Big Rivers Electric Corporation
Case No. 2009-00040
Historical Test Period Filing Requirements
and Table of Contents

Exhibit No.	Volume No(s).	Description	Filing Requirement	Sponsoring Witness(es)
1	1	*A statement of the reason the adjustment is required.*	807 KAR 5:001 Section 10(1)(a)1	C. William Blackburn
2	1	*A statement that the utility's annual reports, including the annual report for the most recent calendar year, are on file with the Commission in accordance with 807 KAR 5:006, Section 3(1).*	807 KAR 5:001 Section 10(1)(a)2	C. William Blackburn
3	1	*If the utility is incorporated, a certified copy of the utility's articles of incorporation and all amendments thereto or all out-of-state documents of similar import. If the utility's articles of incorporation and amendments have already been filed with the commission in a prior proceeding, the application may state this fact making reference to the style and case number of the prior proceeding.*	807 KAR 5:001 Section 10(1)(a)3	C. William Blackburn
4	1	*If the utility is a limited partnership, a certified copy of the limited partnership agreement and all amendments thereto or all out-of-state documents of similar import. If the utility's limited partnership agreement and amendments have already been filed with the commission in a prior proceeding, the application may state this fact making reference to the style and case number of the prior proceeding.*	807 KAR 5:001 Section 10(1)(a)4	C. William Blackburn
5	1	*If the utility is incorporated or a is a limited partnership, a certificate of good standing or certificate of authorization dated within sixty (60) days of the date the application is filed.*	807 KAR 5:001 Section 10(1)(a)5	C. William Blackburn
6	1	*A certified copy of a certificate of assumed name as required by KRS 365.015 or a statement that such a certificate is not necessary.*	807 KAR 5:001 Section 10(1)(a)6	C. William Blackburn
7	1	*The proposed tariff in a form which complies with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed.*	807 KAR 5:001 Section 10(1)(a)7	David A. Spainhoward
8	1	*The utility's proposed tariff changes, identified in compliance with 807 KAR 5:011, shown either by:* *(a) Providing the present and proposed tariffs in comparative form on the same sheet side by side; or,* *(b) Providing a copy of the present tariff indicating proposed additions by italicized inserts or underscoring and striking over proposed deletions.*	807 KAR 5:001 Section 10(1)(a)8	David A. Spainhoward
9	1	*A statement that customer notice has been given in compliance with subsections (3) and (4) of this section with a copy of the notice.*	807 KAR 5:001 Section 10(1)(a)9	David A. Spainhoward
10	1	*Notice of Intent. Utilities with gross annual revenues greater than $1,000,000 shall file with the commission a written notice of intent to file a rate application at least four (4) weeks prior to filing their application. The notice of intent shall state whether the rate application shall be supported by a historical test period or a fully forecasted test period. This notice shall be served upon the Attorney General, Utility Intervention and Rate Division.*	807 KAR 5:001 Section 10(2)	David A. Spainhoward

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Exhibit No.	Volume No(s).	Description	Filing Requirement	Sponsoring Witness(es)
11	1	*Form of notice to customers. Every utility filing an application pursuant to this section shall notify all affected customers in the manner prescribed herein. The notice shall include the following information: (a) The amount of the change requested in both dollar amounts and percentage change for each customer classification to which the proposed rate change will apply; (b) The present rates and the proposed rates for each customer class to which the proposed rates would apply; (c) Electric, gas, water and sewer utilities shall include the effect upon the average bill for each customer class to which the proposed rate change will apply; (d) Local exchange companies shall include the effect upon the average bill for each customer class for the proposed rate change in basic local service; (e) A statement that the rates contained in this notice are the rates proposed by (name of utility); however, the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice; (f) A statement that any corporation, association, or person with a substantial interest in the m (g) A statement that any person who has been granted intervention by the commission may obta (h) A statement that any person may examine the rate application and any other filings made b (i) The commission may grant a utility with annual gross revenues greater than $1,000,000, up*	807 KAR 5:001 Section 10(3)	David A. Spainhoward
12	1	*Manner of notification. Sewer utilities shall give the required typewritten notice by mail to all of their customers pursuant to KRS 278.185.*	807 KAR 5:001 Section 10(4)(a)	David A. Spainhoward
13	1	*Manner of notification. Applicants with twenty (20) or fewer customers affected by the proposed general rate adjustment shall mail the required typewritten notice to each customer no later than the date the application is filed with the commission.*	807 KAR 5:001 Section 10(4)(b)	David A. Spainhoward
14	1	*Manner of notification. Except for sewer utilities, applicants with more than twenty (20) customers affected by the proposed general rate adjustment shall give the required notice by one (1) of the following methods: 1. A typewritten notice mailed to all customers no later than the date the application is filed with the commission; 2. Publishing the notice in a trade publication or newsletter which is mailed to all customers no later than the date on which the application is filed with the commission; or 3. Publishing the notice once a week for three (3) consecutive weeks in a prominent manner in a newspaper of general circulation in the utility's service area, the first publication to be made within seven (7) days of the filing of the application with the commission.*	807 KAR 5:001 Section 10(4)(c)	David A. Spainhoward
15	1	*Manner of notification. If the notice is published, an affidavit from the publisher verifying the notice was published, including the dates of the publication with an attached copy of the published notice, shall be filed with the commission no later than forty-five (45) days of the filed date of the application.*	807 KAR 5:001 Section 10(4)(d)	David A. Spainhoward

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Exhibit No.	Volume No(s).	Description	Filing Requirement	Sponsoring Witness(es)
32	1	*A list of all commercially available or in-house developed computer software, programs, and models used in the development of the schedules and work papers associated with the filing of the utility's application. This list shall include each software, program, or model; what the software, program, or model was used for; identify the supplier of each software, program, or model; a brief description of the software, program, or model; the specifications for the computer hardware and the operating system required to run the program.*	807 KAR 5:001 Section 10(6)(o)	C. William Blackburn
33	1	*Prospectuses of the most recent stock or bond offerings.*	807 KAR 5:001 Section 10(6)(p)	C. William Blackburn
34	1	*Annual report to shareholders, or members, and statistical supplements covering the two (2) most recent years from the utility's application filing date.*	807 KAR 5:001 Section 10(6)(q)	C. William Blackburn
35	1	*The monthly management reports providing financial results of operations for the twelve (12) months in the test period.*	807 KAR 5:001 Section 10(6)(r)	C. William Blackburn
36	1	*Securities and Exchange Commission's annual report for the most recent two (2) years, Form 10-Ks and any Form 8-Ks issued within the past two (2) years, and Form 10-Qs issued during the past six (6) quarters updated as current information becomes available.*	807 KAR 5:001 Section 10(6)(s)	C. William Blackburn
37	2	*If the utility had any amounts charged or allocated to it by an affiliate or general or home office or paid any monies to an affiliate or general or home office during the test period or during the previous three (3) calendar years, the utility shall file:* *1. A detailed description of the method and amounts allocated or charged to the utility by the affiliate or general or home office for each charge allocation or payment;* *2. An explanation of how the allocator for the test period was determined; and* *3. All facts relied upon, including other regulatory approval, to demonstrate that each amount charged, allocated or paid during the test period was reasonable;*	807 KAR 5:001 Section 10(6)(t)	C. William Blackburn
38	2	*If the utility provides gas, electric or water utility service and has annual gross revenues greater than $5,000,000, a cost of service study based on a methodology generally accepted within the industry and based on current and reliable data from a single time period.*	807 KAR 5:001 Section 10(6)(u)	Counsel
39	2	*Local exchange carriers with fewer than 50,000 access lines shall not be required to file cost of service studies, except as specifically directed by the commission. Local exchange carriers with more than 50,000 access lines shall file:* *1. A jurisdictional separations study consistent with Part 36 of the Federal Communications Commission's rules and regulations; and* *2. Service specific cost studies to support the pricing of all services that generate annual revenue greater than $1,000,000, except local exchange access:* *a. Based on current and reliable data from a single time period; and* *b. Using generally recognized fully allocated, embedded, or incremental cost principles.*	807 KAR 5:001 Section 10(6)(v)	C. William Blackburn
40	2	*Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:* *(a) A detailed income statement and balance sheet reflecting the impact of all proposed adjustments;*	807 KAR 5:001 Section 10(7)(a)	C. William Blackburn

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Exhibit No.	Volume No(s).	Description	Filing Requirement	Sponsoring Witness(es)
41	2	*Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:* *(b) The most recent capital construction budget containing at least the period of time as proposed for any pro forma adjustment for plant additions.*	807 KAR 5:001 Section 10(7)(b)	David A. Spainhoward
42	2	*Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:* *(c) For each proposed pro forma adjustment reflecting plant additions provide the following information:* *1. The starting date of the construction of each major component of plant;* *2. The proposed in-service date:* *3. The total estimated cost of construction at completion;* *4. The amount contained in construction work in progress at the end of the test period;* *5. A schedule containing a complete description of actual plant retirements and anticipated plant retirements related to the pro forma plant additions including the actual or anticipated date of retirement;* *6. The original cost, cost of removal and salvage for each component of plant to be retired during the period of the proposed pro forma adjustment for plant additions;* *7. An explanation of any differences in the amounts contained in the capital construction budg* *8. The impact on depreciation expense of all proposed pro forma adjustments for plant additio*	807 KAR 5:001 Section 10(7)(c)	C. William Blackburn
43	2	*Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:* *(d) The operating budget for each period encompassing the pro forma adjustments.*	807 KAR 5:001 Section 10(7)(d)	C. William Blackburn
44	2	*Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:* *(e) The number of customers to be added to the test period-end level of customers and the related revenue requirements impact for all pro forma adjustments with complete details and supporting work papers.*	807 KAR 5:001 Section 10(7)(e)	C. William Blackburn
45	2	*Direct Testimony of Mark A. Bailey*		
46	2	*Direct Testimony of William Steven Seelye*		
47	2	*Direct Testimony of C. William Blackburn*		

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EXHIBIT 37

Filing Requirement
807 KAR 5:001 Section 10(6)(t)
Sponsoring Witness: C. William Blackburn

Description of Filing Requirement:

If the utility had any amounts charged or allocated to it by an affiliate or general or home office or paid any monies to an affiliate or general or home office during the test period or during the previous three (3) calendar years, the utility shall file:

1. A detailed description of the method and amounts allocated or charged to the utility by the affiliate or general or home office for each charge allocation or payment;

2. An explanation of how the allocator for the test period was determined; and

3. All facts relied upon, including other regulatory approval, to demonstrate that each amount charged, allocated or paid during the test period was reasonable;

Response:

Big Rivers has one affiliate – Big Rivers Leasing Corp – which was established in connection with the leveraged lease agreements which have now been terminated. Big Rivers intends to dissolve this subsidiary in 2009 subsequent to receiving an order in the Unwind proceeding. Big Rivers is charged a small amount of direct expenses from this subsidiary and is not subject to any further allocation of costs. In 2008, Big Rivers was charged $8,500 in direct expenses (telephone, labor, office supplies, etc.) by Big Rivers Leasing Corp.

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EXHIBIT 38

Filing Requirement
807 KAR 5:001 Section 10(6)(u)
Sponsoring Witness: Counsel

<u>Description of Filing Requirement:</u>

If the utility provides gas, electric or water utility service and has annual gross revenues greater than $5,000,000, a cost of service study based on a methodology generally accepted within the industry and based on current and reliable data from a single time period.

<u>Response:</u>

Big Rivers has requested a waiver of this filing requirement in the Notice and Application. Also see Direct Testimony of William Steven Seelye.

Big Rivers Electric Corporation
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EXHIBIT 39

Filing Requirement
807 KAR 5:001 Section 10(6)(v)
Sponsoring Witness: C. William Blackburn

Description of Filing Requirement:

Local exchange carriers with fewer than 50,000 access lines shall not be required to file cost of service studies, except as specifically directed by the commission. Local exchange carriers with more than 50,000 access lines shall file:

1. A jurisdictional separations study consistent with Part 36 of the Federal Communications Commission's rules and regulations; and

2. Service specific cost studies to support the pricing of all services that generate annual revenue greater than $1,000,000, except local exchange access:

a. Based on current and reliable data from a single time period; and

b. Using generally recognized fully allocated, embedded, or incremental cost principles.

Response:

Big Rivers is not a local exchange carrier.

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EXHIBIT 40

Filing Requirement
807 KAR 5:001 Section 10(7)(a)
Sponsoring Witness: C. William Blackburn

Description of Filing Requirement:

Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(a) A detailed income statement and balance sheet reflecting the impact of all proposed adjustments;

Response:

A detailed statement of operations (income statement), balance sheet and statement of cash flows (direct method, statement of operations format), reflecting the impact of all proposed adjustments, are attached hereto. The historical test period is the 12 months ended November 30, 2008. Also, please note that because Big Rivers' rate request is based on the cash needs approach, the statement of cash flows is also included.

Big Rivers Electric Corporation

1	**Statement of Cash Flows (Direct format)**	**Historical Period***	**Difference**	**Schedule 1.XX**	**Proforma**
2	Electric Energy Revenues	213,622,001	(19,330,507)	11,13	194,291,494
3	Income From Leased Property (Net)	42,105,193	(2,410,574)	1,2	39,694,620
4	Other Operating Revenue and Income	10,072,208	5,447,094	11	15,519,302
5	Total Oper. Revenues & Patronage Capital	**265,799,402**	**(16,293,987)**		**249,505,415**
6	Operating Expense - Production - Excluding Fuel	0	0		0
7	Operating Expense - Production - Fuel	0	0		0
8	Operating Expense - Other Power Supply	(120,476,897)	(3,027,208)	11	(123,504,105)
9	Operating Expense - Transmission**	(9,256,799)	403,983	8,11	(8,852,816)
10	Operating Expense - Distribution	0	0		0
11	Operating Expense - Customer Accounts	0	0		0
12	Operating Expense - Customer Service & Information	(732,757)	0		(732,757)
13	Operating Expense - Sales	(611,486)	160,225	7	(451,261)
14	Operating Expense - Administrative & General	(17,657,990)	6,949,786	2,7,8,9,10	(10,708,204)
15	Total Operation Expense	**(148,735,928)**	**4,486,786**		**(144,249,142)**
16	Maintenance Expense - Production	0	0		0
17	Maintenance Expense - Transmission	(3,848,315)	0		(3,848,315)
18	Maintenance Expense - Distribution	0	0		0
19	Maintenance Expense - General Plant	(232,061)	0		(232,061)
20	Total Maintenance Expense	**(4,080,376)**	**0**		**(4,080,376)**
21	Depreciation and Amortization Expense	0	0		0
22	Taxes	(2,282,460)	1,240,000	5	(1,042,460)
23	Interest on Long-Term Debt	(58,294,657)	(4,648,034)	4	(62,942,691)
24	Interest Charged to Construction - Credit	0	0		0
25	Other Interest Expense	(8,826)	0		(8,826)
26	Asset Retirement Obligation	0	0		0
27	Other Deductions	(74,337)	72,916	7	(1,421)
28	Total Cost of Electric Service	**(213,476,583)**	**1,151,667**		**(212,324,916)**
29	Operating Margins	**52,322,819**	**(15,142,319)**		**37,180,499**
30	Interest Income	4,630,505	(4,450,070)	12	180,435
31	Allowance for Funds Used During Construction	0	0		0
32	Income (Loss) from Equity Investments	0	0		0
33	Other Non-operating Income (Net)	0	0		0
34	Generation & Transmission Capital Credits	0	0		0
35	Other Capital Credits and Patronage Dividends	390,656	(389,250)	6	1,406
36	Extraordiary Items	0	0		0
37	Net Patronage Capital or Margins	**57,343,980**	**(19,981,639)**		**37,362,341**
38					
39	Capital Expenditures	(21,417,957)	(978,126)	3	(22,396,083)
40	Special Funds	92,937	0		92,937
41	Principal Payments	(40,834,358)	873,452	4	(39,960,906)
42	Leveraged Lease Termination	(107,119,580)	107,119,580	6	0
43	Net Increase/(Decrease in Cash and Cash Equivalents	**(111,934,978)**	**87,033,267**		**(24,901,711)**
44	Cash and Cash Equivalents - Beginning of Period	**147,496,732**			
45	Cash and Cash Equivalents - End of Period	**35,561,754**			

* The historical test period is the 12 months ended 11/30/2008.

** O&M expense, excl. Other Power Supply, accrual to cash adjustments reflected in Transmission Operations.

Summary of Revenue (Decifiency):	
Historical Test Period Revenue (Deficiency)	(111,934,978)
Proforma Adjustments made to Statement of Operations	(26,109,372)
Proforma Adjustments made only to Balance Sheet	444,164
Proforma Adjustments already reflected in Balance Sheet	112,698,475
Total Proforma Adjustments per Statement of Cash Flows	87,033,267
Resulting Proforma Revenue (Deficiency)	(24,901,711)

Exhibit 40 KAR 5:001 Section 10(7)(a)
Sponsoring Witness: Blackburn

Big Rivers Electric Corporation

		Historical Period*	Difference	Schedule 1.XX	Proforma
1	**Balance Sheet**				
2	**Assets And Other Debits**				
3	Total Utility Plant in Service	1,763,852,827	978,126	Note 2	1,764,830,953
4	Construction Work in Progress	24,939,129	0		24,939,129
5	Total Utility Plant	1,788,791,957	978,126		1,789,770,083
6	Accum. Provision for Depreciation and Amort.	877,406,098	0		877,406,098
7	Net Utility Plant	911,385,858	978,126		912,363,984
8	Non-Utility Property (Net)	0	0		0
9	Investments in Subsidiary Companies	0	0		0
10	Invest. In Assoc. Org. - Patronage Capital	3,384,781	0		3,384,781
11	Invest. In Assoc. Org. - Other - General Funds	684,993	0		684,993
12	Invest. In Assoc. Org. - Other - Nongeneral Funds	0	0		0
13	Investments in Economic Development Projects	10,000	0		10,000
14	Other Investments	5,334	0		5,334
15	Special Funds	497,103	0		497,103
16	Total Other Property and Investments	4,582,211	0		4,582,211
17	Cash - General Funds	52,229	0		52,229
18	Cash - Construction Funds - Trustee	0	0		0
19	Special Deposits	569,779	0		569,779
20	Temporary Investments	34,939,746	0		34,939,746
21	Notes Receivable (Net)	0	0		0
22	Accounts Receivable - Sales of Energy (Net)	16,525,975	(16,293,987)	Note 1	231,988
23	Accounts Receivable - Other (Net)	2,557,736	0		2,557,736
24	Fuel Stock	0	0		0
25	Materials and Supplies - Other	685,331	0		685,331
26	Prepayments	3,931,415	0		3,931,415
27	Other Current and Accrued Assets	551,014	0		551,014
28	Total Current and Accrued Assets	59,813,225	(16,293,987)		43,519,238
29	Unamortized Debt Discount & Extraor. Prop. Losses	739,786	0		739,786
30	Regulatory Assets	0	0		0
31	Other Deferred Debits	94,253,482	0		94,253,482
32	Accumulated Deferred Income Taxes	6,332,491	0		6,332,491
33	Total Assets and Other Debits	1,077,107,054	(15,315,861)		1,061,791,193
34	**Liabilities and Other Credits**				
35	Memberships	75	0		75
36	Patronage Capital	0	0		0
37	Operating Margins - Prior Years	(267,578,826)	(26,109,372)	Note 1	(293,688,198)
38	Operating Margin - Current Year	22,879,721	0		22,879,721
39	Non-Operating Margins	99,445,587	0		99,445,587
40	Other Margins and Equities	4,444,502	0		4,444,502
41	Total Margins & Equities	(140,808,940)	(26,109,372)		(166,918,312)
42	Long-Term Debt - RUS (Net)	867,491,416	873,452	Note 2	868,364,868
43	Long-Term Debt - Other (Net)	170,185,135	0		170,185,135
44	Total Long-Term Debt	1,037,676,551	873,452		1,038,550,003
45	Accumulated Operating Provisions and Asset Retirement Obligations	3,498,828	0		3,498,828
46	Total Other Noncurrent Liabilities	3,498,828	0		3,498,828
47	Notes Payable	0	0		0
48	Accounts Payable	12,699,394	9,371,221	Note 1 and 2	22,070,615
49	Current Maturities Long-Term Debt	0	0		0
50	Taxes Accrued	805,592	0		805,592
51	Interest Accrued	7,872,071	548,838	Note 2	8,420,909
52	Other Current and Accrued Liabilities	1,765,587	0		1,765,587
53	Total Current & Accrued Liabilities	23,142,644	9,920,059		33,062,703
54	Deferred Credits	153,597,971	0		153,597,971
55	Accumulated Deferred Income Taxes	0	0		0
56	Total Liabilities and Other Credits	1,077,107,054	(15,315,861)		1,061,791,193

* The historical test period ended 11-30-2008.

	Debit	Credit	Exhibit Seelye-2 key
Note 1: Proforma Adjustment Post-Closing Entry			
Margins and Equities	26,109,372		
Accounts Receivable		16,293,987	
Accounts Payable		9,815,385	
Note 2: Proforma Adjustments made only to Balance Sheet			
Accounts Payable	444,164		
Total Utility Plant in Service	978,126		Schedule 1.03
Long-Term Debt		873,452	Schedule 1.04
Interest Accrued on Long-Term Debt		548,838	Schedule 1.05

Exhibit 40 KAR 5:001 Section 10(7)(a)
Sponsoring Witness: Blackburn

Big Rivers Electric Corporation

		Historical Period*	Difference	Schedule 1.XX	Proforma
1	**Statement of Operations - $**				
2	Electric Energy Revenues	208,542,899	(19,330,507)	11,13	189,212,392
3	Income From Leased Property (Net)	29,507,988	(2,410,574)	1,2	27,097,414
4	Other Operating Revenue and Income	10,157,117	5,447,094	11	15,604,211
5	Total Oper. Revenues & Patronage Capital	248,208,004	(16,293,987)		231,914,018
6	Operating Expense - Production - Excluding Fuel	0	0		0
7	Operating Expense - Production - Fuel	0	0		0
8	Operating Expense - Other Power Supply	116,147,238	3,027,208	11	119,174,446
9	Operating Expense - Transmission	7,458,458	(403,983)	8,11	7,054,475
10	Operating Expense - Distribution	0	0		0
11	Operating Expense - Customer Accounts	0	0		0
12	Operating Expense - Customer Service & Information	732,757	0		732,757
13	Operating Expense - Sales	611,486	(160,225)	7	451,261
14	Operating Expense - Administrative & General	17,657,990	(3,650,207)	2,7,8,9,10	14,007,783
15	Total Operation Expense	142,607,928	(1,187,207)		141,420,721
16	Maintenance Expense - Production	0	0		0
17	Maintenance Expense - Transmission	3,848,315	0		3,848,315
18	Maintenance Expense - Distribution	0	0		0
19	Maintenance Expense - General Plant	232,061	0		232,061
20	Total Maintenance Expense	4,080,376	0		4,080,376
21	Depreciation and Amortization Expense	5,128,247	0		5,128,247
22	Taxes	1,119,847	0		1,119,847
23	Interest on Long-Term Debt	75,351,567	(4,881,041)	4,6	70,470,525
24	Interest Charged to Construction - Credit	(538,129)	0		(538,129)
25	Other Interest Expense	8,826	0		8,826
26	Asset Retirement Obligation	0	0		0
27	Other Deductions	(1,638,949)	1,693,964	6,7	55,016
28	Total Cost of Electric Service	226,119,713	(4,374,284)		221,745,429
29	Operating Margins	22,088,291	(11,919,703)		10,168,588
30	Interest Income	13,591,604	(13,411,169)	6,12	180,435
31	Allowance for Funds Used During Construction	0	0		0
32	Income (Loss) from Equity Investments	0	0		0
33	Other Non-operating Income (Net)	0	0		0
34	Generation & Transmission Capital Credits	0	0		0
35	Other Capital Credits and Patronage Dividends	791,430	(778,500)	6	12,930
36	Extraordinary Items	0	0		0
37	Net Patronage Capital or Margins	36,471,325	(26,109,372)		10,361,953

* The historical test period is the 12 months ended 11/30/2008.

Big Rivers Electric Corporation
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EXHIBIT 41

Filing Requirement
807 KAR 5:001 Section 10(7)(b)
Sponsoring Witness: David A. Spainhoward

Description of Filing Requirement:

Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(b) The most recent capital construction budget containing at least the period of time as proposed for any pro forma adjustment for plant additions.

Response:

See the Direct Testimony of David A. Spainhoward, particularly Exhibit Spainhoward-1.

Big Rivers Electric Corporation
Case No. 2009-00040
Historical Test Period Filing Requirements

EXHIBIT 42

Filing Requirement
807 KAR 5:001 Section 10(7)(c)
Sponsoring Witness: C. William Blackburn

Description of Filing Requirement:

Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(c) For each proposed pro forma adjustment reflecting plant additions provide the following information:

1. The starting date of the construction of each major component of plant;

2. The proposed in-service date;

3. The total estimated cost of construction at completion;

4. The amount contained in construction work in progress at the end of the test period;

5. A schedule containing a complete description of actual plant retirements and anticipated plant retirements related to the pro forma plant additions including the actual or anticipated date of retirement;

6. The original cost, cost of removal and salvage for each component of plant to be retired during the period of the proposed pro forma adjustment for plant additions;

Big Rivers Electric Corporation
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Historical Test Period Filing Requirements

EXHIBIT 42

Filing Requirement
807 KAR 5:001 Section 10(7)(c)
Sponsoring Witness: C. William Blackburn

Description of Filing Requirement (continued):

7. An explanation of any differences in the amounts contained in the capital construction budget and the amounts of capital construction cost contained in the pro forma adjustment period; and

8. The impact on depreciation expense of all proposed pro forma adjustments for plant additions and retirements;

Response:

See attached.

BIG RIVERS ELECTRIC CORPORATION
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1. See PRO FORMA ADDITIONS Work Paper for the construction starting date of each major component of plant.

2. See PRO FORMA ADDITIONS Work Paper for the proposed in-service date of major components of plant.

3. See PRO FORMA ADDITIONS Work Paper for total estimated cost of construction at completion.

4. See PRO FORMA ADDITIONS Work Paper for the contruction work in progress at the end of the test period, 11/30/08.

5. See PRO FORMA RETIREMENTS Work Paper for schedule containing complete description of anticipated plant retirements related to the pro forma plant additions including the anticipated date of retirement.

6. See PRO FORMA RETIREMENTS Work Paper for the original cost, cost of removal and salvage for each component of plant to be retired during the period of the proposed pro forma adjustment for plant additions.

7. The pro forma amount for the 2009 Transmission and A&G budget is $14,331,923, the amount of the 2008 capital expenditures. The actual 2009 Transmission and A&G construction budget is $16,436,813, but Big Rivers is requesting only the amount of the 2008 expenditures.

8. The impact of depreciation expense for plant additions is $97,855 (Additions Work Paper) and retirements is $79,545 (Retirements Work Paper) for a total depreciation expense impact of $177,400.

BIG RIVERS ELECTRIC CORPORATION
Case No. 2009-00040
Filing Requirement 807 KAR 5:001 Section 10(7)(c)

PRO FORMA ADDITIONS

		Item #1	Item #2	Item #3	Item #4	Item #8 (Partial)
					Test Period	Additions
1		Starting	In-Service	Cost @	CWIP	Deprec Exp
2	Project Description	Date	Date	Completion	11/30/08	2009
3	Non-Incremental Construction					
4	COLEMAN:					
5	Capital Valve Replacements	Jan-09	Jan-09	10,000	0	165
6		Mar-09	Mar-09	20,000	0	270
7	Conductor license	Feb-09	Feb-09	15,000	0	220
8	C3 DCS Sequence of Events	Jan-09	Jul-09	65,000	0	485
9	C3 monitor replacement	Jan-09	Jan-09	12,000	0	198
10	C3 DCS power supplies	Jan-09	Jan-09	70,000	0	1,144
11	C3 DCS controllers replace	Jan-09	Jan-09	65,000	0	1,067
12	Underground natural gas line	Jan-09	Jan-09	150,000	0	2,464
13	GREEN:					
14	Capital Valve Replacements	Feb-09	Feb-09	25,000	0	370
15	G2 supervisory turbine controls	Mar-09	May-09	35,000	0	336
16	G2 precipitator field	Mar-09	Oct-09	100,000	0	316
17	G1 thickener rake drive	Mar-09	Apr-09	50,000	0	632
18	G2 thickener rake drive	Mar-09	Apr-09	50,000	0	632
19	G2 inlet scrubber operator	Mar-09	Mar-09	7,000	0	99
20	G2 flyash hopper	Feb-09	May-09	500,000	0	5,516
21	G2 air heater gas outlet exp joints	Feb-09	Apr-09	200,000	0	2,384
22	G2 west superheater spray	Feb-09	Apr-09	150,000	0	1,792
23	G2 west superheater spray attmp	Feb-09	Feb-09	45,000	0	670
24	G2 turbine packing HP-IP rows	Feb-09	May-09	50,000	0	483
25	G2 generator retaining rings	Feb-09	Apr-09	500,000	0	5,536
26	G2 air heater baskets	Feb-09	May-09	495,000	0	5,173
27	G2 reheater tubes	Feb-09	May-09	600,000	0	6,265
28	Upgrade CMS	Jan-09	Jan-09	75,000	0	1,298
29	Coal hdlg control replace	Mar-09	Apr-09	100,000	0	1,192
30	Server replace	Mar-09	Mar-09	10,000	0	135
31	G2 DA trays	Jan-09	Jan-09	25,000	0	407
32	G2 steam coils (4)	Jan-09	Jan-09	75,000	0	1,232
33	Cooling tower fan shroud	Jan-09	Jan-09	216,000	0	3,289
34	Bottom ash controls-2010	Mar-09	2010	16,000	0	0
35	WILSON:					
36	Capital Valve Replacements	Feb-09	Feb-09	25,000	0	370
37	Magnetic separater #4 replace	Feb-09	Feb-09	52,000	0	780
38	ME panel replace	Feb-09	Feb-09	350,000	0	5,510
39	Filtrate transfer pumps replace (4)	Feb-09	Feb-09	40,000	0	600
40	480V breakers (5) replace	Feb-09	Feb-09	90,000	0	1,200
41	Slurry recirc motor replace	Mar-09	Mar-09	112,000	0	1,584
42	Discharge pump #4 replace	Feb-09	Feb-09	40,000	0	600
43	Wastewater/impoundment pond pump	Feb-09	Feb-09	60,000	0	900
44	Flyash blower #1	Feb-09	Feb-09	50,000	0	790
45	Reverse osmosis water trmt sys	Feb-09	Feb-09	450,000	0	6,710
46	Cooling tower fan replace (3)	Feb-09	Feb-09	200,000	0	2,770
47	FGD pump house replace	Feb-09	Feb-09	125,000	0	1,970
48	TR and rapper precipitator control	Feb-09	Feb-09	250,000	0	3,940
49	PA fan silencers	Feb-09	Feb-09	130,000	0	1,940
50	Engineering	Mar-09		100,000	0	0
51	Electrical refurbish (phase 1 of 4)	Feb-09		300,000	0	0
52	Misc controls and transmitters	Feb-09	Feb-09	10,000	0	150
53	REID/HMPL:					
54	H1 CCS field wiring and devices	Feb-09	Apr-09	41,230	0	496
55	H1 Temperature reheater tubes	Mar-09	Mar-09	714,770	0	9,594
56	Total Non-Incremental Construction			6,871,000	0	83,674
57	Incremental Construction-Post CAIR					
58	Coleman boiler tube metal overlays	May-09	Jun-09	250,000	0	2,364
59	Green boiler tube metal overlays	Mar-09	May-09	520,000	0	5,733
60	HMP&L SCR catalyst	Feb-09	Mar-09	61,160	0	864
61	Green O2 Probes (12)	Mar-09	May-09	72,000	0	791
62	Wilson Catalyst	Feb-09	Feb-09	260,000	0	4,100
63	Green Air Shroud Actuators	Mar-09	May-09	30,000	0	329
64	Total Incremental Construction			1,193,160	0	14,181
65	TOTAL PRO FORMA ADDITIONS			8,064,160	0	97,855

BIG RIVERS ELECTRIC CORPORATION
Case No. 2009-00040
Filing Requirement 807 KAR 5:001 Section 10(7)(c)

PRO FORMA RETIREMENTS

		Item #5			Item #6		Item #8 (Partial)
	Project Description	Anticipated Retirement	Anticipated Ret Date	Retirement Amount	Removal	Salvage	Retirement Deprec Exp 2009
3	**Non-Incremental Construction**						
4	COLEMAN:						
5	Capital Valve Replacements	Capital valves	Jan-09	5,000	0	0	7
6		Capital valves	Mar-09	10,000	0	0	45
7	Conductor license	No retirement					0
8	C3 DCS Sequence of Events	C3 DCS Sequence of Events	Jul-09	41,224	0	0	434
9	C3 monitor replacement	"	Jan-09	(Included in	0	0	(Included in
10	C3 DCS power supplies	"	Jan-09	$41,224	0	0	41,224
11	C3 DCS controllers replace	"	Jan-09	above)	0	0	above)
12	Underground natural gas line	Underground natural gas line	Jan-09	22,663	0	0	34
13	GREEN:						
14	Capital Valve Replacements	Capital valves	Feb-09	12,500	0	0	38
15	G2 supervisory turbine controls	G2 supervisory turbine controls	May-09	75,635	0	0	525
16	G2 precipitator field	G2 precipitator field	Oct-09	417,266	0	0	6,570
17	G1 thickener rake drive	G1 thickener rake drive	Apr-09	71,750	0	0	452
18	G2 thickener rake drive	G2 thickener rake drive	Apr-09	33,381	0	0	212
19	G2 inlet scrubber operator	G2 inlet scrubber operator	Mar-09	None	0	0	0
20	G2 flyash hopper	G2 flyash hopper	May-09	458,993	0	0	3,615
21	G2 air heater gas outlet exp joints	G2 air heater gas outlet exp joints	Apr-09	125,180	0	0	748
22	G2 west superheater spray	G2 west superheater spray	Apr-09	114,849	0	0	684
23	G2 west superheater spray attmp	G2 west superheater spray attmp	Feb-09	18,777	0	0	56
24	G2 turbine packing HP-IP rows	G2 turbine packing HP-IP rows	May-09	122,652	0	0	850
25	G2 generator retaining rings	G2 generator retaining rings	Apr-09	278,011	0	0	1,536
26	G2 air heater baskets	G2 air heater baskets	May-09	390,151	0	0	2,910
27	G2 reheater tubes	G2 reheater tubes	May-09	438,130	0	0	3,270
28	Upgrade CMS	No retirement					0
29	Coal hdlg control replace	Coal handling control	Apr-09	62,590	0	0	372
30	Server replace	Server	Mar-09	3,300	0	0	15
31	G2 DA trays	G2 DA trays	Jan-09	10,432	0	0	16
32	G2 steam coils (4)	G2 steam coils (4)	Jan-09	31,295	0	0	47
33	Cooling tower fan shroud	Cooling tower fan shroud	Jan-09	88,309	0	0	122
	Bottom ash controls-2010	Retirement in 2010					
	WILSON:						
36	Capital Valve Replacements	Capital valves	Feb-09	12,500	0	0	38
37	Magnetic separater #4 replace	Magnetic separater #4	Feb-09	24,784	0	0	74
38	ME panel replace	ME panel	Feb-09	185,953	0	0	586
39	Filtrate transfer pumps replace (4)	Filtrate transfer pumps (4)	Feb-09	14,203	0	0	42
40	480V breakers (5) replace	480V breakers (5)	Feb-09	43,381	0	0	116
41	Slurry recirc motor replace	Slurry recirc motor	Mar-09	53,986	0	0	255
42	Discharge pump #4 replace	Discharge pump #4	Feb-09	19,281	0	0	58
43	Wastewater/impoundment pond pump	Wastewater/impoundment pond pump	Feb-09	20,810	0	0	62
44	Flyash blower #1	Flyash blower #1	Feb-09	55,947	0	0	176
45	Reverse osmosis water trmt sys	Reverse osmosis water trmt sys	Feb-09	69,820	0	0	208
46	Cooling tower fan replace (3)	Cooling tower fan (3)	Feb-09	93,554	0	0	258
47	FGD pump house replace	FGD pump house	Feb-09	60,252	0	0	190
48	TR and rapper precipitator control	TR and rapper precipitator control	Feb-09	158,744	0	0	500
49	PA fan silencers	PA fan silencers	Feb-09	62,662	0	0	186
50	Engineering	No retirement					0
51	Electrical refurbish (phase 1 of 4)	No retirement					0
52	Misc controls and transmitters	No retirement					0
53	REID/HMPL:						
54	H1 CCS field wiring and devices	No retiement					0
55	H1 Temperature reheater tubes	No retirement					0
56	**Total Non-Incremental Construction**			**3,707,965**	**0**	**0**	**66,531**
57	**Incremental Construction-Post CAIR**						
58	Coleman boiler tube metal overlays	None	Jun-09	0	0	0	0
59	Green boiler tube metal overlays	None	May-09	0	0	0	0
60	HMP&L SCR catalyst	Catalyst	Mar-09	894,019	0	0	4,224
61	Green O2 Probes (12)	(12) O2 probes	May-09	243,660	0	0	1,919
62	Wilson Catalyst	Catalyst	Feb-09	1,891,840	0	0	5,959
63	Green Air Shroud Actuators	Actators	May-09	115,737	0	0	911
	Total Incremental Construction			**3,145,256**	**0**	**0**	**13,014**
65	**TOTAL PRO FORMA RETIREMENTS**			**6,853,221**	**0**	**0**	**79,545**

Big Rivers Electric Corporation
Case No. 2009-00040
Historical Test Period Filing Requirements

EXHIBIT 43

Filing Requirement
807 KAR 5:001 Section 10(7)(d)
Sponsoring Witness: C. William Blackburn

Description of Filing Requirement:

Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(d) The operating budget for each period encompassing the pro forma adjustments.

Response:

Big Rivers' 2008 and 2009 operating budgets (statement of operations or statement of revenues and expenses), with monthly detail, are attached hereto.

BIG RIVERS ELECTRIC CORPORATION
STATEMENT OF REVENUES AND EXPENSES

2009 BUDGET -- MONTHLY TRANSACTIONS

	JAN 2009	FEB 2009	MAR 2009	APR 2009	MAY 2009	JUN 2009	JUL 2009	AUG 2009	SEP 2009	OCT 2009	NOV 2009	DEC 2009	YEAR 2009
1. ELECTRIC ENERGY REVENUES	19,458,556	17,741,401	16,576,237	15,913,980	15,842,370	16,168,006	17,518,565	16,659,376	15,709,721	16,165,101	15,698,988	17,307,819	200,760,120
2. INCOME FROM LEASED PROPERTY - NET	2,516,592	2,509,740	2,482,525	2,420,710	2,391,049	2,371,295	2,387,861	2,383,687	2,363,120	2,407,754	2,385,481	2,391,384	29,011,198
3. OTHER OPERATING REVENUE AND INCOME	1,297,740	1,297,125	1,297,275	1,297,740	1,297,125	1,297,674	1,298,439	1,297,674	1,297,674	1,298,289	1,302,674	1,299,670	15,579,099
4. TOTAL OPER REVENUES & PATRONAGE CAPITAL	23,272,888	21,548,266	20,356,037	19,632,430	19,530,544	19,836,975	21,204,865	20,340,737	19,370,515	19,871,144	19,387,143	20,998,873	245,350,417
5. OPERATION EXPENSE-PRODUCTION-EXCL FUEL	0	0	0	0	0	0	0	0	0	0	0	0	0
6. OPERATION EXPENSE-PRODUCTION-FUEL	0	0	0	0	0	0	0	0	0	0	0	0	0
7. OPERATION EXPENSE-OTHER POWER SUPPLY	12,772,511	11,099,127	9,659,274	9,132,916	9,284,622	9,683,177	11,593,961	11,332,342	9,630,992	9,679,981	9,367,998	10,034,495	123,271,396
8. OPERATION EXPENSE-TRANSMISSION	605,526	754,502	647,244	623,842	583,144	619,374	633,033	573,208	622,989	576,297	573,962	614,147	7,427,268
11. CONSUMER SERVICE & INFORMATIONAL EXPENSE	63,448	58,756	81,817	68,222	60,715	60,074	69,377	61,820	70,126	61,101	59,108	68,508	783,072
12. OPERATION EXPENSE-SALES	53,457	53,929	157,432	148,929	287,123	149,880	151,289	145,625	151,768	148,457	156,009	148,914	1,752,812
13. OPERATION EXPENSE-ADMINISTRATIVE & GENERAL	1,271,372	1,176,744	1,608,319	1,462,654	1,328,925	1,029,858	1,630,033	940,696	1,400,724	1,034,391	1,026,379	1,135,555	15,045,650
14. TOTAL OPERATION EXPENSE	14,766,314	13,143,058	12,154,086	11,436,563	11,544,529	11,542,363	14,077,693	13,053,691	11,876,599	11,500,227	11,183,456	12,001,619	148,280,198
15. MAINTENANCE EXPENSE-PRODUCTION	0	0	0	0	0	0	0	0	0	0	0	0	0
16. MAINTENANCE EXPENSE-TRANSMISSION	464,498	440,857	396,799	420,685	398,012	391,043	464,137	380,391	631,267	396,657	386,830	432,309	5,203,485
18. MAINTENANCE EXPENSE-GENERAL PLANT	26,707	15,339	15,511	12,993	14,319	25,861	12,298	12,177	13,928	10,777	10,522	11,460	181,892
19. TOTAL MAINTENANCE EXPENSE	491,205	456,196	412,310	433,678	412,331	416,904	476,435	392,568	645,195	407,434	397,352	443,769	5,385,377
20. DEPRECIATION & AMORTIZATION EXPENSE	471,689	471,906	479,125	480,088	480,324	480,552	481,354	486,017	486,102	489,001	489,135	490,462	5,785,755
21. TAXES	92,161	92,161	92,161	92,161	92,161	92,161	92,161	92,161	92,161	92,161	92,161	92,160	1,105,931
22. INTEREST ON LONG-TERM DEBT	6,196,100	6,211,110	6,190,640	4,950,850	5,107,780	4,948,850	5,074,170	5,072,490	4,914,670	5,015,130	4,857,070	4,968,490	63,507,350
23. INTEREST CHARGED TO CONSTRUCTION-CREDIT	(43,990)	(47,720)	(36,160)	(36,220)	(37,030)	(40,020)	(35,480)	(39,480)	(40,230)	(44,110)	(64,210)	(67,720)	(532,370)
24. OTHER INTEREST EXPENSE	600	600	600	600	600	600	610	610	610	610	610	610	7,260
25. OTHER DEDUCTIONS	364,980	342,514	363,373	360,960	354,160	354,790	356,660	353,590	354,640	360,780	355,780	353,470	4,275,697
26. TOTAL COST OF ELECTRIC SERVICE	22,339,059	20,669,825	19,656,135	17,718,680	17,954,855	17,796,200	20,523,603	19,411,647	18,329,747	17,821,233	17,311,354	18,282,860	227,815,198
27. OPERATING MARGINS	933,829	878,441	699,902	1,913,750	1,575,689	2,040,775	681,262	929,090	1,040,768	2,049,911	2,075,789	2,716,013	17,535,219
28. INTEREST INCOME	37,329	30,296	38,671	29,283	22,738	28,695	26,370	21,532	24,564	17,804	8,797	5,746	291,825
29. ALLOWANCE FOR FUNDS USED DURING CONST	0	0	0	0	0	0	0	0	0	0	0	0	0
31. OTHER NON-OPERATING INCOME - NET	0	0	0	0	0	0	0	0	0	0	0	0	0
33. OTHER CAPITAL CREDITS & PAT DIVIDENDS	0	0	546,753	0	0	0	0	0	0	0	0	0	546,753
34. EXTRAORDINARY ITEMS	0	0	0	0	0	0	0	0	0	0	0	0	0
35. NET PATRONAGE CAPITAL OR MARGINS	971,158	908,737	1,285,326	1,943,033	1,598,427	2,069,470	707,632	950,622	1,065,332	2,067,715	2,084,586	2,721,759	18,373,797

BIG RIVERS ELECTRIC CORPORATION
STATEMENT OF REVENUES AND EXPENSES

2008 BUDGET -- MONTHLY TRANSACTIONS

	JAN 2008	FEB 2008	MAR 2008	APR 2008	MAY 2008	JUN 2008
1. ELECTRIC ENERGY REVENUES	16,934,408	15,606,293	15,352,227	15,050,122	15,711,277	14,945,535
2. INCOME FROM LEASED PROPERTY - NET	2,530,264	2,523,059	2,522,068	2,433,883	2,429,913	2,425,831
3. OTHER OPERATING REVENUE AND INCOME	796,135	800,080	795,520	796,135	795,520	797,002
4. TOTAL OPER REVENUES & PATRONAGE CAPITAL	20,260,807	18,929,432	18,669,815	18,280,140	18,936,710	18,168,368
5. OPERATION EXPENSE-PRODUCTION-EXCL FUEL	0	0	0	0	0	0
6. OPERATION EXPENSE-PRODUCTION-FUEL	0	0	0	0	0	0
7. OPERATION EXPENSE-OTHER POWER SUPPLY	9,959,941	8,423,121	8,399,504	8,016,090	8,126,235	8,568,992
8. OPERATION EXPENSE-TRANSMISSION	622,208	717,216	561,289	604,022	549,029	545,260
11. CONSUMER SERVICE & INFORMATIONAL EXPENSE	67,280	60,922	62,060	67,171	62,466	58,659
12. OPERATION EXPENSE-SALES	50,018	47,705	58,805	51,405	202,830	51,385
13. OPERATION EXPENSE-ADMINISTRATIVE & GENERAL	1,261,454	1,209,694	1,125,572	1,369,621	1,233,037	1,695,533
14. TOTAL OPERATION EXPENSE	11,960,901	10,458,658	10,207,230	10,108,309	10,173,617	10,919,829
15. MAINTENANCE EXPENSE-PRODUCTION	0	0	0	0	0	0
16. MAINTENANCE EXPENSE-TRANSMISSION	356,718	278,552	281,933	346,459	297,914	285,268
18. MAINTENANCE EXPENSE-GENERAL PLANT	19,179	140,912	42,928	35,690	31,001	25,000
19. TOTAL MAINTENANCE EXPENSE	375,897	419,464	324,861	382,149	328,915	310,268
20. DEPRECIATION & AMORTIZATION EXPENSE	437,590	438,323	439,730	439,974	440,147	440,315
21. TAXES	92,777	92,777	92,777	92,777	92,777	92,777
22. INTEREST ON LONG-TERM DEBT	6,168,900	6,249,640	6,169,180	5,941,149	6,707,850	5,937,359
23. INTEREST CHARGED TO CONSTRUCTION-CREDIT	(86,730)	(97,000)	(105,120)	(73,920)	(80,990)	(88,550)
24. OTHER INTEREST EXPENSE	1,400	1,400	1,400	1,400	1,400	1,410
25. OTHER DEDUCTIONS	(240,360)	(224,120)	(239,439)	(216,738)	(224,577)	(216,738)
26. TOTAL COST OF ELECTRIC SERVICE	18,710,375	17,339,142	16,890,619	16,675,100	17,439,139	17,396,670
27. OPERATING MARGINS	1,550,432	1,590,290	1,779,196	1,605,040	1,497,571	771,698
28. INTEREST INCOME	1,643,994	1,527,569	1,650,394	1,587,924	1,630,892	1,596,641
29. ALLOWANCE FOR FUNDS USED DURING CONST	0	0	0	0	0	0
31. OTHER NON-OPERATING INCOME - NET	0	0	0	0	0	0
33. OTHER CAPITAL CREDITS & PAT DIVIDENDS	0	0	778,506	0	0	0
34. EXTRAORDINARY ITEMS	0	0	0	0	0	0
35. NET PATRONAGE CAPITAL OR MARGINS	3,194,426	3,117,859	4,208,096	3,192,964	3,128,463	2,368,339

	JUL 2008	AUG 2008	SEP 2008	OCT 2008	NOV 2008	DEC 2008	YEAR 2008
1. ELECTRIC ENERGY REVENUES	16,481,805	15,506,288	14,940,279	16,336,429	14,431,688	16,948,023	188,244,374
2. INCOME FROM LEASED PROPERTY - NET	2,426,787	2,422,497	2,396,239	2,446,207	2,402,848	2,393,565	29,353,161
3. OTHER OPERATING REVENUE AND INCOME	797,617	797,002	797,002	797,617	811,002	797,138	9,577,770
4. TOTAL OPER REVENUES & PATRONAGE CAPITAL	19,706,209	18,725,787	18,133,520	19,580,253	17,645,538	20,138,726	227,175,305
5. OPERATION EXPENSE-PRODUCTION-EXCL FUEL	0	0	0	0	0	0	0
6. OPERATION EXPENSE-PRODUCTION-FUEL	0	0	0	0	0	0	0
7. OPERATION EXPENSE-OTHER POWER SUPPLY	11,065,823	10,805,822	8,623,269	8,384,194	7,749,919	8,790,957	106,913,867
8. OPERATION EXPENSE-TRANSMISSION	581,604	537,967	543,695	587,701	540,158	587,584	6,977,733
11. CONSUMER SERVICE & INFORMATIONAL EXPENSE	67,513	59,253	59,475	67,449	59,086	67,439	758,793
12. OPERATION EXPENSE-SALES	52,793	51,405	81,630	48,168	57,418	46,773	800,335
13. OPERATION EXPENSE-ADMINISTRATIVE & GENERAL	1,145,681	1,002,175	997,289	1,174,250	914,512	1,063,692	14,192,510
14. TOTAL OPERATION EXPENSE	12,913,414	12,456,622	10,305,358	10,261,762	9,321,093	10,556,445	129,643,238
15. MAINTENANCE EXPENSE-PRODUCTION	0	0	0	0	0	0	0
16. MAINTENANCE EXPENSE-TRANSMISSION	326,162	458,204	461,614	320,664	265,063	326,520	4,005,071
18. MAINTENANCE EXPENSE-GENERAL PLANT	24,390	11,207	10,212	24,828	7,938	21,825	395,110
19. TOTAL MAINTENANCE EXPENSE	350,552	469,411	471,826	345,492	273,001	348,345	4,400,181
20. DEPRECIATION & AMORTIZATION EXPENSE	441,126	454,748	465,477	465,961	469,406	469,406	5,402,203
21. TAXES	92,777	92,777	92,777	92,777	92,777	92,776	1,113,323
22. INTEREST ON LONG-TERM DEBT	6,096,200	6,201,300	5,902,659	6,038,680	6,254,690	6,034,500	73,704,107
23. INTEREST CHARGED TO CONSTRUCTION-CREDIT	(82,360)	(43,990)	(33,600)	(36,260)	(31,950)	(33,410)	(793,880)
24. OTHER INTEREST EXPENSE	1,420	1,420	1,420	1,420	1,420	1,410	16,920
25. OTHER DEDUCTIONS	(224,577)	(224,578)	(193,557)	(204,578)	(216,737)	(224,568)	(2,650,567)
26. TOTAL COST OF ELECTRIC SERVICE	19,590,552	19,407,710	17,012,360	16,965,254	16,163,700	17,244,904	210,835,525
27. OPERATING MARGINS	115,657	(681,923)	1,121,160	2,614,999	1,481,838	2,893,822	16,339,780
28. INTEREST INCOME	1,638,648	1,625,433	1,582,577	1,608,931	1,541,891	1,617,404	19,252,298
29. ALLOWANCE FOR FUNDS USED DURING CONST	0	0	0	0	0	0	0
31. OTHER NON-OPERATING INCOME - NET	0	0	0	0	0	0	0
33. OTHER CAPITAL CREDITS & PAT DIVIDENDS	0	0	0	0	0	0	778,506
34. EXTRAORDINARY ITEMS	0	0	0	0	0	0	0
35. NET PATRONAGE CAPITAL OR MARGINS	1,754,305	943,510	2,703,737	4,223,930	3,023,729	4,511,226	36,370,584

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Big Rivers Electric Corporation
Case No. 2009-00040
Historical Test Period Filing Requirements

EXHIBIT 44

Filing Requirement
807 KAR 5:001 Section 10(7)(e)
Sponsoring Witness: C. William Blackburn

Description of Filing Requirement:

Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:

> *(e) The number of customers to be added to the test period-end level of customers and the related revenue requirements impact for all pro forma adjustments with complete details and supporting work papers.*

Response:

See Direct Testimony of William Steven Seelye, Exhibit Seelye-2, Schedule 1.13 and see Direct Testimony of C. William Blackburn.

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2009-00040

DIRECT TESTIMONY OF
MARK A. BAILEY

ON BEHALF OF
BIG RIVERS
ELECTRIC CORPORATION

MARCH 2, 2009

DIRECT TESTIMONY OF
MARK A. BAILEY

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DIRECT TESTIMONY OF
MARK A. BAILEY

I. INTRODUCTION

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

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

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

A. Yes, I have testified before this Commission previously, most recently as part of Big Rivers' Unwind Transaction in Case No. 2007-00455 regarding the transaction in which Big Rivers and E.ON U.S., LLC ("E.ON") proposed unwinding their 1998 Transaction (the "Unwind Transaction"). In addition, I have testified before state regulatory commissions in Arkansas, Texas, Louisiana, and Oklahoma.

II. PURPOSE OF TESTIMONY

Q. Please summarize the purpose of your testimony in this proceeding.

A. The purpose of my testimony is to explain Big Rivers' immediate and urgent need for emergency interim rate relief, as well as on-going rate relief. Big Rivers must raise sufficient cash to meet its short-term obligations as they become due or face insolvency.

Big Rivers needs an emergency rate increase of 21.6 percent effective April 1, 2009 to collect the required cash before it is needed. Any delay in the effective date beyond April 1, 2009 will require an even greater percentage rate increase to collect the same amount of cash. There is no room for movement in this rate request: every dollar sought is needed to meet Big Rivers' very real debt obligations between now and next January.

My testimony begins by introducing the witnesses who will testify for Big Rivers, with a brief description of the topics each witness will address. I also provide a summary of the events which have required Big Rivers to file this request for rate relief – from the unprecedented meltdown in the global financial markets, to the downgrading of the credit support by Ambac Assurance Corporation ("Ambac"), to Big Rivers' need to terminate its leveraged lease with Phillip Morris Capital Corporation ("PMCC") for $121.7 million ("PMCC Buyout"), and to an increase in Big Rivers' annual interest payment on its pollution control bonds ("PCBs") of $12.5 million.

I discuss the various short-term and long-term factors that have created Big Rivers' current poor cash position. I also describe the risks and contingencies which Big Rivers will face that require cash reserves to be accumulated beyond January 2010.

Finally, I provide a summary of Big Rivers' interim and permanent rate requests. I also describe certain commitments Big Rivers is willing to make in connection with the issuance of the relief requested in this proceeding.

III. INTRODUCTION OF WITNESSES AND THEIR TESTIMONY

Q. Mr. Bailey, would you please identify the witnesses that will testify for Big Rivers and the areas which their testimony will address?

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

1) William Steven Seelye (Exhibit 46). Mr. Seelye, Big Rivers' outside rate consultant, discusses the cash-needs approach Big Rivers used to determine its revenue requirements in this proceeding. In addition to describing Big Rivers' revenue requirements, Mr. Seelye provides an overview of Big Rivers' *pro forma* adjustments and his support for the rate relief requested.

2) C. William Blackburn (Exhibit 47). Mr. Blackburn, Big Rivers' Senior Vice President Financial & Energy Services & CFO, provides the background of Big Rivers'

current financial situation in his testimony. Mr. Blackburn offers support for the immediate need and the amount of the rate relief requested. He also testifies regarding the future cash contingencies and financial risks that will confront Big Rivers over the next several years. Mr. Blackburn also supports certain *pro forma* adjustments.

3) David A. Spainhoward (Exhibit 48). Mr. Spainhoward, Big Rivers' Senior Vice President External Relations & Interim Vice President Production, sponsors Big Rivers' tariffs as part of this testimony. He also supports the incremental environmental operation and maintenance expenditure *pro forma* adjustment and the capital expenditure *pro forma* adjustment. Mr. Spainhoward also discusses the commitments Big Rivers is willing to make.

IV. REASONS FOR BIG RIVERS' NEED FOR A GENERAL RATE INCREASE AND INTERIM RATE RELIEF

A. Relief Sought

Q. What relief does Big Rivers request in these proceedings?

A. Big Rivers has an immediate and urgent need to increase its revenue during the remainder of 2009. Without increasing its cash flows, Big Rivers will not be able to meet its payment obligations and remain solvent. Big Rivers is proposing that the Commission increase Big Rivers' rates on an emergency interim basis starting April 1, 2009. The proposed rate increase is designed to produce additional annual revenue of $24.9 million, which is equivalent to a 21.6% increase. Without implementing a rate increase that will produce $16.6 million ($24.9 million annually starting April 1, 2009) by early January 2010, Big Rivers projects that it will run out of cash and be insolvent.

Q. **Are there specific obligations that trigger this immediate and urgent need to increase cash to meet Big Rivers' debt service?**

A. Yes. Big Rivers has a promissory note in the amount of $12.4 million to PMCC due on December 15, 2009. Big Rivers has another debt service payment of $15.8 million due to the United States Rural Utilities Service ("RUS") due on January 4, 2010.

Q. **Does Big Rivers project that it will have enough cash on hand to meet these two obligations?**

A. No. As of February 3, 2009, Big Rivers had $25.7 million of cash on hand. And at current rate levels, Big Rivers will not generate sufficient revenues to cover these requirements, as described in the testimony of Mr. Blackburn.

Q. **Is Big Rivers pursuing other alternatives to meeting these cash requirements?**

A Yes. Foremost among the alternatives Big Rivers is continuing to pursue is the closing of the Unwind Transaction described to the Commission and presented for its approval in

Case No. 2007-00455. Should the Unwind Transaction with E.ON close, Big Rivers will be able to meet its expected short-term and medium-term obligations. If the Unwind Transaction closes, Big Rivers will withdraw this application and refund the amounts collected under any interim rate relief allowed pursuant to this request.

Absent closing of the Unwind Transaction, Big Rivers will pursue other avenues to raise cash, such as reducing its internal costs and pursuing changes to its RUS agreements to either permit additional borrowings or to defer debt service.

It is critical to understand that Big Rivers needs a combination of cost-cutting and the requested rate increase to remain solvent. Without a combination of emergency interim rate relief and deferred or eliminated expenditures, Big Rivers will run out of cash and have no borrowing recourse on January 4, 2010.

Q. **Why haven't you put more pressure on your creditors to lend you additional funds before asking for a rate increase?**

A. First, Big Rivers' leverage with its creditors is minimal given its weak financial position, particularly in this unpredictable financial market. Second, Big Rivers' creditors continue focusing on the Unwind Transaction. It is unlikely our creditors will turn their attention to alternatives while the Unwind Transaction is still viable. Third, as I discuss later, Big Rivers is structurally limited in its ability to borrow additional money.

Q. Apart from the need to raise cash to meet the two known short-term obligations you mentioned, does Big Rivers otherwise need to increase its rates?

A. Yes. Big Rivers also has an ongoing need to increase rates beyond these two short-term obligations in December 2009 and January 2010. Even after those obligations are met Big Rivers still needs a general increase in its rates to cover its projected ongoing cash requirements.

Q. Has Big Rivers determined its future cash requirements in connection with this request?

A. Yes. As part of this filing, Mr. Seelye (Exhibit 46) presents a calculation of Big Rivers' test-year cash requirements. This calculation uses an historical test period of the twelve months ended November 30, 2008, adjusted for known and measurable *pro forma* changes. The analysis shows that Big Rivers has an ongoing need to increase test-year revenues by $24.9 million to cover its cash requirements.

Q. Are there any other factors which support a long-term general increase in rates in the amount requested?

A. Yes. Big Rivers' New RUS Note annual debt service will ramp up from $82.5 million in 2009 to $98.6 million in 2012. Without the proposed general increase in revenue, Big Rivers will be unable to meet this $16.1 million annual increase in its obligations in 2012.

Q. What are the consequences of not obtaining emergency rate relief beginning April 1, 2009?

A. Although Big Rivers has an ongoing need to increase its rates, the immediate need is to ensure Big Rivers has sufficient cash to allow it to make the upcoming payments to PMCC and RUS. Irrespective of what its rates need to be on a going-forward basis – that is, after January 2010 – Big Rivers' rates will need to be increased by at least 21.6% from April 1, 2009, through November 30, 2009, if Big Rivers is to be in a position to make these payments. Therefore, we respectfully ask that the Commission allow us to place the proposed rates into effect starting April 1, 2009.

If there is delay in implementing the emergency rates, then the rate increase necessary through November 30, 2009 would have to be scaled up to enable Big Rivers to meet the $12.4 million payment obligation to PMCC on December 15, 2009, the $15.8 million payment obligation due to the RUS on January 4, 2010, and its normal ongoing operating expenses. The bottom line is that Big Rivers will need to increase its revenues by approximately $16.6 million through November 30, 2009 (eight months of the $24.9 million annual increase) if it has any expectation of being able to meet these payment obligations.

A delay in the April 2009 implementation would merely drive up the percentage increase in rates that would be necessary to allow Big Rivers to make the upcoming payments to

PMCC and RUS. If there is a delay in implementing rates on an emergency basis, Big Rivers will still need $16.6 million in additional revenue through the end of the year, but there simply will be fewer months in 2009 to collect the $16.6 million to allow Big Rivers to make the payments to PMCC and RUS. Mr. Seelye shows the effects of delay graphically in his testimony (Exhibit 46).

Put bluntly, Big Rivers needs its proposed rates to be effective beginning April 1, 2009, because otherwise the company's credit or operations will be materially impaired or damaged, as it will not be collecting sufficient revenue to pay its bills when they become due.

Q. What are the consequences of Big Rivers' not paying its bills as they become due?

A. If Big Rivers defaults on its obligations under the 1998 Transaction, and that transaction unravels, Big Rivers would achieve the worst of both worlds by losing the benefits of the 1998 Transactions, if not all of its assets, without receiving the benefits of the Unwind Transaction, including the roughly $756 million that E.ON has offered to contribute to Big Rivers in the Unwind Transaction.

B. The Need for Interim Rate Relief

Q. Doesn't Big Rivers' request for interim rate relief run contrary to the findings of the Commission in its December 23, 2008 order in an East Kentucky Power case, Case

No. 2008-00436, regarding the circumstances under which a well-managed cooperative should seek interim rate relief?

A. Not at all. I believe Big Rivers' request for interim rate relief is entirely consistent with the Commission's position in that order. In the order to which you refer, the Commission referenced a prior case in which it had granted interim rate relief and stated that: "As a general matter, prudently managed utilities will not willingly place themselves in a position where interim rate relief during the suspension period is necessary to avoid a material impairment of the utility's credit or operations."

I certainly agree with this concept. Big Rivers is seeking interim rate relief not because of any action it willingly took or failed to take, but because the downgrade of Ambac's financial rating as a result of an unprecedented crisis in the financial markets created overwhelming risks for Big Rivers that had to be resolved. It is a credit to the management that preceded me that Big Rivers, with no ability to borrow, was in a position to eliminate its exposure to the tremendous risks that crisis created for Big Rivers.

Q. **What does Big Rivers hope to accomplish with this rate request?**

A. Big Rivers' primary goal is to avoid the certainty that it will be unable to pay its bills when due over the next year unless it receives an infusion of cash. To accomplish this goal, Big Rivers must obtain interim rate relief effective April 1, 2009.

Second, this rate relief would allow Big Rivers to buy time to close the Unwind Transaction, which would solve the problems discussed in this case but avoid passing a point of no return from a solvency standpoint if the Unwind Transaction does not close. Big Rivers cannot delay rate relief and still achieve its primary mission of remaining solvent.

Q. Is there something that has happened in the Unwind Transaction that has affected your confidence that the Unwind Transaction will close, and precipitated a request for rate relief that is only required if it does not close?

A. No. This is simply a matter of timing. In my view, it would be extraordinarily imprudent to bet Big Rivers' future existence on the closing of the Unwind Transaction, when there are so many reasons the Unwind Transaction may not close that are out of Big Rivers' control. It is not inconsistent to say that I am as confident now as I was during the hearing in the Unwind Transaction proceeding that the Unwind Transaction will close.

C. Background to the Current Urgency for Interim Relief

Q. How is it that Big Rivers now finds itself in the position of needing an immediate infusion of cash?

A. This issue is addressed in detail in the testimony of Mr. Blackburn, in which he discusses Big Rivers' financial history from 1998 to today. In short, however, Big Rivers' present financial position is a product of the current meltdown in the financial markets. The meltdown created uncertainty that was particularly destabilizing to Big Rivers given Big Rivers' financial structure and the commitments Big Rivers had undertaken in the past.

Q. Why didn't Big Rivers ask the Commission for rate relief before now?

A. Quite simply, we were concentrating all of our efforts on getting the Unwind Transaction approved through the hearing in the Unwind Transaction proceeding on December 2 and 3, 2008. We also monitored the potential closing date for the Unwind Transaction to see if that might occur before this rate request filing was absolutely required. We have recognized since prior to the PMCC Buyout that a rate increase would be required if the Unwind Transaction was delayed or unsuccessful. I frankly discussed the potential need for a rate increase during my testimony in the Unwind proceeding, and we turned our attention to preparing a rate request immediately after the hearing in the Unwind proceeding. Big Rivers filed notice on February 2, 2009, and Big Rivers' Board of Directors authorized us to file for rate relief on February 20, 2009.

Q. In addition to the turmoil in the financial markets, is there a structural limitation Big Rivers has faced which has contributed to Big Rivers' need for interim rate relief?

Yes. As Mr. Blackburn discusses, a distinct structural limitation inherent in the 1998 Transaction is a greatly restricted ability of Big Rivers to borrow money. The overwhelming majority of Big Rivers' assets are already pledged as security to its creditors. Moreover, Big Rivers' financing documents provide for no accommodation of new lenders and offer no flexibility to grant new lenders a security interest. Because existing creditors are unwilling to lend Big Rivers additional money given its weak balance sheet, and new creditors are unwilling to lend it funds from a position subordinate to the existing creditors, Big Rivers has been unable to obtain significant new borrowings.

The current uncertainty in financial markets has been particularly damaging to Big Rivers because of the structural inability to borrow which already existed.

Q. Apart from this structural inability to borrow, why has the recent financial instability been so damaging to Big Rivers?

A. Historically, Big Rivers has coped with its inability to borrow new funds by relying on accumulated cash to meet unforeseen financial needs. As of August 2008, Big Rivers had approximately $149.4 million in cash and cash equivalents available to it. However, in June 2008, Ambac Assurance Company, a formerly AAA credit rated insurer acting as credit support for some of Big Rivers' financial obligations -- relating to certain leveraged leases of Big Rivers' generating units dating from 2000 -- had its rating downgraded by financial rating agencies. This downgrade triggered a cascade of financial problems for Big Rivers that culminated in Big Rivers buying out its 2000 leveraged leases with PMCC on September 30, 2008. As a consequence of that buyout, which is discussed at length by Mr. Blackburn in his testimony, Big Rivers expended $109.3 million in cash and incurred the $12.4 million promissory note that is now due no later than December 15, 2009. And as of February 3, 2009, Big Rivers' cash balance sits at $25.7 million.

Q. How did the downgrade of Ambac's credit rating result in the decision to terminate the PMCC leveraged leases?

A. The effect of Ambac's downgrade was to fatally weaken its credit support of Big Rivers' obligations to PMCC. Because maintaining qualified credit support was a requirement under the PMCC leveraged leases, the loss of Ambac's qualification to serve in that role constituted an event of default by Big Rivers under the terms of that lease. Although Big Rivers explored a number of alternatives to obtain a replacement for the lost Ambac credit support, the restrictions on Big Rivers' ability to borrow under its existing financial arrangements, combined with Big Rivers' general financial weakness and the unprecedented market meltdown, created a situation where Big Rivers could not obtain replacement credit support. Ultimately, Big Rivers determined that the least risky and most financially beneficial solution was to terminate the PMCC leveraged leases, which Big Rivers did effective September 30, 2008.

Q. Could Big Rivers have delayed in resolving the PMCC leveraged lease issues?

A. No, not in my opinion. Because of the loss of Ambac as qualified credit support, Big Rivers was in default if PMCC had enforced its remedies. PMCC had agreed to temporarily waive enforcement of its remedies, but its tolerance for additional waivers by the end of September 2008 was thin. PMCC also had stated that it was willing to reduce its termination value payment by $7.5 million and that it was willing to loan Big Rivers a variable amount (up to $20.0 million) on a short-term basis provided the termination was completed in the third quarter. Moreover, it was Big Rivers' considered opinion that further delay would serve only to increase the costs of the PMCC termination while continuing to expose Big Rivers to the very great credit risk of Ambac as well as American International Group, Inc. ("AIG").

AIG, which like Ambac was faltering, held a guaranteed investment contract for Big Rivers, the purpose of which was to reduce the termination value payment owed to PMCC. Big Rivers had no guarantee that AIG or Ambac would remain solvent, given the market turmoil. Moreover, the value of the AIG guaranteed investment contract in late September was close to $24.0 million greater than it had been several months earlier. Weighing all of these factors, Big Rivers determined that the prudent course of action was to draw down its cash reserve and buy out PMCC.

Q. How did the pendancy of the Unwind Transaction play into the decision to buy out PMCC?

A. It made the decision easier. If we bought out PMCC and the Unwind closed, E.ON would contribute $60.9 million toward the cost of the PMCC Buyout. If we consummated the PMCC Buyout and the Unwind did not close, the risks associated with doing nothing would be eliminated. As I mentioned, those risks included PMCC calling a default, or a bankruptcy of Ambac or AIG, any of which would have inevitably resulted in bankruptcy for Big Rivers.

Q. What was the total cost to Big Rivers of the PMCC Buyout?

A. On September 30, 2008, Big Rivers paid PMCC approximately $121.7 million, of which $12.4 million was the loan from PMCC now due on or before December 15, 2009.

Q. You mentioned that another financial impact on Big Rivers of the global financial meltdown is an increased interest expense on Big Rivers' pollution control bonds. Please explain.

A. In addition to providing credit support for the PMCC leveraged lease, Ambac provided credit support for some of Big Rivers' pollution control bonds. As a result of the downgrading of Ambac, the interest rate on certain of those PCBs rose to 18 percent, the maximum rate. On an annualized basis, Big Rivers is being required to pay $12.5 million more in interest than in 2007. Because refinancing the PCBs without a credit rating is problematic, Big Rivers needs additional revenue to pay this additional obligation.

D. Other Factors Supporting the Need for a Rate Increase

Q. You mentioned that Big Rivers has another large obligation due on January 4, 2010. Please explain.

A. Big Rivers will owe a cash payment to the RUS of approximately $15.8 million on January 4, 2010. In addition, from 2009 through 2012, Big Rivers' obligations to the RUS will increase up to an additional $16.1 million annually.

Q. Going forward, apart from known cash requirements, is there any other justification for Big Rivers' request for increased rates?

A. Yes. Because of circumstances outside of Big Rivers' control and related to the meltdown in global financial markets, Big Rivers' accumulated cash reserves have been almost completely depleted by the PMCC Buyout. Yet because of Big Rivers' practical inability to borrow under the terms of its existing financing arrangements, Big Rivers' cash reserves have represented Big Rivers' primary means of meeting unanticipated risks and contingencies that could create new financial obligations for Big Rivers. In addition to needing cash to cover Big Rivers' debt service, Big Rivers equally needs to rebuild cash to meet future risks and contingencies.

Q. What sort of risks and contingencies are you referring to with regard to this need to rebuild cash reserves?

A. The risks and contingencies that Big Rivers faces are more fully described in Mr. Blackburn's testimony (Exhibit 47). However, the range of risks and contingencies include things such as (a) new capital expenditures for changes in law under the 1998 Transaction with E.ON, (b) environmental cost exposure under the 1998 Transaction with E.ON, (c) litigation risk with E.ON over outstanding contractual disputes which otherwise would be settled by closing of the Unwind Transaction, (d) potential funds in the event of other contractual claims under the 1998 Transaction documents, (e) potential litigation with the Smelters concerning their claim for non-contractual service upon the expiration of their current wholesale sourced contracts with E.ON, (f) any payments required in association with securing power to meet unanticipated load growth (including potential for peaking capacity), and (g) requirements to refinance Big Rivers' pollution control bonds due to increased interest costs occasioned by deterioration in Ambac's creditworthiness. Absent ready cash on hand, any one of these issues could create serious financial difficulties for Big Rivers.

Q. Have any of these risks and contingencies been reflected in the revenue requirements in this case?

A. No. It would be extremely difficult to quantify these risks and contingencies. Nonetheless, they are very real, and Big Rivers must be prepared financially to meet them.

V. <u>SUMMARY OF RATE REQUEST</u>

Q. What is the amount of the revenue increase Big Rivers is requesting?

A. Big Rivers is requesting a $24.9 million annual revenue increase.

Q. How will this increase affect Big Rivers' rates?

A. It constitutes a 21.6% increase in rates. For rural customers, the demand charge increases to $8.963/kW (from $7.370/kW), and the energy charge increases to $24.811/MWh (from $20.400/MWh). For large industrial customers, the demand charge increases to $12.345/kW (from $10.150/kW), and the energy charge increases to $16.680/MWh (from $13.715/MWh). On a blended basis, the rural rate increases to $44.22/MWh (from $36.36/MWh), and the large industrial rate increases to $38.57/MWh (from $31.71/MWh). These revised rates are reflected in Big Rivers' proposed Tariff (Exhibit 7) and are discussed in Mr. Seeley's testimony (Exhibit 46).

Q. Has Big Rivers performed a cost of service study to support its rate request?

A. No. Big Rivers' rates have been developed on the basis of cash-needs revenue requirements. Big Rivers has virtually no ability to borrow, but has imminent financial obligations which developed over a relatively short period that it is required to meet. Given the urgency, Big Rivers did not have time to develop a cost of service methodology with its Members, to prepare a cost of service study and to agree with its

Members on a rate design. Big Rivers has, however, ensured that the increase will be flowed through Big Rivers' Members on a proportional basis.

VI. <u>BIG RIVERS' COMMITMENTS</u>

Q. Is Big Rivers continuing to pursue other alternatives to mitigate the requested increase in rates?

A. Yes. Big Rivers is considering all practical ways to mitigate these rates. Big Rivers' management is examining all expenses with an eye to reducing internal cash needs. In doing so, Big Rivers will remain mindful of its duty and commitment to provide reliable service and will not compromise that obligation.

Q. Is it possible that Big Rivers will not need the total amount of the increase it has requested?

A. Yes, but it is unlikely. Interest rates could change or general financial market conditions could improve or worsen. In addition, prices in the wholesale power market could either increase or decrease. As in any rate case filing, Big Rivers will submit updates on changes that affect its *pro forma* adjustments and the proposed level of its increase.

I should note, however, that we are not asking for an increase that will generate enough cash to meet all of our obligations. It will also be necessary for us to defer or to cut expenditures. If circumstances change so that more cash is available, we may simply not need to defer as many expenditures or defer them as long. It is inconceivable to me that circumstances would improve so much that we will not need to defer expenditures at all or will require a smaller rate increase.

Q. Given that Big Rivers' cash requirements are a major contributing factor to this requested rate increase, is Big Rivers willing to make any reporting commitments regarding cash levels as part of this request?

A. Yes. As explained by Mr. Spainhoward in his testimony, Big Rivers will continue to meet the reporting requirements ordered by the Commission in Case No. 98-00267. Those reporting requirements include submission of updated financial models.

Q. Does Big Rivers propose any commitments related to its Integrated Resource Plan ("IRP")?

A. Yes. As discussed by Mr. Spainhoward, Big Rivers proposes to file its IRP by November 2010.

Q. Does Big Rivers believe that the increase it now seeks should remain in effect indefinitely?

A. No. The present request is designed to meet short-term and medium-term needs. On a longer-term basis Big Rivers believes it is appropriate for it to file another rate case as a follow up to this proceeding. Big Rivers commits to doing so by no later than July 1, 2011. Filing another general rate case by that date will serve to ensure that Big Rivers is on an appropriate path to returning to financial stability.

VII. CONCLUSION

Q. Mr. Bailey, what message do you want the Commission to take away from your testimony?

A. Big Rivers has an immediate and urgent need for a 21.6% interim rate increase effective April 1, 2009, to meet its financial obligations as they become due. I will stop short of saying we are in a crisis, but we desperately need this increase to avert a crisis.

If the effectiveness of the rate increase is delayed until after April 1, 2009, the percent increase will necessarily need to be greater in order to meet Big Rivers' obligations in December 2009 and January 2010. Even with the rate increase requested and an effective date of April 1, 2009, Big Rivers will not be able to meet its obligations without deferring or eliminating expenditures.

The revenue requirement in this case does not include amounts for risks and contingencies Big Rivers needs to be financially prepared to meet in the future. There is no room for movement in the amount of rate relief we are requesting; we are requesting the minimum amount necessary to avoid insolvency in January 2010.

On the positive side, there is little risk in the Commission approving the emergency interim rate relief. If the Unwind Transaction closes, Big Rivers will refund the full increase it is authorized to collect in this case. If the Unwind Transaction does not close, Big Rivers has committed to filing another general rate case by no later than July 1, 2011.

Q. Does this conclude your testimony at this time?

A. Yes.

VERIFICATION

I verify, state, and affirm that the foregoing testimony is true and correct to the best of my knowledge and belief.

Mark A. Bailey

Mark A. Bailey

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark A. Bailey on this the 26th day of February, 2009.

Paula Mitchell

Notary Public, Ky. State at Large
My Commission Expires 1-12-13

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2009-00040

DIRECT TESTIMONY OF WILLIAM STEVEN SEELYE

ON BEHALF OF
BIG RIVERS
ELECTRIC CORPORATION

MARCH 2, 2009

DIRECT TESTIMONY OF
WILLIAM STEVEN SEELYE

I. INTRODUCTION

Q. Please state your name, address and position.

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

Q. By whom are you employed?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility marketing, regulatory analysis, cost of service, rate design and depreciation studies.

Q. On whose behalf are your testifying?

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

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

A. I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville Gas and Electric Company. From May 1979 until December 1990, I held various positions within the Rate Department of Louisville Gas and Electric Company. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left Louisville Gas and Electric Company in July 1996 to form The Prime Group, LLC, with another former employee of the Company. Since then, we have performed cost of service studies, developed revenue requirements and designed rates for well over 130 investor-owned, cooperative and municipal utilities across North America. A more detailed description of my qualifications is included in Exhibit Seelye-1.

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

A. Yes. I have testified in over 45 regulatory proceedings in 11 different jurisdictions regarding revenue requirements, cost of service and rate design. A listing of my testimony in other proceedings is included in Exhibit Seelye-1.

Q. Have you developed rates for electric cooperatives?

A. Yes. I have developed rates for a number of generation and transmission cooperatives ("G&T cooperatives"), including Hoosier Energy, South Mississippi Electric Power Association, Big Rivers Electric Corporation, Southern Illinois Power Cooperative, Corn Belt Power Cooperative, and East Kentucky Power Cooperative, Inc. I have also supervised the preparation of cost of service studies and the development of rates for over 130 electric distribution cooperatives.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor the calculation of Big Rivers' revenue requirement and to support the proposed rates to its members.

Q. Do you have any exhibits to your testimony?

A. Yes. I have prepared or supervised the preparation of the following exhibits to my prepared testimony:

- Exhibit Seelye-1 – Qualifications of William Steven Seelye
- Exhibit Seelye-2 – Determination of Revenue Requirements
- Exhibit Seelye-3 – Reconciliation of Test-Year Billing Determinants
- Exhibit Seelye-4 – Analysis of Proposed Rates

Q. Please summarize your testimony.

A. Big Rivers is proposing an annual increase in revenues of $24.9 million based on *pro forma* operating results for the historical test year ended November 30, 2008, which is equivalent to a 21.6 percent increase based on *pro forma* test-year member tariff revenue. Because its cash reserves have been significantly depleted over the past 12 months, Big Rivers has an immediate and urgent need to increase rates in order meet its financial obligations.

In September 2008, Big Rivers made a cash payment to Philip Morris Capital Corporation ("PMCC") of $109.3 million and executed a $12.4 million promissory note to buy out its interest in the leveraged lease. In addition to increased debt service costs, increased operation and maintenance expenses, and projected lower margins on non-tariff wholesale sales, Big Rivers will be required to make two significant cash payments to creditors near year end 2009.

Specifically, Big Rivers must be in a position to make the $12.4 million payment to PMCC on December 15, 2009, and another $15.8 million payment to the United States Rural Utilities Service ("RUS") on January 4, 2010. Because of its practical inability to finance, Big Rivers will be unable to meet these payment obligations without a significant increase in revenue. Big Rivers is therefore requesting that the Commission place the proposed rates into effect on an emergency interim basis beginning April 1, 2009, in order to enable Big Rivers to generate enough cash to meet these payment obligations to PMCC and the RUS and to continue to operate the utility.

Big Rivers' revenue requirement was developed based on an analysis of its cash needs. Because Big Rivers essentially has no near-term ability to finance its cash requirements, its revenues must be adequate to cover its payment requirements -- which include the payment obligations to PMCC and RUS and its normal ongoing operating expenditures. Using the cash needs approach for determining Big Rivers' revenue requirement, 13 *pro forma* adjustments were made to the cash results for the 12 months ended November 30, 2008. The level of revenue requirement determined from the analysis reflects the amount of cash necessary to cover Big Rivers' *pro forma* cash requirements, without *__any__* additional cash coverage. The resulting revenue requirement for this proceeding only covers what might be referred to as Big Rivers' normal ongoing expenditures. Because the $12.4 million PMCC promissory note matures December 15, 2009, it has been excluded from the revenue requirement in this case. Still, the PMCC promissory note payment is a significant cash need for Big Rivers.

Big Rivers has both an immediate and on-going need for higher revenue. Its immediate need is largely driven by the previously mentioned requirement to pay PMCC and RUS a total of $28.2 million. The ongoing need to increase Big Rivers' revenues -- which is reflected in the determination of Big Rivers' revenue requirement in this proceeding -- is primarily driven by increases in operating expenditures and projected decreases in non-tariff wholesale margins. Big Rivers is proposing a $24.9 million revenue increase to cover its ongoing payment obligations, and is asking the Commission to allow it to place the full increase into effect on April 1, 2009.

The bottom line is that Big Rivers needs a rate increase of 21.6 percent if it is to have any expectation of being in a position to remain solvent through January 4, 2010. Even with a 21.6 percent increase going into effect on April 1, 2009, cost cutting and cost deferral measures must also be implemented.

II. NEED FOR AN EMERGENCY INTERIM RATE INCREASE

Q. What circumstances created the need for Big Rivers to request emergency interim rate relief?

A. The meltdown in the global financial markets has taken a serious toll on Big Rivers. The crippling of major financial institutions in the U.S. and abroad have created a cascading effect that ultimately resulted in a significant reduction in Big Rivers' cash balances which previously had permitted the utility to deal with normal cost volatility that it experienced.

Q. What specifically triggered the reduction in Big Rivers' cash balances?

A. Big Rivers has been seriously and adversely affected by a credit rating downgrade of Ambac Assurance Corporation ("Ambac") by Moody's Investors Service ("Moody's") which occurred on June 19, 2008. Ambac was the surety bond provider for Big Rivers' 2000 leveraged lease of its Green and Wilson generating stations and is the credit enhancer for two series of pollution control bonds associated with the Wilson station, the series 1983, $58.8 million variable rate demand bonds, and series 2001 $83.3 million periodic auction rate securities. Moody's downgrade of Ambac triggered an obligation for Big Rivers to either find satisfactory replacement or make a termination payment to PMCC within 60 days to avoid a default. No satisfactory alternative to a buyout was found. On September 30, 2008, Big Rivers paid $109.3 million in cash and executed an 8.5 percent promissory note for $12.4 million to PMCC to buyout its interest in the leveraged lease. As mentioned earlier, the PMCC promissory note is due no later than December 15, 2009. The PMCC promissory note, with interest, will cost Big Rivers $13.7 million from inception through maturity.

As the creditworthiness of Ambac has fallen, interest rates have increased from an average of 3.74 percent in 2007, to the maximum rate of 18 percent on the periodic auction rate securities, while $18.4 million of the variable rate demand bonds that are currently in the market bear 8 percent, with the balance being held by the standby bond purchaser (liquidity provider), Dexia Credit Local, at the current bank rate of 3.25 percent. On an annualized basis, the current rates result in an incremental cost to Big Rivers of $12.5 million over the 2007 amount.

Primarily because of the leveraged lease buyout and the increased cost of the pollution control bonds, Big Rivers' cash and cash equivalent balance has declined from $149.4 million on August 31, 2008, to $25.7 million as of February 3, 2009, a reduction of $123.7 million. The events that led to the reduction in Big Rivers' cash balances are described in detail in Mr. Blackburn's testimony.

Q. Why is it necessary to implement rates on an emergency interim basis on April 1, 2009?

A. As already mentioned, Big Rivers has two large payment obligations to its creditors coming up in December 2009 and January 2010.

Furthermore, Big Rivers' operating expenditures are projected to increase and its margins on non-tariff wholesale sales are projected to decrease due to current conditions in wholesale power markets, which are not expected to improve anytime soon because of the economic recession. Big Rivers estimates it will be unable to meet its debt service obligations beginning the first business day of January 2010 without (i) emergency rate relief, (ii) cost deferral measures, and/or (iii) successfully refinancing or restructuring certain debt obligations. Big Rivers will need to pursue all these courses of action in order to remain solvent. It is thus essential that Big Rivers increase its rates as soon as possible in order to build sufficient cash to meet the $28.2 million payment obligations to its creditors coming up in December 2009 and January 2010.

Q. **What relief does Big Rivers request in these proceedings?**

A. Without increasing its cash receipts, either through increased rates or otherwise, Big Rivers will not be able to meet its payment obligations and remain solvent. Big Rivers is proposing to increase rates on an emergency basis starting April 1, 2009. The proposed rate increase is designed to produce additional annual revenue of $24.9 million, which is equivalent to a 21.6% increase. Without implementing a rate increase that will produce at least this amount of revenue, Big Rivers projects that it will run out of cash by January 2010. Consequently, if emergency rates are not implemented, Big Rivers risks insolvency by January 4, 2010, when its $15.8 million New RUS Note quarterly debt service payment is due.

Q. What are the consequences if Big Rivers does not implement emergency interim rates beginning April 1, 2009?

A. It is imperative that Big Rivers build up sufficient cash balances so it will have the funds to make the upcoming payments to PMCC and RUS. Irrespective of what its rates need to be on a going-forward basis – that is, after January 2010 – Big Rivers' rates will need to be increased by at least 21.6 percent from April 1, 2009, through November 30, 2009, if Big Rivers is to be in a position to make these payments. Because Big Rivers does not receive payment from its members until approximately the 25th day of the subsequent month, November 2009 is the last month of service for which Big Rivers' members can be billed at the higher emergency interim rates to allow Big Rivers to collect sufficient funds to make the payment that is due on January 4, 2010, to RUS. If there is delay in implementing emergency interim rates, then the rate increase necessary through

November 30, 2009, would need to be scaled up to enable Big Rivers to meet the \$12.4 million payment obligation to PMCC on December 15, 2009 and the \$15.8 million payment obligation due to the RUS on January 4, 2010. The bottom line is that Big Rivers will need to increase its revenues by approximately \$16.6 million through the end of 2009 (\$24.9 million ÷ 12 months x 8 months ≅ \$16.6 million) if it has any expectation of being able to meet these payment obligations. A delay in the April 2009 implementation would merely drive up the percentage increase in rates that would be necessary to allow Big Rivers to make the upcoming payments to PMCC and RUS. If there is a delay in implementing rates on an emergency basis, Big Rivers will still need \$16.6 million in additional revenue through the end of the year but there simply will be fewer months in 2009 to collect that same \$16.6 million needed to allow Big Rivers to make the payments to PMCC and RUS. The following table shows the approximate percentage rate increase for the remainder of the year assuming various dates for the implementation of emergency interim rates:

Implementation Date for Emergency Interim Rates	Months Required to Build Cash Requirement	Approximate Percentage Rate Increase Required
April 1, 2009	8	21.6%
May 1, 2009	7	24.7%
June 1, 2009	6	28.8%
July 1, 2009	5	34.6%
August 1, 2009	4	43.2%
September 1, 2009	3	57.7%
October 1, 2009	2	86.5%
November 1, 2009	1	172.6%

Q. Does Big Rivers have a need for higher rates after the upcoming payment obligations to PMCC and RUS are satisfied?

A. Yes. As will be discussed below, the revenue requirement used to determine the $24.9 million increase includes *pro forma* adjustments for known and measurable items. It is extremely important to understand, however, that Big Rivers' proposed revenue requirement represents cash requirements on a *going forward basis* and thus *does not include* the $13.7 million principal and interest payments, from inception to maturity, to PMCC.

To deal with its critical need for cash to make the payments to PMCC and RUS, Big Rivers could have reasonably proposed to implement an even larger increase on an emergency interim basis. In fact, Big

Rivers gave careful consideration to doing just that – specifically, proposing an emergency interim increase of approximately 38.4 percent during months of April through November 2009 and then reducing the increase back down to the proposed 21.6 percent in December 2009 to reflect its *pro forma* or *going forward* revenue requirements. In an effort to keep the rate impact to members to a minimum, however, Big Rivers decided to pursue cost deferrals and other actions with great diligence in order to limit the emergency interim rate increase to the level determined through the application of the *pro forma* revenue requirement calculation described below. In other words, Big Rivers cannot meet its additional cash needs through this revenue increase alone, but must couple the rate increase with cost cuts, cost deferrals, and other efforts to improve cash flow.

Q. Does Big Rivers anticipate even higher costs in the future?

A. Yes. After the $28.9 million payment obligations are met, Big Rivers' cash balances essentially will be depleted, yet Big Rivers must deal with further potential increases in operating expenses, the continuing need to make capital expenditures to ensure that reliable service will continue to be provided, and higher debt service costs. It is also important to note in this regard that Big Rivers' revenue requirement does not reflect the scheduled ramping up of debt service payment to RUS. Big Rivers' New RUS Note does not have level debt service, but will ramp up from $82.5 million in 2009 to $98.6 million in 2012, a $16.1 million increase.

III. REVENUE REQUIREMENT

Q. Please describe how revenue requirements were determined for Big Rivers.

A. Big Rivers' revenue requirements were determined using the *cash-needs approach*. With the cash-needs approach, the components of revenue requirements include operation and maintenance ("O&M") expenditures, debt service requirements, taxes, and capital expenditures not debt-financed. Under the cash-needs approach, a margin component normally would be included in revenue requirements to provide additional debt service coverage; but in an effort to keep the rate increase to a minimum, Big Rivers did not include a margin component in revenue requirements.

The O&M expenditure component of revenue requirements reflects the actual test-year expenditures derived from the utility's accounting records with adjustments to reflect known and measurable changes to test-year results. The debt service component of revenue requirements consists of principal and interest requirements on debt outstanding during the period when rates go into effect. The tax component of revenue requirement represents actual test-year amounts adjusted to reflect known and measurable changes to test-year results, particularly, the elimination of income taxes (due to termination of the leveraged lease) paid by Big Rivers during the test year.

The capital expenditure component of revenue requirements consists of the replacement of existing facilities, normal extensions and improvements, and major capital improvements and replacements which are known and measurable. Specifically, the capital expenditures included in revenue requirements consist of (i) Non-Incremental Capital Costs, as defined in Big Rivers' 1998 transaction ("1998 Transaction") documents, (ii) Incremental Capital Costs, as defined in the 1998 Transaction documents, (iii) transmission plant capital expenditures, and (iv) general plant capital expenditures. For Non-Incremental Capital Costs the amounts included in *pro forma* revenue requirements represent Big Rivers' share of the Capital Budget Limits for 2009. For Incremental Capital Costs the amounts included in *pro forma* revenue requirements represent Big Rivers' share of the amount set forth in the 2009 WKEC revised budget.

For transmission plant capital expenditures and general plant capital expenditures, the amounts included in *pro forma* revenue requirements represent the capital expenditures actually incurred by Big Rivers during the test year. During the test year, Big Rivers spent a total of $14.3 million in transmission and general plant capital expenditures, which compares to $18.1 million included in Big Rivers' construction and capital budget for 2009. Albeit conservative, Big Rivers considers the $14.3 million amount for transmission and general plant expenditure to be reasonable on a going-forward basis. It should be emphasized that all of these expenditures must be funded with available cash rather than with debt.

Big Rivers' *revenue deficiency* is determined as the difference between its *pro forma* test-year revenues and *pro forma* test-year cash revenue requirements (cash expenditure requirements).

Q. Is the cash-needs approach a standard methodology for determining utility revenue requirements?

A. Yes, the cash-needs approach is a standard methodology for determining revenue requirements for municipal and cooperative utilities -- i.e., not-for-profit utilities. The cash-needs approach is not normally used for investor-owned utilities, which are organized to earn a profit on behalf of its owners or equity holders. As far as I know, the so-called *utility approach* is universally used to determine revenue requirements for investor-owned utilities. From my own experience, virtually all municipal utilities and the majority of the cooperative utilities with whom I have worked use the cash-needs approach, or some variation of the cash-needs approach, for determining revenue requirements. Specifically, utilities that determine revenue requirements using the cash-needs approach will determine the magnitude of a rate adjustment by evaluating whether their projected revenue at current rates will be sufficient to cover cash requirements for the next two or three years. If revenues are not sufficient then they will increase rates to a level that will allow their revenues to cover cash outflows, including O&M expenditures, principal and interest on debt, expected capital expenditures, plus sufficient margins to ensure that the utility's cash-based Interest Coverage and/or Debt Service Coverage will be adequate.

Q. Please discuss the differences between the cash-needs approach and the utility approach for determining revenue requirements?

A. Stated simply, with the cash-needs approach, revenue requirements represent the amount of *cash* that the utility needs to operate, whereas, with the utility approach, revenue requirements represent the utility's cost of service stated on an *accrual* basis. The principal difference between the two methodologies is that depreciation and other amortizations are not included in revenue requirements determined using the cash needs approach but they are included in revenue requirements determined using the utility approach. Because depreciation represents a noncash expense (or simply an accrual), depreciation expenses are not included in revenue requirements using the cash-needs approach. The cash outflow associated with depreciation occurs when the related asset is acquired, i.e., when the capital expenditure is made. Instead of depreciation expenses, capital expenditures not financed with debt (or through current revenue) and principal payments on debt are included in revenue requirements determined using the cash-needs approach. The following table summarizes the components included in revenue requirements under the two methodologies:

Cash Needs Approach	*Utility Approach (Accrual)*
• Operations and Maintenance Expenditures • Interest Payments • Principal Payments on Debt • Capital Expenditures from current revenue • Tax payments • Margins (debt coverage)	• Operations and Maintenance Expenses • Interest Accruals • Depreciation Expenses • Tax Accruals • Margins (debt coverage)

Although both methodologies are widely used by electric, gas and water utilities, perhaps the best discussion describing the differences between the two methodologies can be found in the American Water Works Association ("AWWA") Manual M1 titled *Water Rates*, Fourth Edition, published in 1991. Particularly, see pages 1-4.

Q. Why is the cash-needs approach appropriate for Big Rivers?

A. As explained in the testimony of C. William Blackburn, Big Rivers' cash reserves have been significantly depleted. Furthermore, Big Rivers has virtually no ability to borrow additional funds to meet its cash requirements. A utility can normally increase cash inflows (raise cash) by either borrowing or increasing revenues. Without the ability to borrow additional funds, increasing revenues is the only tool available to Big Rivers to increase cash inflows. Consequently, Big Rivers must have sufficient revenues to cover its cash requirements. If cash inflows are insufficient to cover its cash requirements, revenues must be adjusted to cover the shortfall.

Furthermore, Big Rivers' current rates have been in place since 1997 and are based upon the 1998 Transaction. These rates were supported by the statement of cash flows per the financial forecast model filed in that case. Cash flow is more relevant to Big Rivers, as the company has no borrowing capability, and because of the significant differences (for Big Rivers) between the reported amounts for accrual accounting vs. cash accounting. While standard calculations of TIER and DSC for Big Rivers may appear robust, insolvency will result just as surely from a lack of cash.

Q. Did the Commission consider Big Rivers' cash needs when current rates were established in Case No. 97-204?

A. Yes. The Commission recognized the importance of setting Big Rivers' rates at a level that would allow it to maintain enough cash to provide safe and reliable service. In its Order in Case No. 97-204, the Commission stated that, "From the perspective of Big Rivers and its major creditors, our decision should not reduce the cash flow reflected in Big Rivers' financial models, thus preserving Big Rivers' ability to meet its operating expenses and debt service payments." (Case No. 97-204, Order dated April 30, 1998, at p.20.) (Exhibit No. 51 to the Application in this proceeding.) It is my understanding that the paramount consideration in the evaluation of the adequacy of Big Rivers' rate levels in Case No. 97-204 was the analysis of cash flows from Big Rivers' financial model. In ordering paragraph 21 of the Order, the Commission directed Big Rivers to "file a report, appended to its annual report, comparing the actual cash flows for the calendar year with the amounts included in the SUP-11 financial model filed in this proceeding." (Id., at p. 46.) The Order in Case No. 98-267, which related the 1998 Amendments to Station Two Contracts, stated that, "The Commission did not design rates for only the 1996 normalized test year, as implied in this exhibit [an exhibit submitted by one of the Smelters -- Commonwealth]. The billing units in [the exhibit] do not correspond to those included in the Big Rivers' financial model which the Commission utilized to develop rates for [the Smelter] and all other members of its class for the entire 25-year term of the lease transaction." (Case No. 98-267, Order dated July 14, 1998, at p. 11.) (Exhibit No. 52 to the Application in this proceeding.)

Q. Please describe the *pro forma* adjustments to Big Rivers' test-year cash results.

A. Certainly. Let's take them one by one, in numerical order:

Schedule 1.01 – Incremental Environmental O&M

(Sponsored by David A. Spainhoward)

Under the WKEC operating and lease agreement, Big Rivers is responsible for funding its cost-share for Incremental Environmental O&M, as defined therein. Through 2010, Big Rivers' cost-share is 20.0 percent. In 2011, it is 40.26 percent, and it is 33.90 percent thereafter, through 2023. For the historical period, Big Rivers' 20.0 percent cost-share was $600,155. The *pro forma* year cost of $3,095,168 is based on WKEC's revised 2009 budget reflecting the newly imposed year-round CAIR, which served to significantly increase annual Incremental Environmental O&M cost. Accordingly, the *pro forma* adjustment is to increase the revenue requirement by $2,495,013. This adjustment is described in Mr. Spainhoward's testimony.

Schedule 1.02 – Eliminate Unwind Cost Share

(Sponsored by C. William Blackburn)

In connection with pursuing the Unwind, Big Rivers has executed several cost-share agreements with E.ON to fund the ongoing transaction costs. Generally, Big Rivers has been responsible for funding 25.0 percent of such costs. During the 12 month historical period ended November 30, 2008, Big Rivers' share of such costs was $4,454,079. Absent the Unwind, Big Rivers will incur no such costs, and has therefore made a *pro forma* adjustment to eliminate such amount, thereby reducing Big Rivers' revenue requirement.

Schedule 1.03 – Capital Expenditures

(Sponsored by David A. Spainhoward)

Capital expenditures are comprised of four components – Non-Incremental Capital Costs, Incremental Capital Costs, both as defined in the WKEC 1998 Transaction Documents, transmission plant expenditures, and general plant expenditures. For Non-Incremental Capital Costs the amounts included in *pro forma* revenue requirements represent Big Rivers' share of the Capital Budget Limits for 2009. Big Rivers' Incremental Capital Cost share, bearing the same percentage noted above for its Incremental Environmental

Capital cost share, was $378,367 for the historical period, and per WKEC's 2009 revised budget is $1,193,160. For transmission and A&G capital, Big Rivers proposes no *pro forma* adjustment, as the historical test period amount of $14,331,923 is believed to be representative of an ongoing forward period. Further, although Big Rivers' 2009 budget includes $18,101,213 in capital expenditures for transmission and A&G, we've proposed no *pro forma* adjustment. In summary, total capital expenditures for Big Rivers for the *pro forma* period are $22,396,083, while the historical period amount was $21,417,957. The result is a *pro forma* adjustment to increase Big Rivers' revenue requirement by $978,126. This adjustment is described in Mr. Spainhoward's testimony.

Schedule 1.04 – Normalize Debt Service

(Sponsored by C. William Blackburn)

Big Rivers has proposed a *pro forma* debt service adjustment. For normalized debt service, Big Rivers used actual/forecast debt service on the New RUS Note, the RUS ARVP Note, the LEM Settlement Note and the Green River Coal Obligation for the 12 month period ended August 31, 2009 (assuming the maximum suspension period such that the proposed rates would be effective September 1, 2009), while annualizing the interest rates applicable to the PCBs on February 3,

2009. The PMCC promissory note debt service has been intentionally excluded, as was the leveraged lease date of termination cash payment. The result is normalized debt service of $102,903,597 ($62,942,690 interest, $39,960,907 principal). Actual debt service for the historical period, the 12 months ended November 30, 2008, including the PMCC Promissory Note, but excluding the net leveraged lease cash buyout amount of $107,119,580, which is eliminated on Schedule 1.06, was $99,129,015 ($58,294,657 interest, $40,834,358 principal). The resulting *pro forma* adjustment is to increase Big Rivers' revenue requirement by $3,774,582.

Schedule 1.05 – Eliminate Income Taxes

(Sponsored by C. William Blackburn)

Big Rivers first failed the 85.0 percent member income test in 1983, and the IRS approved non-exempt filing status until notified otherwise. While generating net operating losses ("NOLs") for many years, on both a regular tax and alternative minimum tax ("AMT") basis, Big Rivers first became subject to the alternative minimum tax beginning with the year 2000, due to consummating the 2000 leveraged lease transaction. Big Rivers was subject to the AMT each year since, except for the years 2001 and 2002, when the 90.0 percent AMT NOL limitation was suspended. Now, as a result of the buyout of the leveraged leases in 2008, it is unlikely Big Rivers will pay either the AMT or the regular tax for tax years beyond 2008. Accordingly, the AMT paid during 2008 included in the historical period is being eliminated, serving to reduce Big Rivers' revenue requirement by $1,240,000.

Schedule 1.06 – Eliminate Leveraged Lease
(Sponsored by C. William Blackburn)

As discussed above, due primarily to the Ambac downgrade, Big Rivers executed a buyout of the leveraged lease during 2008, resulting in a net cash payment to the equity participants of $107,119,580 on the termination date. Further, as a result of CoBank's lender role in that transaction, Big Rivers received patronage capital from CoBank -- $389,250 in cash during the historical period. As a result of the buyouts that occurred during 2008, this *pro forma* adjustment to the historical period reduces Big Rivers' revenue requirement by $106,730,330.

Schedule 1.07 – Eliminate Promotional, Political and Institutional Advertising Costs and Donations
(Sponsored by C. William Blackburn)

807 KAR 5:016 provides that no expenditures may be includable in an electric utility's cost of service for rate-making purposes which are for promotional advertising, political advertising or institutional advertising. One example of such costs is the Touchstone Energy costs for both Big Rivers and its members. Big Rivers is also including herein all civic costs and donations (charitable contributions). This *pro forma* adjustment results in a $385,010 reduction in Big Rivers' revenue requirement.

Schedule 1.08 – Eliminate Certain Miscellaneous Costs

(Sponsored by C. William Blackburn)

Big Rivers proposes to exclude certain employee relations and "above the norm" Board of Directors costs from its revenue requirement. The result is a decrease in Big Rivers' revenue requirement of $53,183.

Schedule 1.09 – Rate Case Cost

(Sponsored by C. William Blackburn)

Big Rivers has estimated its cost in connection with this case will be $331,000. In accordance with normal Commission practice, this cost, as updated, would be amortized over a 3 year period, resulting in an increase to the revenue requirement of $110,333.

Schedule 1.10 – Normalize Pension Cost

(Sponsored by C. William Blackburn)

While Big Rivers has "frozen" new entrants into its defined benefit ("DB") plan, replacing it with a defined contribution ("DC") plan, most current employees are participants in the DB plan. Due to the generally poor equity performance over the past 18 months, Big Rivers funded $4,521,507 to its DB plan during the historical period. Per correspondence from Mercer (Louisville, KY office), the actuary used by Big Rivers, dated January 19, 2009, the normalized pension expense is approximately $2,035,003, adjusted for estimated eligible compensation. Accordingly, Big Rivers proposes this *pro forma* adjustment to reduce revenue requirement by $2,486,504.

Schedule 1.11 – Normalize Off-System Sales, Other Revenue and Purchased Power

(Sponsored by C. William Blackburn)

This *pro forma* adjustment to increase the revenue requirement by $18,889,357 results primarily from a current view of the forward price at the Cinergy hub, which is down from what was realized during the historical period. This adjustment is described in Mr. Blackburn's testimony. It reflects a less robust market for non-tariff wholesale sales than what was realized during the historical test period.

Schedule 1.12 – Normalize Interest Income

(Sponsored by C. William Blackburn)

As discussed above, due principally to the $107,119,580 2008 leveraged lease buyout, and the higher rates for the PCBs, Big Rivers' cash and cash equivalent balance has declined significantly, to $25,705,294 on February 3, 2009, when this *pro forma* adjustment was prepared. At the same time, interest rates have precipitously fallen, resulting in these funds being invested at 0.7 percent. The result is a reduction in interest income on cash and cash equivalents from $4,630,505 during the historical period to $180,435 for the *pro forma* period. In summary, the result is a *pro forma* adjustment in the amount of $4,450,070 to increase Big Rivers' revenue requirement.

Schedule 1.13 – Normalize Member Tariff Revenue

(Sponsored by C. William Blackburn)

This *pro forma* adjustment is comprised of three elements – weather normalization for the Rural load, annualizing new or terminated Large Industrial loads, and the termination of the revenue discount adjustment on September 1, 2008. It results in a *pro forma* adjustment to increase member tariff revenue by $2,381,642. This adjustment is described in Mr. Blackburn's testimony.

Q. Please summarize the resuilt of the cash-based revenue requirements.

A. Exhibit Seelye-2 summarizes Big Rivers' $274,137,047 cash-based revenue requirement, based on the historical test year ended November 30, 2008, plus the 13 *pro forma* adjustments discussed above. As demonstrated therein, Exhibit Seelye-2 reflects a $24,901,711 revenue deficiency amount, representing the 21.6 percent member tariff wholesale rate increase that Big Rivers requests Commission approval to implement as of April 1, 2009.

IV. <u>PROPOSED RATES</u>

Q. Have you prepared an exhibit showing the reconstruction of Big Rivers' test-year billing determinants?

A. Yes. The reconstruction of Big Rivers' electric billing determinants (revenue proof) is shown on Exhibit Seelye-3. As shown on page 1 of this exhibit, when Big Rivers' current rates are applied to test-year actual billing determinants the resultant calculated revenues precisely match actual revenues during the test year.

Q. Have you prepared an exhibit showing the effect of the proposed rates on *pro forma* revenue?

A. Yes. Exhibit Seelye-4 shows the increase in revenue by rate class from applying Big Rivers' proposed rates to *pro forma* billing determinants. In this analysis, the *pro forma* billing determinants and *pro forma* revenue reflect the following *pro forma* adjustments: (i) the adjustment to reflect current industrial customers; (ii) the adjustment to reflect normal temperatures; and (iii) the adjustment to reflect the elimination of the revenue discount adjustment. These adjustments are discussed in Mr. Blackburn's direct testimony. As shown on page 1 of this exhibit, the proposed rates result in a 21.6 percent increase in both the rural member rate (Rural Rate) and the large industrial customer rate (Industrial Rate).

Q. How were the rates determined?

A. The demand and energy charges of Big Rivers' two rates were increased by the same percentage. Increasing the rate components by the same percentage ensures that members served under the Rural Rate and members' retail customers taking service under the Industrial Rate will receive the same percentage increase. Applying the same percentage increase to each rate component also maintains the current break-even load factor between the two rates. The break-even load factor is the load factor (i.e., the relationship between average demand and billing demand) at which an industrial customer would be economically indifferent between the two rates. Under Big Rivers' proposed rates, the break-even load factor will remain at the current level of 57.0 percent.

Q. Did Big Rivers prepare a cost of service study to support its proposed rates?

A. No. Big Rivers' proposed rates were developed by allocating the proposed percentage revenue increase to each rate component and each rate schedule on a *pro rata* basis. Allocating the increase in this way facilitates the flow through of the increase by the Big Rivers' Member systems on a proportional basis as required by KRS 278.455(2). As with any G&T cooperative, supporting changes to Big Rivers' rate design with a cost of service study would require a long and involved effort in working with its member systems to develop and explaing the cost of service methodology and rate design. Based on my experience, the process of obtaining board approval for a change in the rate design typically takes anywhere from four to twelve months. Due to the urgency of this rate case filing, Big Rivers did not have enough time to develop a cost of service methodology with its Members, to prepare a cost of service study, to develop various rate design alternatives, to present and explain the results of the cost of service study and rate design alternatives to its Members, and then to obtain board of directors approval on a particular rate design. Even then it is likely that any significant modification to Big Rivers' rates would require that one or more of its Members file general rate cases rather than adjusting rates pursuant to KRS 278.455(2). Without going through this process, it was my recommendation that each component of Big Rivers' rates should be adjusted by the same percentage increase. Big Rivers' proposed rates, which were developed in accordance with this recommendation, were approved by Big Rivers' Board of Directors.

Q. Does this conclude your direct testimony?

A. Yes.

VERIFICATION

I verify, state, and affirm that the foregoing testimony is true and correct to the best of my knowledge and belief.

William Steven Seelye

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by William Steven Seelye on this the 26th day of February, 2009.

Notary Public, Ky. State at Large
My Commission Expires 2/21/2010

QUALIFICATIONS OF WILLIAM STEVEN SEELYE

Summary of Qualifications

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

Employment

Senior Consultant and Principal
The Prime Group, LLC
(July 1996 to Present)

Provides consulting services in the areas of tariff development, regulatory analysis revenue requirements, cost of service, rate design, fuel and power procurement, depreciation studies, lead-lag studies, and mathematical modeling.

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

Prepared retail and wholesale rate schedules and filings submitted to the Federal Energy Regulatory Commission (FERC) and state regulatory commissions for numerous of electric and gas utilities. Performed cost of service or rate studies for over 130 utilities throughout North America. Prepared market power analyses in support of market-based rate filings submitted to the FERC for utilities and their marketing affiliates. Performed business practice audits for electric utilities, gas utilities, and independent transmission organizations (ISOs), including audits of production cost modeling, retail utility tariffs, retail utility billing practices, and ISO billing processes and procedures.

Manager of Rates and Other Positions
Louisville Gas & Electric Co.
(May 1979 to July 1996)

Held various positions in the Rate Department of LG&E. In December 1990, promoted to Manager of Rates and Regulatory Analysis. In May 1994, given additional responsibilities in the marketing area and promoted to Manager of Market Management and Rates.

Education

Bachelor of Science Degree in Mathematics, University of Louisville, 1979
54 Hours of Graduate Level Course Work in Industrial Engineering and Physics.

Expert Witness Testimony

Alabama: Testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments.

Colorado: Testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case.

FERC: Submitted direct and rebuttal testimony in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment.

Submitted direct and responsive testimony in Docket No. ER05-522-001 concerning a rate filing by Bluegrass Generation Company, LLC to charge reactive power service to LG&E Energy, LLC.

Submitted testimony in Docket Nos. ER07-1383-000 and ER08-05-000 concerning Duke Energy Shared Services, Inc.'s charges for reactive power service.

Submitted testimony in Docket No. ER08-1468-000 concerning changes to Vectren Energy's transmission formula rate.

Submitted testimony in Docket No. ER08-1588-000 concerning a generation formula rate for Kentucky Utilities Company.

Submitted testimony in Docket No. ER09-180-000 concerning changes to Vectren Energy's transmission formula rate.

Florida: Testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole Electric Cooperative Inc.'s wholesale rates and cost of service.

Illinois: Submitted direct, rebuttal, and surrebuttal testimony in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service.

Indiana: Submitted direct testimony and testimony in support of a settlement agreement in Cause No. 42713 on behalf of Richmond Power & Light regarding revenue requirements, class cost of service studies, fuel adjustment clause and rate design.

Submitted direct and rebuttal testimony in Cause No. 43111 on behalf of Vectren Energy in support of a transmission cost recovery adjustment.

Kansas: Submitted direct and rebuttal testimony in Docket No. 05-WSEE-981-RTS on behalf of Westar Energy, Inc. and Kansas Gas and Electric Company regarding transmission delivery revenue requirements, energy cost adjustment clauses, fuel normalization, and class cost of service studies.

Kentucky: Testified in Administrative Case No. 244 regarding rates for cogenerators and small power producers, Case No. 8924 regarding marginal cost of service, and in numerous 6-month and 2-year fuel adjustment clause proceedings.

Submitted direct and rebuttal testimony in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg Utilities' rates.

Submitted direct and rebuttal testimony in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan.

Submitted direct and rebuttal testimony in Case No. 99-176 on behalf of Delta Natural Gas Company, Inc. concerning cost of service, rate design and expense adjustments in connection with Delta's rate case.

Submitted direct and rebuttal testimony in Case No. 2000-080, testified on behalf of Louisville Gas and Electric Company concerning cost of service, rate design, and pro-forma adjustments to revenues and expenses.

Submitted rebuttal testimony in Case No. 2000-548 on behalf of Louisville Gas and Electric Company regarding the company's prepaid metering program.

Testified on behalf of Louisville Gas and Electric Company in Case No. 2002-00430 and on behalf of Kentucky Utilities Company in Case No. 2002-00429 regarding the calculation of merger savings.

Submitted direct and rebuttal testimony in Case No. 2003-00433 on behalf of Louisville Gas and Electric Company and in Case No. 2003-00434 on behalf of Kentucky Utilities Company regarding pro-forma revenue, expense and plant adjustments, class cost of service studies, and rate design.

Submitted direct and rebuttal testimony in Case No. 2004-00067 on behalf of Delta Natural Gas Company regarding pro-forma adjustments, depreciation rates, class cost of service studies, and rate design.

Testified on behalf of Kentucky Utilities Company in Case No. 2006-00129 and on behalf of Louisville Gas and electric Company in Case No. 2006-00130 concerning methodologies for recovering environmental costs through base electric rates.

Testified on behalf of Delta Natural Gas Company in Case No. 2007-00089 concerning cost of service, temperature normalization, year-end normalization, depreciation expenses, allocation of the rate increase, and rate design.

Submitted testimony on behalf of Big Rivers Electric Corporation and E.ON U.S. LLC in Case No 2007-00455 and Case No. 2007-00460 regarding the design and implementation of a Fuel Adjustment Clause, Environmental Surcharge, Unwind Surcredit, Rebate Adjustment, and Member Rate Stability Mechanism for Big Rivers Electric Corporation in connection with the unwind of a lease and purchase power transaction with E.ON U.S. LLC.

Submitted testimony in Case No. 2008-00251 on behalf of Kentucky Utilities Company and in Case No. 2008-00252 on behalf of Louisville Gas and Electric Company regarding pro-forma revenue and expense adjustments, electric temperature normalization, jurisdictional separation, class cost of service studies, and rate design.

Submitted testimony in Case No. 2008-00409 on behalf of East Kentucky Power Cooperative, Inc., concerning revenue requirements, pro-forma adjustments, cost of service, and rate design.

Nevada: Submitted direct and rebuttal testimony in Case No. 03-10001 on behalf of Nevada Power Company regarding cash working capital and rate base adjustments.

Submitted direct and rebuttal testimony in Case No. 03-12002 on behalf of Sierra Pacific Power Company regarding cash working capital.

Submitted direct and rebuttal testimony in Case No. 05-10003 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Submitted direct and rebuttal testimony in Case No. 05-10005 on behalf of Sierra Pacific Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case Nos. 06-11022 and 06-11023 on behalf of Nevada Power Company regarding cash working capital for a gas general rate case.

Submitted direct and rebuttal testimony in Case No. 07-12001 on behalf of Sierra Pacific Power Company regarding cash working capital for an electric general rate case.

Submitted direct testimony in Case No. Docket No. 08-12002 on behalf of Nevada Power Company regarding cash working capital for an electric general rate case.

Nova Scotia: Testified on behalf of Nova Scotia Power Company in NSUARB – NSPI – P-887 regarding the development and implementation of a fuel adjustment mechanism.

Submitted testimony in NSUARB – NSPI – P-884 regarding Nova Scotia Power Company's application to approve a demand-side management plan and cost recovery mechanism.

Submitted testimony in NSUARB – NSPI – P-888 regarding a general rate application filed by Nova Scotia Power Company.

Submitted testimony on behalf of Nova Scotia Power Company in the matter of the approval of backup, top-up and spill service for use in the Wholesale Open Access Market in Nova Scotia.

Virginia: Submitted testimony in Case No. PUE-2008-00076 on behalf of Northern Neck Electric Cooperative regarding revenue requirements, class cost of service, jurisdictional separation and an excess facilities charge rider.

Big Rivers Electric Corporation
Cash-Based Revenue Requirement
Based on Test Year Ended November 30, 2008

Description	Actual Cash Requirements 12 Mo Ended Nov 08	Incremental Environmental O&M Schedule 1.01	Eliminate Unwind Cost Share Schedule 1.02	Capital Expenditures Schedule 1.03	Normalize Debt Service Schedule 1.04	Eliminate Income Taxes Schedule 1.05	Eliminate Leveraged Lease Schedule 1.06	Eliminate Promo Advertising, Political, Lobbying and Donations Schedule 1.07	Eliminate Certain Misc Expenses Schedule 1.08
Other Power Supply	120,476,897								
O&M	32,339,407		(4,369,640)					(312,094)	(53,183)
Taxes	2,282,460					(1,240,000)			
Debt Service									
Interest	58,294,657				4,648,034				
Principal	40,834,358				(873,452)				
Capital Expenditures	21,417,957			978,126					
Interest Income	(4,630,505)								
Other Deductions	74,337							(72,916)	
Other Interest Expense	8,826								
Special Funds	(92,937)								
Leveraged Lease Termination	107,119,580						(107,119,580)		
Subtotal	378,125,036	0	(4,369,640)	978,126	3,774,582	(1,240,000)	(107,119,580)	(385,010)	(53,183)
Less: Patronage Capital	(390,656)						389,250		
Gross Revenue Requirement	377,734,380	0	(4,369,640)	978,126	3,774,582	(1,240,000)	(106,730,330)	(385,010)	(53,183)
Revenue	265,799,402	(2,495,013)	84,439						
Revenue Deficiency	(111,934,978)	(2,495,013)	4,454,079	(978,126)	(3,774,582)	1,240,000	106,730,330	385,010	53,183

Big Rivers Electric Corporation
Cash-Based Revenue Requirement
Based on Test Year Ended November 30, 2008

Description	Rate Case Expenses Schedule 1.09	Normalize Pension Costs Schedule 1.10	Normalize Off-System Sales, Other Revenue and Purchased Power Schedule 1.11	Interest Income Schedule 1.12	Normalize Tariff Revenue Schedule 1.13	Net Adjusted Cash Requirements
Other Power Supply			3,027,208			123,504,105
O&M	110,333	(2,486,504)	(402,906)			24,825,414
Taxes						1,042,460
Debt Service						
Interest						62,942,691
Principal						39,960,906
Capital Expenditures						22,396,083
Interest Income				4,450,070		(180,435)
Other Deductions						1,421
Other Interest Expense						8,826
Special Funds						(92,937)
Leveraged Lease Termination						0
Subtotal	110,333	(2,486,504)	2,624,302	4,450,070	0	274,408,532
Less: Patronage Capital						(1,406)
Gross Revenue Requirement	110,333	(2,486,504)	2,624,302	4,450,070	0	274,407,126
Revenue			(16,265,055)		2,381,642	249,505,415
Revenue Deficiency	(110,333)	2,486,504	(18,889,357)	(4,450,070)	2,381,642	**(24,901,711)**

Big Rivers Electric Corporation
Pro forma Adjustments

Incremental Environmental O&M

1	Proforma Year *	3,095,168
2	Historical Year	600,155
3	Pro forma Adjustment	2,495,013

4 Account 413 - Expenses of Electric Plant Leased to WKEC.
5 Income From Leased Property (Net)
* Reflects year-round CAIR, effective 1/1/2009.

Description: Big Rivers' 1998 lease and operating agreement with WKEC requires it to fund its cost-share of Incremental Environmental O&M, as defined therein. Through 2010, Big Rivers' cost-share is 20%. In 2011 it's 40.26%. Threreafter, thru 2023, it's 33.9%

Big Rivers Electric Corporation
Pro forma Adjustments

Eliminate Unwind Costs

1	Proforma Year	0	
2	Historical Year	4,454,079	
3	Pro forma Adjustment	(4,454,079)	
4	Account 413 - Expenses of Electric Plant Leased to WKEC	84,439	Income from Leased Property (Net)
5	Account 921 - Office Supplies and Expenses	82,058	Operating Expense - A&G
6	Account 923 - Outside Services Employed	4,223,579	Operating Expense - A&G
7	Account 928 - Regulatory Commission Expenses	63,983	Operating Expense - A&G
8	Account 930 - Miscellaneous General Expenses	20	Operating Expense - A&G
9		4,454,079	

Description: Big Rivers has cost-share agreements in place with E.ON in connection with all "Unwind" transaction costs. Generally, Big Rivers pays 25% of such costs, with E.ON paying 75%. This proforma adjustment serves to eliminate Big Rivers share of all such costs incurred during the historical test period.

Big Rivers Electric Corporation
Pro forma Adjustments

Capital Expenditures

1	Proforma Year:	
2	Non-Incremental Capital Cost	6,871,000
3	Incremental Capital Cost	1,193,160
4	Transmission and General	14,331,923
5	Total	22,396,083
6	Historical Year:	
7	Non-Incremental Capital Cost	6,707,667
8	Incremental Capital Cost	378,367
9	Transmission and General	14,331,923
10	Total	21,417,957
11	Pro forma Adjustment	**978,126**
12	Account 104 - Electric Plant Leased to WKEC.	
13	Total Utility Plant in Service	

Description: The 1998 lease and operating agreement with WKEC requires Big Rivers to fund its share of Non-Incremental Capital Costs, the Big Rivers Contribution Amount, both as defined therein. The Big Rivers Contribution Amount for 2009 is $6,871,000. Similarly, the agreement requires Big Rivers to fund its share of Incremental Capital Costs, as defined. Through 2010, Big Rivers cost-share is 20%. It's 40.26% in 2011. Thereafter, through 2023, it's 33.9%. WKEC's 2009 budget calls for Big Rivers Incremental Capital cost-share to be $1,193,160. Big Rivers proposes no proforma adjustment for transmission and general plant capital expenditures.

Big Rivers Electric Corporation
Pro forma Adjustments

Debt Service

1	Proforma Year * **:	
2	Beginning Principal Balance	$ 1,037,560,073
3	Beginning Accrued Interest	6,985,552
4	Beginning Prepaid Interest	4,302,953
5	Interest Expense	70,470,524
6	**Interest Payment**	62,942,690
7	Interest Charged to Prepaid Expense	421,778
8	Interest Compounded	5,958,178
9	**Principal Payment**	39,960,907
10	Ending Accrued Interest	8,133,429
11	Ending Prepaid Expense	3,881,175
12	Ending Principal Balance	1,003,557,344
13	Debt Service	**$ 102,903,597**
14	Historical Year**:	
15	Beginning Principal Balance	$ 1,060,349,278
16	Beginning Accrued Interest	7,096,484
17	Beginning Prepaid Interest	4,302,953
18	Loan Proceeds	12,380,000
19	Interest Expense	65,273,653
20	**Interest Payment**	58,294,657
21	Interest Charged to Prepaid Expense	421,778
22	Interest Compounded	5,781,631
23	**Principal Payment**	40,834,358
24	Ending Accrued Interest	7,872,071
25	Ending Prepaid Expense	3,881,175
26	Ending Principal Balance	1,037,676,551
27	Debt Service	$ 99,129,015
28	**Pro forma Adjustment**	
29	**Interest Payment**	**4,648,034**
30	**Principal Payment**	**(873,452)**
31	Total	**3,774,582**
32	Account 224 - Long-Term Debt	(873,452)
33	Account 237 - Interest Accrued	(548,838)
34	Account 427 - Interest on Long-Term Debt	5,196,872
35		3,774,582

*Proforma excludes PMCC Promissory Note.
** Excludes Leveraged Lease (see Schedule 1.06).

Description: Pro forma debt service for Big Rivers' RUS Debt, the LEM Settlement Note, and the Green River Coal Obligation is for the 12 month period ended 8/31/2009 (end of the maximum suspension period). For the pollution control bonds, the interest rates in effect 2/17/09 have been annualized. Debt service on the $12.38 million 8.5% PMCC promissory note due 12/15/09 has been excluded. The leveraged lease is reflected in Schedule 1.06.

Exhibit Seelye-2
Schedule 1.05
Sponsoring Witness: Blackburn
Page 1 of 1

Big Rivers Electric Corporation
Pro forma Adjustments

Eliminate Income Tax

1	Pro forma Year	0
2	Historical Year	1,240,000
3	Pro forma Adjustment	(1,240,000)

4 Account 190 - Accumulated Deferred Income Taxes.

Description: During the historical test period, Big Rivers paid $1,240,000 in alternative minimum tax. As a result of terminating the leveraged lease during 2008, it's unlikely Big Rivers will have future income tax liability. Accordingly, this proforma adjustment is to eliminate income taxes.

Big Rivers Electric Corporation
Pro forma Adjustments

Eliminate Leveraged Lease

1	Pro forma Year >>>		**0**	
2	Historical Year:			
	Account No.	Account Description	Amount	
3	128045	Restricted Investments	(180,583,361)	Special Funds
4	171045	Interest Receivable	(11,288,454)	Interest Income
5	189050	Deferred Loss	76,334,449	Other Deductions
6	224145	Restricted Obligations	171,206,875	Principal Payments
7	224148	PMCC Promissory Note	(12,380,000)	Principal Payments
8	237145	Accrued Interest	11,594,648	Interest Income
9	253045	Deferred Gain	53,726,426	Other Deductions
10	419045	Interest Income	(9,802,036)	Interest Income
11	425045	Amortization of Gain	(2,244,297)	Other Deductions
12	425050	Amortization of Gain	(194,270)	Other Deductions
13	4271XX	Interest on Long-Term Debt	10,077,913	Interest on Long-Term Debt
14	428150	Amortization of Loss	671,687	Other Deductions
15		Termination Cash Cost	**107,119,580**	
16		Bank of America	(2,212,002)	
17		Phillip Morris Capital Corporation	109,331,582	
18			107,119,580	
19	424000	Capital Credits & Patronage Alloc	(778,500.00)	Other Capital Credits & Patronage
20	123100	Patronage Capital from Assoc Coops	389,250.00	
21		CoBank Patronage Cash Receipt	(389,250.00)	
22			**106,730,330**	
23	**Pro forma Adjustment**		**(106,730,330)**	

Description: Big Rivers bought out the equities' interest in the leveraged lease during the historical test period. This pro forma adjustment serves to eliminate the impact the leveraged lease had on Big Rivers cash flow during the historical test period.

Exhibit Seelye-2
Schedule 1.07
Sponsoring Witness: Blackburn
Page 1 of 1

Big Rivers Electric Corporation
Pro forma Adjustments

Eliminate Promotional, Political and Institutional Advertising Cost and Donations

1	Pro forma Year >>>		**0**	
2	Historical Year:			
3	Account No.	Account Description	Amount	
4	913110	Advertising Expense	160,225	Operating Expense - Sales
5	93011X	General Advertising Expense	151,869	Operating Expense - A&G
6	426110	Donations	57,899	Other Deductions
7	426410	Civic, Political and Related	15,017	Other Deductions
8			**385,010**	
9	**Pro forma Adjustment**		**(385,010)**	

Description: Promotional, political and institutional advertising, as well as donations, are generally excluded for rate-making purposes. Accordingly, all such costs incurred during the historical test period are being eliminated.

Big Rivers Electric Corporation
Pro forma Adjustments

Miscellaneous Expense (Employee Relations and Certain Board of Director Expenses)

1	Pro forma Year >>>		**0**	
2	Historical Year:			
3	Account No.	Account Description	Amount	
4	566	Miscellaneous Transmission Expenses	1,077	Operating Expense - Transmission
5	921	Office Supplies and Expenses	5,815	Operating Expense - A&G
6	926	Employee Pensions and Benefits	14,859	Operating Expense - A&G
7	930	Miscellaneous General Expenses	31,432	Operating Expense - A&G
8			**53,183**	
9	**Pro forma Adjustment**		**(53,183)**	

Description: To remove for rate-making purposes certain employee relations and board of director expenses.

Exhibit Seelye-2
Schedule 1.09
Sponsoring Witness: Blackburn
Page 1 of 1

Big Rivers Electric Corporation
Pro forma Adjustments

Rate Case Expense * **

1	Proforma Year (one-third)	110,333
2	Historical Year	0
3	Pro forma Adjustment	110,333

4 Account 928 - Regulatory Commission Expenses.
Operating Expense - A&G
* "Unwind" rate case expenses eliminated in Schedule 1.02.
** Represents one-third of the estimated cost of $331,000.

Description: This adjustments reflects the standard 3-year amortization of rate case expenses.

Exhibit Seelye-2
Schedule 1.10
Sponsoring Witness: Blackburn
Page 1 of 1

Big Rivers Electric Corporation
Pro forma Adjustments

Normalize Pension Cost

1	Pro forma Year	2,035,003	
2	Historical Year	4,521,507	
3	Pro forma Adjustment	**(2,486,504)**	
4	Account 165 - Prepayments	486,074	
5	Account 219 - Other Comprehensive Income	(4,958,073)	
6	Account 232 - Accounts Payable	1,172,420	Operating Expense - A&G
7	Account 920 - A&G Salaries	813,075	
8		(2,486,504)	

Description: During the historical test period, Big Rivers funded $4,521,507 into its defined benefit pension plan. For proforma purposes, the normalized pension funding amount of $2,035,003 is included, per Mercer (Big Rivers' actuary).

Big Rivers Electric Corporation
Pro forma Adjustments

Normalize Non-Tariff Energy Sales, Other Revenue and Purchased Power

1	**Revenue**		
2	Electric Energy Revenues - Non-Tariff Energy Sales (Accounts 447.171 - 447.299) (Including Sales to Smelters)	$	(21,712,149)
3	Other Operating Revenue and Income (Account 456)		5,447,094
4	Total Revenue	$	(16,265,055)
5	**Other Power Supply and Transmission**		
6	Purchased Power (Account 555) - Operating Expense - Other Power Supply	$	(2,167,219)
7	Other Expenses (Account 557) - Operating Expense - Other Power Supply		5,194,427
8	Transmission of Electricity by Others (Account 565) - Operating Expense - Transmission		(402,906)
9	Total Expense	$	2,624,302
10	**Pro forma Adjustment to Increase Revenue Requirement**	**$**	**(18,889,357)**

Description: To normalize non-tariff sales based on current wholesale market conditions, including transmission, and Big Rivers current purchased power cost.

Big Rivers Electric Corporation
Pro forma Adjustments

Normalize Interest Income

1	**Pro forma Year *:**			
2		@ 2/3/2009		
3		Balance	Rate	Interest
4		Balance Rate		
5	Fidelity	25,134,428	0.71%	177,700
6	TVA Deposit	570,867	0.48%	2,734
7		25,705,294		180,435
8	**Historical Year >>**			4,630,505
9	**Pro forma Adjustment**			**(4,450,070)**
10	Account 419 - Interest Income			3,609,133
11	Account 171 - Interest and Dividends Receivable			840,937
12				4,450,070

* Big Rivers' leveraged lease cash buyout cost upon termination was $107,119,580, significantly reducing Big Rivers' cash and cash equivalents, and interest income. Also, investment rates are lower vs. the historical test period.

Description: To reflect the currently estimated amount of interest income on cash reserves.

Big Rivers Electric Corporation
Proforma Adjustments

Normalize Member Tariff Revenue

1	Adjustment to Reflect Current Industrial Customers for a Full Year		648,547
2	Adjustment to Reflect Temperature Normalization		(1,026,905)
3	Adjustment to Elimination of Revenue Discount Adjustment		2,760,000
4	Proforma Adjustment to Reduce Revenue Requirement	Electric Energy Revenues	2,381,642

	Members' Customer	Description of Adjustment	Adjustment in kWh Sales	Adjustment in Billing Demand	Energy Revenue	Demand Revenue	Revenue Adjustment
5							
6					$ 0.013715	$ 10.150	
7	Armstrong Coal (formerly Ohio Co. Coal)	Increased sales to an existing customer	9,941,486	11,830	136,347	$120,075	$256,422
8	Armstrong Coal S.H. Dock (new)	New customer	24,000,000	48,000	329,160	$487,200	$816,360
9	Cardinal River	Closure of facility	(39,080)	(973)	(536)	($9,876)	($10,412)
10	KMMC, LLC	Reduced sales to an existing customer	(2,079,641)	(7,384)	(28,522)	($74,948)	($103,470)
11	Midway Mine	Closure of facility	(7,701,611)	(20,170)	(105,628)	($204,726)	($310,353)
12	Adjustment to Reflect Current Industrial Customers for a Full Year						$648,547

		Adjustment in kWh Sales	Adjustment in Billing Demand	Energy Revenue	Demand Revenue	Revenue Adjustment
13						
14				$ 0.020400	$ 7.370	
15	Adjustment to Reflect Temperature Normalization	(17,812,582)	(90,031)	$ (363,377)	$ (663,528)	$ (1,026,905)
16	Rural					$ 2,059,413
17	Large industrial					700,587
18	Adjustment to Elimination of Revenue Discount Adjustment					$ 2,760,000

Big Rivers Electric Corporation
Reconciliation of Billing Determinants
For the 12 Months Ended November 30, 2008

Rate	Billing Determinants		Charge		Billings	
Rural Delivery Point Service						
Demand Charge	5,172,631	kW-Mo	7.37	/kW-Mo	$	38,122,290
Energy Charge	2,364,365,582	kWh	$ 0.02040	/kWh		48,233,058
Total Demand and Energy Charges					$	86,355,348
Green Power						626.26
Revenue Discount Adjustment						(2,059,413)
Total					$	84,296,562
Revenues per Statement of Operations					$	84,296,562
Difference					$	-
Large Industrial Customer Delivery Point Service						
Demand Charge	1,637,388	kW-Mo	10.15	/kW-Mo	$	16,619,488
Energy Charge	922,976,509	kWh	$ 0.01372	/kWh		12,658,623
Total Demand and Energy Charges					$	29,278,111
Green Power						-
Power Factor Provision and Off-System Sales Credit						88,198
Revenue Discount Adjustment						(700,587)
Total					$	28,665,722
Revenues Per Statement of Operations					$	28,665,722
Difference					$	-
Total					**$**	**112,962,284**

Big Rivers Electric Corporation
Summary of Revenue Increase
Based on Pro-Forma Billing Determinants
For the 12 Months Ended November 30, 2008

Revenues		Actual Test-Year Revenues		Adjustment to Reflect Current Industrial Customers		Adjustment to Reflect Normal Temperature		Adjustment to Reflect Elimination of Revenue Discount Adjustment		Pro-Forma Revenues at Current Rates		Pro-Forma Revenues at Proposed Rates		Revenue Increase	Percentage Increase
Rural Delivery Point Service	$	84,296,562				(1,026,905)		2,059,413	$	85,329,069	$	103,776,297	$	18,447,227	21.6%
Large Industrial Customer Delivery Point Service		28,665,722		648,547				700,587	$	30,014,856	$	36,504,851	$	6,489,995	21.6%
Total	$	112,962,284	$	648,547	$	(1,026,905)	$	2,760,000	$	115,343,926	$	140,281,148	$	24,937,222	21.6%

Energy (kWh)	Actual Test-Year kWh Sales	Adjustment to Reflect Current Industrial Customers	Adjustment to Reflect Normal Temperature	Pro-Forma kWh Sales
Rural Delivery Point Service	2,364,365,582		(17,812,582)	2,346,553,000
Large Industrial Customer Delivery Point Service	922,976,509	24,121,154		947,097,663
Total		24,121,154	(17,812,582)	6,308,572

Billing Demand (kW-Months)	Actual Test-Year Billing Demand	Adjustment to Reflect Current Industrial Customers	Adjustment to Reflect Normal Temperature	Pro-Forma Billing Demand
Standard Wholesale Rate -- Rurals	5,172,631		(90,031)	5,082,600
Large Industrial Customer Rate	1,637,388	31,303		1,668,691
Total	6,810,019	31,303	(90,031)	6,751,291

Big Rivers Electric Corporation
Reconciliation of Billing Determinants
For the 12 Months Ended November 30, 2008

Rate	Billing Determinants	Current Rate		Proposed Rate	
		Charge	Billings	Charge	Billings
Rural Delivery Point Service					
Demand Charge	5,172,631 kW-Mo	7.3700 /kW-Mo	$ 38,122,290	8.963 /kW-Mo	$ 46,362,292
Energy Charge	2,364,365,582 kWh	$ 0.02040 /kWh	48,233,058	$ 0.024811 /kWh	58,662,274
Total Demand and Energy Charges			$ 86,355,348		$ 105,024,566
Green Power			626.26		626.26
Revenue Discount Adjustment (Eliminated)			-		-
Temperature Normalization Adjustment - Demand	(90,031) kW-Mo	$ 7.3700 /kW-Mo	(663,528)	$ 8.963 /kW-Mo	(806,948)
Temperature Normalization Adjustment - Energy	(17,812,582) kWh	$ 0.02040 /kWh	(363,377)	$ 0.024811 /kWh	(441,948)
Total			$ 85,329,069		$ 103,776,297
Increase					$ 18,447,227
Percentage Increase					21.6%
Large Industrial Customer Delivery Point Service					
Demand Charge	1,637,388 kW-Mo	10.15 /kW-Mo	$ 16,619,488	12.345 /kW-Mo	$ 20,213,555
Energy Charge	922,976,509 kWh	$ 0.013715 /kWh	12,658,623	$ 0.016680 /kWh	15,395,248
Total Demand and Energy Charges			$ 29,278,111		$ 35,608,803
Green Power			-		
Power Factor Provision and Off-System Sales Credit			88,198		107,272
Revenue Discount Adjustment (Eliminated)			-		-
Current Industrial Customer Adjustment - Demand	31,303 kW-Mo	10.15 /kW-Mo	317,725	12.345 /kW-Mo	386,436
Current Industrial Customer Adjustment - Energy	24,121,154 kWh	$ 0.013715 /kWh	330,822	$ 0.016680 /kWh	402,341
Total			$ 30,014,856		$ 36,504,851
Increase					$ 6,489,995
Percentage Increase					21.6%

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2009-00040

DIRECT TESTIMONY OF
C. WILLIAM BLACKBURN

ON BEHALF OF
BIG RIVERS
ELECTRIC CORPORATION

MARCH 2, 2009

TABLE OF CONTENTS

DIRECT TESTIMONY OF
C. WILLIAM BLACKBURN

I. INTRODUCTION

Q. Please state your name, position, and qualifications.

A. My name is C. William Blackburn. I am employed by Big Rivers Electric Corporation ("Big Rivers") as its Senior Vice President Financial & Energy Services & Chief Financial Officer ("CFO"). I have been CFO since November 2005. Prior to that, I held the position of Vice President Power Supply for 9 years. Upon closing of the transaction that will unwind Big Rivers' 1998 lease with E.ON U.S., LLC ("E.ON") and its affiliates (the "Unwind Transaction"), described in Case No. 2007-00455 (the "Unwind Proceeding"), my title will remain the same. I have testified on behalf of Big Rivers many times before the Kentucky Public Service Commission ("KPSC" or the "Commission"), including for fuel hearings, environmental cases, rate cases, and transmission cases. Most recently I testified in the Unwind Proceeding. Altogether I have been employed by Big Rivers for a total of 31 years.

II. OVERVIEW AND PURPOSE OF TESTIMONY

Q. Please describe the purpose of your testimony in these proceedings.

A. The principal purpose of my testimony is to provide a detailed overview of the circumstances that have forced Big Rivers to file this request for emergency interim and permanent rate relief. Big Rivers understands the gravity of the relief it is seeking. My testimony demonstrates why Big Rivers is compelled to seek this relief at this time.

I begin my testimony by explaining why Big Rivers is seeking interim rate relief at the same time it is trying to close the Unwind Transaction. Because this case will only continue if the Unwind Transaction fails to close, I will describe the precarious financial position Big Rivers faces under those circumstances as a result of the collapse of the financial markets and the effects of that collapse on Ambac Assurance Corporation ("Ambac") and its role in transactions to which Big Rivers is a party. My testimony also will explain the critical nature of cash to Big Rivers' operations because of Big Rivers' practically non-existent ability to borrow money to finance its operations. I will also detail the circumstances surrounding Big Rivers' purchase and termination on September 30, 2008, of the leveraged leases to which a Philip Morris Capital Corporation subsidiary ("PMCC") was a party (the "PMCC Buyout"). I will also describe the potential future risks Big Rivers is facing if the Unwind Transaction does not close, which support the need for Big Rivers to maintain adequate cash reserves.

My testimony further addresses the reasonableness of Big Rivers' rates if the rate relief Big Rivers is seeking is implemented. I also provide specific support for five of the *pro forma* adjustments to the test year revenue requirements as part of this testimony: the adjustment to eliminate Unwind cost shares (Schedule 1.02); the adjustment to normalize debt service (Schedule 1.04); the adjustment to normalize pension cost (Schedule 1.10); the adjustment to normalize off-system sales, other revenue and purchase power expenses (Schedule 1.11); and the adjustment to normalize tariff revenues (Schedule 1.13). And finally, I affirm the portions of the information required by 807 KAR 5:001 for which I am the sponsor.

III. BIG RIVERS' UNWIND EFFORTS

Q. Mr. Blackburn, has the Commission approved Big Rivers' proposal submitted in P.S.C. Case No. 2007-00455 to Unwind its 1998 Transaction with E.ON U.S.?

A. Not yet. Big Rivers expects an order approving its request to enter into the Unwind Transaction in the near future.

Q. If the Unwind Transaction is approved and closes, is the rate adjustment sought in this case still required?

A. This case will become moot with the closing of the Unwind Transaction, but only if and when the Unwind Transaction actually does close.

Q. Why does Big Rivers require the emergency interim rate relief it now seeks when the Unwind Transaction closing remains on the horizon?

A. As Mr. Bailey also notes in his Direct Testimony (Exhibit 45), if the Unwind Transaction does not close, the cash infusion sought in this case is absolutely critical to Big Rivers. There are numerous reasons why a planned closing and the Unwind Transaction could fail literally at the last minute. Because the closing cannot occur until the expiration of the period in which an appeal can be taken from the Commission's order in the Unwind Proceeding, the earliest a closing can occur is upon expiration of the thirty-three day appeal period after the issuance of an order approving the Unwind Transaction. Big Rivers cannot wait to determine whether it needs to file for emergency interim rate relief, because it cannot generate the cash it requires at the submitted rate levels if the rates proposed go into effect later than April 1, 2009.

And even if the Unwind Transaction closes, there is no guarantee that it will close on a timely basis after the expiration of the appeal period. As the

Commission is aware, there are scores of closing conditions to be met before the Unwind Transaction can close. While delay of the closing beyond the earliest closing date is highly undesirable and could even threaten the Unwind Transaction, a delay nevertheless could occur. Moreover, Big Rivers and the E.ON Entities require the consent of the City of Henderson to the transaction. If obtaining that consent requires filing a contract amendment with the Commission, substantial delays to closing could result. For all the reasons explained in Big Rivers' Application and exhibits, so long as there is a chance that the Unwind Transaction could fail to close, the risks to Big Rivers of delaying emergency interim rate relief beyond April 1 are too substantial to accept.

Big Rivers also has certain conditions to closing relating to the condition of its generation units being restored to its control, and other potentially significant matters. If an issue arises regarding one of those closing conditions, Big Rivers does not want the decision about satisfaction of that condition to be unduly influenced by concerns regarding the financial condition of the company if the closing does not occur.

Q. **Would Commission approval of the emergency interim rate relief requested have any effect on the rates Big Rivers requested in the Unwind Proceeding?**

A. Commission approval of the rate relief requested herein would have no effect whatsoever on the rates requested in the Unwind Proceeding should the Unwind Transaction close. When the Unwind Transaction closes, this case would become moot. If Big Rivers has already begun collecting interim rate relief, the amounts collected will be refunded in the first billing cycle after closing of the Unwind Transaction.

Q. Why does the need for a rate increase differ if the Unwind Transaction closes?

A. The Unwind Transaction is expressly designed to eliminate the very problems that inhibit Big Rivers from resolving the current projected cash shortfall other than by raising cash by seeking immediate rate relief. Big Rivers requires the emergency interim relief it requests in order to build up sufficient cash to meet operating expenses as they occur. The need for an increased cash reserve is heightened by the virtual inability of Big Rivers to obtain new financing under the terms of its existing financing transactions. Closing of the Unwind Transaction would eliminate both of these concerns. Big Rivers would receive significant cash payments from E.ON at closing, including E.ON's payment of one-half of the costs of the PMCC Buyout ($60.9 million). These cash payments would provide Big Rivers with sufficient cash to pay off the short-term bridge loan with PMCC ($12.4 million) that otherwise would be due December 15, 2009, and to retain an ample operating balance to meet known expenses as they occur. Moreover, closing of the Unwind Transaction would greatly improve Big Rivers' ability to obtain financing for unexpected costs. As I noted in the Unwind Proceeding, obtaining an investment grade credit rating and operating under the new financing agreements is one of the chief advantages of the Unwind Transaction. Big Rivers' current financial situation in which it has pending significant known expenditures, a low level of operating cash, and an inability to borrow additional funds is exactly the situation the Unwind Transaction's new financing arrangements were designed to ameliorate.

Q. Would Commission approval of this request make the Unwind Transaction less likely to occur?

A. No. The Unwind Transaction's merits remain strong for Big Rivers, and the Unwind Transaction remains Big Rivers' preferred alternative.

IV. BIG RIVERS' FINANCIAL HISTORY SINCE 1998

A. The 1998 Transaction

Q. Mr. Blackburn, what do you believe is the principal reason that Big Rivers now finds itself unable to meet projected costs absent emergency interim rate relief?

A. Big Rivers' current cash poor situation is directly attributable to the unprecedented ongoing turmoil in global financial markets. If not for the present market meltdown that led to the PMCC Buyout in September 2008, I believe Big Rivers would have been able to continue to operate under its current rate structure supported by Big Rivers' cash balances.

Q. Do you believe Big Rivers' operations under the 1998 Transaction made it more vulnerable to the effects of the global financial market meltdown?

A. I do. Big Rivers' operation under the 1998 Transaction imposed a number of financial limitations on Big Rivers, particularly with respect to its ability to obtain new financing, which made it more vulnerable to the global financial market meltdown. While there is no question that Big Rivers' history of operations under the 1998 Transaction has been positive and a success, certain aspects of the 1998 Transaction without a doubt have hampered Big Rivers' ability to withstand the global financial meltdown.

Q. Could you please explain the historical factors that you believe to have contributed to the current situation?

A. Certainly. I think the relevant historical factors begin with the 1998 Transaction with E.ON and that it is important to provide an overview of Big Rivers' operations under that transaction. In the 1998 Transaction, Big Rivers entered into a 25-year long-term lease of its generating units (including its contractual commitments to operate the City of Henderson's Station Two) in return for fixed lease payments from E.ON and its subsidiaries. Big Rivers also obtained a right to purchase a fixed quantity of power from LG&E Energy Marketing ("LEM") (an E.ON subsidiary) at negotiated, essentially fixed rates, which power Big Rivers then used to meet its Members' needs.

The fixed power purchase rates established in the 1998 Transaction have proven to be advantageous for Big Rivers and its Members. Since 1998, Big Rivers' Member rates have remained level, with the only change to those rates being the implementation of a credit, the Member Discount Adjustment ("MDA"), which reduced Member payments between 2001 and 2008 by approximately $3.7 million each year. Over the past ten and one-half years of operation under the 1998 Transaction's terms Big Rivers has not until now sought to increase its base rates.

Big Rivers has successfully engaged in numerous non-tariff wholesale sales (both off-system sales and sales to its Members for their non-requirements needs such as Kenergy Corp.'s two aluminum Smelters' Tier 3 power) under which it has purchased fixed-price power from LEM not required for its Members' tariff needs and sold that power at prices that have yielded significant margins. These margins have kept Big Rivers financially viable, have allowed Big Rivers to maintain and reduce its 1998 rate levels, and have permitted it to pay down its debt to the United States Rural Utilities Service ("RUS").

Despite these noted benefits, the 1998 Transaction also included limitations on Big Rivers. For example, the plan of reorganization manifested in the 1998 Transaction left Big Rivers with only limited means of financing its operations and only limited ways of meeting potential unanticipated financial risks by obtaining needed financing.

Q. You have mentioned the advantages of the 1998 Transaction. Please describe the financing limitations of the 1998 Transaction.

A. There was an assumption from the outset under the 1998 Transaction that Big Rivers' capital requirements could be satisfied largely out of cash flow.

Structurally, the 1998 Transaction left Big Rivers with little ability to raise capital for growth or development. The financing agreements as currently reflected in the Third Restated Mortgage, as amended, also were based on this assumption, as they were designed to protect existing lenders and did not provide for the flexible accommodation of new lenders.

Q. How was this protection of existing lenders accomplished?

A. The Third Restated Mortgage constituted a first lien on, and security interest in, almost all of Big Rivers' real and personal property, both tangible and intangible. It also included after-acquired property provisions which purported to extend the lien and security interest of the Third Restated Mortgage to the real and personal property acquired by Big Rivers subsequent to the date of execution and delivery of the Third Restated Mortgage. This broad grant of the lien and security interest in virtually all of Big Rivers' real and personal property, both existing and after-acquired, made it extremely difficult for Big Rivers to finance on the basis of a first lien and security interest in any property outside the Third Restated Mortgage.

Q. Did the Third Restated Mortgage offer any accommodation of new lenders?

A. No. In fact, because the existing Intercreditor Agreement made no provision for accommodation of a prospective future lender or lenders, any such lenders would need to be introduced into the agreement on a purely *ad hoc* basis, with no provision for obtaining an equal security interest.

Q. Were there any further factors that made new financing more difficult?

A. Yes. As Big Rivers' principal creditor, and one having suffered through a Big Rivers bankruptcy, the RUS was unwilling to make additional financial outlays to Big Rivers. Both the New RUS Loan Agreement and the RUS Mortgage were structured as "no future advances" agreements, thereby cutting off Big Rivers at the outset from one of the largest sources of additional cooperative financing. In fact, the phrase "(No Future Advances)" was even incorporated into the title of the New RUS Loan Agreement: "New RUS Agreement (No Future Advances) dated as of July 15, 1998 between Big Rivers Electric Corporation and the United States of America."

Moreover, Big Rivers' condition as a utility emerging from bankruptcy protection made it too weak initially to attract unsecured sources of credit in the market.

Q. Did Big Rivers take any action to minimize the negative effect of its inability to borrow in the 1998 Transaction?

A. Yes. Big Rivers knew that the margins it was able to earn on its non-tariff wholesale sales were a potentially significant revenue stream. Although certain portions of these margins were required to be used to repay RUS debt, the remaining portions were subject to Big Rivers' control.

Q. What did Big Rivers decide to do with these sales margins?

A. Because Big Rivers increasingly recognized that additional borrowing was extremely difficult under the terms of the 1998 Transaction, Big Rivers determined that it was necessary for it to build a cash balance, rather than relying on debt so that liquid funds would be available for it to use to meet its financial needs. Whereas another utility might routinely rely on unsecured loans or other readily available financing to meet a new financial need, Big Rivers knew it had greatly limited recourse to such an alternative under the 1998 Transaction. Building a liquid cash reserve would serve in a way as a self-financing of any unanticipated costs as the cash on hand could be used in place of a borrowing.

Q. Did Big Rivers have any specific kinds of costs in mind at the time it began building a cash reserve for unanticipated costs?

A. Coming out of the 1998 Transaction, Big Rivers recognized that there were a number of potential expenditures for which it might need to retain funds given its limited borrowing ability. Big Rivers' operating risks then were little different than Big Rivers' operating risks now: contractual issues with E.ON under the 1998 Transaction; new laws or regulations that could create costs; litigation with E.ON, Kenergy's two Smelter customers, or others; and costs to meet its Members' power requirements, including potential needs for additional capacity. In Section V(B) of this testimony I describe these ongoing operating risks that could create future unanticipated costs for which an established cash reserve would be needed. Those descriptions apply equally to Big Rivers' past operations and help to explain why Big Rivers built its cash reserves during its course of operations under the 1998 Transaction.

B. The Big Rivers Leveraged Leases

Q. Mr. Bailey identifies the buyout of the PMCC leveraged leases as the principal cause of Big Rivers' cash depletion. When did Big Rivers enter into those leveraged leases?

A. Big Rivers entered into two sets of leveraged leases of its Wilson and Green Units in 2000. These leveraged leases are described in a September 25, 2008 Affidavit of C. William Blackburn submitted in the Unwind Proceeding ("Blackburn Affidavit"), attached as Exhibit 54, at pp. 10-11.

Q. Why did Big Rivers enter into these leveraged leases?

A. Big Rivers entered into the leveraged leases in order to monetize certain tax benefits that otherwise would have been unused. The leveraged leases offered Big Rivers a means to obtain an up-front cash benefit of $64.0 million that it used to reduce its debt and debt service payments.

Q. Did the Commission have occasion to review Big Rivers' decision to enter into the leveraged leases prior to Big Rivers' execution of those leases?

A. Yes. Big Rivers presented the leveraged leases to the Commission in Case No. 99-450. Although Big Rivers requested that the Commission disclaim jurisdiction over the leveraged leases on the grounds that no securities or evidences of indebtedness would be issued, the Commission denied that request. Instead, the Commission found the leveraged leases to be evidences of indebtedness under KRS 278.300(1) and that the modifications to the existing mortgage documents and 1998 Transaction documents needed to be approved by it. After conducting its review, the Commission authorized Big Rivers to execute the leveraged leases by orders issued November 8, 1999 (Exhibit 50), as amended on January 28, 2000 (Exhibit 51).

Q. In approving the leveraged leases, did the Commission consider Big Rivers' potential financial exposure in the event of an early termination of those leases?

A. Yes. The Commission's order in Case No. 99-450 in November 1999 specifically expressed concerns regarding Big Rivers' potential financial exposure in the event of an early termination of the leveraged leases. However, after weighing the documents and responses in the record, the Commission concluded that adequate provisions had been made regarding Big Rivers' potential exposure from an early termination due to an event of loss or event of default. The Commission approved the leveraged leases even though Big Rivers estimated that an early termination could amount to a net financial exposure of as much as $218 million.

Q. What did the leveraged leases provide in the event of an early termination?

A. In the event of an early termination of one or the other of the set of leveraged leases, the leveraged leases provided that Big Rivers would owe a Termination Value Payment approximately equal to the remaining lease payments that Big Rivers otherwise would have made. The specific provisions regarding early termination are discussed in the Blackburn Affidavit at pp. 11-12, 13-15. As further described in the Blackburn Affidavit, Big Rivers entered into a number of financial contracts with independent financial entities (American International Group, Inc. ("AIG") and Ambac) to guarantee and offset these potential termination payments. See Blackburn Affidavit at pp. 14-17.

Q. Was Big Rivers the only cooperative or utility to enter into leveraged lease transactions of this type during the time period in question?

A. No. Big Rivers was not the only consumer-owned electric utility to enter into similar leveraged lease transactions involving electric generation and/or transmission assets in roughly the same time frame. At least six other electric generation and transmission cooperatives and three municipal electric systems entered into one or more similar transactions in the period from 1996 through 2002.

Q. What proceeds did Big Rivers receive and what did Big Rivers do with the proceeds of the 2000 leveraged leases?

A. Because the leveraged leases required granting security interests in the facilities to third parties, the RUS was required to consent to the leveraged leases. The RUS conditioned its consent on Big Rivers applying the total net cash benefit of $64.0 million to the RUS New Note, which Big Rivers did. This resulted in a recalculation of the RUS New Note debt service schedule to reflect the lower principal balance. The result of this recalculation was a reduction by $3.7 million in Big Rivers' annual debt service.

Q. What did Big Rivers do with the approximately $3.7 million in reduced annual debt service?

A. The $3.7 million in annual debt service savings were used by Big Rivers to reduce rates to its Members for a period of time. Specifically, beginning September 2000, Big Rivers implemented the MDA for an initial period of two years. Subsequently, Big Rivers extended the MDA each year through August 2008. Big Rivers' Members thus directly benefited from the leveraged leases during the period 2000 to 2008. The Members received both a direct rate benefit as well as the indirect benefit of having a stronger Big Rivers due to the $64.0 million reduction in Big Rivers' RUS debt.

Q. When and why did the MDA terminate?

A. Big Rivers chose to allow the MDA to expire on August 31, 2008. By that time the global financial meltdown had already begun, and Big Rivers was well into its efforts to resolve issues in connection with the PMCC leveraged lease due to Ambac's precarious financial condition. Continuing to extend the MDA was no longer prudent under the circumstances, and thus it was terminated.

C. Termination of the Leveraged Leases

1. Overview of Termination

Q. You mentioned earlier that Big Rivers has now bought out and terminated the PMCC leveraged leases, is that correct?

A. Yes. Big Rivers bought out the PMCC leveraged leases on September 30, 2008 by making a payment to PMCC of approximately $121.7 million, $109.3 million in cash and a $12.4 million 8.5% promissory note due no later than December 15, 2009. The general terms under which Big Rivers paid off the PMCC leveraged leases are set forth in detail in the Blackburn Affidavit at pp. 3-4; 36-44, although those terms do not reflect a fixed promissory note amount.

2. Reason for PMCC Buyout

Q. Why did Big Rivers terminate the PMCC leveraged leases early?

A. Moody's Investors Services ("Moody's") on June 19, 2008 downgraded Ambac's claims-paying ability to "Aa3." This downgrade in Ambac's financial situation exposed Big Rivers to adverse consequences under the contractual terms of the leveraged leases. Big Rivers' decision to undertake the PMCC Buyout was a direct outgrowth of this destabilization of Ambac, which itself was caused by general market instability.

Q. Was there any reason that Big Rivers could have expected Ambac to lose its financial rating at the time it entered into the leveraged leases?

A. Absolutely not. Ambac was a triple-A rated insurer and was included in the leveraged leases as a means to reduce risk. Absent the kind of general, across-the-board unthinkable collapse in financial markets such as is now taking place there was no reason whatsoever for Big Rivers to have had any concerns about Ambac.

Q. How did Ambac figure into the PMCC leveraged leases?

A. Ambac's role in the PMCC leveraged leases was to serve as an insurer of Big Rivers' payment obligations to PMCC by providing credit support. Big Rivers was required to maintain throughout the term of the PMCC leveraged leases certain minimum collateral requirements to secure its financial obligations to the trustee and PMCC. These collateral requirements largely related to the lease termination payments established as liquidated damages sufficient to discharge the debt in the leveraged leases, to pay the unrecovered portion of the investor's cash investment in the leased assets, and to make the investor whole for any tax detriment to the investor resulting from an early termination.

Q. As a result of the downgrade in Ambac's claims paying ability did the agreement with Ambac still qualify under the terms of the agreements negotiated with PMCC?

A. No. Moody's downgrade of Ambac to "Aa3" precluded Big Rivers from relying on the Ambac credit support arrangement to meet the contractual collateral requirement.

Q. What did the PMCC leveraged lease documents require in such event?

A. As described in the Blackburn Affidavit at p. 13, Big Rivers was obligated to obtain replacement collateral arrangements within 60 days or else Big Rivers would be in default of the leverage lease agreements.

Q. What remedies did the PMCC leveraged lease agreement documents provide to PMCC in the event of an uncured event of default like this?

A. As described in the Blackburn Affidavit at pp. 13-14, the PMCC leveraged lease documents provided PMCC with a number of options in the event of a default. However, the most likely remedy was for the leveraged leases to be terminated at PMCC's direction.

Q. What would have been the practical effect on Big Rivers of PMCC exercising one of these remedies?

A. Depending upon the remedy exercised, Big Rivers would have owed a termination payment. During the Summer of 2008, the aggregate termination payment under the three PMCC leveraged leases was approximately $221.5 million.

Q. Did the structure of the 2000 PMCC leverage leases provide for any offsets against a lease termination payment that would be owed by Big Rivers?

A. Yes. As described in the Blackburn Affidavit at pp. 15-17, the PMCC leveraged leases structurally included three separate payment agreements, one of which was the AIG guaranteed investment contract, the proceeds of which could be applied by Big Rivers to offset a termination payment owed to PMCC. The agreements served to economically defease the equity portion of the rent under the PMCC Leases and the purchase option price under the fixed price purchase option provided in the PMCC Leases.

Q. Were the amounts of these three offsetting agreements fixed?

A. No. The amount received under the payment agreements was subject to exact quantification only at the time of redemption, and was tied to general market conditions.

Q. Can you estimate what Big Rivers' exposure to PMCC would have been during the Summer of 2008 if PMCC declared an event of default based on the Ambac downgrade?

A. Absent a negotiated resolution, commencing 60 days after June 19, 2008 (the date of the Ambac credit downgrade), PMCC could have declared an event of default that ultimately would have resulted in Big Rivers being required to pay PMCC the difference between the $221.5 million contractually-specified termination payment and the estimated net proceeds of the three funding agreements.

Q. Would Big Rivers' exposure have increased if Ambac had entered bankruptcy and could not satisfy its obligations?

A. Yes, significantly. As described in the Blackburn Affidavit at pp. 17-18, the termination value payment described above assumed a situation with a still viable Ambac, albeit one with a downgrade in its financial rating such that it could no longer adequately collateralize Big Rivers' obligations to PMCC. In the event of an Ambac bankruptcy, Ambac might have exposed Big Rivers to significant obligations of an additional $583 million above the described termination value payments. See Blackburn Affidavit at pp. 34-36.

3. Big Rivers' Resolution of PMCC Issues

Q. How did Big Rivers resolve the issues created by the loss of the Ambac credit support?

A. Big Rivers ultimately determined that the cleanest, least-risk and least-cost solution was termination of the PMCC leveraged leases through a negotiated buyout with PMCC. While Big Rivers recognized this buyout would have a significant effect on its cash balances, Big Rivers determined that it was the most prudent option available and that it was better to be proactive than to have its financial situation dictated to it by external events. This PMCC Buyout took place on September 30, 2008.

Q. Did Big Rivers consider other options to resolve the financial difficulties posed by the Ambac ratings downgrade?

A. Initially, Big Rivers and its financial advisors saw three potential solutions to the Ambac situation: (1) provide an alternative credit enhancement meeting the requirements of the operative documents of the PMCC leveraged leases; (2) develop new collateralization of the equity amounts potentially owed in the event of a default under the PMCC leveraged leases; and (3) terminate the PMCC leveraged leases in a negotiated buyout. Big Rivers took the third option only after full exploration of the other options between June 2008 and September 2008 had eliminated them as reasonable possibilities.

Q. What did Big Rivers conclude regarding the potential for providing an alternative credit enhancement?

A. As explained in the Blackburn Affidavit at pp. 23-26, Big Rivers determined that given its existing restrictions on obtaining new financings unencumbered or subordinated to the numerous existing financing obligations, it would be extremely difficult, if not impossible, to find a credit enhancer that would accept Big Rivers without an investment grade credit rating. This conclusion remained the same even if the new credit enhancer essentially could be placed in the same security package as Ambac, including being secured under Big Rivers' first lien instrument. And as further explained in the Blackburn Affidavit at pp. 24-26, replacement of Ambac as credit enhancement also might require replacement of the underlying $583 million obligations given the way Ambac's security arrangements were structured. This complication would have made an alternate credit enhancer expensive at best, unavailable at worst. Moreover, in even the best scenario, negotiation and documentation of an alternate credit enhancer would have required time that Big Rivers did not have.

Q. Did Big Rivers nevertheless explore third-party credit enhancement suppliers?

A. Yes. Big Rivers explored the possibility of obtaining alternative credit enhancement from other insurers and banks. The tightness in the credit markets made credit enhancement of this sort extremely expensive, even for those unlike Big Rivers with good credit. This problem later became further exacerbated by market conditions such that by September 2008 it was a practical impossibility.

Q. What did Big Rivers conclude regarding its second option – use of an alternate collateralization under the PMCC leveraged leases?

A. Although Big Rivers initially regarded an alternate cash collateralization method as offering an acceptable solution to the Ambac downgrade, it was a more complicated financial structure, and the RUS ultimately informed Big Rivers that it was not interested in pursuing that alternative except upon terms which Big Rivers could not accept. Big Rivers' consideration of this alternative before rejecting it is discussed in the Blackburn Affidavit at pp. 26-31.

Q. What caused Big Rivers to choose the PMCC Buyout solution when it did?

A. With both alternate credit enhancement and an alternative collateralization off the table as options, and with Big Rivers continuing in potential default of its leverage lease obligations to PMCC, Big Rivers in September 2008 had no reasonable alternative to a negotiated PMCC Buyout. While Big Rivers could have done nothing, that alternative would have merely ceded control over the timing of a termination of the leverage lease to PMCC given its ability to declare a default by ending its voluntary waiver of its remedies. And doing nothing would have meant foregoing a number of benefits and, depending on timing, could have endangered Big Rivers' ability to enter into the Unwind Transaction or to remain solvent if the Unwind Transaction did not close. By contrast, proactively entering into the PMCC Buyout offered some notable advantages.

Q. **Please describe these advantages.**

A. A first advantage to the PMCC Buyout over doing nothing was E.ON's agreement to fund one-half of the net payment to PMCC ($60.9 million) in the event the Unwind Transaction closed. Faced with a potential smaller contribution of its own funds in the event of an Unwind closing, Big Rivers determined that it could enter into a leveraged lease buyout and still agree to prepay the agreed-upon $125 million to the RUS upon closing of the Unwind Transaction. The PMCC Buyout thus kept the Unwind Transaction on track to close.

A second key advantage was that Big Rivers after a PMCC Buyout would remain financially stable, albeit in a weakened cash and revenue position, even if the Unwind Transaction did not occur. Big Rivers knew it would need a rate increase in that eventuality, but this potential need for a rate increase was deemed preferable to risking Big Rivers' financial existence. Were Big Rivers to have done nothing, it would have continued to face the uncertainty and risk of financial catastrophe concerning the possible future failure of AIG or Ambac, which in September 2008 appeared more and more likely to occur with the passage of time. The instability in the world credit markets provided a very strong and immediate incentive to complete a PMCC Buyout during September 2008, as Big Rivers likely could not have survived a bankruptcy of either AIG or Ambac.

A third advantage already discussed was that changes to interest rates caused by instability in credit markets had increased the value of the AIG guaranteed investment contract in September 2008. By making the PMCC Buyout at a time when the value was high, Big Rivers was able to reduce its net cash outlay. Big Rivers received a value of $92.6 million for the AIG guaranteed investment contract in September 2008, thereby capturing an additional $24 million of value compared to redemption values prevailing earlier in the Summer of 2008 when the AIG guaranteed investment contract would have yielded only $68.0 million. Waiting could have resulted in erosion of these benefits and a lower value being received for the AIG guaranteed investment contract, thus making a buyout a potential impossibility because Big Rivers might not have had sufficient cash to proceed.

A fourth key advantage was that Big Rivers was under significant time pressure. PMCC had elected temporarily to forebear exercising any remedies available to it relating to Big Rivers' default on its collateralization obligation while productive negotiations continued, but Big Rivers had no assurances that PMCC would continue to waive exercise of its remedies. PMCC was pressing hard for a third quarter resolution of this issue, and Big Rivers understood PMCC might reconsider its waivers if a buyout were not achieved come October 1. PMCC further had informed Big Rivers that its offer of the \$12.4 million short-term bridge loan would expire at the end of September. PMCC also had offered a \$7.5 million concession on the termination payment that was not available indefinitely. PMCC thus was in the driver's seat and could have declared a default at any time. Accepting their loan and termination payment concession at that time, especially in light of the fact that the AIG guaranteed investment contract was also at a relatively high value, was a financial advantage that otherwise would have been foregone.

A fifth and final advantage was that a buyout put Big Rivers in charge of its own destiny without being dependent on the Unwind Transaction closing. Had Big Rivers put all of its eggs in the Unwind Transaction basket it would have lost critical leverage in negotiations that were likely to occur before the Unwind Transaction closed.

Q. How did the RUS view the buyout of the PMCC leveraged leases?

A. The RUS approved Big Rivers' decision to enter into the PMCC Buyout. Big Rivers remained in full consultation with the RUS during this period.

Q. Can you explain in greater detail Big Rivers' concerns regarding the potential failure of AIG and Ambac in deciding to enter into the PMCC Buyout when it did?

A. As of September 2008, the future of AIG was unknown and unknowable given the turmoil then being experienced in world credit markets, AIG's financial fragility at that time, and the United States government's attempts to bolster AIG's economic condition. Even today AIG's continued financial health remains in doubt, as yet another financial bailout of AIG is now under consideration just five months after the September 2008 government bailout of AIG. The risk of AIG's failure in September 2008 was real and the consequences to Big Rivers of that failure were enormous. In the event that AIG had become bankrupt prior to a PMCC Buyout, Big Rivers would have lost the AIG guaranteed investment contracts. In those circumstances, Big Rivers still would have been obligated for the termination payment ($221.5 million) to PMCC, but would have lost the AIG guaranteed investment contracts (valued at $92.6 million on September 30, 2008) to offset that obligation.

Q. What would have been the implications to Big Rivers of an Ambac bankruptcy prior to a termination of the PMCC leveraged leases?

A. An Ambac bankruptcy would have been even more catastrophic for Big Rivers because of Big Rivers' resulting exposure to the additional $583 million obligation. This would have been an insurmountable obligation for Big Rivers. See Blackburn Affidavit at pp. 35-36.

4. Financial Effect of PMCC Buyout

Q. Mr. Blackburn, can you please summarize the final terms of the PMCC Buyout deal as negotiated with PMCC?

A. Certainly. Big Rivers agreed to pay PMCC a negotiated termination payment of $214 million less the actual value produced by the sale and redemption of the AIG guaranteed investment contract and other funding agreements. The termination payment amount was based on the liquidated damages provision contractually included in the PMCC leveraged lease documentation. Although the PMCC leveraged leases specified a stated termination payment of $221.5 million as of September 2008 for the three PMCC leveraged leases concerned, Big Rivers and PMCC negotiated a $7.5 million reduction in the stated termination payment. This amount plus the $12.4 million short-term loan represented PMCC's principal contribution to the economic resolution. As explained in the Blackburn Affidavit at pp. 41-43, the amount of this loan was dependent upon the value of the AIG guaranteed investment contract and other funding agreements to limit Big Rivers' total out-of-pocket expenses to $109 million, an amount Big Rivers had determined as the maximum out-of-pocket exposure it was willing to make given its cash on hand.

Big Rivers had determined that it needed to maintain no less than $20 million of cash on hand after engaging in the PMCC Buyout, pending either (i) a February 2009 closing of the Unwind Transaction when Big Rivers would receive E.ON's one-half share of the net PMCC termination payment or (ii) an assumed rate surcharge above status quo rates (initially proposed to be effective January 1, 2009) which Big Rivers would need to ensure stable and secure operations going forward.

Q. Taken as a whole, do you believe that the proposed PMCC Buyout was a prudent resolution of the issues presented by the Ambac credit downgrade?

A. Absolutely. In September 2008, Big Rivers was out of compliance with the requirements of the operative documents of the PMCC leveraged leases obligating it to provide equity credit enhancement of a specified credit quality. But for PMCC's temporary waiver of its right to declare a default based on this noncompliance, Big Rivers would have faced an obligation to pay a sum which was well in excess of the proceeds of the economic defeasance instruments securing its obligations under the PMCC leveraged leases.

Big Rivers needed to resolve the PMCC leveraged lease issues whether or not the Unwind Transaction closed, and this buyout alternative both continued to permit the Unwind Transaction to move forward and reduced the costs to which Big Rivers otherwise would have been exposed. Had Big Rivers waited to terminate these leases it would have risked declaration of a default by PMCC, risked continued exposure to the credit risk of Ambac and AIG, and the AIG guaranteed investment contract redemption value would have continued to float, adversely affecting Big Rivers were the value to decline.

Entering into the PMCC Buyout in September 2008 eliminated each of those risks.

Q. Did Big Rivers have any better option if it did not complete the PMCC Buyout at that time?

A. No, it did not, except to gamble and do nothing – thereby putting Big Rivers' fate in others' hands and risking that Big Rivers would not be thrown into bankruptcy. PMCC had stated that its bridge loan was only available if the PMCC Buyout closed in the third quarter of 2008 (i.e., by September 30). Addressing the Ambac downgrade was not a question of if, but a question of when. If Big Rivers had ignored the Ambac downgrade and Ambac had slipped into bankruptcy, Big Rivers itself would have faced almost certain bankruptcy. Options other than a PMCC Buyout were either impractical, more expensive, or unacceptable to the RUS, as I discussed earlier. Delaying a PMCC Buyout likely would have cost more, exposed Big Rivers to greater risk of an AIG or Ambac failure, and would have caused Big Rivers to miss the favorable financing terms and conditions that were then available to Big Rivers. Furthermore, the PMCC Buyout made Big Rivers less vulnerable in negotiating other parties' demands in the context of the Unwind Transaction. Had the PMCC issues remained in play other parties potentially could have gained leverage over Big Rivers.

Q. Could Big Rivers have entered into the PMCC Buyout had it not been for its prior decision to accumulate a large cash reserve against the likelihood of an unexpected financial event of this nature?

A. No, Big Rivers most certainly could not have chosen to enter into the PMCC Buyout had it not been for its cash reserves. Big Rivers was not in a position to borrow additional money. I consider it to have been an extraordinary advantage to Big Rivers to have had enough cash to meet this unanticipated challenge, even though this was not one of the risks that Big Rivers expressly had anticipated at the time it began accumulating those reserves.

V. <u>BIG RIVERS' FINANCIAL RISKS WITHOUT THE UNWIND TRANSACTION</u>

A. Current Financial Status

Q. What is Big Rivers' current cash position?

A. After paying for the PMCC Buyout and operations over the past six months, Big Rivers has a remaining cash balance of $25.7 million as of February 3, 2009.

Q. In broad terms can you describe the recent changes to Big Rivers' cash balance from a cash flow perspective?

A. Certainly. At the end of August, Big Rivers had approximately $149.4 million of cash. Big Rivers had out-of-pocket cash expenditures of $109.3 million for the PMCC Buyout, $9.2 million for capital expenditures, and approximately $43.1 million for debt service payments (totaling $161.6 million in outlays). Between September 1, 2008 and February 3, 2009, Big Rivers had a net excess of receipts vs. other disbursements of $37.9 million. There has thus been a net outflow of approximately $123.7 million (the $37.9 million of net excess receipts less the $161.6 million in outlays) against the prior $149.4 million cash balance, resulting in the now greatly reduced cash balance of $25.7 million.

Q. Does Big Rivers now have any readily available options for obtaining additional cash through borrowings?

A. No. As I noted earlier, Big Rivers is unable in its current financial structure to borrow additional money in the open market on a long-term basis because of its complex loan arrangements as well as the restrictions imposed by the RUS loan documents. RUS itself will not loan Big Rivers money because of

Big Rivers' weakened financial condition, and the RUS has informed Big Rivers that it will not subordinate its security interests again. Big Rivers will continue to work with the RUS to soften this view, but at present it seems unlikely.

Big Rivers does have a $15 million line of credit with CFC, but by its terms that line of credit must be paid down to a zero balance at least once a year. Accordingly, that line of credit is nothing more than a stop gap if additional cash balances are not accrued to pay down any draws upon its funds. CFC has supplied Big Rivers with an additional $2.5 million line of unsecured credit in connection with damages from the recent January 2009 ice storm, and CFC indicated that it was unwilling to loan more than a total of $3 million to Big Rivers on an unsecured basis.

Q. **Mr. Blackburn, could you estimate the effect on Big Rivers' cash and cash equivalent balance as of January 2010 (after the New RUS Note Payment of $15.8 million) if the interim rate relief requested herein is granted as proposed?**

A. Yes. Big Rivers' year end 2008 cash and cash equivalent balance was $39.0 million. Granting the interim rate relief request for an incremental $16.6 million will result in a net $8.3 million reduction in cash based on Big Rivers' *pro forma* 2009 revenue requirement deficiency of $24.9 million. Certain rate case expenses and other *pro forma* adjustments to cash flow not included in rates result in an additional $0.7 million reduction in cash flow. Payment on the PMCC promissory note, which is not included in Big Rivers' *pro forma* revenue requirement, including interest will result in another reduction of $13.4 million in Big Rivers' cash. As of year end 2009, Big Rivers thus will have $16.6 million in cash remaining ($39.0 million less $22.4 million). The first business day of January, 2010 (January 4), Big Rivers will receive a $2.6 million lease payment from WKEC which will be offset by $0.6 million in non-incremental capital costs Big Rivers will owe to WKEC. Big Rivers will then, on January 4, 2010, make a quarterly New RUS Note Payment of $15.8 million. Accordingly, Big Rivers will have a $2.8 million in cash and cash equivalent balance as of January 5, 2010. This amount would be augmented by any additional cost savings Big Rivers could obtain by deferral or elimination of costs.

Q. What would Big Rivers' projected cash balance be on January 5, 2010 if the interim rate relief requested were not implemented?

A. Without the $16.6 million generated by January 2010 under the interim rate relief request, Big Rivers would have $16.6 million less than the January 5, 2010 $2.8 million amount projected above (i.e., negative $13.8 million).

Q. Are there any other 2009 costs that could further reduce the January 5, 2010 projected cash balance?

A. Yes. Big Rivers' 2009 budget includes certain expenditures not included in the *pro forma* such as incremental right of way clearing, expanded energy efficiency programs, and additional capital expenditures, none of which are included in these cash flows, and all of which are under consideration as potential costs to cut or defer. The above-calculated cash balance also does not include any costs for Big Rivers' cost share of the Unwind Transaction costs in 2009. Nor does it include rate case expenses above the *pro forma* amount. And it also does not include any costs relating to the January 27, 2009 winter storm to the extent not covered by insurance, FEMA or the $2.5 million CFC unsecured line of credit. Big Rivers would, however, have the available amount on its $15 million line of credit with CFC available to it.

Q. After you have met your debt obligations through January 2010, will Big Rivers have sufficient cash reserves going forward?

A. No. As I state above, even with the requested interim rate relief Big Rivers will have only $2.8 million in cash available to it in January 2010. This is a disturbingly low amount of cash, particularly because the rate relief requested is expected only to meet Big Rivers' projected revenue requirements in 2010. It is imperative that a cash reserve be rebuilt after January 2010 through the combination of this rate increase and reductions in Big Rivers' costs of operations. As I stated earlier, historically Big Rivers' only alternative to fund unanticipated costs since the beginning of the 1998 Transaction has been to use its cash working capital and accumulated cash reserves. With those cash reserves now greatly depleted Big Rivers is extremely vulnerable to potential unanticipated costs. Absent restoration of cash reserves any one of a number of categories of unanticipated costs could place Big Rivers back in bankruptcy.

Q. Are there any known cost increases on the near horizon for Big Rivers?

A. Yes. Beginning in 2009, Big Rivers' New RUS Note annual debt service will ramp up from $82.5 million in 2009 to $98.6 million in 2012. Without some increase in revenue or offsetting decreases in costs, Big Rivers will be unable to meet this $16.1 million annual increase in its obligations.

B. Potential Financial Risks for Big Rivers

Q. Could you provide some idea of the kind of unanticipated costs Big Rivers might need to fund in the future?

A. There are a wide variety of such costs. Generally speaking I would divide them into the following categories: (1) new capital expenditures for changes in Law under the 1998 Transaction with E.ON; (2) environmental cost exposure under the 1998 Transaction with E.ON; (3) litigation risk with E.ON over outstanding contractual disputes which otherwise would be settled by closing of the Unwind Transaction; (4) potential funds in the event of other contractual claims under the 1998 Transaction documents; (5) litigation risk with the Smelters concerning their claim for non-contractual service upon the expiration of their current wholesale sourced contracts with E.ON; (6) any payments required in association with securing power to meet unanticipated load growth (including potential for peaking capacity); and (7) requirements to refinance Big Rivers' pollution control bonds due to increased interest costs occasioned by deterioration in Ambac's creditworthiness. Any of these situations could involve a significant outlay of cash which Big Rivers would not be able to meet unless additional cash reserves are accumulated.

Q. What are Big Rivers' risks with respect to capital expenditures under the 1998 Transaction?

A. One of the larger potential cash outlays Big Rivers could experience would be liability for its share of any necessary capital expenditures due to changes in law or regulation under the terms of the 1998 Transaction documents. Over the past ten years plus of operation under the 1998 Transaction, Big Rivers has paid its share of capital expenditures out of its cash flow and cash balances. Failure to make a payment under the 1998 Transaction could result in a default under the operative Transaction Documents.

Q. You mentioned that another situation where Big Rivers could be required to make additional expenditures would be a change in environmental law, correct?

A. Yes. Changes in environmental law are another example of a potential risk that would require new payments by Big Rivers from accrued funds. Because payment responsibilities between Big Rivers and E.ON due to changes in environmental law can vary under the 1998 Transaction documents, Big Rivers also may be involved in litigation regarding any changes should its interpretations differ from those of E.ON. Accordingly, separate and apart from any expenditures stemming from changes in environmental law, any litigation also would require additional expenditures for lawyers and consultants.

Q. You also mentioned potential litigation with E.ON concerning Energy Imbalance payments as a potential future risk requiring potential cash?

A. Yes, this is another potential cost which Big Rivers conceivably could be required to pay. After several years of operation under the 1998 Transaction, E.ON asserted to Big Rivers that it believed that Big Rivers owed additional payments for Energy Imbalance services based on E.ON's interpretation of the Power Purchase Agreement, an interpretation with which Big Rivers has vigorously disagreed. As part of the negotiations of the Unwind Transaction, Big Rivers and E.ON agreed to eliminate this issue in the event that the Unwind Transaction closes. However, should E.ON and Big Rivers be unable to close the Unwind Transaction, Big Rivers expects that E.ON once again may pursue these claims. Any recovery for these claims would need to be paid from cash on hand.

Q. And is it true that other contractual claims could expose Big Rivers to a risk of a significant cash outlay as well?

A. Yes. Under the terms of the 1998 Transaction operative documents, each party when presented with a contractual claim with which it disagrees must pay the disputed amount in full within three days and then contest those claims later. Failure to make a payment constitutes a default of the agreements unless cured and could lead to possible termination of the 1998 Agreement. Accordingly, Big Rivers must retain an additional cash reserve to accommodate a potential disputed amount. This issue is discussed in greater detail in the testimony of David A. Spainhoward, Exhibit 48.

Q. You also mentioned a potential litigation with the Smelters as another contingency for which Big Rivers needs to retain additional amounts of cash. Could you please explain the basis for this litigation?

A. In connection with the 1998 Transaction the Smelters began to purchase their power requirements sourced at the wholesale level from E.ON. The Smelters' intent in 1998 was to no longer source wholesale power from Big Rivers. The Smelters' existing contracts with E.ON terminate in 2011 and 2012, and, under the terms of their existing contractual arrangements bargained for in 1998, the Smelters were to source their power supply from the market thereafter. Market prices now exceed Big Rivers' wholesale rates. The Smelters have suggested that they retain a non-contractual right to purchase their power requirements with wholesale power sourced from Big Rivers. Big Rivers disagrees with this view given the amendment of Big Rivers' wholesale requirements contracts in 1998 to except sales to the Smelters. Given the Smelters' desire to obtain lower-cost power, Big Rivers expects that the Smelters may pursue these claims through the legal process, either at this Commission or otherwise. At a minimum, Big Rivers needs to make available sufficient cash reserves to fund a legal dispute.

Q. Would Big Rivers also have a need to maintain cash associated with potential load growth or to permit transactions in wholesale power markets such as MISO?

A. Yes, without a doubt. With Big Rivers' balance sheet being as weak as it is from an equity standpoint, Big Rivers' ability to buy power on the market is significantly reduced at certain times. Counterparties with whom Big Rivers contracts often require Big Rivers to post a letter of credit from its CFC $15 million letter of credit facility underlying its line of credit in order for Big Rivers to buy and sell power. To the extent Big Rivers in the future were to require a longer-term power purchase, such as a situation involving a new load or where Big Rivers might be required to provide the Smelters with their power requirements, a significant quantity of cash could be tied up in a line of credit to maintain creditworthiness. At present, it is unlikely that Big Rivers' own credit would support such a long-term purchase unless augmented by additional cash.

Q. Could the same credit limitation apply to a sale of power by Big Rivers?

A. Absolutely. With respect to selling power, Big Rivers already has to be very careful when it places a transaction in the market because if the market were to move a margin call could be required. Because Big Rivers cannot get additional funds from the RUS, its only source to make a margin call is sometimes the $15 million letter of credit with CFC, which cannot be exceeded. This at times operates to limit the amount Big Rivers can sell. It also limits the counterparties which are willing to deal with Big Rivers.

Q. Could load growth also indicate a need to add peaking power?

A. Yes. One option to purchasing any unmet Big Rivers power requirements from the market would be to consider adding peaking power. At present, Big Rivers' ability to schedule Southeastern Power Administration ("SEPA") power as firm is curtailed due to ongoing problems at SEPA's Wolf Creek facilities. Were these difficulties to continue it is conceivable that Big Rivers will have to procure additional peaking power.

Q. You also mentioned a known need for Big Rivers to refinance its Wilson Station PCBs due to increased interest expenses attributable to the Ambac financial downgrade. Could you please explain this need?

A. Yes. The interest rate Big Rivers pays on its PCB debt has skyrocketed due to the deterioration in the credit worthiness of Ambac. Ambac is the surety bond provider for two series of pollution control bonds associated with the

Wilson station, the series 1983 $58.8 million variable rate demand bonds, and the series 2001 $83.3 million periodic auction rate securities. As the creditworthiness of Ambac has fallen, interest rates on the PCBs have increased from an average of 3.74% in 2007, to a maximum rate of 18.0% percent on the periodic auction rate securities. On an annualized basis, the interest Big Rivers must pay today as compared to what it paid in 2007 has increased by $12.5 million.

The sooner Big Rivers can obtain a refinancing of this debt with an entity other than Ambac, the better. In the absence of such a refinancing, which may be difficult to accomplish in today's market given the restrictions on Big Rivers' ability to borrow, Big Rivers requires additional funds to meet these increased interest costs.

VI. BENCHMARK COMPARISON OF NEW RATES

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

A. Attached as Exhibit Blackburn-1 I provide a listing of Big Rivers' historical rural wholesale rates for the period 1994 through 2008. Exhibit Blackburn-1 shows that Big Rivers' rates were reduced in 1998 to approximately $36.72/MWh as a result of the 1998 Transaction. Thereafter they were further reduced by the MDA to as low as $34.99/MWh in 2003. With the elimination of the MDA in August of 2008, Big Rivers' annual rates for that year were $35.90/MWh. And Big Rivers' current base rates are $36.36/MWh.

Q. Has Big Rivers performed any benchmarking of its proposed new wholesale rates to the rates of other utilities in Kentucky?

A. Yes. Exhibit Blackburn-2 attached to my testimony provides a comparison of Big Rivers' proposed rural rates for each of its three member distribution cooperatives compared against the other Kentucky utilities. The rates are shown in terms of the monthly bill for 1,000 kWh (based on monthly residential electric bills as of July 1, 2008 for the other Kentucky utilities). Even with the increase in rates sought in this expedited emergency request for interim rate relief, the rates for Kenergy, Meade County and Jackson Purchase remain comparable to the other rural electric cooperatives shown in Exhibit Blackburn-2. Big Rivers has not increased its Member rates in 15 years, so the present rate increase merely restores its Members' rates to a competitive position vis-à-vis the other distribution cooperatives' rates.

Q. How do Big Rivers' Members' retail rates compare to residential rates nationwide?

A. Big Rivers' Members' residential rates compare extremely favorably to nationwide rates, even with the requested rate increase. Kentucky remains a very low-cost state in terms of its electric rates, and Big Rivers' Members' rates will remain very competitive compared to the rates prevailing in the rest of the country. Exhibit Blackburn-3 presents a chart comparing the proposed rates for Big Rivers' Members to average residential rates in Kentucky and nationwide by region. This exhibit establishes that Big Rivers' Members' residential rates will remain competitive in Kentucky, and extremely competitive nationwide.

VII. EXPLANATION OF *PRO FORMA* ADJUSTMENTS

Q. Mr. Blackburn, are you supporting any of the *pro forma* adjustments to Big Rivers' test year revenue requirements?

A. Yes. I am specifically supporting as part of this testimony five of the *pro forma* adjustments: Schedules 1.02, 1.04, 1.10, 1.11, and 1.13. I also supplied the source information used by Mr. Seelye in his testimony, Exhibit 46, and am the supporting witness regarding Big Rivers' other *pro forma* adjustments (except for Schedules 1.01 and 1.03 for which Mr. Spainhoward is the supporting witness).

Q. Please explain the elimination of the Unwind Cost Share in Schedule 1.02.

A. In connection with pursuing the Unwind Transaction, Big Rivers has executed several cost-share agreements with E.ON to fund the ongoing transaction costs. Generally, Big Rivers has been responsible for funding 25.0 percent of such costs. During the 12 month historical period ended November 30, 2008, Big Rivers' share of such costs was $4,454,079. For purposes of the *pro forma* adjustment I have assumed no Unwind Transaction costs and have eliminated such amounts in the revenue requirement. However, as and to the extent the Unwind Transaction continues during 2009 (and even if it does not ultimately close for whatever reason) Big Rivers will incur costs relating thereto. The original *pro forma* adjustment assumed a closing would either occur in March or April or it would have been determined that a closing would not occur. To the extent additional delays occur in closing the Unwind Transaction, Big Rivers will incur additional Unwind Transaction costs that are not included in the *pro forma* test year revenue requirement.

Q. Please explain how Big Rivers normalized debt service expenses in Schedule 1.04.

A. Big Rivers has proposed a *pro forma* debt service adjustment. For normalized debt service, Big Rivers used actual/forecast debt service on the New RUS Note, the RUS ARVP Note, the LEM Settlement Note, and the Green River Coal Obligation for the 12 month period ended August 31, 2009 (assuming the maximum suspension period such that the proposed rates would be effective September 1, 2009). Big Rivers annualized the interest rates applicable to the PCBs on February 3, 2009. The $12.4 million PMCC promissory note debt service has been intentionally excluded, as was the leveraged lease buyout payment of $109.3 million. The result is normalized debt service of $102.9 million ($62.9 million interest and $40.0 million principal). Actual debt service for the historical period, the 12 months ended November 30, 2008, including the PMCC Promissory Note, but excluding the net leveraged lease cash buyout amount of $107.1 million (eliminated on Schedule 1.06), produces a debt service of $99.1 million ($58.3 million interest and $40.8 million principal). The resulting *pro forma* adjustment is thus to increase Big Rivers' revenue requirement by $3.8 million.

Q. Please explain how Big Rivers normalized pension costs in Schedule 1.10.

A. Currently, Big Rivers has "frozen" new entrants into its defined benefit ("DB") pension plan and has replaced it with a defined contribution ("DC') pension plan. However, most current employees remain participants in the DB pension plan. Due to the generally poor equity performance over the past 18 months, Big Rivers has funded $4.5 million to its DB during the historical period ending November 1, 2008. Big Rivers' actuary, Mercer, as of January 19, 2009 has estimated Big Rivers' normalized pension expense to be approximately $2.0 million adjusted for estimated eligible compensation. Accordingly, Big Rivers proposes a *pro forma* adjustment to reduce its revenue requirement by approximately $2.5 million to reflect this difference.

Q. Please explain how you performed the normalization for off-system sales, other revenues, and purchased power expenses in Schedule 1.11.

A. In developing its *pro forma* adjustment to normalize off-system sales, other revenue and purchased power, Big Rivers first identified the projected purchase power resources available to it in 2009 under its contracts with LEM and SEPA. Since SEPA is currently a "run of river" non-firm resource due to issues associated with certain of its hydroelectric facilities which removed Big Rivers' ability to schedule firm, it was necessary for Big Rivers to project hourly energy purchases from the open market to support its native load during peak months in 2009. Therefore, the historic test year SEPA availability will be different than the projected SEPA availability for 2009.

Next, Big Rivers calculated its available monthly excess energy for 2009 by taking these total purchase power resources and subtracting from them its obligations to the Members under their all-requirements contracts. This calculated amount is the excess energy available to Big Rivers to make Non-Tariff Wholesale sales during 2009. From this amount, Big Rivers then made certain known reductions for existing contracts. Big Rivers has executed two "Tier 3" contracts with Kenergy for 2009 delivery totaling 113 MWs for service to the Smelters on a system firm basis, as well as an additional "up to" 30 MWs of fully interruptible service. All remaining on-peak energy, after accounting for losses and possible scheduling inefficiency, is the amount Big Rivers projects in 2009 to be able to sell in the open market. Additionally, Big Rivers' *pro forma* also includes 50 MW of power purchased from Southern Illinois Power Cooperative ("SIPC") and resold to Kenergy for delivery to the Smelters as additional Tier 3 power for January and February 2009.

In order to convert the projected 2009 available power into *pro forma* revenues, Big Rivers took the excess energy identified above and used the price based on either the applicable contractual agreements or the MISO-CIN Hub January 22, 2009 forward price curve for on-peak energy. This revenue calculation less the test year revenue results in a total *pro forma* adjustment to increase the revenue requirement by $18.9 million.

The historical test year contained 11 months of power purchases from SIPC, while the 2009 contractual commitment from SIPC is for only two months. This results in a material decrease in the purchase power expense reflected in the *pro forma* adjustment.

Q. Please explain how you performed the normalization of tariff revenue in Schedule 1.13.

A. In order to normalize tariff revenues, Big Rivers first eliminated the MDA, which Big Rivers allowed to expire on August 31, 2008. This normalization simply increased revenues to reflect the base rates without use of the MDA. To complete normalization of tariff revenues, Big Rivers also performed a weather normalization and made specific adjustments to correct inaccuracies in the load forecasts for three of its industrial customers.

Q. How did Big Rivers perform weather normalization in Schedule 1.13?

A. To start, Big Rivers calculated normalized weather estimates for rural kWh and rural peak demand by Member cooperative for the period December 2007 through November 2008. Big Rivers used regression models to produce the normalized energy estimates for each cooperative. Big Rivers based its normal heating and cooling degree days on 20 year averages ending

December 2008. For Kenergy and Meade County, Big Rivers used Evansville weather as a proxy. For Jackson Purchase, Big Rivers used Paducah weather as a proxy. This study determined that for the 12 months ending November 2008, weather was fairly close to the observed twenty-year averages.

Next, Big Rivers determined normalized peak demands based on the monthly normalized energy estimates and monthly normalized load factors. The normalized load factors were developed for each month and computed as the respective monthly average for the years 2001 through 2008.

Q. How did Big Rivers adjust for large industrial customer deviation?

A. Because Big Rivers' test year relied in part on the 2007 load forecast, it was necessary for Big Rivers also to adjust those load forecasts to account for known material deviations for its large industrial customers. Big Rivers' review identified three such instances which are corrected in the *pro forma* adjustment.

First, Cardinal River Resources was assumed in the Load Forecast to have a monthly peak of just under 1 MW and monthly energy needs of approximately 200 to 250 MWhs. However, as of July 2008, Cardinal River's peak load and energy needs have decreased to zero. Accordingly, this load was set to zero in the *pro forma* adjustment.

Second, KMMC, LLC was assumed in the Load Forecast to have a monthly of peak between 3.4 and 4.0 MW and monthly energy needs of approximately 1000 MWhs to 1500 MWhs. However, as of about June 2008, KMMC's monthly peak load has decreased to between 1 and 2 MW and energy needs are under 100 MWhs. These corrected amounts are used in the *pro forma* adjustment.

Third, Dyson Creek Mine was assumed in the Load Forecast to have no demand or energy needs after 2007. However, in 2008 Dyson Creek has a monthly demand of approximately 0.05 MW and energy needs of about 25 MWhs. These corrected amounts are used in the *pro forma* adjustment.

VIII. <u>COMPLIANCE WITH 807 KAR 5:0001</u>

Q. Mr. Blackburn, have you reviewed the answers provided in the exhibits attached to this application, which purport to address Big Rivers' compliance with the historical period filing requirements under 807 KAR 5:0001 and its various subsections?

A. Yes, I have. I hereby incorporate and adopt as part of this Direct Testimony those exhibits for which I am identified as the sponsoring witness as shown in the Table of Contents for this Application.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

VERIFICATION

I verify, state, and affirm that the foregoing testimony is true and correct to the best of my knowledge and belief formed after a reasonable inquiry.

C. William Blackburn

C. William Blackburn

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by C. William Blackburn on this the 26th day of February, 2009.

TBW

Notary Public, Ky. State at Large
My Commission Expires 2/21/2010

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy® Cooperative

Actual Historical Rural Wholesale Rate

Year	$/MWh
1994	45.58
1995	44.76
1996	42.72
(1) 1997	40.17
1998	36.72
1999	36.44
(2) 2000	36.25
2001	35.27
2002	35.38
2003	34.99
2004	35.06
2005	35.19
2006	35.58
2007	35.22
(3) 2008	35.90

(1) Current base rate effective September 1997.

(2) Revenue Discount Adjustment effective September 2001.

(3) Revenue Discount Adjustment terminated September 2008; current base rate is 36.36.

Touchstone Energy®
The power of human connections

Exhibit Blackburn-1

COMPARISON OF RESIDEN.   LECTRIC BILLS AS OF 07/01/08

COMPANY	UTILITY I.D.	PURSUANT TO CASE NO.	MINIMUM BILL	kWh INCL.	BASE BILL	FAC CHARGE	ENVIRON. SURCHARGE	MO. BILL FOR 1,000 kWh
INVESTOR OWNED								
KENTUCKY POWER	300	2006-00507	5.86	0	$70.61	$11.31	$3.33	$85.25
KENTUCKY UTILITIES	400	2006-00509	5.00	0	$61.46	$0.90	$3.28	$65.64
LG&E	500	2006-00510	5.00	0	$68.89	$1.34	$1.03	$71.26
DUKE ENERGY	800	2006-00172	4.50	0	$77.74	$5.77	*	$83.50
RURAL ELECTRIC								
Small - Less than 20,000 Customers								
BIG SANDY	1000	2006-00473	7.18	0	$76.92	$7.86	$3.49	$88.27
GRAYSON	1800	2006-00480	8.16	0	$86.84	$7.60	$3.75	$98.19
SHELBY ENERGY	3000	2006-00487	7.37	0	$79.85	$6.07	$3.96	$89.88
Medium - 20,000-30,000 Customers								
CLARK ENERGY	1200	2006-00476	5.48	0	$81.36	$7.26	$3.51	$92.13
CUMBERLAND ELECTRIC	1300	2006-00477	5.13	0	$77.74	$8.26	$3.68	$89.68
FARMERS	1500	2006-00478	7.48	50	$73.37	$6.06	$3.54	$82.97
FLEMING-MASON ENERGY	1600	2007-00022	9.75	0	$85.39	$6.31	$4.51	$96.21
INTER-COUNTY ENERGY	2200	2006-00481	5.69	0	$79.11	$7.13	$3.26	$89.50
JACKSON PURCHASE	2400	2007-00116	9.00	0	$71.11	**	*	$71.11
LICKING VALLEY	2500	2006-00483	7.17	0	$80.56	$6.06	$3.50	$90.11
MEADE COUNTY	2600	2006-00500	9.85	0	$69.86	**	*	$69.86
NOLIN	2700	2006-00466	8.13	0	$81.54	$7.06	$3.88	$92.46
TAYLOR COUNTY	3200	2006-00489	7.10	0	$76.62	$6.45	$3.72	$86.79
Large - 30,000 Customers and above								
BLUE GRASS ENERGY	2000200	2006-00475	5.44	0	$73.79	$7.11	$3.54	$84.44
BGE-Fox Creek District		2006-00475	5.53	30	$76.20	$7.11	$3.66	$86.97
HARRISON Elec Customers	2000	2006-00475	9.10	0	$83.61	$7.11	$4.01	$94.73
JACKSON ENERGY	2300	2007-00333	9.50	0	$95.13	$6.46	$4.05	$105.64
KENERGY	2000100	2006-00369	9.91	0	$69.87	**	*	$69.87
OWEN ELECTRIC	2800	2006-00485	5.64	0	$80.97	$7.16	$4.11	$92.24
SALT RIVER ELECTRIC	2900	2006-00486	7.91	0	$75.11	$5.87	$3.62	$84.60
SOUTH KENTUCKY	3100	2006-00488	8.20	0	$80.79	$7.17	$3.68	$91.64

This schedule includes only the major components of a monthly residential electric bill as of April 1, 2008.
Additional credits and/or charges may apply.
*Does not participate in environmental surcharge mechanism.
**Does not participate in fuel adjustment charge mechanism.

Exhibit Blackburn-2

Big Rivers' members provide some of the lowest cost residential electricity in the nation.

Average Residential Rate – Kentucky
As of July 1, 2008

Kentucky Utility	Cents/ kWh
East Kentucky Power Cooperatives	9.1
Kentucky Power	8.5
Duke Energy	8.4
LG&E	7.1
Kentucky Utilities	6.6

Source: Kentucky Public Service Commission

Proposed Residential Rate	**7.9**

Average Residential Rate – National
December 2007

National Region	Cents/ kWh
Pacific Noncontiguous	22.6
New England	15.9
Middle Atlantic	13.5
Pacific Contiguous	11.5
West South Central	10.6
South Atlantic	9.8
East North Central	9.4
Mountain	8.8
East South Central	8.3
West North Central	7.6
Kentucky	7.4

Source: Energy Information Administration

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

Case No. 2009-00040

DIRECT TESTIMONY OF DAVID A. SPAINHOWARD

ON BEHALF OF
BIG RIVERS
ELECTRIC CORPORATION

March 2, 2009

DIRECT TESTIMONY OF
DAVID A. SPAINHOWARD

Q. Please state your name, your address, your position with Big Rivers Electric Corporation and your qualifications.

A. My name is David A. Spainhoward. My current business address is 201 Third Street, Henderson, Kentucky 42420. I have been an employee of Big Rivers Electric Corporation ("Big Rivers") since 1972. My current position is Senior Vice President External Relations & Interim Chief Production Officer at Big Rivers. Before holding my current position, I held the position of Vice President Contract Administration and Regulatory Affairs. I have also held positions in the Big Rivers Corporate Planning, Real Estate, Accounting and Purchasing departments. I am a graduate of Oakland City University in Oakland City, Indiana with the degree of Bachelor of Science in Management. I also have a Master of Science in Management degree from Oakland City University.

Q. Have you previously testified before this Commission?

A. Yes. I have previously submitted testimony and personally appeared before the Kentucky Public Service Commission ("KPSC" or "Commission") in numerous other matters. I was one of Big Rivers' witnesses in the case approving Big Rivers' 1998 transactions (the "1998 Transaction") with subsidiaries or affiliates of LG&E Energy Corp., now E.ON U.S., LLC and its affiliates (the "E.ON Entities"). I also recently testified in Big Rivers' application for approval of various agreements to terminate the 1998 Transaction (the "Unwind Transaction"), P.S.C. Case No. 2007-00455.

I. <u>INTRODUCTION</u>

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

A. My testimony addresses three principal areas. First, my testimony describes two of the *pro forma* test year revenue requirement adjustments being made in this case: Schedule 1.01, which reflects *pro forma* adjustments to 2008 test year Incremental Environmental Operation and Maintenance Costs, as that term is defined in my testimony; and Schedule 1.03 to reflect *pro forma* adjustments to Big Rivers' 2008 test year annual capital expenditures. Each of these two categories of *pro forma* adjustments is, at least in part, associated with changes in Big Rivers' costs relating to environmental costs, although certain other costs can affect Big Rivers' annual capital expenditures, as I explain below. Big Rivers' costs in turn are themselves partly based on the underlying documents reflecting the 1998 Transaction, which documents provide for Big Rivers to share with Western Kentucky Energy Corp. ("WKEC") in portions of these cost increases.

Second, my testimony describes certain changes to Big Rivers' tariff to implement the rate adjustment presented herein. While certain of these changes implement the increased rates and charges sought in this case, some of the changes previously were presented to the Commission in Big Rivers' Unwind Transaction proceeding, P.S.C. Case No. 2007-00455, and Big Rivers desires that these changes be made to Big Rivers' tariff on a going forward basis, with or without the Unwind Transaction. I also explain Big Rivers' proposal for its integrated resource plan ("IRP") process. I also discuss the elimination of the expired Member Discount Adjustment from the tariff. I further present Big Rivers' commitment to continue meeting the reporting requirements established by the Commission in the 1998 Transaction case.

Third, I provide analysis of the dispute resolution process in the present transaction with WKEC in support of Mr. Blackburn's testimony. Finally, my testimony addresses the items required by 807 KAR 5:001 for which I am the sponsoring witness.

II. DESCRIPTION OF *PRO FORMA* ADJUSTMENTS

Q. Does Big Rivers propose any *pro forma* adjustments to the 2008 test year revenue requirements as part of this filing?

A. Yes. As explained in the Direct Testimony of Mr. Seelye, Exhibit 46, Big Rivers has used an historical test year ending November 30, 2008, to determine its revenue requirements. As Mr. Seelye explains, a number of *pro forma* adjustments to this 2008 test year are necessary in order to more accurately reflect Big Rivers' revenue requirements on a cash basis going forward.

Q. Which *pro forma* adjustments do you discuss as part of this testimony?

A. In this testimony I describe two of the necessary *pro forma* adjustments to the 2008 test year. First, I describe the *pro forma* adjustment necessary to reflect Incremental Environmental Operation and Maintenance ("O&M') expenses (Schedule 1.01). Second, I describe the adjustment to reflect annual capital expenditures (Schedule 1.03).

A. Schedule 1.01 – Incremental Environmental O&M *Pro Forma* Adjustment

Q. What is your understanding of the purpose of Schedule 1.01 – the Incremental Environmental O&M *pro forma* Adjustment, attached to Mr. Seelye's testimony as part of Exhibit Seelye-2?

A. The purpose of the *pro forma* adjustment attached to Mr. Seelye's revenue requirements analysis as Schedule 1.01 is to adjust the historical test year ending November 30, 2008, to reflect known and measurable changes in Big Rivers' responsibility to WKEC for incremental environmental operating and maintenance expenses under the terms of the documents implementing the 1998 Transaction (the "1998 Transaction Documents") with WKEC, which are attached to this Application as Exhibit 54. My testimony provides the basis for this adjustment.

Under the terms of the 1998 Transaction Documents, Big Rivers owes WKEC on a monthly basis certain "Incremental Environmental O&M Costs" and "Incremental Capital Costs," both of which are defined terms in those documents. The test year actual Incremental Environmental O&M Costs invoiced and paid by Big Rivers to WKEC under the terms of the 1998

Transaction Documents and included in the unadjusted test year reflect costs associated with the purchase of NOx allowances and additional NOx emissions control operational costs were based on a five-month control period, known as the "Ozone Season." Because of court decisions directly affecting the applicable NOx control regime applicable during 2009, the five-month Ozone Season effectively became a twelve-month Ozone Season, and the price of emissions allowances has increased dramatically. The last of these court decisions was on December 23, 2008, which post-dated the hearings in the Big Rivers Unwind Transaction. Environmental laws enforceable in 2009 now require the purchase of NOx allowances and the operation of SCRs and other NOx control equipment to satisfy both twelve-month and five-month Ozone Season limits. These changes require adjustment of the test-year to reflect the amounts WKEC will charge Big Rivers for Big Rivers' share of the known 2009 NOx control costs, including allowance purchases, because these changes will affect Big Rivers' cash level in 2009.

Q. Please describe the *pro forma* adjustment in Schedule 1.01, found in Exhibit Seelye-2, which Big Rivers now believes is necessary for use in its revenue requirement.

A. Using a twelve-month NOx control period instead of a five-month control period is not a difficult adjustment because it is merely a reversion to the same compliance standard in effect since 2005. Consequently, Big Rivers has obtained information from WKEC on NOx compliance costs based upon expanding test year five-month compliance costs to year-round compliance. The information on these costs obtained from WKEC is reflected on my Exhibit Spainhoward-1, page 2.

Q. Are any other adjustments necessary to reflect the impact of the late 2008 court decisions on NOx compliance costs?

A. Yes. The WKEC calculations of the 2009 NOx compliance costs include all costs other than known changes in the price for the cost per allowance for NOx allowances anticipated to be required to achieve NOx compliance for 2009. I have prepared an input to Exhibit Seelye-2, Schedule 1.01 for NOx allowances by multiplying the allowance purchase (shortfall) requirement in 2009 by a current allowance price of $3,350 per allowance based on the *Coal Trader*, Monday, January 26, 2009 price of NOx allowances, which was the best available information at the time the *pro forma* adjustment was prepared. These calculations are shown on Exhibit Spainhoward-1, page 1.

Q. Please explain how your calculations are reflected on Exhibit Seelye-2, Schedule 1.01.

A. The *pro forma* amount of $3,095,168 shown on Exhibit Seelye-2, Schedule 1.01, line 1, is the sum of (i) Big Rivers' share of the net allowance costs for 2009 shown on Exhibit Spainhoward-1, page 1, line 11, $849,316, and (ii) Big Rivers' share of the total fixed and variable O&M costs provided by WKEC shown on Exhibit Spainhoward-1, page 2, line 10, $2,245,852.

Q. Are the *pro forma* adjustments you propose reasonable, and based on known and measurable changes in circumstances?

A. Yes. WKEC began operating under the year round compliance provision of the NOx control regulations on January 1, 2009. While the *pro forma* adjustment is based on what are essentially WKEC budget numbers for costs other than emissions allowances, Big Rivers is contractually required under the 1998 Transaction Documents to reimburse WKEC for 20% of its actual costs. The 2009 budget is based on several years of operating experience by WKEC on a five-month basis. In order to calculate NOx control costs based on twelve months of operation, WKEC extrapolated the five months of historic experience to twelve months, and Big Rivers determined the costs of allowances that would be required to achieve compliance. Big Rivers considers the budgeted costs to be known, measurable and reasonable, and reflective of costs that will be very close to actual costs in 2009. These amounts will reduce Big Rivers' cash flow in 2009.

B. Schedule 1.03 – *Pro Forma* Adjustment for Capital Expenditures

Q What is the purpose of Schedule 1.03, found in Exhibit Seelye-2, – the Incremental Capital Costs *pro forma* Adjustment?

A. The purpose of the *pro forma* adjustment attached to Mr. Seelye's revenue requirements analysis as Schedule 1.03 is to adjust the historical test year ending November 30, 2008, to reflect known and measurable changes in Big Rivers' responsibility to WKEC for incremental capital costs under the terms of the 1998 Transaction Documents with WKEC. My testimony provides the basis for this adjustment.

Q. What types of capital costs and other costs is Big Rivers exposed to that are adjusted in Schedule 1.03, found in Exhibit Seelye-2 – *Pro forma* Adjustment for Capital Expenditures?

A. Big Rivers is responsible for three kinds of capital expenditures during the term of its 1998 Transaction with WKEC: (1) Incremental Capital Costs; (2)

Non-Incremental Capital Costs; and (3) transmission plant expenditures and general plant expenditures. Each of these three categories of costs is reflected in Schedule 1.03.

Q. Describe Big Rivers' obligations with respect to Incremental Capital Costs as reflected in Schedule 1.03.

A. Under the 1998 Lease and Operating Agreement, one of the 1998 Transaction Documents, Big Rivers is responsible in 2009 for 20% of the cost of any capital expenditure made to comply with a new law or any revision or change to an existing law, including any new or revised environmental law. These costs are defined as "Incremental Capital Costs." WKEC has informed Big Rivers that based on a twelve-month NOx control period for 2009, Big Rivers' share of Incremental Capital Costs will be $1,193,160, as reflected in Exhibit Seelye-2, Schedule 1.03, at line 3, and on my Exhibit Spainhoward-1, page 5, line 8. Support for test year Incremental Capital Costs of $378,367 shown on Exhibit Seelye-2, Schedule 1.03, at line 3, is found on my Exhibit Spainhoward-1, page 3, line 18. The most recent WKEC Incremental Capital capital construction budget for year 2009 is attached to my Exhibit Spainhoward-1, at page 5. This information is provided to comply with the filing requirement found in 807 KAR 5:001 Section 10(7)(b), which is referenced in Application Exhibit 41.

Q. Please describe Big Rivers' obligations with respect to Non-Incremental Capital Costs.

A. Section 8.4(b) of the Lease and Operating Agreement provides that each expenditure made for a Capital Asset which is not classifiable as an Incremental Capital Cost is deemed to be a Non-Incremental Capital Cost. During 2009, Big Rivers' share of Non-Incremental Capital Cost is defined as the "Big Rivers Contribution Amount," and is a fixed, scheduled amount of \$6,871,000. The Big Rivers Contribution Amount for 2009 is shown on Exhibit Seelye-2, Schedule 1.03, at line 2. During the historical test year, the Big Rivers Contribution Amount was \$6,707,667. The Big Rivers Contribution Amount for the 2008 test year is shown on Exhibit Seelye-2, Schedule 1.03, at line 7, and is found on my Exhibit Spainhoward-1, page 3, line 30. Big Rivers is required to pay WKEC 1/12th of the Big Rivers Contribution Amount each month for the twelve months of the calendar year. Big Rivers' Contribution Amount is booked as "first dollars spent" by WKEC. The most recent WKEC Non-Incremental Capital capital construction budget for year 2009 is attached to my Exhibit Spainhoward-1, at pages 6 through 8. This budget shows the "BREC Portion" as "0" because Big Rivers' share of the budget of \$26.3 million is the scheduled "Big Rivers Contribution Amount" of \$6.9 million established in the 1998 Transaction Documents. This information is provided to comply with the filing requirement found in 807 KAR 5:001 Section 10(7)(b), which is referenced in Application Exhibit 41.

Q. Describe Big Rivers' obligations with respect to transmission plant expenditures and general plant expenditures.

A. Big Rivers' transmission plant expenditures and general plant expenditures are solely the responsibility of Big Rivers to incur in its prudent judgment. No *pro forma* adjustment is necessary for transmission plant expenditures and general plant expenditures. Accordingly, Big Rivers has used its historic 2008 test year amounts for these costs. This amount, $14,331,923, is shown on Exhibit Seelye-2, Schedule 1.03, at line 4, and on my Exhibit Spainhoward-1, page 4, line 38. The most recent Big Rivers transmission plant expenditures and general plant expenditures construction budget for year 2009 is attached to my Exhibit Spainhoward-1, at pages 9 through 12. This information is provided to comply with the filing requirement found in 807 KAR 5:001 Section 10(7)(b), which is referenced in Application Exhibit 41.

III. DESCRIPTION OF BIG RIVERS' TARIFF CHANGES AND ITS PROPOSAL TO REINSTITUTE ITS IRP OBLIGATIONS

A. The Big Rivers Tariff

Q. Will Big Rivers be making any changes to its tariffs on file with the Commission in order to implement the rates requested?

A. Yes. Big Rivers is proposing to make a number of changes with respect to its existing tariff.

Q. Has Big Rivers provided a description of the changes to the existing Big Rivers tariff in its filing?

A. Yes. Big Rivers has attached as Exhibit 8 to this filing a comparison of Big Rivers' currently applicable tariff sheets to its proposed tariff. And Exhibit 7 presents a clean version of the proposed tariff sheets.

Q. Mr. Spainhoward, would you please walk us through the changes to the Big Rivers tariff?

A. Certainly. There are two reasons for the changes proposed to Big Rivers' tariff: first, to eliminate or update certain defunct or inapplicable provisions to reflect current circumstances; and second, to reflect the change in rates requested in this Application. With respect to the changes falling into the first category, Big Rivers decided to change these provisions initially as part of its general review of its tariff completed as part of the filing it made in Case No. 2007-00455 to implement the Unwind Transaction (which included a proposed tariff to be effective on and after the date of closing of the proposed Unwind Transaction). Because the present filing will go into effect only if there is a delay or failure in the completion of the Unwind Transaction, Big Rivers determined to incorporate these identified and desired tariff changes now as part of this filing as well, in case operation under this revised tariff extends longer than expected.

Q. Big Rivers has proposed an amendment to Section A(9) of its tariff, Exhibit 8, at First Revised Sheet No. 5, to eliminate the use of a Billing Review Committee. Could you please explain why Big Rivers no longer intends to use this committee?

A. Big Rivers' existing tariff provides that in billing periods where there is a potential special metering issue that a committee comprised of members of Big Rivers' energy control group, engineering and transmission group, and accounting group will be employed to review demand and energy quantities. Although Big Rivers intends to perform the same tasks, Big Rivers no longer considers it necessary to employ a special committee to do so, and thus eliminates this reference. A parallel change was presented in the Unwind Transaction tariff filed in Case No. 2007-00455.

Q. Please explain the language changes to the power factor calculation found in Application Exhibit 8, Section A(11) of First Revised Sheet No. 6.

A. Big Rivers' existing tariff in Section A(11) requires that Big Rivers' three member distribution cooperatives ("Members") maintain a power factor at the time of maximum demand of not less than 90% leading or lagging. Big Rivers now proposes additional clarifying language that provides that Big Rivers will adjust the maximum metered demand in situations in which this specified 90% leading or lagging power factor is not met. In this way, Members will have a financial incentive to maintain the required power factor, and Big Rivers will be compensated for any failure to maintain this required level. Under the proposed adjustment, the maximum metered demand will be multiplied by 90% and then divided by the actual power factor percentage. This will result in increases in the metered demand where the power factor is less than 90%. A parallel change was presented in the Unwind Transaction tariff filed in Case No. 2007-00455.

Q. Please explain the changes made by Big Rivers to its tariff, Application Exhibit 8, rate schedule C.4.d at First Revised Sheet No. 20.

A. These changes revise the demand and energy charges to the Big Rivers rural delivery points to produce the revenue requirement sought in this case. The demand charge is increased from $7.37 per kW per month to $8.963 per kW per month. The energy charge is increased from $0.02040 per kWh to $0.024811 per kWh.

Q. Please explain the changes made by Big Rivers to its tariff, Application Exhibit 8, rate schedule C.7 at Third Revised Sheet No. 38.

A. These changes revise the demand and energy charges to the Big Rivers large industrial customer delivery points to produce the revenue requirement sought in this case. The demand charge is increased from $10.15 per kW per month to $12.345 per kW per month. The energy charge is increased from $0.013715 per kWh to $0.016680 per kWh.

Q. Please explain the changes made by Big Rivers to its tariff, Application Exhibit 8, rate schedule 9 at First Revised Sheet Nos. 52, 54 and 55.

A. This section of Big Rivers' tariff addresses rates for Cogenerator and Small Power Producers over 100 kW. The charge for supplementary demand is increased from $7.37 per kW per month to $8.963 per kW per month. The charge for supplementary energy is increased from $0.0204 per kWh to $0.024811 per kWh. The charge for unscheduled back-up demand is increased from $7.37 per kW per month to $8.963 per kW per month. The charge for on-peak maintenance service scheduled demand is increased from $1.835 per kW per week to $2.2408 per kW per week. The charge for on-peak maintenance energy is increased from $0.0204 per kWh to $0.024811 per kWh. The charge for off-peak maintenance service scheduled demand is increased from $1.835 per kW per week to $2.2408 per kW per week. The charge for off-peak maintenance energy is increased from $0.0204 per kWh to $0.024811 per kWh. The charge for excess demand is increased from $7.37 per kW per month to $8.963 per kW per month. There are currently no customers taking service under Big Rivers' Cogenerator and Small Power Producers over 100 kW rate schedules.

Q. Please explain why Big Rivers proposes to eliminate its Member Discount Adjustment Rider, which is shown as being stricken in Big Rivers' Application Exhibit 8, rate schedule 12, Seventh Revised Sheet No. 74.

A. Big Rivers allowed this rider to expire by its terms on August 31, 2008. Since the tariff has expired, it should be eliminated from the tariff. Big Rivers also proposes to eliminate from the renewable energy resource tariff, Exhibit 8, First Revised Sheet No. Sheet 77, language that refers to the Member Discount Adjustment Rider.

B. Integrated Resource Plan

Q. Please describe Big Rivers' current obligations with respect to the Integrated Resource Plan.

A. Kentucky Administrative Regulation 807 KAR 5:058 establishes an integrated resource planning process that requires the Commission to review the long-range resource plans of electric utilities subject to its jurisdiction. Big Rivers most recently filed its IRP with the Commission on November 29, 2005, in P.S.C. Case No. 2005-00485. Later, on January 11, 2006, Big Rivers filed a motion to hold the case in abeyance. On April 18, 2006, Big Rivers asked the

Commission to continue to hold the case in abeyance, and the Commission agreed to do so pending disposition of the Unwind Transaction.

Q. **How does Big Rivers propose to meet its IRP obligations if the Unwind Transaction is not closed?**

A. Big Rivers requested in the Application in Case No. 2007-00455 that the Commission terminate Case No. 2005-00485 which has been held in abeyance for the past two years. In Case No. 2007-00455 Big Rivers committed to file its next IRP no later than November 2010. Whether or not the Unwind Transaction closes, Big Rivers believes that maintaining this requested timing remains the best course of action and renews its request for this IRP filing date as part of this Application.

Q. **Why does Big Rivers propose to wait until November 2010 to file an IRP?**

A. The IRP filed in November 2005 was not based on Big Rivers operating its generation. Accordingly, it is appropriate to hold Big Rivers' IRP obligations in abeyance until resolution of the Unwind Transaction. To do otherwise could result in significant efforts being expended on an IRP that would not reflect operations under the Unwind Transaction. Whether or not the Unwind Transaction closes as planned, Big Rivers is conducting a new load forecast in

2009, which should be completed by August 2009. This new forecast will be the basis for the development of a new IRP. Accordingly, Big Rivers believes that a postponement of the filing of its IRP until 2010 is appropriate and will allow a useful presentation based on the best and most recent information available.

C. 1998 Transaction Reporting Requirements

Q. Did the Commission impose any reporting and other requirements on Big Rivers in connection with its approval of the 1998 Transaction?

A. Yes. The Commission approved the 1998 Transaction in orders dated April 30, 1998 in P.S.C. Case No. 97-204 and July 14, 1998 in P.S.C. Case No. 98-267 (the "1998 Orders"). The 1998 Orders are attached as Exhibits 51 and 52 to the Notice and Application in this case. Big Rivers will resume filing the reports required in those orders, in the manner agreed by the Commission.

IV. DESCRIPTION OF IMPACT OF DISPUTE RESOLUTION PROCESS ON BIG RIVERS' CASH REQUIREMENTS

Q. Mr. Blackburn, in his testimony, refers to the need for Big Rivers to have adequate cash on hand to meet any needs created by any claim from E.ON

subsidiary WKEC under the 1998 Transaction Documents. Will you please explain basis in the 1998 Transaction Documents for that concern?

A. Yes. The Participation Agreement from the 1998 Transaction Documents provides in Article 17 that if WKEC gives Big Rivers notice of default under the 1998 Transaction Documents for failure to pay all amounts it contends are due and payable thereunder, Big Rivers must pay the amount demanded within three days. If Big Rivers disputes the existence or nature of the asserted default, Big Rivers can then activate the dispute resolution process under Article 15 of the Participation Agreement. But the amount of the demand is required to be paid within three days of the claim, or Big Rivers will be in default under the 1998 Transaction Documents, and subject to all the remedies available to WKEC for default, potentially including termination of the 1998 Transaction Documents. Depending upon the amount of the claim, the requirement to raise a large amount of cash in three days could create an insurmountable problem for an entity, like Big Rivers, that has virtually no access to credit. In his testimony in the Unwind Transaction case, Mr. Paul Thompson of E.ON made it clear that if the Unwind Transaction does not close, WKEC will staunchly defend all of its contractual rights under the 1998 Transaction, which he forecasted would "not make it good" for Big Rivers and Big Rivers' Members. He went so far as to list a number of areas in which he anticipates disputes. Under the circumstances, Big Rivers must take seriously the need to have adequate cash on hand to respond to any disputes with WKEC that could result in monetary claims against Big Rivers.

V. COMPLIANCE WITH 807 KAR 5:001

Q. Mr. Spainhoward, have you reviewed the answers provided in Exhibits 7 through 15, 17, 19, 20 and 41, which address Big Rivers' compliance with the historical period filing requirements under 807 KAR 5:001 and its various subsections?

A. Yes, I have. I hereby incorporate and adopt those portions of Exhibits 7 through 15, 17, 19, 20 and 41, for which I am identified as the sponsoring witness as part of this Direct Testimony.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

I verify, state, and affirm that the foregoing testimony is true and correct to the best of my knowledge and belief.

David Spainhoward

David A. Spainhoward

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by David A. Spainhoward on this the 26th day of February, 2009.

Notary Public, Ky. State at Large
My Commission Expires 2/21/2010

Exhibit Spainhoward-1

WKE Incremental Net Allowance Consumption Budget
January 2009 version - post-CAIR announcement

		2009
1	OTAG NOx allowances short	(43)
2	OTAG NOx allowances price	$700
3	OTAG sub-cost	($30,030)
4	Annual NOx allowances short	1,277
5	Annual NOx allowances price	$3,350
6	Annual sub-cost	$4,276,610
7	SO2 allowances short	0
8	SO2 allowances price	$140
9	SO2 sub-cost	$0
10	**net allowance costs**	**$4,246,580**
11	**BREC 20%**	**$849,316**

WKE Incremental Fixed and Variable O&M Budget
January 2009 version - post-CAIR announcement

		2009
	Fixed O&M	
1	O&M Labor	$732,201
2	O&M Non-labor	$1,077,134
	Variable O&M	
3	Ammonia	$4,776,698
4	Emulsified Sulfur	$159,787
5	Hydrated Lime	$1,565,202
6	Incremental Equip Parasitic Load costs	$2,788,221
7	incremental Labor G&A	$70,017
8	Incremental non-Labor G&A	$60,000
9	**Total Fixed & Variable O&M**	**$11,229,260**
10	**BREC 20%**	**$2,245,852**

Exhibit Spainhoward-1

Exhibit Spainhoward-1

INCREMENTAL & NON-INCREMENTAL CAPITAL EXPENDITURES

December 1, 2007-November 30, 2008

1	**INCREMENTAL CAPITAL EXPENDITURES**		
2	Amount booked 11/30/08:		
3	WKE Station II	30,579,829.58	
4	WKEC	107,950,043.53	
5	CWIP	2,403,875.06	
6	Retirements	1,676,333.61	
7	Total		142,610,081.78
8	Amount booked 11/30/07:		
9	WKE Station II	30,579,829.58	
10	WKEC	104,531,897.06	
11	CWIP	2,106,367.40	
12	Retirements	1,580,651.73	
13	Total		138,798,745.77
14	Total Expenditures from 12/1/07-11/30/08		3,811,336.01
15	Big Rivers Incremental %		X .20
16			762,267
17	AC Payable-Incremental Capital Assets		(383,896)
18	Incremental Capital Expenditures 12/1/07-11/30/08		378,367
19	**NON-INCREMENTAL CAPITAL EXPENDITURES**		
20	December 2007:		
21	BREC Share of Capital Expenditures		
22	$6,572,000/12 months =		547,667
23	January-November 2008:		
24	BREC Share of Capital Expenditures		
25	$6,720,000/12 months X 11 months =		6,160,000
26			6,707,667
27	AC Payable-Non-Incremental Capital Assets		0
28			6,707,667
29	**TOTAL INCREMENTAL AND NON-INCREMENTAL CAPITAL EXPENDITURES**		
30			**7,086,034**

CAPITAL EXPENDITURES

December 1, 2007-November 30, 2008

			11/30/2007	11/30/2008	TOTAL	INCR/NON-INCR	TRANS & A/G
1							
2	CAPITAL EXPENDITURES		Beg Balance	End Balance	CAP EXP	CAP EXP	CAP EXP
3	101000	Transmission and A&G Plant	225,091,787.98	228,401,229.98	3,309,442.00		3,309,442.00
4	104000	Leased Production & Gas Turbine Plant	1,521,535,592.13	1,534,975,629.70	13,440,037.57	13,440,037.57	
5	105000	Land-Future use for Combustion Turbine	0.00	475,967.50	475,967.50		475,967.50
6	106000	Unclassified Transmission and A&G Plant	0.00	0.00	0.00		0.00
7	107000	Construction-Transmission and A&G	12,589,239.39	22,792,260.98	10,203,021.59		10,203,021.59
8		Less Capitalized Interest			(538,129.00)		(538,129.00)
9	107100	Non-Incremental Construction -BREC	(2,355,036.57)	0.00	2,355,036.57	2,355,036.57	
10	107110	Incremental Construction-BREC	341,715.51	(704,068.64)	(1,045,784.15)	(1,045,784.15)	
11	107200	Non-Incremental Construction -WKEC	4,108,954.83	1,165.40	(4,107,789.43)	(4,107,789.43)	
12	107210	Incremental Construction-WKEC	1,764,654.89	2,849,771.70	1,085,116.81	1,085,116.81	
13	108100	Accumulated Depreciation-Production	(756,891,055.04)	(780,551,696.02)	(23,660,640.98)	(23,660,640.98)	
14	108400	Accumulated Depreciation-Gas Turbine	(5,115,073.74)	(5,304,804.05)	(189,730.31)	(189,730.31)	
15	108500	Accumulated Depreciation-Transmission	(104,668,317.04)	(109,151,764.90)	(4,483,447.86)		(4,483,447.86)
16	108700	Accumulated Depreciation-A&G	(6,699,847.33)	(7,070,318.17)	(370,470.84)		(370,470.84)
17	108800	Retirement-Removal Costs	115,607.88	186,177.78	70,569.90		70,569.90
18	108900	Accumulated Net Gains/Losses on Retirements	40,126,871.93	42,355,149.17	2,228,277.24	1,909,320.98	318,956.26
19	111100	Accumulated Amortization-Station Two Assets	(17,742,350.05)	(19,124,421.04)	(1,382,070.99)	(1,382,070.99)	
20	111900	Accumulated Net Gains/Losses on Station Two Retirements	733,172.99	1,255,578.88	522,405.89	522,405.89	
21	183000	Preliminary Charges-Transmission and A&G Construction	436,133.24	616,494.71	180,361.47		180,361.47
22	232750	Accounts Payable-Non-Incremental Capital Assets	0.00	0.00	0.00	0.00	
23	232751	Accounts Payable-Incremental Capital Assets	(610,742.95)	(994,639.12)	(383,896.17)	(383,896.17)	
24	232900	Accounts Payable-Retainage	(320,205.65)	(282,800.62)	37,405.03		37,405.03
25	253250	Deferred Credit-Non-Incremental Assets-Residual Value	(49,866,263.00)	(54,776,478.00)	(4,910,215.00)	(4,910,215.00)	
26	253251	Deferred Credit-Incremental Assets-Residual Value	(92,829,804.90)	(89,855,601.77)	2,974,203.13	2,974,203.13	
27					(4,190,330.03)	(13,394,006.08)	9,203,676.05
28	Depreciation		Dec-07	Jan 08-Nov 08			
29	403510	Depreciation Expense-Transmission Stations	209,030.99	2,299,544.60	2,508,575.59		2,508,575.59
30	403520	Depreciation Expense-Transmission Poles & Lines	193,594.03	2,142,379.59	2,335,973.62		2,335,973.62
31	403700	Depreciation Expense-A&G	23,227.13	260,470.30	283,697.43		283,697.43
32	413300	Depreciation Expense-Plant Leased to WKEC	2,178,646.33	23,593,194.16	25,771,840.49	25,771,840.49	
33	413400	Amortization Expense-Station Two Plant Leased to WKEC	135,690.52	1,524,762.26	1,660,452.78	1,660,452.78	
34					32,560,539.91	27,432,293.27	5,128,246.64
35	RVP Obligation		Dec-07	Jan 08-Nov 08			
36	412100	WKEC Contributions to Capital-Amortized to Income	(755,841.14)	(6,196,412.01)	(6,952,253.15)	(6,952,253.15)	
37					(6,952,253.15)	(6,952,253.15)	0.00
38	CAPITAL EXPENDITURES				(21,417,956.73)	(7,086,034.04)	(14,331,922.69)

Exhibit Spainhoward-1

WKE Incremental Capital Budget
January 2009 version - post-CAIR announcement

	Capital	2009
1	Coleman boiler tube metal overlays	$1,250,000
2	Green boiler tube metal overlays	$2,600,000
3	HMP&L SCR catalyst	$305,800
4	Green O2 Probes (12)	$360,000
5	Wilson Catalyst	$1,300,000
6	Green Air Shroud Actuators	$150,000
7	**Capital Total**	**$5,965,800**
8	**BREC 20% share**	**$1,193,160**

Exhibit Spainhoward-1

Western Kentucky Energy

2009 Capital Budget

Shared Non-Incremental

Draft

GROSS CAPITAL

Project #	Description	WKEC Gross Capital Budget	City of Henderson Portion	BREC Portion	WKEC Net Capital Budget	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
COLEMAN																		
Unassigned	C-3 Condenser Vacuum Pump Replacement	120,000	0	0	120,000					60,000	60,000							120,000
Unassigned	C-3 Deflector Wall Replacement	765,000	0	0	765,000					382,500	382,500							765,000
Unassigned	C-3 hot end primary tube replacement	1,920,000	0	0	1,920,000					960,000	960,000							1,920,000
Unassigned	C-3 Boiler Insulation	250,000	0	0	250,000					125,000	125,000							250,000
Unassigned	C-3 A Mill Liner Replacement with inlet auger	300,000	0	0	300,000					150,000	150,000							300,000
Unassigned	C-3 Soot Blower Replacement	100,000	0	0	100,000					50,000	50,000							100,000
Unassigned	C-3 A & B PA Fan Housing Replacement	300,000	0	0	300,000					150,000	150,000							300,000
Unassigned	C-3 PA Hot/Cold/Rating Damper Drivers	160,000	0	0	160,000					80,000	80,000							160,000
WK09C015B	C-3 B Buss 4160v Switchgear Replacement	1,065,000	0	0	1,065,000					532,500	532,500							1,065,000
Unassigned	C-3 Slag Grinder Replacement	90,000	0	0	90,000					45,000	45,000							90,000
Unassigned	Capital Valve Replacement	100,000	0	0	100,000	10,000		20,000	10,000	10,000	30,000		10,000		10,000			100,000
Unassigned	Ash Sluice Pump	80,000	0	0	80,000							80,000						80,000
Unassigned	Circulating Water Pump	200,000	0	0	200,000								200,000					200,000
Unassigned	C-3 Expansion joints (4), air heater air side & gas side	270,000	0	0	270,000					270,000								270,000
Unassigned	Conveyor Belt Replacement	50,000	0	0	50,000							50,000						50,000
Unassigned	PI Server and SemAPI Replacement	20,000	0	0	20,000						20,000							20,000
Unassigned	Upgrade CEM's (hardware bypass stacks)	25,000	0	0	25,000							25,000						25,000
Unassigned	Purchase Conductor License (another client)	15,000	0	0	15,000		15,000											15,000
Unassigned	C3 DCS Sequence of Events (includes GPS Clock)	165,000	0	0	165,000	25,000		40,000			100,000							165,000
Unassigned	DMZ Server Replacement	15,000	0	0	15,000						15,000							15,000
Unassigned	Precipitator Controls/Kirk Key Upgrade	115,000	0	0	115,000					115,000								115,000
Unassigned	C3 monitor replacement including 40" alarm monitor	12,000	0	0	12,000	12,000												12,000
Unassigned	C3 DCS power supplies	70,000	0	0	70,000	70,000												70,000
Unassigned	Coal Handling flop gate 7, 9, and 11 replace	85,000	0	0	85,000									85,000				85,000
Unassigned	Replace number 1 and 17 belt scale	25,000	0	0	25,000				25,000									25,000
Unassigned	Barge Unloader Bucket	120,000	0	0	120,000									120,000				120,000
Unassigned	C-3 CEM Duct Gas Analyser	75,000	0	0	75,000						75,000							75,000
Unassigned	4160 Switchgear (2) Replacement for crusher house	65,000	0	0	65,000						65,000							65,000
Unassigned	Barge Unloader 480 Breaker Replacement	55,000	0	0	55,000				55,000									55,000
Unassigned	C-3 480 Volt MCC replacement (2)	160,000	0	0	160,000						160,000							160,000
Unassigned	C-3 DCS Controllers Replacement	65,000	0	0	65,000	65,000												65,000
Unassigned	Plant vibration monitoring replacement	65,000	0	0	65,000					65,000								65,000
Unassigned	Replace underground Natural Gas line	150,000	0	0	150,000	150,000												150,000
Total Coleman		7,072,000	0	0	7,072,000	332,000	15,000	60,000	90,000	2,995,000	3,000,000	155,000	210,000	205,000	10,000	-	-	7,072,000
GREEN																		
Unassigned	GN - Capital Valves	100,000	0	0	100,000		25,000			25,000			25,000			25,000		100,000
Unassigned	G2 - Supervisory Turbine Controls/ETS	185,000	0	0	185,000			35,000	100,000	50,000								185,000
Unassigned	G2 - Rpl Precipitator Field (4th & 5th Field)	1,000,000	0	0	1,000,000			100,000	100,000	300,000					500,000			1,000,000
Unassigned	GN - Conveyor Belts	80,000	0	0	80,000				20,000	20,000	20,000	20,000						80,000
Unassigned	G1 - Rpl Thickener Rake Drive	80,000	0	0	80,000			50,000	30,000									80,000
Unassigned	G2 - Rpl Thickener Rake Drive	80,000	0	0	80,000			50,000	30,000									80,000
Unassigned	GN - Bleed Pumps (Qty. 2) (5&6 of 8)	90,000	0	0	90,000				30,000						60,000			90,000
Unassigned	G2 - Inlet Scrubber Operator	7,000	0	0	7,000			7,000										7,000
Unassigned	G2 - Flyash Hopper	1,100,000	0	0	1,100,000		250,000	250,000	250,000	350,000								1,100,000
Unassigned	G2 - Air Heater Gas Outlet Exp Joints	300,000	0	0	300,000		100,000	100,000	100,000									300,000
Unassigned	GN - Rpl Cooling Tower Deck	100,000	0	0	100,000				100,000									100,000
Unassigned	GN - Fire Water Pump Diesel	15,000	0	0	15,000							15,000						15,000
Unassigned	G1 - Mill Gearbox	300,000	0	0	300,000								250,000	50,000				300,000
Unassigned	G2 - Install West SH Spray Venturi	275,000	0	0	275,000		50,000	100,000	125,000									275,000
Unassigned	G2 - Rpl West SH Spray Attmp Venturi	45,000	0	0	45,000		45,000											45,000
Unassigned	G2 - Turbine Packing HP-IP Rows (also LP)	300,000	0	0	300,000		50,000		150,000	100,000								300,000
Unassigned	GN - Ash Sluice Pump (2 of 3)	168,000	0	0	168,000							100,000	68,000					168,000
Unassigned	GN - Ash Seal Pump (2 of 3)	125,000	0	0	125,000								125,000					125,000
Unassigned	G2 - B Service Water Pump (3 of 4)	40,000	0	0	40,000								40,000					40,000
Unassigned	G2 - Generator Retaining Rings	680,000	0	0	680,000		250,000	250,000	180,000									680,000
Unassigned	G2 - Air Heater Baskets	895,000	0	0	895,000		195,000	300,000	200,000	200,000								895,000
Unassigned	G2 - Reheater Tubes	1,050,000	0	0	1,050,000		600,000			450,000								1,050,000
Unassigned	G1 - IW Discharge Piping	75,000	0	0	75,000									50,000	25,000			75,000
Unassigned	GN - Upgrade CEMS and Reason code panel	75,000	0	0	75,000	75,000												75,000
Unassigned	GN - Rpl Coal Handling Controls	150,000	0	0	150,000			100,000	50,000									150,000
Unassigned	GN - Rpl PI Server & SemAPI	10,000	0	0	10,000			10,000										10,000

Exhibit Spainhoward-1

Exhibit Spainhoward-1

Unassigned	GN - Rpl DMZ Server	15,000	0	0	15,000						15,000							15,000
Unassigned	G2 - Rpl DA Trays	25,000	0	0	25,000	25,000												25,000
Unassigned	G2 - Scrubber Controls - I/O & HMI	475,000	0	0	475,000				475,000									475,000
Unassigned	G2 - Bottom Ash Controls	150,000	0	0	150,000				150,000									150,000
Unassigned	G2 - Rpl Mist Eliminators	425,000	0	0	425,000				425,000									425,000
Unassigned	G2 - Flyash Hopper Isolation Gate	38,000	0	0	38,000				38,000									38,000
Unassigned	G2 - Boiler Drains	250,000	0	0	250,000				250,000									250,000
Unassigned	G2 - A&B Scrubber Inlet Duct Replacement	750,000	0	0	750,000				750,000									750,000
Unassigned	GN - Slaker Water Pump (2 of 3)	75,000	0	0	75,000				75,000									75,000
Unassigned	G2 - Steam Coils(4)	75,000	0	0	75,000	75,000												75,000
Unassigned	GN - Cooling Tower Fan Shroud	216,000	0	0	216,000	216,000												216,000
Unassigned	GN - Landfill Downdrains	20,000	0	0	20,000						20,000							20,000
Unassigned	GN - Water Plant Sump Pumps (2)	30,000	0	0	30,000						30,000							30,000
Unassigned	GN - 6" Diesel Pump	50,000	0	0	50,000						50,000							50,000
Unassigned	G1 - Bottom Ash Controls - 2010 Project	16,000	0	0	16,000			16,000										16,000
Unassigned	G1 - Upgrade SOE Migrate to DCS	20,000	0	0	20,000				20,000									20,000
Total Green		9,955,000	0	0	9,955,000	391,000	1,565,000	1,368,000	3,648,000	1,495,000	135,000	135,000	508,000	100,000	585,000	25,000	-	9,955,000
REID/HMPL																		
Unassigned	RH - Misc Capital Valves	90,000	22,679	0	67,321			25,000		20,000		25,000				20,000		90,000
Unassigned	RH - Misc Conveyor Belts	90,000	22,679	0	67,321							10,000		80,000				90,000
Unassigned	RH - Booth System Control Box	22,000	5,544	0	16,456				22,000									22,000
Unassigned	RH - Loop Calibrators (2)	4,000	1,008	0	2,992			4,000										4,000
Unassigned	RH - Control Room Pressurizing Fans	35,000	8,820	0	26,180					35,000								35,000
Unassigned	RH - Water Plant Bldg Heat Improvements	25,000	6,300	0	18,700					25,000								25,000
WK06S021B	H0 - DCS Engineering (Complete in 2010)	166,000	50,545	0	115,455										166,000			166,000
Unassigned	H0 - Rpl PI Server & SemAPI	10,000	3,045	0	6,955						10,000							10,000
Unassigned	H0 - Upgrade CEMs	30,000	9,135	0	20,865						30,000							30,000
Unassigned	H0 - Rpl Bleed Lines 8" (2)	200,000	60,897	0	139,103							200,000						200,000
Unassigned	H0 - Rpl Elevator Doors/Frames	100,000	30,449	0	69,551						100,000							100,000
Unassigned	H0 - Rpl Thickener Return Line 16"	200,000	60,897	0	139,103				200,000									200,000
Unassigned	H0 - Wetbottom Drains	300,000	91,346	0	208,654										300,000			300,000
WK08S013B	H1 - Rpl WDPF FGD & SCR Controls	140,000	42,628	0	97,372			140,000										140,000
WK08S016B	H1 - CCS Field Wiring & Devices	118,565	36,102	0	82,463		59,280		59,285									118,565
WK08S014B	H1 - CCS Controls	461,435	140,501	0	320,934			461,435										461,435
Unassigned	H1 - Control Room	100,000	30,449	0	69,551			100,000										100,000
Unassigned	H1 - AH Inlet Expansion Joints (2)	160,000	48,718	0	111,282			160,000										160,000
Unassigned	H1 - Burner Deck Vent Fans	30,000	9,135	0	20,865									30,000				30,000
Unassigned	H1 - Cooling Tower Distribution Deck	200,000	60,897	0	139,103			200,000										200,000
Unassigned	H1 - FD Fan Outlet Damper A&B Rexa Drives	20,000	6,090	0	13,910			20,000										20,000
Unassigned	H1 - Feedwater Heater Emergency drain Valve	160,000	48,718	0	111,282			160,000										160,000
Unassigned	H1 - Hydrogen Purity Meters	22,000	6,699	0	15,301			22,000										22,000
Unassigned	H1 - Install Sootblower Power Disconnects	16,000	4,872	0	11,128			16,000										16,000
Unassigned	H1 - Rpl Mist Eliminator	175,000	53,285	0	121,715			175,000										175,000
Unassigned	H1 - Rpl Precip Hoppers (9-12) 4 total	250,000	76,122	0	173,878			250,000										250,000
Unassigned	H1 - Rpl Slag Grinders (2)	75,000	22,837	0	52,163			75,000										75,000
Unassigned	H1 - Rpl Sootblowers (20-23 of 23) 4 total	112,000	34,103	0	77,897			112,000										112,000
Unassigned	H1 - Rpl Wallblowers (8-10 of 24) 3 total	40,000	12,179	0	27,821			40,000										40,000
Unassigned	H1 - Rpl Temperature Reheater Tubes	1,400,000	426,282	0	973,718			1,400,000										1,400,000
Unassigned	H2 - Burner Deck Vent Fans	30,000	9,135	0	20,865									30,000				30,000
Unassigned	H2 - Rpl WDPF FGD & SCR Controls	60,000	18,269	0	41,731			60,000										60,000
Unassigned	H1 - High Energy Pipe Hangers	100,000	30,449	0	69,551			100,000										100,000
Unassigned	H1 - Rpl AH Steam Coils (2)	21,000	6,394	0	14,606				21,000									21,000
Unassigned	H2 - #6 HP Heater Re-tube	300,000	91,346	0	208.654										300,000			300,000
Unassigned	R1 - Rpl Reclaim Vent Fan	30,000	0	0	30,000								30,000					30,000
Unassigned	R1 - Stack Lighting	200,000	0	0	200,000							200,000						200,000
Unassigned	R1 - Upgrade CEMs	20,000	0	0	20,000			20,000										20,000
Total Reid/HMPL		5,513,000	1,588,552	0	3,924,448	0	59,280	3,540,435	302,285	80,000	140,000	435,000	30,000	140,000	766,000	20,000	0	5,513,000
WILSON																		
Unassigned	Capital Valves	100,000	0	0	100,000		25,000		25,000		50,000							100,000
Unassigned	Magnetic Separator Replacement #4	52,000	0	0	52,000		52,000											$52,000
Unassigned	Process Control System Replacement (3)	52,000	0	0	52,000					52,000								52,000
Unassigned	ME Panel Replacements	350,000	0	0	350,000		350,000											350,000
Unassigned	Superheat Tube Replacement Section B (milestone payments)	600,000	0	0	600,000								600,000					600,000
Unassigned	Replace filtrate transfer pumps (4 of 4)	40,000	0	0	40,000		40,000											40,000
Unassigned	Replace Switchgear 480v breakers (5 per year, 18,000/breaker) - FG	90,000	0	0	90,000		90,000											90,000
Unassigned	Slurry recirc motor replacements	112,000	0	0	112,000			112,000										112,000
Unassigned	Conveyor belt replacements (10-1 and 10-2)	235,000	0	0	235,000								235,000					235,000
Unassigned	Gravity Sand Filter replacement (1 of 3)	100,000	0	0	100,000									100,000				100,000
Unassigned	Fire Hydrant replacements	50,000	0	0	50,000				50,000									50,000
Unassigned	Upgrade CEMS (IT)	20,000	0	0	20,000								20,000					20,000
Unassigned	Plant Discharge Pump replacement No. 14	40,000	0	0	40,000		40,000											40,000
Unassigned	Waste water/impoundment pond pump replacement (4 of 6)	60,000	0	0	60,000		60,000											60,000

Unassigned	Precip Outlet Guilotine Damper milestone payments	600,000	0	0	600,000										600,000			600,000
Unassigned	Turbine Blade milestone payments	300,000	0	0	300,000										300,000			300,000
Unassigned	#1 Flyash Blower - first and second stage	50,000	0	0	50,000		50,000											50,000
Unassigned	Reverse Osmosis Water Treatment System	450,000	0	0	450,000		450,000											450,000
Unassigned	Cooling tower fan replacement (#1, #6 & #9)	200,000	0	0	200,000		200,000											200,000
Unassigned	Open Landfill	300,000	0	0	300,000							300,000						300,000
Unassigned	FGD pump house replacement	125,000	0	0	125,000		125,000											125,000
Unassigned	TR and Rapper Precip control replacement	250,000	0	0	250,000		250,000											250,000
Unassigned	PA Fan Silencers	130,000	0	0	130,000		130,000											130,000
Unassigned	DCS Client computer replacement	35,000	0	0	35,000				35,000									35,000
Unassigned	Precip controls	10,000	0	0	10,000									10,000				10,000
Unassigned	Engineering	400,000	0	0	400,000			100,000		100,000			100,000			100,000		400,000
Unassigned	Electrical Refurbishment (Phase 1 of 4)	300,000	0	0	300,000		300,000											300,000
Unassigned	Guillotine Damper (Prepay)	270,000	0	0	270,000							270,000						270,000
Unassigned	Misc Controls and Transmitters	10,000	0	0	10,000		10,000											10,000
Total Wilson		5,331,000	0	0	5,331,000	0	2,172,000	212,000	110,000	152,000	50,000	570,000	955,000	110,000	900,000	100,000	0	5,331,000
SHARED NONINCREMENTAL CAPITAL		27,871,000	1,588,552	0	26,282,448	723,000	3,811,280	5,180,435	4,150,285	4,722,000	3,325,000	1,295,000	1,703,000	555,000	2,261,000	145,000	0	27,871,000

Exhibit Spainhoward-1

Big Rivers Electric Corporation
2009 Transmission and A&G Construction & Capital Budget
(Includes capitalized interest & labor overheads)

	WO/Project Number	Est. Date In-Service	Description	January	February	March	April	May	June
			2009 Capital Budget						
1		month purchased	DGA Monitoring for EHV Transformers (Coleman, Wilson, Reid)		80,000	80,000	80,000	50,000	
2		"	Hot Oil Spray Transformer Dryout System						110,000
3		"	Battery Load Tester	35,000					
4		"	A/C Unit Replacements					4,000	4,000
5		"	Energy Control Telephone System			6,000			
6		"	Hoist, Grips, and Rope -- Replacements			2,500			
7		"	ET&S Computer HVAC Unit			3,500			
8		"	Hydraulic Pump and Press -- Replacement			3,500			
9		"	Tool Replacements					1,000	
10		"	Portable Generator (2) -- Replacements				900		
11		"	Typewriter	750					
12		"	Go Tract Vehicle -- Replacement						
13		"	3/4 Ton, 4x4 Crew Cab Pickup Truck-Replace Veh #254	40,000					
14		"	3/4 Ton, 4x4 Ext Cab Pickup Truck-Replace Veh #258						
15		"	1/2 Ton, 4x4 Ext Cab Pickup Truck-Vegetation Management	27,000					
16		"	1/2 Ton, 4x4 Ext Cab Pickup Truck-Replace Veh #262	27,000					
17		"	1/2 Ton, 4x4 Ext Cab Pickup Truck-Replace Veh #285						
18		"	GIS--Personal Computer/Laptop Replacements/Server Replacements			35,000	35,000		35,000
19		"	Cisco Network Equipment & Switch Upgrades			10,000			
20		"	Servers, Firewalls, Switches, Computer Equipment - Disaster Recovery Center		45,000		2,500	25,000	
21		"	Personal Computers--27 Desktops - (22 Replacements; 2 New)		41,400	7,500	1,200		
22		"	Compliance Tracking Software (NERC, SERC, CIPS)					50,000	
23		"	Uniterruptible Power Supply (UPS) Replacement				30,000		
24		"	Laptop Computers (6 Replacements; 1 New)		3,500		18,000		
25		"	Cyber Security Equipment			7,000			7,000
26		"	Software Tools			5,800		5,000	
27		"	Autocad Upgrade		20,000				
28		"	LaserFiche			5,000	5,000		5,000
29		"	Remote Access to SOE's, Digital Relays			5,000			
30		"	Scanner	10,000					
31		"	Printer Replacements (4)		3,500			6,000	
32		"	Enterprise Risk Management Software	5,000					
33		"	Additional Disk for Coop Web Computer				1,500		
34		"	Office Furniture	3,750	750	12,000			
35		"	Electrical Safety Demo Unit	5,000					
36		"	Inductor for High Voltage Demo Trailer	5,000					
37		"	Rescue Mannequin & Parts	3,950					
38		"	Multimedia Projector	2,000					
39		"	Digital Camera Lenses	500					
40			**Total 2009 Capital Budget**	164,950	194,150	182,800	174,100	141,000	161,000

Exhibit Spainhoward-1

Big Rivers Electric Corporation
2009 Transmission and A&G Construction & Capital Budget
(Includes capitalized interest & labor overheads)

	WO/Project Number	Est. Date In-Service	Description	July	August	September	October	November	December	Total
			2009 Capital Budget							
1		month purchased	DGA Monitoring for EHV Transformers (Coleman, Wilson, Reid)							290,000
2		"	Hot Oil Spray Transformer Dryout System							110,000
3		"	Battery Load Tester							35,000
4		"	A/C Unit Replacements	4,000	4,000					16,000
5		"	Energy Control Telephone System							6,000
6		"	Hoist, Grips, and Rope -- Replacements			2,500				5,000
7		"	ET&S Computer HVAC Unit							3,500
8		"	Hydraulic Pump and Press -- Replacement							3,500
9		"	Tool Replacements			1,000				2,000
10		"	Portable Generator (2) -- Replacements			900				1,800
11		"	Typewriter							750
12		"	Go Tract Vehicle -- Replacement				450,000			450,000
13		"	3/4 Ton, 4x4 Crew Cab Pickup Truck-Replace Veh #254							40,000
14		"	3/4 Ton, 4x4 Ext Cab Pickup Truck-Replace Veh #258				35,000			35,000
15		"	1/2 Ton, 4x4 Ext Cab Pickup Truck-Vegetation Management							27,000
16		"	1/2 Ton, 4x4 Ext Cab Pickup Truck-Replace Veh #262							27,000
17		"	1/2 Ton, 4x4 Ext Cab Pickup Truck-Replace Veh #285				27,000			27,000
18		"	GIS--Personal Computer/Laptop Replacements/Server Replacements	40,000		40,000				185,000
19		"	Cisco Network Equipment & Switch Upgrades	10,000						20,000
20		"	Servers, Firewalls, Switches, Computer Equipment - Disaster Recovery Center			10,000				82,500
21		"	Personal Computers--27 Desktops - (22 Replacements; 2 New)							50,100
22		"	Compliance Tracking Software (NERC, SERC, CIPS)							50,000
23		"	Uniterruptible Power Supply (UPS) Replacement							30,000
24		"	Laptop Computers (6 Replacements; 1 New)							21,500
25		"	Cyber Security Equipment			7,000				21,000
26		"	Software Tools	5,000			5,000			20,800
27		"	Autocad Upgrade							20,000
28		"	LaserFiche							15,000
29		"	Remote Access to SOE's, Digital Relays		5,000					10,000
30		"	Scanner							10,000
31		"	Printer Replacements (4)							9,500
32		"	Enterprise Risk Management Software							5,000
33		"	Additional Disk for Coop Web Computer							1,500
34		"	Office Furniture							16,500
35		"	Electrical Safety Demo Unit							5,000
36		"	Inductor for High Voltage Demo Trailer							5,000
37		"	Rescue Mannequin & Parts							3,950
38		"	Multimedia Projector							2,000
39		"	Digital Camera Lenses							500
40			**Total 2009 Capital Budget**	59,000	9,000	61,400	517,000	0	0	1,664,400

Exhibit Spainhoward-1

Big Rivers Electric Corporation
2009 Transmission and A&G Construction & Capital Budget
(includes capitalized interest & labor overheads)

	WO/Project Number	Est. Date In-Service	Description	January	February	March	April	May	June
			2009 Construction Budget						
41	I420H008	03/09	Add Gravel to Meade County Substation	0	0	14,652	0	0	0
42	I370H014	09/09	CEHV to Coleman C1 & C2 Teleprotection Replacement	0	0	0	6,770	6,769	3,093
43	I370H006	11/09	Coleman to Newtonville 161kV Reconductor			3,320	3,786	3,797	1,943
44	I370H007	12/09	Cumberland River Crossing Modification						2,581
45	I370H005	12/10	Cumberland-Caldwell Springs Tap 69 kV Line	0	0	0	0	0	0
46	W910000		Daviess Co Airport Line Reroute					893	893
47	I420H022	10/09	Digital Fault Recorder Upgrade for Coleman						
48	I420H024	12/09	Digital Fault Recorder Upgrade for Portable						
49	I420H023	11/09	Digital Fault Recorder Upgrade for Reid						
50	I420H021	10/09	Digital Fault Recorder Upgrade for Wilson						
51	W8640000	12/09	Falls of Rough-McDaniels 69 kV Line	44,192	69,081	69,788	24,024	19,104	94,053
52	I370H002	12/09	Hancock 69kV Capacitor Bank						3,633
53	I370H009	10/09	Horse Fork Tap 69kV Switch Modification			6,557	2,664		
54	W8950000	03/09	McCracken Co 69kV Line Terminal for Olivet Tap	48,383	76,743	5,847	3,954		
55	I370H012	08/09	McCracken Co RTU Replacement			6,769	6,769	3,093	21,093
56	I370H003		National AL 13.8kV Switchgear for Southwire Feed			893	893		893
57	W8700000	07/09	Oil Spill Prevention Control & Countermeasures System	75,306	75,656	76,040	75,944	61,224	5,277
58	W9170000	07/09	Olivet-Church Road Tap 4.6 M 69kV Line	194,954	190,432	89,880	40,476	35,596	21,579
59	I420H007	12/09	Pole Change Outs	50,609	50,609	50,624	50,624	50,624	50,684
60	W9260000	02/09	Reconductor 4-K & 5-D between Hopkins & S Hanson	202,056	5,483				
61	W8850000	02/09	Reconductor Line 6-A Reid Swyd/Daviess Co Sub	306,346	61,596				
62	I370H008	06/09	REHV to Hopkins 161kV Reroute	6,756		40,446	151,310		
63	I370H013	12/09	Reid 69kV RTU Replacement						
64	I420H006	09/09	Replace Fifteen (15) 161kV Disconnects at Reid				40,226	40,226	40,241
65	I420H025	03/09	Replace Nine (9) 69kV PTs at Daviess County Sub		4,837	44,837			
66	I420H004	06/09	Replace Substation Battery at Livingston Co Substation						15,932
67	I420H002	06/09	Replace Substation Battery at McCracken Substation						15,932
68	I420H003	06/09	Replace Substation Battery at Wilson EHV Substation						28,932
69	I420H001	05/09	Replace Substation Security Fence at Hardinsburg Substation					26,676	
70	I420H005	09/09	Replace Three (3) MIOD Operators at Dover						
71	I420H026	04/09	Replace Twelve (12) 69kV PTs at Henderson County Sub			58,444	6,444		
72	I370H017	09/09	Spill Prevention Containment Control Implementation	202,652	203,622	254,871	255,645	101,115	45,650
73	W9230000	01/10	Two Way Radio System	88,576	68,876	380,705	50,915	252,085	213,075
74	I420H010	12/09	Upgrade Metering at Coleman Road to 28 MVA						
75	W9070000	03/09	US 60 Bypass Relocation Lines 18-G & 13-E	165,441	49,351	3,861			
76	W9300000	12/10	White Oak Substation	14,876	12,723	13,646	25,065	111,565	262,259
77	I370H001	12/10	Wilson 161-69kV Substation Facilities						
78	I370H004	12/10	Wilson 69kV Line to Centertown	11,032	11,097	11,157	11,207	11,257	11,307
79			**Total 2009 BREC Construction Budget**	1,411,179	880,106	1,132,337	756,716	724,024	839,050
80			**Grand Total 2009 Transmission and A&G Capital & Construction Budget**	**1,576,129**	**1,074,256**	**1,315,137**	**930,816**	**865,024**	**1,000,050**

Exhibit Spainhoward-1

Big Rivers Electric Corporation
2009 Transmission and A&G Construction & Capital Budget
(Includes capitalized interest & labor overheads)

	WO/Project Number	Est. Date In-Service	Description	July	August	September	October	November	December	Total
			2009 Construction Budget							
41	I420H008	03/09	Add Gravel to Meade County Substation	0	0	0	0	0	0	14,652
42	I370H014	09/09	CEHV to Coleman C1 & C2 Teleprotection Replacement	126,646	56,510	0	0	0	0	199,788
43	I370H006	11/09	Coleman to Newtonville 161kV Reconductor	1,953	202,796	203,766	154,079	22,840	14,900	613,180
44	I370H007	12/09	Cumberland River Crossing Modification	3,967	74	74	89	116,429	2,055	125,269
45	I370H005	12/10	Cumberland-Caldwell Springs Tap 69 kV Line	8,484	14,554	32,150	17,275	11,878	62,179	146,520
46	W910000		Daviess Co Airport Line Reroute				893	446	893	4,018
47	I420H022	10/09	Digital Fault Recorder Upgrade for Coleman				923			923
48	I420H024	12/09	Digital Fault Recorder Upgrade for Portable						849	849
49	I420H023	11/09	Digital Fault Recorder Upgrade for Reid					848		848
50	I420H021	10/09	Digital Fault Recorder Upgrade for Wilson				923			923
51	W8640000	12/09	Falls of Rough-McDaniels 69 kV Line	34,203	34,343	34,493	42,266	24,773	24,873	515,193
52	I370H002	12/09	Hancock 69kV Capacitor Bank	7,047	7,523	28,129	58,488	106,095	106,220	317,135
53	I370H009	10/09	Horse Fork Tap 69kV Switch Modification	893		48,000				58,114
54	W8950000	03/09	McCracken Co 69kV Line Terminal for Olivet Tap							134,927
55	I370H012	08/09	McCracken Co RTU Replacement	1,093						38,817
56	I370H003		National AL 13.8kV Switchgear for Southwire Feed	1,310	1,758	2,232	2,232	1,339	893	12,443
57	W8700000	07/09	Oil Spill Prevention Control & Countermeasures System	5,277	4,643					379,367
58	W9170000	07/09	Olivet-Church Road Tap 4.6 M 69kV Line							572,917
59	I420H007	12/09	Pole Change Outs	50,713	50,713	50,728	51,264	51,264	51,311	609,767
60	W9260000	02/09	Reconductor 4-K & 5-D between Hopkins & S Hanson							207,539
61	W8850000	02/09	Reconductor Line 6-A Reid Swyd/Daviess Co Sub							367,942
62	I370H008	06/09	REHV to Hopkins 161kV Reroute							198,512
63	I370H013	12/09	Reid 69kV RTU Replacement	3,866	6,312	2,606	2,606	20,607	2,647	38,644
64	I420H006	09/09	Replace Fifteen (15) 161kV Disconnects at Reid	40,241	40,241	40,279				241,454
65	I420H025	03/09	Replace Nine (9) 69kV PTs at Daviess County Sub							49,674
66	I420H004	06/09	Replace Substation Battery at Livingston Co Substation							15,932
67	I420H002	06/09	Replace Substation Battery at McCracken Substation							15,932
68	I420H003	06/09	Replace Substation Battery at Wilson EHV Substation							28,932
69	I420H001	05/09	Replace Substation Security Fence at Hardinsburg Substation							26,676
70	I420H005	09/09	Replace Three (3) MIOD Operators at Dover	10,251	10,251	6,500				27,002
71	I420H026	04/09	Replace Twelve (12) 69kV PTs at Henderson County Sub							64,886
72	I370H017	09/09	Spill Prevention Containment Control Implementation	5,450						1,069,005
73	W9230000	01/10	Two Way Radio System	605,945	1,272,115	439,160	203,909	2,516,383	76,148	6,167,892
74	I420H010	12/09	Upgrade Metering at Coleman Road to 28 MVA				2,583	2,583	1,680	6,846
75	W9070000	03/09	US 60 Bypass Relocation Lines 18-G & 13-E							218,653
76	W9300000	12/10	White Oak Substation	263,301	364,415	366,572	368,639	1,523,330	490,007	3,816,398
77	I370H001	12/10	Wilson 161-69kV Substation Facilities					2,456	9,070	11,526
78	I370H004	12/10	Wilson 69kV Line to Centertown	11,357	11,407	6,928	6,958	6,990	7,019	117,716
79			**Total 2009 BREC Construction Budget**	1,181,997	2,077,655	1,261,617	913,127	4,408,261	850,744	16,436,813
80			**Grand Total 2009 Transmission and A&G Capital & Construction Budget**	**1,240,997**	**2,086,655**	**1,323,017**	**1,430,127**	**4,408,261**	**850,744**	**18,101,213**

Exhibit Spainhoward-1

Exhibit 49

Order in Case No. 99-450 dated November 24, 1999, re: Big Rivers Electric Corporation's Application for Approval of a Leveraged lease of Three Generating Units (First Order)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

BIG RIVERS ELECTRIC CORPORATION'S APPLICATION FOR APPROVAL OF A LEVERAGED LEASE OF THREE GENERATING UNITS	)))	CASE NO. 99-450

ORDER

On November 8, 1999, Big Rivers Electric Corporation ("Big Rivers") filed an application seeking authority, if needed, to implement a sale and leaseback transaction ("lease transaction") involving certain generating facilities owned by Big Rivers.[1] The application requested the Commission to disclaim jurisdiction over the lease transaction and the documents to be issued in connection with the lease transaction. In the alternative, Big Rivers sought Commission approval of the lease transaction and the documents considered to be "evidences of indebtedness," including amendments to the documents approved by the Commission in 1998 in conjunction with the LG&E Energy

[1] Specifically, Big Rivers proposed to consummate a leveraged lease of its ownership interest in the D. B. Wilson Unit No. 1 ("Wilson Unit"), the Robert D. Green Units No. 1 and 2 ("Green Units"), and the common facilities owned by Big Rivers that are located at the Green Units site. The Wilson Unit, Green Units, and the common facilities at the Green Units site are referenced as the "Facilities."

Corp. lease transaction ("LEC transaction").[2] Additionally, Big Rivers requests permission to deviate from the filing requirements of 807 KAR 5:001, Section 11, to the extent its application was not in compliance with that regulation. Finally, due to the complexity and timing of the lease transaction, Big Rivers requests that the Commission expedite its review of the proposed lease transaction and grant the requested approvals no later than November 24, 1999.

The Attorney General, Southwire Company, and Alcan Aluminum Corporation were granted intervention in this proceeding. An informal conference was held at the Commission's offices on October 21, 1999 to provide additional explanations about the proposed transaction.

The Wilson Unit is located in Ohio County, Kentucky, and was placed into commercial operation in November 1986. The Green Units are located in Webster County, Kentucky, and were placed into commercial operation in December 1979 and January 1981. The units are coal-fired steam electric generating stations that are equipped with sulfur dioxide scrubbers. The combined net rated capability of the units is 874 MW.

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[2] Case No. 97-204, The Application of Big Rivers Electric Corporation, Louisville Gas and Electric Company, Western Kentucky Energy Corp., Western Kentucky Leasing Corp., and LG&E Station Two Inc. for Approval of Wholesale Rate Adjustment for Big Rivers Electric Corporation and for Approval of Transaction, final Order dated April 30, 1998, and Case No. 98-267, The Application of Big Rivers Electric Corporation for Approval of the 1998 Amendments to Station Two Contracts Between Big Rivers Electric Corporation and the City of Henderson, Kentucky and the Utility Commission of the City of Henderson, final Order dated July 14, 1998. Under the terms of the LEC transaction, Big Rivers leases its generating assets to subsidiaries or affiliates of LG&E Energy Corp. Big Rivers has been operating under the terms of that agreement since July 15, 1998, the closing date of the LEC transaction.

Big Rivers states in the application that the purpose of the proposed lease transaction is to simultaneously sell and lease back certain ownership rights, and use the net cash benefit from the lease transaction to pay down approximately $70 million of its debt. The proposed lease transaction will consist of up to six sales and leasebacks involving two equity investors and separate undivided interests in Big Rivers' ownership interest in the Facilities.

The form of the lease transaction will be a long-term lease ("Head Lease") of an undivided interest in the Facilities from Big Rivers to the trustee[3] of a trust estate created for the benefit of the equity investor. The trustee will also lease from Big Rivers an undivided interest in the sites the Facilities are located on for a term identical to that of the Head Lease ("Ground Lease"). A Participation Agreement will set forth the terms of the closing conditions, the payment of transaction costs, certain covenants and indemnification of the parties, and other general matters relating to the lease transaction.

The Head Lease will be considered a sale of the undivided interest in the Facilities for federal income tax purposes because the term of the Head Lease extends beyond the entire expected economic useful life of the Facilities. The trustee will pay all the rent under the Head Lease on the closing date. The trustee will finance the rent

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[3] Exhibit 3 of the application identifies the trustee as the State Street Bank and Trust Company of Connecticut, N.A.

payment with a combination of equity from the equity investor and the proceeds of non-recourse loans to the trustee.[4]

The trustee will lease the trust's undivided interest in the Facilities back to Big Rivers under a shorter-term lease ("Facilities Lease") for a term that extends beyond the expiration of the LEC transaction.[5] The Facilities Lease will be a conventional "triple net" lease, under which Big Rivers will have the obligation to maintain and insure the Facilities and will incur the risk of loss with respect to the Facilities. The trustee will also lease the Facilities' sites back to Big Rivers for the term of the Facilities Lease ("Ground Sublease").

The Facilities Lease will be subject to the terms of the LEC transaction. The lease transaction documents will provide that at the end of the term of the LEC transaction, or its early termination, Big Rivers will be responsible for the operation and maintenance of the Facilities through the end of the Facilities Lease term. At the end of the Facilities Lease, Big Rivers will have the option to either purchase the remaining leasehold interest of the trust under the Head Lease or operate the Facilities on behalf

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[4] These non-recourse loans will be secured by the trustee's interest in the Facilities under the Head Lease, the Facilities Lease, the Ground Lease and Sublease, Big Rivers' payment of rent, certain investment instruments purchased by Big Rivers and assigned to the trustee, and the trustee's interest in the Big Rivers Mortgage.

[5] The term of the Facilities Lease for the Wilson Unit will be approximately 27 years and for the Green Units approximately 25 years.

of the trust and locate an unrelated, third party to purchase power generated from the Facilities.[6]

Big Rivers will economically defease its periodic rent obligations under the Facilities Lease by using a portion of the rent payment received under the Head Lease on the closing date to purchase investment instruments[7] from affiliates of Ambac Assurance Corporation ("Ambac") and another institution. The payments under these investment instruments in the aggregate will be equal in timing and amount to Big Rivers' basic rent obligation under the Facilities Lease.[8] In addition, these investments will provide for payment of an amount sufficient to fund Big Rivers' right to purchase the trustee's interest in the Facilities at the end of the Facilities Lease term.

Big Rivers will have the option to purchase the equity investor's interest in the trust if either the lease transaction becomes illegal with respect to Big Rivers and cannot be restructured in a manner acceptable to the parties or burdensome indemnities become due by Big Rivers. Big Rivers will pay the trustee a purchase price for the trustee's interest under the Head Lease equal to a specified amount ("Termination

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[6] Under the purchase option, Big Rivers would pay a fixed purchase price plus unpaid rent. The fixed purchase option price will be economically defeased. Under the continued operations option, the terms and conditions for the operation of the Facilities and the associated power purchase agreement will be governed by two additional documents, an Operating and Support Agreement and a Service Contract.

[7] The investment instruments will take the form of guaranteed investment contracts, prepaid swap agreements, or interest bearing deposits.

[8] In its application, Big Rivers states that the acquisition of the investment instruments will be made by a wholly owned, limited purpose corporate subsidiary of Big Rivers created for this transaction in order to limit the impact of certain state and local taxes. Big Rivers will use a portion of the rent payment under the Head Lease as a capital infusion to the new subsidiary, in order for the subsidiary to acquire these investment instruments.

Value"). In addition, involuntary termination of the Facilities Lease can occur in the event of loss or an event of default.[9] Generally, a termination of the Facilities Lease due to an event of loss will require that Big Rivers purchase the equity investor's interest in the trust by payment of an amount equal to the Termination Value plus all unpaid rent. Following an event of default under the Facilities Lease, the equity investor will be entitled to put its beneficial interest in the trust under the Head Lease to an Ambac subsidiary for the full amount of Termination Value. Under the terms of an arrangement called a Lessor Swap, the obligations of the Ambac subsidiary will be guaranteed by Ambac pursuant to a surety bond. The Ambac subsidiary would then be entitled to put this beneficial interest in the trust to Big Rivers for the full amount of the Termination Value or an alternate cash settlement procedure. Under the terms of an arrangement called the Big Rivers Swap, Ambac will guarantee Big Rivers' obligations pursuant to a financial guarantee insurance policy.

Big Rivers will issue a promissory note to the trustee to evidence its obligation to pay the Termination Value under the Facilities Lease and to the Ambac subsidiary to pay the Termination Value under the Big Rivers Swap. Big Rivers will also grant to the trustee, the equity investor, the Ambac subsidiary, and the lenders, a mortgage and security agreement in Big Rivers' ownership interest in all of its property that is subject to the Big Rivers Mortgage to secure the performance of its obligations to pay certain contractual, tort, and other indemnities under the lease transaction. This mortgage and

[9] An event of loss refers to either the physical destruction of the assets without rebuilding, condemnation by eminent domain, or public utility regulation of the equity investor by reason of the lease transaction. An event of default refers to performance defaults by various parties to the lease transaction agreements or the downgrading of Ambac. See the Response to the Commission's November 16, 1999 Order, Item 14.

security agreement will be subject and subordinate to the Big Rivers Mortgage, the Head Lease, the Facilities Lease, the Ground Lease and Sublease, the LEC transaction, and Big Rivers' arrangements with the city of Henderson, Kentucky ("Henderson").

The lease transaction will not affect the operation and maintenance of the Facilities by Western Kentucky Energy Corp. ("WKEC") pursuant to the LEC transaction. The affiliates of LG&E Energy Corp. associated with the LEC transaction ("LG&E Parties") have raised 11 specific concerns about the proposed lease transaction. Based on the information provided and statements made by Big Rivers, the LG&E Parties have stated that they have no objection to Big Rivers proceeding with the development of the proposed lease transaction.[10]

The LG&E Parties required as a condition to consenting to the proposed lease transaction that the parties to the transaction agree to subordinate their interest under the Head Lease to the interests of the LG&E Parties under the LEC transaction. In consideration for the subordination of interest, and in order for the equity investor and the associated lenders to enjoy the full economic benefit of the investments and loans, Big Rivers will partially assign the Power Purchase Agreement between Big Rivers and LG&E Energy Marketing, Inc. to the trustee. Big Rivers will also assign the right to receive a portion of the rent paid by WKEC under the lease of the Facilities in the LEC transaction to the trustee. The trustee will reassign these interests back to Big Rivers in

[10] The LG&E Parties have reserved the right to withhold their final approval of the transaction until such time as the transaction documentation has been finalized and the concerns of the LG&E Parties have been satisfactorily addressed. See Response to the Commission's November 16, 1999 Order, Item 9.

the lease transaction for the term of the Facilities Lease and the trustee will have no rights or obligations under this assignment unless the Facilities Lease is terminated under specific circumstances.

The common facilities located at the Green Units' site are used jointly in the operation of the Green Units and the Station Two Facility owned by Henderson. The proposed lease transaction will not affect the continued access to these common facilities by Henderson or the LG&E Energy Corp. affiliate that operates the Station Two Facility under the LEC transaction. No consents or approvals will be required from Henderson for the proposed transaction.

Based on current information, Big Rivers has estimated that as a result of the lease transaction, it will receive approximately $913 million. Payments to establish the debt and equity defeasance instruments are estimated to cost approximately $825 million. Enhancement fees and expenses for legal, advisory, appraisal, and miscellaneous services are estimated to cost approximately $18 million.[11] This results in a net cash benefit of $70 million.[12] The final amount of the net cash benefit will vary based upon the interest rate obtained on the closing date for the defeasance deposits and changes in other assumptions.

Big Rivers' accumulated net operating losses will be used to offset federal income taxes that would be recognized on the net gain realized by Big Rivers as a

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[11] The estimated proceeds and associated costs are shown in the Response to the Commission's November 16, 1999 Order, Item 14.

[12] Big Rivers has indicated that it will record the net cash benefit in Account No. 253 – Other Deferred Credits, and amortize the amount on a straight-line basis over the expected lease term of 27 years. See Response to the Commission's November 16, 1999 Order, Item 3.

result of the transaction. The total amount of the net cash benefit will be paid to the Rural Utilities Service ("RUS") and applied to the RUS New Note as a condition of receiving RUS consent to the lease transaction. The RUS New Note debt service schedule will be recalculated to reflect the lower principal balance.[13] Big Rivers anticipates that this recalculation will reduce its annual debt service by approximately $5 million. The Big Rivers' board of directors has deferred a decision on the use of the savings until the transaction is completed and the annual debt service savings can be accurately determined.

Big Rivers is seeking a written determination from the Kentucky Revenue Cabinet ("Revenue Cabinet") concerning certain state tax issues. As of the filing of its application, Big Rivers had not received this determination. In addition, Big Rivers' member cooperatives must approve the lease transaction. The proposed lease transaction will be submitted to the member cooperatives between November 8 and 20, 1999.

Big Rivers included with its application a motion requesting the Commission to disclaim jurisdiction over the proposed leveraged lease transaction. The motion states that the transaction is not a financing subject to Commission jurisdiction because no securities or evidences of indebtedness will be issued. Big Rivers asserts that, although it will execute two notes, an amendment to its existing mortgage, and a new subordinated mortgage, such documents only secure its performance under the

[13] In its application, Big Rivers indicated it anticipated that RUS would also allow Big Rivers to receive a reduction in debt service costs that RUS would realize by using the net cash benefit it received to prepay high interest notes to the Federal Financing Bank on the underlying RUS debt. However, no written verification of this benefit has been received by Big Rivers.

leveraged lease and do not evidence current new or refinanced debt or securities. Alternatively, Big Rivers claims that the transaction falls within the exemption to the Commission's financing authority under KRS 278.300(10) because the financing is subject to the control of an agency of the federal government, the RUS.

The Commission finds no merit in this motion. Even though the purpose of the two new notes is to secure Big Rivers' performance of certain contractual obligations, the notes are evidences of indebtedness that require prior Commission approval under KRS 278.300(1). Furthermore, the mortgage amendment and new subordinated mortgage to be executed by Big Rivers must also be approved since they are modifications to documents previously reviewed and approved by the Commission.

Although the Commission has previously disclaimed jurisdiction over financings that are subject to the control of a federal agency, such as RUS, the leverage lease proposed here is not under the control of RUS. The terms and conditions of the transaction are not being established by RUS, but by private banks and non-governmental investors. The participation of RUS has been limited to granting requisite approval of the transaction and lien accommodations, activities that do not rise to the level of control that exists when RUS is the lender for the transaction.

In addition, the proposed transaction will require modifications to many of the documents previously approved by the Commission in conjunction with Big Rivers' 1998 lease of its generating assets to a subsidiary of LG&E Energy Corp.[14] As such, these modifications to previously approved documents will need Commission approval.

[14] Case No. 98-267, final Order dated July 14, 1998.

Big Rivers also included a motion for expedited consideration, stating that the Commission will need to approve the transaction by November 24, 1999 for a closing to be held by the end of the year. If the transaction does not close by the end of 1999, the benefits to Big Rivers and its members will be reduced by an estimated $6-$8 million. While this potential reduction in benefits amounts to only approximately 10 percent of the total estimated benefits, the absolute amount is very significant, particularly in light of Big Rivers' financial condition and its debt service requirements.

Based on the significant benefit reduction if a decision is not issued by November 24, 1999, the Commission has given this application a high priority status to ensure that a final decision is issued by that date. The Commission notes that at the suggestion of its Staff, an informal conference was held at our offices on October 21, 1999 to allow Big Rivers an opportunity to explain the details of the transaction to Staff and intervenors. The application was then filed on November 8, 1999, giving the Commission and intervenors only 16 days to investigate a highly complex and detailed financial transaction.

While Big Rivers maintains that its application could not have been filed earlier because the transaction was "susceptible to change" and "in flux,"[15] the record demonstrates that on September 1, 1999, Big Rivers provided the Revenue Cabinet with a very detailed, written description of the proposed transaction.[16] Had such a description been provided to the Commission at that time, our investigation would have been greatly facilitated and our attention would not have had to be diverted from other

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[15] Response to the Commission's November 16, 1999 Order, Item 7.

[16] Id., Item 6.

pending cases. The Commission admonishes Big Rivers that such dilatory conduct will not be tolerated in the future. Big Rivers is put on notice that time-sensitive applications must be filed as early as possible, not weeks after the major parameters of the transaction are known with reasonable certainty.

The Commission has concerns about Big Rivers' potential financial exposure due to an early termination of the Facilities Lease. Based on the documents and responses in this record, it appears that adequate provisions have been made concerning the potential exposure from an early termination due to an event of loss or event of default. Big Rivers has acknowledged that an early termination at its direction would result in a financial exposure of as much as $218 million.[17]

An example of an early termination initiated voluntarily by Big Rivers would be the situation where under the defeased lease transaction, burdensome indemnities become due by Big Rivers. Such a situation implies that Big Rivers' financial condition has deteriorated and it may not possess the financial resources to pay the Termination Value. However, Big Rivers has stated that it could only exercise this option if it possessed sufficient financial resources to pay the Termination Value. Big Rivers notes that the RUS has been kept apprised of all aspects of the proposed lease transaction, and the RUS is well aware that the potential early termination exposure exceeds the upfront net proceeds to be paid to the RUS. Big Rivers has concluded that it would be extremely unlikely RUS would acquiesce to the proposed lease transaction if it perceived there to be a significant possibility of an early termination of the Facilities

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[17] Id., Item 4.

Lease.[18] Given Big Rivers' statements and assurances of the RUS's understanding of the potential exposure, the Commission finds this potential exposure to be reasonably addressed.

The Commission, after consideration of the evidence of record and being otherwise sufficiently advised, finds that Big Rivers should be authorized to proceed with the proposed transaction. Based on the description of the proposed transaction, the primary benefit of the proposed lease transaction is the $70 million net cash benefit and the estimated $5 million reduction in Big Rivers' debt service obligations to the RUS. The reduction in debt service obligations results from both an additional interest rate reduction and a restructured debt service schedule. The RUS has given verbal assurances in face-to-face meetings with Big Rivers as recently as November 16, 1999 that both the interest rate reduction and the restructured debt service schedule will be reflected in the appropriate documents.[19] The Commission advises Big Rivers that the Commission's approval of the lease transaction is predicated upon the inclusion of both an interest rate reduction and a debt service schedule restructuring.

IT IS THEREFORE ORDERED that:

1. The motion for a disclaimer of jurisdiction over the proposed lease transaction is denied.

2. Big Rivers is authorized to execute a lease of its Wilson and Green Units, along with the associated common facilities at the Green Units' site, pursuant to a sale and leaseback transaction as described in the application.

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[18] Id., Item 5.

[19] Id., Item 3(d).

3. Big Rivers shall agree only to such terms, conditions, and prices that are consistent with said parameters as set out in the application.

4. Within 10 days of the date of this Order, Big Rivers shall file with the Commission copies of a letter from its lease counsel that the proposed lease transaction is in compliance with the applicable sections of the Internal Revenue Service Code and any guidelines, rules, or regulations promulgated by the Internal Revenue Service concerning such lease transactions.

5. Big Rivers shall file with the Commission copies of the Revenue Cabinet determination concerning Kentucky tax issues within 10 days of its receipt. If the Revenue Cabinet determination causes Big Rivers to abandon the proposed transaction, notice of that decision should be included with the filing.

6. Big Rivers shall file with the Commission copies of the final approvals of the lease transaction from its member cooperatives, the LG&E Parties, and the RUS within 10 days of their receipt. Any conditions included in the final approvals that were not a part of the record in this proceeding shall be identified and the effect of the conditions summarized.

7. Big Rivers shall, within 30 days of the completion of the sale and leaseback transaction, file two copies of all transaction documentation with the Commission. In addition, Big Rivers shall include an executive summary of the terms and conditions of the finalized transaction. The summary shall note and explain any terms and conditions that are different from those described in the application.

8. Big Rivers shall, in the first monthly financial report filed with the Commission after the booking of the benefits from the sale and leaseback transaction,

include notes to its respective financial statements explaining the determination of the benefits recognized from the transaction. This shall include the disclosure of the final transaction price, the gross up-front benefit amount received by Big Rivers, the total expenses to achieve the transaction, the total amount applied to the RUS New Note, and an explanation of any debt service revisions provided by the RUS.

Done at Frankfort, Kentucky, this 24th day of November, 1999.

By the Commission

ATTEST:

Helen C. Helton

Executive Director

Exhibit 50

Order in Case No. 99-450 dated January 28, 2000, re: Big Rivers Electric Corporation's Application for Approval of a Leveraged lease of Three Generating Units (Second Order)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

BIG RIVERS ELECTRIC CORPORATION'S APPLICATION FOR APPROVAL OF A LEVERAGED LEASE OF THREE GENERATING UNITS	)))	CASE NO. 99-450

O R D E R

On November 24, 1999, the Commission authorized Big Rivers Electric Corporation ("Big Rivers") to execute a lease of its D. B. Wilson Unit No. 1 ("Wilson Unit") and its Robert D. Green Units No. 1 and 2 ("Green Units"), along with the associated common facilities at the Green Units' site, pursuant to a sale and leaseback transaction ("lease transaction") as described in Big Rivers' November 8, 1999 application. As the final terms and conditions of the lease transaction had not been finalized, Big Rivers was authorized to agree only to such terms, conditions, and prices that were consistent with the parameters set out in its application. In addition, Big Rivers was advised that the Commission's approval of the lease transaction was predicated upon the inclusion of both an interest rate reduction and a debt service schedule reduction from the Rural Utilities Service ("RUS").[1]

On January 24, 2000, Big Rivers filed a motion to reopen this docket for the purpose of reauthorizing the proposed lease transaction, due to the fact that certain assumptions and representations have changed since the Commission's November 24, 1999 Order. Big Rivers also requested that the Commission find that no further

[1] November 24, 1999 Order at 13.

approvals are required for the equity participants or the owner trust to participate in the lease transaction, provided that this finding did not constitute any approval under KRS Chapter 278 that may be required if either group assumed responsibility for the operation of one or more of the generating units. Finally, Big Rivers requested expedited consideration of the motion, noting that the optimum date for it to close the lease transaction was March 1, 2000, which would require Commission approval by January 28, 2000.

Exhibit A to Big Rivers' January 24, 2000 motion includes a description of the specific changes in the term sheet for the lease transaction. The most significant change is related to the reduction of Big Rivers' debt service obligations to the RUS. In its original application, Big Rivers stated that the RUS had agreed to reduce the interest rate on Big Rivers' debt and restructure the debt service in recognition of the total net cash benefit being paid to RUS and applied to the New RUS Note. However, the RUS has informed Big Rivers that because of changes in its debt due to the bankruptcy restructuring, the benefit of an interest rate reduction is not available.[2] In addition, RUS is requiring as a precondition to its approval of the lease transaction that it be paid at least $70 million at the closing of the lease transaction, which will be reflected as a permanent reduction in like amount in the principal of the New RUS Note.

Because of the changes in the lease transaction terms, applicable interest rates, and the passage of time, Big Rivers currently estimates that the net cash benefit is

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[2] "Because there is no longer a connection between BREC's direct obligations to RUS and RUS's guarantee of BREC's pre-bankruptcy obligations to FFB, there is no additional benefit to pass on to BREC in the form of an interest rate reduction on its indebtedness to RUS." See January 24, 2000 Motion to Reopen, Exhibit B.

$68.1 million.[3] As this estimate is below the RUS-required minimum of $70 million, Big Rivers has indicated that it would make up the difference out of available cash or by the application of prepayments already made to RUS. In addition, Big Rivers now anticipates that its annual debt service will be reduced by $4.0 million.[4]

The Commission, after consideration of the evidence of record and being otherwise sufficiently advised, finds that Big Rivers should be authorized to proceed with the proposed lease transaction as revised. The early payment of $70 million on the New RUS Note and the associated $4 million annual reduction in Big Rivers' debt service obligation to the RUS are very significant benefits. The numerous changes to the terms and conditions of the proposed lease transaction do not appear to have increased Big Rivers' potential financial exposure.

The Commission further finds that the leasing of the Wilson and Green Units to the Owner Trust, with an immediate lease back to Big Rivers, does not constitute a change in control of a utility or of the units themselves. Thus, no additional approvals are needed under KRS 278.020(4) or (5). As acknowledged by Big Rivers, this finding does not constitute an approval under KRS Chapter 278, or obviate the need for such approval, if the equity participants, the Owner Trust, or any lender as assignee of the

[3] In its November 8, 1999 application, Big Rivers had initially estimated that the net cash benefit would be $70 million, but indicated it could be as high as $77 million. See January 24, 2000 Motion to Reopen at 4-5.

[4] Big Rivers had originally estimated the savings from the debt payment and interest rate reduction was approximately $5.2 million. Of that total estimate, the interest rate reduction was worth approximately $1.2 million annually over the balance of the term of the New RUS Note. The current estimate of $4 million annually assumes a payment to RUS of $70 million. See January 24, 2000 Motion to Reopen at 4.

Owner Trust, assumes present responsibility for the operation of one or more of the generating units.

IT IS THEREFORE ORDERED that:

1. Big Rivers is authorized to execute the proposed lease transaction, as originally authorized in the November 24, 1999 Order, subject to the changes in assumptions, representations, and term sheet as described in the January 24, 2000 motion to reopen.

2. Big Rivers shall agree only to such terms, conditions, and prices that are consistent with said parameters as set out in the application, as revised by the motion to reopen.

3. No further approvals are required under KRS Chapter 278 for the equity participants, the Owner Trust, or any lender as assignee of the Owner Trust to participate in the proposed lease transaction, as revised by the motion to reopen.

4. Within 10 days of the date of this Order, Big Rivers shall file with the Commission copies of a letter from its lease counsel providing positive assurance that the proposed lease transaction, as revised by the motion to reopen, is in compliance with the applicable sections of the Internal Revenue Service Code and any guidelines, rules, or regulations promulgated by the Internal Revenue Service concerning such lease transactions.

5. Big Rivers shall file with the Commission copies of any rulings or decisions concerning the applicability of the Kentucky real estate transfer tax under KRS 142.050 to the proposed lease transaction, as revised by the motion to reopen. If such ruling or

decision causes Big Rivers to abandon the proposed transaction, notice of that decision should be included with the filing.

6. Ordering Paragraph Nos. 6 through 8 of the November 24, 1999 Order shall remain in full force and effect as if separately ordered herein.

Done at Frankfort, Kentucky, this 28th day of January, 2000.

By the Commission

ATTEST:

uty Executive Director

Exhibit 51

Order in Case No. 97-204 dated April 30, 1998, re: The Application of Big Rivers Electric Corporation, Louisville Gas and Electric Company, Western Kentucky Energy Corp., and LG&E Station Two Inc. for Approval of Wholesale Rate Adjustment for Big Rivers Electric Corporation and for Approval of Transaction

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF BIG RIVERS ELECTRIC CORPORATION, LOUISVILLE GAS AND ELECTRIC COMPANY, WESTERN KENTUCKY ENERGY CORP., WESTERN KENTUCKY LEASING CORP., AND LG&E STATION TWO INC. FOR APPROVAL OF WHOLESALE RATE ADJUSTMENT FOR BIG RIVERS ELECTRIC CORPORATION AND FOR APPROVAL OF TRANSACTION	)	CASE NO. 97-204

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF BIG RIVERS ELECTRIC CORPORATION, LOUISVILLE GAS AND ELECTRIC COMPANY, WESTERN KENTUCKY ENERGY CORP., WESTERN KENTUCKY LEASING CORP., AND LG&E STATION TWO INC. FOR APPROVAL OF WHOLESALE RATE ADJUSTMENT FOR BIG RIVERS ELECTRIC CORPORATION AND FOR APPROVAL OF TRANSACTION	)	CASE NO. 97-204

O R D E R

BACKGROUND

On June 30, 1997, Big Rivers Electric Corporation ("Big Rivers") and the LG&E Parties[1] (collectively referred to as "Applicants") filed an application requesting the Commission to approve or declare nonjurisdictional numerous rate, financing and operating agreements that are an integral part of Big Rivers' efforts to implement the First Amended Plan of Reorganization ("Reorganization Plan") approved by the U.S. Bankruptcy Court in Big Rivers' Chapter 11 proceeding. These agreements provide for a long-term lease of Big Rivers' generating units to WKEC, reduced wholesale rates for Big Rivers' four member distribution cooperatives, and the financings necessary to effectuate a restructuring of Big Rivers' debts.

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[1] The LG&E Parties are wholly-owned subsidiaries of LG&E Energy Corp. ("LEC"). The subsidiaries which are co-applicants with Big Rivers are Louisville Gas and Electric Company ("LG&E"); Western Kentucky Energy Corp. ("WKEC"); Western Kentucky Leasing Corp. ("Leaseco"); and WKE Station Two Inc. ("Station Two Subsidiary"), formerly known as LG&E Station Two Inc. In addition, LG&E Energy Marketing Inc. ("LEM"), formerly known as LG&E Power Marketing Inc., is a party to numerous agreements making up the proposed transaction.

The Applicants requested a declaration from the Commission that implementation of the Reorganization Plan does not constitute a transfer of ownership or control over Big Rivers within the meaning of KRS 278.020(4) or 278.020(5). In the alternative, they requested that if the Commission determines that there is a transfer of control within the meaning of the statute, that the Commission approve the transfer of control, as implemented through a series of Reorganization Plan documents.[2] Approval was also requested of a Transmission Service and Interconnection Agreement, including to the extent required, Big Rivers' Open Access Transmission Tariff, which is to be filed at the Federal Energy Regulatory Commission ("FERC"). The Applicants have filed in this case numerous versions of the Reorganization Plan documents, as well as the corresponding tariffs which reflect the provisions of those documents.

In summary, the proposed transaction is structured into two phases. Under Phase I, WKEC will operate and maintain the Big Rivers' generating units, Big Rivers will sell all power generated to LEM, and LEM will resell to Big Rivers power sufficient to meet its wholesale obligations. All power not resold by LEM to Big Rivers can be sold by LEM for its own account. Leaseco will purchase from Big Rivers the generation-related inventory[3] at its fair market value, all personal property at its net book value, and will be assigned

[2] The Reorganization Plan documents include the Participation Agreement; the Facilities Operating Agreement; the Cost Sharing Agreement; the Power Purchase Agreement; the Lease and Operating Agreement; the Mortgage and Security Agreement; the Guarantee Agreement; the Nondisturbance Agreement; and the Tax Indemnification Agreement. See Application, at 14-15.

[3] Included in this inventory is all of Big Rivers' fuel and scrubber reagent, spare parts, SO_2 emission allowances, and all materials and supplies held for use in conjunction with the operation of the generating facilities.

certain intangible assets.[4] After necessary federal regulatory approvals are received, and prior to or contemporaneously with the commencement of Phase II, Leaseco will be merged with and into WKEC.

In Phase II, WKEC will lease Big Rivers' generating facilities for a 25-year term, perform all necessary operations and maintenance services, and sell the output of the generating facilities to LEM. WKEC will be an Exempt Wholesale Generator ("EWG") in accordance with Section 32 of the Public Utilities Holding Company Act of 1935 ("PUHCA") and its wholesale sales of power will be under the exclusive jurisdiction of FERC.

Station Two Subsidiary will subcontract with Big Rivers to perform operations and maintenance services for the Henderson Municipal Power & Light ("HMP&L") Station Two facility, and Big Rivers will assign to Station Two Subsidiary certain of its rights and obligations under contracts with HMP&L for operation of HMP&L's Station Two facility. Big Rivers' wholesale power supply contracts with its four member cooperatives will be revised, as well as the member cooperatives' retail contracts with the aluminum Smelters.[5]

The Reorganization Plan further provides that Big Rivers will contract with LEM to purchase power from LEM, at levels sufficient to cover all of the anticipated needs of Big Rivers' members. Big Rivers' outstanding debt with the Rural Utilities Service ("RUS"), formerly the Rural Electrification Administration, has been restructured and the current credit providers for Big Rivers' pollution control bonds have been replaced by new credit

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4 Intangible assets include real property leases, equipment leases, permits, and contracts used in connection with the operation of the generating facilities.

5 The aluminum smelters are the Southwire Company and NSA, Inc. ("Southwire") and Alcan Aluminum Corporation ("Alcan").

providers. Once the necessary approvals for the Reorganization Plan have been secured, Big Rivers will be out of the generating business while retaining its wholesale supply, transmission, and planning functions.

Big Rivers requested authority to implement on an interim basis rate reductions for wholesale electric service commencing on September 1, 1997 and continuing through the earlier of the closing date of the proposed transaction or August 31, 1998. The rate reductions proposed in Big Rivers' interim rates mirrored those of its proposed permanent rates. The Commission, by Order dated August 29, 1997, suspended the interim rates for one day and allowed them to become effective subject to change for service rendered on and after September 2, 1997. The Commission also determined that the approved interim rates should remain in effect only until issuance of a final rate Order determining the reasonableness of the proposed permanent rates.[6]

The Commission received requests for and granted intervention to the Office of the Attorney General ("AG"), Southwire, Alcan, Green River Electric Corporation ("Green River"), Henderson Union Electric Cooperative Corporation ("Henderson Union"), Jackson Purchase Electric Cooperative Corporation ("Jackson Purchase"), Meade County Rural Electric Cooperative Corporation ("Meade County"), Chase Manhattan Bank ("Chase"), Bank of New York, Commonwealth Industries Inc., Willamette Industries Inc. ("Willamette"), PacifiCorp Power Marketing Inc., and the Kentucky Association of Plumbing, Heating and Cooling Contractors, Inc.

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6 Case No. 97-204, Order dated August 29, 1997, at 4.

Informal conferences were held at the Commission's offices on July 16, 1997, October 8, 1997, and February 4, 1998. Public hearings were held on November 18 - 24, 1997 and March 18, 1998. Initial briefs were filed on January 30, 1998 with reply briefs filed on February 13, 1998. Supplemental briefs which were limited to the "unforeseen cost" issue were filed on March 30, 1998, with supplemental reply briefs filed on April 6, 1998.

HISTORY

Big Rivers is a rural electric cooperative utility, organized pursuant to KRS Chapter 279, which provides generating and transmission services to its four owner members. Each of its members is a rural electric cooperative utility engaged in the distribution of electricity and collectively they serve 91,500 customer members in 22 western Kentucky counties.

Big Rivers began experiencing financial problems in the mid-1980's shortly after completing construction of its newest generating station, the Wilson Generating Station ("Wilson"). Those problems were precipitated by a number of factors, including the relatively high cost of Wilson, a significant reduction in load growth, and claims by the Smelters that any rate increase would render their operations noncompetitive in world markets and drive them out of business. Big Rivers was eventually able to negotiate a debt restructuring agreement with its creditors which the Commission approved in 1987 along with higher rates for all customers, including new rates for the Smelters which varied with the price of aluminum.

The revenue levels necessary to satisfy Big Rivers' debts as restructured in 1987 could not be achieved solely from power sales to its four member cooperatives. Rather, additional revenues needed to be generated each year through the sale of increasing levels of power to non-member wholesale customers. Unfortunately, the wholesale market for power was soft during this time and Big Rivers' sales efforts were unsuccessful in producing the revenue levels necessary. By the early 1990's Big Rivers recognized that it would soon be in a default position and it began discussions with RUS on the need for further debt restructuring.

Big Rivers' fortunes also changed from bad to worse during this period with the criminal and civil investigations and trials involving bribes and kickbacks in connection with its coal contracts and a former general manager. In an effort to find a long-term solution to its mounting financial problems, Big Rivers hired a "turn-around" specialist to advise and assist management in pursuing available business options. This action led to Big Rivers' solicitation of business offers and the eventual decision in early 1996 to pursue a business arrangement with PacifiCorp Holdings, Inc. ("PacifiCorp"). Under the terms of that transaction, a subsidiary of PacifiCorp would lease Big Rivers' generating units for 25 years and sell back to Big Rivers certain quantities of power at pre-established prices. While negotiating the terms of this transaction, Big Rivers was also negotiating with its major creditors to achieve a consensual restructuring of its debts and with its system's two largest retail customers, two aluminum smelters, to achieve long-term rate reductions and rate stability. When its efforts to achieve a consensual debt restructuring were unsuccessful, Big Rivers filed on September 25, 1996 a petition for reorganization under Chapter 11 of the Bankruptcy Code.

Big Rivers' Plan of Reorganization, as originally filed with the Bankruptcy Court on January 22, 1997, included the lease transaction with PacifiCorp and lower electric rates that had been negotiated with the two smelters, one large non-smelter industrial customer and the four member cooperatives. The following month the Bankruptcy Court initiated an auction process to determine whether the PacifiCorp lease was providing maximum value to the Big Rivers' estate. The only entity to submit a bid in this process was LEC, and on March 19, 1997 the Bankruptcy Court accepted LEC's lease proposal on the basis that it would provide greater value to the Big Rivers' estate.

Big Rivers' Plan of Reorganization, as amended, which now included a lease transaction with subsidiaries of LEC and the lower rates previously negotiated with certain customers, was approved by the Bankruptcy Court on June 9, 1997. While the Bankruptcy Court has exclusive jurisdiction over a debtor's plan of reorganization, that jurisdiction does not include the right to approve a change in rates for a debtor utility whose rates are subject to regulation. Rather, the Bankruptcy Code, 11 U.S.C. §1129(a)(6), requires a debtor utility to obtain all necessary rate approvals from the appropriate regulatory agencies as a condition for final approval of a reorganization plan that includes a change in rates.

DISCUSSION OF ISSUES

Unforeseen Cost Issue

The Big Rivers' tariffs for service to Alcan and Southwire, which are to remain in effect for 12-13 years, specified that the Smelter rates contained therein would not be adjusted to reflect any cost or payment incurred by Big Rivers or the member distribution cooperatives for any expenditures due to legislation, regulatory action, legal action, or due to any other reason, whether foreseeable or unforeseeable (commonly known as the unforeseen cost issue).[7] This tariff provision was premised on the assumption that there would be no major changes in environmental law or regulation during the remaining term of the Smelter contracts, which extend to 2010 for Southwire and 2011 for Alcan.[8]

Contrary to this assumption, on October 10, 1997, the U. S. Environmental Protection Agency ("EPA") issued a notice of proposed rulemaking which would significantly reduce the existing emission levels for nitrogen oxide (NOx). The emission reductions, if implemented, have the potential to significantly increase Big Rivers' capital and operating costs such that wholesale rate increases would be necessary. This tariff provision became the focus of extensive cross-examination during the November 1997 hearing. Numerous questions were raised concerning the financial ability of Big Rivers to absorb this or any other unforeseen costs without increasing rates and whether exempting the Smelters from paying an appropriate share of unforeseen costs would obligate all other

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[7] First Revised Exhibit 3(b), filed September 25, 1997, Item 9, at 48, 76, and 77 of 115. The tariffs referenced the following examples of such action: carbon tax, BTU tax, CO, emissions reduction, or any other environmental or energy tax, charge, or liability.

[8] Transcript of Evidence ("T.E."), Volume I, November 18, 1997, at 100.

customers to pay the Smelters' share. At the conclusion of the November 1997 hearing, the Commission stated that the absence of a resolution of the unforeseen cost issue was a serious deficiency and suggested that the affected parties attempt to negotiate a mechanism to allocate future unforeseen costs in an equitable manner to each class of ratepayers.[9]

Big Rivers and the LG&E Parties notified the Commission on January 27, 1998 that a resolution of the unforeseen cost issue had been agreed to by some of the parties[10] and a term sheet for the resolution was submitted on February 3, 1998. In summary, the unforeseen cost resolution includes the following provisions:

1) LEM will supply directly to Henderson Union and Green River the wholesale power needed to serve Alcan and Southwire, with LEM assuming all the risks for the Smelter loads.

2) Big Rivers will continue to supply wholesale power to Henderson Union and Green River for their non-smelter loads, as well as the total loads of Jackson Purchase and Meade County.

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9 T.E., Volume V, November 24, 1997, at 235-236.

10 The parties agreeing to the Resolution were Big Rivers, the LG&E Parties, Alcan, Southwire, Green River, Henderson Union, and Meade County.

3) LEM will pay directly to RUS, on the behalf of Big Rivers, the level of Smelter net margins originally included in Big Rivers' financial models.[11]

4) Big Rivers and LEM agreed to a number of changes concerning the financing of all future capital improvements envisioned for the Big Rivers' generating facilities.

5) Revisions were made to the RUS mortgage which provide Big Rivers a financing source for its share of future capital improvements.[12]

6) The use of arbitrage sale proceeds was revised, which would allow Big Rivers to make additional payments on its RUS mortgage as well as the RUS asset residual value note ("ARVP").

7) Big Rivers will pay to LEM $1.85 million per year over the 25-year lease. The Smelters will pay to LEM an additional .5 mills per KWH on Tier 1 and Tier 2 power purchased.

8) Big Rivers was required by RUS to make additional up-front payments on its mortgage, and Big Rivers and LEM agreed to

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11 The original Big Rivers' financial model was provided in the Application as Appendix L. While revisions to the financial model have been prepared and submitted, all versions are based on the version contained in Appendix L. These subsequent revisions have been identified as "MH-5A," "MH-5B," "SUP-11," and "SUP-16."

12 Referred to in the record as the "clawback" provision.

a financing arrangement which would allow Big Rivers to make the additional payments.

Big Rivers, the LG&E Parties, Alcan, Southwire, and Chase all expressed support for the unforeseen cost resolution.[13] Big Rivers stated that the resolution addressed the Commission's concerns regarding how Big Rivers would meet future unforeseen costs, including the possible impact of the EPA's NOx proposal, without the subsidization of the Smelters by non-Smelter customers.[14] The LG&E Parties noted that the resolution changes Big Rivers' initial funding responsibilities for capital expenses and allows it additional funds and increases its financial flexibility in the early years of the transaction.[15] Alcan and Southwire argue that the resolution should be given a chance to close since it has the potential to finally resolve the difficult Big Rivers' situation in a manner that is fair to all customer classes and creditors.[16] Chase contends that the resolution provides significant benefits to Big Rivers and its non-Smelter customers, in that Big Rivers is protected from credit risks associated with the Smelters, Big Rivers and its other customers are shielded from unforeseen costs attributable to the Smelters' load, and all customers will enjoy the same rates they were to receive under the Reorganization Plan.[17]

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13 The Bank of New York filed a statement on March 30, 1998 concurring with the statements filed by Chase, but did not file a separate brief.

14 Big Rivers Supplemental Initial Brief at 4.

15 LG&E Parties Initial Brief Addressing Future Unforeseen Cost Issue at 14-15.

16 Alcan and Southwire Supplemental Brief on Unforeseen Cost Resolution at 15.

17 Chase Brief Concerning "Unforeseen Costs" Issue at 3.

Willamette did not oppose the unforeseen cost resolution, noting that it was more fair and reasonable than Big Rivers' original proposal.[18] However, Willamette expressed its concern that the customers remaining with Big Rivers would have to bear the annual $1.85 million payment to LEM, either directly through the cost of electric power or indirectly by other revenue that would otherwise be dedicated to offsetting costs borne by Big Rivers' customers.[19]

The AG opposed the unforeseen cost resolution, contending that the filing was incomplete and the record lacked sufficient evidence upon which to base a decision.[20] The AG further argued against the resolution because it would cause Big Rivers to incur additional expenses to maintain the Smelters' fixed rates and negate the Smelters' contribution to the debt payments, all to the detriment of the other customers.[21] The AG also claims that the resolution will cause Big Rivers, Green River, and Henderson Union to be in violation of KRS 279.095 because they will no longer be operated for the mutual benefit of their members.[22]

In support of the unforeseen cost resolution, Big Rivers prepared an economic analysis which compared the cash flows generated in its financial model under two scenarios. The first financial model, identified as MH-5A, included no expenditures for

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18 Willamette Initial Brief on the Unforeseen Cost Issue at 1.

19 Id. at 6.

20 AG Initial Brief on the Unforeseen Cost Resolution at 2.

21 Id. at 7.

22 Id. at 8-10.

unforeseen costs; while the second, identified as SUP-11, reflected the $1.85 million annual payments.[23] The comparison revealed that, over the 25-year term, SUP-11 showed a cumulative decrease in cash flow of $130.3 million on a nominal basis and a negative $18.5 million cumulative net present value when compared to MH-5A.[24] In each year of the analysis, the ending cash balance was positive, but at lower levels in SUP-11 than in MH-5A. However, arbitrage sales were not modeled in either MH-5A or SUP-11.

In evaluating the reasonableness of the unforeseen cost resolution, the Commission has considered all of the arguments put forth by the parties and the economic analysis prepared by Big Rivers. In addition, the Commission has considered the potential impact that arbitrage sales would have on the economic analysis which compared the financial models MH-5A and SUP-11. Arbitrage sales are defined in the Reorganization Plan as all net revenues received in any particular calendar year resulting from one of three types of transactions. The first reflects the net benefit of purchasing power from third parties instead of purchasing such power from LEM during off-peak periods. The second reflects the net benefit of selling equivalent amounts of power using purchases from LEM during peak periods. The third reflects the net revenues of any new off-system power sales in excess of net revenues currently projected for such sales.[25] Originally, the net revenues

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23 MH-5A is a version of the Appendix L financial model updated before the November 1997 hearing, prior to the parties addressing the unforeseen cost issue. SUP-11 is based on MH-5A, but reflects the impact of the Resolution, and was filed on February 23, 1998, as part of the Robison, Schaefer, and Hite Supplemental Testimony.

24 Response to the Commission's March 10, 1998 Order, Item 1, page 4 of 16.

25 Application Appendix C, page 35 of 121, First Amended Plan of Reorganization. The current projections for off-system sales are incorporated into the financial

from arbitrage sales were to be allocated 50 percent to Big Rivers and 50 percent as a payment on the RUS ARVP. As part of the unforeseen cost resolution, the allocation was changed to one third to Big Rivers, one third as payment on the RUS mortgage, and one third as payment on the ARVP. The Commission believes that arbitrage sales were an important benefit originally to Big Rivers' Reorganization Plan and that the unforeseen cost resolution's changes to arbitrage sales have increased that benefit.

The Commission finds that the unforeseen cost resolution is reasonable and addresses the concerns expressed at the November 24, 1997 hearing. The change in the way capital expenditures are financed, the adjustment in the allocation of operation and maintenance costs, the availability of financing resources for Big Rivers in the event additional unforeseen capital expenditures arise, the guarantee of the Smelter margins, and the revisions to arbitrage sale proceeds are all improvements to the overall transaction. The benefits of these improvements outweigh any detriments of the additional expenses for Big Rivers. While the ending cash flow is lower with the unforeseen cost resolution than without it, such a comparison is inappropriate. The financial model without the resolution included no expenditures for unforeseen costs, although Big Rivers was at risk for all such costs. The financial model with the resolution transfers that previously unquantifiable risk to the LG&E Parties for a known cost. The unforeseen cost issue has thus been resolved in a manner which produces significant additional benefits for non-Smelter customers without changing non-Smelter rates and is consistent with the cooperatives' obligations under KRS 279.095. Therefore, based on the representations

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model, beginning in 2011.

and concepts expressed in the documents filed on or before February 27, 1998, the Commission approves in principle the unforeseen cost resolution.

Market Power Purchases

A central feature of Big Rivers' application is the proposal to allow Alcan, Southwire, and certain Large Industrial Customers the option of acquiring a portion of their power needs from third-party suppliers of their choice, no earlier than January 1, 2001.[26] This option is incorporated into the proposed Smelter tariffs as "Tier 3" and in the proposed Large Industrial Customer tariffs as "Market Power Purchases."

Smelters' Tier 3 Purchases. The interim tariffs permitted to go into effect on September 2, 1997 created three rate levels for Alcan and Southwire: Tier 1, Tier 2, and Tier 3. Under the interim tariffs, the maximum demand available under Tier 1 and Tier 2 energy is 233,000 KW for Alcan and 339,000 KW for Southwire, at a 98 percent load factor for each Smelter. Any demand in excess of these levels qualifies for purchase under Tier 3. The Smelter tariffs are structured as energy only rates which include the fixed costs typically recovered through a demand charge. The Tier 1 energy volumes

26 This option was part of the original application, as well as a component of the Resolution.

constitute the Smelters' minimum purchase obligation[27] and the payment of the Tier 1 energy charges constitute their respective take-or-pay obligations to Big Rivers. The energy rates for Tier 1, Tier 2, and Tier 3 are fixed under the interim tariffs, and a separate transmission rate is included for Tier 3 energy only.[28]

Under the proposed tariffs,[29] the three tier rate structure is retained, with LEM supplying power directly to Henderson Union and Green River for consumption by the Smelters. The demand and energy levels are essentially the same as those in the interim tariffs. The rates for Tier 1 and Tier 2 energy are the same as in the interim tariff, with the exception of the additional .5 mill per KWH payment to LEM to resolve the unforeseen cost issue. Two changes occur on January 1, 2001. First, the Tier 2 energy rate, which had been fixed, will be subject to change annually in accordance with a schedule incorporated into the tariff. Second, the Tier 3 energy rate, which had also been fixed at the same rate as in the interim tariff, is terminated and LEM has no further obligation to supply the Smelters power in excess of the Tier 1 and Tier 2 volumes. All power consumed in excess

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27 Alcan's minimum purchase obligation, Tier 1, is calculated by multiplying 2,304,960 KWH by the number of days in the billing month; the Tier 2 purchase allowance is the difference between the minimum purchase obligation and the amount calculated by multiplying 5,480,160 KWH by the number of days in the billing month. For Southwire, the minimum purchase obligation is based on 3,045,840 KWH and the Tier 2 purchase allowance is based on 7,973,280 KWH. See Second Revised Exhibit 3(a), filed August 22, 1997, pages 26, 27, and 36 of 52.

28 The Tier 1 energy rate is \$.0307 per KWH; Tier 2 is \$.02098 per KWH; and the total Tier 3 rate, excluding transmission, is \$.01958 per KWH. The Tier 3 transmission rate is \$.98 per KW per month of Tier 3 demand. See Second Revised Exhibit 3(a), filed August 22, 1997, pages 25, 26, 34, and 35 of 52.

29 The reference "proposed tariffs" reflects the terms and conditions contained in the documents filed on February 27, 1998. Also, these proposed tariffs reflect the impact of the resolution, which the Commission has accepted in principle.

of the Smelters' Tier 1 and Tier 2 maximum demands can be acquired from any power supplier at market-based rates. For these purchases the Smelters are to assume the responsibilities of identifying the third-party supplier, setting the terms of the transaction, calculating the amount of losses involved, and securing the transmission path.[30] The Smelters' respective distribution cooperatives, Green River or Henderson Union, would sign the actual contracts with the third-party supplier and purchase the power to supply the Smelters.

The AG opposed the Tier 3 market purchase provision, contending that wholesale market access for retail customers by contract is retail wheeling which is not authorized by the Territorial Boundary Act for electric service, KRS 278.016-278.018. The AG argues that the parties that negotiated Tier 3 have achieved electric deregulation and dictated its terms, without the benefit of legislative direction or oversight, for all incremental power used by the two largest retail electric customers in Kentucky. If Tier 3 is approved, the AG contends, it will establish a precedent which will encourage large power users served by other utilities to ask for similar or better treatment, and as a policy matter, such a precedent should not be established.[31]

Big Rivers, the LG&E Parties, Alcan, Southwire, and Chase disagreed with the bases for the AG's opposition and cited numerous arguments to support the market purchase option. They contend that the option is not retail wheeling, is not contrary to Kentucky law or public policy, need not await any legislative analysis of electric industry

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[30] Response to the Commission's October 21, 1997 Order, Items 4 and 26.

[31] AG Initial Brief at 7-10.

restructuring, and is not dissimilar to the right afforded to Gallatin Steel Company in 1995 to choose its wholesale power supplier. The market purchase option, they claim, is designed to reduce costs to the Smelters without raising costs for other customers,[32] while the Reorganization Plan as a whole brings the benefits of competitively priced power to all customers.[33]

Other Industrials' Market Power Purchases. Big Rivers proposed that three years after closing its Reorganization Plan certain Large Industrial Customers could acquire a portion of their power requirements under market-based conditions. To be eligible, a customer would have to have a peak demand of one MW or greater, sign a contract for a minimum term of five years, have a base contract demand of not less than 75 percent of its maximum contract demand, and have a minimum contractual monthly load factor of 70 percent.[34] Big Rivers estimated that six customers could be eligible for this market-based proposal.[35]

The AG opposed this proposal, claiming it was an attempt to offer other industrial customers rates similar to the market purchase Tier 3 proposal for the Smelters. While agreeing that the proposal did not create the same contractual market access as the Smelters would have, the AG argued that the proposal should be rejected because Big

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32 Big Rivers Reply Brief at 8-9.

33 LG&E Parties Initial Brief at 16.

34 Revised Big Rivers Transaction Tariff, filed February 23, 1998, Item 29 at Original Sheet No. 37.

35 Response to the Commission's August 12, 1997 Order, Item 29. The customers are Commonwealth Aluminum, Kimberly-Clark (Scott Paper), Willamette, World Source, A-CMI, and Wal-Mart Store No. 701.

Rivers was giving up the right to serve a portion of its load, as well as the ability to earn a full contribution to fixed costs, for no apparent reason. The AG contends that there is no reason for a bankrupt utility to offer such a pricing option.[36]

The LG&E Parties supported the proposal, noting that if market power is priced below Big Rivers' system power, industrial customers who accepted the market-priced option could achieve lower average prices by blending system-priced power with market-priced power.[37] Chase stated that, like the market purchase Tier 3 proposal, this proposal for large industrial customers did not violate the certified service territory statute.[38]

Commission Analysis. Big Rivers has served its member distribution cooperatives for many years through a succession of full requirements contracts that have been required by the RUS to secure prior loan funds. As part of the negotiating process that led to the rates embodied in the Reorganization Plan, the RUS and other affected parties agreed to modify these full requirements contracts to accommodate the market power purchases for the Smelters and qualifying industrial customers. No similar accommodations have been forthcoming for any other customer.

The market purchase rate proposals constitute, at a minimum, the functional equivalent of retail wheeling for 8 out of 91,500 customers. If the electric industry in Kentucky is to be restructured to include retail wheeling, the Commission believes that such a restructuring should be undertaken voluntarily, in a reasoned and comprehensive

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36 AG Initial Brief at 11.

37 LG&E Parties Initial Brief at 14.

38 Chase Initial Post-Hearing Brief at 4.

manner which is designed to meet the overall needs of the Commonwealth and all its citizens, not just the specific needs of a single utility and a few large customers. Further, the Commission does not believe that electric restructuring can permanently be implemented on a case-by-case approach until a rigorous investigation of all aspects of the issue results in a determination that restructuring is in the public's best interest. Until that determination is made, proposals to offer 8 out of 91,500 customers the right to seek lower cost power through retail wheeling constitute unreasonable preferences in violation of KRS 278.170(1).

The existing regulatory scheme in Kentucky requires electric utilities to serve all customers within their certified territorial boundaries. For the Big Rivers' distribution cooperatives, this statutory obligation includes not only the distribution of electric energy to their customers, but also the selection and acquisition of an adequate source of supply to meet the foreseeable needs of their customers. The Commission does not believe that it has the authority to revise this statutory scheme to transfer, from the utility to a limited group of customers, the function of selecting a source of supply to meet those customers' needs. The market purchase options proposed here are dissimilar to the transaction approved in 1995 when East Kentucky Power Cooperative Corporation ("East Kentucky") lacked sufficient capacity to fulfill its contractual obligation to supply Owen Electric Cooperative for service to Gallatin Steel Company.[39] The contracts and tariffs in that case indicate that East Kentucky fulfilled its contractual obligation by selecting the source of

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[39] Case No. 94-456, East Kentucky Power Cooperative, Inc.'s Filing of a Proposed Contract with Gallatin Steel Company.

additional generating capacity, not by granting the retail customer the right to select the source of generation.

Therefore, the proposals to terminate the Tier 3 fixed rate after 2000 and to implement market purchase Tier 3 and the Market Power Purchase option for other industrial customers in three years are rejected. Green River and Henderson Union will be responsible for securing additional quantities of power for the Smelters after 2000. The cost for this power is unknown at this time and may result in future changes to the Tier 3 rate for the Smelters.

<u>Revenue Decrease Allocation and Rate Design</u>

For purposes of calculating the revenue impact of its proposed rates, Big Rivers utilized a test year ended December 31, 1996. Based on the rates in effect at the end of the test year, and various normalization adjustments to the actual demand and energy units billed during the test year, Big Rivers calculated its normalized test year revenues to be $266,261,661.[40] Big Rivers calculated pro forma revenues of $231,482,524, based on its proposed rates and several billing adjustments which reduce its billing demand from a normalized level of 14.4 million KW to a pro forma level of 13.4 million KW. The result is a decrease in revenues of $34.8 million, or 13.06 percent.[41]

Based on Big Rivers' pro forma revenue analysis, the proposed rates produce the following decreases and average rates for Big Rivers' three customer groups:[42]

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40 Application Exhibit 17, at 1, 5 and 6.

41 <u>Id.</u> at 1 and 8.

42 "Existing Average Rate" and "Proposed Average Rate" derived from Application Exhibit 17 at 5-8; "Total Decrease" and "Percentage Decrease" from Application

Customer Group	Existing Average Rates	Proposed Average Rate	Total Decrease	Percentage Decrease
1. Smelters:	28.85 mills/KWH	24.7 mills/KWH	13.7 percent	$20.2 million
2. Non-Smelter industrials:	34.60 mills/KWH	31.1 mills/KWH	12.8 percent	$6 million
3. Rurals:	42.18 mills/KWH	37.2 mills/KWH	11.8 percent	$8.6 million

The Commission finds that Big Rivers' comparison of its proposed rates to its existing rates is flawed. In determining customers' adjusted billing units, Big Rivers relied on its most recent Power Requirements Study to change the demand and energy billing units for several customers. For instance, Willamette's demand billing units were increased by 99,000 KW and its energy billing units were increased by 75 million KWH.[43] Big Rivers also included the impact of the market purchase option in calculating pro forma revenue. In determining the percentage rate decrease, Big Rivers compared pro forma revenue based on pro forma billing units to normalized revenue based on normalized billing units, thereby masking the true effect of the proposed rate change. The Commission believes that a more valid analysis would be one that compares customers' annual bills based on pro forma billing units at both Big Rivers' old base rates and its proposed base rates.[44] Under such a comparison the average decrease for each customer group would be: Smelters - 18.0 percent; non-Smelter industrials - 12.3 percent; and Rurals - 9.2 percent.

Exhibit 17 at 7-8.

43 Application Exhibit 17 at 3 and 5.

44 For this analysis, Big Rivers' proposed base rates for the Smelters include the agree upon .5 mills per KWH to resolve the unforeseen cost issue.

Big Rivers presented a cost-of-service analysis which reflected both its pre-restructuring cost structure and its post-restructuring cost structure. The results of this analysis were consistent with the allocation of the proposed decrease amongst the customer classes.

AG Rate Issues. The AG objected to the proposed rates, focusing primarily on the rates offered to the Smelters. The AG urges rejection of the proposed Smelter rates and associated contracts because the Smelters are allowed to leave the Big Rivers system after 2011, their rates are fixed for the term of their current contracts, and their take-or-pay obligations are dramatically reduced.[45] Based on the AG's cost-of-service study, he also argues that the Tier 2 rates make no meaningful contribution to fixed costs, the Smelters make a smaller contribution to fixed costs than other classes, and the Smelters' rates are priced below their cost of service. The AG also argues that the proposed treatment of stranded costs and exit fees for the Smelters is unfair, unjust, and discriminatory.[46] Based on the results of his own cost-of-service study, the AG recommended rejection of the proposed rates for all customer classes and adoption of a $5.36 per KW per month demand charge and a 19.58 mills per KWH energy charge for all customer classes and all sales.[47]

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45 Brown Kinloch Direct Testimony at 16-28.

46 AG Initial Brief on the Unforeseen Cost Resolution at 10. In this brief, the AG notes that his original objections to the proposed Smelter rates now focus on Henderson Union and Green River, rather than Big Rivers, due to the impacts of the resolution of the unforeseen cost issue.

47 Brown Kinloch Direct Testimony at 42.

Big Rivers noted that the proposed rates are an integral part of the Reorganization Plan and are supported by its cost-of-service study.[48] Big Rivers criticized the AG's cost-of-service study as flawed in its treatment of the purchased power costs from LEM and for proposing rates which resulted in disproportionate rate reductions favoring the rural customers at the expense of the Smelters.[49]

Alcan and Southwire contend that the AG's cost-of-service study is flawed in assuming that purchased power costs were composed only of energy costs, omitting the lease and transmission payments as factors to be included, not considering the lower Smelter line losses, and allocating to the Smelters transmission costs below 161 KV.[50]

The Commission finds the AG's arguments to be less than persuasive. Since the Smelters new contracts will expire at the same time as their old contracts, they are not being allowed to leave the Big Rivers' system. Resolution of the unforeseen cost issue, coupled with the fixed cost of wholesale power from LEM, justifies the prohibition of future rate adjustments, except as noted herein, attributable to wholesale but not retail cost changes. While the Smelters take-or-pay obligations have been reduced, Big Rivers suffers no harm because LEM has agreed to guarantee the margins from Smelter sales at levels above the take-of-pay obligations.

In addition, the record demonstrates that the AG's cost-of-service study is flawed in assuming that purchase power costs are composed only of energy costs, by allocating

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48 Big Rivers Reply Brief at 11-12.

49 Id.

50 Alcan and Southwire Main Brief at 15 and 20.

costs of transmission facilities below 161 KV to the Smelters, and by omitting consideration of the lease and transmission payments and the lower Smelter line losses. These flaws undermine his proposed alternative rates. The AG has also failed to justify why his proposed class rate reductions are more reasonable than Big Rivers. The Commission also finds unacceptable the underlying premise in the AG's proposal which is the need for a rate increase in 2012 of 29 percent in the demand charge and 4 percent in the energy charge.[51] Thus, the AG's rate proposals are not reasonable and will not be accepted.

Willamette Rate Issues. Willamette argues that the rates proposed for it are discriminatory, not based on cost of service, and are the result of negotiations that included neither itself nor a majority of the industrial customers. It contends that its decrease of 7.29 percent is not as large as that of some other customers in the large industrial class, its additional load has been ignored by Big Rivers, and it should be granted lower rates more in line with those of the Smelters given its status as the system's third largest customer with the third highest load factor. Willamette also argues that the impact of load factor on cost of service should be reflected in rates. In fact, Willamette argues that unless it signs a five year contract that puts 25 percent of its load at market risk, it will receive a 1.5 percent rate increase.[52] As an alternative to revised lower rates, Willamette proposed

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[51] T.E., Volume V, November 24, 1997, at 227-228.

[52] Willamette Initial Brief at 2 and 6.

that all its load in excess of its current 55.5 MW level be eligible for the Market Power Purchase option.[53]

Big Rivers disagreed with Willamette's arguments and rate proposals, noting that Willamette has different load and operating characteristics from the Smelters which justify a different classification of service. Big Rivers argues that Willamette will receive the overall rate reductions available to all non-Smelter industrial customers and will be eligible for the Market Power Purchase option.[54] Big Rivers' revenue comparison shows individual non-Smelter industrial customers experiencing annual bill reductions ranging from 1.51 percent to 26.83 percent, with a class average reduction of 12.82 percent.[55]

The Commission finds Willamette's arguments to be unpersuasive. Willamette's analysis ignores the changes made by Big Rivers in developing its pro forma revenues and presents its arguments regarding the proposed increase based on the same flawed comparison used by Big Rivers. When customers' annual bills based on pro forma billing units at both Big Rivers' old base rates and its proposed base rates are compared, Willamette's proposed decrease will be 12.8 percent while the non-Smelter industrial class has an average decrease of 12.3 percent. Thus, Big Rivers' proposed decrease for Willamette compares favorably with that of the non-Smelter industrial class as a whole and, therefore Willamette suffers no undue discrimination by Big Rivers' rate proposal. In addition, Willamette has not demonstrated and the Commission finds no basis to believe

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53 Biscopick Direct Testimony at 16-17.

54 Big Rivers Reply Brief at 13-19.

55 Application Exhibit 17, page 7.

that Willamette's proposal will generate the revenue levels needed by Big Rivers under the Reorganization Plan. The Commission further finds that Big Rivers' proposal does not unfairly single out Willamette for a lesser rate decrease than other customers within its class. Therefore, Willamette's rate proposals are denied.

Large Industrial Customer Rates Having rejected the Market Power Purchase option, the Commission finds it necessary to develop a schedule of rates for the large industrial class that will generate over the next 25 years the same approximate revenue stream as the rates proposed by Big Rivers. The Commission also finds merit in the argument raised by Willamette that differences in customers' load factors affect a utility's cost of service and such differences should be reflected in rates.

A simple approach to developing a new rate schedule for the non-smelter industrials would be to retain the $7.37 demand charge proposed by Big Rivers and then calculate the energy charge necessary to generate the additional required revenues. However, a demand charge that is substantially lower than the previous charge of $10.15 per KW necessitates an energy charge that would be significantly higher than the previous energy charge. Such a high energy charge, coupled with the impact of eliminating the Market Power Purchase option, would have a detrimental impact on high load factor customers because they would pay revenues markedly in excess of those produced by Big Rivers' proposed rates.

A rate design with a higher demand charge and corresponding lower energy charge will minimize such impact for the higher load factor customers that would have been eligible for the Market Purchase option. Therefore, the rates for the non-smelter industrial class will retain the $10.15 demand charge that had been in effect prior to the interim rates and the entire decrease will be achieved through a reduction in the energy charge. The result is an energy charge of 13.715 mills per KWH for all energy sold. This energy charge is appropriate because, as Big Rivers pointed out, its post-restructuring variable costs of 18.44 mills per KWH as per its cost-of-service analysis are somewhat artificial because of the energy-only pricing structure contained in the power purchase agreement with LEM.[56] Had that pricing structure included separate demand and energy components, Big Rivers' cost of service would reflect much lower variable costs.[57] A comparison of the results of the Commission-developed rates to the results of Big Rivers' old rates using the pro forma billing units reflects an average decrease of 11.64 percent for the non-smelter industrial class with a 12.58 percent decrease for Willamette. Willamette will continue to have among the lowest rates on the Big Rivers system. Based on these factors, the Commission is satisfied that its rate design is fair, just, and reasonable for all customers in the non-smelter industrial class and should be adopted.

Smelter Tariff Provisions. The AG objected to two provisions in the Henderson Union and Green River Smelter tariffs. One provision would prohibit any adjustment to rates to reflect cost or payment incurred by Big Rivers or the cooperatives for any expenditures incurred due to legislation, regulatory, or legal action. The AG argues such a provision attempts to divest the Commission of its authority to change rates.[58] The other provision would allow the Smelters to avoid the payment of stranded costs or exit fees.

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56 Application Exhibit 11 at 48.

57 Id. at 49.

58 AG Initial Brief at 3.

The AG argues that the issue of stranded costs and exit fees will be a subject for electric industry deregulation, and that such a prohibition infringes upon the legislative prerogative, and unduly favors the Smelters.[59]

Big Rivers countered that under the terms of the Reorganization Plan, there should be no stranded costs or exit fees for anyone on the Big Rivers system to pay.[60] The LG&E Parties contend that the proposed resolution of the unforeseen cost issue eliminates any concerns that non-smelter customers would be at risk for future unforeseen costs related to the Smelter load.[61] Alcan and Southwire stated their belief that all stranded cost issues have been dealt with in the Reorganization Plan.[62]

For Big Rivers, the Commission finds that the lease transaction, coupled with the unforeseen cost resolution, will minimize any risk that non-Smelter customers would be allocated the Smelters' share of costs resulting from legislative, regulatory, or legal changes. Similarly, this transaction will minimize the risk of stranded costs or exit fees allocable to the Smelters at the wholesale level. Thus, these provisions do not appear to be unreasonable for application to Big Rivers' wholesale costs.

However, the Commission finds that the same situation does not exist at the retail level. It is impossible to predict the cost changes that could occur over the next 13 years for Henderson Union and Green River and there is no agreement, analogous to the

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59 Id. at 12.

60 Big Rivers Initial Brief at 23.

61 LG&E Parties Initial Brief Addressing Future Unforeseen Cost Issue at 17.

62 Alcan and Southwire Supplemental Brief on Unforeseen Cost Resolution at 9.

unforeseen cost resolution, to provide indemnification for changes in retail costs allocable to the Smelters. Neither the prohibition for cost adjustments due to legislative, regulatory, or legal action nor the prohibition of stranded costs or exit fees are reasonable at the distribution level and it is unreasonable to include these provisions in the distribution cooperative tariffs and contracts with the Smelters.

Other Transaction Issues

Lease of Generating Units. Big Rivers has proposed to lease, for a term of 25 years, all its generating units to WKEC while having a 25 year right to purchase power, within established minimum and maximum quantities, from LEM. The lease transaction is the centerpiece of the Reorganization Plan and it enables Big Rivers to divest itself of its generating capacity while purchasing only the quantities of power projected to be needed over the 25 year term. The Commission finds that the proposed lease transaction does constitute a change in control within the parameters of KRS 278.020(4) and 278.020(5) and is subject to our jurisdiction. Based on a review of the record and the lease transaction as evidenced by the documents on file as of February 27, 1998, the Commission finds that WKEC has the financial, managerial, and technical expertise to operate Big Rivers' generating units and the transfer is in accordance with law, for a proper purpose and is consistent with the public interest. Therefore, the Commission will approve the lease transaction in principle, subject to verification that the final transaction documents do not materially change the transaction as reviewed in this case.

In addition, the Commission finds that the proposed accounting treatment for the lease transaction is in accordance with generally accepted accounting principles and the Commission concurs with that treatment. Big Rivers should provide the Commission with the accounting entries made to record the lease transaction within 10 days of their entry on the books of Big Rivers.

Transmission Service and Interconnection Agreement. The Applicants requested approval of the Transmission Service and Interconnection Agreement, as well as Big Rivers' Open Access Transmission Tariff, which will be filed at FERC. The Commission finds that, to the extent these documents are subject to our jurisdiction, they are reasonable and should be approved in principle subject to review of the final draft agreements to verify that there have been no material changes.

Evidences of Indebtedness. Big Rivers and the LG&E Parties have requested the Commission's approval for Big Rivers to issue evidences of indebtedness as contained in several of the transaction documents.[63] These financings are an integral part of the Reorganization Plan and are necessary to implement the debt restructuring and lease transaction. The Commission finds that the proposed financing is for a lawful object within Big Rivers' corporate purpose, is necessary and appropriate for the proper performance of its wholesale electric service to the public and will not impair its ability to perform that service, and is reasonably necessary and appropriate for such purpose.

Station Two Subsidiary. Big Rivers and the LG&E Parties requested that the Commission approve Big Rivers' transfer to the Station Two Subsidiary of certain obligations with respect to HMP&L's Station Two facility. In addition, the LG&E Parties

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63 The documents in question are the Cost Sharing Agreement; the Lease and Operating Agreement; the Mortgage and Security Agreement; the agreement with new credit providers AMBAC and Credit Suisse First Boston, relating to the Pollution Control Bonds, to the extent required; and the security instruments evidencing liens given to LEM under the terms of the revised Participation Agreement.

requested that the Commission declare the Station Two Subsidiary to be a jurisdictional utility because KRS 96.520 limits a municipal utility to selling excess power either out of state or to a Commission-regulated utility.

The Commission finds that the transfer of HMP&L Station Two facility obligations to the Station Two Subsidiary is reasonable and will be approved. At the March 18, 1998 hearing, the LG&E Parties stated that legislation was pending in the 1998 Regular Session of the Kentucky General Assembly which would eliminate the need to declare the Station Two Subsidiary to be a jurisdictional utility. This legislation has since been approved by the General Assembly and signed by the Governor.[64] Therefore, the request to declare the Station Two Subsidiary a jurisdictional utility is denied as moot.

EWG Status. Big Rivers and the LG&E Parties requested that the Commission declare each of Big Rivers' generating facilities to be an "eligible facility" within the meaning of Section 32(a)(2) of PUHCA. This finding is a prerequisite for WKEC to be declared an exempt wholesale generator by FERC and thereby exempt from all provisions of PUHCA.

After examining the evidence, the Commission finds that the generating facilities of Big Rivers have been used for the generation of electric energy exclusively for sale at wholesale. The Commission further finds that allowing the Big Rivers generating facilities to be eligible facilities will benefit consumers by allowing Big Rivers to consummate its Reorganization Plan which includes the lease transaction, is in the public interest, and does not violate Kentucky law. At the request of the LG&E Parties, the Commission will

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64 Senate Bill 269 was passed by the Senate on February 27, 1998, the House of Representatives on March 23, 1998, and was signed by the Governor on April 1, 1998.

condition this grant of eligible facility status upon the closure of the transaction between Big Rivers and the LG&E Parties.

Wholesale Power Contracts. Big Rivers and the LG&E Parties requested that the Commission approve the amendments to the wholesale power contracts with the member distribution cooperatives. As with other transaction documents, the Commission finds that these contracts as filed by February 27, 1998, should be approved in principle, subject to deletion of the Smelters' exemptions from distribution level cost changes due to legislative, regulatory, or legal action or distribution level stranded costs and exit fees. The final drafts of these contracts will be reviewed as part of the new proceeding to ensure that appropriate changes have been made to reflect the decisions herein and that no other material changes have been made.

Consolidation of Pending Fuel-Related Cases

In its Application, Big Rivers requested that this case be consolidated with two fuel-related cases currently pending at the Commission. This request was subsequently expanded when Big Rivers filed its initial brief on February 13, 1998 to include additional fuel adjustment clause ("FAC") proceedings covering November 1, 1990 through April 30, 1994 which were remanded to the Commission in January 1998. Big Rivers argues that consolidation of these proceedings with the case at bar and the Commission's approval of the rates set forth in Big Rivers' Plan of Reorganization will render those cases moot.

As a result of an extensive investigation into Big Rivers' fuel procurement practices, the Commission on July 21, 1994, in Case No. 90-360-C,[65] found that Big Rivers had incurred unreasonable fuel costs as a result of its decisions to enter certain coal supply

[65] Case No. 90-360-C, An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 1990 to April 30, 1993.

contracts and required Big Rivers to amortize and credit those costs to its customers. Based upon the record developed in Case No. 90-360-C, the Commission in subsequent FAC review proceedings[66] ordered Big Rivers to make additional credits to its customers.

As a result of judicial reviews filed by Big Rivers and the Smelters, the Franklin Circuit Court affirmed the Commission's July 21, 1994 Order to disallow the unreasonable fuel costs, but remanded the matter to the Commission to determine whether two fuel contracts complied with the FAC regulation and whether the fuel costs associated with those contracts were prudent or the result of improper fuel procurement practices.[67] The Court further directed the Commission to determine, if appropriate, the amount of any additional refunds.

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66 Case No. 92-490-B, An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from May 1, 1993 to October 31, 1993 (August 9, 1994); Case No. 92-490-C, An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 1993 to April 30, 1994 (November 1, 1994); Case No. 94-458, An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 1992 to October 31, 1994 (March 5, 1996); Case No. 94-458-A, An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 1994 to April 30, 1995 (June 19, 1996); Case No. 94-458-B, An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from May 1, 1995 to October 31, 1995 (July 9, 1996); Case No. 94-458-C, An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 1995 to April 30, 1996 (October 16, 1996).

67 Big Rivers Electric Corp. v. Pub. Serv. Com'n, No. 94-CI-01184, slip op. at 14 (Franklin Cir. Ct. Oct. 20, 1995).

The Commission and Big Rivers appealed the Franklin Circuit Court ruling. Finding that the Franklin Circuit Court's judgment was not final, the Kentucky Court of Appeals on July 3, 1997 dismissed these appeals.[68] On January 14, 1998, the Kentucky Supreme Court denied the Commission's Motion for Discretionary Review.[69] As a result, these cases are again before the Commission.[70]

Having considered Big Rivers' request for consolidation, the Commission denies it. As the request relates to the remanded proceedings, it was not properly raised. The proceedings involving Big Rivers' FACs were not remanded to the Commission until January 14, 1998. The issue was not before the Commission when the principal hearing in this matter was held and was raised for the first time in Big Rivers' initial brief.[71] The parties have not had an adequate opportunity to address the issue.[72]

Moreover, consolidation of the fuel cases into this proceeding is inconsistent with the express directives of the Franklin Circuit Court judgment. The Court directed the Commission to make certain determinations regarding two fuel contracts and the fuel costs

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68 Pub. Serv. Com'n v. Big Rivers Electric Corp., No. 95-CA-3079-MR, slip op. at 2-3 (Ky. Ct. App. July 3, 1997).

69 Pub. Serv. Com'n v. Big Rivers Electric Corp., No. 97-SC-610-D (Ky. Jan. 14, 1998).

70 Not all of the Orders have been remanded to the Commission. Actions for review of Commission Orders in Cases No. 94-458, 94-458-A, 94-458-B, and 94-458-C are still pending before Franklin Circuit Court and have not been remanded to the Commission.

71 Big Rivers Initial Brief at 25-33.

72 For that matter, Big Rivers failed to provide notice of its request to all parties in Case No. 90-360-C. The record fails to reflect that any notice of the consolidation proposal was given to Prestige Coal Company.

incurred under those contracts. Consolidation will not advance this objective but impede it. Under Big Rivers' proposed approach, the Commission would consolidate the cases into this proceeding and then take no further action.

The Commission is not the appropriate forum to address Big Rivers' argument that the Bankruptcy Court's approval of the Plan of Reorganization extinguishes any right of ratepayers to pursue refunds and renders the Franklin Circuit Court judgment moot. That forum is the Franklin Circuit Court. As the matter currently stands, Franklin Circuit Court has directed the Commission to take certain actions. Its judgment has not been modified, suspended or revoked. No court of superior jurisdiction has relieved the Commission of its obligations under the judgment. Absent such court action, the Commission must comply with the judgment and make the required determinations. Given the voluminous record and complex issues in the remanded cases, those determinations should be made in a separate proceeding and not be consolidated with this proceeding.

Depreciation Study

Big Rivers disclosed during the proceeding that the required accounting for the lease transaction might result in the book value of Wilson being overstated, and that there might have to be an asset book value write down. However, before Big Rivers could finalize its determination of the need for a write down, it had initiated a new depreciation study, which has not yet been completed.

The Commission finds that within 30 days of Big Rivers' completion and acceptance of a new depreciation study, a copy should be filed with the Commission. No changes in depreciation rates should be implemented under that study until the Commission has reviewed the new study. Big Rivers should also promptly inform the Commission of its determination regarding the need for an asset book value write down and, if one is determined to be necessary, initiate the appropriate proceeding.

Debt Service Plan

The AG objected to the debt service schedule contained in Big Rivers' financial model, contending that it was back loaded. The AG argued that only 36 percent of the principal on the RUS debt will be paid by the time the Smelters are expected to leave the Big Rivers system.[73] The AG notes that under the unforeseen cost issue resolution, more of the debt service is shifted to the later years of the transaction, when only the non-Smelter ratepayers are still on the system.[74]

The Smelters argued that the AG's statement about the 36 percent figure is true, but completely misleading because debt service is not measured only by the repayment of principal, but by the sum of principal and interest. The Smelters stated that the projected debt service schedule, agreed to by the lenders, represents a largely levelized combination of interest and debt principal payments.[75]

The Commission has reviewed the arguments and concludes that the AG's analysis has not taken into consideration the entire scope of the impact of the transaction, as modified by the unforeseen cost resolution. The AG's argument fails to consider the fact that the repayments to RUS must equal a pre-determined present value, regardless of the timing of principal and interest payments. This arrangement allows Big Rivers a degree of flexibility during the early years of the transaction. In addition, the AG does not appear

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73 AG Initial Brief at 18.

74 AG Initial Brief on the Unforeseen Cost Resolution at 2.

75 Alcan and Southwire Main Brief at 31.

to have considered the impact of LEM's lease payments or the potential impact of arbitrage sales on the outstanding debt. Concerning the impact of the unforeseen cost resolution, Big Rivers apparently had no loan sources to fund the up-front capital expenditures as envisioned in the original plan. While the resolution did result in a shift of the debt service schedule, it also provided Big Rivers with a needed source of financing for its reduced capital expenditures responsibilities. Therefore, while the situation identified by the AG is an important consideration, taken in light of the overall benefits and provisions of the transaction as modified, the Commission finds that the arguments of the AG do not justify the rejection of the proposed debt service schedule.

Monitoring and Reporting

The proposed transaction, as modified by the resolution of the unforeseen cost issue, contains what the Commission believes to be a valuable incentive to Big Rivers: the ability to make arbitrage sales and Other Sales.[76] Big Rivers has placed a significant amount of reliance on its ability to make Other Sales and the revenues to be generated by those sales will be critical to its long-term financial restructuring.[77] To encourage Big Rivers to utilize this option to its greatest potential, and to ensure that the Commission is timely informed of Big Rivers' progress in making both arbitrage sales and Other Sales, the Commission will require Big Rivers to:

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[76] Other Sales are off-system sales envisioned in Big Rivers' financial models to begin after the termination of the current Smelter contracts in 2011.

[77] From 2011 to 2022, Big Rivers forecasts annual gross sales revenues ranging from $36.1 million to $45.9 million, which represents 15 to 20 percent of all gross sales revenues during the period. See Robison, Schaefer, and Hite Supplemental Testimony, Exhibit SUP-11, lines 304 through 309. Percentage impact is determined by dividing line 307 by line 309 in any year after 2010.

- Develop and file with the Commission within 60 days of the Transaction Closing Date, a strategic plan concerning arbitrage sales;

- Develop and file with the Commission within 30 days of the date of this Order, an interim sales plan, to be in effect until the strategic sales plan is implemented;

- File with the Commission within six months after the date of this Order, and every six months thereafter, a report on arbitrage sales and Other Sales; and

- File with the Commission a report, appended to its annual report, comparing its actual cash flows for the calendar year with the amounts included in the SUP-11 financial model filed in this proceeding.[78]

SUMMARY AND CONCLUSION

Throughout this proceeding the Applicants, the Smelters, and three distribution cooperatives have repeatedly stated that the proposed rates are an integral part of the Reorganization Plan, were the result of intense and extensive negotiations, and that any modifications could disrupt the carefully balanced interests of those who participated in the negotiations. Simultaneously, the AG and one distribution cooperative, Jackson Purchase, have vigorously opposed the proposed rates on the basis that the benefits of the reorganization have not been fairly distributed among all customer classes, resulting in unduly preferential rates for some customers. The Commission has taken all these statements into consideration and has made the findings and decisions set forth herein based on the evidence and the critical need for Big Rivers to emerge from bankruptcy as quickly as possible.

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[78] The report will be based on lines 363 through 411 of SUP-11, and include explanations for any deviations from the SUP-11 figures in excess of 10 percent.

It has not been an easy task to balance all aspects of the transaction and the proposed rates with our statutory obligations under KRS Chapter 278. Our task was not made any easier by the inclusion of certain rate provisions which appeared to be the product of less than equal bargaining leverage among the parties to the Reorganization Plan. We recognize that there will need to be some changes to the transaction to accommodate our findings. However, we do not believe that those changes will significantly alter either the purpose or the intent of the transaction.

From the perspectives of Big Rivers and its major creditors, our decisions should not reduce the cash flow reflected in Big Rivers' financial models, thus preserving Big Rivers' ability to meet its operating expenses and debt service payments. In addition, as a result of the resolution of the unforeseen cost issue, the margins that were projected to be earned on sales to the Smelters will now be guaranteed by LEM. Although we have denied the market power purchase option for large industrial customers, we have developed rates for this class which provide a reasonable rate reduction, generally between 7 to 12 percent based upon anticipated loads, without requiring the commitment to a five year contract. For the rural consumers, the rate reductions implemented in September 1997 will remain in effect. In addition, the resolution of the unforeseen cost issue should provide significant financial protections to the rural and large industrial customers from the risks of new regulatory, legal or environmental costs not associated with their load.

From the perspective of the Smelters, our decisions retain the fixed prices for Tier 1 and Tier 2 power which is critical to their ability to compete in the world-wide aluminum market. Although we have denied the Tier 3 market purchases for the Smelters' incremental power needs, our decision to allow LEM to supply the Smelters' Tier 1 and Tier 2 power provides an extra margin of reliability and allows Green River and Henderson Union to reduce their full-requirements relationship with Big Rivers. While we have rejected the Smelters' exemption from unforeseen costs and exit fees at the distribution level, we have allowed such exemptions for any wholesale costs or fees attributable to Big Rivers. We truly believe that Big Rivers and the Smelters are vital to the economy of western Kentucky and their fortunes have been intertwined for many years. Even though our decisions today sever most of their existing ties, the Smelters' ability to purchase reasonably priced power at fixed costs from LEM is the result of the availability of valuable generating assets on the Big Rivers system.

Transaction Documentation Approval

The application, as filed on June 30, 1997, contained the supporting transaction documents which were incomplete or otherwise noted as being subject to further revision. Over the next five months, the Applicants filed revisions to the transaction documents and many were not finalized as of the November 1997 hearing. To accommodate the Applicants, the Commission established December 19, 1997 as the due date for final drafts of the documents and January 15, 1998 as the date to resolve the unforeseen cost issue.

Documents were not in final draft form by late December 1997. The Applicants subsequently requested, and the Commission granted, an extension to January 30, 1998 to resolve the unforeseen cost issue. On January 27, 1998, the Applicants and the Smelters filed a joint notice that the unforeseen cost issue had been resolved in principle, but not yet reduced to writing, and subsequently requested to indefinitely suspend the briefing schedule. The Commission, by Order dated January 29, 1998, denied the request, citing KRS 278.190(3) as limiting our rate jurisdiction to 10 months, which would expire on April 30, 1998.

A supplemental procedural schedule dated February 13, 1998 was adopted to investigate the unforeseen cost resolution and it established February 23, 1998 as the final date for all documents. The Applicants filed some documents by that date, but indicated that others were incomplete and would be filed later that week. The AG objected to this delay and, by Order dated February 26, 1998, the Commission extended the due date to February 27, 1998, but admonished the Applicants that any documents not filed by that date would not be considered in this case.

In contravention of the February 26, 1998 Order, the Applicants continued to file documents after the due date. Chase then objected, claiming a denial of due process, when the Applicants filed additional documents on March 19, 1998, after the supplemental public hearing.

The Commission well recognizes the importance of the pending transaction to Big Rivers' financial rehabilitation and the need to act as expeditiously as possible. However, the parties' due process rights must be respected and accommodated. In addition, the continual revisions to the transaction documents have frustrated the Commission's investigative efforts to the extent that we are no longer confident that the transaction contemplated by the Applicants is not materially different from the transaction reviewed at the March 18, 1998 hearing. Therefore, we will approve the transaction documents in principle as filed with the Commission on the due date of February 27, 1998.

To afford the parties and the Commission an opportunity to verify that no material changes have been made to the structure of the transaction, we will require the Applicants to file as quickly as possible, but no later than May 29, 1998, final drafts of all transaction documents that have undergone any changes since February 27, 1998. The documents should be filed in a new docket with copies to all parties to this case. The scope of review will be limited to determining whether the final transaction documents have materially changed since those filed by February 27, 1998 and to review the changes necessitated by this Order. Each document filed should contain a clear identification of each change and be supported by a detailed explanation of the reason for the change. The review should take no more than 30 days and will include one round of discovery and an informal conference or hearing if necessary.

IT IS THEREFORE ORDERED that:

1. Based on the documents on file with the Commission as of February 27, 1998, the proposed transaction, as modified by the resolution of the unforeseen cost issue, is approved in principle, subject to the modifications contained in this Order.

2. The market power provision in the Smelters' Tier 3 rate and the Market Power Purchase option for certain Large Industrial Customers are hereby denied and the termination date on the Tier 3 fixed rate is rejected.

3. The rates for non-Smelter industrial customers are modified as discussed in this Order. The remaining rates proposed by Big Rivers and contained in the tariff draft bearing an issued date of February 23, 1998 are approved. All rates approved herein are effective for service rendered on and after the date of this Order.

4. The alternative rates proposed by the AG are hereby denied.

5. The alternative rate proposed by Willamette is hereby denied.

6. Provisions in the Smelters' tariffs and their contracts with the distribution cooperatives prohibiting rate adjustments to reflect costs or payments incurred by the distribution cooperatives for expenditures due to legislation, regulatory, or legal action are rejected.

7. Provisions in the Smelters' distribution cooperative contracts and tariffs exempting the Smelters from paying any stranded costs or exit fees relating to the distribution cooperatives are rejected.

8. The Applicants shall file, in a new case, the final drafts of the transaction documents supported by a clear identification of each change made and a detailed explanation of each change to the versions on file with the Commission as of February 27, 1998. The Applicants shall serve copies of all documents on the parties to this case, who shall be deemed parties to the new case.

9. The Transmission Service and Interconnection Agreement, and Big Rivers Open Access Transmission Tariff are approved in principle subject to review of the final drafts of the documents.

10. Evidences of indebtedness required of Big Rivers in conjunction with the transaction documents are approved in principle, subject to review of the final transaction documents.

11. The transfer of control of Big Rivers' generating units to WKEC and the transfer of the HMP&L Station Two facility obligations are hereby approved in principle, subject to review of the final version of the transaction documents.

12. Big Rivers' generating facilities are "eligible facilities" within the meaning of Section 32(a)(2) of PUHCA, subject to the closure of the transaction as contemplated by Big Rivers and the LG&E Parties.

13. Big Rivers shall file the accounting entries made to record the lease transaction within 10 days of entry into the books of Big Rivers.

14. The Wholesale Power Contracts between Big Rivers and the distribution cooperatives are approved in principle, subject to the revisions discussed in this Order and subject to the review of the final version of the contracts.

15. Big Rivers shall file a copy of the new depreciation study within 30 days of its completion and acceptance, and shall not implement any changes in depreciation rates recommended in that study until the Commission has reviewed the study.

16. Big Rivers shall not write down the book value of any generating station without prior Commission approval.

17. Within 30 days of the date of this Order, Big Rivers shall file its tariffs, reflecting all revisions and modifications as described in this Order.

18. Within 60 days of the transaction closing date, Big Rivers shall file a strategic plan for maximizing arbitrage sales.

19. Within 30 days of the date of this Order, Big Rivers shall file an interim sales plan, to be in effect until the strategic sales plan is implemented.

20. Within six months of the date of this Order, and every six months thereafter, Big Rivers shall file a report of arbitrage sales and Other Sales.

21. Big Rivers shall file a report, appended to its annual report, comparing its actual cash flows for the calendar year with the amounts included in the SUP-11 financial model filed in this proceeding. The report shall be based on lines 363 through 411 of SUP-11, and include explanations for any deviations from the SUP-11 amounts in excess of 10 percent.

22. The reports required herein shall initially be submitted by Big Rivers subject to further modifications as deemed necessary by the Commission, to allow for the monitoring of Big Rivers' compliance with the transaction and the findings of this Order.

Nothing contained herein shall be construed as a finding of value for any purpose or as a warranty on the part of the Commonwealth of Kentucky, or any agency thereof, as to the securities authorized herein.

Done at Frankfort, Kentucky, this 30th day of April, 1998

By the Commission

ATTEST:

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Executive Director

Exhibit 52

Order in Case No. 98-267 dated July 14, 2008, re: The Application of Big Rivers Electric Corporation for Approval of the 1998 Amendments to Station Two Contracts between Big Rivers Electric Corporation and the City of Henderson, Kentucky and the Utility Commission of the City of Henderson

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF BIG RIVERS)
ELECTRIC CORPORATION FOR APPROVAL)
OF THE 1998 AMENDMENTS TO STATION)
TWO CONTRACTS BETWEEN BIG RIVERS) CASE NO. 98-267
ELECTRIC CORPORATION AND THE CITY)
OF HENDERSON, KENTUCKY AND THE)
UTILITY COMMISSION OF THE CITY OF)
HENDERSON)

O R D E R

By Order dated April 30, 1998 in Case No. 97-204,[1] the Commission approved new rates for Big Rivers Electric Corporation ("Big Rivers"), and approved in principle a 25 year lease of its generating units to a subsidiary of LG&E Energy Corp. The Commission's decision was based on the transaction as reflected in the documents filed as of February 27, 1998. However, since many of the documents were revised after that date, the Commission directed that the final drafts of all jurisdictional documents be submitted in this case for a determination of whether material changes have been made to the structure of the transaction.

This case was established on May 15, 1998 when Big Rivers filed the 1998 Amendments to Station Two Contracts which relate to its operation of the City of Henderson's Station Two Generating Plant. Over the next 45 days, Big Rivers filed the

[1] The Application of Big Rivers Electric Corporation, Louisville Gas and Electric Company, Western Kentucky Energy Corp., Western Kentucky Leasing Corp., and LG&E Station Two Inc. For Approval of Wholesale Rate Adjustment for Big Rivers Electric Corporation and For Approval of Transaction.

final drafts of all transaction documents. A procedural schedule was entered providing all parties an opportunity to engage in discovery and a public hearing was held on July 6, 1998.

The Commission notes at the outset that this is anything but a routine review of documents relating to a rate adjustment and asset lease. Big Rivers is a debtor in possession under Chapter 11 of the United States Bankruptcy Code. The documents under review are essential and critical components of Big Rivers' plan of reorganization as approved by the Bankruptcy Court on June 1, 1998. All of the parties to Case No. 97-204 were made parties to this case. Most of them participated to some extent in this case, but no party objected to any of the documents under review herein. The absence of any objection, however, does not diminish the Commission's obligation to ensure that there have been no material changes in the transaction. This obligation takes on greater importance here since the term of the lease is 25 years and the power contracts have terms that extend up to 25 years.

Based on a comprehensive analysis of the final drafts of the transaction documents, the Commission finds that there have been several material changes made to the structure of the lease transaction. The most current economic analysis of the lease transaction, filed by Big Rivers on July 7, 1998 and identified as PSC2-38R, has been compared to the one identified as SUP-11, which formed the basis for our conditional approval in Case No. 97-204. To the extent the transaction has undergone a material change, it is discussed herein.

Transmission Service for Smelter Loads

The documents on file with the Commission as of February 27, 1998 provided as follows with respect to the Smelters' transmission service:

1) Green River Electric Corporation ("Green River") and Henderson Union Electric Cooperative Corp. ("Henderson Union") would arrange for and reserve transmission on Big Rivers' transmission system for Tier 1 Energy, Tier 2 Energy, and Tier 3 Energy purchased from LG&E Energy Marketing Inc. ("LEM") for resale to Southwire Company ("Southwire") and Alcan Aluminum Corporation ("Alcan").[2]

2) Transmission services were to be provided at Big Rivers' Open Access Transmission Tariff ("OATT") rates.[3]

3) Green River and Henderson Union were responsible for all transmission costs and were entitled to a transmission credit against the total payments owed to LEM. The credit equaled the amount the cooperative paid to Big Rivers for the transmission of Tier 1 Energy, Tier 2 Energy, Tier 3 Interruptible Energy, and Tier 3 Backup Energy.[4]

4) LEM would pay to the RUS, on behalf of Big Rivers, a monthly smelter margin payment ("monthly margin payments"), which reflected the net smelter margins originally included in Big Rivers' financial model. The

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[2] See Case No. 97-204, Document filing of February 23, 1998, Volume III, Tabs 15 and 16, at 8-12. The reference is to the Amendments to the Wholesale Power Agreements between Big Rivers and Green River and Big Rivers and Henderson Union, Paragraphs 3 and 4.

[3] Id. at 11.

monthly margin payments would remain fixed regardless of the amount of power actually supplied by LEM to the Smelters and the payments specifically excluded any transmission service revenues.[5]

Big Rivers, the LG&E Parties, and the Smelters had strongly stressed the significance of the guaranteed monthly margin payments and the significant benefit this arrangement represented to Big Rivers.[6] The Commission accepted this argument, noting in the April 30, 1998 Order that the guarantee of the smelter margins was an improvement to the overall transaction, which the Commission approved in principle.

The changes made to the transaction documents reviewed in Case No. 97-204 include the following relating to transmission service for the Smelters' load:

1) LEM will arrange for and reserve transmission on Big Rivers' transmission system for Tier 1 Energy, Tier 2 Energy, and Tier 3 Energy. LEM will continue to provide Green River and Henderson Union with the energy resold to the Smelters, with the types and amounts of transmission reserved by LEM for these sales being referred to as Member Transmission.[7]

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[4] See Case No. 97-204, Documents filed February 27, 1998, the Agreements between Henderson Union and LEM and Green River and LEM, Schedule A, part g.

[5] See Case No. 97-204, Supplemental Testimony of A. J. Robison, Stephen Schaefer, and Mark A. Hite, at 4, 5, and 8.

[6] See Case No. 97-204, Transcript of Evidence, Volume VI, March 18, 1998, at 11-12, 15, and 48; Big Rivers Supplemental Initial Brief at 14-16; LG&E Parties Initial Brief Addressing Future Unforeseen Cost Issue at 3; Alcan and Southwire Supplemental Brief on Unforeseen Cost Resolution at 4-5.

[7] Document filing of May 29, 1998, Volume II, Tab 8, at 19-25. The reference is to the Transmission Service and Interconnection Agreement, Sections 6.5.1 and 6.5.2.

2) LEM will continue to pay the monthly margin payments to the RUS on behalf of Big Rivers. However, these payments have been revised to include the revenue for smelter transmission service, which was originally shown separately in the Big Rivers financial model.[8]

3) As long as the full monthly margin payments are made pursuant to the terms of the transaction agreements, Big Rivers will deem the full cost of the Member Transmission to have been paid at the then applicable OATT rate as part of the monthly margin payments. Consequently, LEM's cumulative cost for Member Transmission charged by Big Rivers will never exceed the cumulative amount of the monthly margin payments.[9]

The impact of these changes on Big Rivers is that if its OATT transmission rate increases, it will no longer recover the full smelter margin payments and its cost of transmission service. The margin payments are now to be reduced by any increase in transmission rates above the levels agreed to by the Smelters.

Big Rivers contends that it had always borne the economic risk of future changes in transmission costs as applied to the fixed wholesale power rates for service to the Smelters for which the monthly margin payments are to be received. Big Rivers argues that the designation of a portion of the monthly margin payments as a transmission payment at OATT rates in no way changes the economic positions of Big Rivers and

[8] Response to the Commission's June 12, 1998 Order, Item 7, page 37 of 81.

[9] Document filing of May 29, 1998, Volume II, Tab 8, at 22-23.

the LG&E Parties, but merely provides Big Rivers with the same economic risk regarding transmission which it has always had.[10]

The significant changes to the smelter transmission arrangements presented by Big Rivers and the LG&E Parties have affected the Commission's evaluation of the overall lease transaction. The documents upon which the Commission based its April 30, 1998 approval in principle stated that smelter transmission service would be obtained at OATT rates. At that time, the monthly margin payments excluded transmission service revenues, making it impossible to adjust the payments for transmission cost changes. The revisions proposed in this proceeding allow the smelter margins modeled by Big Rivers to be used to offset any shortfall in transmission revenues resulting from the actual OATT rates exceeding the transmission rates agreed to by the Smelters. In the event of such a shortfall in transmission revenue, the proposed revisions to the smelter transmission service will result in lower overall revenues to Big Rivers and expose its non-smelter customers to potential rate increases.

Big Rivers contends that it has always borne this economic risk, and that the proposed revisions do not change the arrangement that was part of the unforeseen cost resolution. The documents on file with the Commission as of February 27, 1998 do not support this position. Based on those documents, Green River and Henderson Union had the initial risk of fluctuations in OATT rates for the smelter load transmission service; however, the transmission credit appeared to shift this risk to LEM. The revisions proposed in this proceeding now shift that risk back to Big Rivers.

[10] Response to the Commission's June 12, 1998 Order, Item 13(c), page 7 of 10.

Big Rivers has contended that it does not expect its transmission rates, as modeled in its financial model,[11] to change during the terms of the Smelters' contracts. Big Rivers claims that it is just as likely that its transmission rates will decrease as increase, but has offered no analysis or study to support its claim.

The Commission finds it likely, however, that for Big Rivers to improve its ability to make arbitrage sales, it may have to join an Independent System Operator ("ISO") to eliminate transmission rate pancaking. In the event the transmission rates established for the ISO are higher than Big Rivers' OATT, under the proposed revision, Big Rivers is faced with a no win situation. If it does not join an ISO, its ability to make critical arbitrage sales could be restricted. If it does join, it would incur additional costs for transmitting power to the Smelters, but would be unable to recover those costs from LEM or the Smelters. Big Rivers' inability to recover these costs would put pressure on its overall financial condition, and could eventually result in higher rates for its remaining customers.

Having considered all of the factors discussed herein, the Commission will accept the designation of LEM, rather than Green River and Henderson Union, as the party responsible for arranging and reserving transmission service with Big Rivers. The Commission also accepts the inclusion of the transmission revenues from the Smelters, as shown in Big Rivers' financial model, in the monthly margin payments. However, the

[11] The latest update of Big Rivers' financial model, identified as PSC2-38R, shows transmission rates through 2006 at $.98/KW/month. In 2007, the rate for network transmission appears to increase to $1.02/KW/month while non-firm point-to-point transmission is priced at $1.04/KW/month. In the year immediately after the Smelter contracts are scheduled to expire, all transmission is shown at the $1.04/KW/month rate.

Commission finds unreasonable the provision that allows increases in the OATT rates charged to LEM, except as modeled originally by Big Rivers, to be offset by the remaining portion of the monthly margin payment. That portion of the monthly margin payment reflecting the modeled net smelter margins exclusive of transmission revenues should remain as described in the documents on file with the Commission as of February 27, 1998.

In determining an equitable methodology for the recovery of unforeseen increases in transmission costs due to the Smelters' load, the Commission will be guided by the unforeseen cost resolution previously negotiated by the parties to the transaction. Under this approach, for any increase in Big Rivers' OATT rate in excess of that included in its financial model, 50 percent of the excess will be charged to LEM as part of its transmission costs. The bundled rates charged by LEM to Green River and Henderson Union will be equally adjusted. Consequently, the bundled rates charged by Green River and Henderson Union to Southwire and Alcan, respectively, will be adjusted to reflect the 50 percent of the increase in transmission costs. In the event that Big Rivers' OATT rate falls below the transmission rate included in its financial model, the rates charged to LEM, Green River, Henderson Union, Southwire, and Alcan will not be reduced. Any revenues in excess of the OATT rates should be retained by Big Rivers as an offset to the $1.85 million payment it makes each year as its 50 percent contribution to resolve the Smelters' indemnification for future unforeseen costs.

Agreement for Electric Service to Commonwealth Industries, Inc.

One of the documents filed in this proceeding was a draft of a new Agreement for Retail Electric Service ("Agreement") between Green River and Commonwealth Industries, Inc. ("Commonwealth"). As a preliminary matter, the Commission notes that filing of this Agreement was not anticipated. There was no indication by any party in Case No. 97-204 that the agreement for service to Commonwealth would be subject to any additional negotiations or revisions. Apparently, one or both of the parties to the Agreement were dissatisfied with the Commission's April 30, 1998 Order in Case No. 97-204, and seized the opportunity presented by this instant case to submit a revised contract for electric service. Although the Agreement is not within the intended scope of this case, in the interest of administrative efficiency we will consider the merits of the Agreement.

This Agreement, when compared to one reviewed in Case No. 97-204, contains several changes which tend to favor the interests of Commonwealth over those of Green River and its wholesale power supplier, Big Rivers. The most significant of these changes is the establishment of two primary levels of power and billing for service to Commonwealth: (1) Peaking Power - defined as power and associated energy taken at 35,000 KW and above at a load factor of 10 percent or less, up to a maximum of 5,000 KW; and (2) all other power ("non-peaking power") and associated energy, taken at 35,000 KW and below.

Under its previous agreement, Commonwealth was required to take-or-pay for the full $10.15 demand charge applied to its contract demand of 40,000 KW, regardless of its actual demand level. Under the proposed Agreement, Commonwealth's non-peaking demand will be capped at a maximum of 35,000 KW to which the $10.15

demand charge will be applied. All energy taken up to the 35,000 KW level will be billed at Big Rivers' wholesale energy rate plus a retail energy adder of $.0003 per KWH. For the Peaking Power, all demand in excess of 35,000 KW would incur no demand charge, but would be billed a "peaking energy charge of $0.075" per KWH plus the retail adder previously mentioned.

Commonwealth contends that, compared to its previous agreement, this Peaking Power provision provides it with the proper financial incentive to manage its operation processes to eliminate the short term surges in power consumption that occur on its system from time to time. These surges in consumption cause its billing demand to spike above its 35,000 KW contract demand.[12] Commonwealth also argues that the pricing terms included in the proposed Agreement will produce a revenue level closer to the level envisioned in the Commission's April 30, 1998 Order in Case No. 97-204. Commonwealth makes these assertions based on its historic demand and energy billing units for calendar years 1996-1997.

Based on a review of the merits of the proposed Agreement, the Commission finds that it should be rejected. None of the proponents of the Agreement have shown good cause to justify granting Commonwealth terms or prices for electric service that are more favorable than those available to others within the same customer class, i.e. non-smelter industrial customers served from dedicated delivery points. A demand charge of $10.15 for each KW in excess 35,000 KW will provide Commonwealth with a

[12] In Case No. 97-204, Big Rivers modeled a continuous demand level of 35,000 KW for Commonwealth throughout the 25-year planning horizon without recognizing any "needle peaks" or "spike demands" in excess of 35,000 KW.

far greater financial incentive to avoid surges in consumption than will the proposed Peaking Power energy rate.

Particularly unpersuasive are Commonwealth's arguments regarding its annual electric bill as calculated under: 1) the rates proposed by Big Rivers in Case No. 97-204; 2) the rates approved by the Commission in Case No. 97-204; and 3) the rates under this proposed Agreement. Commonwealth's Exhibit 2, which is intended to be an analysis of its annual electric bill and the corresponding level of revenues flowing to Big Rivers, is misleading. The Commission did not design rates for only the 1996 normalized test year, as implied in this exhibit. The billing units in Commonwealth's Exhibit 2 do not correspond to those included in the Big Rivers' financial model which the Commission utilized to develop rates for Commonwealth and all other members of its class for the entire 25-year term of the lease transaction.

Commonwealth has calculated its annual electric bill to be higher than what it might have expected because it utilized a demand level consistently higher than the 35,000 KW included in Big Rivers' model. Had Commonwealth utilized its expected demand level of 35,000 KW, its calculation of revenues would have been less by $487,200 per year.[13]

Customers' electric bills and the corresponding level of utility revenues are affected by both the rates and the customers' usage. It would be pure coincidence if Commonwealth or any other customer consumed power at levels identical to those in the normalized historic test year or the 25-year forecast. Commonwealth cannot

[13] (468,000 KW * $10.15) = $4,750,200
less: (420,000 KW * $10.15) = $4,263,000 equals $487,200.

reasonably expect to receive special treatment merely because it now asserts that its consumption levels will differ from those incorporated into the Big Rivers' model.

Capital Budgets

On April 6, 1998, Big Rivers and the LG&E Parties executed a document entitled "New Participation Agreement," which replaced the original Participation Agreement and the Amended and Restated Participation Agreement contemplated by the lease transaction. This New Participation Agreement reflected changes in the transaction documents related to the resolution of the unforeseen cost issue, as well as clarifications of the parties' intent and the correction of errors.[14] On June 10, 1998, Big Rivers and the LG&E Parties filed a document entitled "Second Amendment to the New Participation Agreement" ("Second Amendment"). The Second Amendment reflected numerous clarifications and corrections to the majority of the lease transaction documents, reflected the decisions announced in the Commission's April 30, 1998 Order, and resolved uncertainties related to environmental issues. In addition, the Second Amendment addressed and resolved differences of opinion between Big Rivers and the LG&E Parties concerning the appropriate composition of the annual capital budget.[15]

Subsequent to filing the documents in February 1998 to resolve the unforeseen cost issue, Big Rivers and the LG&E Parties discovered there were significant differences between the amounts each party projected for the annual capital budgets for Big Rivers' generating plants. At that time, there was no upper limit on Big Rivers'

[14] Response to the Commission's June 12, 1998 Order, Item 7, page 5 of 81.

exposure for non-incremental capital costs, which were reflected in the annual capital budget. Thus, the annual capital budget levels represented a major area of uncertainty in Big Rivers' financial modeling. As reflected in the Second Amendment, the LG&E Parties agreed to limit Big Rivers' exposure to unlimited increases in the annual capital budgets. Big Rivers had originally projected non-incremental capital costs to be $83.8 million over the life of the lease transaction. The Second Amendment capped this total exposure at $147.7 million, an increase of $63.9 million over the transaction term.[16]

While the Commission can appreciate Big Rivers' desire to limit its exposure to increases in the capital budgets, the impacts of incurring an additional $63.9 million in costs on Big Rivers' financial model should be considered. Big Rivers was requested to provide an update of the SUP-11 version of its financial model that reflected the lease transaction as described in the documents filed in this case. The ending cash balance at the end of the lease term was shown in SUP-11 as $171.8 million.[17] The updated financial model, PSC2-38R,[18] showed that the ending cash balance at the end of the lease term was $24.8 million.[19] The difference between the SUP-11 and PSC2-38R

[15] Id., pages 13 through 22 of 81.

[16] Response to the Attorney General's First Information Request, Item 4, pages 2 and 3 of 5.

[17] See Case No. 97-204, Supplemental Testimony of A. J. Robison, Stephen Schaefer, and Mark A. Hite, Supplemental Exhibit 11, Printout of File SUP11.WK4, Year 2022, Line 404.

[18] Big Rivers had originally filed an updated financial model, PSC2-38, in its response to the Commission's June 23, 1998 Order, Item 38. However, at the public hearing on July 6, 1998, Big Rivers indicated that it had discovered some errors in that filing and submitted the revised financial model, PSC2-38R, as Big Rivers Cross-Examination Exhibit No. 2.

versions of the financial model reflected numerous revisions to the financial model, including the additional $63.9 million in non-incremental capital costs provided by the terms of the Second Amendment.

The Commission finds that the modifications to the annual capital budgets required by the Second Amendment are reasonable and should be approved. However, this and other modifications contained in Big Rivers' financial model heighten concerns about Big Rivers' financial condition during the later years of the lease. In the April 30, 1998 Order, the Commission required Big Rivers to file a supplemental annual report comparing its actual cash flows for the calendar year with the amounts included in the SUP-11 financial model. The report was to be based on lines 363 through 411 of SUP-11, and include explanations for any deviations from the SUP-11 amounts in excess of 10 percent. The Commission will continue this requirement, but will substitute the updated financial model PSC2-38R for SUP-11, with the report now based on lines 285 through 333 of PSC2-38R. In addition, to better monitor Big Rivers' financial condition over the term of the lease transaction, Big Rivers will be required to submit with its annual report an updated version of its financial model.[20] The updated financial model will cover the period beginning with the current annual report year and ending with the last year of the lease transaction. All changes in assumptions and variables from one year to the next should be explained in detail.

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[19] Big Rivers Cross-Examination Exhibit No. 2, File PSC2-38R.WK4, Year 2022, Line 326.

[20] One hard copy of the updated financial model and one computer disc version should be provided.

Revolving Credit Agreement

On June 26, 1998, Big Rivers filed a copy of a revolving credit agreement ("Credit Agreement") it has entered into with the National Rural Utilities Cooperative Finance Corporation ("CFC"). Under the terms of the Credit Agreement, CFC will provide Big Rivers a maximum aggregate principle amount outstanding of $15 million. For each 12-month period the Credit Agreement is in effect, Big Rivers will be required to reduce to zero all amounts outstanding for at least five consecutive business days, with the first reduction due within 360 days of the first advance. The term of the Credit Agreement is 5 years. Big Rivers believes that the CFC Credit Agreement does not require Commission approval.

The Commission's jurisdiction to approve evidences of indebtedness is set forth in KRS 278.300. Specifically excluded from that jurisdiction under KRS 278.300(8) is the approval of notes payable at periods of not more than 2 years from the date issued and renewable for not more than a total of 6 years. The Commission finds that the terms of the CFC Credit Agreement fall within this exemption and, therefore, we agree with Big Rivers that no Commission approval is needed.

Smelters' Tier 3 Service Contracts

The proposed power contracts between Green River, Henderson Union, and the Smelters contain specific provisions concerning contracts for Tier 3 service from third-party power suppliers. When seeking Commission approval to make a sale of Tier 3 power to the Smelters, Green River and Henderson Union are contractually obligated to request that such approval be effective 20 days from the date of notice.[21] However, KRS 278.180(1) requires a minimum of 30 days notice prior to changing a rate, unless good cause is shown to shorten the notice period to 20 days. Green River and Henderson Union have indicated that the parties would accept a revision to the power agreements that reflects the 30-day statutory requirement.[22]

The Commission finds that the power agreements between Green River, Henderson Union, and the Smelters should be revised to reflect the 30-day notice provision set forth in KRS 278.180(1). Including this notice in the power agreements will not prevent any of the parties to those agreements from requesting a shorter notice period on a case-by-case basis when a Tier 3 service contract is filed.

Promissory Note for LEM Advances

Big Rivers has requested that the Commission approve the promissory note associated with the LEM advances, noting that such approval was omitted from the April 30, 1998 Order in Case No. 97-204. While we believe that note to have been implicitly approved by that Order, the Commission now explicitly finds that the promissory note for the LEM advances is for a lawful object within Big Rivers' corporate purpose, is necessary and appropriate for the proper performance of its wholesale electric service to the public and will not impair its ability to perform that service, and is reasonably necessary and appropriate for such purpose.

[21] See Agreement for Electric Service between Alcan and Henderson Union and Agreement for Electric Service between Southwire and Green River, Section 9.2.

[22] Response to the Commission's June 23, 1998 Order, Item 20.

1998 Amendments to the Station Two Contracts

Big Rivers has requested that the Commission approve the 1998 Amendments to the Station Two Contracts, which were filed with the Commission on May 15, 1998. The Commission finds that these documents are reasonable and should be approved.

Green River Wholesale Contract Amendment, Schedule 1

On June 6, 1998, Big Rivers submitted a substitute Schedule 1 to its wholesale power agreement with Green River. The substitute Schedule 1 reflects the inclusion of the proposed new service agreement between Green River and Commonwealth. Based on the decision herein to reject the new Commonwealth agreement, the Commission rejects the substitute Schedule 1 to the wholesale power agreement.

Standby Bond Purchase Agreements

On June 24, 1998, Big Rivers filed Standby Bond Purchase Agreements ("Standby Agreements") related to its 1983 and 1985 Pollution Control Bonds ("1983 and 1985 Bonds") and Credit Suisse First Boston, the new provider of letters of credit for those bonds. The Standby Agreements were required as part of the rating agencies' evaluation of the 1983 and 1985 Bonds. Big Rivers requested that the Commission permit the late filing of the Standby Agreements in this case.

As the Standby Agreements are an integral part of the overall financial restructuring of Big Rivers' obligations, the Commission will permit the late filing and hereby approves the Standby Agreements as part of all other financial agreements presented in this proceeding.

Confidentiality Petition for Marketing Plan

As part of its April 30, 1998 Order in Case No. 97-204, the Commission required Big Rivers to file an interim sales plan which would address how Big Rivers planned to pursue arbitrage sales opportunities until the lease transaction closed. On May 29, 1998, Big Rivers filed its Interim Sales Plan and a petition for confidential treatment of that document. On June 18, 1998, Alcan and Southwire responded to the petition, requesting a modification to the petition that would permit all parties to Case No. 97-204 who have executed appropriate confidentiality agreements to obtain copies of the Interim Sales Plan. On June 23, 1998, Big Rivers filed its reply to the Smelters' response, expressing its opposition to the request. At the July 6, 1998 public hearing, Big Rivers requested that the Commission include a ruling on the petition for confidential treatment in its Order in this proceeding.

The Commission finds that it is not appropriate to rule on Big Rivers' petition for confidentiality or the Smelters' request for access in this proceeding. The Interim Sales Plan was filed in Case No. 97-204, and the petition and request will be adjudicated in that case. In addition, the Commission finds no reason to modify its normal procedures for the processing of requests for confidentiality.

Distribution Cooperative Tariff

Green River and Henderson Union have submitted proposed Smelter tariffs to the Commission for approval. The proposed tariffs incorporate both the agreements for electric service between the cooperatives and the respective Smelters and Schedule A of those agreements, which details the terms and rates for Smelter service. Alcan and Southwire have notified the Commission of their opposition to incorporating the agreements for electric service into the tariffs, contending that the proposed tariffs only need to incorporate Schedule A. At the July 6, 1998 hearing the Smelters identified this disagreement as an issue for the Commission to address in this Order.

The Commission finds that there has been no evidence offered by the Smelters to justify the exclusion of the agreements for electric service from the smelter tariffs as filed with the Commission. Consequently, the Commission will not require Green River or Henderson Union to remove the language incorporating the agreements for electric service from the proposed tariffs.

Jurisdiction over OATT

On July 1, 1998, Big Rivers, Alcan, Green River, Henderson Union, and Southwire filed a joint motion requesting that the Commission assert jurisdiction over Big Rivers' OATT to the extent that the Federal Energy Regulatory Commission ("FERC") does not assert jurisdiction over the OATT. The July 1, 1998 motion notes that Big Rivers' status as a generation and transmission cooperative, combined with the limited jurisdiction of FERC over such entities, creates a "regulatory gap" in jurisdiction over many provisions of the OATT. The parties to the July 1, 1998 motion request that the Commission fill this regulatory gap by asserting jurisdiction, subject to five specific limitations enumerated in the motion.

Big Rivers was formed pursuant to the requirements of KRS Chapter 279. KRS 279.210 provides that every corporation formed under that chapter shall be subject to the general supervision of the Commission and shall be subject to all the provisions of KRS 278.010 to 278.450 inclusive, and KRS 278.990. Therefore, to the extent that FERC has not asserted jurisdiction over Big Rivers' OATT, the Commission will do so, in accordance with KRS Chapters 278 and 279. However, the Commission will assert this jurisdiction without the specific limitations referenced in the July 1, 1998 motion, as the applicants have not demonstrated why the expression of such limitations are necessary or reasonable.

Fuel Adjustment Clause Cases

Big Rivers has requested that, concurrent with our decision in this case, all pending fuel adjustment clause ("FAC") cases be dismissed. Motions to dismiss are currently pending in each of those FAC cases. While the FAC cases have not been consolidated with the instant case, the Commission recognizes their importance to the closing of Big Rivers' lease transaction. Therefore, Orders will be issued in the near future holding in abeyance those FAC cases that have been remanded to the Commission and that are not directly affected by the Franklin Circuit Court Order of June 29, 1998 in Civil Action No. 94-CI-01184. Those cases will be closed once Franklin Circuit Court recalls and vacates its Judgment of October 20, 1995 in that action. As to those cases that are directly affected by the Franklin Circuit Court Order of June 29, 1998, we find that the motions to dismiss are moot and Orders to that effect will be issued by the Commission in the near future. As to all remaining FAC cases, the Commission intends to issue Orders in the near future closing those cases without the need for further action by Big Rivers.

SUMMARY AND CONCLUSION

As announced in the April 30, 1998 Order in Case No. 97-204, the purpose of this proceeding was to review the final drafts of all jurisdictional documents to determine whether any material changes had been made to the lease transaction. As discussed in this Order, material changes have been made in the areas of smelter transmission service and Big Rivers' funding obligations to the annual capital budgets.

While we have denied the proposed methodology for the recovery of unforeseen increases in transmission costs due to the Smelters' load, we believe that the approved methodology represents a fair and reasonable solution. While we have accepted the modifications to the annual capital budgets, these changes will be costly to Big Rivers over the next 25 years. Consequently, Big Rivers' long-term financial survival is not a certainty but, rather, is a goal that will have to be achieved by management. Critical to meeting this goal will be the successful marketing of power off-system. A greater degree of Commission monitoring will also be necessary and, thus, we have established additional financial reporting requirements for Big Rivers. The Commission remains optimistic that with continued hard work and dedication by Big Rivers, its financial viability will be assured and it will prosper hand-in-hand with the economy of Western Kentucky.

IT IS THEREFORE ORDERED that:

1. Based on the final drafts of all documents filed in this proceeding, Big Rivers' proposed lease transaction with the LG&E Parties is approved, subject to the modifications contained in this Order.

2. The proposed methodology for the recovery of unforeseen changes in transmission costs due to the Smelters' load is denied.

3. A 50/50 sharing methodology for the recovery of unforeseen changes in transmission costs due to the Smelters' load, as discussed in this Order, is approved.

4. The proposed revision to Schedule 1 of the Green River Wholesale Power Contract with Big Rivers and the proposed new agreement between Green River and Commonwealth are denied.

5. Ordering Paragraph No. 21 of the April 30, 1998 Order in Case No. 97-204 is modified to the extent that the PSC2-38R financial model, lines 285 through 333, shall replace the reference to the SUP-11 financial model, lines 363 through 411. In addition, Big Rivers shall annually file an updated version of its financial model with its annual report to the Commission, covering the period beginning with the current annual report year and ending with the last year of the lease transaction. All changes in assumptions and variable from one year to the next shall be explained in detail.

6. All evidences of indebtedness required to be issued by Big Rivers in conjunction with the transaction documents are approved, including the LEM Promissory Note and the Standby Agreements. The CFC Credit Agreement is exempt from Commission approval.

7. The Smelter Tier 3 Service Contracts are modified to provide the Commission with 30 days notice of effectiveness, in accordance with KRS 278.180(1).

8. The 1998 Amendments to the Station Two Contracts are approved.

9. The Smelters' objection to the form of the Green River and Henderson Union Smelter Tariffs is overruled.

10. Big Rivers' OATT filed in this proceeding is hereby approved and the OATT shall be subject to the jurisdiction of this Commission to the extent that FERC has not asserted jurisdiction and preempted this Commission.

11. Within 30 days of the date of this Order, Big Rivers shall file its tariffs, reflecting all revisions and modifications as described in this Order.

12. Ordering Paragraph Nos. 13, 15, 16, 18, 20, and 22 of the April 30, 1998 Order in Case No. 97-204 shall remain in full force and effect as if separately ordered herein.

Nothing contained herein shall be construed as a finding of value for any purpose or as a warranty on the part of the Commonwealth of Kentucky, or any agency thereof, as to the securities authorized herein.

Done at Frankfort, Kentucky, this 14th day of July, 1998.

By the Commission

ATTEST:

Executive Director

Exhibit 53

Affidavit of C. William Blackburn submitted on September 25, 2008, in Case No. 2007-00455 describing the buyout of Phillip Morris Capital Corporation leveraged lease interest

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

THE APPLICATIONS OF BIG RIVERS ELECTRIC CORPORATION FOR: (I) APPROVAL OF WHOLESALE TARIFF ADDITIONS FOR BIG RIVERS ELECTRIC CORPORATION, (II) APPROVAL OF TRANSACTIONS, (III) APPROVAL TO ISSUE EVIDENCES OF INDEBTEDNESS, AND (IV) APPROVAL OF AMENDMENTS TO CONTRACTS; AND OF E.ON U.S., LLC, WESTERN KENTUCKY ENERGY CORP. AND LG&E ENERGY MARKETING INC. FOR APPROVAL OF TRANSACTIONS	)	CASE NO: 2007-00455

AFFIDAVIT OF
C. WILLIAM BLACKBURN

Commonwealth of Kentucky)
County of Henderson)

Comes the Affiant, C. William Blackburn, and after first being duly sworn, affirms that the answers given to the following questions are true and correct to best of his knowledge and belief.

I. OVERVIEW

Q. Please state your name and position.

A. My name is C. William Blackburn. I am employed by Big Rivers Electric Corporation ("Big Rivers") as its Vice President Financial Services, Chief Financial Officer ("CFO") and Interim Vice President Power Supply.

Q. Are you the same C. William Blackburn who earlier provided testimony in these proceedings?

A. I am.

Q. Why is Big Rivers now presenting this Affidavit?

A. Big Rivers is presenting this Affidavit in order to keep the Commission fully apprised with the terms of a negotiated financial resolution of complications arising under its 2000 leveraged lease transactions of undivided interests in Plants Green and Wilson with Bluegrass Leasing Corporation, a subsidiary of Philip Morris Capital Corporation ("PMCC") (the "PMCC Lease Transaction"). These complications were precipitated by a downgrade in the claims-paying ability of Ambac Assurance Corporation ("Ambac") by Moody's Investors Services ("Moody's") on June 19, 2008, which downgrade exposed Big Rivers to adverse consequences under the contractual terms of the leveraged lease transactions with PMCC.

After several months of focused efforts, sharpened by the recent unrest in financial markets, Big Rivers has resolved the issues relating to Ambac's financial downgrade by agreeing to an immediate termination of its leveraged lease transactions with PMCC under a negotiated buyout structure featuring financial contributions from Big Rivers and PMCC (the "PMCC Buyout").

Q. How is this Affidavit structured?

A. I begin with an overview of the existing PMCC Leveraged Leases in order to explain why the Ambac credit downgrade precipitated the need for Big Rivers to act to buy them out.

I then explain various measures Big Rivers considered prior to determining to enter into the PMCC Buyout on the terms explained in this Affidavit. As this section demonstrates, Big Rivers' decision to enter into the PMCC Buyout on the expedited timeframe explained herein was the most prudent option available to Big Rivers and came only after consideration of a number of alternatives.

I conclude with a discussion of the terms of the PMCC Buyout and the roles played by the various parties financially in the buyout. I also briefly explain the relationship between the PMCC Buyout and Big Rivers' proposed Unwind Transaction, approval for which has been sought in the above captioned case. Big Rivers is in the process of supplementing its application in this proceeding and will be making that filing shortly.

Q. Is Big Rivers filing this Affidavit and the documents implementing the PMCC Buyout in order to obtain Commission approval of those documents?

A. No. As explained in the attached September 25, 2008 letter from counsel for Big Rivers to the Commission, the PMCC Buyout is non-jurisdictional. In this respect the PMCC Buyout is the same as the buyout of the leveraged lease transactions with a subsidiary of Bank of America Leasing Corporation (successor by merger to Fleet Bank, herein "BoA")("BoA Buyout"), which did not require Commission approval. Big Rivers is providing this Affidavit and these documents to the Commission for informational purposes.

Q. Are the facts in the September 25, 2008 letter from Big Rivers' counsel to the Commission true and correct to the best of your knowledge and belief?

A. Yes. I have provided the factual basis for the statements in that letter and have reviewed that letter to make sure that it is accurate.

II. <u>THE PMCC LEVERAGED LEASES AND AMBAC'S CREDIT DOWNGRADE</u>

Q. Would you please provide an overview of Big Rivers' 2000 Leveraged Leases?

A. Certainly. As the Commission is aware, in 2000 Big Rivers entered into five leveraged lease transactions, two of which concerned an undivided 57.2% interest in D.B. Wilson Unit No. 1 involving BoA (the "BoA Lease Transaction") and three others of which concerned 100% undivided interests in Plants Robert D. Green Units 1 and 2 and a 42.8% interest in D. B. Wilson Unit No. 1 involving Bluegrass Leasing, a subsidiary of PMCC. Generally speaking, these leases provided the investors/lessors (BoA and PMCC) with certain advantages of ownership in return for an upfront payment to Big Rivers, and Big

Rivers then was required to lease back the units over a specified term designed to compensate the investors for their initial capital outlay. The Lease Agreements obligated Big Rivers to provide credit enhancements for the benefit of the investors/lessors for Big Rivers' obligations under the Lease. In the event the Lease Transactions were to end prematurely, the negotiated terms of the agreements provided for certain termination value payments to be made by Big Rivers as liquidated damages to reflect the expected financial benefits yet to be achieved by BoA and PMCC as investors.

Q. How does Ambac figure into these arrangements?

A. Ambac's role in the PMCC Leveraged Leases was to serve as an insurer of Big Rivers' obligations to PMCC. As I noted above, Big Rivers was required to maintain throughout the term of the PMCC Leveraged Leases certain minimum collateral requirements to secure its financial obligations to the lessor (largely relating to certain lease termination payments established as liquidated damages sufficient to discharge the debt in the lease transaction, to pay the unrecovered portion of the investor's cash investment in the leased assets, and to make the investor whole for any tax detriment to the investor resulting from an early termination). These minimum collateral requirements, which are set forth in Section 7.5 of the Participation Agreement between Big Rivers and PMCC, were to be provided in the form of a Qualifying Swap, a Qualifying Facility Lease Surety Bond, or a Qualifying Letter of Credit (all terms as defined under the terms of the Participation Agreement). In 2000, Big Rivers determined to meet this requirement by entering into a Qualifying Swap with a subsidiary of Ambac, Ambac Credit Products, LLC ("ACP"). Big Rivers paid Ambac a financial premium to provide this guaranty.

Q. Does the agreement with Ambac still qualify as a Qualifying Swap under the terms of the agreements negotiated with PMCC?

A. No, it does not. On June 19, 2008, Moody's rating service downgraded the claims-paying ability of Ambac (and thus ACP) to "Aa3" thereby rendering Big Rivers' existing credit default swap provided by Ambac as non-qualifying under the terms of the Participation Agreement (which required a minimum Aa2 rating). Big Rivers was served notice under the PMCC lease that as a consequence of the Ambac downgrade, Big Rivers no longer was able to rely on the Ambac arrangement as a Qualifying Swap to meet this contractual collateral requirement.

Q. What do the PMCC Lease Transaction documents require in the event of a loss of the Ambac Qualifying Swap?

A. Section 7.5 of the Participation Agreement requires Big Rivers to replace a Qualifying Swap which has become non-qualifying within 60 days of Big Rivers' actual notice of such event or the date of receiving notice from the Owner Participant. Section 16(h) of the Facility Lease provides that it shall be an Event of Default thereunder if Big Rivers fails to observe or perform an obligation in Section 7.5 of the Participation Agreement. No additional notice or cure period is required for such nonperformance to ripen into an Event of Default after the 60 day replacement period specified in Section 7.5 of the Participation Agreement.

Q. What remedies does the Participation Agreement provide to PMCC in the event of an uncured event of default?

A. Under the provisions of the Leasehold Mortgage and Security Agreement of the PMCC Lease Transaction, PMCC, as the Owner Trust, has generally assigned most of its rights under the Facility Lease to AME Investments, LLC, as Agent on behalf of the Lenders, but has retained the right to declare the Facilities Lease in default and make the demand for payment of the Equity Portion of Termination Value pursuant to Section 17.1(g) of the Facility Lease. Thus, a failure by Big Rivers to perform its covenant to maintain "Qualifying" credit enhancement pursuant to Section 7.5 of the Participation Agreement or a failure to satisfy Basic Rent obligations can lead to either AME Investments, as Agent for the Lenders, or PMCC, as the Owner Trust, exercising remedies under the Facility Lease.

If an Event of Default under the Facility Lease occurs on grounds of failure to perform the obligation required by Section 7.5 of the Participation Agreement or a failure to make the necessary payments, PMCC would have the option to (i) settle the Qualifying Swap with ACP; (ii) exercise remedies under the Facility Lease; or (iii) exercise the Special Equity Remedy provided in Section 11A of the Participation Agreement. Settlement of the Qualifying Swap by the Owner Participant could result in the election by ACP to settle the Big Rivers Swap with Big Rivers. Were PMCC comfortable with ACP's current ability to fulfill its obligations under the Qualifying Swap, presumably PMCC would pursue this remedy.

Q. What would be the practical effect on Big Rivers of PMCC exercising one of these remedies?

A. Depending upon the remedy exercised, Big Rivers would either owe a Termination Value payment or the Equity Portion of Termination Value payment (either to PMCC directly or to ACP were PMCC to elect to settle the swap with it). At present, the current aggregate Equity Portion of Termination Value under the three Facility Leases is approximately $222 million, meaning that Big Rivers would owe PMCC this amount in the event of a default under the PMCC Lease Transaction.

Q. Does the structure of the 2000 PMCC Lease Transaction provide for any offsets against a Termination Value Payment that would be owed?

A. Yes. The PMCC Lease Transactions provide for Big Rivers to have the proceeds of the Payment Agreement, the Funding Agreement and the securities subject to the Government Securities Pledge Agreement to apply against such Termination Value Payment obligation. As structured, the proceeds of the Payment Agreement should be sufficient to discharge Big Rivers' obligation to pay a portion of Termination Value in an amount equal to the outstanding principal balance of the Series A Loan. Under existing market conditions, the proceeds of the securities subject to the Government Securities Pledge Agreement should be more than sufficient to discharge Big Rivers' obligations to pay a portion of Termination Value in an amount equal to the outstanding balance of the Series B Loan. And in a default, the Funding Agreement would be redeemed by AIG Matched Funding Corp., a subsidiary of American International Group, Inc. ("AIG"), in an amount equal to the Market Termination Amount. The three AIG Funding Agreements serve to economically defease the equity portion of the rent under the PMCC Leases and the purchase option price under the fixed price purchase option provided in the PMCC Leases.

Q. Are the amounts of these three offsetting AIG Funding Agreements fixed?

A. No. The amount received would be subject to exact quantification only at the time of redemption. The redemption value under the AIG Funding Agreements is tied to general market conditions such as the London Inter Bank Overnight Rate ("LIBOR"). Changes to LIBOR have a resulting effect on the redemption value. The amount Big Rivers could expect to receive from a redemption has varied significantly over the last three months depending upon the condition of the financial markets. Although at certain points these proceeds from the offsetting agreements was estimated to be in the neighborhood of $68 million, more recent market conditions have indicated a value in the neighborhood of $85 million to $92 million.

Q. How would you estimate Big Rivers' exposure to PMCC were it to declare an event of default based on the Ambac credit downgrade in the absence of some negotiated resolution?

A. Absent a negotiated resolution, PMCC, commencing 60 days after June 19, 2008 (the date of the Ambac credit downgrade), can determine to declare an event of default that ultimately would result in Big Rivers generally being required to pay PMCC the difference between $222 million (the Equity Portion of Termination Value payment) and the estimated net proceeds of the three AIG Funding Agreements, also called the AIG guaranteed investment contract ("GIC"). The difference would be an obligation of Big Rivers not covered by the proceeds of any economic defeasance instruments.

Q. Would Big Rivers' exposure increase were Ambac to enter bankruptcy such that it could not satisfy its obligations?

A. Yes, significantly. The termination value payment described above assumes a situation with a still viable Ambac, albeit one with a downgrade in its financial rating such that it can no longer adequately collateralize Big Rivers' obligations to PMCC. This scenario assumes that Ambac would still be able to satisfy obligations regarding the "loop debt" involved in the PMCC Lease Transactions. Were Ambac to enter bankruptcy or otherwise be unable to satisfy its obligations regarding this "loop debt", Big Rivers would be exposed to significant "loop debt" obligations which could exceed an additional $583 million above the amount owed under the described termination value payments. I explain the specifics of this risk at greater length in my testimony below.

Q. Why did the loss of the Ambac arrangement as a Qualifying Swap cause Big Rivers to delay its ongoing effort in this case to obtain approval to unwind its long-term lease transaction with E.ON U.S., LLC ("E.ON") (the "Unwind Transaction")?

A. The Ambac ratings downgrade came at a time immediately before the scheduled hearing date in this proceeding. At the time, Big Rivers and E.ON were hopeful that they would be able to obtain Commission approval for the Unwind Transaction based on the record they had presented to the Commission. But Big Rivers' support for obtaining that approval rested in part on the modeling of Big Rivers' financial situation after closing of the Unwind Transaction.

Given the above-described PMCC contractual requirements, and the potential for an event of default absent a satisfactory resolution, Big Rivers knew immediately after learning of the Ambac downgrade on June 19, 2008 that a financial resolution of the Ambac issues would be required before the Unwind Transaction could be closed. Big Rivers was aware that resolution of the loss of the Ambac Qualifying Swap almost certainly would increase Big Rivers' costs in one respect or another and that any replacement arrangement likely would have a measurable financial effect on Big Rivers. Accordingly, on June 26, 2008, Big Rivers and E.ON in a conference call notified the Commission and other parties that the pending Application and hearing in this proceeding would be affected by the Ambac credit downgrade and that Big Rivers and E.ON had no choice but to request a postponement of the July 1, 2008 hearing date in Case No. 2007-00455 to permit Big Rivers to negotiate a resolution of this issue.

III. BIG RIVERS' APPROACH TO RESOLVING THE AMBAC CREDIT DOWNGRADE ISSUES

Q. How did Big Rivers ultimately determine to resolve the issues created by the loss of the Ambac Qualifying Swap?

A. Although Big Rivers considered a number of financial resolutions to resolve the issues created by the loss of the Ambac Qualifying Swap, Big Rivers ultimately determined that the cleanest, least-risk and least-cost solution would be to terminate the PMCC Lease Transaction through a negotiated buyout with PMCC to take place no later than September 30, 2008. As I mentioned, Big Rivers already had terminated two similar leases of undivided interests in Plant Wilson with trusts owned by a subsidiary of BoA on June 30, 2008, and this structure offered a tried and true alternative while offering Big Rivers a means to capitalize on currently high redemption values of the AIG Funding Agreements. Moreover, this PMCC Buyout approach maintained satisfactory Big Rivers economics even were the Unwind Transaction not to close, and Big Rivers required a resolution in either event.

Accordingly, Big Rivers, upon consultation with its board, the Rural Utilities Service ("RUS"), and E.ON determined that a similar buyout of the PMCC Leveraged Leases offered the best means of resolving the potential defaults under the Leverage Leases presented by the loss of the Ambac Qualifying Swap while at the same time minimizing Big Rivers' continued exposure to an increasingly unstable financial market. Below, I discuss the specifics by which the existing PMCC Leveraged Lease structure will be terminated. But first I discuss the course of negotiations and events that led Big Rivers to select a buyout as the preferred solution.

Q. You state that under the terms of the PMCC Leveraged Lease Participation Agreement Big Rivers had 60 days to develop a credit enhancement proposal or a replacement credit proposal. Did Big Rivers implement a final credit enhancement proposal within the 60 days permitted by the Participation Agreement?

A. No, it did not. Sixty days after June 19, 2008 was August 18, 2008, and Big Rivers was not able to finalize and implement a new credit enhancement or credit replacement arrangement by that date. However, Big Rivers worked with PMCC, E.ON, the RUS and other parties to develop a mutually acceptable financial resolution to the dilemma presented by the Ambac rating downgrade and an increasingly apparent AIG instability. Although not completed by August 18, the parties made sufficient progress such that PMCC elected temporarily to forebear exercising any remedies available to it. The parties thus continued to negotiate the plan Big Rivers is now describing to the Commission.

Q. Would PMCC indefinitely have continued to waive this noncompliance had Big Rivers been unable to negotiate this resolution?

A. No. Big Rivers' noncompliance was only temporarily waived by the equity parties and the lenders in the PMCC Lease Transaction. Although Big Rivers' decision to terminate the PMCC Lease Transaction by September 30, 2008 was made in part to capitalize on current market conditions which have produced higher values for the AIG Funding Agreements while eliminating continued exposure to Ambac and AIG credit risk, an additional significant consideration was Big Rivers' wish to satisfy PMCC's need for a resolution of this issue prior to the end of the third financial quarter. Absent a PMCC Buyout by the end of the third quarter, Big Rivers had no assurance that these waivers would be extended indefinitely, thus potentially subjecting Big Rivers to the risk of a declaration of an event of default by PMCC or its agent.

Q. What other options did Big Rivers consider to resolve the financial difficulties posed by the Ambac ratings downgrade?

A. Initially, Big Rivers and its financial advisors saw three potential avenues for Big Rivers to deal with the difficulty posed by the loss of the Ambac Qualifying Swap: (1) provide an alternative credit enhancement meeting the requirements of the operative documents of the PMCC Lease Transaction; (2) develop new collateralization of the equity amounts potentially owed in the event of a default under the PMCC Lease Transaction; and (3) terminate the PMCC Lease Transaction in a buyout transaction.

Q. What did Big Rivers conclude regarding the potential for providing an alternative credit enhancement?

A. Sections 7.5, 7.6 and 7.7 of the Participation Agreement set forth the requirements for a qualifying credit enhancement. In order to qualify, the credit enhancement must constitute: (i) a credit default swap in a form similar to the swaps insured by Ambac, and be made or insured by an entity the long-term senior unsecured debt obligations or financial strength rating of which is at least "AA" by Standard & Poor's and "Aa2" by Moody's; (ii) a surety bond issued by an insurer, the long-term senior unsecured debt obligations or financial strength ratings of which is at least "AA" by S&P and "Aa2" by Moody's; or (iii) a letter of credit issued by a bank, the long-term senior unsecured debt obligations of which are rated at least "AA" by S&P and "Aa2" by Moody's. Thus, although the types of enhancement can come from a variety of financial institutions, the ratings are roughly similar and exclusive. Given Big Rivers' existing restrictions on obtaining new financings unencumbered or subordinated to the numerous existing obligations, Big Rivers determined that it would be extremely difficult, if not impossible, to find a credit enhancer that would accept Big Rivers without an investment grade credit rating. This conclusion remained the same even if the new credit enhancer essentially could be placed in the same security package as Ambac, including being secured under Big Rivers' first lien instrument.

Q. Were there any other obstacles to the use of alternative credit enhancers?

A. Yes. Providing alternative credit enhancement in the Lease Transaction is complicated by the fact that the existing credit enhancement, the Qualifying Swaps insured by Ambac, also provide the means to avoid the imposition of the provisions of Section 502(b)(6) of the United States Bankruptcy Code on the claims of the equity investor and lenders in the Lease Transactions. The Qualifying Swaps provide for settlement in the amount of the total Termination Value under the leases. The Big Rivers Swaps under which Ambac could seek payment from Big Rivers for an identical amount following settlement of the Qualifying Swaps are secured by a security interest in the AIG guaranteed Funding Agreement, the FHLMC securities used in the economic defeasance of the Series B debt and the Ambac-issued Payment Agreement. Another credit enhancer stepping into the shoes of Ambac under the Qualifying Swaps likely would be reluctant to accept this security package, the single largest component of which is the Ambac-insured Payment Agreement.

Replacement of Ambac as credit enhancer under the Qualifying Swaps might necessitate replacement of the Series A "loop debt" arrangements as well, which would be a further complication. This replacement also likely would prove expensive, as few entities, if any, are able to provide such a vehicle with "zero weighting" – that is, not having to reserve against its exposure under the loan in the "loop debt" structure since it is secured by the obligation of its affiliate. If zero weighting for the remaining portion of the Series A "loop debt" were not achieved, the Payment Agreement would reflect an implicit yield lower than the coupon on the non-lessee-provided portion of the Series A "loop debt", which would make this replacement at best expensive and, at worst, unavailable.

Q. Did Big Rivers nevertheless explore third-party credit enhancement suppliers and their willingness to provide alternative credit enhancement?

A. Yes. Despite the weakness of this approach, Big Rivers in late June and early July explored the possibility of providing alternative credit enhancement with a number of insurers and banks. Even then, the tightness in the credit markets made credit enhancement of this sort extremely expensive, even for those unlike Big Rivers with good credit. This problem now is further exacerbated. For this reason, Big Rivers ultimately rejected the possibility of introducing additional credit enhancement into the PMCC Lease Transactions.

Q. What did Big Rivers conclude regarding its second option – developing an alternate collateralization under the PMCC Leveraged Leases?

A. Initially, Big Rivers regarded an alternate cash collateralization method as offering an acceptable solution to resolving the loss of the Ambac Qualifying Swap. Under an alternate cash collateralization method, Big Rivers considered reserving a portion of the proceeds from the Unwind Transaction in an amount necessary to cover the so-called "equity strip" in the PMCC Lease Transaction. The "equity strip" that would be collateralized under this approach would be an amount equal to (i) the Equity Portion of the Termination Value set forth in the Participation Agreement (calculated as the gross Termination Value minus the outstanding principal balance of Series A and Series B debt) minus (ii) the accreted value of the AIG Funding Agreements. The amount Big Rivers would need to collateralize would decline over time during the remaining term of the Lease Transactions as the accreted value of the AIG Funding Agreements increases.

In order to fund this cash collateralization approach, Big Rivers would have needed to reduce its initial prepayment of RUS debt upon closing of the Unwind Transaction significantly by approximately $150 million at the time this option was under consideration (the AIG GIC redemption price in July and early August was estimated at approximately $68 million). However, this approach would allow Big Rivers to have the use of certain funds acting as the collateral because the accreted value of the AIG Funding Agreements would increase and because the Equity Portion of the Termination Value would be reduced each year to reflect another year of operation under the Agreement (and thereby reducing the amount in the "equity strip" required to be collateralized). These amounts could then have been used to prepay additional amounts of RUS debt. Big Rivers saw this ever-declining nature of the obligation to be collateralized as the principal recommendation for this approach. In the meantime, amounts held in reserve for collateral would have been held in an account maintained with U.S. Bank, National Association, as securities intermediary and collateral agent.

Q. Did Big Rivers pursue the cash collateralization alternative with PMCC, RUS, and other parties?

A. Yes. Big Rivers initially pursued this cash collateralization alternative as its preferred option. Big Rivers first met with representatives of the RUS in Washington, D.C. on July 9, 2008 to present the details of the alternate option as capable of meeting the PMCC Leveraged Lease's collateralization requirements. The RUS requested Big Rivers to present a summary of the Ambac issues arising under the PMCC Leveraged Lease documents. The RUS also requested that Big Rivers describe and summarize the alternate cash collateralization proposal Big Rivers was recommending to the RUS. Big Rivers provided RUS with an executive summary of the cash collateralization approach on July 14, 2008. RUS subsequently considered these materials and followed up with a series of written questions, answers to which Big Rivers provided on August 8, 2008.

Q. How did the RUS respond to the alternate cash collateral approach?

A. Despite Big Rivers' efforts to promote the cash collateralization alternative, in late August RUS informed Big Rivers that it was not interested in pursuing the cash collateralization alternative.

Q. Why was the RUS reluctant to agree to the cash collateralization alternative?

A. The RUS expressed two concerns. First, the RUS did not support a reduction of the necessary magnitude in the amount of RUS debt to be prepaid at closing. The RUS was uncomfortable agreeing to a proposal that would result in an approximate $150 million decrease in the debt that would be prepaid to it. The RUS opined that the only way it could even consider a reduction of the debt to be paid at closing of this magnitude would be if Big Rivers were to agree to eliminate the new Indenture and to begin paying interest on the ARVP Note. Big Rivers could not agree to either of these conditions. Second, the RUS was concerned that the alternate cash collateral approach failed to eliminate the risk of further downgrades in Ambac's financial condition, particularly given the potential exposure on the "loop debt" were Ambac to enter bankruptcy or otherwise be unable to satisfy its obligations relating to that debt. By retaining PMCC and its collateralization requirements, the RUS was uncertain that its agreement to reduce the debt prepayment would buy it any additional protection, even though it would resolve the concerns regarding replacement of the Ambac collateralization.

Q. Are there any other considerations disfavoring the collateralization approach?

A. Yes. Subsequent to the RUS' expression of disinterest in the collateralization approach, additional information regarding the precarious financial condition of AIG was disclosed. Because the collateralization approach continued to include a major role for AIG and its redemption of the AIG Funding Agreements, the decision by

RUS and subsequently Big Rivers no longer to pursue the collateralization approach was a good one in hindsight.

Q. How then did Big Rivers come to adopt the PMCC Buyout approach as its preferred resolution?

A. Faced with the RUS' rejection of the cash collateral option, Big Rivers, E.ON, and other parties re-examined the viability of a lease termination approach. On its own, Big Rivers had already determined that a termination of the PMCC Leveraged Leases offered a number of significant benefits. Termination of the PMCC Leveraged Leases would permit Big Rivers to close the Unwind Transaction, would remove Big Rivers from further exposure to the credit volatility of Ambac and AIG, would eliminate continued exposure to indemnities to participants in the Lease Transaction, would eliminate the need for consents or waivers in the future from participants in the Lease Transactions, and would serve to greatly simplify the documentation of the Unwind Transaction. Big Rivers already had entered into a buyout of the BoA Lease Transaction, and Big Rivers recognized the tremendous advantages of removing PMCC from its future financial planning.

Despite these advantages, however, Big Rivers initially had determined that a termination of the PMCC Leveraged Lease would require a substantial cash payment to PMCC of an amount roughly equivalent to $145 million, the Equity Portion of the Termination Value (assuming an AIG Funding Agreement redemption (*i.e.*, GIC) of approximately $68 million). Because this amount, like the alternative cash collateralization option, would require a reduction in the RUS debt prepayment, Big Rivers thought the cash collateralization option's freeing up of collateral as time passed to be a preferable alternative.

Q. What circumstances caused Big Rivers to favor the PMCC Buyout solution?

A. One incentive to favor the PMCC Buyout was E.ON's agreement to fund one-half of the residual lease termination payment to PMCC as an incentive to permit the Unwind Transaction to close. Faced with a much smaller ultimate contribution of its own funds in the event of an Unwind, Big Rivers determined that it could enter into a lease termination and still agree to prepay $125 million to the RUS upon closing of the Unwind Transaction. Second, irrespective of E.ON's participation in the buyout, changes to LIBOR caused by the instability in credit markets caused the value of the AIG Funding

Agreements to increase, thereby lowering the Equity Portion of the Termination Value Payment to PMCC, further increasing the attractiveness of this alternative. Third, a PMCC Buyout would simplify Big Rivers' finances and eliminate the uncertainty concerning the possible failure of AIG or Ambac. The instability in the world credit markets provides a very strong incentive to complete a PMCC Buyout at this time.

Q. How did the RUS view a buyout of the PMCC Lease Transaction?

A. On August 29, 2008, Big Rivers approached the RUS regarding its interest in a lease termination structured in this fashion, and the RUS agreed to review this approach, subject to receipt of further documentation. Big Rivers provided this documentation to the RUS on September 3, 2008. RUS then agreed in principle to this approach on September 12, 2008, thereby permitting Big Rivers to prepare and submit this alternative to the Commission for its approval, pending final RUS approval and execution of buyout documentation.

Q. Did Big Rivers initially intend to terminate the PMCC Lease Transaction as early as September 30, 2008?

A. No. Initially, Big Rivers' discussions with E.ON and PMCC were based on a PMCC Buyout that would take place upon closing of the Unwind Transaction. However, the increased value in the AIG Funding Agreements due to market instability and the disclosed financial instability of AIG led Big Rivers to conclude that an earlier termination by September 30, 2008 offered the greatest opportunity to maximize the value of the AIG Funding Agreements while eliminating continued exposure to the credit of AIG and Ambac. Accordingly, Big Rivers and PMCC have agreed to the terms of the PMCC Buyout now being presented to the Commission on an expedited basis in order to lock in all of these advantages now.

Q. You state that a principal reason Big Rivers is arranging a buyout of PMCC at this time is to eliminate the uncertainty of the failure of AIG or Ambac. Please explain.

A. The future of AIG is unknown and unknowable given the recent turmoil in world credit markets, AIG's financial fragility and the United States government's attempt to bolster AIG's economic condition. The risk of failure is real and the consequences are enormous. In the unlikely event that AIG becomes bankrupt, Big

Rivers would lose the AIG Funding Agreements, which were valued at approximately $88.3 million as of September 25, 2008. Big Rivers would still face a $222 million obligation to PMCC, but would not have the $88.3 million AIG Funding Agreements to offset that obligation.

Q. What are the implications of a potential bankruptcy of Ambac?

A. An Ambac bankruptcy would be potentially catastrophic for Big Rivers because of Big Rivers' resulting exposure to the "loop debt" in the Leveraged Leases.

Q. Please explain.

A. Big Rivers' Series A debt obligation under the Leveraged Leases is held in a company in which Ambac is a minority subsidiary. This Series A debt – or "loop debt" – is offset by a guaranty by Ambac itself to pay the Series A debt obligation. The amount of the Series A debt is $583 million as of July 2008.

If Ambac were to go bankrupt, the amount of its guaranty of the Series A debt would be reset by a bankruptcy court. If, for example, the Ambac guaranty was ultimately worth ten cents on the dollar, Big

Rivers' exposure to the "loop debt" would be over half a billion dollars ($583 million - $58.3 million = $524.7 million).

Q. Would this potential $500,000,000.00-plus obligation be an additional obligation of Big Rivers on top of its other debt?

A. Yes. Big Rivers' $500 million "loop debt" obligation would be in addition to Big Rivers' other obligations, including (as of July 2008) $778.7 million to the Rural Utilities Service, $101.5 million for the RUS ARVP Note, $222 million to PMCC, $15.9 million to LG&E, and $142.1 million for Big Rivers' Pollution Control Bonds. Clearly, eliminating the risks associated with a failure of either AIG or Ambac by buying out PMCC now is highly desirable for Big Rivers.

IV. THE PMCC BUYOUT SOLUTION

Q. When does Big Rivers propose to close the PMCC Lease Transaction termination?

A. Although Big Rivers, E.ON and PMCC originally contemplated a buyout on the closing date of the Unwind Transaction, Big Rivers now intends to close the PMCC Lease Transaction termination on or before the close of business on September 30, 2008 in order to lock in the favorable AIG Funding Agreement market value, to limit continued exposure to the credit of AIG and Ambac, and to end reliance on PMCC's waiver of exercise of its remedies due to default. Big Rivers intends to close the PMCC Buyout regardless of whether the Unwind Transaction occurs.

Q. Is there anything in the PMCC Leveraged Leases which prohibits a termination of the leases as contemplated by Big Rivers?

A. No, not to my knowledge. As I stated earlier, the template for the PMCC Buyout is the same as for the BoA Buyout that Big Rivers successfully closed in June 2008.

Q. How much has Big Rivers agreed to pay PMCC in connection with the PMCC Buyout?

A. Big Rivers agreed to pay PMCC a negotiated termination payment of $214 million less the actual value produced by the sale and redemption of the AIG Funding Agreements and government securities. The termination payment amount is based on the liquidated damages provision contractually included in the PMCC Leveraged Lease documentation. While the PMCC Leveraged Leases specified a starting Termination Value of $222 million at present for the three leases concerned, Big Rivers and PMCC negotiated an $8 million reduction in the stated termination value. This amount represents PMCC's principal contribution to the economic resolution. However, as discussed below, PMCC also has agreed to contribute to Big Rivers a short-term unsecured loan in a maximum amount of $20 million (varying depending on the value of the AIG GIC), to be paid back in full by Big Rivers on the earlier to occur of December 31, 2009 or the date of closing of the Unwind Transaction between Big Rivers and E.ON. This loan is an additional incentive for Big Rivers to agree to an immediate buyout

Q. Does Big Rivers know currently the exact amount that will be owed to PMCC after the AIG Funding Agreements and securities are redeemed or sold?

A. No. The exact amount of the proceeds from the AIG Funding Agreements to be redeemed and the federal agency securities to be sold to reduce the $214 million otherwise payable to PMCC will be known only when Big Rivers locks in the redemption price with AIG. This

AIG price will vary on a daily basis with LIBOR, and AIG has stated that it will permit Big Rivers to lock in a price that will be good for 48 hours. Although the tentative redemption price for the Funding Agreements was estimated on September 25, 2008 to be approximately $88.3 million, the price will be subject to daily fluctuation until Big Rivers actually locks in a price with AIG.

Q. How much of the resulting PMCC termination payment will Big Rivers be responsible for paying after redemption of the AIG Funding Agreement and sale of the securities if the Unwind Transaction closes?

A. Under the terms of their negotiated Cost Sharing Agreement, Big Rivers and E.ON agreed to share equally in the net amount required to be paid to PMCC in connection with the termination after the redemption of the AIG Funding Agreements and securities. As part of the agreement between Big Rivers and PMCC based on the underlying PMCC Leveraged Lease documents, the actual proceeds of the redemption of the AIG Funding Agreements and any remaining proceeds realized from the sale of the federal agency securities first will be utilized by Big Rivers to reduce the $214 million owed to PMCC. Big Rivers will be responsible for paying this amount to

PMCC on or before September 30, 2008. In the event of an Unwind Transaction closing, this remaining net amount paid by Big Rivers to PMCC, less any amount from Co-Bank or other parties involved, will be shared equally between Big Rivers and E.ON.

Q. When does the Cost Share Agreement provide for E.ON to make this payment to Big Rivers?

A. The Cost Share Agreement provides for E.ON to pay its one-half share of the net PMCC Buyout cost at closing of the Unwind Transaction. In addition, although the Cost Share Agreement has not been finalized, it currently provides that the 50/50 sharing of the net PMCC Buyout cost between E.ON and Big Rivers will be capped at $55 million for E.ON if the Unwind Transaction closes after December 31, 2008.

Q. Given the fluctuation in the value of the AIG Funding Agreements, how can Big Rivers know that it is able to afford the PMCC Buyout without a closing of the Unwind Transaction and the receipt from E.ON of its one-half share?

A. Before agreeing to a PMCC Buyout on or before September 30, 2008, Big Rivers determined that it would not be willing to enter into a

PMCC Buyout prior to closing of the Unwind Transaction unless its total out of pocket exposure could be limited to $109 million. Big Rivers arrived at this figure as the maximum amount it was willing to pay given its available cash on hand of approximately $129 million. Big Rivers determined that it needed to maintain no less than $20 million of cash on hand after engaging in the PMCC Buyout, pending either (i) a closing of the Unwind Transaction when Big Rivers would receive E.ON's one-half share of the net PMCC termination payment or (ii) a rate surcharge of approximately ten percent above status quo rates which Big Rivers will immediately seek to ensure stable and secure operations going forward.

Q. What mechanism did Big Rivers and PMCC agree upon to maintain a maximum Big Rivers cash outlay of $109 million and a minimum cash on hand of $20 million after closing of the PMCC Buyout?

A. Big Rivers and PMCC negotiated a variable amount, short-term unsecured bridge loan from PMCC to provide Big Rivers with additional financing up to the earlier to occur of December 31, 2009 or the date of closing of the Unwind Transaction. PMCC indicated that while it was willing to explore a short-term unsecured bridge loan at an 8.5% interest rate to get Big Rivers to the closing of the Unwind Transaction or to a point at which Big Rivers could seek an adjustment to its rates, PMCC stated that under no circumstances would it be willing to lend Big Rivers more than $20 million on an unsecured basis. Given this maximum loan amount and Big Rivers' view that it could not spend more than $109 million in cash, Big Rivers and PMCC determined that PMCC would offer a sliding scale short-term loan based off this maximum $109 million payment.

Q. How is the actual amount of the PMCC loan to be determined?

A. Big Rivers and PMCC agreed that the loan amount would pivot on the amount required to make Big Rivers' immediate out of pocket expense $109 million on the PMCC lease termination subject to the $20 million maximum loan. As an example, assuming the $88.3 million AIG GIC value on September 25, 2008, Big Rivers' net termination payment to PMCC would be $125.7 million ($214 million less $88.3 million). Subtracting $109 million from that figure yields a loan amount of $16.7 million. Given the maximum loan amount of $20 million, the maximum net PMCC lease termination payment Big Rivers could afford while adhering to the $109 million maximum outlay would be

$129 million. Thus, the PMCC Buyout requires an AIG GIC value of at least $85 million, as $214 million less $85 million is $129 million.

Q. What happens if the redemption value of the AIG Funding Agreements is less than $85 million?

A. Big Rivers will not enter into the PMCC Buyout unless the AIG Funding Agreements yield at least $85 million.

Q. What will Big Rivers' source of funding be for the PMCC termination payment to be made on or before September 30, 2008?

A. On or before September 30, 2008, Big Rivers will use its own funds to pay for the PMCC Buyout. The actual amount paid to PMCC will be $109 million, which will be the difference between $214 million and the actual redemption value of the AIG Funding Agreements, less the amount of the loan from PMCC determined as set forth above. Big Rivers later potentially will receive a contribution from E.ON at the closing of the Unwind Transaction, depending upon the terms settled upon with E.ON and upon a successful closing.

Q. What if the Unwind Transaction does not close after Big Rivers has entered into the PMCC Buyout?

A. If the Unwind Transaction does not close, Big Rivers will not receive an E.ON contribution towards the PMCC Buyout. Big Rivers still will be required to pay back the amount of the loan from PMCC by December 31, 2009, and it still will have paid the $109 million to accomplish the PMCC Buyout.

Q. Will Big Rivers be financially viable if it is required to absorb the PMCC Buyout costs without the E.ON contribution?

A. Yes, Big Rivers will remain financially viable – on the modeled assumptions that Big Rivers is permitted to seek a rate surcharge of approximately ten percent. Big Rivers will request the Commission to approve a surcharge if the Unwind Transaction cannot be closed.

Q. Has Big Rivers modeled the financial effects on its status quo rates if the PMCC Buyout occurs but the Unwind Transaction does not?

A. Yes. Attachment 1 to this Affidavit includes the output of Big Rivers Unwind Financial Model that assumes no Unwind Transaction, a PMCC Buyout closing effective September 30, 2008, and an assumed AIG GIC value of $88.3 million. This model indicates that Big Rivers would need an approximate ten percent rate surcharge on top of existing rates if the Unwind Transaction is not closed.

Q. In the event the Unwind Transaction does close as contemplated, would there be a financial effect on Big Rivers' post-closing operations due to the PMCC Buyout?

A. Yes. Big Rivers would need to reduce the amount of debt to be paid to the RUS at closing to account for the payments made in connection with the PMCC Buyout. Any such effect would be presented by Big Rivers as part of a revision to its Application presenting the revised terms of its transaction.

Q. Has Big Rivers performed any modeling of its financial status in the event both the PMCC Buyout and the Unwind Transaction occur?

A. Yes. Attachment 2 to this Affidavit presents a version of Big Rivers' Unwind Financial Model previously used in this case that assumes a successful Unwind Transaction effective December 31, 2008. This model assumes an AIG GIC value of approximately $68 million. As this model demonstrates, Big Rivers would remain financially viable.

Q. If the Unwind Transaction closes on December 31, 2008, what effect will the PMCC Buyout have on Big Rivers' average rates through 2023?

A. Attachment 3 to this Affidavit shows that the effect of the PMCC Buyout after an Unwind closing on Big Rivers' Non-Smelter Member rates will be an increase of approximately $0.55 per MWh. The average increase to Big Rivers' Smelter rates will be approximately $0.45 per MWh. (Both calculations assume a December 31, 2008 PMCC Buyout closing with a $68 million GIC. A September 30, 2008 closing with a $88.3 million GIC will result in smaller increases.)

Q. Will the RUS approve the PMCC Buyout before it closes?

A. Yes. The RUS is well aware of the effect of the Ambac and AIG credit risks and enthusiastically supports the PMCC Buyout.

Q. Did Ambac provide any financial contribution to the PMCC Buyout?

A. Ambac has agreed to waive its fees and legal services payments in connection with actions necessary to implement the PMCC Buyout.

Q. How will the termination of the PMCC Lease Transaction be documented?

A. As between PMCC on the one hand and Big Rivers on the other, the documents for the PMCC Buyout will follow the same financial structure utilized for the June 30, 2008 BoA Buyout. The major operative document is an Omnibus Termination Agreement among the various parties, including the providers of the economic defeasance instruments, in accordance with which: (1) Big Rivers will pay the termination payment to PMCC; (2) the Series A and Series B Loans will be discharged through proceeds of the funding agreements discussed above; (3) the Funding Agreement will be redeemed and the proceeds applied to the termination payment to be paid to PMCC; (4) the Owner Trusts' interests in Plant Green and Plant Wilson will be conveyed to Big Rivers and the Head Leases will immediately terminate; and (5) all operative documents for the lease transaction will terminate and all parties will agree to provide any necessary releases to effect the release of any liens or security interests of the lease parties in Big Rivers' property. Accordingly, once the PMCC Buyout is closed, PMCC will have no further financial interest in Big Rivers or any of its facilities, apart from the unsecured bridge loan.

As between Big Rivers and E.ON, the documentation of an E.ON commitment relating to the PMCC Buyout will be filed with the Commission at such time as Big Rivers files an amendment to its Application in the Unwind Transaction and is expected to be reflected in a separate Cost Sharing Agreement.

Q. You state that the PMCC Buyout is structured similar to the BoA Buyout. If that is the case, why was it necessary for Big Rivers to make a financial contribution to the PMCC Buyout but not to the BoA Buyout?

A. While the two lease terminations are structured similarly, they differ greatly in terms of the sizes of the remaining equity values involved, in the timing of the termination request relative to the Ambac downgrade and the general financial market turmoil, and in the perspectives of the parties concerned. PMCC and BoA clearly had many considerations which they valued differently, and the amounts required to terminate their lease transactions reflect that. BoA, as an initial matter, was receptive to a termination of its lease transaction, and negotiations with it did not commence in the context of a potential event of default under the BoA Lease Transaction. Instead, these negotiations began well before the Ambac credit downgrade and the widespread market turmoil. By contrast, the PMCC Buyout largely was negotiated after the Ambac credit downgrade, and the amount paid by Big Rivers to terminate the PMCC Lease Transaction closely tracks the Termination Value payment set forth in the PMCC Lease Transaction. PMCC was simply unwilling to accept a lesser amount to terminate the lease and had the leverage of potentially declaring an event of default if it did not receive an amount sufficient to meet its expectations.

Q. **Taken as a whole, do you believe that the proposed PMCC Buyout is a prudent resolution of the issues presented by the Ambac credit downgrade?**

A. Absolutely. Big Rivers is currently out of compliance with the requirements of the operative documents of the PMCC Leveraged

Leases obligating it to provide equity credit enhancement of a specified credit quality. But for PMCC's waiver of its right to declare an event of default based on this noncompliance, Big Rivers would face an obligation to pay a sum which is well in excess of the proceeds of the economic defeasance instruments securing its obligations under the PMCC Lease Transaction.

Big Rivers must resolve these PMCC Lease Transaction issues whether or not the Unwind Transaction closes, and this buyout alternative both continues to permit the Unwind Transaction to move forward and reduces the costs to which Big Rivers otherwise would be exposed. Were Big Rivers to wait to terminate these leases it would risk continued exposure to the credit risk of Ambac and AIG, and the AIG GIC redemption value would continue to float, adversely affecting Big Rivers were the value to decline. Entering into the PMCC Buyout now eliminates these risks.

Q. Does Big Rivers have any better option if it does not complete the PMCC Buyout at this time?

A. No, it does not. PMCC has stated that its bridge loan is only available if the PMCC Buyout closes in the third quarter of this year. Moreover, addressing the Ambac downgrade is not a question of if, but a question of when. If Big Rivers ignores the Ambac downgrade and Ambac slips into bankruptcy, Big Rivers itself faces almost certain bankruptcy. Options other than a PMCC Buyout are either impractical, more expensive, or unacceptable to the RUS, as I discussed earlier. Delaying a PMCC Buyout would almost certainly cost more, expose Big Rivers to greater risk of an AIG or Ambac failure, and cause Big Rivers to miss the favorable financing terms and conditions currently available to Big Rivers. The time to close the PMCC Buyout is now.

Q. Mr. Blackburn does this conclude your Affidavit?

A. Yes.

Verification

I, C. William Blackburn, Vice President Financial Services, Chief Financial Officer and Interim Vice President Power Supply for Big Rivers Electric Corporation, hereby state that I have read the foregoing Affidavit and the attached cover letter and that the statements contained therein are true and correct to the best of my knowledge and belief, and I verify, state, and affirm that this Affidavit and the attached cover letter are true and correct to the best of my knowledge and belief, on this the 25th day of September, 2008.

C. William Blackburn

C. William Blackburn
Vice President Financial Services, Chief
Financial Officer and Interim Vice President
Power Supply
Big Rivers Electric Corporation

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

The foregoing verification statement was SUBSCRIBED AND SWORN to before me by C. William Blackburn, as Vice President and Chief Financial Officer of Big Rivers Electric Corporation, on this the 25th day of September, 2008.

Paula Mitchell

Notary Public, Ky., State at Large
My commission expires: 1-12-09

ATTACHMENT 1

Existing Transaction - Summary Financials Assuming PMCC Buyout

		PMCC Lease Buyout @ 12/31/08	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	**Energy Balance (GWh)**																
2																	
3	*Sales*																
4	Members		3,501	3,584	3,674	3,760	3,852	3,939	4,032	4,122	4,217	4,308	4,404	4,498	4,596	4,691	4,786
5	Arbitrage		2,042	1,961	2,924	3,568	3,440	3,356	3,264	3,179	3,084	2,995	2,901	2,812	2,714	2,612	2,517
6	*Losses*		44	44	52	58	57	57	57	57	57	57	57	57	57	57	57
7	Sales + Losses		5,586	5,588	6,650	7,386	7,349	7,352	7,354	7,358	7,358	7,360	7,363	7,368	7,367	7,360	7,361
8	*Purchases*																
9	Base (LEM)		5,254	5,252	6,322	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008	7,008
10	SEPA		305	305	305	267	267	267	267	267	267	267	267	267	267	267	267
11	Market		28	32	24	111	74	77	79	83	83	85	88	93	92	85	86
12	Total		5,586	5,588	6,650	7,386	7,349	7,352	7,354	7,358	7,358	7,360	7,363	7,368	7,367	7,360	7,361
13																	
14	**Energy Rates ($/ Mwh)**																
15																	
16	*Sales*																
17	Members																
18	Base		35.45	35.42	35.39	44.91	44.87	44.84	44.81	49.55	49.52	49.49	49.46	49.44	49.41	49.38	49.36
19	% Change			0%	0%	27%	0%	0%	0%	11%	0%	0%	0%	0%	0%	0%	0%
20	Surcharge		5.14	-	1.36	-	-	-	-	-	-	-	-	-	-	-	-
21	Total		40.59	35.42	36.75	44.91	44.87	44.84	44.81	49.55	49.52	49.49	49.46	49.44	49.41	49.38	49.36
22	Arbitrage		49.42	48.14	47.44	48.38	42.67	39.19	39.57	40.93	41.25	42.61	43.82	44.68	44.80	46.34	47.69
23	*Purchases*																
24	Base (LEM)		20.33	20.63	20.95	20.27	20.59	20.92	21.25	21.59	21.93	22.28	22.63	22.99	23.36	23.72	24.08
25	SEPA		22.44	22.44	22.44	28.33	29.04	29.75	29.75	29.75	29.75	30.50	31.24	31.24	31.24	31.24	32.00
26	Market (Peak)		200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00
27																	

Existing Transaction - Summary Financials Assuming PMCC Buyout

	PMCC Lease Buyout @ 12/31/08	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Cash Flow ($M)																
Beginning Balance	147.2	37.5	30.7	42.0	51.6	58.8	61.7	56.5	50.2	57.8	67.2	75.9	85.2	97.9	134.5	147.9
Receipts																
Members		142.1	126.9	135.0	168.9	172.8	176.6	180.7	204.2	208.8	213.2	217.8	222.4	227.1	231.6	236.3
Arbitrage		100.9	94.4	138.7	172.6	146.8	131.5	129.2	130.1	127.2	127.6	127.1	125.6	121.6	121.0	120.0
Other		57.6	57.1	54.9	51.1	53.6	53.7	53.5	54.0	54.3	54.7	55.1	55.4	55.9	57.4	57.9
Total		300.6	278.5	328.7	392.6	373.2	361.8	363.3	388.4	390.3	395.5	400.0	403.5	404.6	410.1	414.3
Disbursements																
Base Purchases		106.8	108.3	132.4	142.0	144.3	146.6	148.9	151.3	153.7	156.1	158.6	161.1	163.7	166.2	168.8
SEPA Purchases		6.8	6.8	6.8	7.6	7.8	7.9	7.9	7.9	7.9	8.1	8.3	8.3	8.3	8.3	8.5
Market Purchases and Related		16.1	16.8	16.1	41.2	46.9	46.4	45.7	45.6	44.5	43.9	43.2	43.3	41.9	39.4	38.5
A&G		17.3	17.8	18.3	18.9	19.5	20.0	20.6	21.3	21.9	22.6	23.2	23.9	24.6	25.4	26.1
RVP		-	-	-	-	-	-	-	-	-	-	-	-	-	-	376.6
Purchase of Production Inventory		-	-	-	-	-	-	-	-	-	-	-	-	-	-	80.1
Other		28.1	9.3	34.2	43.6	34.1	31.9	37.1	40.7	39.8	42.4	43.7	45.5	49.7	51.9	52.6
Total		175.1	159.1	207.9	253.3	252.5	252.8	260.3	266.7	267.8	273.2	277.1	282.2	288.3	291.2	751.3
BREC Share of Capital Expenditures		24.5	18.4	13.6	13.3	8.2	7.9	8.4	9.5	11.1	11.7	13.3	12.3	12.8	13.0	13.5
Debt Service																
New Borrowing		-	-	-	-	-	-	-	-	-	-	-	-	-	-	(451.1)
Principal Repayment (incl. ARVP)		39.2	41.0	53.3	77.6	70.2	71.0	69.7	77.4	79.1	83.5	27.0	85.8	60.8	5.8	176.1
Interest		52.9	48.7	44.3	41.1	39.5	35.2	31.2	27.2	22.8	18.5	73.3	10.5	6.0	86.7	-
Total		92.1	89.7	97.6	118.7	109.6	106.2	100.9	104.6	101.9	102.0	100.3	96.3	66.8	92.5	(275.0)
PMCC Lease Buyout																
Termination Payment (net)	(213.8)															
GIC	89.1															
Net	(124.7)															
PMCC Loan	15.0	(15.7)														
Net Cash Flow	(109.7)	(6.8)	11.2	9.6	7.3	2.9	(5.2)	(6.3)	7.5	9.5	8.6	9.3	12.7	36.6	13.4	(75.6)
Ending Balance	37.5	30.7	42.0	51.6	58.8	61.7	56.5	50.2	57.8	67.2	75.9	85.2	97.9	134.5	147.9	72.3

Existing Transaction - Summary Financials Assuming PMCC Buyout

	PMCC Lease Buyout @ 12/31/08	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Income Statement																
Revenues																
Members		142.1	126.9	135.0	168.9	172.8	176.6	180.7	204.2	208.8	213.2	217.8	222.4	227.1	231.6	236.3
Arbitrage		100.9	94.4	138.7	172.6	146.8	131.5	129.2	130.1	127.2	127.6	127.1	125.6	121.6	121.0	120.0
Other		37.7	37.8	11.9	11.0	11.6	12.0	12.2	13.1	13.9	14.9	16.1	17.7	19.9	24.1	30.3
Total		280.7	259.1	285.6	352.5	331.2	320.1	322.0	347.5	349.9	355.7	361.1	365.7	368.5	376.7	386.6
Expenses																
Base Purchases		106.8	108.3	132.4	142.0	144.3	146.6	148.9	151.3	153.7	156.1	158.6	161.1	163.7	166.2	168.8
SEPA Purchases		6.8	6.8	6.8	7.6	7.8	7.9	7.9	7.9	7.9	8.1	8.3	8.3	8.3	8.3	8.5
Market Purchases and Related		16.1	16.8	16.1	41.2	46.9	46.4	45.7	45.6	44.5	43.9	43.2	43.3	41.9	39.4	38.5
A&G		17.3	17.8	18.3	18.9	19.5	20.0	20.6	21.3	21.9	22.6	23.2	23.9	24.6	25.4	26.1
Interest		60.0	55.2	53.0	50.0	46.7	42.5	39.4	35.6	31.9	28.0	25.2	21.2	17.6	16.5	14.0
Other		32.7	26.2	46.3	48.5	40.3	38.5	42.6	44.2	45.1	47.5	48.6	50.3	54.4	56.2	57.5
Total		239.7	231.2	273.0	308.2	305.4	302.0	305.1	305.9	305.0	306.3	307.2	308.2	310.7	312.0	313.4
Net Margin		41.0	27.9	12.7	44.3	25.8	18.1	16.9	41.6	44.9	49.5	53.9	57.6	57.8	64.7	73.2
Balance Sheet																
Assets																
Net Utility Plant	917.2	959.5	968.0	970.5	954.7	945.4	928.6	911.1	892.5	875.6	860.7	848.6	832.9	817.0	800.7	785.1
Sale-Leaseback Investments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cash & Investments	37.5	30.7	42.0	51.6	58.8	61.7	56.5	50.2	57.8	67.2	75.9	85.2	97.9	134.5	147.9	72.3
Receivables & Other	135.9	131.6	124.8	116.1	116.2	111.1	104.5	99.1	95.6	90.2	85.0	79.9	74.9	69.8	64.9	140.3
Assets	1,090.6	1,121.9	1,134.7	1,138.2	1,129.8	1,118.2	1,089.6	1,060.4	1,045.9	1,033.0	1,021.5	1,013.7	1,005.7	1,021.3	1,013.5	997.8
Liabilities & Equities																
Equities	(130.7)	(89.7)	(61.8)	(49.1)	(4.8)	21.0	39.1	56.0	97.6	142.5	191.9	245.8	303.4	361.2	425.9	499.1
Sale-Leaseback Obligation & Unamortized Gain	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Debt	1,042.1	994.2	959.5	913.0	842.4	779.6	716.3	654.8	585.9	515.8	441.7	365.8	290.4	240.5	163.2	451.1
RVP/ Lease Advance	152.6	190.6	200.2	232.5	243.7	268.6	285.8	301.6	314.8	327.6	341.1	355.1	365.3	373.1	377.6	0.0
Payables & Other	26.6	26.9	36.8	41.9	48.5	49.0	48.4	48.0	47.6	47.2	46.8	47.0	46.7	46.5	46.8	47.5
Liabilities & Equities	1,090.6	1,121.9	1,134.7	1,138.2	1,129.8	1,118.2	1,089.6	1,060.4	1,045.8	1,033.0	1,021.5	1,013.7	1,005.7	1,021.3	1,013.5	997.8

ATTACHMENT 2

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	Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:			12/31/2008	
1	I. Sales (TWH)																				
2																					
3	Rural	2.23	2.41	2.40			2.44	2.49	2.54	2.59	2.65	2.70	2.76	2.82	2.88	2.94	3.00	3.06	3.12	3.18	3.24
4																					
5	Large Industrial	0.96	0.92	0.95			1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
6																					
7	Century	-	-	-			4.14	4.14	4.14	4.15	4.14	4.14	4.14	4.15	4.14	4.14	4.14	4.15	4.14	4.14	4.14
8																					
9	Alcan	-	-	-			3.16	3.16	3.16	3.17	3.16	3.16	3.16	3.17	3.16	3.16	3.16	3.17	3.16	3.16	3.16
10																					
11	Market	2.06	2.84	1.54			1.55	1.83	1.38	1.36	1.41	1.32	1.29	1.24	1.05	1.12	0.87	0.89	0.87	0.85	0.78
12																					
13	Total Sales	5.25	6.16	4.89			12.35	12.71	12.35	12.44	12.56	12.56	12.62	12.68	12.56	12.72	12.57	12.70	12.77	12.83	12.87
14																					

Pro Forma

September 2008

	Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																		Transaction Closing Date:		12/31/2008	
69	Non-Smelter Member Blend																				
72	Base	35.26	35.15	35.09			35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	35.24	35.21	35.20	35.18	35.16	35.14	35.13
73	MRDA	(1.15)	(1.11)	(1.10)			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
74	Regulatory Account Charge						-	-	(0.10)	(0.10)	(0.10)	0.42	0.41	0.40	0.41	0.40	0.39	1.52	1.48	1.45	1.59
75	GRA	-	-	-			-	-	-	-	-	-	-	-	3.55	3.55	3.54	3.54	3.54	3.54	3.56
76																					
77	FAC	-	-	-			11.23	12.76	13.94	16.33	18.27	12.10	9.82	9.91	9.96	10.31	10.56	10.95	10.96	11.52	11.46
78	Environmental Surcharge						2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
79	Surcredit	-	-	-			(3.28)	(3.20)	(3.12)	(3.64)	(3.55)	(3.47)	(3.39)	(3.32)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
80	Non-Smelter Member Economic Rese	-	-	-			(10.14)	(11.96)	(12.35)	(13.35)	-	-	-	-	-	-	-	-	-	-	-
81	Net						-	0.02	1.61	2.59	17.99	12.12	11.79	11.96	10.83	11.50	11.79	12.53	12.80	13.52	13.71
82																					
83	Pre TIER Rebate Total	34.11	34.04	33.99			35.45	35.44	36.90	37.85	53.23	47.85	47.49	47.63	50.02	50.66	50.92	52.77	52.98	53.65	53.99
84	TIER Related Rebate	-	-	-			(0.02)	(1.66)	-	-	-	-	-	-	-	-	-	-	-	-	-
85	*Effective Rate*	34.11	34.04	33.99			35.43	33.78	36.90	37.85	53.23	47.85	47.49	47.63	50.02	50.66	50.92	52.77	52.98	53.65	53.99
86																					
87	Smelters																				
88	Base Rate	-	-	-			28.15	28.15	28.15	28.11	28.15	28.15	28.15	28.11	30.96	30.96	30.96	30.92	30.96	30.96	30.98
89	TIER Adjustment	-	-	-			-	-	1.94	2.45	1.76	2.03	2.94	2.76	3.55	0.54	3.55	2.93	4.20	3.43	4.75
90	Smelter Rate Subject to Price Cap	-	-	-			28.15	28.15	30.09	30.56	29.91	30.18	31.09	30.87	34.51	31.50	34.51	33.85	35.16	34.40	35.73
91	FAC						11.23	12.76	13.94	16.33	18.27	12.10	9.82	9.91	9.96	10.31	10.56	10.95	10.96	11.52	11.46
92	PPA	-	-	-			0.08	(0.39)	0.48	0.27	0.57	0.26	0.44	0.58	2.09	0.88	1.78	1.15	2.07	1.74	2.54
93	Environmental Surcharge						2.19	2.42	3.15	3.24	3.27	3.48	5.36	5.37	5.36	5.58	5.52	5.80	5.95	6.03	6.21
94	Surcharge 1	-	-	-			0.70	0.70	0.70	1.00	1.00	1.00	1.00	1.00	1.40	1.40	1.40	1.39	1.40	1.40	1.40
95	Surcharge 2						0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	1.20	1.20	1.20	1.20	1.20	1.20	1.20
96	Smelter FAC Reserve						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
97	TIER Related Rebate	-	-	-			(0.02)	(1.66)	-	-	-	-	-	-	-	-	-	-	-	-	-
98	Effective Rate	-	-	-			43.19	42.86	49.23	52.28	53.90	47.90	48.58	48.61	54.52	50.86	54.98	54.33	56.74	56.28	58.54
99																					
100	Market	40.45	52.68	57.33			60.94	59.20	63.59	66.81	70.55	62.13	63.43	63.52	64.53	66.02	68.95	67.21	67.69	69.01	69.79
101																					
102	Overall Blend	36.60	42.62	41.34			43.22	42.66	47.17	49.51	55.56	49.38	49.75	49.75	53.85	52.12	54.52	54.67	56.13	56.16	57.53
103																					

Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			12/31/2008	
III. Cash Flows (M$)																				
Operating Receipts																				
Rural	79.4	84.8	84.6		0.0	90.8	92.5	94.1	102.8	145.9	134.2	136.1	139.3	149.7	154.5	158.5	167.4	171.4	176.9	181.3
Large Industrial	29.3	28.5	29.2		0.0	33.4	34.4	35.6	39.5	59.2	54.3	55.3	57.0	61.3	63.8	65.8	70.0	72.1	74.8	77.1
Smelters	-	-	-		-	315.3	324.7	347.2	382.5	393.3	349.5	354.5	355.7	397.9	371.2	401.2	397.5	414.0	410.7	427.2
Offsystem	83.4	149.4	88.2		-	94.3	108.5	87.7	90.9	99.4	82.2	82.1	78.8	67.6	73.6	59.7	59.5	59.1	58.4	54.7
WKEC Lease	47.9	50.8	47.7		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission	6.0	6.3	5.1		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Smelter - Tier 3 Transmission	1.7	1.7	1.7		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gain on Sale of Allowances	-	-	-		-	3.8	3.0	(0.6)	(0.4)	(0.2)	(1.9)	(16.3)	(15.1)	(14.5)	(15.6)	(14.2)	(15.5)	(15.6)	(16.0)	(16.5)
Cobank Patronage Capital & Other	0.6	0.6	0.6		-	-	-	-	0.7	1.6	1.5	-	-	-	-	-	-	-	-	-
Lease Buyout					(71.3)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Interest Earnings	3.7	6.8	5.0		0.0	6.5	5.2	5.3	5.9	3.7	2.8	3.6	3.3	3.2	3.0	3.0	3.4	3.4	3.4	3.4
Total Receipts	252.0	328.9	262.3		(71.3)	544.1	568.3	569.2	622.0	702.8	622.6	615.4	619.0	665.1	650.4	674.0	682.3	704.4	708.1	727.1
Operating Disbursements																				
PPA	98.0	96.3	95.4		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fuel Costs	-	-	-		0.0	270.6	304.9	307.9	344.6	370.3	259.1	259.3	262.0	261.0	267.6	268.7	275.7	277.5	286.7	285.8
SEPA & Other Purchases	11.4	68.0	11.6		0.0	23.1	17.9	28.1	25.7	29.7	25.8	28.2	30.1	48.9	34.0	45.0	37.4	49.3	45.3	55.8
Carbon Tax					-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Carbon Allowance Cost					-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Environmental	0.4	0.5	0.6		(0.0)	30.8	33.7	38.3	39.9	40.9	41.8	51.4	53.0	52.9	55.3	55.3	58.1	60.4	61.4	63.3
Fixed O&M	-	-	-		0.0	101.3	93.3	105.0	104.9	106.0	102.3	111.8	108.5	129.6	113.5	129.3	123.8	133.5	128.7	137.0
Transmission O&M	6.6	7.1	7.4		0.0	8.0	8.3	8.5	8.8	9.0	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.4	11.8	12.1
APM, L/C, Cogen, CW & TVA Trans	4.7	8.8	5.9		0.0	6.3	6.5	5.8	5.7	5.9	6.0	6.2	6.4	6.6	6.8	7.0	7.2	7.4	7.6	7.8
A&G	13.8	15.6	17.2		0.0	29.5	27.8	29.2	29.5	30.3	31.7	32.1	33.0	34.3	35.1	36.0	37.5	38.2	39.5	40.9
Property Taxes & Insurance	2.4	2.3	2.2		0.0	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
Working Capital	6.8	4.6	(8.4)		(0.0)	(21.8)	(2.1)	(1.6)	(2.2)	1.7	4.7	0.1	(0.4)	(1.2)	0.6	(1.8)	(0.6)	(1.7)	(0.6)	(1.5)
PCB Restructuring	-	-	-		-	7.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	2.3	1.9	2.0		(0.0)	(0.7)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Disbursements	146.3	205.1	134.0		0.0	461.3	497.3	529.0	565.5	602.6	489.8	508.0	512.0	552.1	533.7	560.8	560.9	587.1	591.9	613.1
Operating Receipts less Disbursements	105.7	123.8	128.2		(71.3)	82.8	71.0	40.2	56.4	100.3	132.8	107.4	107.0	113.1	116.8	113.3	121.4	117.3	116.3	114.0

Pro Forma

	Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:			12/31/2008	
139																					
140	Operating Receipts less Disbursements	105.7	123.8	128.2		(71.3)	82.8	71.0	40.2	56.4	100.3	132.8	107.4	107.0	113.1	116.8	113.3	121.4	117.3	116.3	114.0
141																					
142	Capital Expenditures																				
143	Generation	6.4	6.6	6.7		(0.0)	36.2	20.6	31.5	23.4	38.5	32.8	33.8	34.8	35.9	36.9	38.1	39.2	40.4	41.6	42.8
144	Transmission	5.9	9.6	14.4		-	10.3	5.3	4.4	5.9	0.5	0.4	0.5	1.6	2.8	3.4	3.5	3.6	3.7	3.8	3.9
145	Transmission Upgrades	-	4.1	0.3		-	5.3	5.6	-	-	-	-	-	-	-	-	-	-	-	-	-
146	A&G	0.9	1.3	1.3		0.0	1.3	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8	1.9	2.0	2.0
147	Extraordinary Generation	-	-	-		-	28.7	17.4	25.4	10.7	8.8	5.2	4.4	2.3	2.8	2.4	7.0	3.4	3.1	2.7	3.3
148	Other (HQ Building, IP)	-	-	-		0.0	11.4	1.0	0.9	0.8	0.8	1.0	0.8	0.8	1.0	0.9	0.9	1.1	0.9	0.9	1.2
149	Total Capital Expenditures	13.2	21.6	22.7		0.0	93.2	51.3	63.7	42.2	50.1	40.9	41.2	41.1	44.1	45.3	51.2	49.1	49.9	50.9	53.3
150																					
151	Income Taxes from Operations	0.4	0.2	0.4		0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
152																					
153	Net Pre-Finance Cash Flow	92.1	102.0	105.1		(71.3)	(10.3)	19.7	(23.5)	14.2	50.1	91.6	65.9	65.5	68.5	71.0	61.6	71.8	66.9	64.9	60.3
154																					
155	Financing																				
156	Principal (Net)	26.4	13.3	41.8		-	13.3	15.1	(55.5)	92.1	30.7	32.6	(171.8)	233.5	38.4	40.6	21.7	45.3	40.1	42.4	16.1
157	Interest	36.9	36.9	51.5		0.0	44.0	43.2	42.3	45.3	41.1	39.2	37.3	35.3	33.4	31.2	28.8	27.5	24.9	22.6	19.8
158	Financing Fees					-	-	-	1.2	-	-	-	6.8	-	-	-	-	-	-	-	-
159	Line of Credit	-	-	-		0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
160	Aggregate Debt Service (Incl. Line	63.4	50.2	93.3		0.0	57.7	58.8	(11.4)	137.9	72.3	72.3	(127.3)	269.3	72.3	72.3	51.0	73.3	65.5	65.5	36.4
161																					
162	Post-Finance Cash Flow	28.7	51.9	11.8		(71.3)	(68.1)	(39.1)	(12.1)	(123.7)	(22.2)	19.3	193.2	(203.8)	(3.7)	(1.3)	10.6	(1.5)	1.4	(0.6)	23.8
163																					
164	Unwind Transaction																				
165	Cash Proceeds	-			374.8																
166	Debt Reduction	-			(134.3)																
167	Misc. Transaction				(3.1)																
168	Net Before Member Reserves				237.5																
169	Non-Smelter Member Economic Rese	-			(157.0)	-	35.5	42.9	45.4	50.2	-	-	-	-	-	-	-	-	-	-	-
170	Smelter Fuel Payment				(7.0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
171																					
172	Net Before Transition Reserve				73.5	-	35.5	42.9	45.4	50.2	-	-	-	-	-	-	-	-	-	-	-
173																					
174	Ending Cash Balances (Incl. Transition	96.5	148.3	160.2	233.6	162.3	129.7	133.5	166.8	93.3	71.1	90.4	283.6	79.8	76.1	74.8	85.4	83.9	85.4	84.8	108.6
175	Reserve)																				

	Calendar Year	2006	2007	2008	Transaction	Lease Termination	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:			12/31/2008	
176	IV. Income Statement (M$)																				
177																					
178	Revenues																				
179	Rural	79.4	84.76	84.6		0.0	90.7	88.3	98.3	102.8	145.9	134.2	136.1	139.3	149.7	154.5	158.5	167.4	171.4	176.9	181.3
180	Large Industrial	29.3	28.53	29.2		-	33.3	32.8	37.2	39.5	59.2	54.3	55.3	57.0	61.3	63.8	65.8	70.0	72.1	74.8	77.1
181	Smelters	-	-	-		-	315.2	312.8	359.3	382.5	393.3	349.5	354.5	355.7	397.9	371.2	401.2	397.5	414.0	410.7	427.2
182	Off-System	83.4	149.38	88.2		-	94.3	108.5	87.7	90.9	99.4	82.2	82.1	78.8	67.6	73.6	59.7	59.5	59.1	58.4	54.7
183	Transmission	6.0	6.29	5.1		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
184	Smelter - Tier 3 Transmission	1.8	1.80	1.8		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
185	Gain on Sale of Allowances	-	-	-		-	3.8	3.0	(0.6)	(0.4)	(0.2)	(1.9)	(16.3)	(15.1)	(14.5)	(15.6)	(14.2)	(15.5)	(15.6)	(16.0)	(16.5)
186	WKEC Lease (Net)	52.3	52.33	52.3		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
187	Lease Buyout					(31.0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
188	Interest Earnings	3.7	6.83	5.0		0.0	6.5	5.2	5.3	5.9	3.7	2.8	3.6	3.3	3.2	3.0	3.0	3.4	3.4	3.4	3.4
189	Total Revenues	255.9	329.92	266.3		(31.0)	543.9	550.6	587.2	621.3	701.3	621.1	615.4	619.0	665.1	650.4	674.0	682.3	704.4	708.1	727.1
190																					
191	Expenses																				
192	PPA	98.0	96.29	95.4		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
193	Fuel Costs	-	-	-		0.0	270.9	298.5	304.5	336.4	364.0	286.6	259.2	261.6	259.8	267.5	267.5	275.1	276.8	285.4	285.4
194	SEPA & Other Purchases	11.4	68.01	11.61		0.0	22.8	19.3	25.9	24.3	27.1	26.5	28.1	29.4	41.7	31.9	38.8	39.1	46.6	44.0	51.3
195	Carbon Tax					-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
196	Carbon Allowance Cost					-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
197	Non-Fuel Variable Production O&M	0.4	0.48	0.6		(0.0)	30.8	33.7	38.3	39.9	40.9	41.8	51.4	53.0	52.9	55.3	55.3	58.1	60.4	61.4	63.3
198	Fixed Production O&M	-	-	-		0.0	101.3	93.3	105.0	104.9	106.0	102.3	111.8	108.5	129.6	113.5	129.3	123.8	133.5	128.7	137.0
199	Transmission O&M	6.6	7.07	7.4		0.0	8.0	8.3	8.5	8.8	9.0	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.4	11.8	12.1
200	APM, L/C, Cogen, CW & TVA Trans	4.7	8.78	5.9		0.0	6.3	6.5	5.8	5.7	5.9	6.0	6.2	6.4	6.6	6.8	7.0	7.2	7.4	7.6	7.8
201	A&G	13.8	15.62	17.2		0.0	29.5	27.8	29.2	29.5	30.3	31.7	32.1	33.0	34.3	35.1	36.0	37.5	38.2	39.5	40.9
202	Property Taxes & Insurance	2.4	2.32	2.2		0.0	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
203	Depreciation & Amortization	32.0	32.15	32.5		0.0	34.3	35.5	44.6	46.0	46.0	46.3	47.9	49.4	63.5	64.8	66.2	67.7	69.1	70.5	72.0
204	Income Tax	-	-	-		-	-	-	-	-	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8
205	Interest Expense (Incl. Financing Fee:	60.7	60.90	63.5		0.0	53.9	49.7	49.2	52.6	48.8	47.4	45.9	44.6	43.2	41.6	39.8	39.2	37.4	35.6	33.6
206	RUS Note & PCB Restructuring Char	-	-	-		0.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
207	Net Sale-Leaseback	(2.6)	(2.56)	(3.4)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
208	Other - Net	(6.0)	(6.32)	(6.6)		(0.0)	(0.3)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
209	Total Expenses	221.4	282.74	226.5		(0.0)	564.9	579.9	619.2	657.1	687.8	608.0	602.5	606.3	652.8	638.4	662.3	670.6	693.1	697.2	716.5
210																					
211	Unwind Transaction	-	-	-	690.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
212																					
213	Non-Smelter Member Economic Reserv	-	-	-	(157.0)	-	35.5	42.9	45.4	50.2	-	-	-	-	-	-	-	-	-	-	-
214																					
215	Smelter FAC Payment	-	-	-	(7.0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
216																					
217	Net Margin	34.5	47.18	39.9	526.8	(31.0)	14.4	13.5	13.4	14.3	13.5	13.2	12.9	12.6	12.4	12.1	11.7	11.7	11.3	11.0	10.6

ATTACHMENT 3

Non-Smelter Member Rates [9/23/08]:

Rate Impact Analysis ($/ MWh)

1. Non-Smelter Members

1	*December Close/ $72.5m Buyout*	47.59
2	MRDA Continued	(0.89)
3	GRA	0.33
4	Regulatory Account	-
5		
6	FAC	-
7	Environmental Surcharge	-
8	Surcharge Credit	-
9	Rebate Realized	0.01
10	Economic Reserve/ MRSM	0.00
11	*Net*	0.01
12		
13	*Overall Change*	(0.55)
14	*December Close/ No PMCC Buyout*	47.03

Smelter Rates [9/23/08]:

Rate Impact Analysis ($/ MWh)

2. Smelters

1	*December Close/ $72.5m Buyout*	51.52
2	MRDA Continued	(0.71)
3	GRA	0.26
4	TIER Adjustment	(0.00)
5	FAC	-
6	Smelter Economic Reserve	-
7	Environmental Surcharge	-
8	Power Purchases	-
9	Surcharge	-
10	TIER Related Rebate	0.01
11	*Overall Change*	(0.45)
12	*December Close/ No PMCC Buyout*	51.07

Attachment 3

Exhibit 54

Selected 1998 Transaction Documents (on CD)

<u>Big Rivers' 1998 Transaction Documents</u>

Index

Exhibit 55

Selected RUS Loan Documents (on CD)

<u>Selected RUS Loan Documents</u>

Index
New RUS Agreement
Third Restated Mortgage & Security Agreement
First Amendment to Third Restated Mortgage & Security Agreement