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June 1, 2009

Jeff DeRouen
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: In the Matter of: Notice and Application of Big Rivers Electric Corporation for a General Rate Adjustment in Rates, P.S.C. Case No. 2009-00040

Dear Mr. DeRouen:

Enclosed for filing on behalf of Big Rivers Electric Corporation ("Big Rivers") are an original and seven (7) copies of Big Rivers' response to the Commission Staff's Fourth Data Request and Big Rivers' response to KIUC's Third Data Requests. I certify that a copy of the responses has been served on the attached service list.

Sincerely yours,

TSK

Tyson Kamuf

C: Mark A. Bailey
David A. Spainhoward
Service List

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SERVICE LIST
BIG RIVERS ELECTRIC CORPORATION
PSC CASE NO. 2009-00040

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

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

VERIFICATION

I verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

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 29th day of May, 2009.

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

VERIFICATION

I verify, state, and affirm that data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

David A. Spainhoward

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by David A. Spainhoward on this the 29th day of May, 2009.

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

VERIFICATION

I verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

C. William Blackburn

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by C. William Blackburn on this the 29th day of May, 2009.

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

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE COMMISSION STAFF'S FOURTH DATA REQUEST
TO BIG RIVERS ELECTRIC CORPORATION
PSC CASE NO. 2009-00040
June 1, 2009

Item 1) Refer to Big Rivers' Response to Commission Staff's Third Data Request, Item 19.

a. Part a. of this request was for all calculations and workpapers supporting the temperature normalization adjustment of $1,026,905 shown in Seelye Exhibit 2, Schedule 1.13. Big Rivers did not provide the requested information. Provide the supporting regression parameters, regression analyses, modeling and forecasting assumptions, and calculations details supporting the temperature normalization adjustment.

b. Refer to part b. of this response, Page 4 of 6. Big Rivers states that, "Normal energy sales were computed for each month as actual sales plus the monthly degree day coefficient times the difference between normal and actual degree days." Describe in detail the reasons for developing the proposed temperature normalization adjustment based on degree day variations for individual months as opposed to degree day variations for a complete season, i.e., the cooling season or the heating season.

c. Part d. of this response provides the differences in the methodology used in this temperature normalization adjustment and that proposed by Mr. Seelye in the most recent Kentucky Utilities and Louisville Gas and Electric rate cases. Explain the reasons for differences noted in response to part d. (ii), (iii), and (iv).

d. Refer to schedule 19.a., page 1 of 1. Provide this schedule for the test year prior to normalization.

Response) a. The regression parameters were provided in Big River's Response to Commission Staffs Third Data Request, Item 19, part b, pages 2-4 of 6. The tables included in the response present the following statistics for each regression parameter: the coefficient, standard error, t-statistic, and p-value. The regression outputs and associated model statistics are on the enclosed CD in files METRIXND_KENERGY_KWH.XLS, METRIXND_JPEC_KWH.XLS, and METRIXND_MCRECC_KWH.XLS. The model statistics are summarized as follows:

Kenergy	
Regression Statistics	
Iterations	6
Adjusted Observations	95
Deg. of Freedom for Error	79
R-Squared	0.980
Adjusted R-Squared	0.976
Durbin-Watson Statistic	1.976
Durbin-H Statistic	#NA
AIC	29.597
BIC	30.027
F-Statistic	253.264
Prob (F-Statistic)	0.0000
Log-Likelihood	-1508.59
Model Sum of Squares	2.33E+16
Sum of Squared Errors	4.84E+14
Mean Squared Error	6.13E+12
Std. Error of Regression	2475798
Mean Abs. Dev. (MAD)	1746941
Mean Abs. % Err. (MAPE)	1.87%
Ljung-Box Statistic	33.64
Prob (Ljung-Box)	0.0913
Skewness	0.024
Kurtosis	3.051
Jarque-Bera	0.0
Prob (Jarque-Bera)	0.9863

Jackson Purchase Energy Corp	
Regression Statistics	
Iterations	6
Adjusted Observations	59
Deg. of Freedom for Error	43
R-Squared	0.984
Adjusted R-Squared	0.978
Durbin-Watson Statistic	1.800
Durbin-H Statistic	#NA
AIC	28.424
BIC	28.987
F-Statistic	176.867
Prob (F-Statistic)	0.0000
Log-Likelihood	-890.86
Model Sum of Squares	4.68E+15
Sum of Squared Errors	7.58E+13
Mean Squared Error	1.76E+12
Std. Error of Regression	1327614
Mean Abs. Dev. (MAD)	899196
Mean Abs. % Err. (MAPE)	1.67%
Ljung-Box Statistic	44.37
Prob (Ljung-Box)	0.0069
Skewness	-0.010
Kurtosis	2.915
Jarque-Bera	0.0
Prob (Jarque-Bera)	0.9868

Meade County RECC	
Regression Statistics	
Iterations	7
Adjusted Observations	59
Deg. of Freedom for Error	43
R-Squared	0.981
Adjusted R-Squared	0.975
Durbin-Watson Statistic	1.795
Durbin-H Statistic	#NA
AIC	28.050
BIC	28.613
F-Statistic	149.146
Prob (F-Statistic)	0.0000
Log-Likelihood	-880.01
Model Sum of Squares	2.71E+15
Sum of Squared Errors	5.21E+13
Mean Squared Error	1.21E+12
Std. Error of Regression	1101008
Mean Abs. Dev. (MAD)	749885
Mean Abs. % Err. (MAPE)	2.04%
Ljung-Box Statistic	42.36
Prob (Ljung-Box)	0.0117
Skewness	0.116
Kurtosis	2.786
Jarque-Bera	0.2
Prob (Jarque-Bera)	0.8297

The modeling assumptions are: (1) energy sales are weather sensitive, (2) weather impacts vary across months within the heating and cooling seasons, and (3) a current 20-year period is a reasonable time period over which to compute normal weather conditions.

The computations of normalized energy sales are provided in spreadsheet "COMPUTATION OF NORMAL RURAL SYSTEM ENERGY.XLS," enclosed on the attached CD. This file presents actual energy sales, actual and normal heating and cooling degree days, and the normalized energy values. The spreadsheet cells containing the normalized amounts include the formulas developed to compute the normal values.

The spreadsheet "COMPUTATION OF NORMAL RURAL SYSTEM ENERGY.XLS" reflects revised normalized energy sales relative to those filed on May 4, 2009. Normal energy sales were computed using the MetixND software package. When creating the spreadsheet "COMPUTATION OF NORMAL RURAL SYSTEM ENERGY.XLS," it was determined that a programming error was made within MetrixND when computing the 20-year normal degree day values. The normal energy

values originally filed sum to 2,346,551 MWh. The corrected sum is 2,351,392 MWh, which is 0.2% higher than the filed amount.

Normalized demands are computed using monthly normalized energy and average monthly load factors. The computations are provided on the enclosed CD in file "NORMALIZED ENERGY AND DEMAND BY COOPERATIVE.XLS". The load factors listed for each cooperative and month represent averages for years 2001-2008. This file includes revisions to the normal demands for the 12 months ending November 2008, which result from revisions to the normal energy values for the same period.

b. The energy normalization adjustment was based on degree day variations for individual months as opposed to degree day variations for a complete season, i.e., the cooling season or the heating season, to capture the varying degree day impacts across months. For instance, the impact on energy consumption of relatively a hot day in May or September is not as significant as in July or August. Similarly, the impact on energy consumption of relatively a cold day in November or March is not as great as that in January. The proportion of air conditioning and heating systems operating in the spring and fall months is not as high as the proportion of systems operating during the respective summer and winter months. The model coefficients support this assumption as their magnitudes increase during the hottest and coldest months. The results of Big Rivers' energy normalization process would be different from a model that had single heating degree day and cooling degree day parameters that represent the entire seasons; however, the model specification used by Big Rivers provides a better tool for estimating weather impacts on a monthly basis than does a model that incorporates the assumption that heating and cooling impacts are constant across all months in their respective seasons.

c. Please note that Big Rivers' temperature normalization adjustment was prepared using models developed by GDS Associates, Inc. and was prepared without reviewing the testimony submitted by Mr. Seelye in the Kentucky Utilities and Louisville Gas and Electric rate cases referenced in the question.

With respect to the differences noted in Big Rivers' response to Item 19, part d. (ii) of the Commission Staff's Third Data Request, Big Rivers believes that it is

reasonable to calculate the temperature normalization adjustments utilizing a multivariate regression analysis that includes heating degree days, cooling degree days and a trend variable. It is Big Rivers' understanding that this is a standard approach used in the industry.

With respect to the differences noted in Big Rivers' response to Item 19, part d. (iii) of the Commission Staff's Third Data Request, Big Rivers believes that for a G&T cooperative it is appropriate to perform the regression analysis using monthly data rather than daily data. Unlike integrated utilities such as Kentucky Utilities and Louisville Gas and Electric Company, Big Rivers does not bill retail customers using billing cycles; therefore, it is less important for Big Rivers to consider daily kWh variations resulting in changes in temperature. Furthermore, because Big Rivers' model analyzed monthly rather than daily sales data, it was appropriate to perform the analysis over multiple years and also to include a trend variable which accounts for changes in sales over time.

With respect to the differences noted in Big Rivers' response to Item 19, part d. (iv) of the Commission Staff's Third Data Request, Big Rivers believes that 20-year average heating and cooling degree days more accurately represent current normal weather conditions than 30-year averages, but still include enough data points to represent a reasonable estimate of mean value temperatures, as opposed to 10- or 15-year averages, for example. Also, Big Rivers collects degree days from the National Oceanic and Atmospheric Administration for Paducah, Kentucky and Evansville, Indiana. Data for the Paducah site (airport) is only available for years beginning 1984; therefore, a 30-year average cannot be computed for the Paducah station. As a result, Big Rivers is not able to provide weather normalized energy estimates based on 30 years. Many utilities across the country now compute normal degree days on 20 years or less, rather than 30 years. Research conducted by Big Rivers' consultant, GDS Associates, Inc., indicates that 16 of 31 electric utilities interviewed across the U.S. and Canada base normal degree days on 20 years or less, while 1 uses 25 years, and 14 use 30 years (Load Forecasting Practices and Methodology Benchmark Study, March 2007).

d. Weather normalized energy sales and peak demand for the 12 months ending November 2007 are provided on the enclosed CD in file "NORMAL ENERGY AND DEMAND_12MOEND-NOV07.XLS

Witness) C. William Blackburn
William Steven Seelye

Item 2) Refer to Big Rivers' Response to KIUC's Second Data Request, Item 6.

a. Refer to page 3 of 7.

1) The first bullet on this page states that for Smelter Tier 3 firm sales, a contract price was used for January through August and a market price for the remainder of the year. Item 6a, page 27 of 35, provides these market prices. Explain how the specific market prices used for each month were selected and provide all supporting documentation.

2) The second bullet on this page states that, for Smelter Tier 3 fully interruptible sales, a contract price is used for January through July and then $30/MWh for the balance of the year. Explain the basis for the change to $30/MWh.

3) The third bullet on this page states that the non-tariff non-smelter on-peak hourly sales were priced at 93.5% of the January 21, 2009 forward price curve for CIN HUB. Explain the basis for pricing the sales at 93.5%.

b. Refer to Item 6, page 4 of 7. The sixth bullet on this page states that Big Rivers is projecting to purchase 23,200 MWhs of energy at an average market price of $150/MWh. In response to Item 6a, page 33 of 35, Big Rivers projects to be able to sell power into the market at prices between $30.08/MWh and $59.19/MWh. Explain the large variance between the rate at which Big Rives can purchase from the market, and the rate at which it can sell into the market, and provide supporting documentation for the projected rates.

c. Refer to Item 6b, page 2 of 2. Provide the calculations to support the amounts shown on lines 6, 11, 20, 26, 27, 28, 34, 35, 36, and 40 in the Pro forma column.

Response) Introduction and Explanation:

For purposes of Big Rivers' response to this Item 2, the following information may be helpful. On-peak power has a duration of 16 hours for each of the 5 work-days in a week and is referred to as a 5x16. It is beneficial to use this type of transaction if it is known that a specific block of megawatts will be purchased or sold for each of the 16 hours. This is usually not the case because Big Rivers has the ability to

cover its demand for 60 to 75% of the 16 on-peak hours of peak days. A peak day would be one of the 5 work-days and it would occur on a very hot day in summer or a very cold day in winter. Big Rivers always has the ability to cover all 16 on-peak hours of a non-peak day. Non-peak days are warmer winter days and cooler summer days.

For hourly transactions, purchases are made hourly based upon need for the next hour. This allows purchase of megawatts needed just for the hour in which the power is needed rather than a block of power for 16 hours (including on-peak hours). This purchase sometimes will be more expensive on an hourly basis but it allows Big Rivers to buy only the quantity needed for the time that it is needed and will usually result in less expense for the day.

The "super-peak" hours are usually the 4 to 6 hours within the 16 peak hours when the hourly price is very high. For a peak day, those super-peak hours are even more critical because the demand is higher.

a. 1) The forward prices were extracted from a spreadsheet on a members-only section of the website of Big Rivers' Marketer, ACES Power Marketing. This file is provided on an enclosed CD in file RateCaseFwdCurve20090210.xls. The forward prices used from the website are contained in the workbook KIUC 2-6 Pro Forma Off-System Sales provided by Big Rivers in response to KIUC 2-6. As noted on the worksheet, "CIN HUB FORWARD PRICES" cell N34 SOCO, also known as Southern Company, prices on 2/10/2009 were actually used for determining pricing. The worksheet labels should read "SOCO" rather than CinHub. The market prices selected were based on Big Rivers' previous trading history and ability to transact at various trading hubs and also reflect an additional cost of $3/MWh to reflect approximate transmission costs across TVA that the smelters would incur if purchasing from any party within the SOCO trading area.

a. 2) The Alcan and Century Extension Agreement to Agreement For Tier 3 Energy and First Amendments dated November 26, 2008, terminate sixty days subsequent to termination of the Big Rivers-E.ON Termination Agreement. Therefore, continuation of the fully interruptible sales and pricing would be subject to renegotiation. The $30/MWh is an estimated price for fully interruptible power

after the expiration of those agreements. This estimate was generated based on telephone conversations with Big Rivers' power marketer ACES Power Marketing.

a. 3) A monthly forward curve price represents the price for each of the on-peak hours for the month. During super-peak hours of peak days, Big Rivers needs all of its power for native load and does not have power to sell into the market. Those super-peak hours are the highest priced and because power is not available to be sold, Big Rivers applies a general 6.5% discount to the forward curve monthly price to arrive at a representative price for the remaining power that Big Rivers will sell. Because weather is the main driver, no two months within the year yield the same load demand results and neither do the same months in different years. Not being able to have perfect knowledge of future power demand dynamics nor power price dynamics, 6.5% is a rule of thumb that Big Rivers has used over the years and it has served Big Rivers well.

b. Quite often during "super-peak" hours Big Rivers' resources are needed to cover native load leaving Big Rivers unable to participate in sales during "super peak" hours. However, Big Rivers often has power to sell the remainder of the on-peak period for a price less than the on-peak price.

When Big Rivers is purchasing power, it is usually during the "super-peak" time period when prices are higher than the on-peak price. Hence the difference between the purchase and sales price.

The $150/MWh represents the average annual price during super-peak pricing hours of each peak day. It was arrived at by considering the super-peak hourly prices at Big Rivers MISO LMP node for 2008. The source data is an Excel file which contains almost all hourly prices for 2008 on one tab and an analysis of the average price of the "super-peak" prices on the other tab. The spreadsheet is provided on an enclosed CD in file KPSC Table 4-2b.xls.

c. Line 6: This calculation is contained in the spreadsheet provided in response to the KIUC 2nd Data Request, Item 6. The spreadsheet file is named "KIUC Q 2-6 Pro forma Off System Sales.xls", on the worksheet "Hourly Sales", cell D24.

Line 11: Line 16 divided by Line 6

Line 20: This calculation is contained in the spreadsheet provided in response to the KPSC 3rd Data Request, Item 13. The spreadsheet file is named "PSC Item #13a Pro Forma Non-tariffed Energy Sales.XLS", on the worksheet "E_Rev", cell O343 plus cell O361.

Line 26: Line 32 divided by Line 4

Line 27: This number is not calculated. It is the price in $/MWh that Big Rivers purchased 50MW from Southern Illinois Power Cooperative (SIPC) for delivery during January thru February 2009.

Line 28: (Line 34 + Line 40 + Line 45) divided by Line 6

Line 34: This calculation includes power purchased from LEM at the contracted price of $20.327/MWh plus an estimate for LEM penalties for power purchased above contracted amounts and a Domtar CoGen Reservation Fee at monthly contracted amounts. The calculation is as follows:

362,015	Market MWh Sales - Line 6
X .9922	loss factor
364,860	required MWh purchases
X $20.327	LEM contract price
$7,416,509	purchased from LEM
$120,000	estimated LEM Penalties
$1,078,800	Domtar CoGen Reservation Fee – contracted at $89,900/mo for 12 months - contained in the spreadsheet provided in response to the KPSC 3rd Data Request, Item 13. The spreadsheet file is named "PSC Item #13a Pro Forma Non-tariffed Energy Sales.XLS", on the worksheet "PP_je", cell P15
$8,615,309	Total Market Purchased Power

Line 35: This calculation is contained in the spreadsheet provided in response to the KIUC 2nd Data Request, Item 6. The spreadsheet file is named "Demand & Energy Pro Forma-SQ Rate Case.xls", on the worksheet "Pro Forma", cell O122.

Line 36: Line 37 - Line 32 - Line 33 - Line 34.

Line 40: This calculation is contained in the spreadsheet provided in response to the KPSC 3rd Data Request, Item 13. The spreadsheet file is named "PSC Item #13a Pro Forma Non-tariffed Energy Sales.XLS", worksheet "TB" cell Q108.

Witness) C. William Blackburn

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE COMMISSION STAFF'S FOURTH DATA REQUEST
TO BIG RIVERS ELECTRIC CORPORATION
PSC CASE NO. 2009-00040
June 1, 2009

Item 3) Refer to the response to the second data request of KIUC, Item 8, page 3 of 7. Provide an update to this schedule to include April 2009.

Response) Please see the attached exhibit Big Rivers' Arbitrage Report for the month of April 2009.

Witness) C. William Blackburn

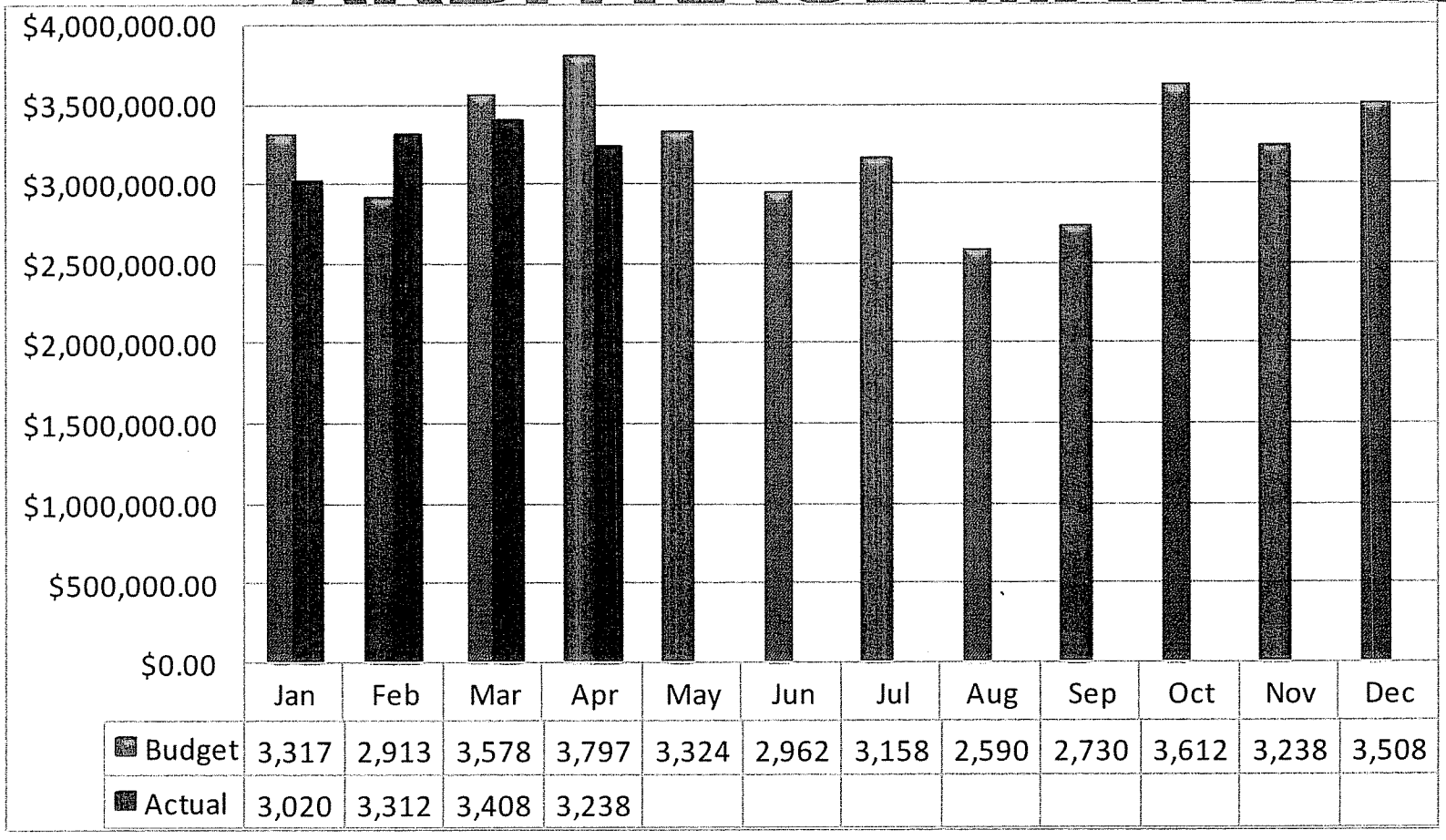
Big Rivers
ELECTRIC CORPORATION

ARBITRAGE REPORT

APRIL, 2009

Big Rivers
ELECTRIC CORPORATION

ARBITRAGE MARGINS



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Budget	3,317	2,913	3,578	3,797	3,324	2,962	3,158	2,590	2,730	3,612	3,238	3,508
Actual	3,020	3,312	3,408	3,238								

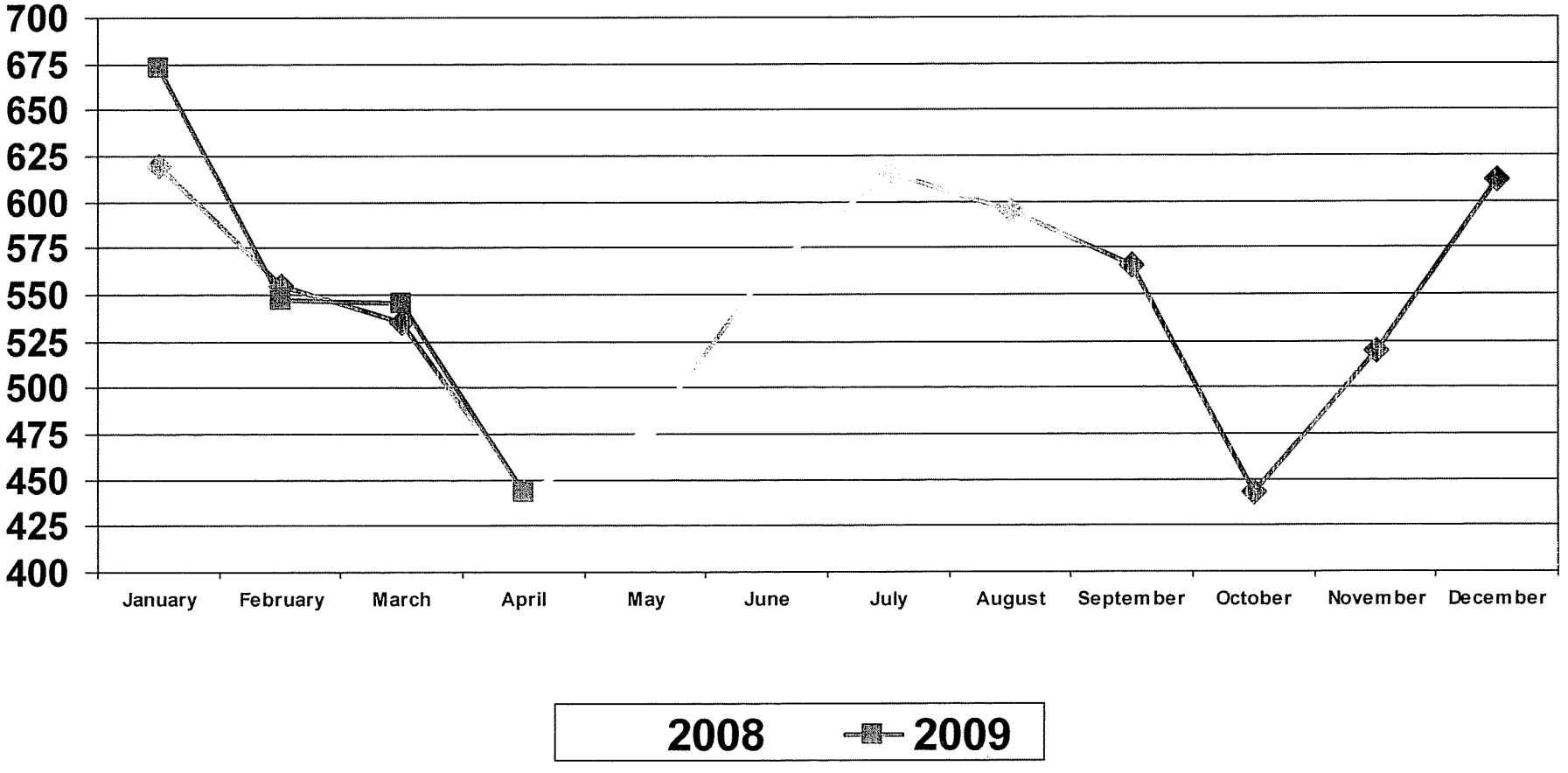
Big Rivers
ELECTRIC CORPORATION

BUDGET VARIANCE

MONTH	BUDGET	ACTUAL	VARIANCE	
January	3,317,006	3,020,553	(296,453)	
February	2,913,274	3,312,943	399,669	
March	3,578,957	3,408,666	(170,291)	
April	3,797,369	3,238,624	(558,745)	EST
May	3,324,590			
June	2,962,531			
July	3,158,566			
August	2,590,238			
September	2,730,766			
October	3,612,767			
November	3,238,873			
December	3,508,117			
Y-T-D	13,606,606	12,980,786	(625,820)	

Big Rivers
ELECTRIC CORPORATION

BIG RIVERS' PEAK



BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE COMMISSION STAFF'S FOURTH DATA REQUEST
TO BIG RIVERS ELECTRIC CORPORATION
PSC CASE NO. 2009-00040
June 1, 2009

Item 4) Refer to Big Rivers' Application, Exhibit 46, Seelye-2, Schedule 1.01 and Big Rivers' Response to commission Staff's Third Data Request, Item 3.b., Pages 2 and 24.

a. The information presented on Pages 2 and 24 appears to indicate that Big Rivers' share of West Kentucky Energy's ("WKE") budgeted Incremental O&M Distribution Expenses for the test year was $894,089 ($883,606, 2008 total - $35,000, December 2008 + $45,483, December 2007). On Schedule 1.01 Big Rivers states its share of WKE's actual Incremental O&M Distribution Expenses for the test year is $600,155 or $293,934 below the budgeted amount. This represents a budget variance of 33 percent. As shown on Schedule 1.01, Big Rivers proposed to increase the test year amount by $2,495,013 to provide for the annual recovery of $3,095,168, Big Rivers' share of WKE's 2009 budgeted costs.

1) Discuss the changes to CAIR that will become effective on January 1, 2009 and how those changes are expected to increase Big Rivers' share of WKE's budgeted Incremental O&M Distribution Expenses by 416 percent ($2,495,013 Increase / $600,155 test year).

2) Provide all evidence available to Big Rivers showing that WKE's budgeted Incremental O&M Distribution Expenses are reasonable.

3) 807 KAR 5:001, Section 10(7) required that all adjustments to historic test year operations must be known and measurable. Discuss how Big Rivers' adjustment on Schedule 1.01 meets this requirement given the significant budget variance noted during the test year.

4) Explain why it would not be appropriate to decrease the pro forma amount by the test-year budget variance of 33 percent.

b. Provide a schedule comparing the budget to actual WKE Incremental O&M Distribution Expenses allocated to Big Rivers for each year since the execution of the lease agreements between Big Rivers and the E.ON affiliates.

Response) a. 1) The Environmental Protection Agency issued the NOx SIP Call which provided specific limits on the number of tons of NOx which could be emitted

from generating units in various states, including Kentucky, during the "Ozone season", which is described as May 1 through September 30 of each year. To comply, Western Kentucky Energy/Big Rivers' control plan included modifications to most of the Big Rivers generating units and the Station Two generating units. The modifications included the installation of SCRs, overfire air, and other controls all of which require capital and O&M expenses to operate. Prior to January 1, 2009, the largest part of these expenses occurred during the five-month Ozone period.

Commencing January 1, 2009, the provisions of the NOx portion of the Clean Air Interstate Rule imposed a second allowance allocation period, based on annual NOx emissions. The new allocation period operates in addition to Ozone season allocation period. Consequently, the control plan shifted from a five month operating plan to a year-round basis, caused by the need for additional allowances to balance against emissions on an annual basis. In addition, the expense of operating installed equipment for five months became a year-round obligation. Compliance will be achieved through a combination of increased operating costs as well as the purchase of allowances.

The operating and maintenance costs of which Big Rivers pays its share include additional auxiliary power costs (parasitic load from operating equipment); incremental labor and non-labor; ammonia costs; emulsified sulfur costs; and hydrated lime.

a. 2) Please see Big Rivers' response to Commission Staff's Third Data Request, Item 3.b. Page 138 of 146 demonstrates how vulnerable Big Rivers costs are to the price of NOx allowances and the operations of the generating units. Big Rivers' 20% share is budgeted to be $849,316. While Big Rivers' actual costs could be more or less depending on the unit operations and the price of allowances, the expected cost is known and measurable. Pages 139 and 140 of 146 indicate a movement in fixed and variable O&M of $5.3 million ($11,229,260 - $5,913,918) from the five month Ozone obligation to the year-round NOx obligation. Moving from 5 months to 12 months, an extrapolation of the $5,913,918 ($5,913,918/5 = $1,182,783) would indicate the cost would be $14,193,396 ($1,182,783 x 12 = $14,193,396). Big Rivers believes the

$11.2 million is reasonable. If the budgeted cost is more, Big Rivers will be required to pay its 20% share. If WKE is successful in reducing costs then Big Rivers pays less.

a. 3) Please see response to a.2 above.

a. 4) It is not appropriate to reduce the pro-forma amount by 33% because Big Rivers is required to pay WKE 20% of actual cost. WKE has budgeted the amounts used in the pro-forma year and Big Rivers is required to pay the budgeted amount and must have the cash to do so. Pursuant to Section 2.3.3 of the Lease and Operating Agreement between Big Rivers and Western Kentucky Energy, Big Rivers is required to fund Incremental Environmental O&M costs on a monthly basis in an amount equal to Big Rivers' Incremental Environmental O&M share of the Incremental Environmental O&M costs estimated by WKE to be incurred in such month consistent with the relevant Annual O&M Budget for the Facilities. Within 120 days after the end of each year, Big Rivers and WKE are to conduct a reconciliation of (a) Big Rivers' Incremental Environmental O&M share of the actual Incremental Environmental O&M costs incurred in that year, with (b) the amount of such costs previously funded by Big Rivers for Incremental Environmental O&M costs for that year, and a reconciling payment is required to be made between the parties.

While the practice has been for WKE to invoice Big Rivers monthly and Big Rivers to pay monthly, the agreements are very clear that Big Rivers' obligation is to fund according to the budget with an annual true-up within 120 days after the end of the year. The result of the Lease and Operating Agreement is that Big Rivers is obligated to pay according to the budget for 2009, whether or not it ultimately results in a 33 percent variance. While a true-up mechanism exists, it comes too late for Big Rivers to meet its 2009/January 2010 cash obligation as described in this case. These cost obligations are known and measurable because they are determined by a known budget number.

b. Please see attached Exhibit 4.

Witness) David A. Spainhoward

Incremental O&M budget vs actual
BREC Share
Response to PSC 4 Item 4. b.

	2004	2005	2006	2007	2008
Budgeted	*$502,247*	*$590,157*	*$684,929*	*$844,260*	*$883,606*
invoiced	$227,145	$351,390	$421,803	$462,082	$600,155
Variance	$275,102	$238,767	$263,126	$382,178	$283,451

	January 2009	February 2009	March 2009	April 2009	**YTD 2009**	YTD with Lime
Pro-Formal	$189,989	$195,098	$220,569	$280,641	$886,297	$886,297
Invoiced	$78,110	$69,916	$82,670	$83,548	$314,244	$530,417
Variance *	$111,879	$125,182	$137,899	$197,093	$572,053	$355,880

WKE has not invoiced Big Rivers for any NOx allowances as of April 30.

In addition, WKE has discovered it has not invoiced Big Rivers for Hydrated Lime associated with SO3 since its inception, June 2006. Big Rivers was notified on May 27 that WKE will be invoicing Big Rivers for its share of that cost which will amount to approximately $216,173.

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE COMMISSION STAFF'S FOURTH DATA REQUEST
TO BIG RIVERS ELECTRIC CORPORATION
PSC CASE NO. 2009-00040
June 1, 2009

Item 5) Refer to Big Rivers' Response to Commission Staff's Third Data Request, Item 5.a., Page 2 of 6. This schedule shows the calculation of Big Rivers' share of WKE's Incremental Capital Budget for the years 2009 and 2010 in the amounts of $1,193,160 and $923,000, respectively. Provide a schedule comparing budget to actual WKE Incremental Capital costs allocated to Big Rivers for each year since the execution of the lease agreements between Big Rives and the E.ON affiliates.

Response) Please see the attached Exhibit 5 comparing budget to actual WKE Incremental Capital costs allocated to Big Rivers for each year since the execution of the agreements between Big Rivers and the E. ON affiliates.

Witness) C. William Blackburn
David A. Spainhoward

BIG RIVERS ELECTRIC CORPORATION
PSC Fourth Data Request - Item 5

Big Rivers' Share of WKEC's Incremental Capital Cost

	Budget	Actual	
1998	$0	$0	
1999	$0	$0	
2000	$0	$910,235	
2001	$0	$2,837,431	
2002	$11,896,000	$10,951,917	
2003	$7,576,000	$10,015,297	
2004	$2,709,000	$1,419,452	
2005	$0	$1,014,676	
2006	$0	($2,900)	
2007	$0	($19,820)	
2008	$0	$411,237	
2009 (Jan-Apr)	$849,160	$959,219	*
TOTALS	$23,030,160	$28,496,745	

* Includes 4 unpaid invoices which Big Rivers has agreed to pay for services or work performed on or before April 30:

HMPL #1 Third Catalyst Layer	$117,645
HMPL #2 Third Catalyst Layer	$131,215
Wilson SO3 Treatment & Insulation	$54,224
HMPL SCR legal costs	$50,515
	$353,598

* Includes 4 unpaid invoices which Big Rivers has not agreed to pay for services or work performed on or before April 30:

C-3 boiler waterwall overlay 2006	$37,025
C-2 boiler waterwall overlay 2007	$197,959
C-1 boiler waterwall overlay 2008	$232,135
Original Nox plan development (Grn SCR's)	$29,900
	$497,018

Item 6) Refer to Big Rivers' Response to Commission Staff's Third Data Request, Item 5.d., Page 1 of 5, and Big Rivers' Application, Exhibit 46, Seelye-2, Schedule 1.03. On Schedule 1.03 Big Rivers requests annual recovery of Transmission and General Plant expenditures in the amount of $14,331,923. This amount is equal to test year Transmission and General Plant expenditures. At Item 5.d. Big Rivers lists its annual Transmission and General Plant expenditures for each of the previous 10 years. As listed, Big Rivers Transmission and General Plant expenditures have fluctuated greatly over the past ten years. The lowest year is 1999 when the amount was negative at $407,465 and the highest year is 2008 when the amount was $15,629,112. Based on the 10-year total of $64,822,155, the 10-year average annual Transmission and General Plant expenditures equals $6,482,216.

a. Explain why the Transmission and General Plant expenditures listed for 1999 is a negative $407,465.

b. The annual Transmission and General Plant expenditures reported for the years 2001 through 2006 tend to be fairly constant. During these years the expenditures ranged from between $5,020,977 to $6,764,463. However, the amounts reported for 2007, 2008 and the test year are significantly higher at $12,130,235, $15,629,112 and $14,331,923, respectively. Given the spike in these expenditures during the last two calendar years, explain why it would not be appropriate to decrease the test year amount to the ten-year average of Transmission and General Plant expenditures to allow for the annual recovery of an amount that is more representative of a normal or average year.

c. Provide the total annual budgeted Transmission and General Plant expenditures for Big Rivers for each of the next five years. Provide detailed budgets when responding to this request.

Response) a. The negative $407,465 is erroneous. Please refer to Schedule A, attached hereto. The corrected 1999 cash paid for Transmission and General Plant capital expenditures was $2,924,966, resulting in total capital expenditures for 1999 of

$5,784,477. The revised 10-year Transmission and General Plant total is $68,154,586, and the 10-year average Transmission and General Plant expenditure equals $6,815,459.

b. Using the historical 10-year average is inappropriate for several reasons. First, the 10-year average does not take into account cost increases over that period. The Handy-Whitman Index of Public Utility Construction Costs, Bulletin No. 169, reflects that costs for Total Transmission Plant have escalated significantly over the past 10 years. Big Rivers' inflation-adjusted transmission and A&G capital expenditures are shown in the following chart:

YEAR	PERCENTAGE INCREASE IN TOTAL TRANSMISSION PLANT COSTS FROM JANUARY 1 OF THE APPLICABLE YEAR TO JANUARY 1, 2009	UNADJUSTED TRANSMISSION AND A&G CAPITAL EXPENDITURES	INFLATION-ADJUSTED TRANSMISSION AND A&G CAPITAL EXPENDITURES
1999	67.2	$2,924,966	$4,890,543
2000	68.7	$2,944,772	$4,967,830
2001	56.4	$5,761,755	$9,011,385
2002	52.2	$5,235,629	$7,968,627
2003	53.1	$5,744,901	$8,795,443
2004	50.3	$5,020,977	$7,546,528
2005	36.1	$5,997,776	$8,162,973
2006	26.0	$6,764,463	$8,523,223
2007	16.1	$12,130,235	$14,083,202
2008	7.1	$15,629,112	$16,738,779
10-Year Total		$68,154,586	$9,068,8534
10-Year Average		$6,815,459	$9,068,853

Thus, the 10-year inflation-adjusted average is $9,068,853, and using a 10-year average without such an adjustment would yield a result that is significantly less than what would actually be representative of a normal year.

Second, the unadjusted 10-year average is influenced by abnormally low expenditures in 1999 and 2000, which resulted from a stringent cost control program that Big Rivers implemented in 1998 following its exit from bankruptcy in an effort to build cash reserves and to protect itself at a time when it was largely unsure of what its true financial position would be post-bankruptcy. It would be unreasonable to include 1999 and 2000 in coming up with a typical year because expenditures in those two years are significantly less than any of the other years listed and are significantly lower than the norm. Expenditures are not anticipated to return to or come close to those levels. Thus, the 10-year average would not accurately reflect ongoing expenditures, making its usage inappropriate for rate-making purposes.

Third, the 10-year historical average is also inappropriate because it would not provide Big Rivers the cash it needs to remain solvent. Big Rivers' Original 2009 Transmission and Administrative & General (A&G) Capital Expenditure Budget was $18,101,213, including capitalized interest of $532,370, as per the attached Schedule B. As a result of management's efforts, that budget was reduced to $8,413,258, including capitalized interest of $91,710, primarily by deferrals of necessary projects. Attached Schedule B also shows the Amended 2009 Transmission and A&G Capital Expenditure Budget. But even with the revised budget, the requested $14,331,923 is still the minimum amount Big Rivers needs to meet its cash needs, assuming that the Commission grants Big Rivers' proposed rate increase. The proposed rate increase is based on Big Rivers' immediate cash needs, which assumed $14,331,923 in transmission and A&G capital expenditures. So, even though Big Rivers now projects that it will spend less than that amount in 2009 as a result of deferrals, any reduction in the proposed $14,331,923 will result in Big Rivers having less cash to meet its needs. A significant reduction in that amount would leave Big Rivers without the cash to satisfy its upcoming obligations.

Moreover, because of Big Rivers' inability to borrow and its depleted cash reserves, the amount for transmission and A&G capital expenditures that Big Rivers recovers through rates must be sufficient to cover those expenditures even in above average years. Big Rivers' test year expenditures were higher than the 10-year average, but Big Rivers was able to make those expenditures because of its cash reserves at the

time. The 2009-2011 transmission and A&G capital budgets are also higher than the 10-year average, but given Big Rivers' depleted cash position, it will only be able to make the expenditures for the projects scheduled in 2009-2011 if the pro forma amount is at least as great as the budgeted amount in any one of those years. The projects contained in the 2009-2011 budgets are necessary and must be funded. For example, the two-way radio replacement project included in the budgets is required because of a change in FCC regulations. Big Rivers must replace its existing radio equipment to comply with the FCC regulations by 2012. The project is being done slightly ahead of the required compliance date because Big Rivers' aging equipment needs to be replaced to maintain a high level of operating performance.

The pro forma amount must also be sufficient to cover projects and expenditures that arise but that are not included in the budgets. For example, because of its cash position, Big Rivers will be unable to make transmission capital expenditures required for economic development projects (like new large industrial loads) that arise unless the pro forma amount has a reasonable degree of margin for unanticipated projects. Also, the pro forma amount must have a degree of margin for other unanticipated expenditures, such as changes in laws and regulations (like with the FCC regulation change), changes in cost of labor and materials, or changes that are required in projects that result from engineering and design changes (for example, if soil tests reveal the need for different designs than currently planned).

Big Rivers believes its requested $14,331,923 is necessary. However, should an average be utilized by the Commission, Big Rivers urges that the Commission consider using a 4-year average consisting of Big Rivers' Amended 2009 Budget amount, its 2010 projected amount, and the two most recent historic year's actual capital expenditures, 2007 and 2008. This 4-year average equals $12,337,999 ([$12,130,235 + $15,629,112 + $8,321,548 + $13,271,100]/4). Big Rivers believes this spending level, at a minimum, would be far more representative of Big Rivers' historic and anticipated expenditures than the flawed 10-year average figure, as it would reduce the impact of the cost increases over the past 10 years and would eliminate the influence on the average of the abnormally low expenditures in 1999 and 2000.

c. Big Rivers has not projected, nor has it historically prepared, its Transmission and A&G capital expenditures for the next 5 years (2009 through 2013). As referenced in b. above, Big Rivers has projected its Transmission and A&G capital expenditures for 2010 to be $13,271,100 and for 2011 to be $8,414,200 (neither include any capitalized interest), as detailed per the attached Schedule C.

Witness) C. William Blackburn
David A. Spainhoward

1999 Transmission and A&G Capital Expenditures - Cash Flow

	Accout No.	ACCOUNT DESCRIPTION	Trial Balance		Generation	Account Total
1						
2	101000	ELECTRIC PLANT IN SERVICE	3,348,144			
3	106000	COMPLETED CONST NOT CLASSIFIED-ELECTRIC	(2,490,220)			
4	107000	CONSTRUCTION WORK IN PROGRESS	301,728			
5	108500	ACCUM PROV FOR DEPRECIATION-TRANSMISSION	(3,833,358)			
6	108700	ACCUM PROV FOR DEPRECIATION-GENERAL PLT	396,198			
7	108800	RETIREMENT WORK IN PROGRESS	23,664			
8	108900	ACCUM PROV FOR DEPRECIATION-RETIREMENTS	718,973	*	1,354,588	2,073,561
9	115000	ACCUM PROV FOR AMORT-J P ACQUISITION ADJ	(51,875)			
10	121000	NON-UTILITY PROPERTY	(145,618)			
11	122000	ACCUM DEPREC-NON-UTILITY PLANT	21,201			
12	183000	PRELIM SURVEY & INVESTIGATION CHARGES	(12,337)			
13	232900	ACCOUNTS PAYABLE-RETAINAGE	82,604			
14	403510	DEPR EXPENSE-TRANSMISSION-STATIONS	2,245,403			
15	403520	DEPR EXPENSE-TRANSMISSION-LINES	1,999,392			
16	403700	DEPR EXPENSE-GENERAL PLANT	226,903			
17	421200	LOSS/(GAIN) ON DISPOSITION OF PROPERTY	112,071		(19,976)	92,095
18	425000	AMORTIZATION EXPENSE-J P ACQUISITION ADJ	51,875			
19	427350	INTEREST CHARGED TO CONST-CR-STATIONS	(48,206)			
20	427360	INTEREST CHARGED TO CONST-CR-LINES	(21,576)			
21		Transmission and A&G Capital Expenditures - Cash Flow	**2,924,966**			

* The amount originally compiled for account 108900 for Transmission and A&G was determined to be ($2,613,572). Other than a $114 revision to account 421200, the correct account 108900 amount is $718,973, increasing the cash paid for Transmission and A&G capital expenditures from ($407,465) to $2,924,966. Including the originally reported Non-incremental Capital, the total cash capital expenditures by Big Rivers for 1999 were $5,784,477.

Big Rivers Electric Corporation
2009 Capital & Construction Budget

	Estimated In-Service Date	Description	Original 2009 Budget Capitalized Cost	Original 2009 Budget Capitalized Interest	Original 2009 Budget Cash Flow	Amended 2009 Budget Capitalized Cost	Amended 2009 Budget Capitalized Interest	Amended 2009 Budget Cash Flow
1		2009 Transmission and A&G Capital Budget						
2	month purchased	DGA Monitoring for EHV Transformers (Coleman, Wilson, Reid)	290,000	0	290,000	80,000	0	80,000
3	"	Hot Oil Spray Transformer Dryout System	110,000	0	110,000	0	0	0
4	"	Battery Load Tester	35,000	0	35,000	35,000	0	35,000
5	"	A/C Unit Replacements	16,000	0	16,000	16,000	0	16,000
6	"	Energy Control Telephone System	6,000	0	6,000	0	0	0
7	"	Hoist, Grips, and Rope -- Replacements	5,000	0	5,000	5,000	0	5,000
8	"	ET&S Computer HVAC Unit	3,500	0	3,500	0	0	0
9	"	Hydraulic Pump and Press -- Replacement	3,500	0	3,500	3,500	0	3,500
10	"	Tool Replacements	2,000	0	2,000	2,000	0	2,000
11	"	Portable Generator (2) -- Replacements	1,800	0	1,800	1,800	0	1,800
12	"	Typewriter	750	0	750	750	0	750
13	"	Go Tract Vehicle -- Replacement	450,000	0	450,000	0	0	0
14	"	3/4 Ton, 4x4 Crew Cab Pickup Truck-Replace Veh #254	40,000	0	40,000	40,000	0	40,000
15	"	3/4 Ton, 4x4 Ext Cab Pickup Truck-Replace Veh #258	35,000	0	35,000	0	0	0
16	"	1/2 Ton, 4x4 Ext Cab Pickup Truck-Vegetation Management	27,000	0	27,000	27,000	0	27,000
17	"	1/2 Ton, 4x4 Ext Cab Pickup Truck-Replace Veh #262	27,000	0	27,000	27,000	0	27,000
18	"	1/2 Ton, 4x4 Ext Cab Pickup Truck-Replace Veh #285	27,000	0	27,000	0	0	0
19	"	GIS--Personal Computer/Laptop Replacements/Server Replacements	185,000	0	185,000	185,000	0	185,000
20	"	Cisco Network Equipment & Switch Upgrades	20,000	0	20,000	0	0	0
21	"	Servers, Firewalls, Switches, Computer Equipment - Disaster Recovery Center	82,500	0	82,500	62,500	0	62,500
22	"	Personal Computers--27 Desktops - (22 Replacements; 2 New)	50,100	0	50,100	41,400	0	41,400
23	"	Compliance Tracking Software (NERC, SERC, CIPS)	50,000	0	50,000	50,000	0	50,000
24	"	Uninterruptible Power Supply (UPS) Replacement	30,000	0	30,000	0	0	0
25	"	Laptop Computers (6 Replacements; 1 New)	21,500	0	21,500	3,500	0	3,500
26	"	Cyber Security Equipment	21,000	0	21,000	21,000	0	21,000
27	"	Software Tools	20,800	0	20,800	20,800	0	20,800
28	"	Autocad Upgrade	20,000	0	20,000	20,000	0	20,000
29	"	LaserFiche	15,000	0	15,000	15,000	0	15,000
30	"	Remote Access to SOE's, Digital Relays	10,000	0	10,000	10,000	0	10,000
31	"	Scanner	10,000	0	10,000	10,000	0	10,000
32	"	Printer Replacements (4)	9,500	0	9,500	3,500	0	3,500
33	"	Enterprise Risk Management Software	5,000	0	5,000	5,000	0	5,000
34	"	Additional Disk for Coop Web Computer	1,500	0	1,500	1,500	0	1,500
35	"	Office Furniture	16,500	0	16,500	4,500	0	4,500
36	"	Electrical Safety Demo Unit	5,000	0	5,000	5,000	0	5,000
37	"	Inductor for High Voltage Demo Trailer	5,000	0	5,000	5,000	0	5,000
38	"	Rescue Mannequin & Parts	3,950	0	3,950	3,950	0	3,950
39	"	Multimedia Projector	2,000	0	2,000	2,000	0	2,000
40	"	Digital Camera Lenses	500	0	500	500	0	500
41		Total 2009 Capital Budget	1,664,400	0	1,664,400	708,200	0	708,200
42								

Big Rivers Electric Corporation
2009 Capital & Construction Budget

	Estimated In-Service Date	Description	Original 2009 Budget Capitalized Cost	Original 2009 Budget Capitalized Interest	Original 2009 Budget Cash Flow	Amended 2009 Budget Capitalized Cost	Amended 2009 Budget Capitalized Interest	Amended 2009 Budget Cash Flow
43		2009 Transmission and A&G Construction Budget						
44	03/09	Add Gravel to Meade County Substation	14,652	0	14,652	0	0	0
45	09/09	CEHV to Coleman C1 & C2 Teleprotection Replacement	199,788	0	199,788	199,788	0	199,788
46	11/09	Coleman to Newtonville 161kV Reconductor *	613,180	11,720	601,460	100,000	0	100,000
47	12/09	Cumberland River Crossing Modification	125,269	0	125,269	125,269	0	125,269
48	12/10	Cumberland-Caldwell Springs Tap 69 kV Line *	146,519	1,830	144,689	0	0	0
49		Daviess Co Airport Line Reroute	4,019	0	4,019	0	0	0
50	10/09	Digital Fault Recorder Upgrade for Coleman	923	0	923	923	0	923
51	12/09	Digital Fault Recorder Upgrade for Portable	848	0	848	849	0	849
52	11/09	Digital Fault Recorder Upgrade for Reid	848	0	848	848	0	848
53	10/09	Digital Fault Recorder Upgrade for Wilson	923	0	923	923	0	923
54	12/09	Falls of Rough-McDaniels 69 kV Line	515,193	37,180	478,013	113,273	4,120	109,153
55	12/09	Hancock 69kV Capacitor Bank	317,135	3,250	313,885	0	0	0
56	10/09	Horse Fork Tap 69kV Switch Modification	58,114	0	58,114	0	0	0
57	03/09	McCracken Co 69kV Line Terminal for Olivet Tap	134,927	7,080	127,847	131,187	3,340	127,847
58	08/09	McCracken Co RTU Replacement	38,817	0	38,817	0	0	0
59		National AL 13.8kV Switchgear for Southwire Feed	12,443	0	12,443	12,443	0	12,443
60	07/09	Oil Spill Prevention Control & Countermeasures System	379,366	32,160	347,206	353,757	6,550	347,207
61	07/09	Olivet-Church Road Tap 4.6 M 69kV Line	572,918	50,490	522,428	537,887	15,460	522,427
62	12/09	Pole Change Outs	609,767	0	609,767	609,767	0	609,767
63	02/09	Reconductor 4-K & 5-D between Hopkins & S Hanson	207,540	9,230	198,310	207,539	9,230	198,309
64	02/09	Reconductor Line 6-A Reid Swyd/Daviess Co Sub	367,943	22,050	345,893	367,942	22,050	345,892
65	06/09	REHV to Hopkins 161kV Reroute	198,512	0	198,512	198,512	0	198,512
66	12/09	Reid 69kV RTU Replacement	38,644	0	38,644	0	0	0
67	09/09	Replace Fifteen (15) 161kV Disconnects at Reid	241,454	0	241,454	241,454	0	241,454
68	03/09	Replace Nine (9) 69kV PTs at Daviess County Sub	49,674	0	49,674	49,674	0	49,674
69	06/09	Replace Substation Battery at Livingston Co Substation	15,932	0	15,932	15,932	0	15,932
70	06/09	Replace Substation Battery at McCracken Substation	15,932	0	15,932	15,932	0	15,932
71	06/09	Replace Substation Battery at Wilson EHV Substation	28,932	0	28,932	28,932	0	28,932
72	05/09	Replace Substation Security Fence at Hardinsburg Substation	26,676	0	26,676	0	0	0
73	09/09	Replace Three (3) MIOD Operators at Dover	27,001	0	27,001	0	0	0
74	04/09	Replace Twelve (12) 69kV PTs at Henderson County Sub	64,889	0	64,889	64,888	0	64,888
75	09/09	Spill Prevention Containment Control Implementation	1,069,004	25,450	1,043,554	1,046,485	2,930	1,043,555
76	01/10	Two Way Radio System	6,167,892	185,440	5,982,452	1,010,860	10,860	1,000,000
77	12/09	Upgrade Metering at Coleman Road to 28 MVA	6,846	0	6,846	6,846	0	6,846
78	03/09	US 60 Bypass Relocation Lines 18-G & 13-E	218,654	6,120	212,534	216,533	4,000	212,533
79	12/10	White Oak Substation	3,816,398	136,510	3,679,888	2,013,020	13,020	2,000,000
80	12/10	Wilson 161-69kV Substation Facilities	11,525	60	11,465	11,466	0	11,466
81	12/10	Wilson 69kV Line to Centertown	117,716	3,800	113,916	22,129	150	21,979
82		Construction Budget	16,436,813	532,370	15,904,443	7,705,058	91,710	7,613,348
83								
84		Total Transmission and A&G	18,101,213	532,370	17,568,843	8,413,258	91,710	8,321,548
85								
86		2009 Incremental & Non-Incremental Capital Budget						
87		Big Rivers' Share Pursuant to Section 20.6.3 of the Second Amendent						
88		to the New Participation Agreement – Non-Incremental Capital	6,871,000	0	6,871,000	6,871,000	0	6,871,000
89		Big Rivers' Share Pursuant to Section 8.4(a) of the Lease and Operating						
90		Agreement – Incremental Capital	831,160	0	831,160	1,193,160	0	1,193,160
91		Total Incremental & Non-Incremental	7,702,160	0	7,702,160	8,064,160	0	8,064,160
92								
93								
94		Grand Total 2009 Capital & Construction Budget	**25,803,373**	**532,370**	**25,271,003**	**16,477,418**	**91,710**	**16,385,708**

	BIG RIVERS ELECTRIC CORPORATION			
	TRANSMISSION AND A&G CAPITAL EQUIPMENT AND CONSTRUCTION PROJECTION *			
	FOR YEARS 2010 and 2011			
			2010	**2011**
1	**Transmission and A&G Capital Equipment Projection**			
2	DGA Monitoring for EHV Transformers	Trans	307,700	0
3	Hot Oil Spray Transformer Dryout System	Trans	116,700	0
4	Battery Load Tester	Trans	0	0
5	A/C Unit Replacements	Trans	17,000	0
6	Energy Control Telephone System	Trans	6,400	0
7	Hoist, Grips, and Rope Replacements	Trans	5,300	0
8	ET&S Computer HVAC Unit	Trans	3,700	0
9	Hydraulic Pump and Press - Replacement	Trans	3,700	0
10	Tool Replacements	Trans	2,100	0
11	Portable Generator Replacements (2)	Trans	1,900	0
12	Typewriter	Trans	0	0
13	Go Tract Vehicle Replacement	Trans	477,400	0
14	3/4 Ton 4X4 Crew Cab Pickup Truck-Replace Veh #254	Trans	0	0
15	3/4 Ton 4X4 Ext Cab Pickup Truck-Replace Veh #258	Trans	37,100	0
16	1/2 Ton 4X4 Ext Cab Pickup Truck-Vegetation Management	Trans	0	0
17	1/2 Ton 4X4 Ext Cab Pickup Truck-Replace Veh #262	Trans	28,600	0
18	1/2 Ton 4X4 Ext Cab Pickup Truck-Replace Veh #285	Trans	28,600	0
19	3/4 Ton 4X4 Ext Cab Pickup Truck-Replace Veh #279	Trans	37,100	0
20	1/2 Ton 4X4 Ext Cab Pickup Truck-Replace Veh #277	Trans	28,600	0
21	Projected Transmission Capital Items	Trans	0	191,200
22	GIS Personal Computer/Laptop Replacements/Server Replacements	A&G	0	0
23	Cisco Network Equipment & Switch Upgrades	A&G	21,200	0
24	Servers,Firewalls,Switches,Computer equipment-Disaster Recovery Center	A&G	21,200	0
25	Personal Computers-27 Desktops-(22 Replacements 2 New)	A&G	53,200	0
26	Compliance Tracking software (NERC,SERC,CIPS)	A&G	0	0
27	Uninterruptable Power Supply (UPS) Replacement	A&G	31,800	0
28	Laptop computers (6 Replacements, 1 New)	A&G	22,800	0
29	Cyber Security Equipment	A&G	0	0
30	Software Tools	A&G	0	0
31	Autocad Upgrade	A&G	21,200	0
32	LaserFiche	A&G	0	0
33	Remote Access ToSOE's, Digital Relays	A&G	0	0
34	Scanner	A&G	0	0
35	Printer Replacements (4)	A&G	10,100	0
36	Enterprise Risk Management Software	A&G	5,300	0
37	Additional Disk For Coop Web Computer	A&G	0	0
38	Office Furniture	A&G	17,000	0
39	Electrical Safety Demo Unit	A&G	0	0
40	Inductor For High Voltage Demo Trailer	A&G	0	0
41	Rescue Mannequin & Parts	A&G	3,100	0
42	Multimedia Projector	A&G	2,100	0
43	Digital Camera Lenses	A&G	500	0
44	Replace Engineering Vehicle	A&G	31,800	0
45	Projected A&G Capital Items	A&G	0	651,300
46	**Capital Equipment**		**1,343,200**	**842,500**
47				

	BIG RIVERS ELECTRIC CORPORATION			
	TRANSMISSION AND A&G CAPITAL EQUIPMENT AND CONSTRUCTION PROJECTION *			
	FOR YEARS 2010 and 2011			
			2010	2011
48	**Transmission and A&G Construction Projection**			
49				
50	Wilson 69/161 kV Transformer Addition	Trans	51,700	2,731,800
51	30 MVAR Hancock Capacitor Addition	Trans	300,500	52,500
52	National Aluminum Switchgear	Trans	0	0
53	6 Mile 69 kV Wilson-Centertown Line	Trans	88,700	864,100
54	7 Mile 69 kV Cumberland To Caldwell Line	Trans	145,200	973,300
55	Re-conductor 3.4 Mile 161 kV Coleman-Newtonville Line	Trans	544,400	0
56	Cumberland River Crossing Tower Relocation 161 kV	Trans	0	0
57	REHV-Hopkins 161 kV Re-route	Trans	0	0
58	Horse Fork Switch Modification	Trans	53,000	0
59	McCracken RTU Replacement	Trans	27,600	0
60	Reid 69 kV RTU Replacement	Trans	29,700	0
61	CEHV-Coleman Teleprotection	Trans	0	0
62	Oil Spill Prevention Control and Countermeasures Phase I	Trans	0	0
63	Falls of Rough 69 kV Line	Trans	470,000	0
64	Oil Spill Prevention Control and Countermeasures Phase II	Trans	0	0
65	Reid-Daviess 161 kV Line Re-conductor	Trans	0	0
66	McCracken-Olivet Church Road 69 kV Bay	Trans	0	0
67	McCracken-Olivet Church Road 69 kV Line	Trans	0	0
68	Two Way Radio Replacement	Trans	5,469,400	0
69	Re-conductor Hopkins-S. Hanson 69 kV Line	Trans	0	0
70	White Oak 69/161 kV Substation	Trans	3,824,800	0
71	South Dermont Radio Controlled Switch	Trans	61,000	0
72	Re-conductor 8 Mile 69 kV Meade County-Garrett Line	Trans	8,700	810,600
73	EMS Conversion To DPN 3.0	Trans	39,000	0
74	Skillman RTU Replacement	Trans	30,200	0
75	REHV RTU Replacement	Trans	30,200	0
76	3 Mile 69 kV Garrett-Flaherty Line	Trans	0	764,900
77	3 Mile Ekron Tap Line	Trans	44,600	718,900
78	US 60 96 kV line Re-route	Trans	0	0
79	Owensboro-Daviess Co Airport 69 kV Line Re-route	Trans	0	0
80	Add Gravel to Meade Co substation	Trans	15,500	0
81	Digital Fault Recorder Upgrade Coleman	Trans	0	0
82	Digital Fault Recorder Upgrade Portable	Trans	0	0
83	Digital Fault Recorder Upgrade Reid	Trans	0	0
84	Digital Fault Recorder Upgrade Wilson	Trans	0	0
85	Pole Change Outs	Trans	636,500	655,600
86	Replace Fifteen (15) 161 kV Disconnects at Reid	Trans	0	0
87	Replace Nine (9) 69 kV PT's at Daviess County Sub	Trans	0	0
88	Replace Station Battery at Livingston County	Trans	0	0
89	Replace Station Battery at McCracken County	Trans	0	0
90	Replace Station Battery at Wilson EHV	Trans	0	0
91	Replace Security Fence at Hardinsburg	Trans	28,300	0
92	Replace Three (3) MOD Operators at Dover	Trans	28,900	0
93	Replace Twelve (12) 69 kV PT's at Henderson County	Trans	0	0
94	**Construction**		**11,927,900**	**7,571,700**
95				
96	**Total Transmission and A&G Capital Equipment and Construction Projection**		**13,271,100**	**8,414,200**
	* Does not include capitalized interest.			

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE COMMISSION STAFF'S FOURTH DATA REQUEST
TO BIG RIVERS ELECTRIC CORPORATION
PSC CASE NO. 2009-00040
June 1, 2009

Item 7) Refer to Big Rivers' Response to Commission Staff's Third Data Request, Item 6.a. On line 12, Big Rivers shows that the portion of its test year principal and interest payment adjustment attributable to its 2001 Ohio County Bonds is $8,047,104.

a. Confirm that the adjustment shown on line 12 accounts for the current 18.5 percent annual rate of interest on these bonds.

b. Provide an update as to the status of Big Rivers' attempts to refinance these bonds or otherwise lower this rate of interest.

Response) a. The interest rate used to calculate the $8,047,104 interest payment adjustment attributable to the 2001 Ohio County Bonds was 18.0% (the maximum rate), which was the rate in effect as of March 1, 2009. Big Rivers is unsure of the source of the 18.5% rate referred to in this question.

b. Months ago, approximately June 2008, Big Rivers was advised by both its bond counsel, Orrick, and its financial advisor, Goldman Sachs, that it would be virtually impossible to write a bond offering prospectus adequately describing the operations of Big Rivers both under the 1998 LG&E Transaction and the then soon-expected Unwind Transaction, including both the existing and post-Unwind bondholder security structure, such that the rating agencies and investors would understand and accept. Also, given the time constraints on staff and counsel due to the on-going Unwind activities, and the always, anticipated imminent closing date for that transaction Big Rivers was advised by its bond counsel and financial advisor to wait until a "go" or "no go" decision was made on the Unwind before pursuing a refunding of these bonds. Because Big Rivers was hopeful of becoming an investment grade credit in connection with the Unwind, likely to result in a significantly lower interest cost, management concurred with that advice. Further, in brief discussions with CFC about potentially acting in multiple roles in a remarketing, they advised Big Rivers to wait post-Unwind for two primary reasons. First, the current interest rate environment is very difficult. Second, CFC is not willing to become a more significant party under the current Big Rivers security structure documentation.

Big Rivers is not currently an investment grade credit. To go into the market for either a short-term or long-term bond refunding with a demand feature or a put feature would require both credit enhancement and a liquidity facility to ensure a successful marketing. This would only have been available to Big Rivers pre-Unwind with an extension of the existing RUS subordination on the existing bonds. RUS has told Big Rivers within the last 30 days that it would not subordinate further. Additionally, Big Rivers was already having great difficulty getting RUS to focus on the Unwind, and did not want to exacerbate that problem with talk of a PCB refinancing that could clearly not be accomplished before the dates on which Big Rivers was telling RUS the Unwind would close.

To do a long-term unenhanced bond transaction would also require RUS subordination to have any chance of obtaining a materially lower interest rate, and even then it is doubtful since the current bonds benefit from an RUS subordination to the credit enhancer. It also required a structure where the credit features would change upon completion of the Unwind, going from a senior to a parity position.

The combination of all these factors made it inadvisable for Big Rivers to divert the time and resources from attempting to complete the Unwind to what was likely to be an unsuccessful effort to refinance the bonds. If Big Rivers is to remain in the status quo it would be worthwhile to approach RUS with a refunding/subordination proposal if Big Rivers' financial advisor advises it that a significant reduction in interest rate is likely to be achieved.

Witness) C. William Blackburn

BIG RIVERS ELECTRIC CORPORATION'S
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PSC CASE NO. 2009-00040
June 1, 2009

Item 8) Refer to Big Rivers' Response to Commission Staff's Third Data Request, Item 7.b.2), and Big Rivers' Response to Commission Staff's First Data Request, Item 19.a.

a. Provide copies of the test year economic development advertisements and state the names of the publications in which they appeared.

b. 807 KAR 5:016, Section 4. (b) prohibits rate recovery of promotional advertising expenses which is defined as "any advertising for the purpose of encouraging any person to select or use the service or additional service of an energy utility…..". In response to Item 7.b.2) Big Rivers argues that economic development benefits its members and therefore should be recovered in rates. To the extent that Big Rivers' economic development advertising promotes the use of electricity, explain how rate recovery of these advertising expenses would not be in violation of the Kentucky regulation.

c. Identify all test year economic development expenses reported in each account listed in Item 19.a. For each expense amount listed, provide a general description of the economic development activity performed and the type of expense, e.g. salaries and wages, contracted services, transportation, etc.

Response) a. A copy of the test year economic development advertisement is attached as Exhibit 8.a.1. The advertisement appeared in the following publications:
- *Celebrating 40 Years of Growing Kentucky, Kentucky Association for Economic Development.*

b. The advertisements have the sole purpose of encouraging economic development in Western Kentucky, irrespective of energy usage.

c. See attached Exhibit 8.c.1. for a listing of all test year economic development expenses with information on activity performed and type of expense.

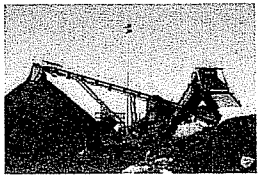
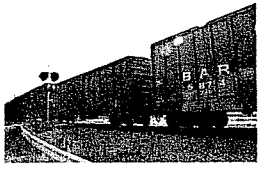
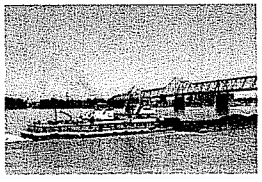
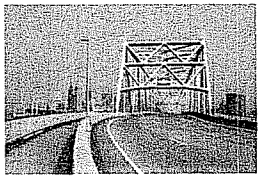
Witness) David A. Spainhoward

Prime location and **abundant resources**

make western Kentucky the *right* business location

Big Rivers Electric Corporation

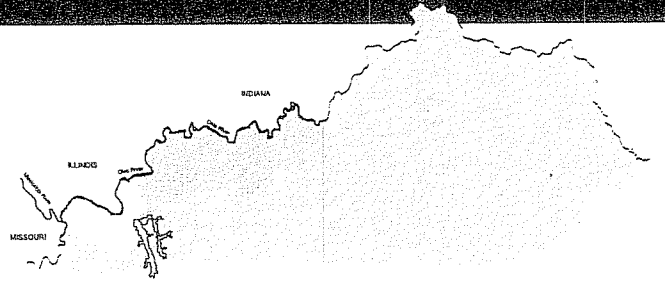
Your Touchstone Energy® Cooperative


Abundant coal supply • Major river ports • Rail & road access • Low industrial rates

Big Rivers Electric, and its three member owners, support economic development within the Commonwealth of Kentucky.

Together, we serve electricity to over 110,000 customers in 22 counties of western Kentucky.



Make western Kentucky home

JPEC Kenergy Meade County RECC

Big Rivers Electric Corporation
Case No. 2009-00040
Economic Development

	Vendor	Amount	Description
	Account 913-Advertising Expense		
1	Jackson Purchase Energy Corporation	$52,255.36	Funds for Coop Economic Development
2	Kenergy	98,691.00	Funds for Coop Economic Development
3		$150,946.36	
	Account 930.2-Miscellaneous General Expenses		
4	KAED	$1,000.00	KAED Spring Conference Sponsor of Keynote Speaker
5	Northwest Kentucky Forward	1,000.00	Assistance with Arkansas Trip-Project Power
6	Northwest Kentucky Forward	7,000.00	Investment-Forward Investing
7	Greater Paducah Partners for Progress	5,000.00	Investment-Greater Paducah Partners for Progress/GPEDC
		$14,000.00	

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE COMMISSION STAFF'S FOURTH DATA REQUEST
TO BIG RIVERS ELECTRIC CORPORATION
PSC CASE NO. 2009-00040
June 1, 2009

Item 9) Refer to Big Rivers' Response to Commission Staff's Third Data Request, Item 9.b., the detailed listing of test year expenses for each member of its Board of Directors.

a. Generally, for each "Board Meeting", a board member was reimbursed for "Expenses" except for board meetings related to the Unwind. Explain why the board members were not reimbursed for expenses incurred to attend Unwind-related board meetings but were reimbursed for expenses incurred to attend meetings not related to the Unwind.

b. Generally, expense reimbursements to board members for attendance of board meetings fluctuated significantly. For example, during the test year Lee Bearden received as little as $139.51 for reimbursement of expenses to attend the February 15, 2008 meeting and as much as $382.30 to attend the December 21, 2007 meeting. Explain why there is such a significant difference in expense reimbursements for board members' attendance at board meetings.

c. The expenses include the costs for all of Big Rivers' board members' attendance at both the 2007 and 2008 KAEC annual meetings.

1) Explain why it is appropriate to include the cost of attending this annual conference in revenue requirements twice, once for 2007 and again for 2008.

2) In previous cooperative rate cases, the Commission has limited rate recovery to the cost of sending the cooperative's delegate or the alternate delegate. State the name of Big Rivers' KAEC delegate and alternate delegate during 2008 and explain why it is appropriate for Big Rivers to recover the cost of sending a director to this meeting that was not its delegate or alternate delegate.

d. The day before each board meeting not labeled as Unwind, there is a fee paid to each board member labeled as either work session or travel day.

1) Describe what is meant by work session.

2) Explain the necessity of the work sessions.

3) Describe what is meant by travel day.

4) Explain why there is not a "travel day" when there is a "work session" on the day preceding the day of a meeting.

5) Explain why there is a need to have a work session on a day other than the day of the board meeting (i.e., explain why the work session could not have occurred on the same day as the board meeting).

e. In August 2008 there were two board meetings not labeled as Unwind. Explain the need for these two meetings.

f. In September 2008 there was a board meeting labeled as "personnel matter," a regular board meeting with no specific label, and the annual meeting.

1) Explain why a special meeting was held for the "personnel matter' and why this could not have been addressed at the regular meeting.

2) Explain the need for the regular meeting one day after the annual meeting and why the subjects addressed at the regular meeting could not have been addressed on the day of the annual meeting.

g. In October 2008 two board meetings were held. Explain why the union contract board meeting and the regular board meeting could not have been combined into one meeting.

h. Each director is paid a fee for days that they attend conferences or classes.

1) Explain the need to make such payments.

2) Are Big Rivers' directors unwilling to attend necessary conferences or classes absent these fees?

3) Are these fees necessary to attract qualified board members?

4) Each director of Big Rivers is on the Board of Directors of his or her respective distribution cooperative. In that capacity, Big Rivers' board members attend conferences and classes. Does Big Rivers take into consideration these conferences and classes when determining whether or not it is necessary or appropriate to

send a board member to a conference or class on behalf of Big Rivers? Explain in full detail.

i. Board members Butler, Denton, Elder, Elliot and Sills attended the NRECA Directors Winter School.

1) Explain why it was necessary for all of these individuals to attend the winter school.

2) Test year expenses include the cost of attending the 2007 and 2008 NRECA Directors Winter School for Butler, Denton and Sills. Explain why it was necessary for these individuals to attend the winter school a second time and why it is appropriate to include both years in pro forma operations.

j. Bearden, Butler and Sills attended the NRECA annual meeting in February 2008. In previous cooperative rate cases, the Commission has limited rate recovery to the cost of sending the cooperative's delegate or the alternate delegate.

1) State the name of Big Rivers' NRECA delegate and alternate delegate during 2008.

2) State why it is appropriate for Big Rivers to recover the cost of sending a director to this meeting who was not its delegate or alternate delegate.

k. Refer to Page 3 of 6.

1) State why rate recovery of the cost for Denton to attend the Illinois Basin Energy Forum is appropriate.

2) State why rate recovery of the cost for Denton to attend the NRECA Directors Summer School in June is appropriate given that he attended the winter school in December 2007 and 2008.

3) State why rate recovery is appropriate for the cost of Denton attending the ACES meetings in August 2008 and November 2008.

l. Refer to Pages 4, 5 and 6.

1) State why rate recovery is appropriate for the cost of Elder attending the SURE executive subcommittee meeting in April 2008.

2) State why rate recovery is appropriate for the cost of Elder, Elliot and Sills attending the ACES meeting in May 2008. Explain why it was necessary for all three members to attend.

3) State why rate recovery is appropriate for the cost of Elliot attending the CoBank Conference in March 2008.

4) State why rate recovery is appropriate for the cost of Sills and Denton to attend the legislative conference in May 2008.

Response) a. Board members are reimbursed for expenses incurred in compliance with the Board-approved Big Rivers' Board Fees and Expenses Policy (which was previously provided in response to the PSC's First Data Request, Item 26). If no expenses were reimbursed for an Unwind-related board meeting, it is because no expenses were incurred, as would be the case if the meeting was a telephonic meeting.

b. Big Rivers' board members are reimbursed only for expenses actually incurred, so the amounts reimbursed to a director in any month varies accordingly. For example, directors are reimbursed for mileage when they travel by personal vehicle to attend to their responsibilities on behalf of Big Rivers. Dependent on their individual travel schedules for a particular month, board members may travel separately or car pool together to attend board meetings and/or other Big Rivers' related functions. Dependent on which director drives to the meeting(s) in a particular month, his/her expenses would be higher during that month due to the mileage reimbursement.

Expenses can also fluctuate dependent upon when the board members receive and submit for recovery their monthly internet service bill which is reimbursed because the directors are sent board meeting materials electronically via their company-furnished personal computer.

It should also be noted that four of Big Rivers' board members live some distance from the Big Rivers' office where monthly board meetings are typically held. As a result, those members typically incur hotel charges while the remaining two board members who live close enough to the office so they drive to the board meeting from home each day of the meeting do not.

In December 2007, Mr. Bearden drove to the board meeting and turned in two months of internet service bills.

c. 1) The test year expenses shown in Big Rivers' Response to Commission Staff's Third Data Request, Item 9.b. do include directors' expenses for attending the KAEC annual meetings in both 2007 and 2008. Big Rivers agrees that only the expenses for the directors' attendance at the 2008 KAEC annual meeting should be included in those expenses, which results in a reduction in expenses by $9,070.26. Big Rivers' directors usually submit their expense reimbursement requests at the next Big Rivers board meeting. The directors who attended the 2007 KAEC annual meeting submitted their expenses while attending the December 2007 Big Rivers' board meeting, which resulted in those expenses being booked in the test year.

c. 2) Dr. James Sills was the delegate and Mr. Lee Bearden was the alternate to the 2008 KAEC annual meeting. Alternates typically attend these sessions in the event a last minute issue makes it impossible for the delegate to attend and/or in the event the delegate becomes ill or must attend to some other pressing emergent issue while the session is underway.

Big Rivers' directors are involved only part-time with the electric utility business and with Big Rivers' affairs. As a result, they do not have the benefit of on-going, full time exposure to issues of major import to the industry and the corporation. Attendance at periodic KAEC, NRECA, ACES, CFC and/or CoBank functions exposes them to speakers who have expertise in utility matters as well as current topics that can have a profound impact on the business. The information directors receive during these functions enables them to better attend to their important responsibilities as Big Rivers' board members.

d. 1-2) As explained in response to Item 9 b., four of Big Rivers' board members live some distance from Big Rivers' office where board meetings are typically held. They have found that traveling to a meeting, taking care of important board business, and returning home during the same day diminishes their ability to effectively function in Big Rivers' best interests. As a result, they typically travel to Henderson the afternoon before the board meeting. Since they are already in town, a work session is typically held beginning at 6:00 p.m.

to provide them with information related to the business or industry or the details of topics to be acted upon officially by the board during the following day's board meeting. Having a work session breaks up what could potentially be a long board meeting and also permits the directors to consider a topic(s) over night prior to taking official action the following day. The evening schedule for the work sessions, and an early start for the board meeting the next morning (8:00 a.m.) also reduce the amount of time a director is required to be away from the director's employment for Big Rivers business.

d. 3-4) A travel day involves a day for travel by the board members to a Big Rivers-related function. Typically, travel days are involved with attendance at a KAEC, NRECA, ACES, CFC, and/or CoBank function since often those sessions begin early which makes travel the morning of the event difficult or impossible. The Big Rivers' Board Fees and Expenses Policy provides for the director to be reimbursed either for a travel day to such events or for attending the event, but not for both. Since Big Rivers' board members are paid a fee for attending a board work session, they are not paid for travel to the session.

d. 5) Please see the response to Item 9. d. 1 and 2.

e. During the board session held on August 4, 2008, Big Rivers' management and financial analyst briefed the board on the financial impact of the Phillip Morris sale/leaseback default mitigation alternatives. This meeting was necessary prior to the regularly-scheduled board meeting because Big Rivers was nearing the end of the time period it had available under the lease agreement to remedy the credit downgrade of Ambac to avoid default under that agreement. The importance of the Phillip Morris lease default matter warranted both management's and the board's undivided attention. It was not possible for Big Rivers' management to prepare for dealing with this important matter on August 4, and simultaneously prepare to present the agenda for the regular board meeting 10 days earlier than scheduled. August 15, 2008, meeting was the regularly-scheduled board meeting.

f. 1) Big Rivers' management does not ask the board to hold a special meeting unless required in connection with urgent business of the corporation. A very important, emergent matter involving an individual who was slated to fill a key senior role in the Big Rivers' organization post Unwind needed to be addressed and acted upon at the September 2008

meeting referenced. This matter arose quickly and in management's view had to be dealt with before the next regularly-scheduled board meeting.

f. 2) Big Rivers' "annual meeting" is its annual meeting of Members. The board of directors meeting the morning following the annual meeting is both a regular Big Rivers board meeting and the Big Rivers annual board meeting. All of Big Rivers' Member (e.g. Meade County, Kenergy, and Jackson Purchase) board members as well as the distribution Members' key staff are invited to Big Rivers' annual meeting. During that meeting attendees receive an annual update of Big Rivers' activities and a dialogue is held regarding Big Rivers' affairs.

During the 2008 annual meeting, the primary topic involved an Unwind update for the Member board members. Since the Big Rivers' board members regularly receive this type of information, it was unique for the Members' board members, but not for Big Rivers' directors. These meetings are typically held in the evening to minimize disruption to the Members' board members' work schedules. If an evening annual meeting was combined with a regular Big Rivers' board meeting it would have lasted much later than would have been practicable given the meaty matters the Big Rivers' board needed to consider. Other advantages of holding the Big Rivers annual meeting the evening before the regularly-scheduled board meeting involved avoidance of duplicate Big Rivers' board expenses and most efficient use of the Big Rivers' board's time to attend both events.

g. Big Rivers' prior Labor Union Agreement expired on October 14, 2008. Although negotiations had occurred for some time prior, tentative agreement was not reached with the Union on a new labor pact until October 7 subject to board approval and a favorable vote by the Union membership. Work continued on the final contract language over the next several days along with preparation of summary documentation for board consideration and approval. A telephonic meeting was held with the board on October 13 to obtain their consent and the Union vote occurred the evening of October 14.

All this occurred prior to Big Rivers' regularly-scheduled board meeting on October 17th. Since the exact date when the tentative contract agreement was reached could not be accurately anticipated, it was not possible to know in advance whether agreement would be reached, or when the regularly-scheduled board meeting would need to be re-scheduled. Regular

board meetings require considerable staff scheduling for all attendees, and considerable staff advance preparation time which also complicated advancing the board meeting to a date that was indeterminable in advance.

h. 1) Big Rivers has a policy of encouraging its directors to attend industry-related meetings that provide educational opportunities and that will provide the director information to better perform his or her functions as a Big Rivers board member. Big Rivers' bylaws contain the minimum requirement that a director achieve the National Rural Electric Cooperative Association Credentialed Cooperative Director certification by the end of his or her sixth consecutive year of service.

As previously explained in response to Item 9. c. 2, Big Rivers' board members devote part time attention to the important business of a ~ $300 million dollar a year corporation with approximately $1 billion in assets that provides a service essential to modern life. To function as effectively as possible, they take advantage of industry-associated events (held by KAEC, NRECA, ACES, CFC and CoBank) to broaden their knowledge of the industry and current events that influence the business and provide exposure to some of the best minds in the business.

In addition, NRECA periodically provides training opportunities for directors to help them acquire and maintain the skills and knowledge they need to function effectively. To attract competent and interested individuals, the Members believe it is appropriate to compensate directors and to pay for their reasonable expenses in attending to their Director responsibilities. Many board members are either self employed or work in businesses where they must leave their own business and/or take vacation or time off without pay to attend to Big Rivers' matters. It is appropriate they be compensated.

h. 2) The matter of whether Big Rivers' directors would be unwilling to attend necessary conferences or classes absent fees has not been discussed to my knowledge. Although Big Rivers is a non-profit corporation, it is not a non-profit charity. Big Rivers provides an essential public service. Given the reasons why their attendance at such events is so important to the corporation, in my view it would be unreasonable to ask directors to participate in these activities without some form of compensation.

h. 3) It is unknown whether paying fees for attending such functions is necessary to attract qualified board members. It does stand to reason that individuals would be more likely to take time away from their businesses to attend to Big Rivers' matters when their reasonable expenses are covered and some form of compensation for their time is recovered.

h. 4) Big Rivers' board members have responsibilities distinct and different from those of a distribution cooperative board member since the businesses are very different. Big Rivers' board members are keenly aware of those differences and take the session subject matter in question into consideration when deciding whether to attend a particular function as a Big Rivers' board member or as a distribution cooperative board member.

i. 1) The importance of attending sessions such as the NRECA Directors Winter School was addressed in responses to Items 9.c.2 and h.1. These sessions provide multiple training topic opportunities and topics which permit each director to participate in the sessions he or she needs for their particular experience and knowledge level. Permitting a limited number of individuals to participate in various training opportunities limits the knowledge and skill the board needs as a whole to function as effectively as possible. Please note that Director Elder did not attend the Winter School, as is shown in Big Rivers' Response to Commission Staff's Third Data Request, Item 9.b., pages 4, line 212.

i. 2) As explained in response to Item 9 i.1. above, these training schools are not static with only a limited number of topics available at each session or with repetitive topics covered year-in and year-out. There are numerous topics available for each director's selection based on the individual's experience and knowledge level. In addition, topics are added and deleted to each session as the industry evolves and as issues come and go. If no additional topics are added to the next session, or topics are not included that an individual director believes would be helpful to that individual, he/she does not attend.

j. 1) The 2008 NRECA annual meeting delegate was Paul Edd Butler and the alternate was Mike Core.

j. 2) As explained in response to Items 9.c.2 and 9.h.1, topics are often addressed at these sessions that broaden the industry skill and knowledge base of all who attend, not just the delegate and alternate. It is important for all board members to possess these skills, not just a limited few.

k. 1) Director Denton is not only a Big Rivers' board member, he is also Big Rivers' board chair and designated board member on the ACES Power Marketing board. It was/is important for Director Denton to have knowledge of the coal industry to understand where fuel costs are moving and how fuel prices affect wholesale power costs and arbitrage revenues. The Illinois Basin Energy Forum was held in Henderson, Kentucky, so his attendance involved no travel or other expenses.

k. 2) The responses provided to Items 9.i.1 and 2 relate to this question as well. Since the number and nature of the topics vary from session to session, it is possible for a director to receive training on different and/or updated topics without repeating any previously received material.

k. 3) As noted in the response to Item 9.k.1, Director Denton is Big Rivers' designated Director on the ACES board. ACES performs critically important services for Big Rivers (and its other members) by helping them identify and manage energy trading risk as well as to identify and execute market electricity sales and purchases which help to maximize revenue opportunities and minimize purchased power expense. Participation in the board meetings and annual member sessions helps keep Mr. Denton up to speed on the latest industry issues and concerns so that he can make better decisions as a Big Rivers' board member.

l. 1) Mr. Elder is Big Rivers' designated director on the KAEC board. As a member of that board he has been appointed a member of the KAEC SURE (Speak Up for Rural Electrification) committee. This committee evaluates and makes recommendations to the KAEC board concerning campaign contributions to various office holders. The process helps assure that individuals who share Big Rivers' interest in various legislative and public policy matters receive the support they need so they can continue to hold positions of responsibility.

l. 2) Big Rivers is a member of ACES. Generally on a once-a-year basis, ACES holds a Members' conference where Member board members as well Big Rivers' Member distribution board members and Member senior management receive information and learn about current power generation, transmission, power trading and risk management matters. It is important these individuals have opportunities to stay current on these important matters so that they can perform as effectively as possible in meeting their individual board and management responsibilities.

l. 3) Please see the responses to Items 9.c.2 and 9.h.1. Please note that Big Rivers was planning a credit relationship with CoBank in the Unwind Transaction, and has had and will in the future seek a credit relationship with CoBank. CoBank is a major lender to electric cooperatives, and Big Rivers is a member of CoBank.

l. 4) The legislative conference permits Big Rivers' board members to interact with NRECA officials to give and receive the latest important information regarding national regulatory and legislative affairs that affect the electric utility and cooperative industry. They also meet with their U.S. Congressional delegation to discuss issues of vital importance to their G&T cooperative and their Members. These meetings help assure that Big Rivers can continue to effectively fulfill its mission of providing reliable, low cost power to its Members.

Witness) Mark A. Bailey

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE COMMISSION STAFF'S FOURTH DATA REQUEST
TO BIG RIVERS ELECTRIC CORPORATION
PSC CASE NO. 2009-00040
June 1, 2009

Item 10) Refer to Big Rivers' Response to Commission Staff's Third Date Request, Items 9 and 10. Included in these responses are references to "fringe benefits" in the amount of $4,027 paid on behalf of Big Rivers' Board of Directors. The fringe benefits include life and accident insurance premiums.

a. State the beneficiary of these insurance policies.

b. Generally, the Commission does not allow cooperatives rate recovery of health insurance benefits paid on behalf of its board of directors. Given the Commission's prior treatment of health insurance premiums, state why rate recovery of the "fringe benefits" is appropriate considering that they are very similar to health insurance premiums.

c. Does Big Rivers pay similar life and accident insurance premiums on behalf of any other part-time employees?

Response) a. The beneficiaries of the life and accident insurance policies are the designated beneficiaries named by the individual insured.

b. Big Rivers considers the fees and expenses paid to or on behalf of its board members appropriate and reasonable because of the additional exposure a director has to accidents and injury in connection with their travels on behalf of Big Rivers. These premiums are not technically "fringe benefits" because directors are not employees of Big Rivers.

c. Big Rivers' board members are not part-time employees of Big Rivers. Big Rivers has no part-time employees.

Witness) Mark A. Bailey

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE COMMISSION STAFF'S FOURTH DATA REQUEST
TO BIG RIVERS ELECTRIC CORPORATION
PSC CASE NO. 2009-00040
June 1, 2009

Item 11) Refer to Big Rivers' Response to Commission Staff's Third Data Request, Item 13.a.

a. Page 1 contains Big Rivers' arbitrage sales accounts, Accounts 447.171 through 447.299. During the test year Big Rivers credited revenue to 18 of these accounts totaling $95.580 million. In the pro forma column Big Rivers proposes adjustments to eliminate the sales credited to 16 of these accounts and increase the sales to two of the accounts (447.191 – Century and Alcan, and 447.244 – Other Market Sales). The net adjustment to these accounts is a decrease of $21.712 million, resulting in the pro forma amount of $73.868 million. Explain and discuss each assumption made when eliminating the revenues credited to the 16 accounts and the increased arbitrage sales volume expected in accounts 447.191 and 447.244.

b. The pro forma amount of $73,868 million referenced in Item 13.a. is supported by the workpapers in the CD at lines 304 through 334 of the worksheet titled E_Rev.

1) Lines 304 through 310 show the MWh pro forma sales volume to the Smelters and hourly sales. Compare these monthly sales volumes to the monthly test year volumes. Provide supporting documentation for the pro forma sales volumes that demonstrates that they represent known and measurable changes to the test year amounts.

2) As the information becomes available, provide monthly updates comparing the actual monthly sales volumes to the pro forma monthly sales volumes shown on Lines 304 through 310).

3) Lines 332 through 334 show the price per MWh at which Big Rivers calculated the pro forma revenue of $73.868 million. Provide support for the pro forma prices demonstrating that they represent known and measurable changes to the test year prices. If Big Rivers obtained these prices from forward price curves, provide support for the published prices and demonstrate that these forward price curve projections have historically been accurate.

4) As the information becomes available, provide monthly updates comparing the actual monthly sales prices to the pro forma monthly sales prices shown on Lines 332 through 334.

Response) a. As footnoted on page 2 of 18 in Big Rivers' response to the Commission Staff's Third Data Request, Item 13.a., projected market sales by customer is unknown. Therefore, Big Rivers utilized a single revenue account number, 447.255, in its pro forma Trial Balance to capture the total estimated market revenue. Big Rivers was not effectively eliminating any of the 16 actual customer account numbers in the historical year, rather it was reclassifying all market revenue into one account. The assumptions made to produce the *pro forma* adjustments referenced are described in Big Rivers' Response to KIUC 2-6, page 3, lines 1-18.

b. 1) Please see attached schedule. In reference to the Smelters MWH data, the test year data lists the actual quantity of power sold to the smelters each month of that test year. Proforma year data lists the quantity of power that is under contract to sell to the smelters each month of the proforma year. The quantity of power for both scenarios is simply the number of hours in each month multiplied by 143 MW which represents the total system firm power equal to 113 MW plus the total electable power equal to 30 MW. The distinguishing factor in the two quantities is that in the test year Big Rivers specified 51 MWs out of the 113 MWs of system firm power could be used by Big Rivers for an off-system sale. The 51 MWs was not reserved for an off-system sale in the proforma year.

In reference to the Century power, the proforma amount is equal to the amount that was contracted and actually sold for January and February only. That sale did not exist in the test year.

In reference to the Arbitrage Hourly Sales, there is a substantial drop in the amount of power available for Big Rivers to sell in the proforma year versus the test year because the 51 MW of power reserved for Big Rivers off-system sales is not in the contract for the proforma year.

b. 2) Please see attached schedule. Big Rivers will provide monthly updates as the information becomes available.

b. 3) Big Rivers used contract prices from January through August to predict the price for the sales to the Smelters. Those prices are obviously fixed, known and measureable, and are discussed in Big Rivers' response to the KIUC Second Data Request, Item 6, page 3, lines 1-18.

September through December prices for arbitrage sales are based upon the February 10, 2009, forward price curve. Big Rivers has historically relied upon forward price curves to place forward trades. Forward price curves are the mid-point of actual bid and ask prices. Transactions occur within the range of these two prices. Forward price curves factor in items like current economic conditions, coal prices in different basins, fuel oil futures, natural gas price projections, regional weather projections and transmission restraints.

Schedule 11.b.4, attached to this response, shows *pro forma* monthly prices compared against the actual results of sales into the market by Big Rivers for the months of March and April of 2009. The conclusion from that comparison is that the *pro forma* prices are too high. The chart shown below represents forward curve data. The hourly curve calculation is shown beside the forward curve data.

Forward Month	On Peak (5x16)	Hourly = OP x .935
Jan-09	46.25	43.24
Feb-09	39.63	37.05
Mar-09	39.25	36.70
Apr-09	39.00	36.47
May-09	37.25	34.83
Jun-09	42.50	39.74
Jul-09	54.04	50.53
Aug-09	53.46	49.99
Sep-09	42.00	39.27
Oct-09	38.52	36.02
Nov-09	37.23	34.81
Dec-09	45.75	42.78

b. 4) Please see attached schedule. Big Rivers will provide monthly updates as the information becomes available.

Witness) C. William Blackburn

Big Rivers Electric Corporation
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	Smelters MWh			Smelters-Century only MWh			Hourly Sales MWh			Total MWh		
	Proforma	Test Year	Variance	Proforma	Test Year	Variance	Proforma	Test Year	Variance	Proforma	Test Year	Variance
January	106,392	72,360	34,032	37,200	0	37,200	27,797	47,272	(19,475)	171,389	119,632	51,757
February	96,096	72,977	23,119	33,600	0	33,600	23,856	56,084	(32,228)	153,552	129,061	24,491
March	106,392	86,859	19,533	0	0	0	41,960	100,898	(58,938)	148,352	187,757	(39,405)
April	102,960	88,076	14,884	0	0	0	57,335	132,567	(75,232)	160,295	220,643	(60,348)
May	106,392	83,137	23,255	0	0	0	39,489	111,675	(72,186)	145,881	194,812	(48,931)
June	102,960	79,789	23,171	0	0	0	19,074	48,713	(29,639)	122,034	128,502	(6,468)
July	106,392	87,845	18,547	0	0	0	14,406	30,055	(15,649)	120,798	117,900	2,898
August	106,392	93,253	13,139	0	0	0	1,086	48,148	(47,062)	107,478	141,401	(33,923)
September	102,960	96,149	6,811	0	0	0	10,917	47,214	(36,297)	113,877	143,363	(29,486)
October	106,392	106,392	0	0	0	0	52,972	61,805	(8,833)	159,364	168,197	(8,833)
November	102,960	102,313	647	0	0	0	37,265	41,208	(3,943)	140,225	143,521	(3,296)
December	106,392	190,210	(83,818)	0	0	0	35,858	32,566	3,292	142,250	222,776	(80,526)
	1,252,680	1,159,360	93,320	70,800	0	70,800	362,015	758,204	(396,189)	1,685,495	1,917,564	(232,069)

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	Smelters MWh			Smelters-Century only MWh			Hourly Sales MWh			Total MWh		
	Proforma	Actual	Variance	Proforma	Actual	Variance	Proforma	Actual	Variance	Proforma	Actual	Variance
January	106,392	102,549	3,843	37,200	37,200	0	27,797	42,832	(15,035)	171,389	182,581	(11,192)
February	96,096	95,607	489	33,600	33,600	0	23,856	70,982	(47,126)	153,552	200,189	(46,637)
March	106,392	95,585	10,807	0	0	0	41,960	110,125	(68,165)	148,352	205,710	(57,358)
April	102,960	71,016	31,944	0	0	0	57,335	140,569	(83,234)	160,295	211,585	(51,290)
May	106,392		106,392	0	0	0	39,489		39,489	145,881	0	145,881
June	102,960		102,960	0	0	0	19,074		19,074	122,034	0	122,034
July	106,392		106,392	0	0	0	14,406		14,406	120,798	0	120,798
August	106,392		106,392	0	0	0	1,086		1,086	107,478	0	107,478
September	102,960		102,960	0	0	0	10,917		10,917	113,877	0	113,877
October	106,392		106,392	0	0	0	52,972		52,972	159,364	0	159,364
November	102,960		102,960	0	0	0	37,265		37,265	140,225	0	140,225
December	106,392		106,392	0	0	0	35,858		35,858	142,250	0	142,250
	1,252,680	364,757	887,923	70,800	70,800	0	362,015	364,508	(2,493)	1,685,495	800,065	885,430

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	Smelters $/MWh			Smelters-Century only $/MWh			Hourly Sales $/MWh		
	Proforma	Actual	Variance	Proforma	Actual	Variance	Proforma	Actual	Variance
January	48.40	48.74	(0.34)	55.50	55.50	0.00	43.24	35.42	7.82
February	48.73	36.09	12.64	55.50	55.50	0.00	37.05	34.46	2.59
March	48.69	48.92	(0.23)	0.00	0.00	0.00	36.70	31.82	4.88
April	48.90	53.64	(4.74)	0.00	0.00	0.00	36.55	27.31	9.24
May	48.12		48.12	0.00	0.00	0.00	34.83		34.83
June	48.90		48.90	0.00	0.00	0.00	39.74		39.74
July	48.97		48.97	0.00	0.00	0.00	50.53		50.53
August	45.47		45.47	0.00	0.00	0.00	49.99		49.99
September	39.22		39.22	0.00	0.00	0.00	39.27		39.27
October	37.68		37.68	0.00	0.00	0.00	36.02		36.02
November	37.28		37.28	0.00	0.00	0.00	34.81		34.81
December	41.08		41.08	0.00	0.00	0.00	42.78		42.78

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Item 12) Refer to Big Rivers' Response to Commission Staff's Third Data Request, Item 13. a., Pages 1 and 2, and the Workpapers on the CD at the worksheet titled E_Rev. The adjustments on Pages 1 and 2 to Account 456 increase test year revenues by $5,447,094 to the pro forma amount of $15,380,732. The monthly detail of the pro forma amount is shown on lines 343 through 364 on the E_Rev worksheet. For each account listed on lines 343 through 364:

a. State the nature of the revenues included in the account during the test year.

b. State the nature of the revenues included in the account in the pro forma.

c. State the basis for the proposed adjustment and provide supporting documentation for the adjustment.

Response) Account 456.100-Other Electric Revenue-Power Supply

a. Represents transmission reservation required by Big Rivers to market power off-system.

b. Same as a.

c. Pro Forma increase is due to an additional 450 MW transmission reservation related to the completion of a 345kV Interconnection with Kentucky Utilities.

Account 456.101-Other Electric Revenue-Kenergy

a. Represents Smelter network transmission charges per Big Rivers' OATT for Tier 3 transmission.

b. Same as a.

c. Pro Forma increase is based on historical data.

Account 456.193-Other Electric Revenue-Domtar CoGen Backup

a. Represents network transmission charges per Big Rivers' OATT for backup generation transmission.

b. Same as a.

c. Pro Forma increase is based on historical data.

Accounts 456.160 & 456.220-Other Electric Revenue-SIPC & HMP&L

a. Represents transmission charges SIPC's interconnection and TVA's interconnection and the wheeling on HMP&L's SEPA purchases.

b. Same as a.

c. Pro Forma decrease is based on historical data.

Account 456.270-Other Electric Revenue-LEM

a. Transmission service provided to LEM in accordance with Section 9.6 of the Participation Agreement.

b. Same as a.

c. No Pro Forma adjustment proposed.

Witness) C. William Blackburn

BIG RIVERS ELECTRIC CORPORATION'S
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Item 13) Refer to Big Rivers' Response to Commission Staff's Third Data Request, Item 13.a.

a. Page 2 contains Big Rivers' purchased power accounts, Accounts 555.110 through 565.100. During the test year Big Rivers debited expenses to 17 of these accounts totaling $119.112 million. Big Rivers proposed adjustments to eliminate the expenses charged to 9 of these accounts and either increase or decrease the test year amount charged to the remaining 8 accounts for a net increase of $2.624 million. Big Rivers proposed adjustments resulting in pro forma purchased power costs of $121.736 million. Discuss the assumptions made when eliminating the expenses debited to the 9 accounts and the adjustments made to the remaining 8 accounts.

b. The pro forma amount of $121.736 million as referenced in Item 13.a. is supported by the workpapers in the CD at the worksheet titled P_Pow. That worksheet provides details of pro forma purchased power costs by vendor. Some of the costs were determined by applying pro forma purchase prices to pro forma purchase volumes while others are stated at fixed fee amounts. For the costs determined using pro forma prices and volumes:

1) Provide a comparison of the monthly pro forma purchase prices and volumes to those for each month of the test year. Provide supporting documentation for the pro forma sales volumes and prices that demonstrates that they represent known and measurable changes to the test year amounts.

2) As the information becomes available, provide monthly updates comparing the actual monthly purchase volumes and prices to the pro forma amounts.

3) For the costs stated at fixed amounts, provide a comparison to the test year amounts and provide an explanation and supporting documentation for all adjustments thereto.

Response) a. As footnoted on page 2 in Big Rivers' response to the Commission Staff's Third Data Request, Item 13.1., projected market purchases by source is unknown. Therefore, Big Rivers utilized a single purchased power account number,

555.188, in its pro forma Trial Balance to capture the total estimated cost of market power purchases. Big Rivers' was not effectively eliminating any of the 17 actual power source account numbers in the test year; rather it was reclassifying all market purchased power to one account.

b. 1) Please see attached schedule.

b. 2) Please see attached schedule. Big Rivers will provide monthly updates as the information becomes available.

b. 3) Please see attached schedule.

Witness) C. William Blackburn

Big Rivers Electric Corporation
Commission Staff's Fourth Data Request
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Item 13.b.(1)

PURCHASED POWER

	LEM MWh			SEPA MWh			Domtar Cogen MWh			SIPC MWh (for Century)			Market Sources MWh		
	Proforma	Test Year	Variance	Proforma	Test Year	Variance	Proforma	Test Year	Variance	Proforma	Test Year	Variance	Proforma	Test Year	Variance
January	430,254	427,366	2,888	22,037	22,037	0	744	744	0	37,200	0	37,200	4,000	431	3,569
February	369,465	386,534	(17,069)	36,574	36,574	0	672	696	(24)	33,600	0	33,600	0	702	(702)
March	376,215	417,673	(41,458)	44,630	44,630	0	744	744	0	0	0	0	0	1,300	(1,300)
April	343,768	406,403	(62,635)	46,938	46,938	0	720	720	0	0	0	0	0	553	(553)
May	372,854	409,083	(36,229)	22,376	22,376	0	744	744	0	0	0	0	0	3,321	(3,321)
June	391,010	409,869	(18,859)	9,651	9,651	0	720	720	0	0	0	0	1,600	348	1,252
July	424,643	425,773	(1,130)	4,899	4,899	0	744	744	0	0	0	0	8,000	15	7,985
August	401,544	417,850	(16,306)	5,742	5,742	0	744	744	0	0	0	0	8,000	21,689	(13,689)
September	357,300	397,851	(40,551)	4,722	4,902	(180)	720	720	0	0	0	0	1,600	2,492	(892)
October	396,566	409,207	(12,641)	3,833	3,654	179	744	744	0	0	0	0	0	325	(325)
November	394,824	406,639	(11,815)	4,147	3,297	850	720	721	(1)	0	0	0	0	239	(239)
December	429,881	427,435	2,446	15,656	15,656	0	744	745	(1)	0	0	0	0	76,079	(76,079)
	4,688,324	4,941,683	(253,359)	221,205	220,356	849	8,760	8,786	(26)	70,800	0	70,800	23,200	107,494	(84,294)

	LEM $/MWh			SEPA $/MWh			Domtar Cogen $/MWh			SIPC $/MWh (for Century)			Market Sources $/MWh		
	Proforma	Test Year	Variance	Proforma	Test Year	Variance	Proforma	Test Year	Variance	Proforma	Test Year	Variance	Proforma	Test Year	Variance
January	20.360	20.280	0.080	12.670	12.160	0.510	55.000	55.000	0.000	54.250	0.000	54.250	150.000	60.530	89.470
February	20.370	20.070	0.300	12.670	12.160	0.510	55.000	55.000	0.000	54.250	0.000	54.250	0.000	90.310	(90.310)
March	20.370	20.070	0.300	12.670	12.160	0.510	55.000	55.000	0.000	0.000	0.000	0.000	0.000	74.400	(74.400)
April	20.370	20.020	0.350	12.670	12.160	0.510	55.000	55.000	0.000	0.000	0.000	0.000	0.000	83.280	(83.280)
May	20.370	20.040	0.330	12.670	12.160	0.510	55.000	55.000	0.000	0.000	0.000	0.000	0.000	14.790	(14.790)
June	20.370	20.130	0.240	12.670	12.160	0.510	55.000	55.000	0.000	0.000	0.000	0.000	150.000	125.270	24.730
July	20.360	20.160	0.200	12.670	12.160	0.510	55.000	55.000	0.000	0.000	0.000	0.000	150.000	80.000	70.000
August	20.360	20.060	0.300	12.670	12.160	0.510	55.000	55.000	0.000	0.000	0.000	0.000	150.000	52.290	97.710
September	20.370	20.070	0.300	12.670	12.160	0.510	55.000	55.000	0.000	0.000	0.000	0.000	150.000	64.870	85.130
October	20.360	20.020	0.340	12.670	12.670	0.000	55.000	55.000	0.000	0.000	0.000	0.000	0.000	57.510	(57.510)
November	20.360	20.080	0.280	12.670	12.670	0.000	55.000	55.000	0.000	0.000	0.000	0.000	0.000	57.660	(57.660)
December	20.360	19.850	0.510	12.670	12.160	0.510	55.000	55.000	0.000	0.000	0.000	0.000	0.000	47.707	(47.707)

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P U R C H A S E D P O W E R

	LEM MWh			SEPA MWh			Domtar Cogen MWh			SIPC MWh (for Century)			Market Sources MWh		
	Proforma	Actual	Variance	Proforma	Actual	Variance	Proforma	Actual	Variance	Proforma	Actual	Variance	Proforma	Actual	Variance
January	430,254	402,857	27,397	22,037	48,689	(26,652)	744	0	744	37,200	37,200	0	4,000	555	3,445
February	369,465	376,877	(7,412)	36,574	34,488	2,086	672	672	0	33,600	33,600	0	0	135	(135)
March	376,215	405,578	(29,363)	44,630	54,576	(9,946)	744	744	0	0	0	0	0	308	(308)
April	343,768	382,527	(38,759)	46,938	57,081	(10,143)	720	720	0	0	0	0	0	131	(131)
May	372,854		372,854	22,376		22,376	744		744	0	0	0	0		0
June	391,010		391,010	9,651		9,651	720		720	0	0	0	1,600		1,600
July	424,643		424,643	4,899		4,899	744		744	0	0	0	8,000		8,000
August	401,544		401,544	5,742		5,742	744		744	0	0	0	8,000		8,000
September	357,300		357,300	4,722		4,722	720		720	0	0	0	1,600		1,600
October	396,566		396,566	3,833		3,833	744		744	0	0	0	0		0
November	394,824		394,824	4,147		4,147	720		720	0	0	0	0		0
December	429,881		429,881	15,656		15,656	744		744	0	0	0	0		0
	4,688,324	1,567,839	3,120,485	221,205	194,834	26,371	8,760	2,136	6,624	70,800	70,800	0	23,200	1,129	22,071

	LEM $/MWh			SEPA $/MWh			Domtar Cogen $/MWh			SIPC $/MWh (for Century)			Market Sources $/MWh		
	Proforma	Actual	Variance	Proforma	Actual	Variance	Proforma	Actual	Variance	Proforma	Actual	Variance	Proforma	Actual	Variance
January	20.327	20.520	(0.193)	12.670	12.670	0.000	55.000	55.000	0.000	54.250	54.250	0.000	150.000	55.710	94.290
February	20.327	20.350	(0.023)	12.670	12.670	0.000	55.000	55.000	0.000	54.250	54.250	0.000	0.000	47.930	(47.930)
March	20.327	20.360	(0.033)	12.670	12.670	0.000	55.000	55.000	0.000	0.000	0.000	0.000	0.000	39.150	(39.150)
April	20.327	20.350	(0.023)	12.670	12.670	0.000	55.000	55.000	0.000	0.000	0.000	0.000	0.000	27.290	(27.290)
May	20.327		20.327	12.670		12.670	55.000		55.000	0.000		0.000	0.000		0.000
June	20.327		20.327	12.670		12.670	55.000		55.000	0.000		0.000	150.000		150.000
July	20.327		20.327	12.670		12.670	55.000		55.000	0.000		0.000	150.000		150.000
August	20.327		20.327	12.670		12.670	55.000		55.000	0.000		0.000	150.000		150.000
September	20.327		20.327	12.670		12.670	55.000		55.000	0.000		0.000	150.000		150.000
October	20.327		20.327	12.670		12.670	55.000		55.000	0.000		0.000	0.000		0.000
November	20.327		20.327	12.670		12.670	55.000		55.000	0.000		0.000	0.000		0.000
December	20.327		20.327	12.670		12.670	55.000		55.000	0.000		0.000	0.000		0.000

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FIXED POWER COST

	SEPA			Reliant - Domtar Reservation Fee			TVA Transmission & Other Reservation		
	Proforma	Test Year	Variance	Proforma	Test Year	Variance	Proforma	Test Year	Variance
January	260,937.00	260,937.07	(0.07)	89,900.00	89,900.00	0.00	213,500.00	222,168.05	(8,668.05)
February	260,937.00	260,937.07	(0.07)	89,900.00	89,900.00	0.00	213,500.00	225,111.11	(11,611.11)
March	260,937.00	260,937.07	(0.07)	89,900.00	89,900.00	0.00	213,500.00	228,551.02	(15,051.02)
April	260,937.00	260,937.07	(0.07)	89,900.00	89,900.00	0.00	213,500.00	254,036.12	(40,536.12)
May	260,937.00	260,937.07	(0.07)	89,900.00	89,900.00	0.00	213,500.00	241,585.60	(28,085.60)
June	260,937.00	260,937.07	(0.07)	89,900.00	89,900.00	0.00	213,500.00	226,886.36	(13,386.36)
July	260,937.00	260,937.07	(0.07)	89,900.00	89,900.00	0.00	213,500.00	217,500.03	(4,000.03)
August	260,937.00	260,937.07	(0.07)	89,900.00	89,900.00	0.00	213,500.00	226,176.24	(12,676.24)
September	260,937.00	260,937.07	(0.07)	89,900.00	89,900.00	0.00	213,500.00	221,447.15	(7,947.15)
October	260,937.00	183,014.35	77,922.65	89,900.00	89,900.00	0.00	213,500.00	204,689.47	8,810.53
November	260,937.00	260,937.07	(0.07)	89,900.00	89,900.00	0.00	213,500.00	204,238.36	9,261.64
December	260,937.00	260,937.07	(0.07)	89,900.00	89,900.00	0.00	213,500.00	492,516.07	(279,016.07)
	3,131,244.00	3,053,322.12	77,921.88	1,078,800.00	1,078,800.00	0.00	2,562,000.00	2,964,905.58	(402,905.58)

(BREC Portion of TVA Area Transmission Charges)

	BREC Transmission Reservation			ACES Power Marketing			*Intercontinental Exchange*		
	Proforma	Test Year	Variance	Proforma	Test Year	Variance	Proforma	Test Year	Variance
January	621,458.00	144,648.52	476,809.48	104,970.00	100,928.72	4,041.28	1,000.00	0.00	1,000.00
February	621,458.00	156,637.68	464,820.32	104,970.00	100,928.72	4,041.28	1,000.00	2,000.00	(1,000.00)
March	621,458.00	159,978.51	461,479.49	104,970.00	100,928.72	4,041.28	1,000.00	2,000.00	(1,000.00)
April	621,458.00	282,801.70	338,656.30	104,970.00	100,928.72	4,041.28	1,000.00	2,000.00	(1,000.00)
May	621,458.00	260,805.68	360,652.32	104,970.00	100,928.72	4,041.28	1,000.00	2,000.00	(1,000.00)
June	621,458.00	157,065.56	464,392.44	104,970.00	100,928.72	4,041.28	1,000.00	2,000.00	(1,000.00)
July	621,458.00	94,233.10	527,224.90	104,970.00	100,928.72	4,041.28	1,000.00	2,000.00	(1,000.00)
August	621,458.00	135,813.76	485,644.24	104,970.00	100,928.72	4,041.28	1,000.00	2,000.00	(1,000.00)
September	621,458.00	127,322.07	494,135.93	104,970.00	100,928.72	4,041.28	1,000.00	2,000.00	(1,000.00)
October	621,458.00	227,779.20	393,678.80	104,970.00	100,928.72	4,041.28	1,000.00	2,000.00	(1,000.00)
November	621,458.00	227,050.56	394,407.44	104,970.00	100,928.72	4,041.28	1,000.00	1,000.00	0.00
December	621,458.00	132,750.44	488,707.56	104,970.00	93,492.47	11,477.53	1,000.00	4,000.00	(3,000.00)
	7,457,496.00	2,106,886.78	5,350,609.22	1,259,640.00	1,203,708.39	55,931.61	12,000.00	23,000.00	(11,000.00)

	Revenue Meter Retrieval Cost			NRUCFC Letter of Credit Fees			PJM Annual Fees		
	Proforma	Test Year	Variance	Proforma	Test Year	Variance	Proforma	Test Year	Variance
January	5,750.00	4,430.97	1,319.03	0.00	15,973.97	(15,973.97)	0.00	0.00	0.00
February	5,750.00	4,411.88	1,338.12	0.00	0.00	0.00	0.00	0.00	0.00
March	5,750.00	5,899.73	(149.73)	19,090.00	14,863.97	4,226.03	0.00	0.00	0.00
April	5,750.00	5,738.30	11.70	0.00	0.00	0.00	0.00	0.00	0.00
May	5,750.00	4,031.58	1,718.42	0.00	0.00	0.00	0.00	0.00	0.00
June	5,750.00	8,945.22	(3,195.22)	19,090.00	20,698.78	(1,608.78)	0.00	0.00	0.00
July	5,750.00	4,765.20	984.80	0.00	0.00	0.00	0.00	0.00	0.00
August	5,750.00	2,508.89	3,241.11	0.00	14,213.75	(14,213.75)	0.00	0.00	0.00
September	5,750.00	8,391.56	(2,641.56)	19,090.00	0.00	19,090.00	0.00	0.00	0.00
October	5,750.00	3,741.41	2,008.59	0.00	0.00	0.00	0.00	0.00	0.00
November	5,750.00	3,032.75	2,717.25	0.00	4,875.00	(4,875.00)	0.00	0.00	0.00
December	5,729.22	3,105.87	2,623.35	19,090.00	18,812.50	277.50	5,000.00	5,000.00	0.00
	68,979.22	59,003.36	9,975.86	76,360.00	89,437.97	(13,077.97)	5,000.00	5,000.00	0.00