920
2012	Aug	3	46	15,397
2012	Sep	3	48	15,946
2012	Oct	3	60	19,976
2012	Nov	3	63	21,062
2012	Dec	3	44	14,828
2013	Jan	3	42	14,033
2013	Feb	3	50	16,616
2013	Mar	3	54	18,066
2013	Apr	3	52	17,206
2013	May	3	61	20,247
2013	Jun	3	47	15,783
2013	Jul	3	46	15,237
2013	Aug	3	48	16,068
2013	Sep	3	47	15,738
2013	Oct	3	57	19,002
2013	Nov	3	62	20,822
2013	Dec	3	47	15,825
2014	Jan	3	42	13,862
2014	Feb	3	49	16,366
2014	Mar	3	53	17,798
2014	Apr	3	51	16,881
2014	May	3	60	19,958
2014	Jun	3	47	15,618
2014	Jul	3	45	15,128
2014	Aug	3	48	15,935
2014	Sep	3	47	15,536
2014	Oct	3	56	18,693
2014	Nov	3	62	20,545
2014	Dec	3	47	15,680
2015	Jan	3	41	13,716
2015	Feb	3	48	16,137
2015	Mar	3	53	17,520
2015	Apr	3	50	16,537
2015	May	3	59	19,586
2015	Jun	3	46	15,371
2015	Jul	3	45	14,924
2015	Aug	3	47	15,717
2015	Sep	3	46	15,258
2015	Oct	3	55	18,332
2015	Nov	3	61	20,211
2015	Dec	3	47	15,510
2016	Jan	3	41	13,658
2016	Feb	3	48	16,027
2016	Mar	3	52	17,379
2016	Apr	3	49	16,345
2016	May	3	58	19,379
2016	Jun	3	46	15,233
2016	Jul	3	44	14,813
2016	Aug	3	47	15,596
2016	Sep	3	45	15,098
2016	Oct	3	54	18,126
2016	Nov	3	60	20,028
2016	Dec	3	46	15,431

Appendix B
Tables – Long-Term Forecast

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

TOTAL SYSTEM REQUIREMENTS

Year	Actual Sales (MWh)	Projected Sales (MWh)	DSM Sales (MWh)	DSM Adj. Sales (MWh)	Percent Growth	Line Loss	DSM Adj. Purchases (MWh)	DSM Adj. Normal (MWh)	Percent Growth
1997	546,472					5.3%	577,117	591,205	
1998	577,924				5.8%	4.8%	607,063	611,649	3.5%
1999	587,713				1.7%	5.4%	620,950	639,278	4.5%
2000	595,780				1.4%	5.6%	631,196	632,004	-1.1%
2001	581,496				-2.4%	6.2%	619,863	631,494	-0.1%
2002	607,779				4.5%	5.4%	642,251	627,721	-0.6%
2003	594,991				-2.1%	5.3%	628,188	648,861	3.4%
2004	608,568				2.3%	5.0%	640,657	661,981	2.0%
2005	648,361				6.5%	4.3%	677,462	678,440	2.5%
2006	630,211				-2.8%	5.1%	663,944	683,172	0.7%
2007	681,409				8.1%	5.2%	718,915	704,836	3.2%
2008	677,877				-0.5%	4.8%	711,876	713,344	1.2%
2009	621,283				-8.3%	5.1%	654,774	655,127	-8.2%
2010	683,481				10.0%	4.6%	716,681	682,629	4.2%
2011	651,539				-4.7%	4.7%	683,764	682,629	0.0%
2012	634,975				-2.5%	5.1%	668,864	667,172	-2.3%
2013		635,121	1,082	634,039	-0.1%	5.0%		667,133	0.0%
2014		627,401	2,066	625,335	-1.4%	5.0%		657,972	-1.4%
2015		617,972	3,071	614,901	-1.7%	5.0%		646,989	-1.7%
2016		612,969	4,101	608,868	-1.0%	5.0%		640,639	-1.0%
2017		618,259	5,151	613,109	0.7%	5.0%		645,103	0.7%
2018		623,361	6,027	617,334	0.7%	5.0%		649,551	0.7%
2019		628,449	6,948	621,501	0.7%	5.0%		653,938	0.7%
2020		633,986	7,792	626,193	0.8%	5.0%		658,878	0.8%
2021		639,871	8,592	631,279	0.8%	5.0%		664,232	0.8%
2022		646,102	9,330	636,772	0.9%	5.0%		670,013	0.9%
2023		652,586	10,056	642,530	0.9%	5.0%		676,075	0.9%
2024		659,322	10,740	648,582	0.9%	5.0%		682,446	0.9%
2025		666,425	11,439	654,986	1.0%	5.0%		689,187	1.0%
2026		674,026	12,139	661,887	1.1%	5.0%		696,451	1.1%
2027		682,041	12,840	669,201	1.1%	5.0%		704,151	1.1%

ANNUAL GROWTH RATES

1997-2002	2.1%						2.2%	1.2%
2002-2007	2.3%						2.3%	2.3%
2007-2012	-1.4%						-1.4%	-1.1%
2012-2017		-0.5%		-0.7%				-0.7%
2017-2022		0.9%		0.8%				0.8%
2022-2027		1.1%		1.0%				1.0%
2012-2027		0.5%		0.4%				0.4%

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

TOTAL SYSTEM REQUIREMENTS

Year	Summer Actual NCP (kW)	Summer Normal NCP (kW)	DSM Impact (kW)	DSM Adj. NCP (kW)	Winter Actual NCP (kW)	Winter Normal NCP (kW)	DSM Impact (kW)	DSM Adj. NCP (kW)
1997	127,059	-			116,524	-		
1998	139,498	-			119,568	-		
1999	151,498	-			122,466	-		
2000	146,254	-			124,265	-		
2001	140,701	-			118,912	-		
2002	146,731	-			111,426	-		
2003	144,002	-			132,502	-		
2004	148,781	157,736			135,785	133,309		
2005	153,634	158,786			125,703	122,687		
2006	152,268	162,728			133,985	146,190		
2007	164,605	156,886			136,664	139,817		
2008	155,891	154,972			141,931	149,843		
2009	152,669	157,712			152,948	149,380		
2010	169,312	158,660			148,041	144,815		
2011	163,838	161,148			138,380	137,070		
2012	160,040	155,798			127,249	137,427		
2013		155,234	201	155,033		137,586	283	137,303
2014		155,604	401	155,203		137,922	566	137,357
2015		155,912	606	155,306		138,203	819	137,383
2016		156,979	816	156,163		139,174	1,100	138,073
2017		158,797	1,031	157,766		140,827	1,381	139,446
2018		159,631	1,230	158,401		141,521	1,633	139,888
2019		160,929	1,438	159,491		142,670	1,885	140,785
2020		162,342	1,640	160,702		143,921	2,137	141,784
2021		163,844	1,819	162,025		145,250	2,361	142,889
2022		165,434	1,984	163,450		146,658	2,585	144,073
2023		167,089	2,152	164,936		148,122	2,808	145,314
2024		168,808	2,318	166,490		149,644	3,032	146,612
2025		170,620	2,489	168,132		151,248	3,256	147,993
2026		172,560	2,660	169,900		152,965	3,480	149,486
2027		174,605	2,831	171,774		154,776	3,704	151,072

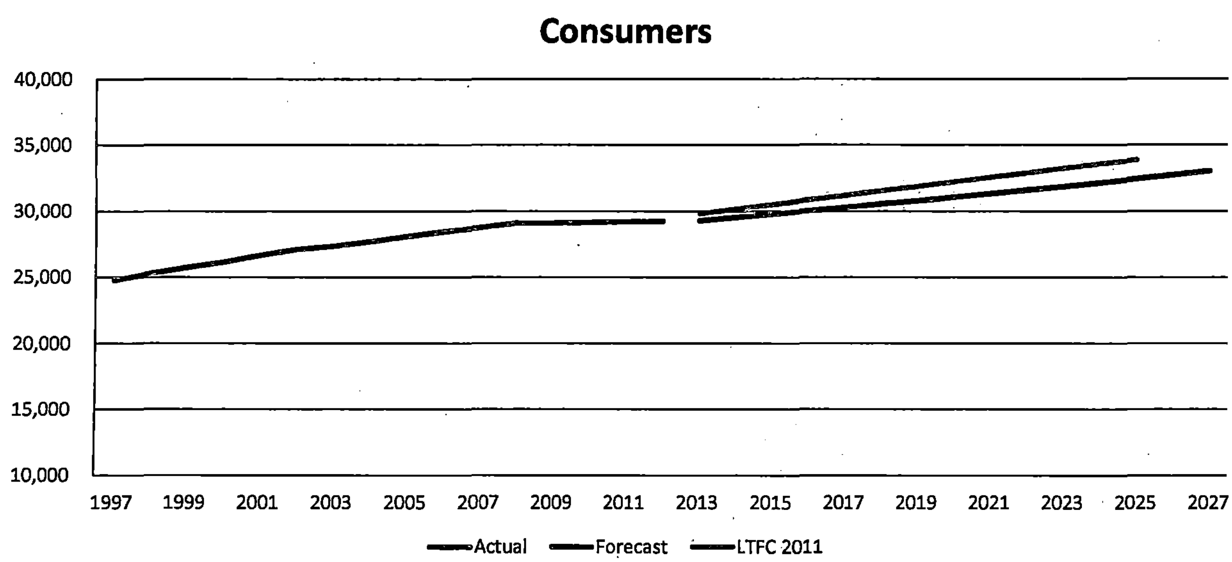
ANNUAL GROWTH RATES								
1997-2002	2.9%				-0.9%			
2002-2007	2.3%				4.2%			
2007-2012	-0.6%	-0.1%			-1.4%	-0.3%		
2012-2017		0.4%		0.3%		0.5%		0.3%
2017-2022		0.8%		0.7%		0.8%		0.7%
2022-2027		1.1%		1.0%		1.1%		1.0%
2012-2027		0.6%		0.5%		1.3%		1.2%

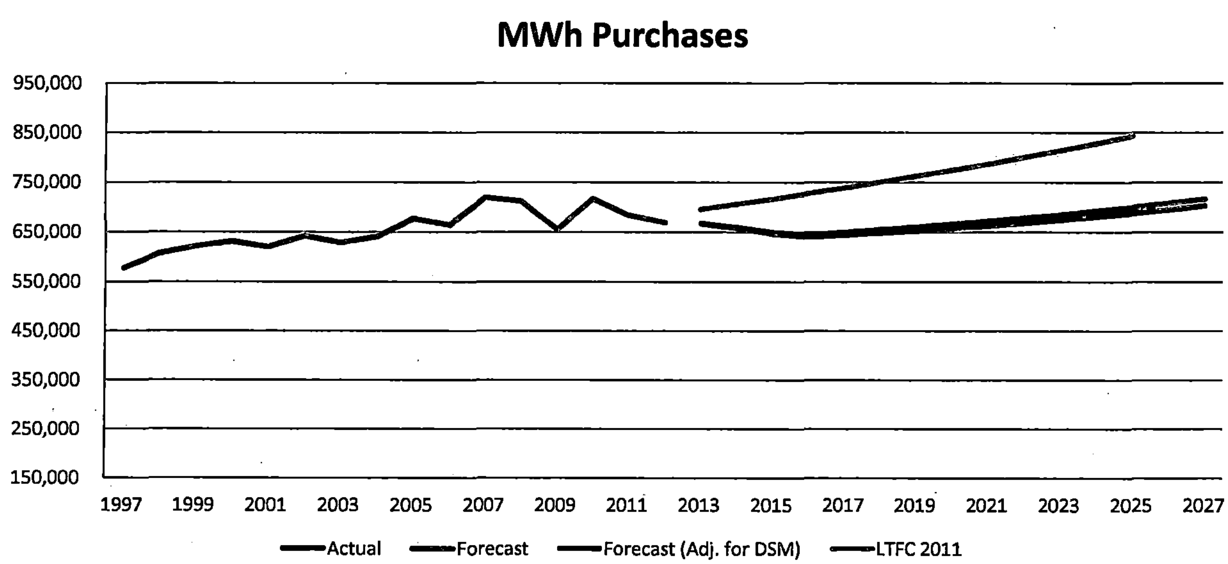
Summer season is May to October. Winter season is November of the prior year through April of the reported year.

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

TOTAL SYSTEM REQUIREMENTS



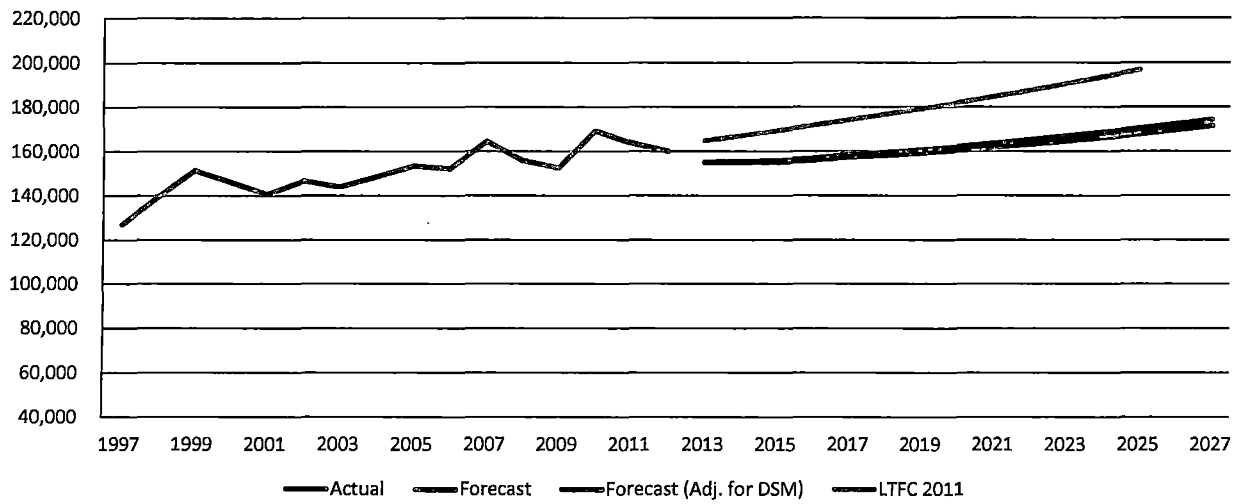


JACKSON PURCHASE ENERGY

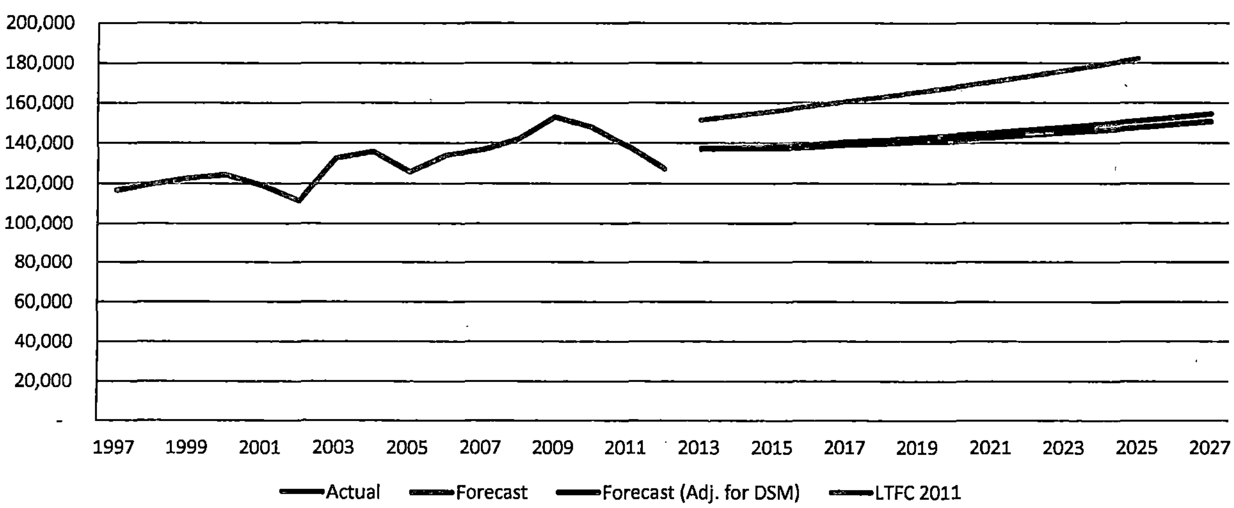
2013 LONG-TERM LOAD FORECAST - BASE CASE

TOTAL SYSTEM REQUIREMENTS

Summer NCP kW



Winter NCP kW



JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

RURAL SYSTEM REQUIREMENTS

Year	Actual Sales (MWh)	Projected Sales (MWh)	DSM Sales (MWh)	DSM Adj. Sales (MWh)	Percent Growth	Line Loss	DSM Adj. Purchases (MWh)	Normalized (MWh)	Percent Growth
1997	493,000					5.9%	523,953	533,550	
1998	521,035				5.7%	5.3%	550,295	550,747	3.2%
1999	533,559				2.4%	5.9%	566,917	580,521	5.4%
2000	546,101				2.4%	6.1%	581,588	577,622	-0.5%
2001	536,700				-1.7%	6.7%	575,142	581,586	0.7%
2002	572,078				6.6%	5.7%	606,588	588,336	1.2%
2003	564,663				-1.3%	5.6%	597,973	615,238	4.6%
2004	573,834				1.6%	5.3%	606,086	624,018	1.4%
2005	611,864				6.6%	4.6%	641,079	639,242	2.4%
2006	606,940				-0.8%	5.3%	640,738	657,023	2.8%
2007	658,091				8.4%	5.5%	696,665	679,507	3.4%
2008	658,576				0.1%	5.0%	693,006	691,946	1.8%
2009	622,241				-5.5%	5.2%	656,138	654,847	-5.4%
2010	668,620				7.5%	4.8%	702,176	665,987	1.7%
2011	643,566				-3.7%	4.8%	676,060	673,046	1.1%
2012	629,278				-2.2%	5.2%	663,607	659,937	-1.9%
2013		629,865	1,082	628,783	-0.1%	5.0%		661,876	-0.3%
2014		622,145	2,066	620,079	-1.4%	5.0%		652,715	-1.4%
2015		612,716	3,071	609,645	-1.7%	5.0%		641,731	-1.7%
2016		607,713	4,101	603,612	-1.0%	5.0%		635,381	-1.0%
2017		613,003	5,151	607,852	0.7%	5.0%		639,845	0.7%
2018		618,104	6,027	612,077	0.7%	5.0%		644,292	0.7%
2019		623,192	6,948	616,244	0.7%	5.0%		648,678	0.7%
2020		628,729	7,792	620,937	0.8%	5.0%		653,618	0.8%
2021		634,615	8,592	626,023	0.8%	5.0%		658,972	0.8%
2022		640,845	9,330	631,516	0.9%	5.0%		664,753	0.9%
2023		647,329	10,056	637,274	0.9%	5.0%		670,814	0.9%
2024		654,065	10,740	643,326	0.9%	5.0%		677,185	0.9%
2025		661,169	11,439	649,730	1.0%	5.0%		683,926	1.0%
2026		668,770	12,139	656,631	1.1%	5.0%		691,190	1.1%
2027		676,785	12,840	663,945	1.1%	5.0%		698,889	1.1%

ANNUAL GROWTH RATES

1997-2002	3.0%			3.0%	2.0%
2002-2007	2.8%			2.8%	2.9%
2007-2012	-0.9%			-1.0%	-0.6%
2012-2017		-0.5%	-0.7%		-0.6%
2017-2022		0.9%	0.8%		0.8%
2022-2027		1.1%	1.0%		1.0%
2012-2027		0.5%	0.4%		0.4%

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

RURAL SYSTEM REQUIREMENTS

Year	Summer Actual NCP (kW)	Summer Normal NCP (kW)	DSM Impact (kW)	DSM Adj. NCP (kW)	Winter Actual NCP (kW)	Winter Normal NCP (kW)	DSM Impact (kW)	DSM Adj. NCP (kW)
1997	127,059	-			108,294	-		
1998	128,946	-			97,621	-		
1999	142,955	-			111,666	-		
2000	137,679	-			103,236	-		
2001	132,536	-			115,614	-		
2002	138,264	-			104,706	-		
2003	136,934	-			126,065	-		
2004	142,560	151,515			114,062	111,586		
2005	145,761	150,913			127,782	124,766		
2006	146,134	156,594			122,149	134,354		
2007	158,540	150,821			129,658	132,812		
2008	152,521	151,602			134,318	142,230		
2009	149,050	154,093			148,125	144,557		
2010	162,957	152,305			139,804	136,578		
2011	161,649	158,959			143,361	142,051		
2012	159,750	155,508			126,100	136,278		
2013		153,333	201	153,132		135,685	283	135,402
2014		153,703	401	153,302		136,021	566	135,456
2015		154,011	606	153,405		136,302	819	135,482
2016		155,078	816	154,262		137,273	1,100	136,172
2017		156,896	1,031	155,865		138,926	1,381	137,545
2018		157,730	1,230	156,500		139,620	1,633	137,987
2019		159,028	1,438	157,590		140,769	1,885	138,884
2020		160,441	1,640	158,801		142,020	2,137	139,883
2021		161,943	1,819	160,124		143,349	2,361	140,988
2022		163,533	1,984	161,549		144,757	2,585	142,172
2023		165,188	2,152	163,035		146,221	2,808	143,413
2024		166,907	2,318	164,589		147,743	3,032	144,711
2025		168,719	2,489	166,231		149,347	3,256	146,092
2026		170,659	2,660	167,999		151,064	3,480	147,585
2027		172,704	2,831	169,873		152,875	3,704	149,171

ANNUAL GROWTH RATES

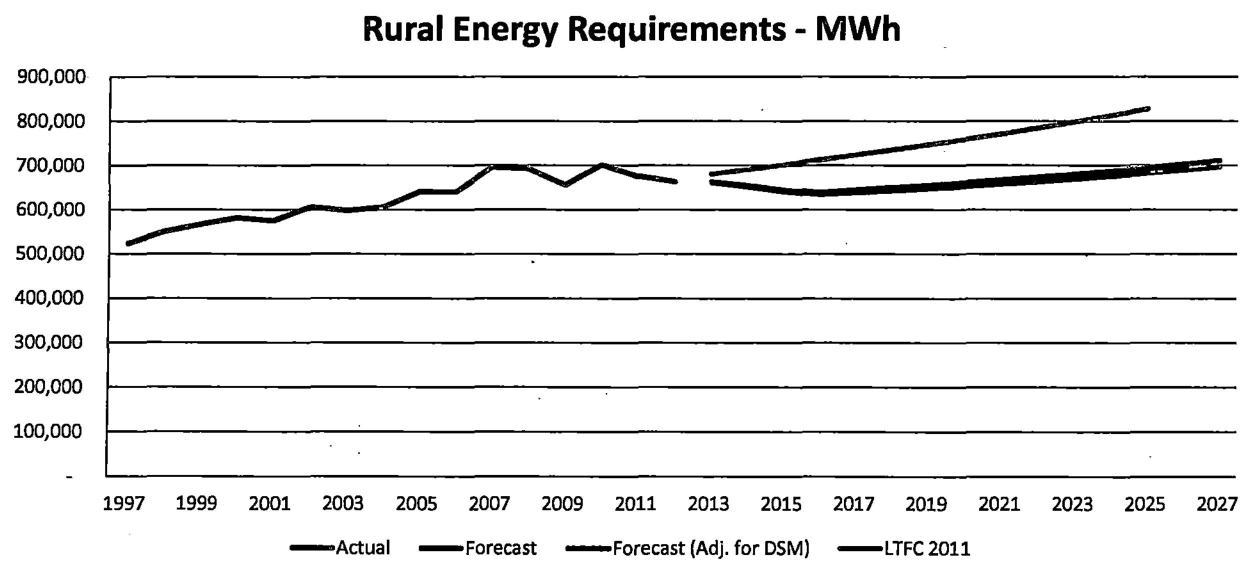
1997-2002	1.7%				-0.7%			
2002-2007	2.8%				4.4%			
2007-2012	0.2%	0.6%			-0.6%	0.5%		
2012-2017		0.2%		0.0%		0.4%		0.2%
2017-2022		0.8%		0.7%		0.8%		0.7%
2022-2027		1.1%		1.0%		1.1%		1.0%
2012-2027		0.7%		0.6%		0.8%		0.6%

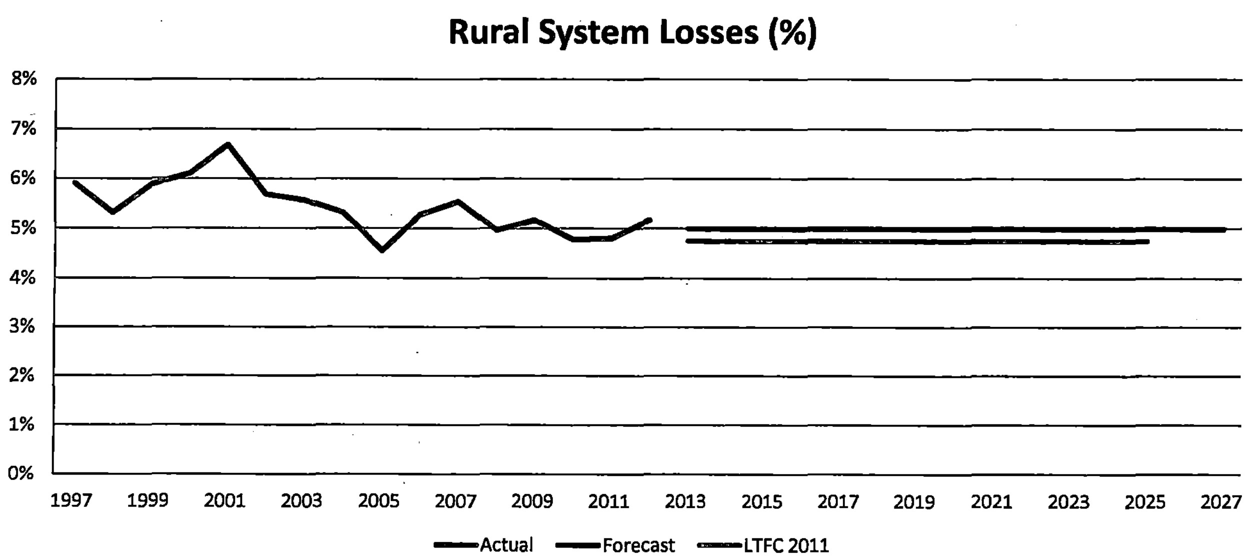
NCP values represent the highest 1-hour peak at the rural system level in each season
Summer season is May to October. Winter season is November of the prior year through April of the reported year.

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

RURAL SYSTEM REQUIREMENTS

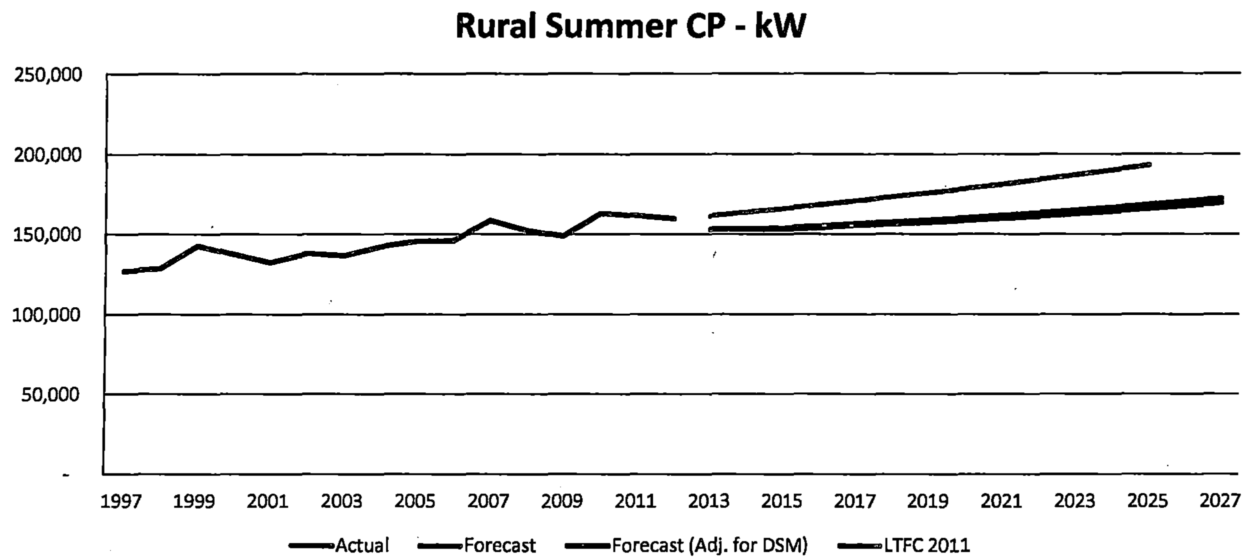


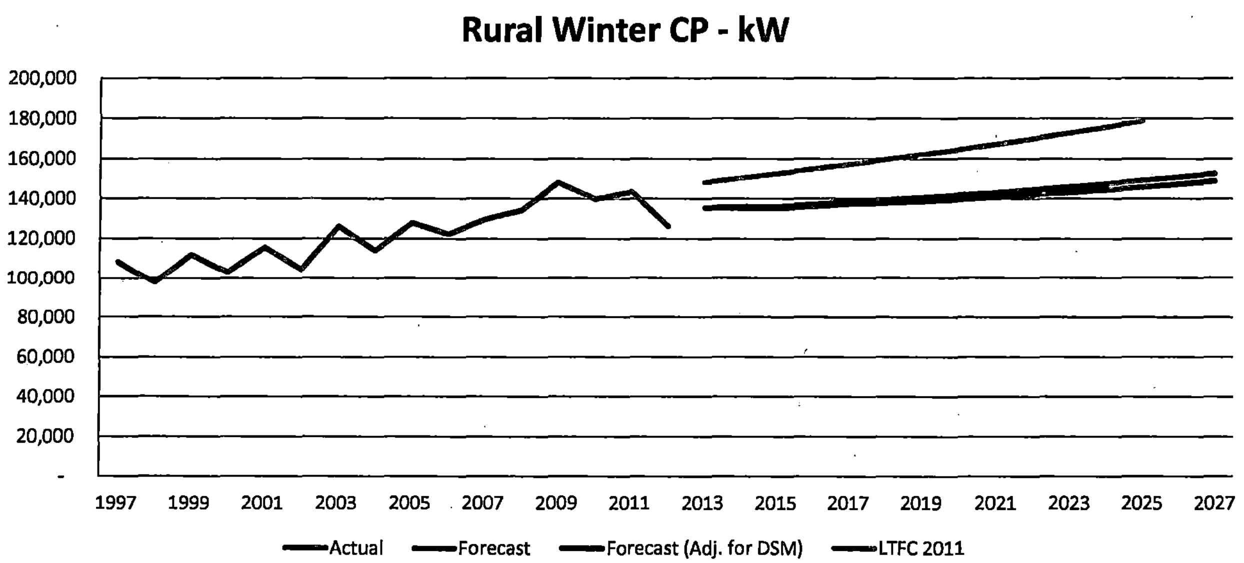


JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

RURAL SYSTEM REQUIREMENTS





JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

TOTAL SYSTEM REQUIREMENTS - NO DSM ADJUSTMENT

Year	Consumers	Percent Growth	Actual Sales (MWh)	Normal Sales (MWh)	Percent Growth	Line Loss	Actual Purchases (MWh)	Normal Purchases (MWh)	Percent Growth
1997	24,767		546,472	559,811		5.3%	577,117	591,205	
1998	25,267	2.0%	577,924	582,289	4.0%	4.8%	607,063	611,649	3.5%
1999	25,725	1.8%	587,713	605,060	3.9%	5.4%	620,950	639,278	4.5%
2000	26,123	1.5%	595,780	596,542	-1.4%	5.6%	631,196	632,004	-1.1%
2001	26,647	2.0%	581,496	592,407	-0.7%	6.2%	619,863	631,494	-0.1%
2002	27,086	1.6%	607,779	594,029	0.3%	5.4%	642,251	627,721	-0.6%
2003	27,343	0.9%	594,991	614,571	3.5%	5.3%	628,188	648,861	3.4%
2004	27,704	1.3%	608,568	628,824	2.3%	5.0%	640,657	661,981	2.0%
2005	28,105	1.4%	648,361	649,297	3.3%	4.3%	677,462	678,440	2.5%
2006	28,461	1.3%	630,211	648,462	-0.1%	5.1%	663,944	683,172	0.7%
2007	28,747	1.0%	681,409	668,065	3.0%	5.2%	718,915	704,836	3.2%
2008	29,092	1.2%	677,877	679,276	1.7%	4.8%	711,876	713,344	1.2%
2009	29,108	0.1%	621,283	621,618	-8.5%	5.1%	654,774	655,127	-8.2%
2010	29,152	0.1%	683,481	651,006	4.7%	4.6%	716,681	682,629	4.2%
2011	29,200	0.2%	651,539	650,458	-0.1%	4.7%	683,764	682,629	0.0%
2012	29,241	0.1%	634,975	633,369	-2.6%	5.1%	668,864	667,172	-2.3%
2013	29,294	0.2%		635,121	0.3%	5.0%		668,272	0.2%
2014	29,546	0.9%		627,401	-1.2%	5.0%		660,146	-1.2%
2015	29,803	0.9%		617,972	-1.5%	5.0%		650,221	-1.5%
2016	30,067	0.9%		612,969	-0.8%	5.0%		644,954	-0.8%
2017	30,327	0.9%		618,259	0.9%	5.0%		650,523	0.9%
2018	30,585	0.8%		623,361	0.8%	5.0%		655,892	0.8%
2019	30,838	0.8%		628,449	0.8%	5.0%		661,248	0.8%
2020	31,102	0.9%		633,986	0.9%	5.0%		667,077	0.9%
2021	31,367	0.9%		639,871	0.9%	5.0%		673,272	0.9%
2022	31,635	0.9%		646,102	1.0%	5.0%		679,830	1.0%
2023	31,911	0.9%		652,586	1.0%	5.0%		686,656	1.0%
2024	32,191	0.9%		659,322	1.0%	5.0%		693,746	1.0%
2025	32,477	0.9%		666,425	1.1%	5.0%		701,224	1.1%
2026	32,782	0.9%		674,026	1.1%	5.0%		709,224	1.1%
2027	33,101	1.0%		682,041	1.2%	5.0%		717,661	1.2%

ANNUAL GROWTH RATES

	Consumers	Actual Sales	Normal Sales	Line Loss	Actual Purchases	Normal Purchases
1997-2002	1.8%	2.1%	1.2%	0.2%	2.2%	1.2%
2002-2007	1.2%	2.3%	2.4%	-0.6%	2.3%	2.3%
2007-2012	0.3%	-1.4%	-1.1%	-0.6%	-1.4%	-1.1%
2012-2017	0.7%		-0.5%	-0.4%		-0.5%
2017-2022	0.8%		0.9%	0.0%		0.9%
2022-2027	0.9%		1.1%	0.0%		1.1%
2012-2027	0.8%		0.5%	-0.1%		0.5%

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

TOTAL SYSTEM REQUIREMENTS - NO DSM ADJUSTMENT

Year	Summer Actual NCP (kW)	Summer Normal NCP (kW)	Percent Growth	Normal Load Factor	Winter Actual NCP (kW)	Winter Normal NCP (kW)	Percent Growth	Normal Load Factor
1997	127,059				116,524			
1998	139,498				119,568			
1999	151,498				122,466			
2000	146,254				124,265			
2001	140,701				118,912			
2002	146,731				111,426			
2003	144,002				132,502			
2004	148,781	157,736		47.9%	135,785	133,309		56.7%
2005	153,634	158,786	0.7%	48.8%	125,703	122,687	-8.0%	63.1%
2006	152,268	162,728	2.5%	47.9%	133,985	146,190	19.2%	53.3%
2007	164,605	156,886	-3.6%	51.3%	136,664	139,817	-4.4%	57.5%
2008	155,891	154,972	-1.2%	52.5%	141,931	149,843	7.2%	54.3%
2009	152,669	157,712	1.8%	47.4%	152,948	149,380	-0.3%	50.1%
2010	169,312	158,660	0.6%	49.1%	148,041	144,815	-3.1%	53.8%
2011	163,838	161,148	1.6%	48.4%	138,380	137,070	-5.3%	56.9%
2012	160,040	155,798	-3.3%	48.9%	127,249	137,427	0.3%	55.4%
2013		155,234	-0.4%	49.1%		137,586	0.1%	55.4%
2014		155,604	0.2%	48.4%		137,922	0.2%	54.6%
2015		155,912	0.2%	47.6%		138,203	0.2%	53.7%
2016		156,979	0.7%	46.9%		139,174	0.7%	52.9%
2017		158,797	1.2%	46.8%		140,827	1.2%	52.7%
2018		159,631	0.5%	46.9%		141,521	0.5%	52.9%
2019		160,929	0.8%	46.9%		142,670	0.8%	52.9%
2020		162,342	0.9%	46.9%		143,921	0.9%	52.9%
2021		163,844	0.9%	46.9%		145,250	0.9%	52.9%
2022		165,434	1.0%	46.9%		146,658	1.0%	52.9%
2023		167,089	1.0%	46.9%		148,122	1.0%	52.9%
2024		168,808	1.0%	46.9%		149,644	1.0%	52.9%
2025		170,620	1.1%	46.9%		151,248	1.1%	52.9%
2026		172,560	1.1%	46.9%		152,965	1.1%	52.9%
2027		174,605	1.2%	46.9%		154,776	1.2%	52.9%

ANNUAL GROWTH RATES

1997-2002	2.9%		-0.9%	
2002-2007	2.3%		4.2%	
2007-2012	-0.6%	-0.1%	-1.4%	-0.3%
2012-2017		0.4%		0.5%
2017-2022		0.8%		0.8%
2022-2027		1.1%		1.1%
2012-2027		0.8%		0.8%

NCP represents the highest 1-hour peak demand recorded during the summer and winter seasons
Summer season is May to October. Winter season is November of the prior year through April of the reported year.

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

RURAL SYSTEM REQUIREMENTS - NO DSM ADJUSTMENT

Year	Actual Energy (MWh)	Normal Energy (MWh)	Percent Growth	Summer NCP (kW)	Summer Normal NCP (kW)	Percent Growth	Load Factor	Winter NCP (kW)	Winter Normal NCP (kW)	Percent Growth	Load Factor
1997	523,953	533,550		127,059				108,294			
1998	550,295	550,747	3.2%	128,946				97,621			
1999	566,917	580,521	5.4%	142,955				111,666			
2000	581,588	577,622	-0.5%	137,679				103,236			
2001	575,142	581,586	0.7%	132,536				115,614			
2002	606,588	588,336	1.2%	138,264				104,706			
2003	597,973	615,238	4.6%	136,934				126,065			
2004	606,086	624,018	1.4%	142,560	151,515		47.0%	114,062	111,586		63.8%
2005	641,079	639,242	2.4%	145,761	150,913	-0.4%	48.4%	127,782	124,766	11.8%	58.5%
2006	640,738	657,023	2.8%	146,134	156,594	3.8%	47.9%	122,149	134,354	7.7%	55.8%
2007	696,665	679,507	3.4%	158,540	150,821	-3.7%	51.4%	129,658	132,812	-1.1%	58.4%
2008	693,006	691,946	1.8%	152,521	151,602	0.5%	52.1%	134,318	142,230	7.1%	55.5%
2009	656,138	654,847	-5.4%	149,050	154,093	1.6%	48.5%	148,125	144,557	1.6%	51.7%
2010	702,176	665,987	1.7%	162,957	152,305	-1.2%	49.9%	139,804	136,578	-5.5%	55.7%
2011	676,060	673,046	1.1%	161,649	158,959	4.4%	48.3%	143,361	142,051	4.0%	54.1%
2012	663,607	659,937	-1.9%	159,750	155,508	-2.2%	48.4%	126,100	136,278	-4.1%	55.3%
2013		663,016	0.5%		153,333	-1.4%	49.4%		135,685	-0.4%	55.8%
2014		654,890	-1.2%		153,703	0.2%	48.6%		136,021	0.2%	55.0%
2015		644,964	-1.5%		154,011	0.2%	47.8%		136,302	0.2%	54.0%
2016		639,698	-0.8%		155,078	0.7%	47.1%		137,273	0.7%	53.2%
2017		645,266	0.9%		156,896	1.2%	46.9%		138,926	1.2%	53.0%
2018		650,636	0.8%		157,730	0.5%	47.1%		139,620	0.5%	53.2%
2019		655,992	0.8%		159,028	0.8%	47.1%		140,769	0.8%	53.2%
2020		661,820	0.9%		160,441	0.9%	47.1%		142,020	0.9%	53.2%
2021		668,015	0.9%		161,943	0.9%	47.1%		143,349	0.9%	53.2%
2022		674,574	1.0%		163,533	1.0%	47.1%		144,757	1.0%	53.2%
2023		681,399	1.0%		165,188	1.0%	47.1%		146,221	1.0%	53.2%
2024		688,490	1.0%		166,907	1.0%	47.1%		147,743	1.0%	53.2%
2025		695,967	1.1%		168,719	1.1%	47.1%		149,347	1.1%	53.2%
2026		703,968	1.1%		170,659	1.1%	47.1%		151,064	1.1%	53.2%
2027		712,405	1.2%		172,704	1.2%	47.1%		152,875	1.2%	53.2%

ANNUAL GROWTH RATES

1997-2002	3.0%	2.0%		1.7%				-0.7%			
2002-2007	2.8%	2.9%		2.8%				4.4%			
2007-2012	-1.0%	-0.6%		0.2%	0.6%		-1.2%	-0.6%	0.5%		-1.1%
2012-2017		-0.4%			0.2%		-0.6%		0.4%		-0.8%
2017-2022		0.9%			0.8%		0.1%		0.8%		0.1%
2022-2027		1.1%			1.1%		0.0%		1.1%		0.0%
2012-2027		0.5%			0.7%		-0.2%		0.8%		-0.3%

NCP values represent the highest 1-hour peak at the rural system level in each season and include distribution losses.

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

RURAL SYSTEM REQUIREMENTS

Year	Actual Energy (MWh)	Normal Energy (MWh)	Percent Growth	Summer Station (NCP kw)	Normal Station (NCP kw)	Percent Growth	Load Factor	Winter Station (NCP kw)	Normal Station (NCP kw)	Percent Growth	Load Factor
1997	523,953	533,550		135,953			44.8%	115,875			52.6%
1998	550,295	550,747	3.2%	137,972			45.6%	104,454			60.2%
1999	566,917	580,521	5.4%	152,962			43.3%	119,483			55.5%
2000	581,588	577,622	-0.5%	147,317			44.8%	110,463			59.7%
2001	575,142	581,586	0.7%	141,814			46.8%	123,707			53.7%
2002	606,588	588,336	1.2%	147,942			45.4%	112,035			59.9%
2003	597,973	615,238	4.6%	146,519			47.9%	134,890			52.1%
2004	606,086	624,018	1.4%	152,539	162,121		43.9%	122,046	119,397		59.7%
2005	641,079	639,242	2.4%	155,964	161,477	-0.4%	45.2%	136,727	133,499	11.8%	54.7%
2006	640,738	657,023	2.8%	156,363	167,555	3.8%	44.8%	130,699	143,759	7.7%	52.2%
2007	696,665	679,507	3.4%	169,638	161,379	-3.7%	48.1%	138,734	142,109	-1.1%	54.6%
2008	693,006	691,946	1.8%	163,197	162,214	0.5%	48.7%	143,720	152,186	7.1%	51.9%
2009	656,138	654,847	-5.4%	159,483	164,879	1.6%	45.3%	158,494	154,676	1.6%	48.3%
2010	702,176	665,987	1.7%	174,364	162,966	-1.2%	46.7%	149,590	146,138	-5.5%	52.0%
2011	676,060	673,046	1.1%	172,965	170,086	4.4%	45.2%	153,396	151,994	4.0%	50.5%
2012	663,607	659,937	-1.9%	170,932	166,393	-2.2%	45.3%	134,926	145,817	-4.1%	51.7%
2013		663,016	0.5%		164,066	-1.4%	46.1%		145,183	7.6%	52.1%
2014		654,890	-1.2%		164,462	0.2%	45.5%		145,543	0.2%	51.4%
2015		644,964	-1.5%		164,792	0.2%	44.7%		145,843	0.2%	50.5%
2016		639,698	-0.8%		165,934	0.7%	44.0%		146,882	0.7%	49.7%
2017		645,266	0.9%		167,878	1.2%	43.9%		148,651	1.2%	49.6%
2018		650,636	0.8%		168,771	0.5%	44.0%		149,393	0.5%	49.7%
2019		655,992	0.8%		170,160	0.8%	44.0%		150,623	0.8%	49.7%
2020		661,820	0.9%		171,672	0.9%	44.0%		151,961	0.9%	49.7%
2021		668,015	0.9%		173,279	0.9%	44.0%		153,384	0.9%	49.7%
2022		674,574	1.0%		174,980	1.0%	44.0%		154,890	1.0%	49.7%
2023		681,399	1.0%		176,751	1.0%	44.0%		156,457	1.0%	49.7%
2024		688,490	1.0%		178,590	1.0%	44.0%		158,085	1.0%	49.7%
2025		695,967	1.1%		180,530	1.1%	44.0%		159,802	1.1%	49.7%
2026		703,968	1.1%		182,605	1.1%	44.0%		161,639	1.1%	49.7%
2027		712,405	1.2%		184,794	1.2%	44.0%		163,576	1.2%	49.7%

ANNUAL GROWTH RATES

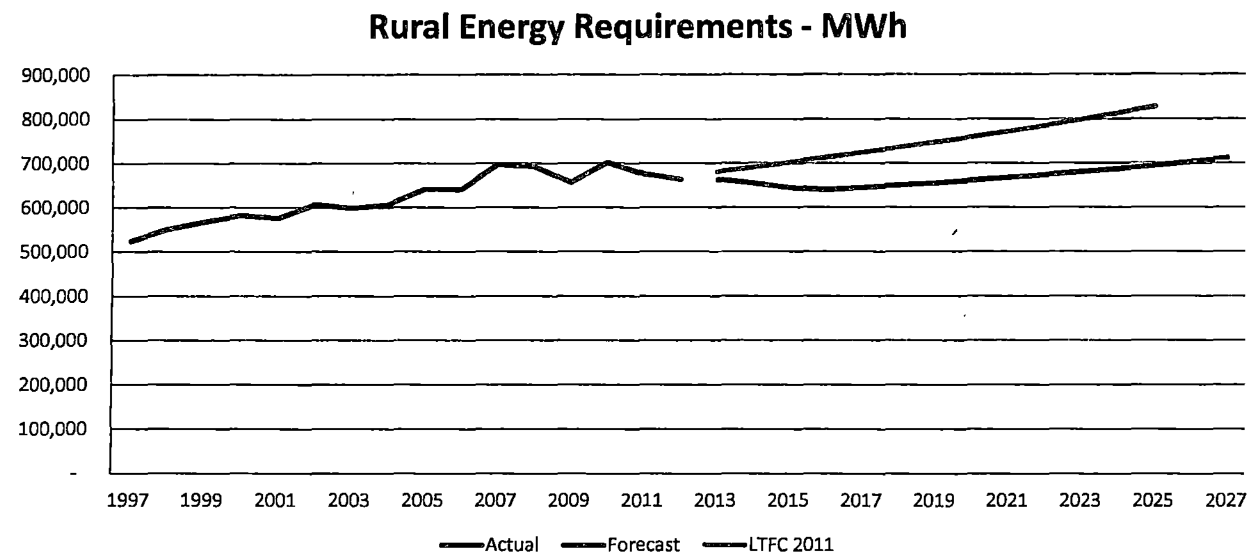
1997-2002	3.0%	2.0%		1.7%				-0.7%			
2002-2007	2.8%	2.9%		2.8%			1.1%	4.4%			
2007-2012	-1.0%	-0.6%		0.2%	0.6%		-1.2%	-0.6%	0.5%		-1.1%
2012-2017		-0.4%			0.2%		-0.6%		0.4%		-0.8%
2017-2022		0.9%			0.8%		0.1%		0.8%		0.1%
2022-2027		1.1%			1.1%		0.0%		1.1%		0.0%
2012-2027		0.5%			0.7%		-0.2%		0.8%		-0.3%

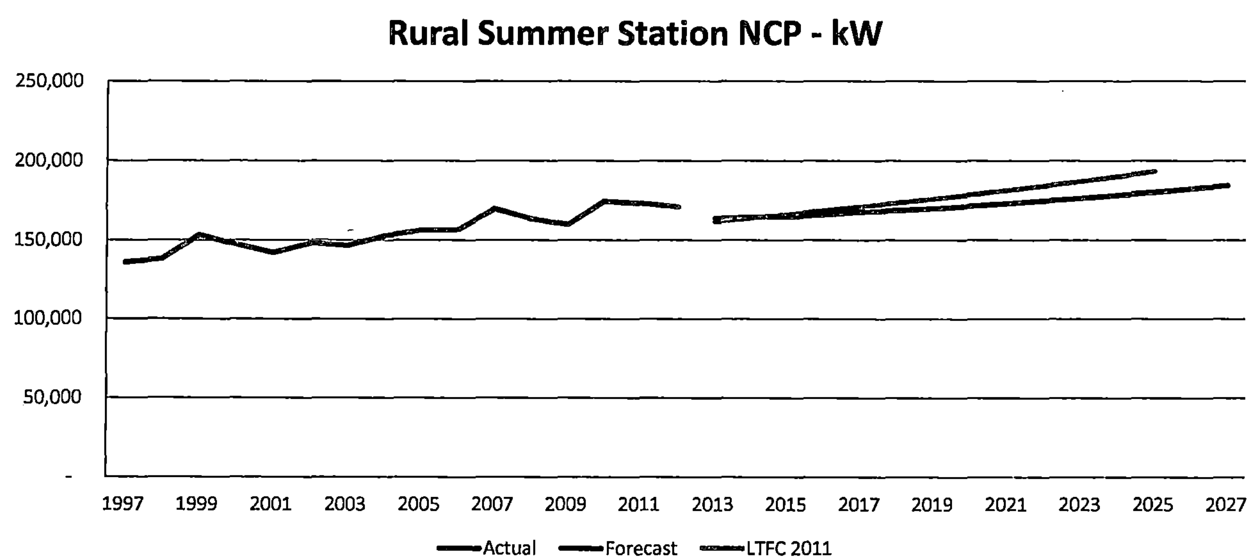
Peak values are reported on a seasonal basis
Rural station NCP represents the sum of each substation NCP and is equal to 107 percent of 1-hour NCP demand

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

RURAL SYSTEM REQUIREMENTS

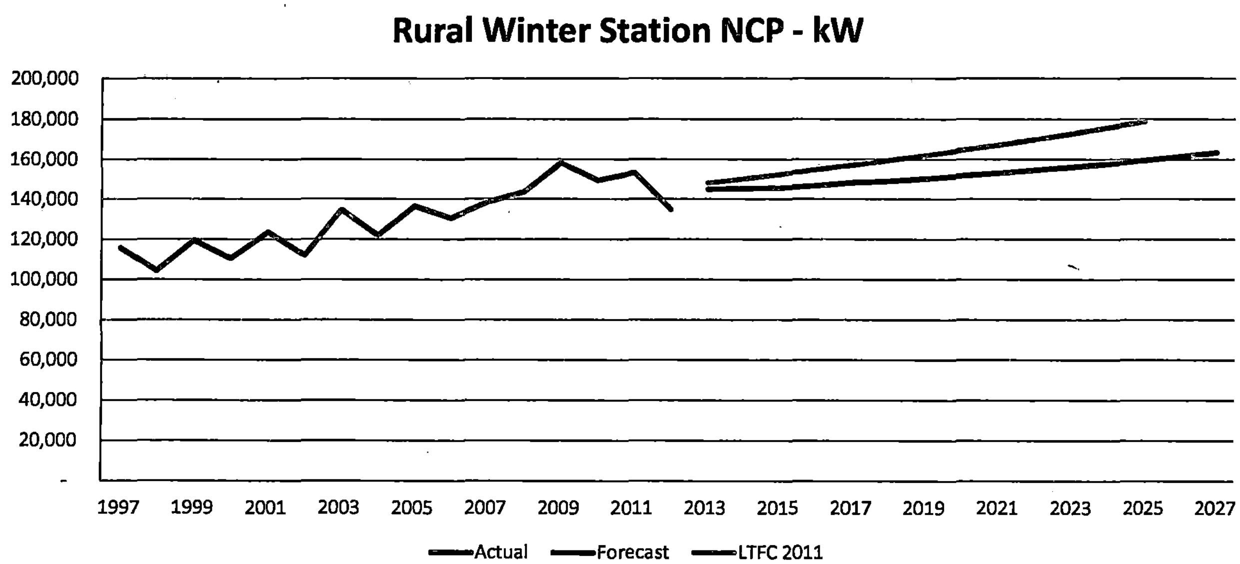




JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

RURAL SYSTEM REQUIREMENTS



JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

RESIDENTIAL CLASSIFICATION

Year	Consumers	Consumer Growth	Percent Growth	Actual Sales (MWh)	Normal Sales (MWh)	Percent Growth	Actual Average Use (kWh/Cust/Mo)	Normal Average Use (kWh/Cust/Mo)	Percent Growth
1997	22,595			320,540	327,313		1,182	1,207	
1998	23,056	462	2.0%	340,818	341,138	4.2%	1,232	1,233	2.1%
1999	23,451	395	1.7%	336,072	345,675	1.3%	1,194	1,228	-0.4%
2000	23,808	357	1.5%	357,488	354,695	2.6%	1,251	1,242	1.1%
2001	24,242	434	1.8%	344,009	348,519	-1.7%	1,183	1,198	-3.5%
2002	24,627	385	1.6%	372,407	359,497	3.1%	1,260	1,216	1.5%
2003	24,817	190	0.8%	360,988	373,215	3.8%	1,212	1,253	3.0%
2004	25,030	213	0.9%	365,736	378,469	1.4%	1,218	1,260	0.5%
2005	25,329	299	1.2%	394,694	393,379	3.9%	1,299	1,294	2.7%
2006	25,607	278	1.1%	382,855	394,425	0.3%	1,246	1,284	-0.8%
2007	25,781	174	0.7%	414,637	402,480	2.0%	1,340	1,301	1.4%
2008	26,038	257	1.0%	415,656	414,901	3.1%	1,330	1,328	2.1%
2009	26,033	(4)	0.0%	387,977	387,058	-6.7%	1,242	1,239	-6.7%
2010	26,053	20	0.1%	441,648	415,803	7.4%	1,413	1,330	7.3%
2011	26,054	1	0.0%	411,230	409,079	-1.6%	1,315	1,308	-1.6%
2012	25,944	(111)	-0.4%	395,869	393,259	-3.9%	1,272	1,263	-3.5%
2013	25,989	45	0.2%		403,743	2.7%		1,295	2.5%
2014	26,210	221	0.8%		398,534	-1.3%		1,267	-2.1%
2015	26,435	225	0.9%		392,126	-1.6%		1,236	-2.4%
2016	26,666	231	0.9%		388,832	-0.8%		1,215	-1.7%
2017	26,895	229	0.9%		392,364	0.9%		1,216	0.1%
2018	27,120	225	0.8%		395,760	0.9%		1,216	0.0%
2019	27,341	221	0.8%		399,144	0.9%		1,217	0.0%
2020	27,572	231	0.8%		402,840	0.9%		1,218	0.1%
2021	27,804	232	0.8%		406,778	1.0%		1,219	0.1%
2022	28,039	235	0.8%		410,955	1.0%		1,221	0.2%
2023	28,280	241	0.9%		415,307	1.1%		1,224	0.2%
2024	28,526	245	0.9%		419,831	1.1%		1,226	0.2%
2025	28,776	250	0.9%		424,610	1.1%		1,230	0.3%
2026	29,043	267	0.9%		429,733	1.2%		1,233	0.3%
2027	29,323	279	1.0%		435,143	1.3%		1,237	0.3%

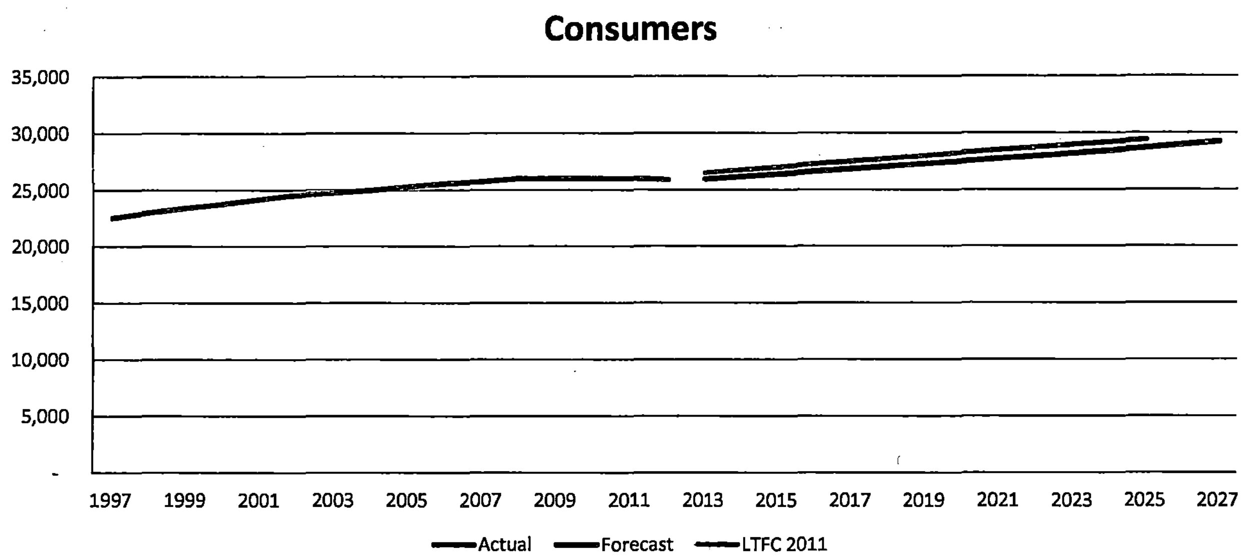
ANNUAL GROWTH RATES

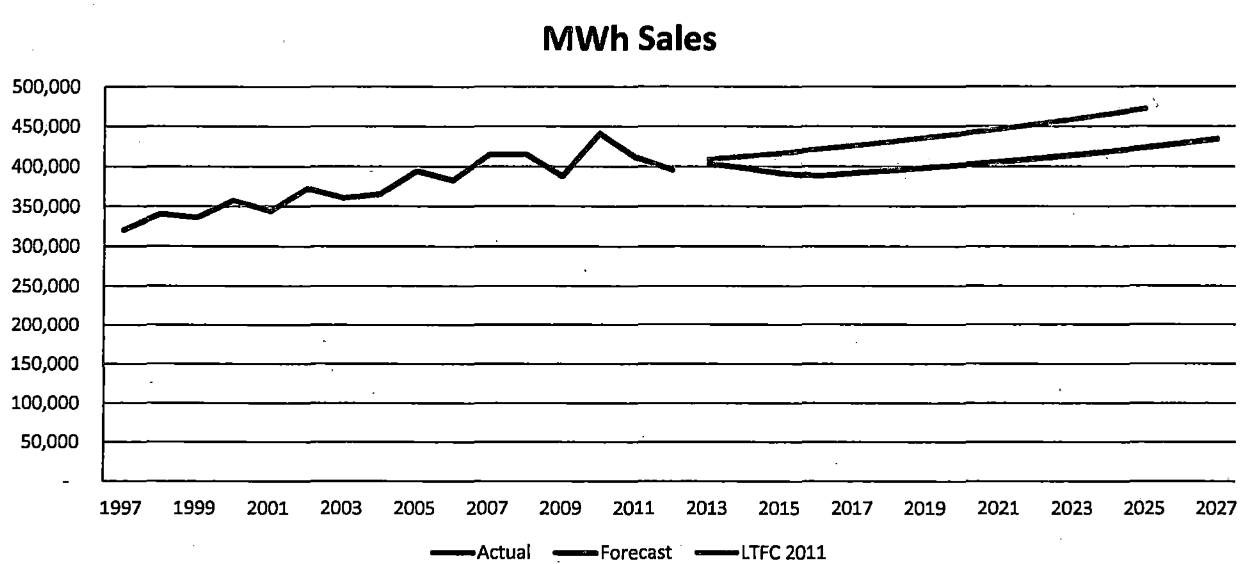
1997-2002	1.7%	406	3.0%	1.9%	1.3%	0.2%
2002-2007	0.9%	231	2.2%	2.3%	1.2%	1.4%
2007-2012	0.1%	32	-0.9%	-0.5%	-1.0%	-0.6%
2012-2017	0.7%	190		0.0%		-0.8%
2017-2022	0.8%	229		0.9%		0.1%
2022-2027	0.9%	257		1.2%		0.2%
2012-2027	0.8%	225		0.7%		-0.1%

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

RESIDENTIAL CLASSIFICATION

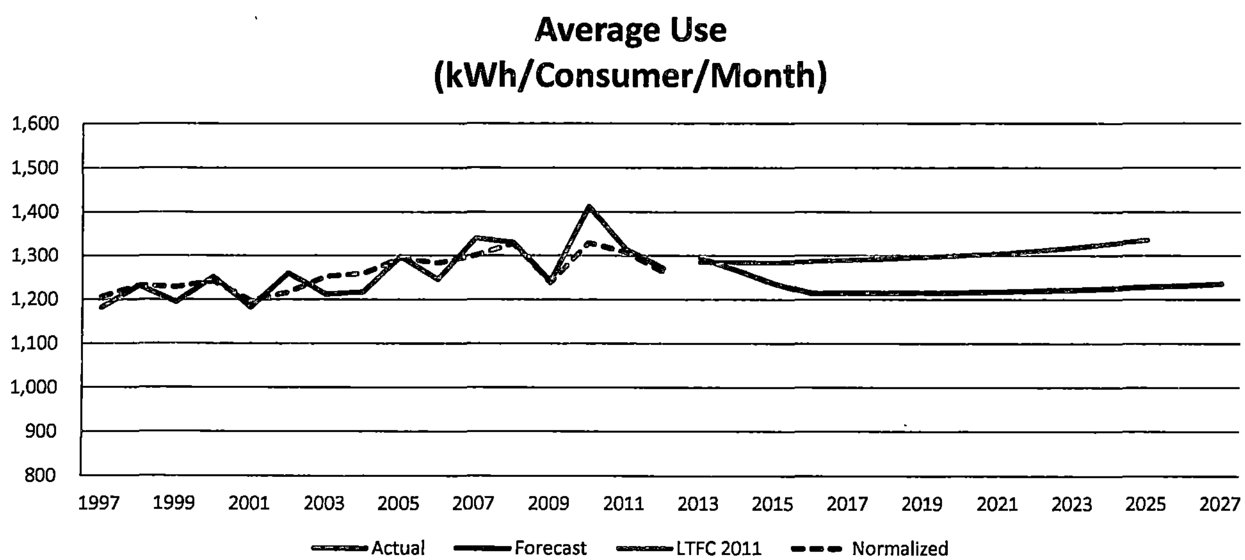




JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

RESIDENTIAL CLASSIFICATION



JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

SMALL COMMERCIAL CLASSIFICATION

Year	Consumers	Consumer Growth	Percent Growth	Actual Sales (MWh)	Normal Sales (MWh)	Percent Growth	Actual Average Use (kWh/Cust/Mo)	Normal Average Use (kWh/Cust/Mo)	Percent Growth
1997	2,151			141,164	143,421		5,468	5,556	
1998	2,188	37	1.7%	145,826	145,933	1.8%	5,554	5,559	0.0%
1999	2,251	64	2.9%	144,464	147,665	1.2%	5,347	5,466	-1.7%
2000	2,292	41	1.8%	146,540	145,609	-1.4%	5,328	5,294	-3.1%
2001	2,382	90	3.9%	141,054	142,557	-2.1%	4,935	4,988	-5.8%
2002	2,437	55	2.3%	145,969	141,666	-0.6%	4,992	4,845	-2.9%
2003	2,501	65	2.7%	146,056	150,131	6.0%	4,866	5,002	3.2%
2004	2,651	150	6.0%	151,859	156,103	4.0%	4,774	4,907	-1.9%
2005	2,756	105	4.0%	164,982	164,544	5.4%	4,988	4,975	1.4%
2006	2,833	77	2.8%	172,671	176,528	7.3%	5,079	5,192	4.4%
2007	2,944	111	3.9%	184,634	180,582	2.3%	5,226	5,111	-1.6%
2008	3,032	88	3.0%	185,058	184,806	2.3%	5,086	5,079	-0.6%
2009	3,056	24	0.8%	174,973	174,667	-5.5%	4,771	4,763	-6.2%
2010	3,080	24	0.8%	192,112	183,497	5.1%	5,198	4,965	4.2%
2011	3,126	46	1.5%	190,023	189,306	3.2%	5,066	5,047	1.6%
2012	3,280	154	4.9%	191,273	190,403	0.6%	4,859	4,837	-4.2%
2013	3,287	7	0.2%		183,963	-3.4%		4,664	-3.6%
2014	3,318	31	1.0%		181,872	-1.1%		4,568	-2.1%
2015	3,350	32	1.0%		179,268	-1.4%		4,460	-2.4%
2016	3,382	33	1.0%		177,966	-0.7%		4,384	-1.7%
2017	3,415	32	1.0%		179,719	1.0%		4,386	0.0%
2018	3,447	32	0.9%		181,419	0.9%		4,386	0.0%
2019	3,479	32	0.9%		183,118	0.9%		4,387	0.0%
2020	3,511	33	0.9%		184,954	1.0%		4,389	0.1%
2021	3,544	33	0.9%		186,895	1.0%		4,394	0.1%
2022	3,578	34	0.9%		188,943	1.1%		4,401	0.1%
2023	3,612	34	1.0%		191,069	1.1%		4,408	0.2%
2024	3,647	35	1.0%		193,273	1.2%		4,416	0.2%
2025	3,683	36	1.0%		195,591	1.2%		4,426	0.2%
2026	3,721	38	1.0%		198,061	1.3%		4,436	0.2%
2027	3,760	39	1.1%		200,659	1.3%		4,447	0.2%

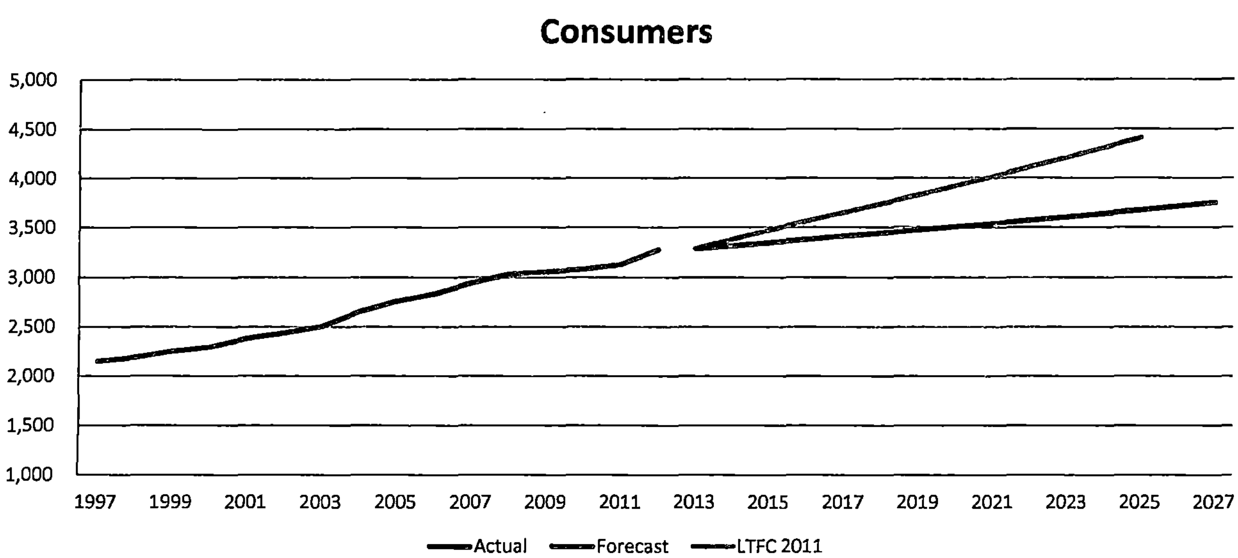
ANNUAL GROWTH RATES

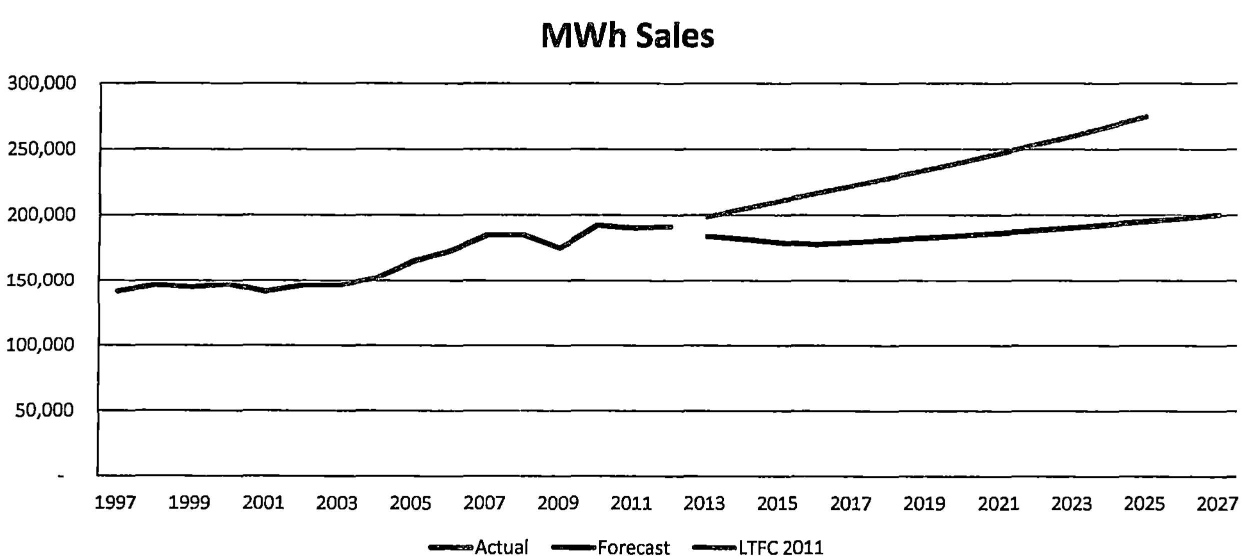
1997-2002	2.5%	57	0.7%	-0.2%	-1.8%	-2.7%
2002-2007	3.9%	102	4.8%	5.0%	0.9%	1.1%
2007-2012	2.2%	67	0.7%	1.1%	-1.4%	-1.1%
2012-2017	0.8%	27		-1.1%		-1.9%
2017-2022	0.9%	33		1.0%		0.1%
2022-2027	1.0%	36		1.2%		0.2%
2012-2027	0.9%	32		0.4%		-0.6%

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

SMALL COMMERCIAL CLASSIFICATION





JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

LARGE COMMERCIAL CLASSIFICATION

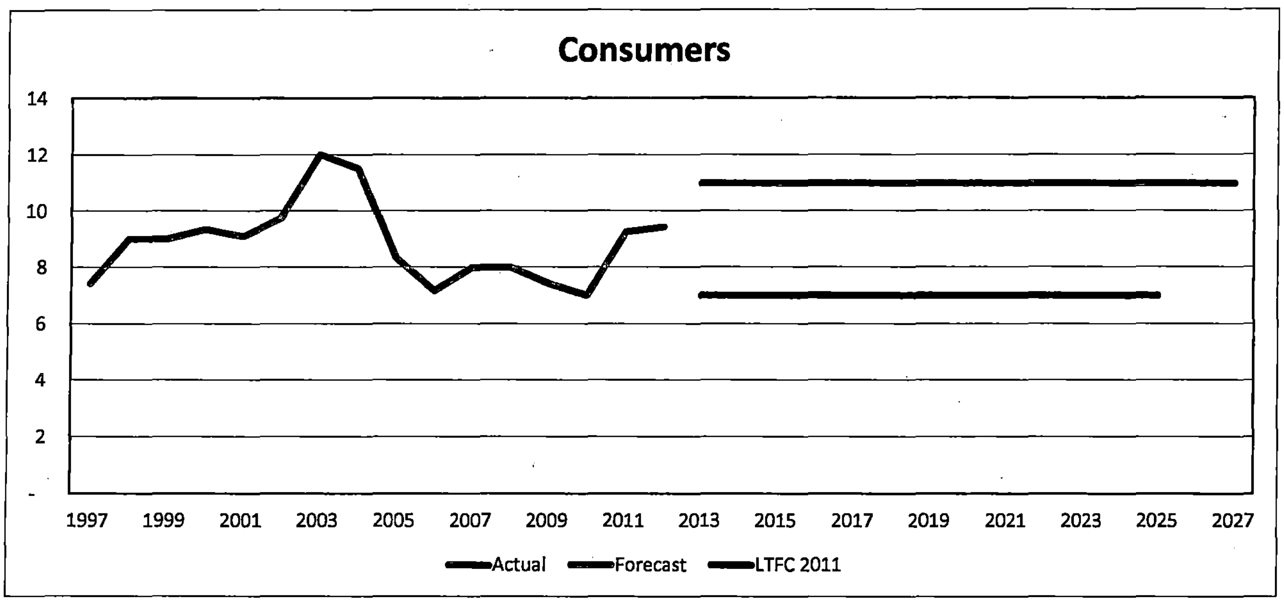
Year	Consumers	Consumer Growth	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
1997	7			84,064		944,544	
1998	9	2	21.3%	90,756	8.0%	840,336	-11.0%
1999	9	0	0.0%	106,492	17.3%	986,037	17.3%
2000	9	0	3.7%	91,230	-14.3%	814,552	-17.4%
2001	9	(0)	-2.7%	95,907	5.1%	879,882	8.0%
2002	10	1	7.3%	88,839	-7.4%	759,309	-13.7%
2003	12	2	23.1%	87,312	-1.7%	606,335	-20.1%
2004	12	(1)	-4.2%	90,271	3.4%	654,141	7.9%
2005	8	(3)	-27.5%	88,009	-2.5%	880,094	34.5%
2006	7	(1)	-14.0%	74,035	-15.9%	860,878	-2.2%
2007	8	1	11.6%	80,480	8.7%	838,336	-2.6%
2008	8	0	0.0%	76,129	-5.4%	793,009	-5.4%
2009	7	(1)	-7.3%	57,299	-24.7%	643,811	-18.8%
2010	7	(0)	-5.6%	48,727	-15.0%	580,080	-9.9%
2011	9	2	32.1%	49,397	1.4%	445,018	-23.3%
2012	9	0	1.8%	46,777	-5.3%	413,953	-7.0%
2013	11	2	16.8%	46,362	-0.9%	351,224	-15.2%
2014	11	0	0.0%	45,950	-0.9%	348,110	-0.9%
2015	11	0	0.0%	45,544	-0.9%	345,027	-0.9%
2016	11	0	0.0%	45,141	-0.9%	341,975	-0.9%
2017	11	0	0.0%	45,141	0.0%	341,975	0.0%
2018	11	0	0.0%	45,141	0.0%	341,975	0.0%
2019	11	0	0.0%	45,141	0.0%	341,975	0.0%
2020	11	0	0.0%	45,141	0.0%	341,975	0.0%
2021	11	0	0.0%	45,141	0.0%	341,975	0.0%
2022	11	0	0.0%	45,141	0.0%	341,975	0.0%
2023	11	0	0.0%	45,141	0.0%	341,975	0.0%
2024	11	0	0.0%	45,141	0.0%	341,975	0.0%
2025	11	0	0.0%	45,141	0.0%	341,975	0.0%
2026	11	0	0.0%	45,141	0.0%	341,975	0.0%
2027	11	0	0.0%	45,141	0.0%	341,975	0.0%

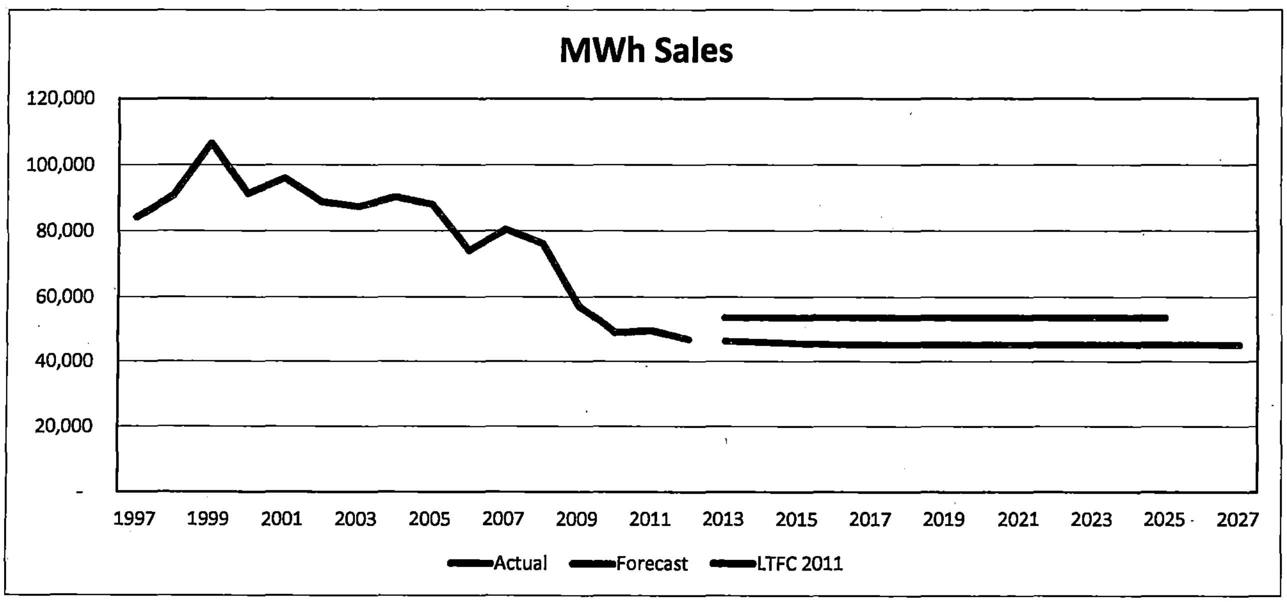
ANNUAL GROWTH RATES				
1997-2002	5.6%	0	1.1%	-4.3%
2002-2007	-3.9%	(0)	-2.0%	2.0%
2007-2012	3.3%	0	-10.3%	-13.2%
2012-2017	3.2%	0	-0.7%	-3.7%
2017-2022	0.0%	0	0.0%	0.0%
2022-2027	0.0%	0	0.0%	0.0%
2012-2027	1.0%	0	-0.2%	-1.3%

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

LARGE COMMERCIAL CLASSIFICATION





JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

RURAL LARGE COMMERCIAL CLASSIFICATION

Year	Consumers	Consumer Growth	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
1997	6			30,900		401,298	
1998	8	2	24.7%	33,989	10.0%	354,047	-11.8%
1999	8	0	0.0%	52,459	54.3%	546,444	54.3%
2000	8	0	4.2%	41,621	-20.7%	416,214	-23.8%
2001	8	(0)	-3.0%	51,186	23.0%	527,693	26.8%
2002	9	1	8.2%	53,176	3.9%	506,441	-4.0%
2003	11	2	25.7%	57,098	7.4%	432,560	-14.6%
2004	11	(1)	-4.5%	55,701	-2.4%	442,067	2.2%
2005	7	(3)	-30.2%	51,626	-7.3%	586,662	32.7%
2006	6	(1)	-15.9%	50,829	-1.5%	686,880	17.1%
2007	7	1	13.5%	58,230	14.6%	693,215	0.9%
2008	7	0	0.0%	57,259	-1.7%	681,657	-1.7%
2009	6	(1)	-8.3%	58,664	2.5%	761,864	11.8%
2010	6	(0)	-6.5%	34,222	-41.7%	475,302	-37.6%
2011	8	2	37.5%	41,693	21.8%	421,140	-11.4%
2012	8	0	2.0%	41,520	-0.4%	411,093	-2.4%
2013	10	2	18.8%	41,105	-1.0%	342,543	-16.7%
2014	10	0	0.0%	40,694	-1.0%	339,118	-1.0%
2015	10	0	0.0%	40,287	-1.0%	335,727	-1.0%
2016	10	0	0.0%	39,884	-1.0%	332,370	-1.0%
2017	10	0	0.0%	39,884	0.0%	332,370	0.0%
2018	10	0	0.0%	39,884	0.0%	332,370	0.0%
2019	10	0	0.0%	39,884	0.0%	332,370	0.0%
2020	10	0	0.0%	39,884	0.0%	332,370	0.0%
2021	10	0	0.0%	39,884	0.0%	332,370	0.0%
2022	10	0	0.0%	39,884	0.0%	332,370	0.0%
2023	10	0	0.0%	39,884	0.0%	332,370	0.0%
2024	10	0	0.0%	39,884	0.0%	332,370	0.0%
2025	10	0	0.0%	39,884	0.0%	332,370	0.0%
2026	10	0	0.0%	39,884	0.0%	332,370	0.0%
2027	10	0	0.0%	39,884	0.0%	332,370	0.0%

ANNUAL GROWTH RATES				
1997-2002	6.4%	0	11.5%	4.8%
2002-2007	-4.4%	(0)	1.8%	6.5%
2007-2012	3.8%	0	-6.5%	-9.9%
2012-2017	3.5%	0	-0.8%	-4.2%
2017-2022	0.0%	0	0.0%	0.0%
2022-2027	0.0%	0	0.0%	0.0%
2012-2027	1.2%	0	-0.3%	-1.4%

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

DIRECT SERVE LARGE COMMERCIAL CLASSIFICATION

Year	Consumers	Consumer Growth	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
1997	1			53,164		4,430,373	
1998	1	0	0.0%	56,768	6.8%	4,730,650	6.8%
1999	1	0	0.0%	54,033	-4.8%	4,502,777	-4.8%
2000	1	0	0.0%	49,608	-8.2%	4,134,039	-8.2%
2001	1	0	0.0%	44,721	-9.9%	3,726,750	-9.9%
2002	1	0	0.0%	35,663	-20.3%	2,971,898	-20.3%
2003	1	0	0.0%	30,214	-15.3%	2,517,861	-15.3%
2004	1	0	0.0%	34,571	14.4%	2,880,908	14.4%
2005	1	0	0.0%	36,383	5.2%	3,031,926	5.2%
2006	1	0	0.0%	23,206	-36.2%	1,933,864	-36.2%
2007	1	0	0.0%	22,250	-4.1%	1,854,179	-4.1%
2008	1	0	0.0%	18,870	-15.2%	1,572,474	-15.2%
2009	1	0	0.0%	(1,364)	-107.2%	(113,700)	-107.2%
2010	1	0	0.0%	14,505	-1163.1%	1,208,745	-1163.1%
2011	1	0	0.0%	7,704	-46.9%	642,010	-46.9%
2012	1	0	0.0%	5,256	-31.8%	438,025	-31.8%
2013	1	0	0.0%	5,256	0.0%	438,025	0.0%
2014	1	0	0.0%	5,256	0.0%	438,025	0.0%
2015	1	0	0.0%	5,256	0.0%	438,025	0.0%
2016	1	0	0.0%	5,256	0.0%	438,025	0.0%
2017	1	0	0.0%	5,256	0.0%	438,025	0.0%
2018	1	0	0.0%	5,256	0.0%	438,025	0.0%
2019	1	0	0.0%	5,256	0.0%	438,025	0.0%
2020	1	0	0.0%	5,256	0.0%	438,025	0.0%
2021	1	0	0.0%	5,256	0.0%	438,025	0.0%
2022	1	0	0.0%	5,256	0.0%	438,025	0.0%
2023	1	0	0.0%	5,256	0.0%	438,025	0.0%
2024	1	0	0.0%	5,256	0.0%	438,025	0.0%
2025	1	0	0.0%	5,256	0.0%	438,025	0.0%
2026	1	0	0.0%	5,256	0.0%	438,025	0.0%
2027	1	0	0.0%	5,256	0.0%	438,025	0.0%

ANNUAL GROWTH RATES				
1997-2002	0.0%	0	-7.7%	-7.7%
2002-2007	0.0%	0	-9.0%	-9.0%
2007-2012	0.0%	0	-25.1%	-25.1%
2012-2017	0.0%	0	0.0%	0.0%
2017-2022	0.0%	0	0.0%	0.0%
2022-2027	0.0%	0	0.0%	0.0%
2012-2027	0.0%	0	0.0%	0.0%

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

IRRIGATION CLASSIFICATION

Year	Consumers	Consumer Growth	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
1997	10			107		890	
1998	10	0	0.0%	121	13.6%	1,010	13.6%
1999	10	0	0.0%	121	-0.2%	1,008	-0.2%
2000	10	0	0.0%	70	-42.0%	585	-42.0%
2001	10	(0)	-3.3%	75	6.5%	644	10.2%
2002	9	(1)	-6.9%	38	-49.1%	352	-45.4%
2003	9	(1)	-5.6%	113	196.9%	1,106	214.4%
2004	8	(1)	-9.8%	164	45.1%	1,780	60.9%
2005	7	(1)	-8.7%	114	-30.4%	1,356	-23.8%
2006	7	0	0.0%	65	-43.2%	770	-43.2%
2007	7	0	0.0%	1,068	1551.4%	12,715	1551.4%
2008	8	1	11.9%	432	-59.6%	4,594	-63.9%
2009	9	1	8.5%	406	-5.9%	3,984	-13.3%
2010	9	0	0.0%	356	-12.4%	3,491	-12.4%
2011	7	(2)	-20.6%	269	-24.5%	3,321	-4.9%
2012	5	(2)	-25.9%	440	63.7%	7,338	121.0%
2013	5	0	0.0%	439	-0.3%	7,317	-0.3%
2014	5	0	0.0%	439	0.0%	7,317	0.0%
2015	5	0	0.0%	439	0.0%	7,317	0.0%
2016	5	0	0.0%	439	0.0%	7,317	0.0%
2017	5	0	0.0%	439	0.0%	7,317	0.0%
2018	5	0	0.0%	439	0.0%	7,317	0.0%
2019	5	0	0.0%	439	0.0%	7,317	0.0%
2020	5	0	0.0%	439	0.0%	7,317	0.0%
2021	5	0	0.0%	439	0.0%	7,317	0.0%
2022	5	0	0.0%	439	0.0%	7,317	0.0%
2023	5	0	0.0%	439	0.0%	7,317	0.0%
2024	5	0	0.0%	439	0.0%	7,317	0.0%
2025	5	0	0.0%	439	0.0%	7,317	0.0%
2026	5	0	0.0%	439	0.0%	7,317	0.0%
2027	5	0	0.0%	439	0.0%	7,317	0.0%

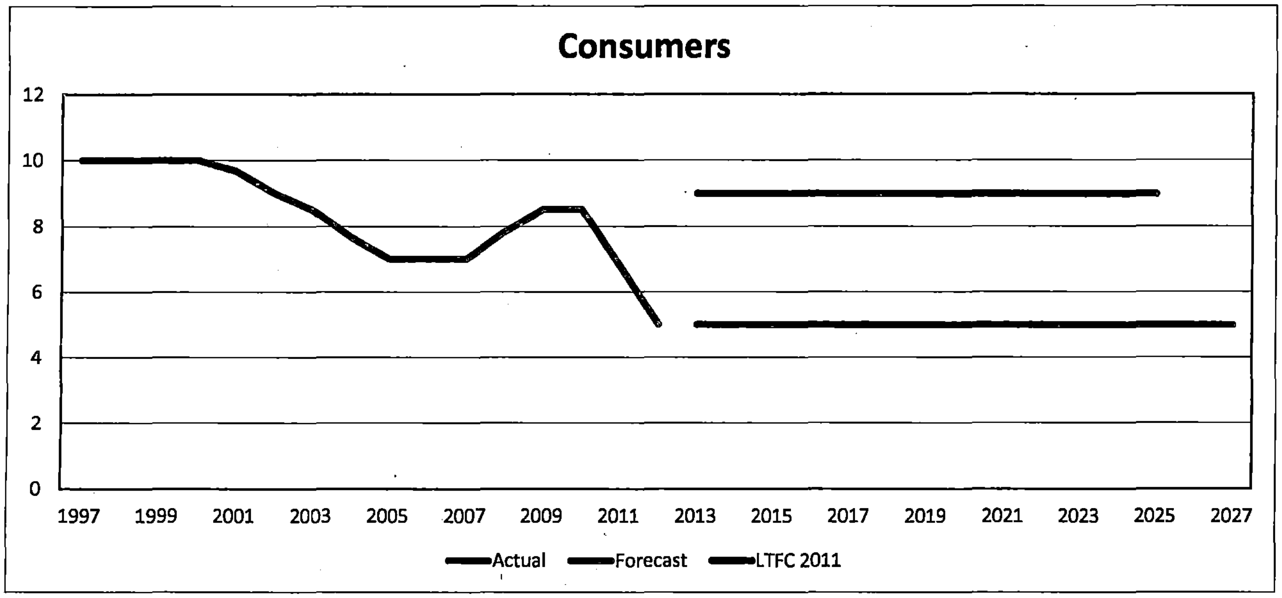
ANNUAL GROWTH RATES

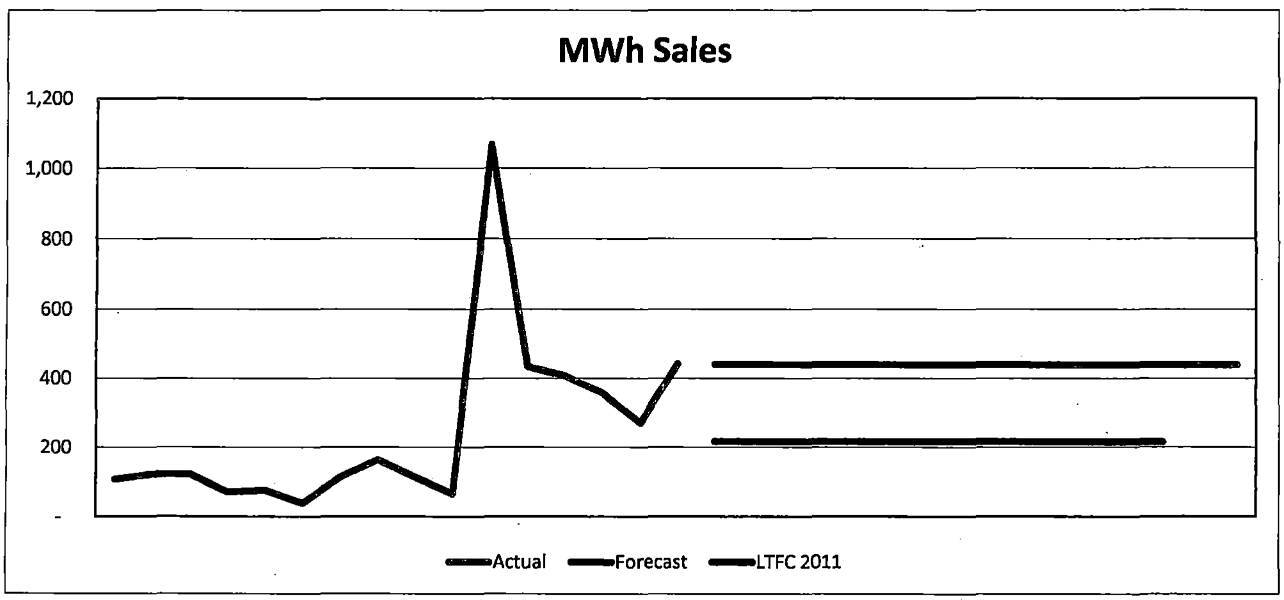
1997-2002	-2.1%	(0)	-18.7%	-16.9%
2002-2007	-4.9%	(0)	94.9%	104.9%
2007-2012	-6.5%	(0)	-16.2%	-10.4%
2012-2017	0.0%	0	-0.1%	-0.1%
2017-2022	0.0%	0	0.0%	0.0%
2022-2027	0.0%	0	0.0%	0.0%
2012-2027	0.0%	0	0.0%	0.0%

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

IRRIGATION CLASSIFICATION





JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

STREET LIGHTING CLASSIFICATION

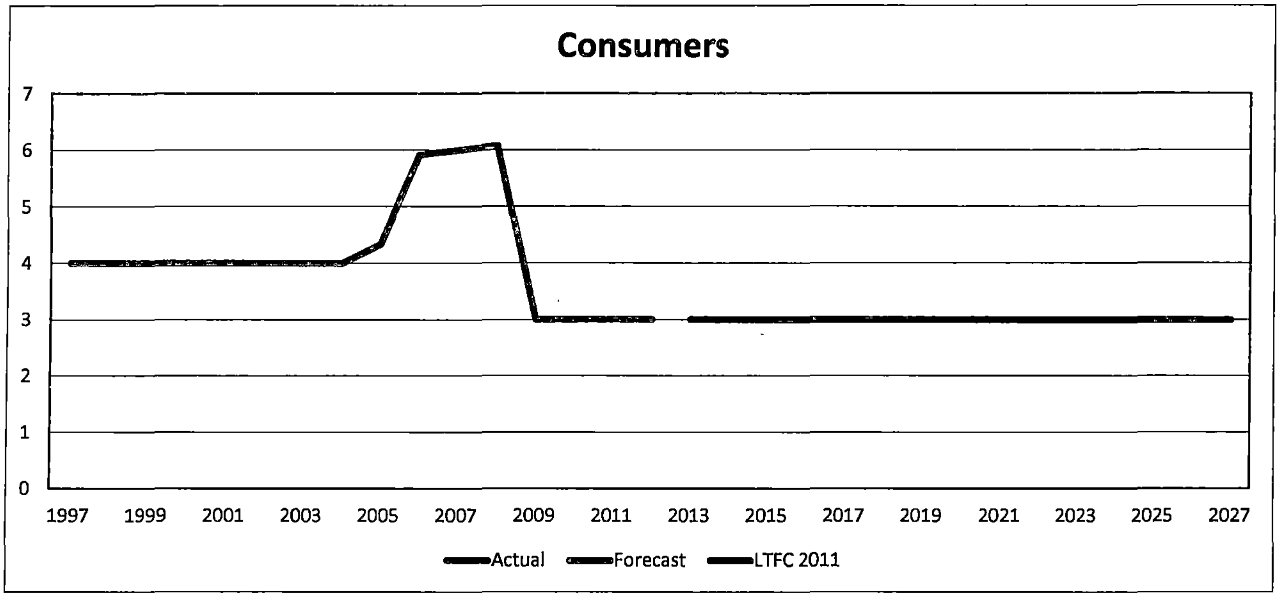
Year	Consumers	Consumer Growth	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
1997	4			396		8,260	
1998	4	0	0.0%	402	1.5%	8,383	1.5%
1999	4	0	0.0%	564	40.2%	11,750	40.2%
2000	4	0	0.0%	452	-19.8%	9,423	-19.8%
2001	4	0	0.0%	451	-0.2%	9,401	-0.2%
2002	4	0	0.0%	525	16.4%	10,946	16.4%
2003	4	0	0.0%	522	-0.7%	10,869	-0.7%
2004	4	0	0.0%	538	3.2%	11,215	3.2%
2005	4	0	8.3%	562	4.5%	10,817	-3.6%
2006	6	2	36.5%	585	4.0%	8,238	-23.8%
2007	6	0	1.4%	590	0.9%	8,194	-0.5%
2008	6	0	1.4%	603	2.1%	8,254	0.7%
2009	3	(3)	-50.7%	627	4.1%	17,421	111.1%
2010	3	0	0.0%	637	1.6%	17,703	1.6%
2011	3	0	0.0%	619	-2.9%	17,188	-2.9%
2012	3	0	0.0%	616	-0.5%	17,106	-0.5%
2013	3	0	0.0%	614	-0.3%	17,054	-0.3%
2014	3	0	0.0%	606	-1.3%	16,833	-1.3%
2015	3	0	0.0%	596	-1.6%	16,568	-1.6%
2016	3	0	0.0%	591	-0.9%	16,426	-0.9%
2017	3	0	0.0%	597	0.9%	16,573	0.9%
2018	3	0	0.0%	602	0.9%	16,715	0.9%
2019	3	0	0.0%	607	0.8%	16,856	0.8%
2020	3	0	0.0%	612	0.9%	17,009	0.9%
2021	3	0	0.0%	618	1.0%	17,172	1.0%
2022	3	0	0.0%	624	1.0%	17,343	1.0%
2023	3	0	0.0%	631	1.0%	17,522	1.0%
2024	3	0	0.0%	637	1.1%	17,707	1.1%
2025	3	0	0.0%	644	1.1%	17,902	1.1%
2026	3	0	0.0%	652	1.2%	18,111	1.2%
2027	3	0	0.0%	660	1.2%	18,330	1.2%

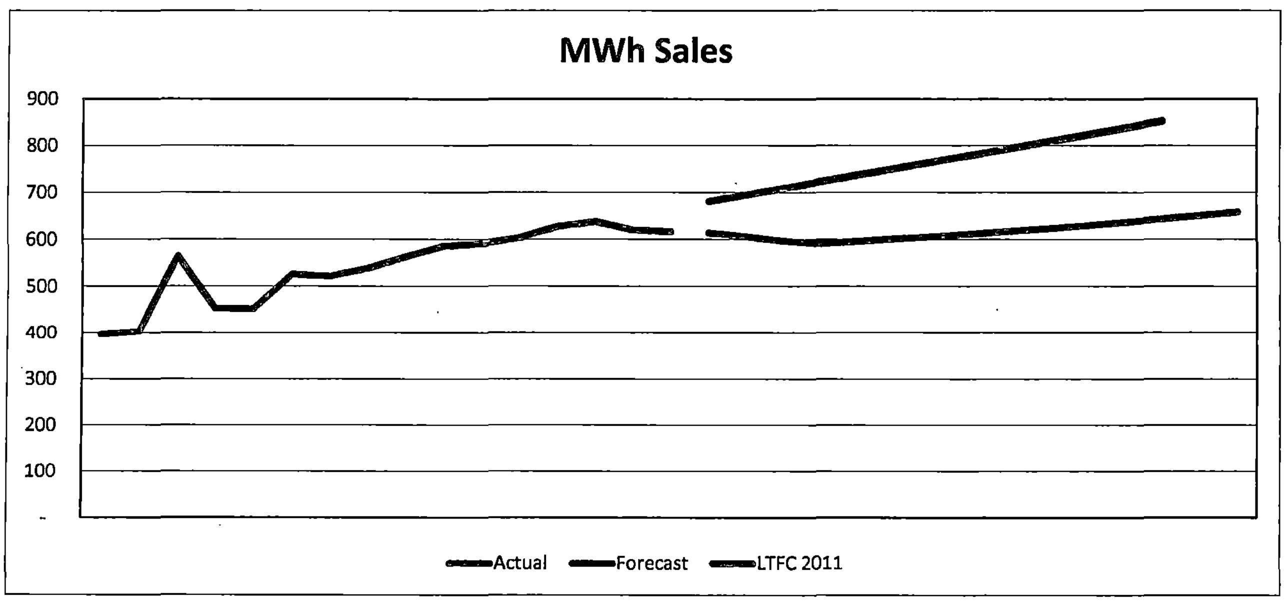
ANNUAL GROWTH RATES				
1997-2002	0.0%	0	5.8%	5.8%
2002-2007	8.4%	0	2.3%	-5.6%
2007-2012	-12.9%	(1)	0.9%	15.9%
2012-2017	0.0%	0	-0.6%	-0.6%
2017-2022	0.0%	0	0.9%	0.9%
2022-2027	0.0%	0	1.1%	1.1%
2012-2027	0.0%	0	0.5%	0.5%

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - BASE CASE

STREET LIGHTING CLASSIFICATION





Appendix C
Tables – Range Forecasts

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - RANGE FORECASTS

TOTAL SYSTEM REQUIREMENTS

Year	Base Case (MWh)	Weather Adjusted (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
1997	577,117	591,205				
1998	607,063	611,649				
1999	620,950	639,278				
2000	631,196	632,004				
2001	619,863	631,494				
2002	642,251	627,721				
2003	628,188	648,861				
2004	640,657	661,981				
2005	677,462	678,440				
2006	663,944	683,172				
2007	718,915	704,836				
2008	711,876	713,344				
2009	654,774	655,127				
2010	716,681	682,629				
2011	683,764	682,629				
2012	668,864	667,172				
2013		668,272	672,133	664,416	704,243	649,240
2014		660,146	667,068	653,282	696,308	640,965
2015		650,221	660,201	640,399	686,431	630,903
2016		644,954	658,053	632,166	681,261	625,487
2017		650,523	666,935	634,627	686,830	631,004
2018		655,892	675,691	636,873	692,228	636,318
2019		661,248	684,509	639,086	697,634	641,615
2020		667,077	693,902	641,730	703,554	647,372
2021		673,272	703,772	644,694	709,865	653,490
2022		679,830	714,123	647,974	716,564	659,964
2023		686,656	724,844	651,485	723,556	666,695
2024		693,746	735,939	655,226	730,837	673,685
2025		701,224	747,549	659,304	738,526	681,053
2026		709,224	759,813	663,855	746,777	688,928
2027		717,661	772,643	668,797	755,494	697,228

ANNUAL GROWTH RATES						
1997-2002	2.2%	1.2%				
2002-2007	2.3%	2.3%				
2007-2012	-1.4%	-1.1%				
2012-2017		-0.5%	0.0%	-1.0%	0.6%	-1.1%
2017-2022		0.9%	1.4%	0.4%	0.9%	0.9%
2022-2027		1.1%	1.6%	0.6%	1.1%	1.1%
2012-2027		0.5%	1.0%	0.0%	0.8%	0.3%

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - RANGE FORECASTS

TOTAL SYSTEM NCP DEMAND - SUMMER

Year	Base Case (kW)	Weather Adjusted (MWh)	ECONOMIC SCENARIOS Optimistic (kW)	ECONOMIC SCENARIOS Pessimistic (kW)	WEATHER SCENARIOS Extreme (kW)	WEATHER SCENARIOS Mild (kW)
1997	127,059	-				
1998	139,498	-				
1999	151,498	-				
2000	146,254	-				
2001	140,701	-				
2002	146,731	-				
2003	144,002	-				
2004	148,781	157,736				
2005	153,634	158,786				
2006	152,268	162,728				
2007	164,605	156,886				
2008	155,891	154,972				
2009	152,669	157,712				
2010	169,312	158,660				
2011	163,838	161,148				
2012	160,040	155,798				
2013		155,234	155,941	153,893	169,078	147,811
2014		155,604	157,057	153,507	167,018	146,012
2015		155,912	158,138	153,043	164,505	143,817
2016		156,979	160,012	153,315	163,166	142,646
2017		158,797	162,182	153,867	164,559	143,861
2018		159,631	164,320	154,370	165,902	145,032
2019		160,929	166,473	154,864	167,242	146,200
2020		162,342	168,766	155,462	168,701	147,472
2021		163,844	171,171	156,143	170,254	148,826
2022		165,434	173,691	156,903	171,899	150,261
2023		167,089	176,302	157,719	173,611	151,754
2024		168,808	179,002	158,590	175,390	153,306
2025		170,620	181,828	159,542	177,267	154,942
2026		172,560	184,811	160,609	179,275	156,694
2027		174,605	187,932	161,769	181,394	158,542

ANNUAL GROWTH RATES						
1997-2002	2.9%					
2002-2007	2.3%					
2007-2012	-0.6%	-0.1%				
2012-2017		0.4%	0.8%	-0.2%	1.1%	-1.6%
2017-2022		0.8%	1.4%	0.4%	0.9%	0.9%
2022-2027		1.1%	1.6%	0.6%	1.1%	1.1%
2012-2027		0.8%	1.3%	0.3%	1.0%	0.1%

NCP equals the sum of Rural system CP and Direct Serve NCP

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - RANGE FORECASTS

TOTAL SYSTEM NCP DEMAND - WINTER

Year	Base Case (kW)	Weather Adjusted (MWh)	ECONOMIC SCENARIOS Optimistic (kW)	ECONOMIC SCENARIOS Pessimistic (kW)	WEATHER SCENARIOS Extreme (kW)	WEATHER SCENARIOS Mild (kW)
1997	116,524	-				
1998	119,568	-				
1999	122,466	-				
2000	124,265	-				
2001	118,912	-				
2002	111,426	-				
2003	132,502	-				
2004	135,785	133,309				
2005	125,703	122,687				
2006	133,985	146,190				
2007	136,664	139,817				
2008	141,931	149,843				
2009	152,948	149,380				
2010	148,041	144,815				
2011	138,380	137,070				
2012	127,249	137,427				
2013		137,586	138,255	136,346	155,277	116,332
2014		137,922	139,262	135,991	153,382	114,915
2015		138,203	140,233	135,574	151,073	113,188
2016		139,174	141,928	135,821	149,840	112,264
2017		140,827	143,857	136,291	151,113	113,211
2018		141,521	145,757	136,721	152,342	114,124
2019		142,670	147,670	137,144	153,568	115,036
2020		143,921	149,706	137,659	154,903	116,028
2021		145,250	151,842	138,249	156,325	117,086
2022		146,658	154,080	138,906	157,830	118,206
2023		148,122	156,398	139,612	159,398	119,373
2024		149,644	158,796	140,368	161,026	120,585
2025		151,248	161,304	141,196	162,744	121,864
2026		152,965	163,952	142,125	164,584	123,233
2027		154,776	166,722	143,138	166,524	124,678

ANNUAL GROWTH RATES

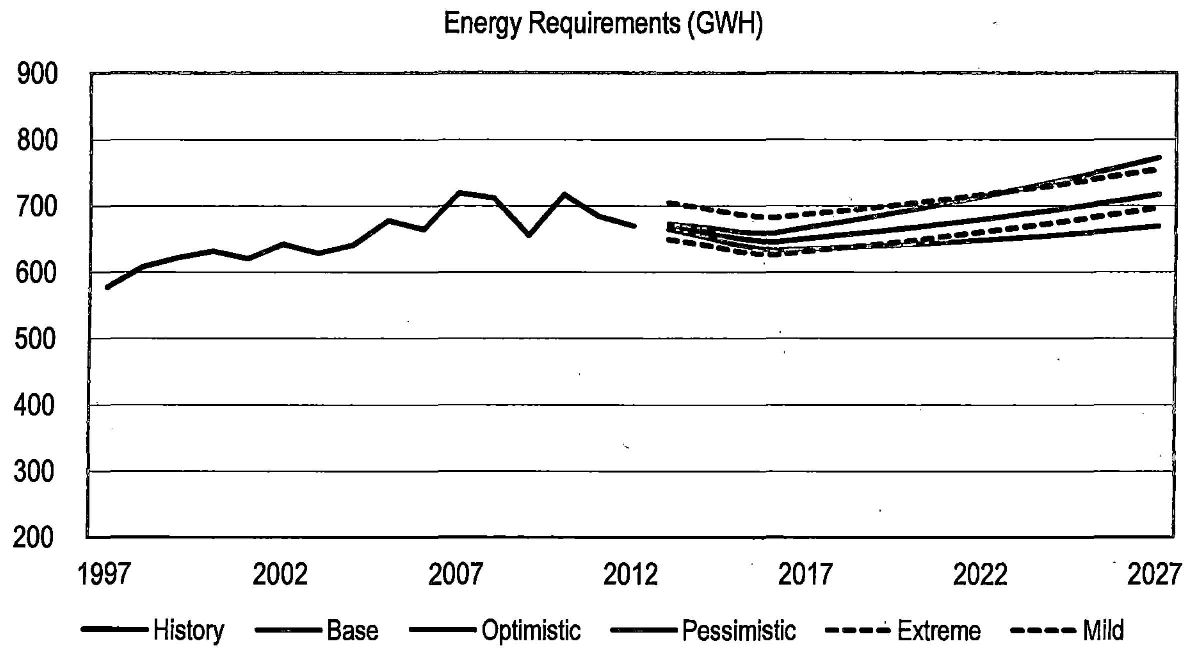
1997-2002	-0.9%					
2002-2007	4.2%					
2007-2012	-1.4%	-0.3%				
2012-2017		0.5%	0.9%	-0.2%	1.9%	-3.8%
2017-2022		0.8%	1.4%	0.4%	0.9%	0.9%
2022-2027		1.1%	1.6%	0.6%	1.1%	1.1%
2012-2027		0.8%	1.3%	0.3%	1.3%	-0.6%

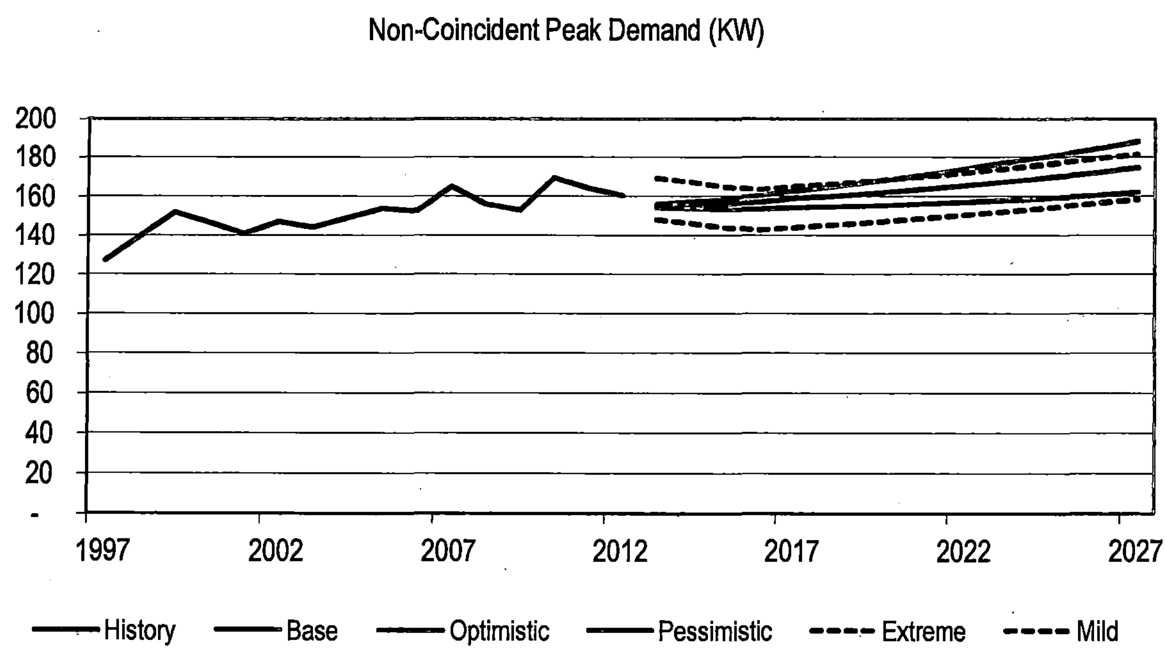
NCP equals the sum of Rural system CP and Direct Serve NCP

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - RANGE FORECASTS

TOTAL SYSTEM REQUIREMENTS





JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM REQUIREMENTS

Year	Base Case (MWh)	Weather Adjusted (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	Mild (MWh)
1997	523,953	533,550				
1998	550,295	550,747				
1999	566,917	580,521				
2000	581,588	577,622				
2001	575,142	581,586				
2002	606,588	588,336				
2003	597,973	615,238				
2004	606,086	624,018				
2005	641,079	639,242				
2006	640,738	657,023				
2007	696,665	679,507				
2008	693,006	691,946				
2009	656,138	654,847				
2010	702,176	665,987				
2011	676,060	673,046				
2012	663,607	659,937				
2013		663,016	666,088	659,948	698,986	643,984
2014		654,890	661,023	648,814	691,052	635,708
2015		644,964	654,156	635,931	681,175	625,646
2016		639,698	652,009	627,698	676,004	620,231
2017		645,266	660,890	630,159	681,573	625,748
2018		650,636	669,646	632,405	686,971	631,062
2019		655,992	678,464	634,618	692,377	636,359
2020		661,820	687,857	637,262	698,298	642,116
2021		668,015	697,727	640,226	704,609	648,233
2022		674,574	708,078	643,506	711,308	654,707
2023		681,399	718,799	647,017	718,300	661,439
2024		688,490	729,894	650,758	725,580	668,428
2025		695,967	741,505	654,836	733,270	675,797
2026		703,968	753,768	659,387	741,520	683,672
2027		712,405	766,599	664,329	750,237	691,971

ANNUAL GROWTH RATES

1997-2002	3.0%	2.0%				
2002-2007	2.8%	2.9%				
2007-2012	-1.0%	-0.6%				
2012-2017		-0.4%	0.0%	-0.9%	0.6%	-1.1%
2017-2022		0.9%	1.4%	0.4%	0.9%	0.9%
2022-2027		1.1%	1.6%	0.6%	1.1%	1.1%
2012-2027		0.5%	1.0%	0.0%	0.9%	0.3%

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM CP DEMAND - SUMMER

Year	Base Case (MWh)	Weather Adjusted (MWh)	ECONOMIC SCENARIOS Optimistic (kW)	ECONOMIC SCENARIOS Pessimistic (kW)	WEATHER SCENARIOS Extreme (kW)	WEATHER SCENARIOS Mild (kW)
1997	127,059	-				
1998	128,946	-				
1999	142,955	-				
2000	137,679	-				
2001	132,536	-				
2002	138,264	-				
2003	136,934	-				
2004	142,560	151,515				
2005	145,761	150,913				
2006	146,134	156,594				
2007	158,540	150,821				
2008	152,521	151,602				
2009	149,050	154,093				
2010	162,957	152,305				
2011	161,649	158,959				
2012	159,750	155,508				
2013		153,132	153,524	152,107	166,976	145,709
2014		153,302	154,410	151,551	164,717	143,710
2015		153,405	155,255	150,912	161,998	141,310
2016		154,262	156,888	151,006	160,449	139,930
2017		155,865	158,810	151,375	161,627	140,929
2018		156,500	160,719	151,709	162,771	141,901
2019		157,590	162,633	152,025	163,903	142,861
2020		158,801	164,693	152,452	165,159	143,930
2021		160,124	166,893	152,981	166,534	145,106
2022		161,549	169,224	153,601	168,014	146,376
2023		163,035	171,640	154,273	169,558	147,701
2024		164,589	174,150	155,004	171,171	149,087
2025		166,231	176,779	155,811	172,877	150,553
2026		167,999	179,566	156,732	174,714	152,133
2027		169,873	182,490	157,747	176,661	153,810

ANNUAL GROWTH RATES						
1997-2002	1.7%					
2002-2007	2.8%					
2007-2012	0.2%	0.6%				
2012-2017		0.0%	0.4%	-0.5%	0.8%	-1.9%
2017-2022		0.7%	1.3%	0.3%	0.8%	0.8%
2022-2027		1.0%	1.5%	0.5%	1.0%	1.0%
2012-2027		0.6%	1.1%	0.1%	0.9%	-0.1%

Rural CP equals highest 1-hour simultaneous peak on all rural substations

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM CP DEMAND - WINTER

Year	Base Case (MWh)	Weather Adjusted (MWh)	ECONOMIC SCENARIOS Optimistic (kW)	ECONOMIC SCENARIOS Pessimistic (kW)	WEATHER SCENARIOS Extreme (kW)	WEATHER SCENARIOS Mild (kW)
1997	108,294	-				
1998	97,621	-				
1999	111,666	-				
2000	103,236	-				
2001	115,614	-				
2002	104,706	-				
2003	126,065	-				
2004	114,062	111,586				
2005	127,782	124,766				
2006	122,149	134,354				
2007	129,658	132,812				
2008	134,318	142,230				
2009	148,125	144,557				
2010	139,804	136,578				
2011	143,361	142,051				
2012	126,100	136,278				
2013		135,402	135,743	134,489	153,093	114,148
2014		135,456	136,425	133,895	150,916	112,448
2015		135,482	137,105	133,261	148,352	110,468
2016		136,172	138,476	133,270	146,838	109,263
2017		137,545	140,083	133,502	147,831	109,929
2018		137,987	141,692	133,717	148,808	110,590
2019		138,884	143,316	133,925	149,782	111,249
2020		139,883	145,062	134,227	150,865	111,990
2021		140,988	146,940	134,626	152,063	112,824
2022		142,172	148,922	135,093	153,345	113,721
2023		143,413	150,982	135,609	154,688	114,663
2024		144,711	153,123	136,175	156,093	115,652
2025		146,092	155,374	136,813	157,588	116,707
2026		147,585	157,765	137,552	159,203	117,852
2027		149,171	160,276	138,374	160,919	119,073

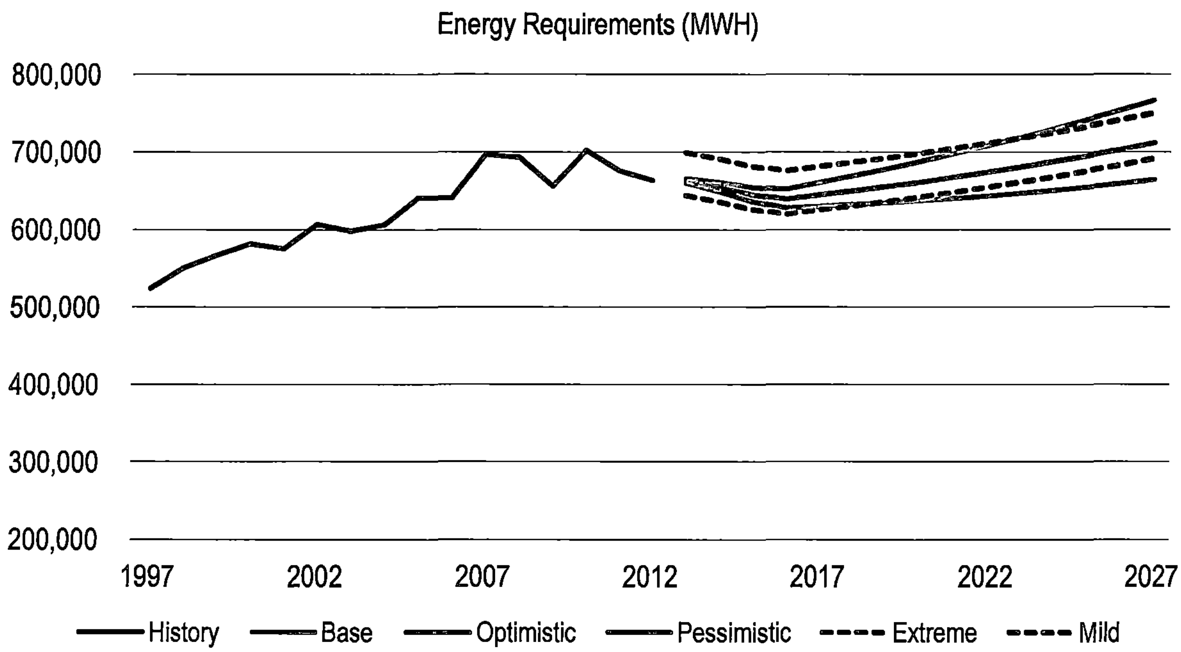
ANNUAL GROWTH RATES						
1997-2002	-0.7%					
2002-2007	4.4%					
2007-2012	-0.6%	0.5%				
2012-2017		0.2%	0.6%	-0.4%	1.6%	-4.2%
2017-2022		0.7%	1.2%	0.2%	0.7%	0.7%
2022-2027		1.0%	1.5%	0.5%	1.0%	0.9%
2012-2027		0.6%	1.1%	0.1%	1.1%	-0.9%

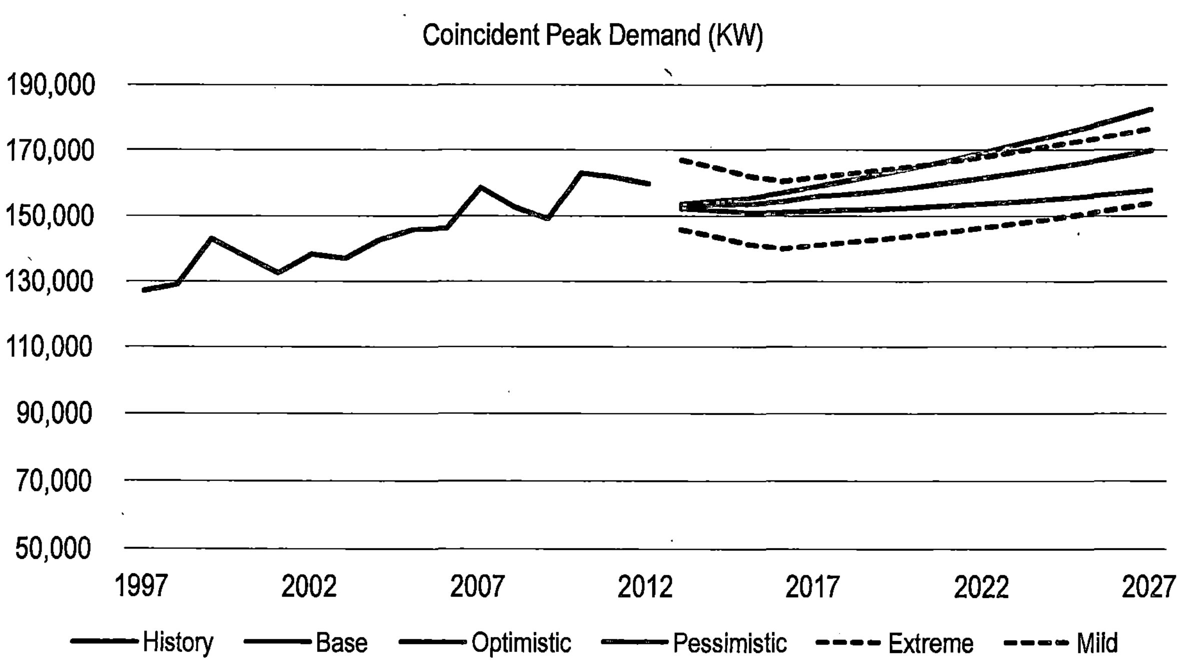
Rural CP equals highest 1-hour simultaneous peak on all rural substations

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM REQUIREMENTS





JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM DELIVERY POINT NCP DEMAND - SUMMER

			ECONOMIC SCENARIOS		WEATHER SCENARIOS	
Year	Base Case (MWh)	Weather Adjusted (MWh)	Optimistic (kW)	Pessimistic (kW)	Extreme (kW)	Mild (kW)
1997	135,953	-				
1998	137,972	-				
1999	152,962	-				
2000	147,317	-				
2001	141,814	-				
2002	147,942	-				
2003	146,519	-				
2004	152,539	162,121				
2005	155,964	161,477				
2006	156,363	167,555				
2007	169,638	161,379				
2008	163,197	162,214				
2009	159,483	164,879				
2010	174,364	162,966				
2011	172,965	170,086				
2012	170,932	166,393				
2013		163,851	164,271	162,754	178,665	155,909
2014		164,033	165,219	162,159	176,247	153,770
2015		164,143	166,123	161,476	173,338	151,201
2016		165,061	167,870	161,576	171,680	149,725
2017		166,776	169,927	161,972	172,941	150,794
2018		167,455	171,969	162,329	174,165	151,834
2019		168,621	174,018	162,667	175,376	152,861
2020		169,917	176,221	163,124	176,721	154,006
2021		171,333	178,576	163,690	178,191	155,263
2022		172,858	181,069	164,353	179,775	156,622
2023		174,448	183,655	165,073	181,427	158,040
2024		176,110	186,341	165,855	183,153	159,523
2025		177,867	189,154	166,718	184,978	161,091
2026		179,759	192,136	167,703	186,944	162,783
2027		181,764	195,264	168,789	189,028	164,577

ANNUAL GROWTH RATES						
1997-2002	1.7%					
2002-2007	2.8%					
2007-2012	0.2%	0.6%				
2012-2017		0.0%	0.4%	-0.5%	0.8%	-1.9%
2017-2022		0.7%	1.3%	0.3%	0.8%	0.8%
2022-2027		1.0%	1.5%	0.5%	1.0%	1.0%
2012-2027		0.6%	1.1%	0.1%	0.9%	-0.1%

Delivery point NCP is the sum of substation NCPs and estimated at 107 percent of Rural CP demand

JACKSON PURCHASE ENERGY

2013 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM DELIVERY POINT NCP DEMAND - WINTER

Year	Base Case (MWh)	Weather Adjusted (MWh)	ECONOMIC SCENARIOS Optimistic (kW)	ECONOMIC SCENARIOS Pessimistic (kW)	WEATHER SCENARIOS Extreme (kW)	WEATHER SCENARIOS Mild (kW)
1997	115,875	-				
1998	104,454	-				
1999	119,483	-				
2000	110,463	-				
2001	123,707	-				
2002	112,035	-				
2003	134,890	-				
2004	122,046	119,397				
2005	136,727	133,499				
2006	130,699	143,759				
2007	138,734	142,109				
2008	143,720	152,186				
2009	158,494	154,676				
2010	149,590	146,138				
2011	153,396	151,994				
2012	134,926	145,817				
2013		144,880	145,245	143,903	163,810	122,139
2014		144,938	145,975	143,267	161,480	120,320
2015		144,966	146,702	142,590	158,737	118,200
2016		145,704	148,170	142,599	157,117	116,911
2017		147,173	149,889	142,847	158,179	117,624
2018		147,646	151,611	143,077	159,225	118,331
2019		148,606	153,348	143,300	160,266	119,037
2020		149,674	155,216	143,622	161,425	119,829
2021		150,857	157,226	144,050	162,707	120,722
2022		152,124	159,346	144,549	164,079	121,681
2023		153,452	161,551	145,102	165,516	122,690
2024		154,841	163,842	145,707	167,020	123,748
2025		156,318	166,250	146,390	168,619	124,877
2026		157,916	168,808	147,181	170,347	126,102
2027		159,613	171,496	148,060	172,183	127,408

ANNUAL GROWTH RATES

1997-2002	-0.7%					
2002-2007	4.4%					
2007-2012	-0.6%	0.5%				
2012-2017		0.2%	0.6%	-0.4%	1.6%	-4.2%
2017-2022		0.7%	1.2%	0.2%	0.7%	0.7%
2022-2027		1.0%	1.5%	0.5%	1.0%	0.9%
2012-2027		0.6%	1.1%	0.1%	1.1%	-0.9%

Delivery point NCP is the sum of substation NCPs and estimated at 107 percent of Rural CP demand

Appendix D
Econometric Model Specifications

JACKSON PURCHASE ENERGY
2013 LOAD FORECAST
MODEL SPECIFICATIONS

RESIDENTIAL CONSUMERS - SHORT-TERM FORECAST

Dependent Variable: Residential Consumers

Model Type: Econometric

Model Specification:

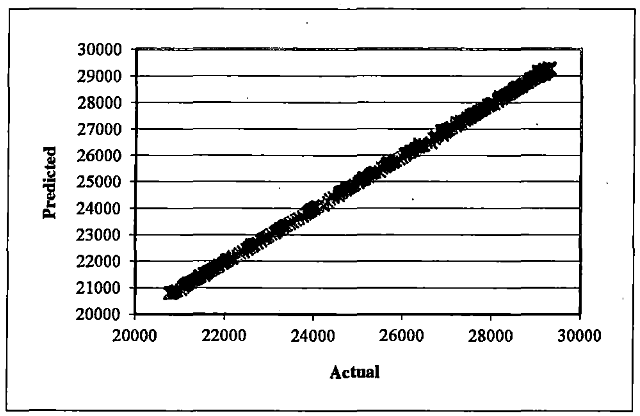
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
Simple		0.862	0.060	14.386	0.00%
Trend		0.062	0.022	2.793	0.56%
Seasonal		(0.127)	0.094	(1.348)	17.87%

Summary Model Statistics:

R-Squared	0.9998
Adjusted R-Squared	0.9998
Durbin-Watson Statistic	2.0
Mean Abs. % Err. (MAPE)	0.10%

Adjusted Observations	276
Deg. of Freedom for Error	273
F-Statistic	#NA
Prob (F-Statistic)	#NA
Bayesian Information Criterian (BIC)	7.24
Model Sum of Squares	2,153,254,087
Sum of Squared Errors	360,221
Mean Squared Error	1,319.49
Std. Error of Regression	36.32
Mean Abs. Dev. (MAD)	27.26

Predicted vs. Actual



JACKSON PURCHASE ENERGY

2013 LOAD FORECAST

MODEL SPECIFICATIONS

RESIDENTIAL CONSUMERS - LONG-TERM FORECAST

Dependent Variable: Residential Consumers

Model Type: Econometric

Model Specification:

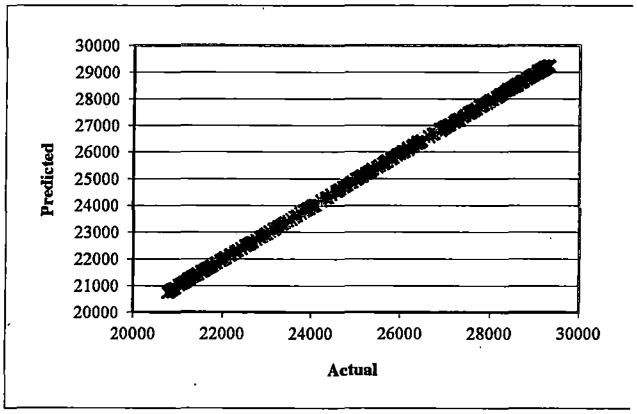
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
CONST		(22,186)	1,978	(11.2)	0.00%
HH		341.562	36.917	9.3	0.00%
HHMKT		69,034.960	1,734.516	39.8	0.00%
AR		1.006	0.003	294.8	0.00%

Summary Model Statistics:

R-Squared	1.0000
Adjusted R-Squared	1.0000
Durbin-Watson Statistic	2.2410
Mean Abs. % Err. (MAPE)	0.04%

Adjusted Observations	275
Deg. of Freedom for Error	271
F-Statistic	3,271,279
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	5.45
Model Sum of Squares	2,126,589,849
Sum of Squared Errors	58,724
Mean Squared Error	216.69
Std. Error of Regression	14.72
Mean Abs. Dev. (MAD)	10.69

Predicted vs. Actual



JACKSON PURCHASE ENERGY

2013 LOAD FORECAST

MODEL SPECIFICATIONS

RESIDENTIAL USE - LONG-TERM FORECAST

Dependent Variable: Residential Use

Model Type: Econometric

Model Specification:

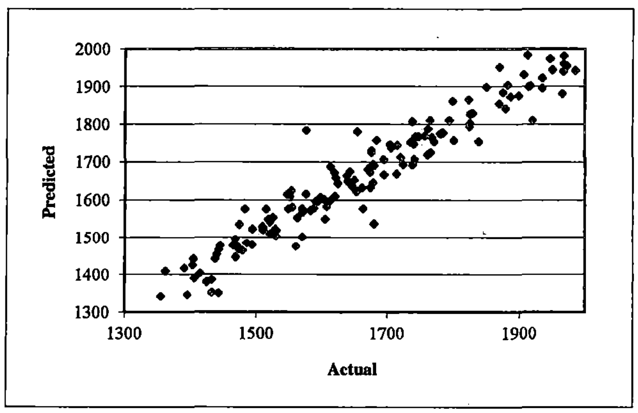
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
CONST		1,372.30	323	4.2	0.00%
HHIncome		2.958	3.188	0.9	35.46%
Rural Price		(46.045)	17.825	(2.6)	1.05%
WTCDD		3.815	0.091	41.9	0.00%
WTHSS		3.566	0.078	45.8	0.00%
Binary Variable for the month of February		(151.646)	12.651	(12.0)	0.00%
Binary Variable for the month of March		(80.832)	14.268	(5.7)	0.00%
Binary Variable for the month of April		(124.308)	13.253	(9.4)	0.00%
Binary Variable for the month of July		83.736	15.199	5.5	0.00%
Binary Variable for the month of August		101.032	15.533	6.5	0.00%
Binary Variable for the month of October		(65.899)	13.697	(4.8)	0.00%
Binary Variable for the month of November		(123.524)	14.653	(8.4)	0.00%
Binary Variable for the month of December		24.922	13.334	1.9	6.31%
AR(1)		0.502	0.062	8.2	0.00%

Summary Model Statistics:

R-Squared	0.9778
Adjusted R-Squared	0.9763
Durbin-Watson Statistic	2.03
Mean Abs. % Err. (MAPE)	1.97%

Adjusted Observations	215
Deg. of Freedom for Error	201
F-Statistic	681
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	8.11
Model Sum of Squares	22,276,563
Sum of Squared Errors	506,122
Mean Squared Error	2,518.02
Std. Error of Regression	50.18
Mean Abs. Dev. (MAD)	36.63

Predicted vs. Actual



BIG RIVERS ELECTRIC CORPORATION
2013 LOAD FORECAST
MODEL SPECIFICATIONS

RURAL COINCIDENT PEAK DEMAND - LONG-TERM FORECAST

Dependent Variable: Rural Summer CP Demand

Model Type: Econometric

Model Specification:

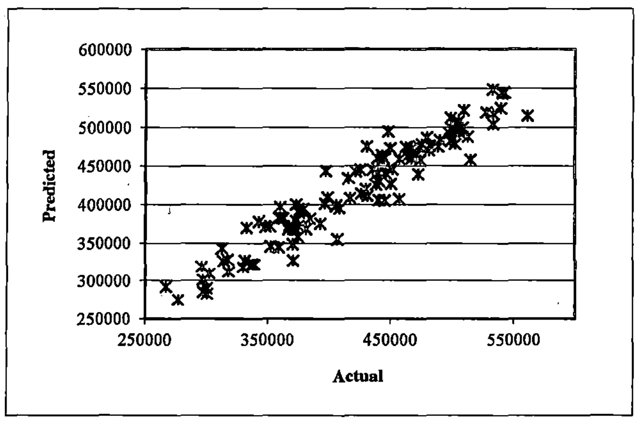
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
CONST		(275,590)	89,289	(3.1)	0.26%
AnnRuralKWHn_Pr50		0.0003	0.0000	6.5	0.00%
MWthr.PkCDD65		6,474.7721	1,110.4976	5.8	0.00%
MWthr.Lag2PkCDD65		3,220.1211	1,213.9820	2.7	0.93%
MWthr.PkHDD55		3,563.3012	447.5456	8.0	0.00%
MWthr.Lag2PkHDD55		1,160.5155	464.2642	2.5	1.41%
MBin.Mar		(22,359.6207)	8,097.9876	(2.8)	0.69%
MBin.Apr		(40,911.8124)	9,251.0132	(4.4)	0.00%
MBin.May		(44,289.7990)	7,978.2796	(5.6)	0.00%
MBin.Oct		(47,065.278)	8,857.951	(5.3)	0.00%

Summary Model Statistics:

R-Squared	0.917
Adjusted R-Squared	0.91
Durbin-Watson Statistic	2.04
Mean Abs. % Err. (MAPE)	3.92%

Adjusted Observations	108
Deg. of Freedom for Error	98
F-Statistic	121
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	20.28
Model Sum of Squares	499,761,124,731
Sum of Squared Errors	45,112,203,896
Mean Squared Error	460,328,611.18
Std. Error of Regression	21,455.27
Mean Abs. Dev. (MAD)	15,900.98

Predicted vs. Actual



Appendix E
RUS Form 341

USDA-RUS

POWER REQUIREMENTS STUDY SUMMARY

1. BORROWER DESIGNATION	Kentucky 21
Form Approved OMB No. 0572-0054	Exp. Date Available Upon Req.
2. NAME OF BORROWER	Jackson Purchase Energy
3. DATE	6-Aug-13

CLASS OF CONSUMER	NO. OF CONSUMERS			AVERAGE MONTHLY kWh USAGE		
	Base Year 2012	2017	2022	Base Year 2012	2017	2022
4. Rural Residential	25,944	26,895	28,039	1,272	1,216	1,221
5. Seasonal						
6. Irrigation	5	5	5	7,338	7,317	7,317
7. Commercial & Industrial 1000 kVA or less	3,280	3,415	3,578	4,859	4,386	4,401
8. Commercial & Industrial over 1000 kVA	9	11	11	413,953	341,975	341,975
9. Public Street & Highway Lighting	3	3	3	17,106	16,573	17,343
10. Other Sales to Public Authorities						
11. Sales for Resale - RUS Borrowers						
12. Sales for Resale - Others						

TOTAL SYSTEM POWER REQUIREMENTS

ITEM	Base Year 2012	2017	2022
13. Annual MWh Requirements	668,864	645,103	670,013
14. Including Losses @	5.1%	5.0%	5.0%
15. Annual Load Factor (Based on maximum monthly system peak demand)	47.7%	46.7%	46.8%
16. Maximum Monthly System Peak Demand (kW) (kW) ○ coincident ● noncoincident	160,040	157,766	163,450

17. Source(s) of Supply

Big Rivers Electric Corporation

18. Previous Power Requirements Study Date: May 2011

19. Comments (Use and additional sheet if more space is needed)

Borrower's General Manager (Signature)	Date	General Field Representative (Signature)	Date

RUS Form 341 (Rev. 1-87)

ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

Response to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Kentucky Industrial Utility Customers, Inc.'s Second Request for Information, Item Nos. 1, 3, 4, 9, 10, 11, 15, 17, 18, 20, 23, 25, 26, 36, 37, 42, 43, and 48 originally filed September 3, 2013

FILED: July 18, 2019

ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

In the Matter of:

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

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withdrawing Confidential Treatment
of previously filed Confidential Documents

Responses to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information,
Item No. 1
originally filed September 3, 2013

Information submitted on CD accompanying responses

Big Rivers
ELECTRIC CORPORATION

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In the Matter of:

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

Responses to the Commission's Orders, dated June 18, 2019,
withdrawing Confidential Treatment
of previously filed Confidential Documents

Responses to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information,
Item No. 3
originally filed September 3, 2013

Information submitted on CD accompanying responses

**Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013**

**September 30, 2013
Confidential Markings Removed – July 18, 2019**

Item 4) ***Please explain and supply (electronically with all formula intact) the derivation of row 45 (HMPL Excess to BREC) of tab - Monthly Sources and Uses in the PCM file - Big Rivers PCM Run 4-22-13 (2013-2027).xlsx? Also, explain why row 45 is multiplied by a 1.5 factor in row 75 to derive HMPL Excess Energy.***

Response) HMPL Excess to BREC in row 45 of the "Monthly Sources and Uses" tab shows the amount of excess energy (MWH) per the HMP&L capacity requirements for the city load. The formula takes the HMP&L city capacity requirement (115 MW for May, 2013) and multiplies by number of hours (744 in May, 2013) then subtracts the HMP&L load net of HMP&L SEPA (HMP&L load 425,076 MWH in May, 2013 less HMP&L SEPA 11,328 MWH in May, 2013). The calculation for May, 2013 is shown below:

(115 MW x 744 hours) – (425,076 MWH – 11,328 MWH) = 39,246 MWH.

The formula for the calculation is shown on the Annual Source and Uses tab in row 45.

In row 75, the HMP&L excess MWH are multiplied by $1.50 per MWH which is the amount Big Rivers pays the city per the HMP&L excess energy agreement.

Witness) Robert W. Berry

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In the Matter of:

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

Responses to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Kentucky Industrial Utility Customers, Inc.'s Second Request for Information, Item No. 9 originally filed September 3, 2013

Information submitted on CD accompanying responses

Coal Daily physical market assessment for coal pricing; Coal Trader/Outlook coal forecast; and, J.D. Energy coal forecast subscription. For the time period of this evaluation, Big Rivers did not have any current market bid solicitation data to utilize for the forward forecast. The last market solicitation for term coal supply was issued by Big Rivers in September and received in October 2012 and was too dated (five to six months aged) for this evaluation. The next term solicitation for coal procurement was not received until May 31, 2013.

Also, in regard to transportation, Big Rivers' barge contractual agreement expires December 31, 2013. In this evaluation, Big Rivers utilized a basis of $3.50/ton (with 2.5% year-to-year escalation, to include diesel fuel escalation) for its transportation forecast.

For examples of the various journals and calculation of spot / open position pricing, please see Big Rivers' response to AG 2–57.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013
Confidential Markings Removed – July 18, 2019

Item 11) *The 2016/2017 Base Residual Auction in PJM resulted in a Resource Clearing Price for the RTO of $59.37/MW-day, which is about $1.78/kW-month (http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx). If PJM prices are so low, please provide the economic rationale explaining why the MISO Capacity Market Prices for ACES, Wood Mackenzie, IHS Global, would be so much higher (around $6/kW-month for the same time period per the response to KIUC 1-13). Why wouldn't capacity owners in PJM offer capacity in the MISO market, which would then drive down prices in MISO and bring prices between MISO and PJM closer together.*

Response) Big Rivers relies on experts, like Wood Mackenzie and IHS Global, to project future market prices. It is, however, important to note that if PJM capacity owners sold their capacity in the PJM 2016/2017 Auction in 2013, they would not have capacity available to sell in MISO when the 2016/2017 MISO Auction occurs in early 2016. MISO's current auctions are conducted several months prior to the start of the MISO Planning Year; thus there is currently a significant disconnect in the timing of these two auctions. PJM owners who have already committed their capacity in the PJM Auction will be unable to take advantage of the MISO market until the 2017/2018 planning year. Also, please note that

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

Responses to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Kentucky Industrial Utility Customers, Inc.'s Second Request for Information, Item No. 15 originally filed September 3, 2013

Information submitted on CD accompanying responses

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In the Matter of:

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

Responses to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Kentucky Industrial Utility Customers, Inc.'s Second Request for Information, Item No. 17 originally filed September 3, 2013

Information submitted on CD accompanying responses

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In the Matter of:

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

Responses to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Kentucky Industrial Utility Customers, Inc.'s Second Request for Information, Item No. 18 originally filed September 3, 2013

Information submitted on CD accompanying responses

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ELECTRIC CORPORATION

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In the Matter of:

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

Responses to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Kentucky Industrial Utility Customers, Inc.'s Second Request for Information, Item No. 20 originally filed September 3, 2013

Information submitted on CD accompanying responses

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Kentucky Industrial Utility Customers, Inc.'s
Second Request for Information
dated September 16, 2013

September 30, 2013
Confidential Markings Removed – July 18, 2019

Item 23) *In the spreadsheet - 2013-16 Capital Plan (Alcan RC).xlsx, two categories of HAPS/MATS costs appear, HAPS/MATS - Capitalized Interest, and HAPS/MATS Project. Please discuss what these relate to, and provide a schedule breaking these costs down to the specific project being performed, and the unit where the project is being performed.*

Response) The category 'HAPS/MATS – Capitalized Interest' is simply the capitalized interest for the HAPS/MATS project. Big Rivers capitalizes interest expense on capital projects greater than $250,000. The remainder of capitalized interest is budgeted in the Transmission section of budget, located in the file entitled "2013-16 Capital Plan (Alcan RC).xlsx".

The category HAPS/MATS Project refers to projected capital expenditures for the MATS work. This work includes foundations, silos, blowers, piping, electrical and controls for both DSI (dry sorbent injection) and ACI (Activated Carbon Injection) systems. For 2014, this work is broken down as follows:

Green	$9.28 million
Wilson	$5.24 million
Coleman	$12.84 million

In addition, there is a third line item that represents $292,000 for monitors at HMP&L Station Two.

The file "2013-16 Capital Plan (Alcan RC).xls" was submitted with Big Rivers' response to PSC 1-57. At the time Big Rivers filed its Application it fully intended to proceed with installation of all MATS equipment as approved by the Commission in Case No. 2012-00063. Big Rivers' management currently believes it is prudent to defer MATS expenditures at the Coleman and Wilson plants until closer to the time they will return to service, thus the capital budget associated with the Coleman and Wilson MATS compliance will be less than what has been filed in this case.

Witness) Robert W. Berry

Big Rivers
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In the Matter of:

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

Responses to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Kentucky Industrial Utility Customers, Inc.'s Second Request for Information, Item No. 25 originally filed September 3, 2013

Information submitted on CD accompanying responses

Big Rivers
ELECTRIC CORPORATION

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In the Matter of:

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

Responses to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to the Kentucky Industrial Utility Customers, Inc.'s Second Request for Information, Item No. 26 originally filed September 3, 2013

Information submitted on CD accompanying responses

contemplated by Big Rivers includes a fixed demand component of $7.50 with energy charges and riders charged at Big Rivers' tariff rate equivalent.

b. Big Rivers relied on the principles outlined in an order by the Kentucky Public Service Commission in Administrative Case No. 327 (September 24, 1990), which is attached hereto for reference.

c. Yes.

d. Yes, please see Big Rivers' response to subpart (b) above.

e. Big Rivers' CEO and COO have authorized the proposal of economic development rates to potential counterparties; however, any retail agreements that deviate from tariffed rates will require approval by Big Rivers' board of directors, RUS, and the PSC prior to execution.

f. Big Rivers' position is that economic development rates offered to encourage new or expanded large industrial load should be implemented by special contract between and among Big Rivers, its respective distribution cooperative, and the large industrial customer. Any such contract would be submitted to the Commission for review in accordance with the principles established by the Commission in Administrative Case No. 327.

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Kentucky Industrial Utility Customers, Inc.'s Second Request for Information dated September 16, 2013

September 30, 2013
Confidential Markings Removed – July 18, 2019

Item 37) ***Refer to the Company's response to PSC 2-16 with respect to the AEP Energy Partners transaction.***

a. ***Please provide a current status report on this transaction, including the Company's quantifications of the net margin (gross revenues less variable costs) that the Company projects for each month during the term of the transaction.***

b. ***Please provide the amount of the net margin included in the Company's test year revenue requirement, if any. Provide all assumptions, data, and computations, including electronic workpapers with formulas intact.***

Response)

a. Big Rivers continues to have substantive conversations with AEP Energy Partners on this transaction. The gross margin associated with this transaction is not yet known as this transaction has not been finalized.

b. No net margin on this transaction was included in Big Rivers' test year revenue requirement because a deal has not been consummated.

Witness) Robert W. Berry

Board for approval in November 2013 will include only layup related expenditures for Wilson in 2014, and will not include any capital dollars for Wilson in 2015 or 2016.

b. There is $5.24 million for Wilson MATS and $12.84 million for Coleman MATS included in this number (before capitalized interest). These figures were included in the original 2013 capital expenditure budget, which is the basis for Big Rivers' response to KIUC 1-42(a). As a result of termination of the smelter contracts by Century and Rio Tinto, and the subsequent uncertainty over future operation of these plants, Big Rivers' management agrees that the MATS capital expenditures for Wilson and Coleman should be delayed until a later date that supports the return to service of these plants.

Witness) Robert W. Berry

Item 43) *Refer to the Company's response to AG 1-41 showing the dates of the most recent actual and scheduled outages due to maintenance on the Company's transmission lines.*

a. *For each of the transmission lines, please provide the dates of the actual 2013 outages and the projected dates in 2013 for any outages that have not yet occurred.*

b. *For each of the transmission lines, please provide the actual maintenance expense for each outage that has occurred in 2013 and provide the projected maintenance expense for each outage that has not yet occurred in 2013.*

Response)

a. An outage of the Coleman to Newtonville 161 kV line was taken on July 8, 2013, August 19, 2013 and August 28, 2013 to perform line maintenance and related substation maintenance. Additional outages are necessary to complete the maintenance work in mid-October. The Coleman EHV to Daviess EHV 345 kV line was taken out of service on May 1, 2013 and May 2, 2013. Additional outages are necessary to complete planned maintenance work sometime during the period ranging from September 30, 2013 and October 10,

2013. Outages of the Coleman EHV to Coleman 161 kV lines were taken on August 29, 2013 (C1 line) and September 3, 2013 (C2 line) to perform line maintenance and related substation maintenance work. Additional outages are necessary to complete the planned maintenance work in mid-October. No outages have been taken in 2013 to perform line maintenance on the Reid to Daviess County 161 kV line. Planned outages to perform line maintenance will be necessary in mid-October.

b. The 2013 actual and forecasted line maintenance expenses for each requested line follows:

	Actual 2013 Expense Through September 20, 2013	Remaining Expenses Forecasted for 2013
CEHV to Coleman 161 kV 1 & 2	$7,145	$2,699
Coleman to Newtonville 161 kV	$16,984	$4,824
Reid to Daviess Co. 161 kV	n/a	$137,120
DEHV to CEHV 345 kV	$41,730	$21,842

Witness) Christopher S. Bradley

**EXCERPT FROM THE MINUTES OF REGULAR MEETING
OF THE BOARD OF DIRECTORS
OF BIG RIVERS ELECTRIC CORPORATION
HELD IN HENDERSON, KENTUCKY, ON
FEBRUARY 18, 2011**

After an explanation by Chris Warren, senior budget analyst, and upon management's recommendation, Director Denton moved that the 2010 incentive pay award be approved as presented, subject to any adjustments recommended by outside financial auditors. The motion was seconded and unanimously adopted.

I, Paula Mitchell, Executive Secretary of the Board of Directors of Big Rivers Electric Corporation, hereby certify that the above is a true and correct excerpt from the minutes of the Regular Meeting of the Board of Directors of said Corporation held on 2-18-11.

Paula Mitchell

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy® Cooperative

2010 Incentive Pay Award

Measurement	Weighting	Actual 12/31/2010	0% Miniumum	10% Maximum	Maximum Possible Incentive Rate	Actual 12/31/2010	Incentive Pay
Financial Performance							
North Star ($/kWh)	50%	0.042627	0.043004	0.040937	5.0%	0.91%	$ 182,743
Capital Expenditures, net of capitalized interest ($000s)	5%	43,822	45,030	43,781	0.5%	0.48%	$ 96,392
Safety							
Recordable Incidents	5%	9	10	8	0.5%	0.25%	$ 50,204
Lost Time Incidents	5%	1	2	0	0.5%	0.25%	$ 50,204
Process Improvement							
HP Transition - % Successful Completion	5%	15%	0%	100%	0.5%	0.08%	$ 16,065
Plant Performance							
EAF	5%	93.7%	92.4%	92.7%	0.5%	0.50%	$ 100,408
Heat Rate	5%	11,025	11,170	11,106	0.5%	0.50%	$ 100,408
Transmission System Reliability							
SAIDI Hrs/YR - Jackson Purchase	5%	0.1908	0.743	0.594	0.5%	0.50%	$ 100,408
SAIDI Hrs/YR - Meade County	5%	0.0311	1.047	0.838	0.5%	0.50%	$ 100,408
SAIDI Hrs/YR - Kenergy	5%	0.2436	1.616	1.293	0.5%	0.50%	$ 100,408
SAIDI Hrs/YR - System Wide	5%	0.1772	1.616	1.293	0.5%	0.50%	$ 100,408
Total	100%				10.0%	4.97%	$ 998,058

Base earnings for incentive pay purposes is W-2, plus pre-tax cafeteria plan contributions and 401(k) deferrals, and excludes bonus dollars, taxable educational reimbursement, taxable vehicle, taxable group term life insurance, and accident protection insurance.
Base earnings for the eligible employees for the 12-month period ended December 31, 2010, are $20,081,650. The award for each measurement cannot exceed the maximum, and if the result is between the minimum and maximum, the award is interpolated.

An Incentive Award Payout will only be made to the extent the Company remains in compliance with its loan covenants.

Date: 2/9/2011

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Incentive Pay Awards

2005	5.70%
2006	5.14%
2007	4.92%
2008	3.92%
2009	1.72%
2010	4.97%

EXCERPT FROM THE MINUTES OF REGULAR MEETING OF THE BOARD OF DIRECTORS OF BIG RIVERS ELECTRIC CORPORATION HELD IN HENDERSON, KENTUCKY, ON FEBRUARY 18, 2011

After a presentation by Mr. Bailey on the 2011 incentive pay measures and targets, and all questions answered that were posed by the board, Director Elder moved that the 2011 incentive pay measures and targets be approved as presented. The motion was seconded and unanimously adopted.

I, Paula Mitchell, Executive Secretary of the Board of Directors of Big Rivers Electric Corporation, hereby certify that the above is a true and correct excerpt from the minutes of the Regular Meeting of the Board of Directors of said Corporation held on 2-18-11.

Paula Mitchell

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

Proposed 2011 Incentive Pay Measures & Targets

Measurement	Weighting	0% Minimum	8% Maximum	Maximum Possible Incentive Rate
Financial Performance				
North Star ($/kw)	50%	0.044766	0.043205	4.00%
Safety				
Recordable Incidents	6.25%	9	7	0.50%
Lost Time Incidents	6.25%	2	0	0.50%
Plant Performance/Operations				
EAF	6.25%	91.0%	91.5%	0.50%
Heat Rate	6.25%	11,067	11,000	0.50%
Transmission System Reliability				
SAIDI Hrs/YR - Jackson Purchase	6.25%	0.778	0.622	0.50%
SAIDI Hrs/YR - Meade County	6.25%	0.809	0.647	0.50%
SAIDI Hrs/YR - Kenergy	6.25%	1.578	1.262	0.50%
SAIDI Hrs/YR - System Wide	6.25%	1.578	1.262	0.50%
	25%			
	100%			8.00%

Base earnings for incentive pay purposes is W-2, plus pre-tax cafeteria plan contributions and 401(k) deferrals, and excludes bonus dollars, taxable educational reimbursement, taxable vehicle, taxable group term life insurance, and accident protection insurance.
Base budgeted earnings for the eligible employees for the 12-month period ended December 31, 2011, are $21,771,353. The award for each measurement cannot exceed the maximum, and if the result is between the minimum and maximum, the award is to be interpolated.

An Incentive Award Payout will only be made to the extent the Company remains in compliance with its loan covenants.

Date: 2/15/2011

**EXCERPT FROM THE MINUTES OF REGULAR MEETING
OF THE BOARD OF DIRECTORS
OF BIG RIVERS ELECTRIC CORPORATION
HELD IN HENDERSON, KENTUCKY, ON
FEBRUARY 21, 2012**

After an explanation by Mr. Hite, and upon management's recommendation, Director Elder moved that the 2011 incentive pay award for all non-bargaining employees be approved as presented. The motion was seconded and unanimously adopted.

I, Paula Mitchell, Executive Secretary of the Board of Directors of Big Rivers Electric Corporation, hereby certify that the above is a true and correct excerpt from the minutes of the Regular Meeting of the Board of Directors of said Corporation held on 2-21-12.

Paula Mitchell

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

2011 Incentive Pay Award

Measurement	Weighting	Actual 12/31/2011	0% Minimum	8% Maximum	Maximum Possible Incentive Rate	Actual Payout Rate Based on Performance	Incentive Pay	Incremental Member Value
Financial Performance								
North Star ($/kw)	50%	0.044396	0.044766	0.043205	4.00%	0.95%	$ 195,084	$ 3,396,273
Safety								
Recordable Incidents	6.25%	12	9	7	0.50%	0.00%	$ -	
Lost Time Incidents	6.25%	2	2	0	0.50%	0.00%	$ -	
Plant Performance/Operations								
EAF*	6.25%	93.3%	92.6%	93.1%	0.50%	0.50%	$ 102,676	$ 1,571,280
Heat Rate	6.25%	11,001	11,067	11,000	0.50%	0.49%	$ 100,622	$ 1,332,812
Transmission System Reliability								
SAIDI Hrs/YR - Jackson Purchase	6.25%	0.040	0.778	0.622	0.50%	0.50%	$ 102,676	
SAIDI Hrs/YR - Meade County	6.25%	0.971	0.809	0.647	0.50%	0.00%	$ -	
SAIDI Hrs/YR - Kenergy	6.25%	0.127	1.578	1.262	0.50%	0.50%	$ 102,676	
SAIDI Hrs/YR - System Wide	6.25%	0.318	1.578	1.262	0.50%	0.50%	$ 102,676	
	25%							
	100%				8.00%	3.44%	$ 706,410	$ 6,300,368

Base earnings for incentive pay purposes is W-2, plus pre-tax cafeteria plan contributions and 401(k) deferrals, and excludes bonus dollars, taxable educational reimbursement, taxable vehicle, taxable group term life insurance, and accident protection insurance.

Base earnings for the eligible employees for the 12-month period ended December 31, 2010, are $20,535,171. The award for each measurement cannot exceed the maximum, and if the result is between the minimum and maximum, the award is interpolated.

* The original target of 91.0% was adjusted to 92.6% to account for the planned outage cancellations and scope reductions that occurred throughout the year.

An Incentive Award Payout will only be made to the extent the Company remains in compliance with its loan covenants.

Date: 2/13/2012

Big Rivers
ELECTRIC CORPORATION

Incentive Pay Awards

Year	Percent Achievable	Percent Payout	Percent of Achievable
2005	6.00%	5.70%	95%
2006	6.00%	5.14%	86%
2007	6.00%	4.92%	82%
2008	6.00%	3.92%	65%
2009	6.00%	1.72%	29%
2010	10.00%	4.97%	50%
2011	8.00%	3.44%	43%

Big Rivers
ELECTRIC CORPORATION
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North Star Calculation

	Actual	Actual Adjusted	Budget
Total Cost of Electric Service	556,657,192	556,657,192	558,347,235
Non-Member Revenue	(108,838,865)	(108,838,865)	(78,011,629)
	447,818,327	447,818,327	480,335,605
Adjustments:			
Incentive Pay Accrual		(896,646)	
Green Outages		2,536,069	
Wilson Outage		1,530,908	
HMPL 1 Outage		1,803,470	
Member cost after adjustments	447,818,327	452,792,128	480,335,606
Member kWh	10,199,019,255	10,199,019,255	10,729,981,270
North Star - $/kWh	0.043908	0.044396	0.044766
Minimum Target			0.044766
Maximum Target			0.043205
Addl. Required to achieve Min.	0	0	
Addl. Required to achieve Max.	(7,169,700)	(12,143,501)	

Notes:

$2,932,864 included in Non-Member revenue for the difference between Avoidable Base Charge and the Net Proceeds for the Smelters.

EXCERPT FROM THE MINUTES OF REGULAR MEETING OF THE BOARD OF DIRECTORS OF BIG RIVERS ELECTRIC CORPORATION HELD IN HENDERSON, KENTUCKY, ON FEBRUARY 21, 2012

After a presentation by Mr. Bailey on the 2012 incentive pay measures and targets, and all questions answered that were posed by the board, Director Butler moved that the 2012 incentive pay measures and targets be approved as presented. The motion was seconded and unanimously adopted.

I, Paula Mitchell, Executive Secretary of the Board of Directors of Big Rivers Electric Corporation, hereby certify that the above is a true and correct excerpt from the minutes of the Regular Meeting of the Board of Directors of said Corporation held on 2-21-12.

Paula Mitchell

Big Rivers

Proposed 2012 Incentive Pay Targets

Measurement	Weighting	0% Minimum	6% Maximum	Maximum Possible Incentive Rate	90% Member Value*
Financial Performance					
North Star ($/kw)	50%	0.050925	0.049724	3.00%	$ 12,799,508
Safety					
Recordable Incidents	6.25%	9	7	0.375%	
Lost Time Incidents	6.25%	2	0	0.375%	
Plant Performance/Operations					
EAF	6.25%	88.3%	88.6%	0.375%	$ 914,251
Heat Rate	6.25%	11,029	10,980	0.375%	$ 914,251
Transmission System Reliability					
SAIDI Hrs/YR - Jackson Purchase	6.25%	0.541	0.433	0.375%	
SAIDI Hrs/YR - Meade County	6.25%	0.741	0.593	0.375%	
SAIDI Hrs/YR - Kenergy	6.25%	1.013	0.810	0.375%	
SAIDI Hrs/YR - System Wide	6.25%	1.013	0.810	0.375%	
	25%				
	100%			6.00%	$ 14,628,009

Base earnings for incentive pay purposes is W-2, plus pre-tax cafeteria plan contributions and 401(k) deferrals, and excludes bonus dollars, taxable educational reimbursement, taxable vehicle, taxable group term life insurance, and accident protection insurance. Base budgeted earnings for the eligible employees for the 12-month period ended December 31, 2012, are $22,702,194. The award for each measurement cannot exceed the maximum, and if the result is between the minimum and maximum, the award is to be interpolated.

An Incentive Award Payout will only be made to the extent the Company remains in compliance with its loan covenants.

Date: 2/7/2012

*Assumes maximum payout.

**EXCERPT FROM THE MINUTES OF REGULAR MEETING
OF THE BOARD OF DIRECTORS
OF BIG RIVERS ELECTRIC CORPORATION
HELD IN HENDERSON, KENTUCKY, ON
FEBRUARY 27, 2013**

After a review by Chris Warren, senior budget analyst, and upon management's recommendation, Director Elder moved that the 2012 incentive pay award for all non-bargaining employees be approved as presented. The motion was seconded and unanimously adopted.

I, Paula Mitchell, Executive Secretary of the Board of Directors of Big Rivers Electric Corporation, hereby certify that the above is a true and correct excerpt from the minutes of the Regular Meeting of the Board of Directors of said Corporation held on 2-27-13.

Paula Mitchell

2012 Incentive Pay Award (Prepared 2/18/2013)

Measurement	Weighting	Actual 12/31/2012	0% Minimum	6% Maximum	Maximum Possible Incentive Rate	Payout Rate Based on Performance	Incentive Pay (Base Earnings $ 21,127,933)	Net Incremental Member Value
Financial Performance								
North Star ($/kWh)*	50%	0.048826	0.050925	0.049724	3.00%	3.00%	$ 735,252	$ 21,371,635
Safety								
Recordable Incidents	6.25%	7	9	7	0.38%	0.38%	$ 91,907	
Lost Time Incidents	6.25%	0	1	0	0.38%	0.38%	$ 91,907	
Plant Performance/Operations								
EAF**	6.25%	92.4%	91.6%	91.8%	0.38%	0.38%	$ 91,907	$ 245,428
Heat Rate	6.25%	10,795	11,029	10,980	0.38%	0.38%	$ 91,907	$ 5,290,780
Transmission System Reliability								
SAIDI Hrs/YR - Jackson Purchase	6.25%	0.692	0.541	0.433	0.38%	0.00%	$ -	
SAIDI Hrs/YR - Meade County	6.25%	0.919	0.741	0.593	0.38%	0.00%	$ -	
SAIDI Hrs/YR - Kenergy	6.25%	0.271	1.013	0.810	0.38%	0.38%	$ 91,907	
SAIDI Hrs/YR - System Wide	6.25%	0.544	1.013	0.810	0.38%	0.38%	$ 91,907	
	25%							
	100%				6.00%	5.25%	$ 1,288,691	$ 26,907,843

Base earnings for incentive pay purposes is W-2, plus pre-tax cafeteria plan contributions and 401(k) deferrals, and excludes bonus dollars, taxable educational reimbursement, taxable vehicle, taxable group term life insurance, and accident protection insurance.
Base earnings for the eligible employees for the 12-month period ended December 31, 2012, were $21,127,933. The award for each measurement cannot exceed the maximum, and if the result is between the minimum and maximum, the award is interpolated.

* The actual North Star ($/kWh) was adjusted upward for planned outage cancellations and scope reductions that occurred in 2012.

** The original target of 88.3% was adjusted to 91.6% to account for the planned outage cancellations and scope reductions that occurred throughout the year.

An Incentive Award Payout is only made to the extent the Company remains in compliance with its loan covenants.

Big Rivers

Date: 2/18/2013

EXCERPT FROM THE MINUTES OF REGULAR MEETING
OF THE BOARD OF DIRECTORS
OF BIG RIVERS ELECTRIC CORPORATION
HELD IN HENDERSON, KENTUCKY, ON
FEBRUARY 27, 2013

After a presentation by Mr. Bailey on the 2013 incentive pay measures and targets, and all questions answered that were posed by the board, Director Elliott moved that the 2013 incentive pay measures and targets be approved as presented. The motion was seconded and unanimously adopted.

I, Paula Mitchell, Executive Secretary of the Board of Directors of Big Rivers Electric Corporation, hereby certify that the above is a true and correct excerpt from the minutes of the Regular Meeting of the Board of Directors of said Corporation held on 2-27-13.

Paula Mitchell

Proposed 2013 Incentive Pay Measures & Targets

Measurement	Weighting	0% Minimum	6% Maximum	Maximum Possible Incentive Rate	Maximum Payout	90% Member Value*	
Financial Performance							
North Star ($/kWh)	50%	0.052946	0.051448	3.00%	$ 1,373,951	$ 12,365,559	
Safety							
Recordable Incidents	6.25%	8	6	0.375%			
Lost Time Incidents	6.25%	2	0	0.375%			
Plant Performance/Operations							
EAF	6.25%	92.4%	92.9%	0.375%	$ 12,964	$ 116,677	**
Heat Rate	6.25%	10,835	10,789	0.375%	$ 92,461	$ 832,149	
Transmission System Reliability							
SAIDI Hrs/YR - Jackson Purchase	6.25%	0.671	0.537	0.375%			
SAIDI Hrs/YR - Meade County	6.25%	0.952	0.762	0.375%			
SAIDI Hrs/YR - Kenergy	6.25%	1.112	0.890	0.375%			
SAIDI Hrs/YR - System Wide	6.25%	1.112	0.890	0.375%			
	25%						
	100%			6.00%	$ 1,479,376	$ 13,314,385	

Base earnings for incentive pay purposes is W-2, plus pre-tax cafeteria plan contributions and 401(k) deferrals, and excludes bonus dollars, taxable educational reimbursement, taxable vehicle, taxable group term life insurance, and accident protection insurance.
Base budgeted earnings for the eligible employees for the 12-month period ended December 31, 2013, are $22,173,382. The award for each measurement cannot exceed the maximum, and if the result is between the minimum and maximum, the award is to be interpolated.

An Incentive Award Payout will only be made to the extent the Company remains in compliance with its loan covenants.

*Assumes maximum payout
** Safety, Transmission Reliability and $794,969 of EAF funded by North Star

Date: 2/18/2013

ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

Response to the Commission's Orders, dated June 18, 2019, withdrawing Confidential Treatment of previously filed Confidential Documents

Responses to Ben Taylor and the Sierra Club's Supplemental Request for Information, Item Nos. 7, 9, 10, 11, 15, 23, 25, 26, 29, 30, 31, and 32 originally filed September 30, 2013

FILED: July 18, 2019

ORIGINAL

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
Confidential Markings Removed – July 18, 2019

Item 7) *Refer to lines 9, 80, and 81 of the Stmts RUS tab of the Long-Term Financial Forecast produced in response to PSC 2-14.*

a. Explain the basis for the replacement load sales projected in line 9 for each year of 2016 through 2027.

b. Explain the basis for the replacement load prices projected in line 81 for each year of 2016 through 2027.

c. Identify and produce any study, report, or analysis that supports the replacement load sales and/or replacement load prices projected in lines 9 and 81.

d. Explain how BREC expects to attract significant amounts of replacement load sales at prices that are 25% higher than the market energy price projected in line 80.

Response)

a. Please see Big Rivers' response to KIUC 2-32.

b. Replacement Load was assumed to be sold at a 25% premium to market.

c. Please see Big Rivers' response to KIUC 2-32.

2. Explain how such prices were identified.

3. Identify and produce any study or analysis supporting such carbon price projection.

ii. If not:

1. Explain why not.

2. Identify and produce any study or analysis supporting the assumption of no price on carbon emissions between now and 2027.

3. Identify any other utility that BREC is aware of that assumes in its long term financial forecasting that there will be no price on carbon emissions between now and 2027.

c. For the ACES market energy price forecasts, explain why:

i. The fall 2012 forecast used in the Century rate case projects significant prices increases (13.1% to 25.7% per year) in the [2019 to 2021 time frame.

ii. The August 19, 2013 forecast projects significant price increases (14.3%to 30.8% per year) in the 2021 to 2023 time frame, but increases of less than 4% per year in 2019 and 2020.

iii. The April 2013 forecast used in the Alcan rate case projects significantly lower market energy prices than were projected in the ACES fall 2012 forecast.

iv. There are large swings in successive ACES Indiana Hub electricity price forecasts.

d. State whether Big Rivers has considered the use of other market energy price forecasts in its long term forecasting in order to reduce dependence on the fluctuating ACES forecasts.

i. If not, explain why not.

e. Please clarify what role, if any, the IHS price forecast plays in Big Rivers' long-term forecasting.

Response)

a. For the ACES market energy price forecasts, please see the attached letter from ACES to Big Rivers. For IHS, Big Rivers has not received approval to share the EPA's regulatory timeline under IHS CERA's planning scenario.

b. Please see Big Rivers' responses below.

i. The IHS market power pricing assumes a price on carbon emissions beginning in 2020.

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
Confidential Markings Removed – July 18, 2019

Item 10) *Refer to Capacity Market tab of the Long-Term Financial Forecast capacity market sensitivity analyses provided in response to PSC 2-14.*

a. With regards to the MISO Zone 6 capacity price forecasts found on lines 5 through 8:

i. Explain why the capacity price increases more than from 2015 to 2016.

ii. Explain why the capacity price continues to increase in each year from 2017 through 2027.

iii. Explain why in the years after 2016 the capacity price does not reach some level of equilibrium between the current low price and the substantially higher price projected for 2016.

iv. Identify and produce each capacity price forecast, or any other study or analysis that you relied on in identifying your forecasted capacity prices.

1. For each such capacity price forecast that you relied on, state whether the forecast is for MISO Zone 6.

2. Identify the projected capacity price for each year of such forecast.

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
Confidential Markings Removed – July 18, 2019**

Item 11) ***Refer to BREC's response to SC 1-27. Reconcile the statement that the installation of MATS controls on the Coleman and Wilson plants will be deferred while those units are idled until one year before their expected return to service, with the Long-Term Financial Forecast (tab Capex & Depr, line 20) showing all environmental capital spending completed by June 2014, with zero environmental capital expenditures thereafter through 2027.***

Response) The capital expenditure schedule shown in the Capex & Depr tab of the Long Term Financial Forecast was based on the 2013 budget and financial forecast. This document envisioned all MATS expenditures authorized in PSC Case Number 2012-00063 as being completed by June 2014. Subsequently, and as a result of the contract terminations by Century and Alcan, Big Rivers' management determined it would be prudent to defer MATS expenditures at the Coleman and Wilson plants until closer to their return to service.

Witness) Robert W. Berry

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
Confidential Markings Removed – July 18, 2019

Item 15) *Refer to p. 1 of the 2013 Load Forecast produced in response to AG 1-139, which identifies an approximately 40% increase in retail electricity prices over the years 2014 to 2016, and a resulting 3.2% decline in sales over that same time period.*

a. Identify the starting and ending rates upon which the approximately 40% increase in retail electricity prices is based.

b. Explain how the 3.2% decline in sales is consistent with the price elasticity of demand identified on p. 12 of the Barron testimony.

Response)

a. The approximately 40% increases in retail electricity prices represent a system average, but vary for each of Big Rivers' three member distribution cooperatives. The following table presents the real (deflated) average price, represented as revenue divided by kWh.

	JPEC	MCRECC	KENERGY
2013	6.43	6.90	6.82
2014	7.39	7.87	7.77
2015	8.43	8.95	8.85
2016	9.17	9.63	9.51

Item 23) *Refer to BREC's response to PSC 2-16 and the Attachments to that response.*

a. Confirm that PSC Attachment 2-16 includes only seven RFPs.

b. Confirm that BREC bid on all RFPs identified in PSC Attachment 2-16.

c. For each of the RFPs identified in PSC Attachment 2-16 which BREC bid on, identify the prices that Big Rivers bid for providing energy and capacity in each of the formal responses.

d. Identify the results of each of the RFPs identified in PSC Attachment 2-16, including whether Big Rivers' formal response to each such RFP has been accepted or rejected.

i. In each case where Big Rivers' bid has been rejected and the winning bid is known, identify the prices of the winning bids for providing energy and capacity.

e. State whether there are any additional RFPs not identified in BREC's response to PSC 2-16 and the attachments that BREC has bid on or anticipates bidding on. If so:

i. Identify the utility that issued each RFP, the date of the RFP, the amount of energy and/or capacity sought in the RFP, and the period

Item 25) *Refer to BREC's response to PSC 2-16, which states at page 4 line 3 that "Big Rivers' staff worked with outside consultants to determine a feasible sale price" for the sale or lease of Wilson.*

a. Please provide the names and qualifications for all outside consultants used to determine the sale price of Wilson.

b. Please clarify what BREC and consultants define as a "feasible sale price"

c. Explain why the proposed sale price for Wilson exceeds the plant's net book value.

d. Produce all documents and workpapers (in electronic machine-readable format with formulas intact) used to come up with the "feasible sale price" of $500 million at which BREC offered to sell the Wilson Station to LGE/KU for.

e. Produce all documents and workpapers (in electronic machine-readable format) used to come up with the asking price to lease Wilson Station to LGE/KU $39.7 Million a year annually for a ten (10) year lease.

f. Provide any updates regarding the proposal to sell or lease the Wilson Station to LGE/KU.

Item 26) ***Refer to p. 4 of BREC's response to PSC 2-16. With regards to the offer to sell or lease the Coleman plant.***

a. ***State whether BREC worked with outside consultants to determine the sale price of Coleman.***
   i. ***If so, provide the names and qualifications for all outside consultants used to determine the sale price of Coleman.***
   ii. ***If not, explain why outside consultants were used for determining the sale price of Wilson but not of Coleman.***
b. ***Produce all documents and workpapers (in electronic machine-readable format with formulas intact) used to come up with the proposed $200 million price to sell Coleman to LGE/KU.***
c. ***Produce all documents and workpapers (in electronic machine-readable format) used to come up with the asking price to lease Coleman Station to LGE/KU of $29 Million a year annually for a ten (10) year lease.***
d. ***Explain why the proposed sale price for Coleman exceeds the plant's net book value.***
e. ***Provide any updates regarding the proposal to sell or lease the Coleman Station to LGE/KU.***

Item 29) *Refer to pages 4 to 5 of BREC's response to PSC 2-16*

a. Identify at what price BREC offered to sell each of the Wilson and Coleman plants to each of the following entities:

i. EKPC

ii. Kentucky Power

iii. Duke Kentucky

iv. Duke Energy Indiana

b. Identify at what price and for how many years BREC offered to lease each of the Wilson and Coleman plants to each of the following entities

i. EKPC

ii. Kentucky Power

iii. Duke Kentucky

iv. Duke Energy Indiana

c. State whether Big Rivers has offered to sell or lease the Coleman and/or Wilson plants to any other entity besides LG&E/KU, EKPC, Kentucky Power, Duke Kentucky, Duke Energy Indiana, and Century.

i. If so, identify the entity, the price at which the sales or lease was offered, and the response.

d. State whether Big Rivers re-evaluated the price at which it was offering to sell or lease the Wilson and/or Coleman plants after EKPC determined the offer to be "not cost-effective."

i. If so, what new price(s) did Big Rivers identify?

ii. If not, explain why not

e. State whether Big Rivers re-evaluated the price at which it was offering to sell or lease the Wilson or Coleman plants after Duke Kentucky "decided to pursue proposals . . . from other bidders."

i. If so, what new price(s) did Big Rivers identify?

ii. If not, explain why not

f. Please provide a copy of the notification Big Rivers received from Duke Kentucky referenced in BREC's response to PSC 2-16 at page 6 lines 1-3.

g. Provide any updates regarding the status of BREC's offers to sell or lease the Coleman and/or Wilson plants.

Response)

a-b. Big Rivers objects to these requests on the grounds that they seek information that is neither relevant nor likely to lead to the discovery of admissible evidence.

c. Yes.

i. Big Rivers has offered the sale or lease of all or part of Coleman and Wilson to Energy Consulting Group at the same price as previously provided in this case.

d. No.

i. Not applicable.

ii. Big Rivers did not believe that one entity's determination that the purchase of an asset was not "cost effective" for their organization justified a change in sales strategy.

e. No.

i. Not applicable.

ii. Duke Kentucky chose to pursue proposals from other bidders in their short-term RFP, likely because they are located within PJM and Big Rivers is located in MISO and does not have short-term deliverability for their full needs. Duke's decision to pursue other bidders' proposals did not justify a change in sales strategy.

f. Please see attached.

g. None at this time.

Witness) Robert W. Berry

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
Confidential Markings Removed – July 18, 2019

Item 30) *Refer to BREC's response to PSC 2-16 at p. 7.*

a. Identify the price at which BREC offered to sell the Coleman plant to Century Aluminum.

b. State whether BREC offered to lease the Coleman plant to Century Aluminum.

i. If so, for how many years and at what price?

ii. If not, explain why not.

c. Provide any updates regarding the proposed sale of the Coleman plant to Century Aluminum.

Response)

a. Please see Big Rivers' response to PSC 2-15.

b. During one of the negotiating sessions with Century, Big Rivers offered to Century the option to purchase or lease the Coleman plant. Century has shown no interest in a lease arrangement.

c. Century continues to perform its due diligence on the Coleman plant and at the time of this response it has not engaged in any further discussions with Big Rivers regarding the purchase of Coleman.

Witness) Robert W. Berry

Item 31) *Refer to BREC's response to PSC 2-16 at p. 8*

a. Produce all documents and workpapers (in electronic machine-readable format with formulas intact) regarding the long-term quote Big Rivers provided Gerdau.

b. Produce all communications between Gerdau and BREC regarding the long-term quote Big Rivers provided Gerdau.

Response) Big Rivers objects to this request on the grounds that it is overly broad and unduly burdensome. Big Rivers also objects to this request on the grounds that it seeks information that is neither relevant nor likely to lead to the discovery of admissible evidence.

Witness) Robert W. Berry

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
Confidential Markings Removed – July 18, 2019

Item 32) *Refer to BREC's response to PSC 2-16 at p. 10.*

a. Produce all documents and workpapers (in electronic machine-readable format with formulas intact) regarding the potential lease or sale of generating assets to Goldman Sachs.

b. Produce all communications between Goldman Sachs and BREC regarding the potential lease or sale of generating assets to Goldman Sachs.

Response) Big Rivers objects to this request on the grounds that it is overly broad and unduly burdensome. Big Rivers also objects to this request on the grounds that it seeks information that is neither relevant nor likely to lead to the discovery of admissible evidence.

Witness) Robert W. Berry