SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC
ATTORNEYS AT LAW

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

November 6, 2008

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PUBLIC SERVICE COMMISSION

Via Federal Express

Ms. Stephanie Stumbo
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: 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, PSC Case No. 2007-00455

Dear Ms. Stumbo:

Enclosed for filing in the above-styled matter are an original and ten copies of the responses of Big Rivers Electric Corporation to the October 24, 2008, data requests from the Commission Staff and the Attorney General. Also enclosed is an extra copy of this cover letter, which we request that you file-stamp and return to us in the enclosed envelope. I certify that copies of this letter and the data requests have been served on the parties identified on the attached service list.

Sincerely yours,

James M. Miller

James M. Miller

JMM/ej
Enclosures

cc: Mark A. Bailey
David Spainhoward
Service List

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

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

SERVICE LIST
BIG RIVERS ELECTRIC CORPORATION
PSC CASE NO. 2007-00455

Hon. Robert Michel
Orrick, Herrington & Sutcliffe
666 Fifth Avenue
New York, NY 10103

Hon. Kyle Drefke
Orrick, Herrington & Sutcliffe
Columbia Center
1152 15th Street, NW
Washington, DC 20005

Charles Buechel
Utility & Economic Consulting Inc.
116 Carrie Court
Lexington, KY 40515

Hon. Doug Beresford
Hon. Geof Hobday
Hogan & Hartson
555 Thirteenth Street, NW
Washington, DC 20004

Paul Thompson
E.ON U.S. LLC
220 West Main Street
Louisville, KY 40202

David Sinclair
E.ON U.S. LLC
220 West Main Street
Louisville, KY 40202

D. Ralph Bowling
Western Kentucky Energy Corp.
P. O. Box 1518
Henderson, KY 42419

Hon. Kendrick Riggs
Stoll, Keenon & Ogden PLLC
500 West Jefferson Street
Louisville, KY 40202

Hon. Allyson Sturgeon
E.ON U.S. LLC
220 West Main Street
Louisville, KY 40202

Kelly Nuckols
Jackson Purchase Energy Corp.
P. O. Box 4030
Paducah, KY 42002-4030

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

Sandy Novick
Kenergy Corp.
P. O. Box 18
Henderson, KY 42419

Hon. Frank N. King
Dorsey, King, Gray,
Norment & Hopgood
318 Second Street
Henderson, KY 42420

Hon. David Denton
Denton & Kueler, LLP
P.O. Box 929
555 Jefferson Street, Suite 301
Paducah, KY 42002-0929

Hon. Tom Brite
Brite and Butler
P. O. Box 309
Hardinsburg, KY 40143

Jack Gaines
JDG Consulting, LLC
P. O. Box 88039
Dunwoody, GA 30356

SERVICE LIST
BIG RIVERS ELECTRIC CORPORATION
PSC CASE NO. 2007-00455

Hon. Michael L. Kurtz
Boehm, Kurtz & Lowry
Suite 2110
36 East Seventh Street
Cincinnati, OH 45202

Hon. David Brown
Stites & Harbison, PLLC
1800 Aegon Center
400 West Market Street
Louisville, KY 40202

Henry Fayne
1980 Hillside Drive
Columbus, Ohio 43221

Allan Eyre
631 Mallard Lane
Henderson, KY 42420

Russell Klepper
Energy Services Group
316 Maxwell Road
Alpharetta, GA 30004

Hon. C. B. West
Stoll Keenon Ogden PLLC
201C North Main Street
Henderson, KY 42420

Gary Quick
Henderson Municipal Power & Light
100 5th Street
Henderson, KY 42420

Hon. John N. Hughes
124 West Todd Street
Frankfort, Kentucky 40601

Hon. Dennis Howard
Assistant Attorney General
Office of the Attorney General
Utility & Rate Intervention Division
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601-8204

Mr. David Brevitz
Brevitz Consulting Services
3623 Southwest WoodValley Terrace
Topeka, KS 66614

Don Meade
800 Republic Building
420 W. Muhammad Ali Blvd.
Louisville, KY 40202

Katherine Simpson Allen
Stites & Harbison, PLLC
401 Commerce Street
Suite 800
Nashville, Tennessee 37219

VERIFICATION

I verify, state, and affirm that the foregoing responses for which I am listed as witness are true and correct to the best of my knowledge and belief.

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 6th day of November, 2008.

Vikki G. King

Notary Public, Ky. State at Large
My commission expires: March 3, 2010

VERIFICATION

I verify, state, and affirm that the foregoing responses for which I am listed as a witness are true and correct to the best of my knowledge and belief.

David Spainhoward

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

Subscribed and sworn to before me by David Spainhoward on this the 6th day of November, 2008.

Notary Public, Ky. State at Large
My commission expires: 5/24/2009

VERIFICATION

I verify, state, and affirm that the foregoing responses for which I am listed as a witness are 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 6th day of November, 2008.

Paula Mitchell

Notary Public, Kentucky State at Large
My commission expires: 1-12-09

Item 1) Provide a schedule showing the costs incurred and benefits received by Big Rivers as a result of the Bank of America leveraged lease. The schedule should separately identify each cost, each benefit, and each associated tax impact, if any, by year for 2000 through 2023.

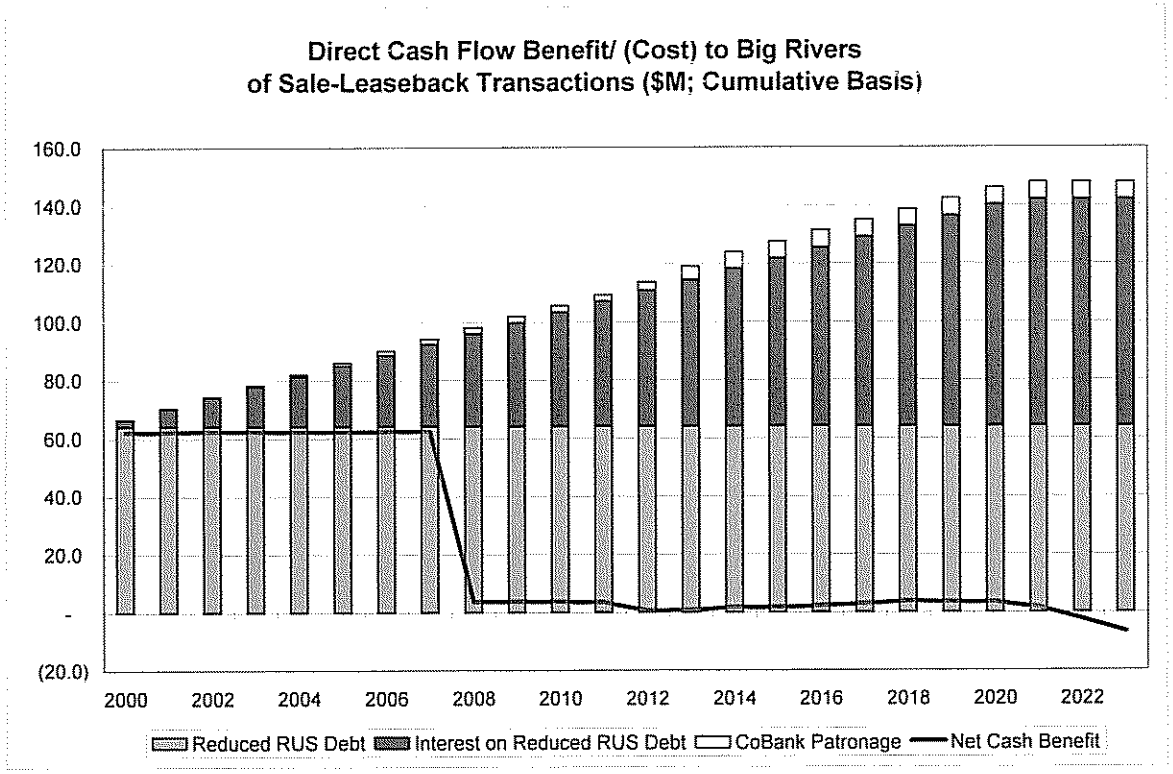
Response) Direct cash flow benefits and (costs) to Big Rivers of both the BoA and PMCC Sale-Leaseback transactions from 2009 to 2023 are depicted below on an annual and on a cumulative basis, assuming an Unwind closing date of 12/31/08 and including the buyouts that have already taken place in 2008. The cumulative net benefit is also shown graphically, page 3 of 3.

- In general terms, the reduction in RUS debt from Sale-Leaseback proceeds at lease inception plus cumulative interest savings is offset by a combination of the Member Discount Adjustment through August 2008 plus buyout and associated financing costs through 2023, for a largely neutral cash result.

- It is important to note, however, that the principal reason for the early buyout of PMCC was to reduce the substantial financial risk and uncertainty Big Rivers faced under the terms of the leases. This was described in the affidavit of C. William Blackburn, Application Exhibit 92. This advantage of the buyouts is not reflected in the schedule attached.

Witness) C. William Blackburn
Robert S. Mudge

		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	**Direct Cash Flow Benefit/ (Cost) to Big Rivers of Sale-Leaseback Transactions ($M)**																								
2																									
3	**Annual**																								
4	Sale-Leaseback Proceeds (used to Prepay RUS)	64.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Reduced RUS Interest	2.6	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	1.8	-	-
6	CoBank Patronage	-	0.1	0.2	0.2	0.2	0.3	0.4	0.4	0.4	-	-	-	0.7	1.6	1.5	-	-	-	-	-	-	-	-	-
7	Member Discount Adjustment	(1.2)	(3.7)	(3.7)	(3.7)	(3.7)	(3.7)	(3.7)	(3.7)	(2.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	AMT	(3.3)	-	-	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	BoA Buyout	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	PMCC Buyout	-	-	-	-	-	-	-	-	(60.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Interest Cost of Buyout Financing	-	-	-	-	-	-	-	-	(0.3)	(3.4)	(3.7)	(4.0)	(7.2)	(5.0)	(4.3)	(3.7)	(3.1)	(3.0)	(2.8)	(4.0)	(3.8)	(3.5)	(4.0)	(4.3)
12	Total	62.0	0.1	0.2	(0.1)	(0.1)	0.0	0.1	0.1	(58.8)	0.2	(0.0)	(0.3)	(2.8)	0.3	0.8	0.0	0.6	0.6	0.9	(0.4)	(0.1)	(1.7)	(4.0)	(4.3)
13																									
14																									
15	**Cumulative**																								
16	RUS Prepay from Sale-Leaseback Proceeds	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0
17	Reduced RUS Interest	2.6	6.3	9.9	13.6	17.3	21.0	24.7	28.3	32.0	35.7	39.4	43.1	46.7	50.4	54.1	57.8	61.5	65.1	68.8	72.5	76.2	78.0	78.0	78.0
18	CoBank Patronage	-	0.1	0.3	0.5	0.7	1.0	1.4	1.8	2.2	2.2	2.2	2.2	2.9	4.4	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
19	Member Discount Adjustment	(1.2)	(4.9)	(8.6)	(12.3)	(15.9)	(19.6)	(23.3)	(27.0)	(29.4)	(29.4)	(29.4)	(29.4)	(29.4)	(29.4)	(29.4)	(29.4)	(29.4)	(29.4)	(29.4)	(29.4)	(29.4)	(29.4)	(29.4)	(29.4)
20	AMT	(3.3)	(3.3)	(3.3)	(3.6)	(3.9)	(4.2)	(4.5)	(4.8)	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)
21	BoA Buyout	-	-	-	-	-	-	-	-	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
22	PMCC Buyout (funded via increased debt)	-	-	-	-	-	-	-	-	(60.9)	(60.9)	(60.9)	(60.9)	(60.9)	(60.9)	(60.9)	(60.9)	(60.9)	(60.9)	(60.9)	(60.9)	(60.9)	(60.9)	(60.9)	(60.9)
23	Interest Cost of Buyout Financing	-	-	-	-	-	-	-	-	(0.3)	(3.7)	(7.4)	(11.4)	(18.6)	(23.6)	(27.9)	(31.6)	(34.7)	(37.7)	(40.5)	(44.6)	(48.4)	(51.9)	(55.9)	(60.2)
24	Total	62.0	62.2	62.4	62.3	62.2	62.2	62.3	62.3	3.5	3.7	3.7	3.4	0.5	0.8	1.6	1.6	2.2	2.9	3.7	3.4	3.3	1.6	(2.4)	(6.7)


Direct Cash Flow Benefit/ (Cost) to Big Rivers
of Sale-Leaseback Transactions ($M; Cumulative Basis)
160.0
140.0
120.0
100.0
80.0
60.0
40.0
20.0
-
(20.0)
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
Reduced RUS Debt
Interest on Reduced RUS Debt
CoBank Patronage
Net Cash Benefit

Item 2) Provide a schedule showing the costs incurred and benefits received by Big Rivers as a result of the Philip Morris Credit Corporation ("PMCC") leveraged lease. The schedule should separately identify each cost, each benefit, and each associated tax impact, if any, by year for 2000 through 2023.

Response) See response to PSC Supplemental Request, October 24, 2008, Item 1, herein.

Witness) C. William Blackburn
Robert S. Mudge

Item 3) At the October 20, 2008 informal conference, Big Rivers distributed a document titled, "Summary of Changes in the Unwind Financial Model, June 2008 vs. October 2008" ("Financial Model Presentation"). Refer to page 11, line 3, of that document which identifies \$0.79 MWh as "Reduced pressure on General Rate Adjustments." Provide a reconciliation of rate increases shown in the June 2008 financial model and in the October 2008 Unwind Financial Model and explain in detail the reasons for each change.

Response) Please see below a reconciliation of the General Rate Adjustments ("GRA") —expressed in \$/MWh—between the June 2008 and October 2008 Financial Models. The derivation of the weighted average difference of \$0.79/MWh shown on page 11, line 3, of the Financial Model Presentation of October 20, 2008 is shown below on a year-to-year basis. The derivation shows the General Rate Adjustment components in each of the June 2008 and October 2008 financial models, in each case on line 75 of the *pro forma* worksheet as indicated below.

Key changes occur as follows:

- 2011: The GRA is \$0.71/MWh less in the October 2008 model than in the June 2008 model. 2010 is the earliest a rate review is assumed to occur in either the June 2008 or October 2008 model. No GRA is needed to take effect in 2011 in the October 2008 model, primarily because of the combined effect of discontinuing the MDA and discontinuing the 2% assumed member rate increase in connection with the PMCC lease buyout.

- 2015: The GRA is $0.89/ MWh less in the October 2008 model than in the June 2008 model, because of offsetting revenues from the discontinued MDA plus increased off-system sales.

- 2017: A GRA is needed in the 10/08 model, but it remains less than in the 6/08 model, for the same reasons as in 2011 and 2015.

Witness) C. William Blackburn
Robert S. Mudge

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE COMMISSION STAFF'S OCTOBER 24, 2008 SUPPLEMENTAL DATA REQUEST TO BIG RIVERS ELECTRIC CORPORATION
PSC CASE NO. 2007-00455
November 7, 2008

		Location in Financial Model	Tot./ Wtd Avg.	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Non-Smelter Member Sales (TWh; both 6/098 and 10/08)		61.96	3.50	3.58	3.67	3.76	3.85	3.94	4.03	4.12	4.22	4.31	4.40	4.50	4.60	4.69	4.79
2	General Rate Adjustments Modeled:																	
3	6/08	Pro forma, Line 75	2.54	-	-	0.71	0.71	0.71	0.71	0.89	0.89	4.43	4.42	4.42	4.42	4.42	4.42	4.41
4	Delta		(0.79)	-	-	(0.71)	(0.71)	(0.71)	(0.71)	(0.89)	(0.89)	(1.00)	(1.00)	(1.00)	(1.00)	(0.99)	(0.99)	(0.87)
5	10/08	Pro forma, Line 75	1.75	-	-	-	-	-	-	-	-	3.43	3.43	3.43	3.43	3.42	3.42	3.54

Item 4) Refer to the Financial Model Presentation, page 9. Provide a breakdown of the actual impact for each amount reflected on line 19 and line 20 under the column headed "$/MWh (blended)."

Response) Please see below a breakdown of the impact of the numbers on lines 19 and 20 of the Financial Model Presentation of 10/20/08, page 9 ("Change in Projected Revenue Requirement, 2009 - 2023"), in terms of dollars ($ millions) and dollars per MWh.

In simple terms, the numbers on lines 19 and 20 of the 10/20 Presentation combine to increase revenue requirements as shown on page 9:

		$M	$/ MWh
Line 19	Interest Expense (Incl. Financing Fees)	45.9	0.27
Line 20	Net Margin	(37.8)	(0.22)
Combined		8.1	0.05

In addition, however, line 19 affects line 20 by contributing to the Net Margin requirement, which is based on achieving a 1.24x Times Interest Earned Ratio, as defined in the Smelter Agreements. Accordingly, the relationship between the numbers on line 19 and line 20 are shown in the context of the Contract TIER calculation, which appears on lines 287 – 301 of the Pro forma worksheet in the Unwind Financial Model (numbers reproduced below).

As between the financial models of June 2008 and October 2008, the change in Net Margin requirement over the period 2009 – 2023 is $37.8 million (see column E, line

288[1] and on line 20 of the Financial Model Presentation of 10/20/08, page 9). This amount results from the net impact of two major factors:

1) Increased interest costs -- apart from sale-leaseback interest -- driven by the need to fund the PMCC lease buyout with additional borrowings (column B, and line 19 from the 10/20/08 Presentation), and

2) The elimination of sale-leaseback interest -- previously included in the Contract TIER formulation per the Smelter Agreements -- as a result of the lease buyouts (column C).

While the increased interest costs must be covered by additional Net Margin in a 1.24:1 ratio (56.4/45.5), this requirement is more than offset by the opposite effect of removing sale-leaseback interest and associated margin requirements (-247.1/ 199.2).

The reduced Net Margin requirement of $37.8 million can be shown as equivalent to $0.22/ MWh over the period 2009 - 2023 when divided by total Non-Smelter Member and Smelter sales of 171.5 TWh.

Note that the small difference -- $0.4 million -- between the increased interest expense indicated on line 19 of the 10/20/08 Presentation and the interest component shown in column B below relates to inclusion of the "Restructuring" expense relating to prepayment of the RUS New Note in the Contract TIER calculation.

Witness) C. William Blackburn

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[1] The term "Earnings" used on line 288 of the Unwind Financial Model is synonymous with "Net Margin" as used in this discussion.

		A	B	C	D	E	F	
	Line Item in Financial Model	**6/08**	**Delta**				**10/08**	
			Impact of Changes in Interest Cost - General	Impact of Changes in Sale-Leaseback Interest	Other	Total		
287	Contract TIER ($M)							
288	Earnings	223.5	10.9	(47.8)	(0.9)	(37.8)	185.7	<< Summary result on line 20 of 10/20/08 presentation
289	Plus: Interest Expense, Financing Fees, and Restucturing	611.3	45.5	-		45.5	656.8	<< Impact from line 19 of 10/20/08 presentation (adjusted for RUS New Note "Restructuring" expense).
290	Plus: Imputed Rate Increase in 2010	41.2	-	-	(41.2)	(41.2)	-	
291	Less: Offset to Imputed Rate Increase in 2010	(38.7)	-	-	38.7	38.7	-	
292	Less: Interest on Sequestered Funds	(31.5)	-	-	3.5	3.5	(28.0)	
293	Total	805.8	56.4	(47.8)	-	8.6	814.5	
294	Plus Sale-Leaseback Interest	199.2	-	(199.2)	-	(199.2)	-	
295	Total	1,005.1	56.4	(247.1)	-	(190.6)	814.5	
296	Divided by							
297	Interest Expense, Financing Fees, and Restructuring	611.3	45.5	-	-	45.5	656.8	
298	Plus Sale-Leaseback Interest	199.2	-	(199.2)	-	(199.2)	-	
299	Total	810.6	45.5	(199.2)	-	(153.7)	656.8	
300							0	
301	*Contract TIER (line 295/ line 299)*	1.24	1.24	1.24	na	1.24	1.24	

Change in Earnings per MWh (blended basis)		
TWh		171.5
$/ MWh		(0.22)

Item 5) Refer to the Financial Model Presentation, Appendix E, page 20 and the October 9, 2008 Motion to Amend and Supplement Application ("10/08 Application"), Exhibit 79. In order to determine the actual dollar amount impact of the "feathering" of the $157 million Non-Smelter Member Economic Reserve on the October Unwind Financial Model, provide revised versions of pages 3 and 4 titled, "Schedule II, Rates, Accrual Based ($/MWh Sold, unless otherwise noted)," showing the amounts on lines 19 through 103 expressed in dollars, rather than $/MWh. Provide one version without gradualism and one version with gradualism.

Response) Please see 3 of 5 for a summary of the rates expressed in dollars with and without gradualism applied to draws on the Economic Reserve. Each dollar amount is derived from the rates in the Pro forma ($/MWh) multiplied by sales (TWh). Line numbers for the dollar amounts below are the same as line numbers in the October Unwind Financial Model, pages 3 and 4, titled "Schedule II, Rates, Accrual Based ($/MWh Sold, unless otherwise noted)," lines 19 through 103, corresponding to rates. Key differences between the scenarios with and without gradualism include:

- Rate smoothing: Rural and Large Industrial revenue requirements are higher in the gradualism case in years 2010 - 2012, but significantly lower in 2013 (see lines 9 and 10 below);

- Interest earnings: More interest is earned on the Non-Smelter Member Economic Reserve in the gradualism case because it is drawn down at a slower rate. Therefore, there is about $1.7 million more in the scenario with gradualism which is used to offset net fuel adjustment and environmental surcharges. Thus, Rural and Large Industrial revenue requirements are somewhat lower overall in the gradualism case.

The summary is followed by an expanded table showing relevant lines from 19 through 103 on the Pro forma expressed in dollars (some calculation, subtotal, and blank lines were omitted for clarity).

Witness) C. William Blackburn
Robert S. Mudge

		Derivation from Financial Model, Pro forma Worksheet	Total	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	**Summary - Rates Expressed in $M**																	
2	*With Gradualism (as filed)*																	
3	Rural	Line 46 x Line 3	2,091.1	90.5	93.2	108.7	111.7	121.8	131.9	136.1	139.3	149.4	154.1	158.3	167.0	171.1	176.6	181.3
4	Large Industrial	Line 67 x Line 5	851.5	33.3	35.0	41.8	43.5	48.3	53.2	55.3	57.0	61.2	63.6	65.7	69.9	72.0	74.7	77.0
5	Smelter	Line 98 x (Lines 7 + 9)	5,631.3	314.6	313.6	359.0	382.9	393.5	340.6	353.3	354.5	397.5	370.5	401.7	397.3	414.3	411.0	427.1
6	Market	Line 100 x Line 11	1,156.6	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
7	Overall Blend	Line 102 x Line 13	9,730.5	532.7	550.4	597.2	628.9	662.9	608.0	626.9	629.6	675.7	661.9	685.3	693.7	716.5	720.7	740.1
8	*Delta*																	
9	Rural		(1.0)	0.0	4.7	10.2	8.6	(24.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Large Industrial		(0.6)	0.0	2.1	4.6	3.9	(11.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	Smelter		(0.0)	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0
12	Market		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Overall Blend		(1.7)	0.0	6.8	14.8	12.5	(35.7)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0
14	*Without Gradualism*																	
15	Rural	Line 46 x Line 3	2,092.1	90.5	88.5	98.5	103.1	146.4	131.9	136.1	139.3	149.4	154.1	158.3	167.0	171.1	176.6	181.3
16	Large Industrial	Line 67 x Line 5	852.1	33.3	32.9	37.3	39.6	59.4	53.2	55.3	57.0	61.2	63.6	65.7	69.9	72.0	74.7	77.0
17	Smelter	Line 98 x (Lines 7 + 9)	5,631.3	314.6	313.6	358.9	382.9	393.4	340.7	353.3	354.5	397.5	370.5	401.7	397.3	414.3	411.0	427.1
18	Market	Line 100 x Line 11	1,156.6	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
19	Overall Blend	Line 102 x Line 13	9,732.1	532.7	543.6	582.3	616.4	698.6	608.1	626.9	629.6	675.7	661.9	685.3	693.7	716.5	720.7	740.1
20																		
21																		

		Derivation from Financial Model, Pro forma Worksheet		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
22																		
23																		
24	**Detail - Rates Expressed in $M**																	
25																		
26	*With Gradualism (as filed)*																	
27																		
28	Rural ($M)	Line 3 x																
29	Base		33	90.8	92.5	94.5	96.4	98.4	100.3	102.4	104.4	106.6	108.6	110.8	113.0	115.3	117.4	119.6
30	Regulatory Account Charge		35	0.0	0.0	(0.3)	(0.3)	(0.3)	1.1	1.1	1.1	1.2	1.2	1.2	4.6	4.6	4.6	5.2
31	GRA		36	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.4	10.6	10.8	11.0	11.2	11.4	12.1
32	FAC		38	27.4	32.2	35.7	43.0	48.9	30.5	27.1	28.0	28.8	30.3	31.8	33.5	34.3	36.8	37.2
33	Environmental Surcharge		39	5.3	6.0	8.0	8.4	8.7	9.4	14.8	15.1	15.4	16.4	16.6	17.7	18.6	19.2	20.1
34	Surcredit		40	(8.0)	(8.0)	(7.9)	(9.4)	(9.4)	(9.4)	(9.4)	(9.4)	(12.9)	(12.9)	(12.9)	(12.9)	(12.9)	(12.8)	(12.8)
35	Non-Smelter Member Economic Reserv		41	(24.7)	(25.1)	(21.3)	(26.4)	(24.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	TIER Related Rebate		45	(0.2)	(4.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	Effective Rate		46	**90.5**	**93.2**	**108.7**	**111.7**	**121.8**	**131.9**	**136.1**	**139.3**	**149.4**	**154.1**	**158.3**	**167.0**	**171.1**	**176.6**	**181.3**
38																		
39	Large Industrial ($M)	Line 5 x																
40	Base		53	33.4	34.4	35.5	36.6	37.7	38.8	39.8	40.9	42.0	43.1	44.2	45.2	46.3	47.4	48.5
41	Regulatory Account Charge		56	0.0	0.0	(0.1)	(0.1)	(0.1)	0.5	0.5	0.5	0.5	0.5	0.6	2.2	2.2	2.2	2.5
42	GRA		57	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.1	4.2	4.3	4.4	4.5	4.6	4.9
43	FAC		59	11.9	14.2	15.9	19.3	22.2	13.9	12.5	12.9	13.4	14.2	14.9	15.8	16.2	17.5	17.7
44	Environmental Surcharge		60	2.3	2.7	3.6	3.8	3.9	4.3	6.8	7.0	7.2	7.7	7.8	8.3	8.8	9.1	9.6
45	Surcredit		61	(3.5)	(3.5)	(3.5)	(4.2)	(4.3)	(4.3)	(4.3)	(4.3)	(6.0)	(6.0)	(6.1)	(6.1)	(6.1)	(6.1)	(6.1)
46	*Non-Smelter Member Economic Reserv*		*62*	*(10.8)*	*(11.1)*	*(9.5)*	*(11.9)*	*(11.1)*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
47	TIER Related Rebate		66	(0.1)	(1.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
48	Effective Rate		67	**33.3**	**35.0**	**41.8**	**43.5**	**48.3**	**53.2**	**55.3**	**57.0**	**61.2**	**63.6**	**65.7**	**69.9**	**72.0**	**74.7**	**77.0**
49																		
50	Non-Smelter Member Blend ($M)	(Lines 3 + 5) x																
51	Base		72	124.1	126.9	130.0	133.0	136.1	139.0	142.3	145.3	148.6	151.7	155.0	158.3	161.6	164.8	168.1
52	Regulatory Account Charge		74	0.0	0.0	(0.4)	(0.4)	(0.4)	1.7	1.7	1.7	1.7	1.7	1.7	6.8	6.8	6.8	7.6
53	GRA		75	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.5	14.8	15.1	15.4	15.7	16.0	16.9
54	FAC		77	39.3	46.4	51.6	62.4	71.1	44.4	39.6	40.9	42.2	44.4	46.7	49.3	50.5	54.2	54.9
55	Environmental Surcharge		78	7.7	8.7	11.6	12.2	12.6	13.7	21.6	22.1	22.6	24.0	24.3	26.1	27.4	28.3	29.7
56	Surcredit		79	(11.5)	(11.5)	(11.5)	(13.7)	(13.7)	(13.7)	(13.7)	(13.7)	(18.9)	(18.9)	(18.9)	(19.0)	(18.9)	(18.9)	(18.9)
57	Non-Smelter Member Economic Reserv		80	(35.5)	(36.1)	(30.8)	(38.3)	(35.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
58	TIER Related Rebate		84	(0.3)	(6.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
59	Effective Rate		85	**123.8**	**128.2**	**150.5**	**155.1**	**170.0**	**185.2**	**191.5**	**196.4**	**210.6**	**217.7**	**223.9**	**236.9**	**243.0**	**251.3**	**258.4**
60																		
61	Smelters ($M)	(Lines 7 + 9) x																
62	Base Rate		88	205.4	205.4	205.4	205.7	205.4	205.4	205.4	205.7	225.3	225.3	225.3	225.6	225.3	225.3	225.9
63	TIER Adjustment		89	0.0	0.0	13.1	16.4	11.6	12.0	20.3	18.9	25.9	3.9	26.8	21.7	31.4	25.7	34.7
64	FAC		91	81.9	94.5	102.5	121.3	134.7	82.2	71.7	72.6	73.0	75.3	77.4	80.2	80.1	84.3	83.7
65	PPA		92	0.5	(2.8)	3.5	2.0	4.2	1.9	3.2	4.2	15.3	6.4	13.0	8.4	15.1	12.7	18.6
66	Environmental Surcharge		93	16.0	17.7	23.0	23.7	23.9	25.4	39.1	39.3	39.1	40.7	40.3	42.4	43.4	44.0	45.3
67	Surcharge 1		94	5.1	5.1	5.1	7.3	7.3	7.3	7.3	7.3	10.2	10.2	10.2	10.2	10.2	10.2	10.2
68	Surcharge 2		95	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	8.8	8.8	8.8	8.8	8.8	8.8	8.8
69	*TIER Related Rebate*		97	*(0.7)*	*(12.6)*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
70	Effective Rate		98	**314.6**	**313.6**	**359.0**	**382.9**	**393.5**	**340.6**	**353.3**	**354.5**	**397.5**	**370.5**	**401.7**	**397.3**	**414.3**	**411.0**	**427.1**
71																		
72	Market ($M)	Line 11 x Line 100		**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**
73																		
74	Overall Blend ($M)	Line 13 x Line 102		**532.7**	**550.4**	**597.2**	**628.9**	**662.9**	**608.0**	**626.9**	**629.6**	**675.7**	**661.9**	**685.3**	**693.7**	**716.5**	**720.7**	**740.1**

	Derivation from Financial Model, Pro forma Worksheet	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Detail - Rates Expressed in $M																
Without Gradualism																
Rural ($M)	Line 3 x															
Base	33	90.8	92.5	94.5	96.4	98.4	100.3	102.4	104.4	106.6	108.6	110.8	113.0	115.3	117.4	119.6
Regulatory Account Charge	35	0.0	0.0	(0.3)	(0.3)	(0.3)	1.1	1.1	1.1	1.2	1.2	1.2	4.6	4.6	4.6	5.2
GRA	36	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.4	10.6	10.8	11.0	11.2	11.4	12.1
FAC	38	27.4	32.2	35.7	43.0	48.9	30.5	27.1	28.0	28.8	30.3	31.8	33.5	34.3	36.8	37.2
Environmental Surcharge	39	5.3	6.0	8.0	8.4	8.7	9.4	14.8	15.1	15.4	16.4	16.6	17.7	18.6	19.2	20.1
Surcredit	40	(8.0)	(8.0)	(7.9)	(9.4)	(9.4)	(9.4)	(9.4)	(9.4)	(12.9)	(12.9)	(12.9)	(12.9)	(12.9)	(12.8)	(12.8)
Non-Smelter Member Economic Reserv	41	(24.7)	(29.8)	(31.6)	(35.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TIER Related Rebate	45	(0.2)	(4.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Effective Rate	46	**90.5**	**88.5**	**98.5**	**103.1**	**146.4**	**131.9**	**136.1**	**139.3**	**149.4**	**154.1**	**158.3**	**167.0**	**171.1**	**176.6**	**181.3**
Large Industrial ($M)	Line 5 x															
Base	53	33.4	34.4	35.5	36.6	37.7	38.8	39.8	40.9	42.0	43.1	44.2	45.2	46.3	47.4	48.5
Regulatory Account Charge	56	0.0	0.0	(0.1)	(0.1)	(0.1)	0.5	0.5	0.5	0.5	0.5	0.6	2.2	2.2	2.2	2.5
GRA	57	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.1	4.2	4.3	4.4	4.5	4.6	4.9
FAC	59	11.9	14.2	15.9	19.3	22.2	13.9	12.5	12.9	13.4	14.2	14.9	15.8	16.2	17.5	17.7
Environmental Surcharge	60	2.3	2.7	3.6	3.8	3.9	4.3	6.8	7.0	7.2	7.7	7.8	8.3	8.8	9.1	9.6
Surcredit	61	(3.5)	(3.5)	(3.5)	(4.2)	(4.3)	(4.3)	(4.3)	(4.3)	(6.0)	(6.0)	(6.1)	(6.1)	(6.1)	(6.1)	(6.1)
Non-Smelter Member Economic Reserv	62	(10.8)	(13.1)	(14.0)	(15.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TIER Related Rebate	66	(0.1)	(1.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Effective Rate	67	**33.3**	**32.9**	**37.3**	**39.6**	**59.4**	**53.2**	**55.3**	**57.0**	**61.2**	**63.6**	**65.7**	**69.9**	**72.0**	**74.7**	**77.0**
Non-Smelter Member Blend ($M)	(Lines 3 + 5) x															
Base	72	124.1	126.9	130.0	133.0	136.1	139.0	142.3	145.3	148.6	151.7	155.0	158.3	161.6	164.8	168.1
Regulatory Account Charge	74	0.0	0.0	(0.4)	(0.4)	(0.4)	1.7	1.7	1.7	1.7	1.7	1.7	6.8	6.8	6.8	7.6
GRA	75	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.5	14.8	15.1	15.4	15.7	16.0	16.9
FAC	77	39.3	46.4	51.6	62.4	71.1	44.4	39.6	40.9	42.2	44.4	46.7	49.3	50.5	54.2	54.9
Environmental Surcharge	78	7.7	8.7	11.6	12.2	12.6	13.7	21.6	22.1	22.6	24.0	24.3	26.1	27.4	28.3	29.7
Surcredit	79	(11.5)	(11.5)	(11.5)	(13.7)	(13.7)	(13.7)	(13.7)	(13.7)	(18.9)	(18.9)	(18.9)	(19.0)	(18.9)	(18.9)	(18.9)
Non-Smelter Member Economic Reserv	80	(35.5)	(42.9)	(45.6)	(50.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TIER Related Rebate	84	(0.3)	(6.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Effective Rate	85	**123.8**	**121.4**	**135.7**	**142.7**	**205.8**	**185.2**	**191.5**	**196.4**	**210.6**	**217.7**	**223.9**	**236.9**	**243.0**	**251.3**	**258.4**
Smelters ($M)	(Lines 7 + 9) x															
Base Rate	88	205.4	205.4	205.4	205.7	205.4	205.4	205.4	205.7	225.3	225.3	225.3	225.6	225.3	225.3	225.9
TIER Adjustment	89	0.0	0.0	13.1	16.4	11.6	12.1	20.3	18.9	25.9	3.9	26.8	21.7	31.4	25.7	34.7
FAC	91	81.9	94.5	102.5	121.3	134.7	82.2	71.7	72.6	73.0	75.3	77.4	80.2	80.1	84.3	83.7
PPA	92	0.5	(2.8)	3.5	2.0	4.2	1.9	3.2	4.2	15.3	6.4	13.0	8.4	15.1	12.7	18.6
Environmental Surcharge	93	16.0	17.7	23.0	23.7	23.9	25.4	39.1	39.3	39.1	40.7	40.3	42.4	43.4	44.0	45.3
Surcharge 1	94	5.1	5.1	5.1	7.3	7.3	7.3	7.3	7.3	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Surcharge 2	95	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	8.8	8.8	8.8	8.8	8.8	8.8	8.8
TIER Related Rebate	97	(0.7)	(12.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Effective Rate	98	**314.6**	**313.6**	**358.9**	**382.9**	**393.4**	**340.7**	**353.3**	**354.5**	**397.5**	**370.5**	**401.7**	**397.3**	**414.3**	**411.0**	**427.1**
Market ($M)	Line 11 x Line 100	**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**
Overall Blend ($M)	Line 13 x Line 102	**532.7**	**543.6**	**582.3**	**616.4**	**698.6**	**608.1**	**626.9**	**629.6**	**675.7**	**661.9**	**685.3**	**693.7**	**716.5**	**720.7**	**740.1**

Item 6) Assume for purposes of answering this question that Big Rivers reacquires operational control of the generating facilities now operated by Western Kentucky Energy Corporation ("WKEC"). Provide a schedule which shows in MWs for each year 2009 through 2023 Big Rivers' maximum peak generating capacity excluding the Southeastern Power Administration ("SEPA") allocation, peak SEPA allocation, maximum peak capacity including SEPA, peak native load, peak smelter load, peak Henderson load, peak committed sales, if any, and reserve margin expressed in MWs and percent. All load figures should be shown separately for base case and high case where available.

Response) Please see attached spreadsheets addressing numbers for the Base Case and High Case. Additionally, Big Rivers has provided the requested information with a change to the SEPA Allocation for the years 2009 through 2012.

Due to safety issues at Wolf Creek, the U.S. Army Corps of Engineers has significantly reduced the level of Lake Cumberland. As a result, the SEPA contract has been under Force Majeure since February 2007. Big Rivers' maximum allocation remains 178 MW. However, under the Force Majeure, Big Rivers is unable to schedule this power. The schedule is determined by SEPA on a daily basis. Therefore, Big Rivers has decided to conservatively assume the capacity to be 0 MW through 2012 when repairs are expected to be completed.

Witness) C. William Blackburn

BASE CASE

	Peak Generating Capacity	Peak SEPA Allocation	Maximum Peak Capacity including SEPA	Peak Native Load	Peak Smelter Load	Peak Henderson Load	Peak Committed Sales	Reserve Margin	Reserve Margin - %
2009	1738	178	1916	677	850	95	0	294	15%
2010	1737	178	1915	687	850	95	0	283	15%
2011	1737	178	1915	699	850	95	0	271	14%
2012	1737	178	1915	709	850	100	0	256	13%
2013	1737	178	1915	721	850	100	0	244	13%
2014	1737	178	1915	732	850	100	0	233	12%
2015	1737	178	1915	745	850	100	0	220	11%
2016	1737	178	1915	756	850	100	0	209	11%
2017	1737	178	1915	769	850	100	0	196	10%
2018	1737	178	1915	781	850	100	0	184	10%
2019	1737	178	1915	794	850	100	0	171	9%
2020	1737	178	1915	806	850	100	0	159	8%
2021	1737	178	1915	820	850	100	0	145	8%
2022	1737	178	1915	832	850	100	0	133	7%
2023	1737	178	1915	844	850	100	0	121	6%

HIGH CASE

	Peak Generating Capacity	Peak SEPA Allocation	Maximum Peak Capacity including SEPA	Peak Native Load	Peak Smelter Load	Peak Henderson Load	Peak Committed Sales	Reserve Margin	Reserve Margin - %
2009	1738	178	1916	717	870	95	0	234	12%
2010	1737	178	1915	728	870	95	0	222	12%
2011	1737	178	1915	741	870	95	0	209	11%
2012	1737	178	1915	752	870	100	0	193	10%
2013	1737	178	1915	765	870	100	0	180	9%
2014	1737	178	1915	776	870	100	0	169	9%
2015	1737	178	1915	790	870	100	0	155	8%
2016	1737	178	1915	804	870	100	0	141	7%
2017	1737	178	1915	823	870	100	0	122	6%
2018	1737	178	1915	840	870	100	0	105	5%
2019	1737	178	1915	859	870	100	0	86	4%
2020	1737	178	1915	878	870	100	0	67	3%
2021	1737	178	1915	898	870	100	0	47	2%
2022	1737	178	1915	918	870	100	0	27	1%
2023	1737	178	1915	938	870	100	0	7	0%

BASE CASE

	Peak Generating Capacity	Peak SEPA Allocation	Maximum Peak Capacity including SEPA	Peak Native Load	Peak Smelter Load	Peak Henderson Load	Peak Committed Sales	Reserve Margin	Reserve Margin - %
2009	1738	0	1738	677	850	95	0	116	7%
2010	1737	0	1737	687	850	95	0	105	6%
2011	1737	0	1737	699	850	95	0	93	5%
2012	1737	0	1737	709	850	100	0	78	4%
2013	1737	178	1915	721	850	100	0	244	13%
2014	1737	178	1915	732	850	100	0	233	12%
2015	1737	178	1915	745	850	100	0	220	11%
2016	1737	178	1915	756	850	100	0	209	11%
2017	1737	178	1915	769	850	100	0	196	10%
2018	1737	178	1915	781	850	100	0	184	10%
2019	1737	178	1915	794	850	100	0	171	9%
2020	1737	178	1915	806	850	100	0	159	8%
2021	1737	178	1915	820	850	100	0	145	8%
2022	1737	178	1915	832	850	100	0	133	7%
2023	1737	178	1915	844	850	100	0	121	6%

Due to dam safety issues at Wolf Creek the U S Army Corps of Engineers has significantly reduced the level of Lake Cumberland As a result the SEPA contract has been under Force Majeure since February 2007 Big Rivers' maximum allocation remains 178MW However, under the Force Majeure Big Rivers is unable to schedule this power; the schedule is etermined by SEPA on a daily basis Therefore, Big Rivers has decided to conservatively assume the capacity to be 0 MW thru 2012 when repairs are expected to be completed

HIGH CASE

	Peak Generating Capacity	Peak SEPA Allocation	Maximum Peak Capacity including SEPA	Peak Native Load	Peak Smelter Load	Peak Henderson Load	Peak Committed Sales	Reserve Margin	Reserve Margin - %
2009	1738	0	1738	717	870	95	0	56	3%
2010	1737	0	1737	728	870	95	0	44	3%
2011	1737	0	1737	741	870	95	0	31	2%
2012	1737	0	1737	752	870	100	0	15	1%
2013	1737	178	1915	765	870	100	0	180	9%
2014	1737	178	1915	776	870	100	0	169	9%
2015	1737	178	1915	790	870	100	0	155	8%
2016	1737	178	1915	804	870	100	0	141	7%
2017	1737	178	1915	823	870	100	0	122	6%
2018	1737	178	1915	840	870	100	0	105	5%
2019	1737	178	1915	859	870	100	0	86	4%
2020	1737	178	1915	878	870	100	0	67	3%
2021	1737	178	1915	898	870	100	0	47	2%
2022	1737	178	1915	918	870	100	0	27	1%
2023	1737	178	1915	938	870	100	0	7	0%

Due to dam safety issues at Wolf Creek the U S Army Corps of Engineers has significantly reduced the level of Lake Cumberland As a result the SEPA contract has been under Force Majeure since February 2007. Big Rivers' maximum allocation remains 178MW However, under the Force Majeure Big Rivers is unable to schedule this power; the schedule is determined by SEPA on a daily basis. Therefore, Big Rivers has decided to conservatively assume the capacity to be 0 MW thru 2012 when repairs are expected to be completed

Item 7) Assume both the unwind scenario and no change in retail electric rates for Jackson Purchase Energy Corporation except to pass through the rates proposed by Big Rivers as shown in the 10/08 Application, Exhibit 79, the Unwind Financial Model, at page 3, lines 33-46. Provide a schedule which shows in dollars for each year 2008 through 2023, a monthly electric bill for a residential customer of Jackson Purchase Energy Corporation using 1,300 kWs. The 2008 monthly bill should reflect pre-unwind and all other years should reflect post-unwind. The monthly bill should show separately the amount of the customer charge, base rate charge, fuel adjustment charge, environmental surcharge, any other credit or charge, and the total bill.

Response) Please see spreadsheet on page 2 of 2.

Witness) Jack D. Gaines

										JPE							
	Item a	BREC Rural Existing $/kWh Purchased b	GRA c	GRA for Regulatory Account d	FAC e	ES f	US g	MRSM h	Rebate i	Customer Charge j	Base Energy Charge (1) k	FAC l	ES m	US n	MRSM o	Rebate p	Total q
1	Existing Rates:									$ 9.00	$ 0.06211						
2																	
3																	
4	Monthly kWh										1,300						
5																	
6	Loss Factor										5.93%						
7																	
8	Year																
9	2008	$ 0.03722	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9.00	$ 80.74	-	-	-	-	-	89.74
10	2009	$ 0.03722	$ -	$ -	$ 0.01122	$ 0.00219	$ (0.00328)	$ (0.01013)	$ -	$ 9.00	$ 80.74	15.50	3.02	(4.53)	(14.00)	-	89.74
11	2010	$ 0.03719	$ -	$ -	$ 0.01295	$ 0.00242	$ (0.00320)	$ (0.01008)	$ (0.00010)	$ 9.00	$ 80.74	17.90	3.34	(4.42)	(13.93)	(0.13)	92.50
12	2011	$ 0.03717	$ -	$ (0.00010)	$ 0.01404	$ 0.00315	$ (0.00312)	$ (0.00838)	$ (0.00176)	$ 9.00	$ 80.60	19.41	4.35	(4.31)	(11.58)	(2.43)	95.04
13	2012	$ 0.03714	$ -	$ (0.00010)	$ 0.01658	$ 0.00324	$ (0.00364)	$ (0.01019)	$ -	$ 9.00	$ 80.61	22.92	4.48	(5.03)	(14.08)	-	97.90
14	2013	$ 0.03712	$ -	$ (0.00010)	$ 0.01846	$ 0.00327	$ (0.00355)	$ (0.00928)	$ -	$ 9.00	$ 80.61	25.51	4.52	(4.90)	(12.82)	-	101.92
15	2014	$ 0.03709	$ -	$ 0.00042	$ 0.01127	$ 0.00348	$ (0.00347)	$ -	$ -	$ 9.00	$ 81.33	15.57	4.81	(4.79)	-	-	105.92
16	2015	$ 0.03707	$ -	$ 0.00041	$ 0.00982	$ 0.00536	$ (0.00339)	$ -	$ -	$ 9.00	$ 81.31	13.57	7.41	(4.68)	-	-	106.62
17	2016	$ 0.03704	$ -	$ 0.00040	$ 0.00993	$ 0.00537	$ (0.00332)	$ -	$ -	$ 9.00	$ 81.30	13.72	7.42	(4.59)	-	-	106.85
18	2017	$ 0.03702	$ 0.00360	$ 0.00041	$ 0.01000	$ 0.00536	$ (0.00449)	$ -	$ -	$ 9.00	$ 86.29	13.82	7.41	(6.21)	-	-	110.31
19	2018	$ 0.03700	$ 0.00360	$ 0.00040	$ 0.01032	$ 0.00558	$ (0.00440)	$ -	$ -	$ 9.00	$ 86.27	14.26	7.71	(6.08)	-	-	111.16
20	2019	$ 0.03698	$ 0.00360	$ 0.00039	$ 0.01060	$ 0.00552	$ (0.00430)	$ -	$ -	$ 9.00	$ 86.26	14.65	7.63	(5.94)	-	-	111.60
21	2020	$ 0.03695	$ 0.00360	$ 0.00152	$ 0.01096	$ 0.00580	$ (0.00422)	$ -	$ -	$ 9.00	$ 87.81	15.15	8.01	(5.83)	-	-	114.15
22	2021	$ 0.03694	$ 0.00360	$ 0.00148	$ 0.01098	$ 0.00595	$ (0.00412)	$ -	$ -	$ 9.00	$ 87.76	15.18	8.23	(5.69)	-	-	114.48
23	2022	$ 0.03692	$ 0.00359	$ 0.00145	$ 0.01156	$ 0.00603	$ (0.00404)	$ -	$ -	$ 9.00	$ 87.72	15.97	8.34	(5.58)	-	-	115.45
24	2023	$ 0.03690	$ 0.00372	$ 0.00159	$ 0.01147	$ 0.00621	$ (0.00396)	$ -	$ -	$ 9.00	$ 88.08	15.85	8.58	(5.47)	-	-	116.04

(1) Includes GRA and GRA for Regulatory Account

Item 8) Provide a schedule showing the same information as requested in Item No. 7 for a residential customer of Kenergy Corp.

Response) Please see spreadsheet attached on page 2 of 2.

Witness) Jack D. Gaines

										Kenergy							
	Item	BREC Rural Existing $/kWh Purchased	GRA	GRA for Regulatory Account	FAC	ES	US	MRSM	Rebate	Customer Charge	Base Energy Charge (1)	FAC	ES	US	MRSM	Rebate	Total
	a	b	c	d	e	f	g	h	i	j	k	l	m	n	o	p	q
1	Existing Rates:									$ 9.91	$0.059956						
2																	
3																	
4	Monthly kWh										1,300						
5																	
6	Loss Factor										4.75%						
7																	
8	Year																
9	2008	$ 0.03722	$.	$ -	$ -	$ -	$ -	$ -	$ -	$ 9.91	$ 77.94	-	-	-	-	-	87.85
10	2009	$ 0.03722	$ -	$ -	$ 0.01122	$ 0.00219	$ (0.00328)	$ (0.01013)	$ -	$ 9.91	$ 77.94	15.31	2.98	(4.47)	(13.83)	-	87.85
11	2010	$ 0.03719	$ -	$ -	$ 0.01295	$ 0.00242	$ (0.00320)	$ (0.01008)	$ (0.00010)	$ 9.91	$ 77.94	17.68	3.30	(4.37)	(13.76)	(0.13)	90.58
12	2011	$ 0.03717	$ -	$ (0.00010)	$ 0.01404	$ 0.00315	$ (0.00312)	$ (0.00838)	$ (0.00176)	$ 9.91	$ 77.80	19.17	4.30	(4.26)	(11.44)	(2.40)	93.08
13	2012	$ 0.03714	$ -	$ (0.00010)	$ 0.01658	$ 0.00324	$ (0.00364)	$ (0.01019)	$ -	$ 9.91	$ 77.81	22.63	4.43	(4.97)	(13.91)	-	95.91
14	2013	$ 0.03712	$ -	$ (0.00010)	$ 0.01846	$ 0.00327	$ (0.00355)	$ (0.00928)	$ -	$ 9.91	$ 77.81	25.19	4.46	(4.84)	(12.66)	.	99.87
15	2014	$ 0.03709	$ -	$ 0.00042	$ 0.01127	$ 0.00348	$ (0.00347)	$ -	$ -	$ 9.91	$ 78.52	15.38	4.75	(4.73)	-	-	103.83
16	2015	$ 0.03707	$ -	$ 0.00041	$ 0.00982	$ 0.00536	$ (0.00339)	$ -	$ -	$ 9.91	$ 78.51	13.40	7.32	(4.62)	-	-	104.52
17	2016	$ 0.03704	$ -	$ 0.00040	$ 0.00993	$ 0.00537	$ (0.00332)	$ -	$ -	$ 9.91	$ 78.49	13.55	7.33	(4.53)	-	-	104.75
18	2017	$ 0.03702	$ 0.00360	$ 0.00041	$ 0.01000	$ 0.00536	$ (0.00449)	$ -	$ -	$ 9.91	$ 83.42	13.65	7.32	(6.13)	-	-	108.16
19	2018	$ 0.03700	$ 0.00360	$ 0.00040	$ 0.01032	$ 0.00558	$ (0.00440)	$ -	$ -	$ 9.91	$ 83.41	14.08	7.61	(6.00)	-	-	109.01
20	2019	$ 0.03698	$ 0.00360	$ 0.00039	$ 0.01060	$ 0.00552	$ (0.00430)	$ -	$ -	$ 9.91	$ 83.39	14.47	7.54	(5.87)	-	-	109.44
21	2020	$ 0.03695	$ 0.00360	$ 0.00152	$ 0.01096	$ 0.00580	$ (0.00422)	$ -	$ -	$ 9.91	$ 84.92	14.96	7.91	(5.75)	-	-	111.95
22	2021	$ 0.03694	$ 0.00360	$ 0.00148	$ 0.01098	$ 0.00595	$ (0.00412)	$ -	$ -	$ 9.91	$ 84.88	14.99	8.13	(5.62)	-	-	112.28
23	2022	$ 0.03692	$ 0.00359	$ 0.00145	$ 0.01156	$ 0.00603	$ (0.00404)	$ -	$ -	$ 9.91	$ 84.83	15.78	8.23	(5.51)	-	-	113.24
24	2023	$ 0.03690	$ 0.00372	$ 0.00159	$ 0.01147	$ 0.00621	$ (0.00396)	$ -	$ -	$ 9.91	$ 85.19	15.66	8.47	(5.40)	-	-	113.83

(1) Includes GRA and GRA for Regulatory Account

Item 9) Provide a schedule showing the same information as requested in Item No. 7 for a residential customer of Meade County Rural Electric Cooperative Corporation.

Response) Please see spreadsheet on page 2 of 2.

Witness) Jack D. Gaines

										Meade							
	Item	BREC Rural Existing $/kWh Purchased	GRA	GRA for Regulatory Account	FAC	ES	US	MRSM	Rebate	Customer Charge	Base Energy Charge (1)	FAC	ES	US	MRSM	Rebate	Total
	a	b	c	d	e	f	g	h	i	j	k	l	m	n	o	p	q
1	Existing Rates:									$ 9.85	$ 0.06001						
2																	
3																	
4	Monthly kWh										1,300						
5																	
6	Loss Factor										4.58%						
7																	
8	Year																
9	2008	$ 0.03722	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9.85	$ 78.01	-	-	-	-	-	87.86
10	2009	$ 0.03722	$ -	$ -	$ 0.01122	$ 0.00219	$ (0.00328)	$ (0.01013)	$ -	$ 9.85	$ 78.01	15.28	2.98	(4.46)	(13.80)	-	87.86
11	2010	$ 0.03719	$ -	$ -	$ 0.01295	$ 0.00242	$ (0.00320)	$ (0.01008)	$ (0.00010)	$ 9.85	$ 78.01	17.65	3.30	(4.36)	(13.73)	(0.13)	90.58
12	2011	$ 0.03717	$ -	$ (0.00010)	$ 0.01404	$ 0.00315	$ (0.00312)	$ (0.00838)	$ (0.00176)	$ 9.85	$ 77.87	19.13	4.29	(4.25)	(11.42)	(2.39)	93.08
13	2012	$ 0.03714	$ -	$ (0.00010)	$ 0.01658	$ 0.00324	$ (0.00364)	$ (0.01019)	$ -	$ 9.85	$ 77.88	22.59	4.42	(4.96)	(13.88)	-	95.90
14	2013	$ 0.03712	$ -	$ (0.00010)	$ 0.01846	$ 0.00327	$ (0.00355)	$ (0.00928)	$ -	$ 9.85	$ 77.88	25.15	4.46	(4.83)	(12.64)	-	99.86
15	2014	$ 0.03709	$ -	$ 0.00042	$ 0.01127	$ 0.00348	$ (0.00347)	$ -	$ -	$ 9.85	$ 78.59	15.35	4.74	(4.72)	-	-	103.81
16	2015	$ 0.03707	$ -	$ 0.00041	$ 0.00982	$ 0.00536	$ (0.00339)	$ -	$ -	$ 9.85	$ 78.58	13.38	7.31	(4.61)	-	-	104.50
17	2016	$ 0.03704	$ -	$ 0.00040	$ 0.00993	$ 0.00537	$ (0.00332)	$ -	$ -	$ 9.85	$ 78.56	13.52	7.31	(4.52)	-	-	104.73
18	2017	$ 0.03702	$ 0.00360	$ 0.00041	$ 0.01000	$ 0.00536	$ (0.00449)	$ -	$ -	$ 9.85	$ 83.48	13.62	7.30	(6.12)	-	-	108.14
19	2018	$ 0.03700	$ 0.00360	$ 0.00040	$ 0.01032	$ 0.00558	$ (0.00440)	$ -	$ -	$ 9.85	$ 83.47	14.06	7.60	(5.99)	-	-	108.98
20	2019	$ 0.03698	$ 0.00360	$ 0.00039	$ 0.01060	$ 0.00552	$ (0.00430)	$ -	$ -	$ 9.85	$ 83.45	14.45	7.53	(5.86)	-	-	109.41
21	2020	$ 0.03695	$ 0.00360	$ 0.00152	$ 0.01096	$ 0.00580	$ (0.00422)	$ -	$ -	$ 9.85	$ 84.98	14.94	7.90	(5.74)	-	-	111.92
22	2021	$ 0.03694	$ 0.00360	$ 0.00148	$ 0.01098	$ 0.00595	$ (0.00412)	$ -	$ -	$ 9.85	$ 84.94	14.96	8.11	(5.61)	-	-	112.25
23	2022	$ 0.03692	$ 0.00359	$ 0.00145	$ 0.01156	$ 0.00603	$ (0.00404)	$ -	$ -	$ 9.85	$ 84.89	15.75	8.22	(5.50)	-	-	113.21
24	2023	$ 0.03690	$ 0.00372	$ 0.00159	$ 0.01147	$ 0.00621	$ (0.00396)	$ -	$ -	$ 9.85	$ 85.25	15.63	8.45	(5.39)	-	-	113.79

(1) Includes GRA and GRA for Regulatory Account

Item 10) Refer to the 10/08 Application, Exhibit 79.

a. On page 5, line 122, fuel costs increase annually from $270.6 million in 2009 to $370.3 million in 2013, but then decrease by $111.2 million to $259.1 million in 2014. Explain why fuel costs as modeled decrease so significantly in 2014.

b. On page 5, line 126, environmental costs increase steadily from 2009 through 2023. Explain why environmental costs do not decrease in 2014 as do fuel costs.

c. On page 8, line 235, Fuel Stock and Related, annual balances increase steadily from 2009 through 2013, decrease significantly in 2014, and then resume increasing through 2023. Explain the reason for the sudden drop in fuel inventory in 2014.

Response) a. WKEC solicited bids for coal supply during March 2008. Big Rivers collaborated with WKEC in regard to fuel bidding, evaluation, selection, and planned coal supply contractual agreement assignment upon completion of the lease termination.

Based upon the bids received, Big Rivers had current marketplace data upon which to evaluate and escalate coal supply opportunities between 2009 and 2013. The majority of the bids offered, however, did not provide any "market" guidance beyond a five-year window. Further, as a result of coal demand outstripping supply, market pricing of fuel had escalated precipitously. While consultants considered the run-up in market pricing to be a near-term price effect (a "bubble" of up to two years), Big Rivers took a more conservative approach in its forecasted estimations through the five-year window (2009 – 2013). Global Insight's forward forecast was utilized for year

2014, and thereafter in Big Rivers' modeling, which is why the forecast dips lower from year 2013 to 2014.

b. Environmental costs are reagent, disposal and allowances. Those costs (other than allowances) are goods and services that are anticipated to continue to increase in price. Allowance prices are based on forecasted prices. No decreases are indicated for environmental costs. *See* response to Item 10.a, above, for the explanation of why fuel costs decrease.

c. The drop in fuel inventory (assignment of value of fuel stock) is aligned with the de-escalation attributable to the Global Insight forecast commencing in 2014 and thereafter.

Big Rivers has used its best efforts, along with input from reputable industry consultants, to estimate probable fuel cost.

Witness) C. William Blackburn
David A. Spainhoward

Item 11) Will a physical inventory of fuel on hand be conducted prior to closing the unwind transaction? If yes, who will conduct the inventory and when will it take place?

Response) Yes. The physical inventory will be conducted by L. Robert Kimball and Associates. The target date for the physical inventory is mid-December 2008.

Witness) C. William Blackburn

Item 12) Refer to the 10/08 Application, Exhibit 78, the Third Supplemental Direct Testimony of C. William Blackburn ("Third Supplemental Blackburn Testimony"). On pages 58-59, Mr. Blackburn states that Big Rivers has begun efforts to construct the "Phase 2" transmission line authorized by the Commission on October 30, 2007, in Case No. 2007-00177.[1] Describe the steps that Big Rivers has taken or will take to commence construction of the Phase 2 transmission line prior to October 30, 2008. If these steps include actual physical construction of the transmission line, provide a current photograph of the project worksite showing the construction work in progress. If these steps include financial commitments, explain the nature and amounts anticipated to be incurred by October 30, 2008.

Response) The steps taken and financial commitments made by Big Rivers to commence the construction of the Phase 2 transmission line on or before October 30, 2008 include the following:

1) completing the route selection, centerline survey, environmental assessment of the proposed construction, and engineering design of the line construction for the 13.19 mile line at a total cost to-date of $341,000. A copy of the line survey and the notice that construction was beginning was sent to the Commission on October 17, 2008 (copy of letter attached).

2) acquiring of private right-of-way easements from approximately one-third of the project property owners at a total cost to-date of $122,000;

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1 Case No 2007-00177, The Application of Big Rivers Electric Corporation For a Certificate of Public Convenience and Necessity to Construct a 161 kV Transmission Line in Ohio County, Kentucky

3) committing to the $4.8 million funding needed to complete the project construction through board of directors' approval of work order;

4) beginning the initial phase of the project construction involving the clearing of trees/brush within available right-of-way easement areas as shown in the attached photograph(s) of the project worksite. In addition, a copy of the first invoice for period ending October 25, 2008 is attached.

5) continuing pursuit of the acquisition of unsecured easements through negotiation with remaining property owners; and

6) beginning the preparation of specifications necessary for the solicitation of bids and purchase of construction materials required on the project.

Witness) David A. Spainhoward

Big Rivers
Electric Corporation

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

October 17, 2008

Ms. Stephanie L. Stumbo
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: Administrative Case No. 2007-00177

Dear Ms. Stumbo:

As directed in the Commission's October 30, 2007 order in the above referenced case, you will find enclosed a copy of the survey of the location of the 161 kV transmission line Big Rivers Electric Corporation will construct. This survey is being submitted prior to construction. Construction will begin this month.

Please feel free to contact me should you have any questions or desire additional information.

Sincerely,

David Spainhoward

David A. Spainhoward
Vice President External Relations &
Interim Chief Production Officer
Big Rivers Electric Corporation

DAS/img
Enclosure

Cc: Mark Bailey
David Crockett ✓
James M. Miller, Esq.

INVOICE NO. 002-101938
Oct 28, 2008
1021401

TOWNSEND

100904
Big Rivers Electric Corp
PO Box 24
201 3rd Street
Henderson KY 42419

Attention: Dana Clevidence

For period ending October 25, 2008

Purchase Order# 118692 W/0819

Description	Hours Type	Hours	Rate	Extended Amount
LABOR				
Foreman/Spray Foreman	REG	40.00	25.30	1,012.00
Trimmer B	REG	80.00	20.00	1,600.00
TOTAL LABOR		120.00		2,612.00
EQUIPMENT				
Pikcup		40.00	7.25	290.00
Power Saw		120.00	0.90	108.00
TOTAL EQUIPMENT		160.00		398.00

Total Amount Due This Invoice: 3,010.00

Foreman - James Booker
Wilson Station

Item 13) Refer to the 10/08 Application, Exhibit 78, pages 60-62. Provide a detailed discussion of Big Rivers' ability to market excess capacity in the quantities and at the prices set forth in the October Unwind Financial Model. Provide any sensitivity analysis which supports these projected quantities and prices.

Response) Big Rivers' 10/08 Application, Exhibit 78 (Third Supplemental Testimony of C. William Blackburn), pages 60-62 presents additional support for Big Rivers' position that an adequate market exists for off-system resale of wholesale power sales transactions now devoted to the Smelters should the Smelters depart Big Rivers' system. As part of that support, Big Rivers presented two principal pieces of information. First, in Exhibit CWB-18, Big Rivers presented information regarding the size of the neighboring wholesale power markets to demonstrate that a robust wholesale market exists in which any excess Smelter energy could be resold. Second, Big Rivers presented Exhibit CWB-19, containing Platt's 2008 *Power Sales Analysis'* projections of the forward price of 7x24 blocks of power at the CinHub over the term of the transaction. The purpose of this Exhibit CWB-19 was to supplement the information already contained in Big Rivers' Unwind Financial Model to provide a second demonstration that wholesale market prices would in all years be in excess of the rate projected to be charged to the Smelters.

As noted in Exhibit 78 at page 62, "Big Rivers' Unwind Financial Model already indicates that in each future year the projected market prices in neighboring markets will be in excess of the rate charged to the Smelters." To be clear, Big Rivers did not intend for Exhibit CWB-19 to serve as its justification for the level of off-system sales incorporated in the Unwind Financial Model or even to have any bearing on that issue. It was provided simply as a second demonstration that forecasted market prices appear uniformly to be in excess of the power price being offered to the Smelters such that if they were to shutdown Big Rivers would have an ability to remarket that energy. Exhibit CWB-19 presents a power price projection that is limited to a single market node, the CinHub, whereas the Unwind Financial Model contains a more comprehensive regional pricing analysis using a regional variable cost dispatch forecast from ACES Power Marketing ("APM") that projects likely dispatches of regional units based on the modeled fuel price forecasts used in the Unwind Financial Model. *See* Exhibit 10, Direct Testimony of C. William Blackburn at page 28. Big Rivers believes that the information contained in the Unwind Financial Model presents its best available evidence regarding both the quantity to be sold and the price to be received for Big Rivers' off-system sales of excess energy, and that remains the case whether or not the Smelters remain on the system.

The quantity of excess energy projected to be sold in the wholesale markets in the Unwind Financial Model is simply a reflection of the units' availability less the sum of the Non-Smelter and Smelter loads to be served. In the Production Cost Model, Application Exhibit 97, Big Rivers has presented the support that it has the ability to produce the level of energy necessary to achieve the projected off-system sales. Mr. Bob Berry, who will be Big Rivers Vice President and Chief Production Officer at the Unwind Closing, has reviewed the Production Cost Model and is in agreement with the availability level of the generating units included therein.

After availability has determined the amount of excess energy available to be sold, the issue becomes whether Big Rivers can effect a sale and at what price. Since 1998 Big Rivers has been extremely successful in selling its excess energy in the wholesale markets. *See* Response to PSC Item 35 dated February 14, 2008 in which I present Big Rivers' marketing of off-system power over the past ten years. Even during the Enron troubles, Big Rivers did not lose any revenues from the collapse of counterparties in the wholesale market. Big Rivers has also demonstrated its ability to move its excess energy into the wholesale markets at an extremely high utilization level on peak as well as off peak. At the closing of the Unwind Transaction, Big Rivers will have sufficient transmission available to move all of its excess energy to its border for delivery into the MISO, KU/LGE and TVA interconnected systems.

Big Rivers also has a firm 100 MW transmission reservation across the TVA system which allows Big Rivers to reach the SOCO and PJM markets. The TVA firm transmission provides Big Rivers the diversity to reach markets that may be trading at a premium due to localized weather or generating conditions.

Obviously, actual market conditions will determine the price received when Big Rivers markets excess energy off-system, but Big Rivers believes the pricing underlying its Unwind Financial Model remains the best information available of these future pricing trends and Big Rivers is confident that it will be able effectively to remarket all excess quantities of energy. Other than the latest version of the Unwind Financial Model presented as Application Exhibit 79, Big Rivers has performed no sensitivity analyses in specific support of the projected quantities and prices reflected therein.

Witness) C. William Blackburn

Item 14) Refer to the Third Supplemental Blackburn Testimony, page 68. Mr. Blackburn states that Big Rivers requested a ruling from the Kentucky Department of Revenue that neither the payment nor receipt of the termination value payment, nor WKEC's waiver of its right to the Residual Value Payment ("RVP"), would be subject to Kentucky sales and use tax but that the Department of Revenue declined to issue such a ruling without first reviewing the Participation Agreement and the Station Two Agreements.

a. Have the Participation Agreement and the Station Two Agreements been provided to the Department of Revenue to review for purposes of rendering a ruling on the question of the payment of Kentucky sales and use tax for the payment and receipt of the termination value payment and WKEC's waiver of its right to the RVP? If yes, state when the agreements were provided and when a written ruling is anticipated. If no, explain why the agreements have not been so provided.

b. Is it reasonable for Big Rivers to enter into the unwind transaction without receiving a ruling from the Department of Revenue regarding this tax issue? Explain the answer and include a schedule showing for years 2008 through 2023 the annual financial impact on Big Rivers of a ruling that all aspects of the unwind transaction are subject to Kentucky sales and use tax.

c. Explain fully the accounting and legal basis for Big Rivers' opinion that the termination value payment and the RVP are not subject to sales and use tax because they constitute intangible property which is not subject to the sales and use tax.

Response) a. Big Rivers has not provided the Participation Agreement or the Station Two Agreements to the Kentucky Department of Revenue (hereinafter the "KDOR"). As discussed more fully in response to question 14(c) herein, Big Rivers believes the termination payment (the "Termination Payment") and the residual value payment ("RVP") relate solely to intangible property. In paragraph 2(C) of KDOR's Revenue Ruling dated February 25, 2008, issued to Big Rivers (the "Big Rivers Ruling") and paragraph B(7) of KDOR's Revenue Ruling dated February 18, 2008, issued to E.ON (the "E.ON ruling"), the KDOR stated:

> [A]ny payments or receipts explicitly for the transfer of intangible property (contract rights, intellectual property, permits, and SO_2 and NO_x allowances, etc.) by WKEC to Big Rivers within the Unwind Transaction are not subject to the sales tax imposed under KRS 139.200 for retail sales of tangible personal property or the furnishing of specified services.

Furthermore, per KRS §§139.200 and 139.100, the Kentucky sales tax applies only to gross receipts from the sale of *tangible* personal property.

Based upon the KDOR's statements, the Kentucky sales and use tax statutes, and the substantial belief of both E.ON and Big Rivers that the Termination Payment and RVP relate solely to intangible rights, each of the parties decided that follow up action with the KDOR was not required.

b. Big Rivers believes it is reasonable to proceed with the unwind transaction in the absence of a definitive ruling as to this tax issue. For the reasons explained in its response to question 14(c) below, Big Rivers believes there are substantial grounds and authority for the position that the Termination Payment and RVP relate to intangible personal property which is not subject to Kentucky sales or use tax. *See*, KRS §§139.100 & 139.200; *see also*, Big Rivers Ruling, paragraph (2)(C).

Accordingly, it is Big Rivers' position that they could successfully refute an assertion that these elements of the unwind transaction are subject to Kentucky sales or use tax.

c. As part of the lease entered into by and between WKEC and Big Rivers pursuant to the Participation Agreement, WKEC was obligated to fund the cost of leasehold improvements (the "Leasehold Improvements"). WKEC was entitled, however, to recoup a portion of its investment through the right to a RVP to the extent of the undepreciated cost of the Leasehold Improvements at lease expiration. Pursuant to the terms of the lease, Leasehold Improvements made by WKEC immediately vested in Big Rivers. Pursuant to the Termination Agreement, WKEC will release Big Rivers from its contractual (intangible) obligation to remit such RVP. In the following cases, the courts discussed whether certain property rights constituted taxable tangible or exempt intangible personal property under Kentucky's sales and use tax law.

In WDKY-TV, Inc. v. Revenue Cabinet, 838 S.W.2d 431 (Ky. App. 1992), the Court of Appeals held that the "right to broadcast television programs" did not constitute tangible personal property as that term is defined under the Kentucky sales and use tax statute, notwithstanding the fact that the transfer of the rights was accompanied by the transfer of tangible personal property (*i.e.*, video tape) which was taxable under the statute. The intangible broadcasting right was not made tangible and therefore taxable when purchased at the same time as the video tape that was being used to transmit the broadcast.

The facts in this case involved certain licensing agreements with syndicators in which WDKY received an exclusive right to broadcast a program in WDKY's market area for a limited number of times over a specified period of time. Generally, WDKY obtained possession of a program in one of two ways – via satellite transmission or by video tape transmission. When the image was transmitted via satellite, a station engineer received the transmission and recorded it on a video tape purchased and owned by the station. Sales and/or use tax was paid on these video tapes. The KDOR sought to tax the transfer of broadcast rights when it was accompanied by the transfer of tangible goods pursuant to KRS 139.310.

The only issue before the Court of Appeals was whether the intangible broadcasting rights were somehow made tangible and therefore taxable when purchased at the same time as a video tape that was being used to transmit the broadcast. The KDOR argued that there was no meaningful distinction between the items of tangible personal property and something tangible in nature. Courts have held that the sale or transfer of a copyright ownership for instance, or of the exclusive rights of copyright, does not, in the absence of an agreement conveying a right in a material object, trigger sales tax.

Thus, the right to the RVP, which is based on the undepreciated cost of the Leasehold Improvements, is an intangible right and does not convey any right to the material object (*i.e.*, the Leasehold Improvements themselves) without a specific contractual obligation to convey the property and improvements with the intangible rights to the RVP. The right to a RVP does not include the conveyance of a right to the tangible personal property itself (since title to the Leasehold Improvements vested in Big Rivers at the time the Leasehold Improvements were made).

The facts here presented are analogous to the facts in WDKY in that the issue concerned whether or not the intangible contract rights can be taxed when the underlying object of those rights concerns certain tangible personal property. Unlike WDKY, the facts here concern intangible contract rights that relate to the right to receive a payment which is determined based on the undepreciated cost of the underlying property, rather than a pure intangible right whose value is wholly independent of the value of the tangible personal property to which it relates. The Court of Appeals in WDKY noted that the "right to use" property can be separate and distinct from the "tangible property" itself.

Thus, the right to a RVP pursuant to the Participation Agreement is separate and apart from the right to the Leasehold Improvement themselves.

The Court of Appeals in Alpha, Ltd. v. Revenue Cabinet, No. 92-CA-002637, slip op. (Ky. App. 1994), held that the right of a taxpayer to exhibit motion pictures in the taxpayer's theaters is distinct from the reel and tape the motion pictures are contained on, and the "exhibition rights" are not tangible property subject to Kentucky use tax. The Court of Appeals held that the right to exhibit motion pictures is an intangible property and is separable from the reel and tape which constitutes tangible personal property. In that case, the taxpayer paid license fees to certain motion picture exhibitors which were located out of state for the right to publicly exhibit motion pictures between the years 1995 and 1997.

The taxpayer was a theater company which publicly exhibited motion pictures in its theaters. The taxpayer typically negotiated with out-of-state distributors, such as Paramount and TriStar to exhibit motion pictures in exchange for a license fee less a house allowance. License fees were usually based upon a percentage of gross receipts received from the admissions. Likewise, the taxpayer also paid a sales tax on the price of admissions paid by the patrons. The Court of Appeals followed the holding in WDKY and decided that the right to use can be separated from the tangible personal property itself and the right to display taped images on the TV screens of a populace is distinct from the right inherent in the ownership of the thing itself, to view the tape for one's own enjoyment.

In Quotron Systems, Inc. v. Revenue Cabinet, Order No. K89-R-1043 (KBTA 1990), the Kentucky Board of Tax Appeals ("KBTA") held that certain financial information provided by the taxpayer to its subscribers did not constitute tangible personal property. The taxpayer was engaged in the business of providing sophisticated financial services to its subscribers who were primarily banks, stock brokerage firms and other businesses, which needed up-to-date information from national stock exchanges.

The financial information provided to the consumers included quotations of the latest sales price of a security, dividends, yield and earnings of selected companies, and various other financial information. The subscribers could access and retrieve financial information via equipment provided by the taxpayer. This equipment consisted of communications processing desk units. The taxpayer installed the equipment on the subscriber's premises; however, it was not a "true" computer and the equipment had no independent value to the subscriber (apart from the financial information services system). The taxpayer did not relinquish control over the units and remained its sole owner at all times. No form of ownership or lease interest vested in or passed to the subscriber. The KBTA held that the equipment placed in the subscriber's offices was merely incidental to the financial information provided and was therefore not subject to sales tax.

Both Alpha and WDKY stand for the proposition that rights in property can be separated from the property itself for sales tax purposes. Thus, if rights connected with certain property are transferred, rather than the tangible personal property itself, the courts are more likely to hold that the interest transferred is intangible property, not subject to Kentucky sales or use tax.

The Termination Payment relates to a release of WKEC from certain contractual obligations and liabilities and is, therefore, intangible in nature. The Termination Payment does not involve the sale of taxable tangible personal property or services. Because the Kentucky sales and use tax only applies to gross receipts from the sale of tangible personal property and certain specified services (none of which are involved here), the Termination Payment would not be subject to such tax. Likewise, WKEC's relinquishment of rights under or pursuant to the Station Two Agreement is exempt from Kentucky sales and use tax as such rights represent intangibles.

WKEC's waiver and release of its future right to receive the RVP from Big Rivers is an intangible property right separate and distinct from the leasehold improvements.

Moreover, an argument could be made that the leasehold improvements constitute fixtures attached to realty. In which case, the leasehold improvements would not be subject to tax, as fixtures are exempt from the Kentucky sales and use tax.

Witness) C. William Blackburn
Counsel

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE COMMISSION STAFF'S OCTOBER 24, 2008
SUPPLEMENTAL DATA REQUEST TO BIG RIVERS ELECTRIC CORPORATION
PSC CASE NO. 2007-00455
November 7, 2008

Item 15) Refer to the 10/08 Application, Exhibit 80, the Third Amendment to Transaction Termination Agreement, Appendix D, "Draft Agreed Order." Has the Draft Agreed Order been executed by WKEC and entered as a final Order by the Energy and Environment Cabinet? If yes, provide a copy of the Order as entered and a narrative description of any changes made prior to its entry, including a description of how such changes, if any, will affect the rights and obligations of Big Rivers with regard to the operation of the Coleman Station and the Wilson Station if the unwind transaction is successfully completed.

Response) According to WKEC's legal counsel, the Agreed Order has been executed by WKEC and forwarded to the Kentucky Energy and Environment Cabinet for signatures and entry as an Order of the Cabinet. No changes have been made to the Agreed Order attached to the Third Amendment to Transaction Termination Agreement. According to the Cabinet's legal counsel, the Agreed Order is being circulated for signatures at the Cabinet.

Witness) David A. Spainhoward

Item 16) Refer to the 10/08 Application, Exhibit 92, Affidavit of C. William Blackburn. Attachment 2 to the affidavit is a model which assumes a successful unwind transaction and further assumes an AIG guaranteed investment contract ("GIC") value of approximately $68 million. Page 41 of the affidavit states that this model demonstrates that Big Rivers would remain financially viable, but page 38 of the affidavit states that Big Rivers would not enter into the PMCC buyout unless the value of the AIG GIC is at least $85 million. Explain why Big Rivers would not proceed with the Buyout if the AIG GIC was valued more than $68 million and less than $85 million.

Response) Big Rivers' response on Page 41 of my affidavit (Exhibit 92) referencing a $68 million GIC value was based on the premise of a simultaneous closing of the unwind transaction and the buyout of PMCC. Under this circumstance, E.ON had agreed to share the cost difference between the termination values of $214 million less the assumed GIC value of $68 million, on a 50% basis. Therefore, the cash flow impact to Big Rivers would have been mitigated, with Big Rivers required to make a net payment of approximately $73 million.

In response to changes in the credit spread required by AIG above the long-term LIBOR rates produced by the circumstances surrounding turmoil in the financial markets and the government loan to AIG during September of this year, the value of the GIC suddenly increased to approximately $85 million. With the financial markets in turmoil, Big Rivers at that time determined it would be better to move forward and buyout the PMCC leveraged leases then rather waiting until closing of the Unwind Transaction. In making this decision, Big Rivers had to be certain it would remain financially viable whether or not the Unwind Transaction closed. At that point in time, Big Rivers projected its lowest cash balance to be approximately $129 million during the following 12 months. As stated on Page 36 of my affidavit (Exhibit 92), Big Rivers determined that it needed to maintain no less than $20 million of cash on hand after engaging in the PMCC buyout.

With the PMCC termination value of $214 million and a GIC value of $85 million, the additional payment to PMCC at termination of the leveraged lease would have been $129 million. In order to achieve the level of cash on hand that Big Rivers had determined it needed to maintain, Big Rivers determined it could pay $109 million in cash and issue an unsecured short-term note to PMCC for $20 million. Since PMCC was not willing to agree to an unsecured note greater than $20 million and Big Rivers had determined its minimum cash on hand level to be $20 million, the GIC had to have a minimum value of $85 million in order for a pre-closing PMCC buyout to be financially viable. Thus, while a $68 million GIC value was acceptable in the context of a simultaneous PMCC buyout and closing of the Unwind Transaction, a higher GIC value was needed for Big Rivers to be able to enter into an early PMCC buyout.

Witness) C. William Blackburn