ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

VOLUME 2 of 5

APPLICATION TABS 30 through 34

FILED: June 28, 2013

ORIGINAL

Big Rivers Electric Corporation
Case No. 2013-00199
Table of Contents

Forecasted Test Year
(Forecast Yest Year 12ME January 15, 2015; Base Period TME September 30, 2013)

Big Rivers Electric Corporation
Case No. 2013-00199
Table of Contents

Forecasted Test Year
(Forecast Yest Year 12ME January 15, 2015; Base Period TME September 30, 2013)

Big Rivers Electric Corporation
Case No. 2013-00199
Table of Contents

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(Forecast Yest Year 12ME January 15, 2015; Base Period TME September 30, 2013)

Big Rivers Electric Corporation
Case No. 2013-00199
Table of Contents

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(Forecast Yest Year 12ME January 15, 2015; Base Period TME September 30, 2013)

Big Rivers Electric Corporation
Case No. 2013-00199
Table of Contents

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(Forecast Yest Year 12ME January 15, 2015; Base Period TME September 30, 2013)

Big Rivers Electric Corporation
Case No. 2013-00199
Table of Contents

Forecasted Test Year

(Forecast Yest Year 12ME January 15, 2015; Base Period TME September 30, 2013)

Big Rivers Electric Corporation
Case No. 2013-00199
Table of Contents

Forecasted Test Year

(Forecast Yest Year 12ME January 15, 2015; Base Period TME September 30, 2013)

Direct Testimony and Exhibits

Volume Number	Tab Number	Witness	Exhibit(s)	Exhibit Decription
5	60	Mark A. Bailey	Exhibit Bailey - 1	Professional Summary
5	61	Billie J. Richert	Exhibit Richert - 1	Professional Summary
			Exhibit Richert - 2	MFIR Calculation
			Exhibit Richert - 3	Generation & Transmisison Cooperatives Comparison Analysis
			Exhibit Richert - 4	Credit Rating Agency Reports
5	62	DeAnna M. Speed	Exhibit Speed - 1	Professional Summary
			Exhibit Speed - 2	Summary of Proposed Changes to Tariff Rates
			Exhibit Speed - 3	Side-by-Side Comparison of Big Rivers Proposed Tariff in CN 2012-000535 (*PSC KY No. 25*) versus Big Rivers Proposed Tariff in CN 2013-00199 (*PSC KY No. 26*)
5	63	Robert W. Berry	Exhibit Berry - 1	Forecasted Production Non-Labor Fixed Departmental Expenses (FDE)
			Exhibit Berry - 2	Forecasted Production Capital Work Plan
5	64	David G. Crockett	[None]	
5	65	Daniel M. Walker	Exhibit Walker - 1	G&T Cooperatives, Ratings and 2011 TIER
			Exhibit Walker - 2	G&T Cooperatives Debt Service Coverage (DSC) Ratios
			Exhibit Walker - 3	Equity Ratio
5	66	Jeffrey A. Williams	Exhibit Williams -1	Professional Summary

Big Rivers Electric Corporation
Case No. 2013-00199
Table of Contents

Forecasted Test Year

(Forecast Yest Year 12ME January 15, 2015; Base Period TME September 30, 2013)

Direct Testimony and Exhibits

Tab No. 30
Filing Requirement
807 KAR 5:001 Section 16(12)(j)
Sponsoring Witness: Billie J. Richert

Description of Filing Requirement:

The prospectuses of the most recent stock or bond offerings;

Response:

Please see the attachment to this response for prospectus of Big Rivers' most recent bond offering.

NEW ISSUE – BOOK-ENTRY ONLY

In the opinion of Orrick, Herrington & Sutcliffe LLP, Bond Counsel, based upon an analysis of existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code") and Title XIII of the Tax Reform Act of 1986, except that no opinion is expressed as to the status of interest on any Bond during any period that such Bond is held by a "substantial user" of facilities financed or refinanced by the Bonds or by a "related person" within the meaning of Section 103(b)(13) of the 1954 Code. In the opinion of Bond Counsel, interest on the Bonds is not a specific preference item for purposes of calculating the federal individual or corporate alternative minimum taxes, although Bond Counsel observes that such interest is included in adjusted current earnings in calculating federal corporate alternative minimum taxable income. Interest on the Bonds is exempt from all present Kentucky personal and corporate income taxes. Bond Counsel expresses no opinion regarding other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the Bonds. See "TAX MATTERS."

$83,300,000
COUNTY OF OHIO, KENTUCKY
Pollution Control Refunding Revenue Bonds, Series 2010A
(Big Rivers Electric Corporation Project)

Dated: Date of Delivery **Due: July 15, 2031**

The County of Ohio, Kentucky (the "County"), Pollution Control Refunding Revenue Bonds, Series 2010A (Big Rivers Electric Corporation Project) (the "Bonds") are limited obligations of the County, payable solely out of the Receipts and Revenues (as defined herein) of the County received under the Financing Agreement (as defined below) and certain other funds pledged therefor under the Bond Indenture (as defined herein), and do not constitute a debt of the County within the meaning of any constitutional or statutory limitation. The Bonds are not general obligations of the County and do not constitute nor give rise to a pecuniary liability of the County or a charge against its general credit or taxing powers. The Receipts and Revenues received by the County include payments sufficient to pay in full the principal of and interest on the Bonds when due, to be made by,

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

The proceeds from the sale of the Bonds will be used to refund the entire outstanding principal amount of the County's Pollution Control Refunding Revenue Bonds, Series 2001A (Big Rivers Electric Corporation Project), Periodic Auction Reset Securities (PARS^{SM}) (the "Refunded Bonds"). The Refunded Bonds were issued to refund bonds previously issued by the County to finance a portion of Big Rivers' cost of certain pollution control and solid waste disposal facilities at Big Rivers' D.B. Wilson Plant Unit No. 1, a coal-fired steam electric generating plant located within the geographical boundaries of the County.

In connection with the issuance of the Bonds, the County and Big Rivers will enter into a loan agreement (the "Financing Agreement") with respect to the Bonds under which the County will loan to Big Rivers funds equal to the principal amount of the Bonds, and Big Rivers will be obligated to repay such loan in amounts equal to the principal and interest payments relating to the Bonds when due. Big Rivers' loan repayment obligations will be evidenced by a note of Big Rivers, which will be an obligation under Big Rivers' Mortgage Indenture (as defined herein), secured equally and ratably with other Mortgage Indenture Obligations (as defined herein) by a mortgage lien on substantially all of the owned tangible and certain of the intangible assets of Big Rivers, subject to certain exceptions and exclusions as described herein.

U.S. Bank National Association is the Trustee, Paying Agent and Registrar under the Bond Indenture, and the trustee under Big Rivers' Mortgage Indenture.

The Bonds are subject to optional redemption, as described herein.

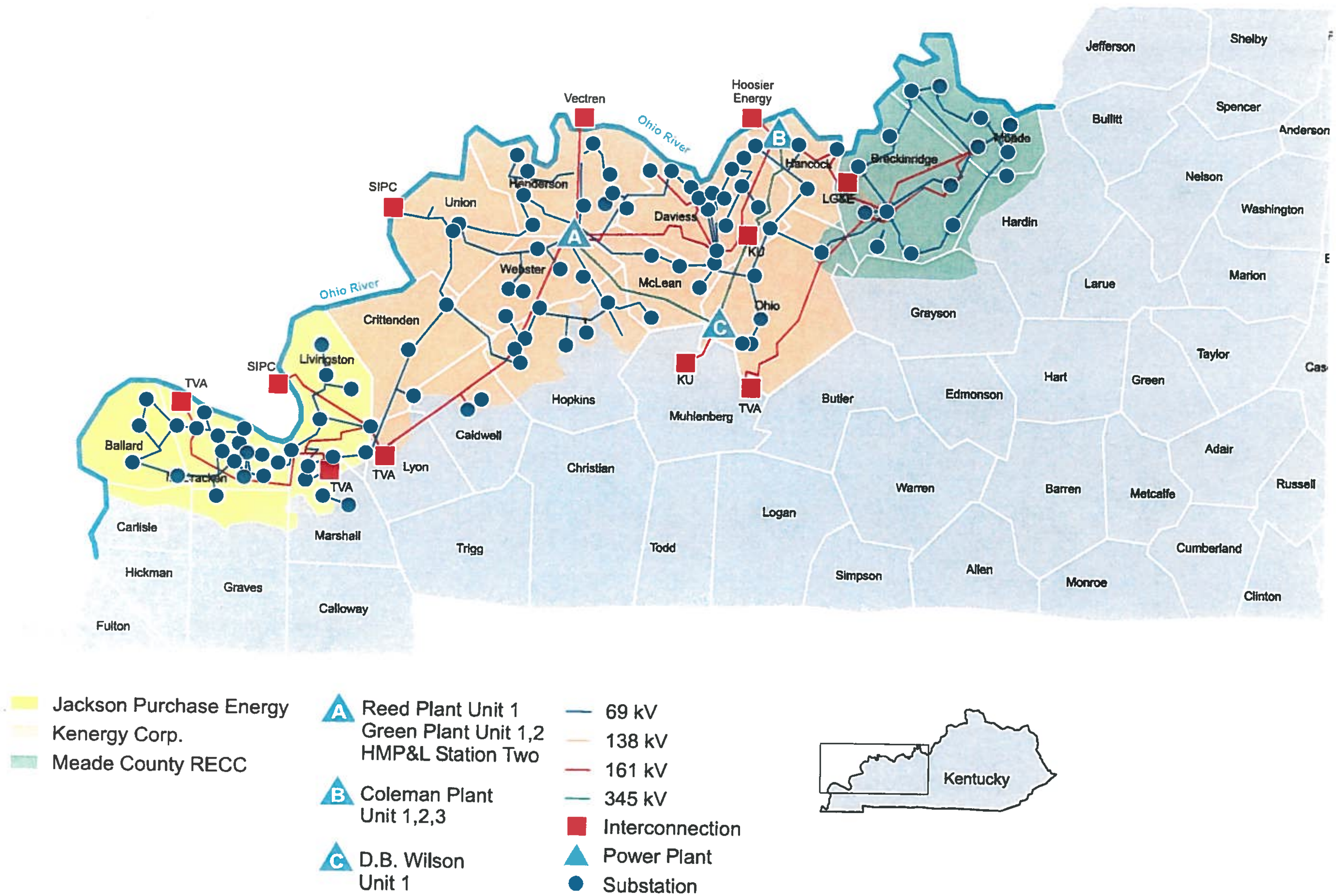
Amount	Interest Rate	Price	CUSIP
$83,300,000	6.00%	100.00%	677288AG7

The Bonds will be issued in fully-registered form and will be registered in the name of Cede & Co., as nominee of The Depository Trust Company, New York, New York ("DTC"). DTC will act as securities depository for the Bonds and purchases of beneficial ownership interests in the Bonds will be made in book-entry only form. The Bonds will be issued in initial denominations of $5,000 or in any integral multiple thereof. Actual purchasers of the beneficial ownership interests in the Bonds will not receive certificates representing their interest in such Bonds. Semiannual interest on the Bonds is payable on January 15 and July 15, commencing on January 15, 2011. So long as Cede & Co. is the registered owner, references herein to the holder or registered owner of the Bonds, including for the purpose of receiving notices under the Bond Indenture, shall mean Cede & Co., and shall not mean such beneficial owners. So long as Cede & Co. or another nominee of DTC is the registered owner of the Bonds, payments of the principal of and premium, if any, and interest on the Bonds will be made directly to DTC or its nominee. Disbursement of such payments to participants in DTC is the responsibility of DTC and disbursement of such payments to beneficial owners is the responsibility of those participants.

The Bonds are offered, subsequent to prior sale, when, as and if issued and accepted by Goldman, Sachs & Co. (the "Underwriter"), subject to the approval of legality by Orrick, Herrington & Sutcliffe LLP, Bond Counsel. Certain legal matters in connection with the Bonds are subject to the approval of Sutherland Asbill & Brennan LLP, Counsel to the Underwriter. Certain legal matters will be passed upon for Big Rivers by Sullivan, Mountjoy, Stainback & Miller PSC, General Counsel for Big Rivers. Certain legal matters for the County will be passed upon by Greg Hill, Esq., counsel to the County. It is expected that delivery of the Bonds will be made on or about June 8, 2010.

Goldman, Sachs & Co.

May 27, 2010


Vectren
Hoosier Energy
Ohio River
SIPC
TVA
KU
LG&E
Union
Henderson
Daviess
Hancock
Breckinridge
Meade
Webster
McLean
Ohio
Crittenden
Livingston
Ballard
McCracken
Marshall
Lyon
Caldwell
Hopkins
Muhlenberg
Butler
Grayson
Hardin
Jefferson
Shelby
Bullitt
Spencer
Anderson
Nelson
Washington
Larue
Marion
Taylor
Hart
Green
Edmonson
Adair
Russell
Christian
Warren
Barren
Metcalfe
Logan
Todd
Trigg
Simpson
Allen
Monroe
Cumberland
Clinton
Carlisle
Hickman
Graves
Calloway
Fulton
Jackson Purchase Energy
Kenergy Corp.
Meade County RECC
Reed Plant Unit 1
Green Plant Unit 1,2
HMP&L Station Two
Coleman Plant
Unit 1,2,3
D.B. Wilson
Unit 1
69 kV
138 kV
161 kV
345 kV
Interconnection
Power Plant
Substation
Kentucky

Big Rivers Electric Corporation
201 Third Street
Henderson, Kentucky 42420

Officers

Mark A. Bailey, President and Chief Executive Officer
C. William Blackburn, Senior Vice President of Financial & Energy Services and Chief Financial Officer

Senior Staff

Robert W. Berry, Vice President of Production
David G. Crockett, Vice President of System Operations
James V. Haner, Vice President of Administrative Services
Mark A. Hite, Vice President of Accounting
Albert M. Yockey, Vice President of Governmental Relations & Enterprise Risk Management

Directors

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

Members

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

Counsel to Big Rivers
Sullivan, Mountjoy, Stainback & Miller PSC
Owensboro, Kentucky

Bond Counsel
Orrick, Herrington & Sutcliffe LLP
New York, New York

Independent Public Accountants
Deloitte & Touche LLP
Chicago, Illinois

Trustee
U.S. Bank National Association
Hartford, Connecticut

Counsel to Underwriter
Sutherland Asbill & Brennan LLP
Atlanta, Georgia

No dealer, broker, salesperson or other person has been authorized to give any information or to make representations, other than as contained in this Offering Statement, and if given or made, such other information or representations must not be relied upon. This Offering Statement does not constitute an offer to sell or the solicitation of an offer to buy, nor shall there be any sale of the Bonds by any person, in any jurisdiction in which it is unlawful for such person to make such offer, solicitation or sale.

The information set forth herein has been furnished by Big Rivers and includes information obtained from other sources, all of which are believed to be reliable. The information and expressions of opinion herein are subject to change without notice and neither the delivery of this Offering Statement nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in Big Rivers' affairs or the affairs of the County. Such information and expressions of opinion are made for the purpose of providing information to prospective investors and are not to be used for any other purpose or relied on by any other party.

The Underwriter has provided the following sentence for inclusion in this Offering Statement: The Underwriter has reviewed the information in this Offering Statement in accordance with, and as part of, its responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriter does not guarantee the accuracy or completeness of such information.

IN CONNECTION WITH THE OFFERING OF THE BONDS, THE UNDERWRITER MAY OVERALLOT OR EFFECT TRANSACTIONS WHICH STABILIZE OR MAINTAIN THE MARKET PRICE OF SUCH BONDS AT LEVELS ABOVE THOSE WHICH MIGHT OTHERWISE PREVAIL IN THE OPEN MARKET. SUCH STABILIZATION, IF COMMENCED, MAY BE DISCONTINUED AT ANY TIME.

IN MAKING AN INVESTMENT DECISION, INVESTORS MUST RELY ON THEIR OWN EXAMINATION OF THE COUNTY AND BIG RIVERS AND THE TERMS OF THE OFFERING OF THE BONDS, INCLUDING THE MERITS AND RISKS INVOLVED.

THE SECURITIES OFFERED HEREBY HAVE NOT BEEN REGISTERED WITH OR RECOMMENDED BY ANY FEDERAL OR STATE SECURITIES COMMISSION OR REGULATORY AUTHORITY. FURTHERMORE, NO SUCH COMMISSION OR REGULATORY AUTHORITY HAS CONFIRMED THE ACCURACY OR DETERMINED THE ADEQUACY OF THIS DOCUMENT. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

THIS OFFERING STATEMENT CONTAINS FORWARD-LOOKING STATEMENTS. IN THIS RESPECT, THE WORDS "MAY," "WILL," "FORECAST," "ESTIMATE," PROJECT," "ANTICIPATE," "EXPECT," "INTEND," "BELIEVE" AND SIMILAR EXPRESSIONS ARE INTENDED TO IDENTIFY FORWARD-LOOKING STATEMENTS. SUCH STATEMENTS ARE BASED ON THE CURRENT EXPECTATIONS OF THE PARTY MAKING SUCH STATEMENTS AS WELL AS ASSUMPTIONS MADE BASED ON THE INFORMATION CURRENTLY AVAILABLE TO SUCH PARTY. A NUMBER OF IMPORTANT FACTORS AFFECTING OUR BUSINESS AND FINANCIAL RESULTS THAT COULD CAUSE ACTUAL RESULTS TO DIFFER MATERIALLY FROM THOSE STATED IN THE FORWARD-LOOKING STATEMENTS ARE DISCLOSED IN THIS OFFERING STATEMENT. FOR ADDITIONAL FACTORS THAT COULD AFFECT THE VALIDITY OF OUR FORWARD-LOOKING STATEMENTS, YOU SHOULD READ THE SECTIONS ENTITLED "RISK FACTORS" AND "RATE AND ENVIRONMENTAL REGULATION" HEREIN. IN LIGHT OF THESE AND OTHER RISKS, UNCERTAINTIES AND ASSUMPTIONS, ACTUAL EVENTS OR RESULTS MAY BE MATERIALLY DIFFERENT FROM THOSE EXPRESSED OR IMPLIED IN THE FORWARD-LOOKING STATEMENTS IN THIS

OFFERING STATEMENT, OR MAY NOT OCCUR. NEITHER WE NOR THE COUNTY HAVE ANY OBLIGATION TO PUBLICLY UPDATE OR REVISE ANY FORWARD-LOOKING STATEMENT, WHETHER AS A RESULT OF NEW INFORMATION, FUTURE EVENTS OR OTHERWISE.

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SUMMARY

The following summary contains information about Big Rivers Electric Corporation ("Big Rivers"; as used in this Offering Statement, "we," "us" and "our" also refer to Big Rivers), the County of Ohio, Kentucky (the "County"), the offering and the terms of the Bonds (as defined herein) that we believe is important. You should read this entire Offering Statement, including our financial statements and the accompanying notes in Appendix A and our Members' (as defined herein) information in Appendix B, for a complete understanding of our operations, the offering and the Bonds.

County of Ohio .... The County, located in western Kentucky, is a public body corporate and politic duly created and existing as a county and political subdivision under the Constitution and laws of the Commonwealth of Kentucky. The County was and is authorized and empowered by law, including particularly the provisions of the Industrial Building Revenue Bond Act (Sections 103.200 through 103.285, inclusive) of the Kentucky Revised Statutes, as amended (the "Act"), to finance certain pollution control and solid waste disposal facilities, including the Facilities as described below, and to enter into and perform its obligations under the Financing Agreement and the Bond Indenture (each, as defined herein). Except for the information in this paragraph and the information solely with respect to the County under the captions "COUNTY OF OHIO, KENTUCKY" and "LITIGATION – Litigation Involving the County" the County did not participate in the preparation of this Offering Statement and does not have or assume any responsibility as to the accuracy or completeness of any information herein, all of which information has been furnished by others.

Big Rivers Electric Corporation .... We were formed in 1961 as a not-for-profit generation and transmission ("G&T") cooperative corporation. We are based in Henderson, Kentucky, and are principally engaged in the business of providing wholesale electric service to our three member electric distribution cooperatives. The Members (as defined herein) of Big Rivers are local consumer-owned distribution cooperatives providing retail electric service on a not-for-profit basis to their customers, who are their members. The customer base of our Members generally consists of residential, commercial and industrial consumers, including two large aluminum smelters (the "Smelters"), within specific geographic areas. The Members provide electric power and energy to customers located in portions of 22 western Kentucky counties. See "BIG RIVERS ELECTRIC CORPORATION," "THE SMELTER AGREEMENTS" and APPENDIX E – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS."

Our principal office is located at 201 Third Street, Henderson, Kentucky 42420. Our telephone number is (270) 827-2561. Our website is www.bigrivers.com.

Facilities .... The pollution control facilities being refinanced are located at Big Rivers' D.B. Wilson Plant Unit No. 1 (the "Facilities"), a coal-fired steam electric generating plant located within the geographical boundaries of the County (the "Wilson Plant") .

The Offering

Securities Offered.................................. Pollution Control Refunding Revenue Bonds, Series 2010A (Big Rivers Electric Corporation Project), due July 15, 2031, in the aggregate principal amount of $83,300,000 (the "Bonds").

The Bonds are limited obligations of the County, payable solely from amounts received by the County from us under the Financing Agreement and certain other funds pledged under the Bond Indenture, and do not constitute a debt of the County within the meaning of any constitutional or statutory limitation. See APPENDIX D – "SUMMARY OF CERTAIN PROVISIONS OF THE BOND INDENTURE."

Interest Payment Dates.......................... The Bonds will bear interest at 6.00 percent per annum. We will pay interest on the Bonds semiannually on January 15 and July 15 of each year, commencing January 15, 2011. See "DESCRIPTION OF THE BONDS – General."

Optional Redemption............................ On or after July 15, 2020, we may redeem the Bonds, in whole or in part, prior to their stated maturity, at our option. See "DESCRIPTION OF THE BONDS – Redemption of Bonds – *Optional Redemption*."

Bond Indenture .... The Bonds will be issued under a Trust Indenture, dated as of June 1, 2010 (the "Bond Indenture"), between the County and U.S. Bank National Association, as trustee (the "Trustee"). See APPENDIX D – "SUMMARY OF CERTAIN PROVISIONS OF THE BOND INDENTURE."

Financing Agreement............................ We and the County will enter into a Loan Agreement, dated as of June 1, 2010 (the "Financing Agreement"), with respect to the Bonds under which the County will loan to us funds equal to the principal amount of the Bonds. We will be obligated to repay such loan in amounts equal to the principal and interest payments relating to the Bonds when due. See APPENDIX C – "SUMMARY OF CERTAIN PROVISIONS OF THE FINANCING AGREEMENT AND THE NOTE."

The Note.. Our payment obligations under the Financing Agreement will be evidenced by a note (the "Note"), which will be an obligation under the Mortgage Indenture (as defined herein), secured equally and ratably by a mortgage lien on substantially all of our owned tangible and certain of our intangible assets, subject to certain exceptions and exclusions. See APPENDIX C – "SUMMARY OF CERTAIN

PROVISIONS OF THE FINANCING AGREEMENT AND THE NOTE" and APPENDIX E – "SUMMARY OF CERTAIN PROVISIONS OF THE MORTGAGE INDENTURE."

Use of Proceeds.. The proceeds from the sale of the Bonds will be used to refund the entire outstanding principal amount of the County's Pollution Control Refunding Revenue Bonds, Series 2001A (Big Rivers Electric Corporation Project), Periodic Auction Reset Securities (PARS[SM]) (the "Refunded Bonds"). See "USE OF PROCEEDS."

Tax Exemption.. Under existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the Bonds is excluded from gross income for federal income tax purposes, except that Bond Counsel has expressed no opinion as to the status of interest on any Bond during any period that such Bond is held by a "substantial user" of facilities financed or refinanced with the proceeds of the Bonds or by a "related person" within the meaning of 103(b)(13) of the Internal Revenue Code of 1954, as amended. Interest on the Bonds is exempt from all present Kentucky personal and corporate income taxes. See "TAX MATTERS."

Big Rivers Electric Corporation

Cooperative Principles............................ We are organized as a cooperative. A cooperative is a business organization owned by its members, which also are its customers. Cooperatives are created to provide goods or services to their members on a not-for-profit basis. See "BIG RIVERS ELECTRIC CORPORATION."

Recent Changes in Business Structure.. In July 2009, we terminated an arrangement under which Western Kentucky Energy Corp. ("WKEC"), a wholly-owned subsidiary of E.ON U.S. LLC ("E.ON"), had leased from us all of the power supply resources we owned. Under this arrangement, WKEC had assumed responsibility for the operation of our generating facilities and for the operation of Station Two ("Station Two"), two coal-fired units owned by the City of Henderson though Henderson Municipal Power & Light ("HMP&L") we previously operated. Under this arrangement we purchased power from LG&E Energy Marketing, Inc. ("LEM"), another wholly-owned subsidiary of E.ON, to serve our Member load.

In July 2009, we terminated these arrangements. We again operate all of our owned generating facilities and Station Two. Further, the power sales agreement under which we previously purchased power from LEM has been terminated. See "BIG RIVERS ELECTRIC CORPORATION – Bankruptcy and Subsequent Operation" and "GENERATION AND TRANSMISSION ASSETS." In connection with the termination of these arrangements, we assumed responsibility for supplying our Member, Kenergy Corp. ("Kenergy"), with approximately 850 MW of power that is necessary for Kenergy to supply a portion of its contractual obligations to the Smelters. See "THE SMELTER AGREEMENTS" and APPENDIX F – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS."

Power Supply Resources .... Our power supply resources consist of 1,444 MW of owned generation resources and up to an additional 390 MW available to us under power purchase arrangements. See "GENERATION AND TRANSMISSION ASSETS."

Our generation resources consist of:

- 443 MW of net nameplate capacity from the Kenneth C. Coleman Plant, a three unit, coal-fired steam electric generating station located near Hawesville, Kentucky.
- 454 MW of net nameplate capacity from the Robert D. Green Plant, a two unit, coal-fired steam electric generating station located near Sebree, Kentucky.
- 417 MW of net nameplate capacity from the Wilson Plant, a single coal-fired, balanced draft steam electric generating unit, located near Centertown, Kentucky on the Green River.
- 130 MW of net nameplate capacity from the Robert A. Reid Plant (the "Reid Plant"), located near Sebree, Kentucky, which includes a 65 MW coal-fired steam electric generating unit and a 65 MW oil-or natural gas-fired combustion turbine generating unit.

Our long-term power purchase arrangements consist of:

- a power sales contract with HMP&L which entitles us to purchase up to 212 MW from HMP&L's Station Two through May 31, 2010, a coal fired generating plant, which we operate. Beginning June 1, 2010, our capacity share will decrease to 207 MW.
- a power purchase agreement with the Southeastern Power Administration ("SEPA") which entitles us to purchase up to 178 MW. We normally use our entitlement under this contract for peaking; however, as a result of problems with certain dams, our capacity entitlement has been suspended and we currently are receiving only energy under this arrangement.

Our Members .... Our Members are Kenergy, Meade County Rural Electric Cooperative Corporation ("Meade") and Jackson Purchase Energy Corporation ("Jackson Purchase", and collectively with Kenergy and Meade, our "Members"). See "OUR MEMBERS."

Wholesale Power Contracts .... Each of Meade, Jackson Purchase and Kenergy is party to a wholesale power contract with us (the "All Requirements

Contracts"). The All Requirements Contracts provide that we are obligated to sell and deliver to the Member, and the Member is obligated to purchase and receive from us, all the electric power and energy which the Member requires for the operation of the Member's system, except Kenergy's requirements for the Smelters, to the extent that we have power and energy and facilities available. Each contract extends through December 31, 2043.

Smelter Agreements .... In addition to the All Requirements Contracts, we and Kenergy are parties to two wholesale electric service agreements (the "Smelter Agreements") under which we provide approximately 850 MW of power which is necessary for Kenergy to supply a portion of its contractual obligations to the Smelters. The Smelter Agreements terminate on December 31, 2023; however, they are terminable upon various conditions with one year's notice to Kenergy and us. Kenergy's obligations to purchase electric service from us to serve the Smelters are exceptions to the "all requirements" obligations in Kenergy's All Requirements Contracts. See "THE SMELTER AGREEMENTS" and APPENDIX F – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS."

Our Mortgage Indenture

Security for the Bonds .... The Note will be secured equally and ratably with all our other obligations issued under the Indenture dated as of July 1, 2009, as supplemented and amended (the "Mortgage Indenture"), between us and U.S. Bank National Association, as trustee (the "Mortgage Indenture Trustee"). Obligations are secured under the Mortgage Indenture by a mortgage lien on substantially all of our owned tangible and certain of our intangible properties, including our electric generation and transmission facilities and certain of our contracts relating to the purchase, sale or transmission of electricity of more than one year in duration and relating to the ownership, operation or maintenance of electric generation, transmission or distribution facilities owned by us, but excluding certain exceptions set forth in the Mortgage Indenture. The lien of the Mortgage Indenture also extends to revenue generated from the sale or transmission of electricity under certain of these contracts. See APPENDIX E – "SUMMARY OF CERTAIN PROVISIONS OF THE MORTGAGE INDENTURE."

Rate Covenant .... The Mortgage Indenture obligates us to establish and collect rates that, subject to any necessary regulatory approvals, are reasonably expected to yield "Margins for Interest" equal to at least 1.10 times our total "Interest Charges" for each fiscal year on debt secured under or prior to or on a parity with the lien of the Mortgage Indenture.

See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF

OPERATIONS – Cooperative Operations – *Coverage Ratios*." For the definitions of "Margins for Interest" and "Interest Charges," see APPENDIX E – "SUMMARY OF CERTAIN PROVISIONS OF THE MORTGAGE INDENTURE – Covenants."

Additional Obligations............................ As long as we are in compliance with the financial test required under the Mortgage Indenture relating to Margins for Interest, we may issue additional indebtedness or other obligations under the Mortgage Indenture. The amount of additional obligations we may issue is based on the amount of specified property additions that have been certified to the Mortgage Indenture Trustee, the principal amount of Mortgage Indenture Obligations previously retired or defeased, and deposits of cash and certain securities previously made with the Mortgage Indenture Trustee, among other things. See APPENDIX E – "SUMMARY OF CERTAIN PROVISIONS OF THE MORTGAGE INDENTURE – Additional Mortgage Indenture Obligations."

Limitation on Distributions to Members.. The Mortgage Indenture prohibits us from making any distribution, including any dividends, or payments of, or retirements of, patronage capital to our Members if at the time of or as a result of such distribution:

- we are in default under the Mortgage Indenture;
- our aggregate margins and equities as of the end of our most recent fiscal quarter would be less than 20% of our total long-term debt and equities; or
- the aggregate amount expended for all distributions on or after the date on which our aggregate margins and equities first reached 20% of our long-term debt and equities shall exceed 35% of our aggregate net margins earned after such date. See "APPENDIX E – SUMMARY OF CERTAIN PROVISIONS OF THE MORTGAGE INDENTURE – Covenants."

Notwithstanding the foregoing and so long as we are not in default under the Mortgage Indenture, we may declare and make distributions at any time if, after giving effect thereto, our aggregate margins and equities as of the end of our most recent fiscal quarter would have been not less than 30% of our total long-term debt and equities as of such date.

As of December 31, 2009, our equity to total capitalization ratio was 31%, and we could have distributed approximately $21.8 million to our Members under the criteria described above.

SUMMARY FINANCIAL DATA

The summary financial data below present selected historical information relating to our financial condition and results of operations. Summary financial data for the three months ended March 31, 2010 that are presented below are unaudited, and reflect all adjustments that we consider necessary (consisting of normal recurring accruals) for a fair presentation of such data. The Balance Sheet data as of December 31, 2009 and 2008 and the Statement of Operations data for years ended December 31, 2009, 2008 and 2007 were derived from our audited financial statements included in APPENDIX A. The Balance Sheet data as of December 31, 2007 and the Statement of Operations data for the years ended December 31, 2006 and 2005 were derived from our audited financial statements for those years. You should read the information contained in this table together with our financial statements, the related notes to the financial statements and the discussion of this information in "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS" included in this Offering Statement.

	Three Months Ended March 31, 2010 (in thousands)	Years Ended December 31, 2009	2008	2007 (in thousands)	2006	2005
Statement of Operations Data:						
Operating Revenues	$137,194	$373,360	$273,181	$329,870	$258,588	$248,955
Operating Expenses	115,642	317,668	178,542	231,836	170,260	168,196
Electric Operating Margins	21,552	55,692	94,639	98,034	88,328	80,759
Interest Expense and Other	12,123	63,207	79,578	70,954	70,370	68,872
Non-operating margin	102	538,845	12,755	20,097	16,584	14,456
Net margin	$ 9,531	$531,330	$ 27,816	$ 47,177	$ 34,542	$ 26,343

	As of March 31, 2010	As of December 31, 2009	2008	2007
		(in thousands, except ratios)		
Balance Sheet Data:				
Assets:				
Utility plant, net	$1,081,552	$1,078,274	$ 912,699	$ 911,634
Other assets	407,563	427,209	161,737	402,524
Total assets	$1,489,115	$1,505,483	$1,074,436	$1,314,158
Equities and Liabilities:				
Capitalization	$1,204,808	$1,213,759	$ 832,747	$1,032,099
Current Liabilities	66,863	67,165	78,091	68,187
Deferred Credits and other	217,444	224,559	163,598	213,872
Total equities and liabilities	$1,489,115	$1,505,483	$1,074,436	$1,314,158
Other Financial Data:				
Equity ratio(1)	32%	31%	-19%	-17%
Margins for Interest ratio(2)(3)	1.78	9.87	1.45	1.64

(1) Our equity ratio is calculated by dividing total equity by total capitalization.

(2) Our Margins for Interest ratio is calculated by dividing our Margins for Interest by Interest Charges, both as defined in the Mortgage Indenture. We became subject to the Mortgage Indenture in 2009; prior to 2009, we did not have a required MFI Ratio (as defined herein). The Mortgage Indenture obligates us to establish and collect rates that, subject to any necessary regulatory approvals, are reasonably expected to yield Margins for Interest equal to at least 1.10 times our Interest Charges for each fiscal year. In addition, the Mortgage Indenture requires a showing of our having met this requirement for certain historical periods as a condition for issuing additional obligations under the Mortgage Indenture. See APPENDIX E – "SUMMARY OF CERTAIN PROVISIONS OF THE MORTGAGE INDENTURE – Covenants" and "– Additional Mortgage Indenture Obligations."

(3) See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Financial Condition – *As of March 31, 2010*" for a discussion of our projected MFI Ratio for the year ending December 31, 2010.

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INTRODUCTION

The purpose of this Offering Statement, which includes the cover page and Appendices hereto, is to provide information in connection with the issuance and sale by the County of Ohio, Kentucky (the "County") of its Pollution Control Refunding Revenue Bonds, Series 2010A (Big Rivers Electric Corporation Project) in the aggregate principal amount of $83,300,000 (the "Bonds"). The Bonds will be issued pursuant to the Constitution and laws of the Commonwealth of Kentucky, including particularly the provisions of Kentucky Revised Statutes Sections 103.200 through 103.285, inclusive (the "Act"). The Bonds will be issued under the terms and conditions of a Trust Indenture, dated as of June 1, 2010 (the "Bond Indenture"), between the County and U.S. Bank National Association, as trustee (the "Trustee"). The Bonds are being issued for the benefit of Big Rivers Electric Corporation ("Big Rivers"; as used in this Offering Statement, "we," "us" and "our" also refer to Big Rivers), a non-profit rural electrical cooperative corporation organized and existing under the laws of the Commonwealth of Kentucky.

USE OF PROCEEDS

The proceeds from the sale of the Bonds will be used to refund the entire outstanding principal amount of the County's Pollution Control Refunding Revenue Bonds, Series 2001A (Big Rivers Electric Corporation Project), Periodic Auction Reset Securities (PARS℠) (the "Refunded Bonds"). The Refunded Bonds were issued to refund certain bonds issued by the County to finance a portion of the costs of certain pollution control and solid waste disposal facilities (the "Facilities") located at our D.B. Wilson Plant Unit No. 1, a coal-fired steam electric generating plant located within the geographical boundaries of the County (the "Wilson Plant"). See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Liquidity and Capital Resources – *Debt and Lease Obligations*" for a discussion of the most recent auction of the Refunded Bonds.

SECURITY FOR AND SOURCES OF PAYMENT OF THE BONDS

Pledge of Funds, Note and Financing Agreement

The Bonds are not general obligations of the County and do not constitute nor give rise to a pecuniary liability of the County or a charge against its general credit or taxing powers. The Bonds shall not constitute an indebtedness of the County within the meaning of the Constitution of Kentucky, but shall be payable solely out of the amounts payable under the Financing Agreement (as defined herein) by us to the County, such amounts being equal to an amount sufficient to pay the principal and interest payments relating to the Bonds when due, and certain other funds pledged therefor under the Bond Indenture ("Receipts and Revenues"). See APPENDIX D – "SUMMARY OF CERTAIN PROVISIONS OF THE BOND INDENTURE."

In connection with the issuance of the Bonds, we will enter into a Loan Agreement, dated as of June 1, 2010 (the "Financing Agreement"), with the County, under which the County will loan the proceeds of the Bonds to us for the purpose of paying the principal amount of the Refunded Bonds upon their redemption, and we will make loan repayments equal to the principal of and interest on the Bonds when due. To evidence and secure our obligation to repay such loan, we will issue a note with respect to the Bonds, dated the date of issuance of the Bonds (the "Note"). The Note will be issued as a parity obligation under our Indenture, dated as of July 1, 2009, as supplemented and amended (the "Mortgage Indenture"), between us and U.S. Bank National Association, as trustee (the "Mortgage Indenture Trustee"). For a description of certain material terms and conditions of the Mortgage Indenture, see

APPENDIX E – "SUMMARY OF CERTAIN PROVISIONS OF THE MORTGAGE INDENTURE." The Financing Agreement provides that we will make the payments under the Note directly to the Trustee for the account of the County.

The payment of principal of and interest on the Bonds will be secured by a pledge by the County to the Trustee, for the benefit of the holders of such Bonds, of (i) the amounts required to be deposited in the Bond Fund, established under the Bond Indenture, including investments made with such amounts and the proceeds thereof, (ii) the County's right, title and interest in and to the Note and payments thereon, (iii) the County's right, title and interest in and to the Receipts and Revenues, all subject to the provisions of the Bond Indenture permitting the application of funds for the purposes and on the terms and conditions set forth in the Bond Indenture and (iv) any and all property which may from time to time be sold, transferred, conveyed, assigned, hypothecated, endorsed, deposited, pledged, mortgaged, granted or delivered to, or deposited with, the Trustee as additional security under the Bond Indenture by the County or anyone on its behalf as such additional security.

Security for Payment of the Mortgage Indenture Obligations

The Note will be secured equally and ratably with all our other obligations issued under the Mortgage Indenture (each a "Mortgage Indenture Obligation," and collectively, "Mortgage Indenture Obligations") by a mortgage lien on substantially all of our owned tangible and certain of our intangible assets, including our electric generation and transmission facilities and certain of our contracts relating to the purchase, sale or transmission of electricity of more than one year in duration and relating to the ownership, operation or maintenance of electric generating, transmission or distribution facilities owned by us, but excluding certain exceptions set forth in the Mortgage Indenture.

The lien of the Mortgage Indenture is subject to certain permitted exceptions set forth in the Mortgage Indenture. The Mortgage Indenture contains provisions subjecting all of our after acquired property, other than certain exceptions set forth in the Mortgage Indenture, to the lien thereof. See APPENDIX E – "SUMMARY OF CERTAIN PROVISIONS OF THE MORTGAGE INDENTURE."

RISK FACTORS

The following is a discussion of certain risks that could affect payments to be made with respect to the Bonds or the market value of the Bonds. This discussion is not exhaustive, should be read in conjunction with all other parts of this Offering Statement, and should not be considered a complete description of all risks that could affect such payments or the market value of the Bonds. Prospective purchasers of the Bonds should analyze carefully the information contained in this Offering Statement, including the Appendices hereto, and additional information in the form of the complete documents summarized herein, copies of which are available as described in this Offering Statement. See "AVAILABLE INFORMATION."

A significant portion of our anticipated gross revenues and retail load of one of our Members, Kenergy, is related to serving the Smelters

Approximately 57% of our total retail load demand and 75% of the energy of one of our Members, Kenergy, is represented by two aluminum smelters: Alcan Primary Products Corporation ("Alcan"), an indirect subsidiary of Alcan Aluminum Corporation, and Century Aluminum of Kentucky General Partnership ("Century"), a wholly-owned subsidiary of Century Aluminum Company. Alcan and Century are referred to herein as the "Smelters." Kenergy supplies each Smelter under a retail electric service agreement and passes through the payments made thereunder to us, except for a retail fee that Kenergy retains. Such pass through payments by Kenergy are expected to comprise 61.5% of our gross revenue in 2010. Both retail electric service agreements provide that if a Smelter plans to discontinue its smelting operations, it may terminate the retail electric service agreement with one year notice. Alcan and Century typically use nearly 368 MW and 482 MW per hour, respectively, and operate 24 hours per day and seven days a week. One Century potline constituting approximately 100 MW is currently shut down and we have not been given a schedule for it returning to service. While we are not aware of any plan of either Smelter to discontinue its operations, if one or both were to do so, we would have a large amount of surplus energy that may be difficult to sell economically. This possibility is especially a concern until we complete our planned upgrade to our transmission lines as discussed herein to allow us access to a broader number of third-party purchasers. See "THE SMELTER AGREEMENTS" and APPENDIX F – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS."

Our rates and service and those of our Members are subject to state regulation

Our rates and service and those of our Members are subject to regulation by the Kentucky Public Service Commission ("KPSC"). Among other powers, Kentucky law authorizes the KPSC to (i) approve our rates and those of our Members as "fair, just and reasonable," (ii) regulate construction of new generation and transmission facilities by issuing certificates of public convenience and necessity, (iii) approve changes in ownership or control of us through sales of assets or otherwise, (iv) approve the issuance or assumption of any securities or evidence of indebtedness, other than to the United States of America acting through the Rural Utilities Service ("RUS"), and (v) administer the state laws assigning each jurisdictional electric distribution utility the exclusive right to provide retail electric service within specified geographic boundaries. The KPSC has approved the issuance of the Bonds.

We and our Members may only charge rates that are approved by the KPSC. When we file a schedule stating new rates with the KPSC, the KPSC may suspend the effective date of that new rate schedule for five or six months, depending upon the methodology we employ to support the new rate schedule. If the proceeding to review the new rate schedule has not been concluded and an order made at the expiration of the suspension period, we may place the new rate schedule in effect, subject to refund if the rates eventually approved by the KPSC are lower than rates in the rate schedule we placed into effect. By law, the KPSC must issue a final decision not later than ten months after we file a new rate schedule. We are entitled to demand, collect and receive fair, just and reasonable rates for the services we render, although we and the KPSC may disagree about what constitutes fair, just and reasonable rates. If we are dissatisfied with an order of the KPSC, we may appeal that order through the Kentucky court system. Any denial by the KPSC or delay in recovery of any portion of our requested rates could have a material negative impact on our Members' or our future operating results, financial condition or liquidity.

Regulations governing climate change may adversely affect our operations and financial performance

Federal and state laws may be enacted that would limit or impose additional costs related to emissions of carbon dioxide ("CO_2") and other greenhouse gases ("GHG"). Several bills have been introduced in the current Congress to reduce GHG emissions, including imposing federal GHG emission caps and a federal renewable energy portfolio standard. One such bill was passed by the House of Representatives on June 26, 2009, and a separate bill is currently being considered by the Senate. Furthermore, the United States Environmental Protection Agency (the "EPA") has taken action to regulate GHG emissions under existing federal law. We cannot predict the outcome or potential impacts of pending climate change legislation or regulations, but it is generally expected that older conventional, fossil-fueled generation facilities, such as our facilities, would be more adversely affected by such laws or regulations than newer facilities or facilities generating electricity from nuclear or renewable fuels. In addition, some legislative proposals, such as the economic stimulus plan, may provide substantial incentives to alternative energy development or limit the construction and operation of conventional power generation facilities in ways that could adversely affect our business plans, revenues or operating costs. See "RATE AND ENVIRONMENTAL REGULATIONS – Global Climate Change." Substantially all of our power supply resources come from fossil-fueled generation facilities. During 2009, resources that we own and operate emitted 19,100 tons of sulfur dioxide ("SO_2"), 10,874 tons of nitrogen oxide ("NO_x") and 25,000 tons of CO_2.

Regulations governing environmental issues may adversely affect our operations and future financial performance

We are required to comply with numerous federal, state and local laws and regulations relating to environmental protection. These laws and regulations change regularly, and new laws and regulations could substantially increase our operating costs or require material capital expenditures. In response to regulatory changes, a substantial portion of our facilities have, in the past decade, been retrofitted with new pollution control equipment, including flue gas desulfurization and selective catalytic reduction equipment. We have $30 million of planned environmental additions through 2013. Although we believe that we have obtained all material environmental approvals currently required to own and operate our currently operating facilities, we may incur significant additional costs to comply with these requirements or with any new requirements that are added as laws change and new regulatory requirements are added. Failure to obtain and maintain all required permits or to comply with environmental laws, regulations and permits could have a material adverse effect on us, including potential civil or criminal liability and the imposition of fines or expenditures of funds to bring our facilities into compliance. Delay in obtaining or failure to obtain and maintain any environmental permits or approvals, or delay or failure to satisfy any applicable environmental regulatory requirements, could hinder the operation of our existing facilities or hinder the sale of energy from these facilities, all of which could result in significant additional cost to us. In addition, private parties may object to the issuance of environmental permits or challenge our operations under our permits. See "RATE AND ENVIRONMENTAL REGULATIONS – Environmental Regulations."

National or state renewable energy standards may increase our costs of operation and adversely affect the utilization of current generation facilities

Although various bills have been introduced in the Kentucky legislature and in the U.S. Congress that would require us to establish and obtain minimum amounts of electric energy from renewable resources, to date, no such legislation has been enacted. If we were required on the national or state level to establish and obtain minimum amounts of electric energy from renewable resources, we would have to purchase such energy and/or invest in renewable resources. Either alternative may result in higher costs to our Members.

We must make long-term decisions involving substantial capital expenditures based on our current projections of future conditions

Our decisions to develop new generation or transmission facilities, enter into long-term power supply arrangements, or pursue other projects are based primarily on long-term forecasts of our obligations to supply all or a portion of our Members' power and energy requirements. We rely on our forecasts to reliably predict factors affecting their requirements such as economic conditions, population trends and actions by others in the development of their generation or transmission facilities. Even though forecasts are less reliable the farther into the future they extend, we must make decisions today based on forecasts often extending a decade or more into the future due to the long lead-time necessary to develop and construct new generation and transmission facilities and the expected useful life of such facilities.

Our forecasts may vary significantly from actual events. As a result, we may fail to develop the appropriate number or type of generation facilities, rely on technology that becomes less competitive, or fail to install or upgrade transmission facilities in locations where they are needed. If we overestimate the growth in our obligations to supply all or a portion of our Members' power or energy requirements, there is no assurance that the price of any surplus power or energy from the excess resources would be economical or could be sold in the market without a loss. If we underestimate the growth in our Members' power or energy requirements, we may be required to purchase power or energy at a cost substantially above the cost we would have incurred to obtain the power or generate the energy from our facilities. Projections regarding the continued growth of our Members' power and energy requirements and the extent of our obligations to serve them increases the potential risks to us if actual events differ significantly from our forecasts.

Future availability and cost of credit may affect our financial results

We will need to access the credit and capital markets in the near future. Although we expect to finance our capital expenditures with internally generated funds, we have a series of pollution control bonds outstanding in the principal amount of $58.8 million maturing in 2013 that we expect to refinance. In addition to the generally level debt service on the RUS Series A Note, we are obligated to make additional principal payments of $60.0 million by October 1, 2012, and $200.0 million by January 1, 2016 on our debt outstanding with RUS. We expect to raise funds in the credit and capital markets in order to refinance this RUS debt and the pollution control bonds.

Market volatility and uncertainty in the financial markets, such as what occurred in the fall of 2008, could potentially affect our cost of capital and access to the credit and capital markets. In addition, if our ratings were lowered, we could be required to pay higher interest rates in future financings, our potential pool of investors and funding sources could decrease and our access to the credit or capital markets could be interrupted for all practical purposes. In the future, our investor base may be limited if we encounter investors who are reluctant to purchase our debt based on climate change or other industry-specific concerns.

Our financial performance depends on the successful operation of electric generating facilities by us and the ability of our facilities and us to deliver electricity to our Members

Operating electric generating facilities and delivery systems involves many risks, including:

- operator error and breakdown or failure of equipment or processes;
- operational limitations imposed by environmental or other regulatory requirements;
- inadequate or unreliable access to transmission and distribution assets;
- labor disputes;
- interruptions of fuel supply;
- compliance with mandatory reliability standards; and
- catastrophic events such as hurricanes, floods, earthquakes, fires, explosions, terrorist attacks, pandemic health events or other similar occurrences.

We depend on transmission facilities, including those operated by other parties, to deliver the electricity that we supply to our Members. If transmission is disrupted, or if capacity is inadequate, our ability to sell and deliver products and satisfy our contractual obligations may be hindered. Although the Federal Energy Regulatory Commission ("FERC") has issued regulations designed to encourage competition in wholesale market transactions for electricity, there is the potential that fair and equal access to transmission systems or transmission capacity will not be available to transmit our electric power. We cannot predict the timing of industry changes as a result of these initiatives or the adequacy of transmission facilities in specific markets.

The initial set of mandatory reliability standards was issued by the North American Electric Reliability Corporation ("NERC") in July 2007. We believe we are in compliance with all of the current NERC standards. We expect that as greater emphasis is placed on securing electrical grid infrastructure, these standards will become stricter over time. The financial impact of mandatory compliance with such standards cannot currently be determined. If mandatory reliability standards are increased in the future, a substantial effect on our operations and financial cash flows could result. In addition, failure to comply with the reliability standards could result in the imposition of fines and penalties.

A decrease in operational performance from our generating facilities and delivery systems or an increase in the cost of operating the facilities could have an adverse effect on our business and results of operations.

Our Members may fail to satisfy their obligations to us

We depend primarily on electric sales to our Members to satisfy our financial obligations. We do not control the operations or financial performance of our Members. Accordingly, we are exposed to the risk that one or more of our Members could default in the performance of their obligations to us, in particular their obligations under long-term wholesale power contracts with us extending through 2043. These defaults could result from financial difficulties at one or more Members or because of intentional actions by such Members. Our operating results and financial condition could be adversely affected if one or more of our Members default on their obligations to us or reject their contractual obligations to us in a bankruptcy proceeding or otherwise.

We cannot assure you that an active trading market will develop for the Bonds

There is no existing trading market for the Bonds. We do not know the extent to which investor interest will lead to the development of a trading market or how liquid that market might be, nor can we make any assurances regarding the ability of holders of Bonds to sell their Bonds or the price at which the Bonds might be sold. Although the Underwriter has informed us that it currently intends to make a market in the Bonds, it is not obligated to do so, and any market making may be discontinued at any time without notice. The market price of the Bonds could be adversely affected as a result.

COUNTY OF OHIO, KENTUCKY

The County, located in western Kentucky, is a public body corporate and politic duly created and existing as a county and political subdivision under the Constitution and laws of the Commonwealth of Kentucky. The County was and is authorized and empowered by law, including particularly the Act to finance certain pollution control and solid waste disposal facilities, including the Facilities, and to enter into and perform its obligations under the Financing Agreement and the Bond Indenture. Pursuant to the Act, on May 4, 2010 the Fiscal Court of the County adopted a resolution which authorized the issuance of the Bonds and the execution and delivery of the Financing Agreement and the Bond Indenture by the County. Except for the information in this paragraph and the information solely with respect to the

County under the caption "SUMMARY – County of Ohio" and "LITIGATION – Litigation Involving the County," the County did not participate in the preparation of this Offering Statement and does not have or assume any responsibility as to the accuracy or completeness of any information herein, all of which has been furnished by others.

BIG RIVERS ELECTRIC CORPORATION

Introduction

General

We are an electric generation and transmission ("G&T") rural electric cooperative corporation. We were organized as a not-for-profit rural electric cooperative under the laws of Kentucky in June, 1961 to enable our Members to pool their resources and provide for the power and transmission needs of their combined service territories. We currently operate as a taxable cooperative. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Critical Accounting Policies – Accounting for Income Taxes." We provide wholesale electric service to our three Members under a number of wholesale power contracts which contracts, in the aggregate, supply the total wholesale power requirements of the Members (see "Wholesale Power Contracts"), except the requirements of Kenergy for service to the Smelters required by the Smelters Agreements.

We own 1,444 net MW of electric generating facilities, described herein under "GENERATION AND TRANSMISSION ASSETS – Generation Resources" and approximately 1,262 miles of transmission lines and 22 substations, described herein under "GENERATION AND TRANSMISSION ASSETS – Transmission."

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

In 2009, our average wholesale revenue per kWh to our Members, including amounts withdrawn from the economic reserve, was $.03983 or $.04113 for rural loads and $.03668 per kWh for large industrial loads (exclusive of the Smelter loads served by Kenergy). Our average wholesale revenue per kWh to Kenergy to serve the two Smelter loads in 2009 was $.04754 per kWh on sales of 3.5 million MWh. Our average wholesale revenue per kWh to Kenergy to serve the Smelter loads pre-Unwind was $.05412 on sales of .6 million MWh. Our average wholesale revenue per kWh to Kenergy to serve the two Smelter loads after the closing of the Unwind was $.04622 on sales of 2.9 million MWh. For the first six and one-half months of 2009, we supplied only a portion of the load of the Smelters. During this period, Kenergy purchased 3.5 million MWh for the Smelters from other sources. Had we supplied the entire load for the Smelters for all of 2009, our sales to Kenergy to serve the Smelters for 2009 would have been 7.0 million MWh. Excluding the Smelters, sales to our Members were 3.2 million MWh in 2009, 2.2 million MWh for rural loads and 1.0 million MWh for large industrial loads. Member Non-Smelter MWh sales in 2009 have decreased by 4.6% from 2008, 6.2% for rural loads and .7% for large industrial loads. To the extent surplus capacity and energy are available, we may sell electricity to non Member utilities and power marketers ("Non-Members"). During 2009, we sold approximately 1.2 million MWh to Non-Members

Cooperative Structure

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

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

The Members

Our Members are Kenergy, Meade County Rural Electric Cooperative Corporation ("Meade") and Jackson Purchase Energy Corporation ("Jackson Purchase"). The Members of Big Rivers are local consumer-owned distribution cooperatives providing retail electric service on a not-for-profit basis to their customers, who are their members. The customer base of the Members generally consists of residential, commercial and industrial consumers within specific geographic areas. The Members provide electric power and energy to customers located in portions of 22 western Kentucky counties. As of December 31, 2009, the Members served approximately 112,000 member-customers (meters). Kenergy has approximately 55,000 retail members, Meade County has approximately 28,000 retail members and Jackson Purchase has approximately 29,000 retail members. See APPENDIX B – MEMBER FINANCIAL AND STATISTICAL INFORMATION.

Bankruptcy and Subsequent Operation

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

In accordance with the Plan of Reorganization, we leased all of our generating facilities to Western Kentucky Energy Corp. ("WKEC"), a wholly-owned subsidiary of LG&E Energy Corp., now E.ON U.S., LLC ("E.ON"). We also assigned to WKEC all of our intangible assets, including our rights under real property leases, equipment leases, permits, intellectual property and contracts used or held exclusively by us in connection with the operation of our generating facilities. WKEC assumed and agreed to perform and discharge all of our obligations under these assets that first arose or accrued on or after the effective date of the Plan of Reorganization. In addition to assuming responsibility for operation of our generating facilities we own, WKE Station Two Inc. ("WKE Station Two"), another wholly owned subsidiary of E.ON, assumed responsibility for the operation of Station Two and our obligation to purchase power from Station Two under the Station Two Power Sales Contract. This assignment and assumption was effected in accordance with an Agreement and Amendments to Agreements by and among HMP&L, WKE Station Two, LG&E Energy Marketing Inc. ("LEM"), WKEC and us dated as of

July 15, 1998 (the "Station Two Agreement"). Pursuant to the Plan of Reorganization, WKEC and WKE Station Two (which was subsequently merged into WKEC) became responsible for our prior responsibilities to operate and maintain the generating facilities we own and Station Two. Capital costs for these generating facilities were shared by WKEC and us in several different ratios depending upon whether or not the capital expenditure was incurred in order to comply with a state law enacted after the effective date of the Plan of Reorganization or a revision or change of an existing law enacted after such date. We were responsible for 20% of the capital costs required in order to comply with such a change in law or regulation. Our responsibility for the capital costs required to maintain the existing capacity of the generating facilities we own and Station Two and not required by changes in law or regulation was generally limited to stipulated annual amounts, which never exceeded $6.8 million. We were not required to contribute to the cost of capital improvements made to a generating facility owned by us or to Station Two in order to increase its generating capacity. Operation and maintenance costs, including fuel, were, for the most part, the responsibility of WKEC.

The Plan of Reorganization (the "LG&E Arrangements") also included a power purchase agreement (the "LEM Power Purchase Agreement") between us and LEM. The LEM Power Purchase Agreement established minimum hourly and annual power purchase amounts that we were required to take and certain maximum hourly and annual power purchase amounts that LEM was required to make available to us. We paid specified fixed rates for power purchased under the LEM Power Purchase Agreement that were not dependent upon market prices for electric power and energy nor the costs associated with power and energy generated by the generating facilities we own and operated by WKE Station Two. In addition to power and energy purchased from LEM under the LEM Power Purchase Agreement, during the duration of the LG&E Arrangements we continued to dispatch our Members' 178 MW Southeastern Power Administration ("SEPA") allocations of hydroelectric power and associated energy (the "SEPA Power") in accordance with a contract with the SEPA (the "SEPA Contract").

If we did not purchase an amount of power from LEM equal to or in excess of a minimum annual amount during a calendar year, the LEM Power Purchase Agreement provided that we were deemed to have received a certain percentage of the difference in the amount of power actually purchased from LEM and the minimum annual amount we were required to purchase under the LEM Power Purchase Agreement. LEM billed us for such percentage of the shortfall as if we had purchased it. We had the right to purchase only our minimum obligation of power and energy under the LEM Power Purchase Agreement and purchase additional power to meet our Member's loads from other suppliers without penalty. This arrangement essentially permitted us to arbitrage the LEM base power requirement. These arbitrage opportunities were available in any hour in which our power purchase rate from the market plus any applicable hourly LEM penalty was less than the amount that we would be charged by LEM at the specified base power rates or in any hour which we could resell our base power under the LEM Power Purchase Agreement to Non-Members at a profit. Most of the earnings we realized from such arbitrage activities were used by us to increase our equity.

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

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

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

Leveraged Lease Transactions

In April, 2000, we entered into five separate leveraged lease transactions involving undivided interests in both units of our Robert D. Green Generating Plant (the "Green Plant") and our Wilson Plant (the "Leveraged Lease Transactions"). The Leveraged Lease Transactions were structured as a long-term lease of an undivided interest under a head lease to limited liability companies created on behalf of an equity investor. Such undivided interests were leased back to us by such limited liability companies for a shorter term. Part of each equity investor's cost for its acquisition of its head lease interest was supplied by non-recourse loans to the limited liability company. We used most of the proceeds of the equity investors' one-time payments of rent for their head lease interests to purchase guaranteed investment contracts, the payments under which were sufficient to discharge all of our rental obligations under each of the leases of the undivided interests back to us.

Unwind of LG&E Arrangements and Termination of Leveraged Lease Transactions

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

As a result of the turmoil in the credit markets commencing in 2007, and in order to facilitate the Unwind, we terminated the Leveraged Lease Transactions prior to their maturities. We terminated some of the Leveraged Lease Transactions in June, 2008 and others in September, 2008. Funds to terminate the Leveraged Lease Transactions were provided by the proceeds of the early termination of the guaranteed investment contracts used for the economic defeasance of the leases, funds provided by E.ON as part of the consideration in the Unwind, and our own funds. As part of the termination of the Leveraged Lease Transaction, all property interests and security interests in any of our property of all parties to the Leveraged Lease Transactions were terminated.

Summary of Major Provisions of Unwind

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

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

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

- We established three reserves, (1) an economic reserve with an initial principal amount equal to $157 million (the "Economic Reserve"), (2) a second economic reserve with an initial principal amount equal to $60.9 million (the "Rural Economic Reserve"), and (3) a transition reserve with an initial principal amount equal to $35 million (the "Transition Reserve"). The Economic Reserve and Rural Economic Reserve accounts were established to help us cushion the effect of any potential future rate increases for fuel, environmental, and purchase power expenses on our rates to our Members for service to their non-Smelter members. The Transition Reserve Account was established as a financial reserve account that would help us mitigate financial costs, if any, associated with the termination of the Smelter Agreements by a Smelter.

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

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

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

- WKEC conveyed to us 14,000 SO_2 allowances allotted by the EPA with a fair market value of approximately $1.0 million on July 16, 2009.

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

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

Change in Capital Structure Resulting from Unwind

On July 16, 2009, we prepaid $140.2 million of the indebtedness we owed to the RUS and the schedule of maximum permitted outstanding balances on the amortizing debt we owe to the RUS was adjusted. The non-interest bearing RUS Series B Note was also restructured in concert with the Unwind into a single "bullet" payment due December 31, 2023. Our debt to RUS was incurred primarily to finance our generating assets. In connection with the Unwind we obligated ourselves to reduce the maximum permitted outstanding balances of our RUS debt by $60.0 million by October 1, 2012 and $200.0 million by January 1, 2016. Currently, we intend to refinance that debt in the capital markets.

We also terminated a secured credit facility with National Rural Utilities Cooperative Finance Corporation ("CFC") providing for a maximum outstanding balance of $15 million and entered into two unsecured revolving credit facilities with a maximum of $50 million each with CFC and CoBank ACB ("CoBank"). See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Liquidity and Capital Resources." The chart set forth below shows the impact of the Unwind on our outstanding debt.

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

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

As a result of the Unwind, we went from an equity to total capitalization ratio of -19% as of December 31, 2008, to 31% as of December 31, 2009.

Resumption of Operational Responsibilities in Connection with Generating Facilities

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

Wholesale Power Contracts with Members

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

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

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

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

Smelter Agreements with Kenergy

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

Existing Generation and Transmission Resources

We supply capacity and energy to our Members principally from a combination of owned generating plants and also from power purchased under long-term contracts with other power suppliers and short-term and spot market purchases. We own interests in seven base load coal-fired generating units and one oil- or natural gas-fired combustion turbine generating unit, all of which are in commercial operation. These units provide us with approximately 1,444 MW of capacity. See "GENERATION AND TRANSMISSION ASSETS – Generation Resources" for a discussion of our existing generation facilities. We also have a variety of purchase arrangements, including the Station Two Power Sales Contract with the City of Henderson and the SEPA Contract, which supply us with up to 390 MW of power. We currently purchase 212 MW from HMP&L pursuant to the Station Two Power Purchase Agreement, which share will decrease on June 1, 2010 to 207 MW, and up to 178 MW under the SEPA Contract. We normally use our entitlement under the SEPA Contract for peaking; however, as a result of problems with certain dams on the Cumberland River hydro system, our capacity entitlement has been suspended and we currently are receiving only energy. See "GENERATION AND TRANSMISSION ASSETS – Other Power Supply Resources" for a discussion of our power purchase arrangements. We also own 1,262 miles of transmission lines and 22 substations and we have additional access to approximately 100 MW of transmission service through agreements with another utility.

SELECTED FINANCIAL DATA

The following financial data present selected information relating to our financial condition and results of operations. Summary financial data for the three months ended March 31, 2010 that are presented below are unaudited, and reflect all adjustments that we consider necessary (consisting of normal recurring accruals) for a fair presentation of such data. The Balance Sheet data as of December 31, 2009 and 2008 and the Statement of Operations data for years ended December 31, 2009, 2008 and 2007 were derived from our audited financial statements included in APPENDIX A. The Balance Sheet data as of December 31, 2007 and the Statement of Operations data for the years ended December 31, 2006 and 2005 were derived from our audited financial statements for those years. The information shown below should be read in conjunction with the financial statements and the related notes thereto in Appendix A. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS."

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

	Three Months Ended March 31, (Unaudited)	Year Ended December 31, (Audited)				
	2010	2009	2008	2007	2006	2005
Operating revenues:						
Member tariff electric energy revenues	$108,152	$259,579	$114,513	$113,281	$108,736	$109,439
Other electric energy revenues	25,674	67,151	90,006	148,611	82,098	71,928
Lease revenue	---	32,027	58,423	58,265	57,896	57,675
Other operating revenues	3,368	14,603	10,239	9,713	9,858	9,913
Total operating revenues	137,194	373,360	273,181	329,870	258,588	248,955
Operating expenses:						
Operations:						
Fuel for electric generation	53,944	80,655	---	---	---	---
Power purchased and interchanged	23,271	116,883	114,643	169,768	114,516	114,500
Production, excluding fuel	12,507	22,381	---	---	---	---
Transmission and other	9,465	35,444	28,600	27,196	21,684	20,309
Maintenance	7,977	29,820	4,258	4,240	3,652	3,195
Depreciation	8,478	32,485	31,041	30,632	30,408	30,192
Total operating expenses	115,642	317,668	178,542	231,836	170,260	168,196
Electric operating margins	21,552	55,692	94,639	98,034	88,328	80,759
Interest expense and other:						
Interest, net of capitalized interest	12,106	59,898	65,719	60,932	60,754	59,639
Interest on obligations related to long-term lease	---	---	6,991	9,919	9,505	9,109
Amort. of loss from termination of lease	---	2,172	811	---	---	---
Income tax expense	---	1,025	5,934	---	---	---
Other, net	17	112	123	103	111	124
Total interest expense and other	12,123	63,207	79,578	70,954	70,370	68,872
Operating margin before non-operating margin	9,429	(7,515)	15,061	27,080	17,958	11,887
Non-operating margin:						
Interest income on restricted investments under long-term lease	---	---	8,742	12,481	12,069	11,670
Gain on "Unwind" Transaction	---	537,978	---	---	---	---
Interest income and other	102	867	4,013	7,616	4,515	2,786
Total non-operating margin	102	538,845	12,755	20,097	16,584	14,456
Net margin	$9,531	$531,330	$ 27,816	$ 47,177	$ 34,542	$ 26,343

BALANCE SHEET
(dollars in thousands)

	Three Months Ended March 31, (Unaudited)	December 31, (Audited)		
	2010	2009	2008	2007
Assets:				
Utility plant, net	$1,081,552	$1,078,274	$912,699	$911,634
Restricted investments under long-term lease	–	–	–	192,932
Restricted Investments – Member rate mitigation	235,193	243,225	–	–
Other deposits and investments, at cost	5,370	5,342	4,693	4,240
Current Assets:				
Cash and cash equivalents	60,376	60,290	38,903	148,914
Accounts receivable	44,484	47,493	20,464	26,683
Fuel inventory	35,258	37,830	–	–
Non-fuel inventory	20,457	20,412	756	768
Prepaid expenses	3,269	3,233	450	131
Total current assets	163,844	169,258	60,573	176,496
Deferred loss–termination of sale-leaseback	–	–	76,001	–
Deferred charges and other	3,156	9,384	20,470	28,856
Total assets	$1,489,115	$1,505,483	$1,074,436	$1,314,158
Equities (Deficit) and Liabilities:				
Capitalization:				
Equities (deficit)	$388,923	$379,392	$(154,602)	$(174,137)
Long-term debt	815,885	834,367	987,349	1,022,345
Obligations under long-term lease	–	–	–	183,891
Total capitalization	1,204,808	1,213,759	832,747	1,032,099
Current liabilities:				
Current maturities of long-term debt and obligations	13,298	14,185	51,771	39,392
Notes payable	10,000	–	–	–
Purchased power payable	1,096	3,362	9,336	13,038
Accounts payable	22,669	30,657	5,832	4,932
Accrued expenses	11,223	9,864	3,134	3,014
Accrued interest	8,577	9,097	8,018	7,811
Total current liabilities	66,863	67,165	78,091	68,187
Deferred credits and other:				
Deferred lease revenue	–	–	10,955	15,537
Deferred gain on sale-leaseback	–	–	–	53,480
Residual value payment obligation	–	–	145,145	141,370
Regulatory liabilities – Member rate mitigation	200,245	207,348	–	–
Other	17,199	17,211	7,498	3,485
Total deferred credits and other	217,444	224,559	163,598	213,872
Total equities and liabilities	$1,489,115	$1,505,483	$1,074,436	$1,314,158

CAPITALIZATION

Our capitalization derived from our financial statements included in APPENDIX A is as follows:

	Three Months Ended March 31, (Unaudited) 2010	December 31, (Audited) 2009
	(in thousands)	
Long-Term debt:		
Secured by the Mortgage Indenture:		
RUS Series A Note	$575,849	$596,786
RUS Series B Note	111,234	109,666
1983 Series Pollution Control Bonds	58,800	58,800
2001A Series Pollution Control Bonds	83,300	83,300
Total long-term debt	$829,183	$848,552
Less: current portion	13,298	14,185
Total long-term debt, excluding current portion	815,885	834,367
Equity:		
Accumulated Margins	394,038	384,507
Other Equities and Accumulated Other Comprehensive Income	(5,115)	(5,115)
Total Equities	388,923	379,392
Total capitalization	$1,204,808	$1,213,759

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

Caution Regarding Forward Looking Statements

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

Executive Overview

The closing of the Unwind in July 2009 resulted in significant changes to our utility operations. Prior to the Unwind, we leased all of our generation assets to WKEC and purchased power from LEM. We received fixed rental payments each year, and LG&E was obligated to operate and maintain our owned generating assets and Station Two. Under this arrangement, both we and WKEC paid an agreed share of capital expenditures and certain environmental operating costs. We fulfilled our power supply arrangements to our Members through the purchased power arrangement with LEM at generally fixed prices significantly below market rates. We operated under these arrangements for the first half of 2009, the year ended December 31, 2008 and the year ended December 31, 2007.

When the Unwind became effective on July 16, 2009, we received $864.6 million compensation, both cash and non-cash, from E.ON. The Unwind gain reported in the 2009 financial statements was $538.0 million, with the $326.6 million difference being reported only in the 2009 balance sheet ($252.9 million of which is comprised of funds deposited into three reserve accounts, the Economic Reserve, the Rural Economic Reserve and the Transition Reserve, that will serve to offset future non-Smelter Member fuel and environmental costs, Member rate mitigation or termination of a Smelter Agreement).

After the closing of the Unwind, we regained the operation of our generation facilities. We are now responsible for the operation and maintenance of our generating assets and for all continued expenses in connection with capital expenditures relating to our generating assets. Since the Unwind, through Kenergy, we supply 850 MW of the Smelters' needs, and not just a small portion of them as supplied pre-Unwind. As a result, our sales to the Smelters increased substantially. In addition, our operating expenses increased substantially. As a result of the Unwind, we went from an equity to total capitalization ratio of -19% as of December 31, 2008, to 31% as of December 31, 2009.

The table below summarizes the $538.0 million Unwind gain:

Item	Unwind Gain (dollars in millions)
Cash	$288.8
Recognize WKE Lease Revenue	7.2
Write-off LEM Marketing Payment and Settlement Note	0.9
Utility Plant – Net	286.5
Inventories (fuels, reagents and M&S)	55.0
SO_2 Allowances	1.0
Write-off Loss on Leveraged Lease Transaction	(73.8)
Other (includes certain transaction costs)	(27.6)
	$538.0

We significantly reduced our 5.75% RUS Series A Note, making a payment of $140.2 million on the Unwind closing date and restructuring the RUS Series A Note to a generally level amount. We are obligated to make a payment to RUS of $60.0 million by October 1, 2012, and another payment of $200.0 million by January 1, 2016 in order to reduce our maximum permitted outstanding balances of our RUS debt in those years. Currently, we intend to refinance such debt in the capital markets. The RUS Series A Note continues to have a final maturity of July 1, 2021.

The non-interest bearing RUS Series B Note was also restructured in concert with the Unwind into a single "bullet" payment due December 31, 2023.

With the closing of the Unwind in 2009, 2010 will be our first full year of operating and maintaining our own generation assets. A major challenge in 2010 is lower projected revenues as a result of the lingering recession. Our 2010 budget reflects this impact with lower Member energy sales and lower prices for electricity in the wholesale market. We have responded with aggressive cost control measures. Every department within Big Rivers was asked to reduce cost. These cost containment measures included, not providing a salary increase for non-union employees, postponing preventative maintenance, as well as multiple other cost control measures.

We are currently budgeting for a MFI Ratio (as defined herein under the caption "Cooperative Operations – *Coverage Ratio*") of 1.10 for 2010, as required by the Mortgage Indenture, which MFI Ratio will result in net margins of $4.8 million. During the first three months of 2010, we achieved net margins of approximately $9.5 million, $6.3 million greater than budget. As described under "Financial Condition – *As of March 31, 2010*" herein, the results for the first three months of 2010 are not indicative of the remainder of the year. However, by combining the margins for the three months ended March 31, 2010 with the budget for the balance of 2010, we expect to be able to achieve a MFI Ratio of 1.15, which MFI Ratio will result in net margins of $7.1 million.

Critical Accounting Policies

General

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

Use of Accounting Policies and Estimates

The application of accounting policies and estimates is a continuing process. As our operations change and accounting guidance evolves, our accounting policies and estimates may be revised. We have identified a number of critical accounting policies and estimates that require significant judgments. We base our judgments and estimates on experience and various other assumptions that we believe are reasonable at the time of application. Our judgments and estimates may change as time passes and more information about the environment in which we operate becomes available. If actual results are different than the estimated amounts recorded, adjustments are made taking the new information into consideration. We discuss our critical accounting policies, significant estimates and other certain accounting policies with our Board of Directors, as appropriate. Our critical accounting policies and significant estimates are discussed below.

Regulatory Accounting

Our accrual basis accounting policies follow the Uniform System of Accounts as prescribed by RUS Bulletin 1767B-1, as adopted by the KPSC. These regulatory agencies retain authority over us and periodically issue orders and instructions on various accounting and ratemaking matters. Our operations meet the criteria for application of regulatory accounting treatment. As a result, we record approved regulatory assets and liabilities that result from the regulated ratemaking process that would not ordinarily be recorded under Generally Accepted Accounting Principles ("GAAP"). We had no Regulatory Assets at December 31, 2009 and our Regulatory Liabilities were $207.3 million. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in Member rates. Regulatory liabilities generally represent amounts established by our regulator to mitigate the net effect on our Members of fuel and environmental surcharges and surcredits. These amounts are recorded in revenue as the underlying fuel and environmental costs are incurred. We continually assess whether any regulatory account we have is probable of future recovery by considering factors such as applicable regulatory environment changes, historical regulatory treatment for similar costs, recent rate orders to other regulated entities and the status of any pending or potential legislation. Based on this continual assessment, we believe our existing regulatory liabilities are probable of future refund. This assessment reflects the current political and regulatory climate at the state level, and is subject to change in the future. If future recovery of costs or refund of liabilities cease to be probable, the asset or liability write-off would be recognized in operating income.

Revenue Recognition

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

Off-Balance Sheet Arrangements

As a result of terminating the Leveraged Lease Transactions, we had no off-balance sheet arrangements as of March 31, 2010.

Accounting for Loss Contingencies

We are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of our financial statements, we make judgments regarding the future outcome of contingent events and record a loss contingency when it is determined that it is probable that a loss has occurred and the amount of the loss can be reasonably estimated. We regularly review current information available to determine whether any such accruals should be adjusted and whether new accruals are required. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the financial statements may differ from the actual outcome once the contingency is resolved, which could have a material impact on our future operating results, financial position or cash flows. We had no contingent matters requiring accrual at December 31, 2009.

Depreciation of Utility Plant

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

We committed to the KPSC that we will complete a new depreciation study and include that study with a filing for a general review of its financial operations and its tariffs before July 16, 2012. Currently, we plan to complete the depreciation study late summer or early fall of 2010 and incorporate that study in our filing with the KPSC which is currently planned for mid-year 2011 with an effective date of January 1, 2012.

Accounting for Income Taxes

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

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

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

At December 31, 2009, we had deferred tax assets of approximately $49.8 million, of which $21.0 million relates to net operating losses. At December 31, 2009, accrued net operating losses amounted to approximately $53.1 million, expiring 2012. Additionally, at December 31, 2009, we had deferred tax liabilities of approximately $23.8 million, which primarily relate to RUS Series B Note. Prior to the termination of our Leveraged Lease Transactions in 2008, we believed that it was more likely than not that we would recover deferred tax assets related to alternative minimum taxation. The termination of the Leveraged Lease Transactions removed an expected source of future taxable income and we determined that an increase in our valuation allowance was appropriate, resulting in a $5.9 million charge.

Pension and Other Postretirement Benefits

We have noncontributory defined benefit pension plans covering approximately 100 of our 600 member work force. The salaried employees defined benefit pension plan was closed to new entrants effective January 1, 2008, and the bargaining employees defined benefit pension plan was closed to new hires effective November 1, 2008. For those not covered in the defined benefit plans, we established base contribution accounts in the defined contribution thrift and 401(k) savings plans, which were renamed the retirement savings plans. The base contribution account is funded by employer contributions based on graduated percentages of the employee's pay, depending on age.

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

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

Funding requirements for defined benefit pension plans are determined by government regulations. Our defined benefit pension plans are fully funded for ERISA purposes, and we have made additional voluntary contributions. At December 31, 2009, for the defined benefit pension plans, the present value of the accumulated benefit obligation exceeded the fair value of plan assets by $3.2 million. We fund our other postretirement benefit plan obligations on a pay-as-you-go basis, on a cash basis as benefits are paid. No assets have been segregated and restricted to provide for the other postretirement benefits. At December 31, 2009, the present value of the projected benefit obligation for the other postretirement benefit plans was $13.9 million

New Accounting Standards

FASB ASC 815, Derivatives and Hedging, established enhanced disclosure requirements concerning derivative instruments and hedging activities. This enhanced disclosure standard requires that objectives for using derivative instruments be disclosed in terms of underlying risk as well as accounting designation in order to better convey the risks that the entity is intending to manage through the use of derivatives. Entities are required to provide enhanced disclosures describing (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under FASB ASC 815 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. We adopted this standard on January 1, 2009 and the adoption had no material effect on our financial position or operations.

FASB ASC 855, Subsequent Events, established a standard for disclosure of events that occur during the period between the balance sheet date and the date on which the financial statements are issued. This standard is effective for interim or annual financial periods ending after June 15, 2009. We adopted the disclosure requirements for subsequent events as outlined in ASC 855.

FASB ASC 105, Generally Accepted Accounting Principles, provides a codification of accounting standards that supersedes all previously existing non-SEC accounting and reporting standards and becomes the authoritative source of GAAP. FASB ASC 105 is effective for annual financial statements issued after September 15, 2009. We have adopted the Accounting Standard Codification established by FASB ASC 105.

Cooperative Operations

Utility Margins

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

Rate Structure

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

Coverage Ratio

Subject to any necessary regulatory approvals, such as KPSC approval and RUS approval, if required, the Mortgage Indenture requires us to establish and collect rates for the use or the sale of the output, capacity or service of our electric generation, transmission and distribution system which are reasonably expected to yield margins for interest, for the twelve-month period commencing with the effective date of the rates, equal to at least 1.10 times total interest charges on debt secured under the Mortgage Indenture during that twelve-month period (the "MFI Ratio"). The MFI Ratio is calculated by dividing the Margins for Interest for a period by the Interest Charges for such period. The definition of Margins for Interest takes into account any item of net margin, loss, gain or expenditure of any affiliate or subsidiary of ours only if we have received such net margins or gains as a dividend or other distribution from such affiliate or subsidiary or if we have made a payment with respect to such losses or expenditures. For the definition of "Margins for Interest" and "Interest Charges" see APPENDIX F – "SUMMARY OF CERTAIN PROVISIONS OF THE MORTGAGE INDENTURE – Covenants." The 2010 budget is set to achieve a $4.8 million net margin and an MFI Ratio of 1.10. See "Financial Condition – *As of March 31, 2010*" herein.

Results of Operations

Sales to Members

Electric sales to our Members are made pursuant to wholesale power contracts with each Member. The table below sets forth the Sales to Members in MWhs for 2009, 2008 and 2007. The Smelter sales are shown both before and after the closing of the Unwind. Before the closing of the Unwind, we supplied only a small portion of the Smelters' needs. Since the Unwind, we supply 850 MW of the Smelters' needs. Our wholesale rate to Kenergy for the Smelters averaged $46.22 per MWh for 2009. Smelter sales during 2010 will be for a full year of service and could approach 7.0 million MWhs.

Rural Member sales include residential and commercial loads. The 2009 rural Member sales reflect a .15 million MWh decline or a 6.28% decrease. This decline is attributable to the current recession and mild weather. Industrial Member sales were relatively flat over the three year period.

Smelter sales in 2008 were1.16 million MWhs or 52.02% less than 2007. During 2007, the Smelters' needs for power were in excess of the normal resources available to us. We purchased a large block of power for the Smelters from the open market.

Sales to Members
(in millions of MWhr)

	2009	2008	2007
Rural Member	2.24	2.39	2.41
Industrial Member	0.92	0.93	0.92
Smelter (Pre-Unwind)	0.58	1.07	2.23
Smelter (Post-Unwind)	2.89	0.00	0.00
	6.63	4.39	5.56

Sales to Non-Members

The table below sets forth the sales to Non-Members in megawatt-hours for 2009, 2008 and 2007. After the closing of the Unwind on July 16, 2009, we had access to all of the generation available from our production assets, which enabled us to sell any excess on the open market. The excess generation was sold in the market to third parties, resulting in an increase of .40 million MWhs or 52%, as compared to 2008.

Sales to Non-Members in 2008 increased by .17 million MWhs, or 28%, from 2007. This increase, in part, reflects an increase in energy available to us from our contract with SEPA which is used to service native load resulting in the additional energy available from our E.ON purchase power contract for off-system sales.

Sales to Non-Members
(in millions of MWhr)

	2009	2008	2007
Non-Member	1.17	0.77	0.60

Other Revenue

The table below sets forth the other revenue for 2009, 2008 and 2007. After the closing of the Unwind on July 16, 2009, the lease payments from E.ON for our generation assets were terminated, resulting in a decrease of $26.4 million or 45.18%. Other operating revenue was $4.4 million or 42.62% greater than 2008. This increase is due to additional transmission revenue from our internal Non-Member energy services departmental activities. An off-set to this revenue increase is included in the operating expenses below. The 2008 lease revenue and other operating revenue were relatively flat from 2007.

Other Revenue
(in thousands)

	2009	2008	2007
Lease revenue	$32,027	$58,423	$58,265
Other operating revenue	14,603	10,239	9,713
	$46,630	$68,662	$67,978

Operating Expenses

The table below sets forth the Operating Expenses for 2009, 2008 and 2007. After the closing of the Unwind on July 16, 2009, we became responsible for the operating expenses for the generating fleet. These expenses resulted in increased operating expenses of $130.8 million, primarily due to the increased Smelter power supply obligation that became effective with the Unwind closing. Depreciation expense increased, due primarily to the assets transferred to us by E.ON as part of the Unwind. This reflects an increase of $1.4 million or 4.65%. Transmission expense increased $6.8 million from 2008 due in part to our increased use of our available transmission capacity for off-system sales purposes. An off-set to this expense increase is included in the operating income shown above. Prior to the Unwind, we purchased all our power, while post-Unwind we generally purchase replacement power when our generation units are in outage. Approximately two-thirds of our purchased power expense is collected in revenue from the Smelters via two automatic rate pass-through provisions, with the remaining one-third associated with our Members' non-Smelter load being collected via (1) the two automatic pass-through provisions, while (2), the non-fuel adjustment charge purchased power adjustment is deferred for future recovery (a regulatory account) following a review by the KPSC. Currently we have a regulatory liability account, which following a future review by the KPSC, we will refund to our Members.

Power purchased and interchanged for 2008 was $55.1 million or 32.47% less than 2007. During 2007, the Smelters' needs for power were in excess of the normal resources available to us. We purchased a large block of power for the Smelters on the open market.

Operating Expenses
(in thousands)

	2009	2008	2007
Fuel for electric generation	$ 80,655	-	-
Power purchased and interchanged	116,883	$114,643	$169,768
Production, excluding fuel	22,381	-	-
Transmission and other	35,444	28,600	27,196
Maintenance	29,820	4,258	4,240
Depreciation	32,485	31,041	30,632
	$317,668	$178,542	$231,836

Interest and Other Charges

The table below sets forth Interest and Other Charges for 2009, 2008 and 2007. Interest expense for 2009 was $5.8 million less than 2008 due to the fact that we paid RUS $140.2 million at closing of the Unwind and the decrease of the interest rate on our variable interest rate pollution control revenue bonds, including the Refunded Bonds. The increase in 2008 as compared to 2007 of $4.8 million is primarily due to the credit downgrade of Ambac (the credit provider for our pollution control revenue bonds) and the resulting increase in the variable rate on our pollution control revenue bonds, including the Refunded Bonds. Additionally, we have amortized the loss from the termination of the Leveraged Lease Transactions from the buyout in 2008 until the closing of the Unwind in 2009. With the termination of the Leveraged Lease Transactions, we no longer consider that it is more likely than not we would recover our net deferred tax assets, therefore the alternative minimum tax credit carry forwards were expensed during 2008.

Interest and Other Charges
(in thousands)

	2009	2008	2007
Interest, net of capitalized interest	$59,898	$65,719	$60,932
Interest on obligations related to long-term lease.	-	6,991	9,919
Amort. of loss from termination of lease	2,172	811	-
Income tax expense	1,025	5,934	-
Other, net	112	123	103
	$63,207	$79,578	$70,954

Operating Margin

The table below sets forth the Operating Margin for 2009, 2008 and 2007. After the closing of the Unwind on July 16, 2009, we were responsible for all production expenses related to our generation fleet. A major 8.5 weeks planned outage for the Wilson Plant was completed in the fall of 2009 at a cost of $9.3 million. This expense, coupled with the depressed power market prices off-system sale and lower Member sales due to weather and the recession, resulted in an the 2009 operating margin decrease of $22.6 million or 149.90%

During 2008, primarily resulting from terminating the Leveraged Lease Transactions, operating margin decreased $12.0 million from 2007, or 44.38%.

Operating Margin
(in thousands)

	2009	2008	2007
Operating Margin	$(7,515)	$15,061	$27,080

Non-Operating Margin

The table below sets forth the amount of Non-Operating Margins for 2009, 2008 and 2007. The Non-Operating Margin in 2009 resulted from the closing of the Unwind. The Non-Operating Margins in 2008 and 2007, under the caption "Interest Income on restricted investments under the long-term lease" below, were from the Leveraged Lease Transactions, which have been terminated.

Non-Operating Margin
(in thousands)

	2009	2008	2007
Interest Income on restricted investments under long-term lease	-	$8,742	$12,481
Gain on Unwind	$537,978	-	-
Interest income and other	867	4,013	7,616
	$538,845	$12,755	$20,097

Net Margin

Primarily due to the closing of the Unwind, net margins were $531.3 million in 2009, compared to $27.8 million in 2008. This increase resulted in a dramatic improvement in our financial condition, with year end 2009 equities of $379.4 million, 25.2% equities to total assets. While the Unwind and pre-Unwind operations generally render comparability of the 2009 net margins to prior years difficult, the key differences between 2009 and 2008 are briefly described in the following paragraph.

Other than the $538.0 million gain on the Unwind, there are five significant items comprising the remaining $34.5 million unfavorable 2009 net margins variance compared to 2008. First, power contracts revenue increased by $126.6 million primarily due to the increased Smelter power supply obligation that became effective with the Unwind, offset by an $139.1 million increase in operating expenses. Second, lease revenue was $26.4 million unfavorable due to the Unwind closing. Third, interest expense decreased $12.8 million primarily due to termination of the Leveraged Lease Transactions; we also paid down $140.2 million of RUS debt on the Unwind closing date and our pollution control bonds bore lower variable interest rates. Fourth, income tax expense decreased $4.9 million due to terminating the Leveraged Lease Transactions in 2008. Fifth, primarily due to termination of the Leveraged Lease Transactions, interest income decreased $11.9 million. All other statement of operations items net to an increase of $1.4 million.

Net Margin
(in thousands)

	2009	2008	2007
Net Margin..................................	$531,330	$27,816	$47,177

Financial Condition

As of March 31, 2010

We have included selected financial data for the three months ended March 31, 2010 in this Offering Statement. We have not, however, included data for the three months ended March 31, 2009 to be used for comparative purposes since the first quarter results of 2009 reflect operations of Big Rivers pre-Unwind and the first quarter results of 2010 reflect operations of Big Rivers post-Unwind.

Operating Revenues for the three months ended March 31, 2010 are much higher than last year primarily as a result of our supplying Kenergy with approximately 850 MW of the power necessary to supply a portion of its contractual obligations to the Smelters. In addition, with the Unwind we became responsible for certain fuel costs and environmental costs that were not our responsibility pre-Unwind. Our current contractual arrangements allow us to recover fuel adjustment surcharges and environmental surcharges both of which contributed to higher Operating Revenues as compared to the first quarter of 2009.

During the period ended March 31, 2010 of our $137.2 million in Operating Revenues, we had approximately $69.0 million in sales to the Smelters, approximately $39.2 million in tariff sales to our non-Smelter Members and approximately $25.6 million in off-system sales. A portion of the off-system sales relates to off-system sales we are making on behalf of Century of 100 MW because one of its potlines is currently down.

With respect to Operating Expenses for the period ended March 31, 2010, we instituted cost containment measures for this period because we expected lower Member energy sales and lower prices for electricity in the wholesale market as a result of the lingering recession.

We are currently budgeting for a MFI Ratio (as defined herein under the caption "Cooperative Operations – *Coverage Ratio*") of 1.10 for 2010, as required by the Mortgage Indenture, based upon a net margin of $4.8 million. By adequately controlling costs, we are projecting that we will be able to exceed the financial measure under our Mortgage Indenture of a MFI Ratio of 1.10. During the first three months of 2010, we achieved net margins of approximately $9.5 million, $6.3 million greater than budget. A return to a more normal regional weather pattern for our winter months and some recovery in the economy provided for stronger sales internally and externally. By combining the favorable year-to-date margins with the budget for the balance of 2010, we expect to be able to achieve a MFI Ratio of 1.15, based upon a net margin of $7.1 million.

Off-system sales volume for the first quarter of 2010 was 643,069 MWh resulting in revenue of $25.7 million. The forecast for the balance of the year reflects off-system sales volume of 981,115 MWh resulting in revenue of $45.1 million.

As of December 31, 2009 compared to December 31, 2008

Our total assets increased to $1,505.54 million as of December 31, 2009, from $1,074.4 million as of December 31, 2008, reflecting cash and other compensation we received in connection with the Unwind. Working capital at December 31, 2009 increased $119.6 million from that of 2008 as a result of the Unwind. Our long-term obligations decreased by $153.0 million primarily reflecting the payment of $140.2 million on our 5.75% RUS Series A Note on the closing date of the Unwind. Our equity increased to $379.4 million as of December 31, 2009, from $(154.6) million as of December 31, 2008, again reflecting compensation to us in connection with the Unwind. Operating revenues for the year ended December 31, 2009 were $373.4 million as compared to $273.2 million for the year ended December 31, 2008 as a result of the increase in sales to the Smelters after the Unwind.

Operating Expenses for 2009 increased to $317.7 million as compared to $178.5 million in 2008 as a result of increases in fuel, production, transmission and maintenance expenses after the Unwind.

Net margins were $531.3 million in 2009 compared to $27.8 million in 2008 primarily as a result of the Unwind.

As of December 31, 2008 compared to December 31, 2007

Our total assets decreased to $1,074.4 million as of December 31, 2008, from $1,314.2 million as of December 31, 2007, reflecting the termination of the Leveraged-Lease Transactions. Working capital at December 31, 2008 decreased from that of 2007, reflecting the $107.1 million net cash payment and $12.4 million promissory note (due December 15, 2009) required for the termination of the Leveraged-Lease Transactions. Our long-term obligations (excluding the obligations related to the Leveraged-Lease Transactions) decreased by $35.0 million, primarily reflecting the principal payments made on the 5.75% RUS debt during 2008. Our liabilities exceeded our assets by $154.6 million as of December 31, 2008, as compared to $174.1 million as of December 31, 2007. This improvement reflects the net margin for 2008 of $27.8 million, offset by an adjustment of $8.3 million to accumulated other comprehensive income relating to FASB ASC 715 "Defined Benefit Plans."

Revenues for 2008 were $273.2 million, compared to $329.9 million for 2007. This $56.8 million decrease in 2008 revenue results primarily from a large block of market power purchased for release to the Smelters in 2007. Off-setting most of the 2008 revenue reduction, operating expenses for 2008 decreased by $53.3 million, also reflecting the large block of power purchased for the Smelters in 2007. Interest expense for 2008 increased by $4.8 million over 2007, reflecting higher interest rates on our $142.1 million variable rate tax-exempt pollution control bonds. The termination of the Leveraged Lease Transactions in 2008 generally accounts for the remainder of the 2008 net margin reduction compared to 2007.

Liquidity and Capital Resources

At December 31, 2009, we held cash and cash equivalents of approximately $60.3 million. We expect to rely upon our cash flows from operations and existing cash and cash equivalents to fund our operating costs and capital requirements during 2010. A material adverse change in operations could impact our ability to fund our liquidity and capital requirements without a new borrowing. Ultimate cash flows from operations are subject to a number of factors, including, but not limited to, the weather, regulatory constraints, economic trends and market volatility.

In July 2009, we entered into a three year, $50.0 million unsecured revolving credit agreement with CoBank. The CoBank credit agreement may be used for capital expenditures and general corporate purposes. On May 12, 2010, the amount outstanding under the CoBank credit agreement was $10.0 million.

In July 2009, we entered into a five year, $50.0 million unsecured revolving credit facility with CFC. The CFC credit agreement may be used for capital expenditures, general corporate purposes or the issuance of letter of credit. As of May 12, 2010, letters of credit in the aggregate amount of $5.9 million were outstanding under the CFC credit agreement.

Amounts available under these revolving credit facilities are accessible should there be a need for additional short-term financing. We expect that cash flows from operations and our existing cash and cash equivalents balance will be sufficient to fund our operating costs and capital requirements during 2010 through 2013.

For a discussion of financing for our projected capital expenditures, see "*Projected Capital Expenditures of Big Rivers Electric Corporation*" and "*Capital Requirements*" below.

Projected Capital Expenditures of Big Rivers Electric Corporation

We annually forecast expenditures required for additional electric generation and transmission facilities and capital for enhancement of existing facilities. We review these projections frequently in order to update our calculations to reflect changes in our future plans, construction costs, market factors and other items affecting our forecasts. Our actual capital expenditures could vary significantly from these projections because of unforeseen construction, changes in resource requirements, changes in actual or forecasted load growth or other issues. We project our 2010 capital expenditures to be $40.8 million. Our long range capital plan details actual and projected construction requirements and system upgrades of approximately $221.6 million for the years 2010 through 2013 as follows:

Projected Capital Expenditures

	Projected				
	2010	2011	2012	2013	Total
	(in thousands)				
Environmental Additions	$ 4,339	$ 7,988	$11,793	$ 5,636	$ 29,756
New Transmission	5,211	4,612	-	-	9,823
Existing Base Load System Upgrades	-	-	-	-	-
Transmission	9,882	7,175	6,263	3,114	26,434
Generation	14,026	40,318	44,615	43,524	142,483
Administration	7,333	1,355	3,012	1,381	13,081
Total	$40,791	$61,448	$65,683	$53,655	$221,577

Some of the more significant capital investments in generation and environmental additions that are represented in the table above for each year include: $1.6 million on phase one of a dust collector replacement project at the Green Plant and the Wilson Plant for compliance with Title V of the Clean Air Act, as amended (the "Clean Air Act"); $3.2 million on FGD life extension at the Wilson Plant; and $1.1 million on a SO_3 mitigation project at the Wilson Plant during 2010.

During 2011 we plan to invest $2.0 million on phase one of a project to elevate the dike for the waste water treatment facility at the Coleman Plant; another $2.8 million on phase two of the dust collector replacement at the Green Plant and Wilson Plant; $3.2 million in protective weld overlay on boiler tubes at the Coleman Plant and the Green Plant; $3.8 million for phase one of a major FGD refurbishment project at the Green Plant; $2.3 million on phase one of a project to apply protective coatings to the boiler, precipitator and scrubber structures at the Green Plant; $1.0 million on precipitator repairs at the Green Plant; \$2.2 million for low NO_x burner replacement at Station Two; \$2.2 million on phase two of the SO_3 mitigation project at the Wilson Plant; and \$1.0 million on phase two of the FGD life extension project at the Wilson Plant.

For 2012 capital investments include \$2.0 million on phase two of the dike elevation project for the waste water treatment facility at the Coleman Plant; \$2.5 million for protective weld overlay on boiler tubes at the Coleman Plant; \$3.1 million to replace the economizer and reheat sections in boilers at the Coleman Plant; \$1.0 million for a turbine overhaul at the Coleman Plant; \$1.6 million on phase two of the protective coating project at the Green Plant; \$1.9 million for precipitator repairs at the Green Plant; \$5.2 million on low NO_x burner replacement and a turbine overhaul at Station Two; and \$5.7 million on superheater tube replacement, and phase three of the FGD life extension project at the Wilson Plant.

In 2013 planned major investments include \$5.0 million in boiler tube and low NO_x burner replacements at the Coleman Plant; \$2.1 million in protective weld overlay on boiler tubes at the Coleman Plant and Wilson Plant; \$2.5 million in precipitator repairs at the Green Plant; \$3.8 million on phase three of the FGD refurbishment and protective coating projects at the Green Plant; \$4.0 million to replace the brick lining inside the scrubber exhaust stack at Station Two; \$1.3 million to replace medium voltage switchgear at Station Two; \$3.8 million to replace condenser tubes at the Wilson Plant; and \$5.6 million to replace low NO_x burners and boiler superheater tubes at the Wilson Plant. Additionally we will invest over \$8 million during this four year period in new or refurbished catalyst for the selective catalytic reductions ("SCR") at the Wilson Plant and Station Two.

Capital expenditures for new transmission resources include increasing our available transfer capability for exporting power off system from approximately 912 MW to 1380 MW.

Historically, RUS loans and loan guarantees have provided the principal source of financing for rural electric cooperatives. While we have utilized these programs, we have also availed ourselves of tax-exempt bond financing, bank loans and leveraged lease financing to finance our electric system. Currently, RUS has a moratorium on any new loans for new base load coal or nuclear generation.

Capital Requirements

We expect to finance substantially all of our projected capital expenditures for the years 2010 through 2013 with internally generated funds.

Debt and Lease Obligations

In addition to the Refunded Bonds, we have outstanding \$58.8 million County of Ohio, Kentucky Pollution Control Refunding Bonds, Series 1983 (Big Rivers Electric Corporation Project) (the "Series 1983 Bonds"), which bear interest at variable rates. Currently, the Series 1983 Bonds are being held as bank bonds by the liquidity provider, bearing an interest rate of 3.25%, as the remarketing agent has been unsuccessful at marketing them at the prescribed maximum rate, 120% of the variable rate index.

On May 25, 2010, a regularly scheduled auction for our outstanding series of periodic auction reset securities (PARs), the Refunded Bonds, having a total principal amount of \$83.3 million, failed as the par amount of sell orders in the auction exceeded the par amount of buy orders by approximately \$4.3 million. As a result, the annual interest rate on the Refunded Bonds reset from 1.7% for the prior 28-day period to 18% for the current 28-day period, which is the maximum rate required under the terms of the Refunded Bonds in the event of a failed auction. At the end of the current period, the Refunded Bonds will be redeemed from the proceeds of the Bonds.

The scheduled maturities of our long-term debt at January 31, 2010 were as follows:

Payments Due by Period

	Total	Remainder of 2010	2011	2012	2013	2014	Thereafter
				(in millions)			
Long-Term Debt[(1)]	$846.6	$12.0	$14.9	$76.1	$79.3	$21.7	$642.6

(1) In the operation of our business we have various other contracts for the purchase of electricity that are not included in the table above but are described elsewhere herein. For a discussion of our long-term power purchase obligations, see "GENERATION AND TRANSMISSION ASSETS – Other Power Supply Resources."

Ratings Triggers

Our credit ratings as of the date of this Offering Statement are Baa1, stable outlook, from Moody's Investor Service ("Moody's"), BBB-, stable outlook, from Fitch Ratings ("Fitch") and BBB-, stable outlook, from Standard & Poor's Credit Market Services, a division of the McGraw-Hill Companies ("S&P").

Under our loan agreement with RUS, if we fail to maintain two investment grade credit ratings, we must notify RUS in writing to that effect within five days after becoming aware of such failure. Next, within 30 days of the date of failing to maintaining two investment grade credit ratings, we must, in consultation with RUS, provide a written plan satisfactory to the RUS setting forth the actions that will be taken that are reasonably expected to achieve two investment grade credit ratings. Before we would be impacted by this restriction, both Fitch and S&P would have to downgrade us one rating step. In the case of Moody's, its rating would have to be lowered three rating steps coupled with at least one rating downgrade from Fitch or S&P.

A change in our credit rating also would have an impact on our CoBank credit line. This agreement contains an adjustment to the annual fees and interest rate paid on any advances based on our existing credit rating. An improvement in the credit rating would lower our cost and deterioration in our credit rating would increase our cost under this agreement. This agreement allows us to utilize our highest credit rating in setting our fees and interest rates. Currently, Moody's is our highest credit rating and sets the costs for us under this agreement. A one-step downgrade by Moody's would result in a .0025% increase unused fee and a .25% increase in the interest rate margin.

RATE AND ENVIRONMENTAL REGULATIONS

General

Many aspects of our business are subject to a complex set of energy, environmental and other governmental laws and regulations at the federal, state and local level.

Kentucky Rate Regulation

The KPSC regulates our rates for the sale of wholesale power to our Members. Among other things, Kentucky law authorizes the KPSC to (i) approve our rates to be "fair, just and reasonable," (ii) regulate our construction of new generation and transmission facilities by issuing certificates of public convenience and necessity, (iii) approve changes in ownership or control of us through sales of assets or otherwise, (iv) approve the issuance or assumption of any securities or evidence of indebtedness, other than to RUS, and (v) administer the state laws assigning each jurisdictional electric distribution utility the exclusive right to provide retail electric service within specified geographic boundaries. The KPSC has approved the issuance of the Bonds. See "RISK FACTORS" for information relating to rate regulation by the KPSC.

RUS Regulation

In addition to the KPSC's direct regulation of us, RUS has certain rights through its loan documents with us that impact our operations (i.e., RUS must consent to the construction of new facilities which are part of our electric system, certain sales or dispositions of property, our execution of certain types of contracts and our making of loans or investments).

Environmental Regulations

We are subject to various federal, state and local laws, rules and regulations with regard to air quality, water quality, waste management and other environmental matters.

These laws, rules and regulations often require us to undertake considerable efforts and substantial costs to obtain licenses, permits and approvals from various federal, state and local agencies. If we fail to comply with these laws, regulations, licenses, permits or approvals, we could be held civilly or criminally liable. Our operations are subject to environmental laws and regulations that are complex, change frequently and have tended to become more stringent over time. An inability to comply with environmental standards could result in reduced operating levels or the complete shutdown of facilities that are not in compliance.

Federal, state and local standards and procedures that regulate the environmental impact of our operations are subject to change. These changes may arise from continuing legislative, regulatory and judicial actions regarding such standards and procedures. Consequently, there is no assurance that environmental regulations applicable to our facilities will not become materially more stringent, or that we will always be able to obtain and renew all required operating permits. We cannot predict at this time whether any additional legislation or rules will be enacted that will affect our operations, and if such laws or rules are enacted, what the cost to us might be in the future because of such actions.

From time to time, we may be alleged to be in violation of or in default under orders, statutes, rules, regulations, permits or compliance plans relating to the environment. From time to time, we may be defending notices of violation, enforcement proceedings or challenges to draft or final construction or operating permits. In addition, we may be involved in legal proceedings arising in the ordinary course of business.

Clean Air

Clean Air Act. The Clean Air Act regulates emissions of air pollutants, establishes national air quality standards for major pollutants, and requires permitting of both new and existing sources of air pollution. Many of the existing and proposed regulations under the Clean Air Act could have a disproportionate impact on coal-based power plants, in particular older plants such as ours, because older plants may not have originally been required to install the same pollution control equipment as newer facilities. On the other hand, as retrofits become available and feasible, we may incur greater costs than competing generating sources to bring facilities up to current standards. Several of our facilities have, in the past decade, been retrofitted with new pollution control equipment, including flue gas desulfurization and selective catalytic reduction equipment, in response to regulatory changes.

Acid Rain Program. The acid rain program requires nationwide reductions of SO_2 and NO_X emissions using a cap-and-trade program reducing allowable emission rates and allocating emission allowances to power plants for SO_2 emissions based on historical or calculated levels. We have sufficient SO_2 and NO_x (seasonal and annual) allowances to comply for the foreseeable future according to our modeled emissions and allowance allocations.

CAIR Program. In March 2005, the EPA issued the Clean Air Interstate Rule ("CAIR"), which was intended to reduce overall NO_X and SO_2 emissions on a regional basis effective in 2009 and 2010, respectively, with a second phase taking effect in 2015. The CAIR program authorized a cap-and-trade emissions allowance trading program, similar to that used in the Acid Rain Program which allowed sources to comply by trading emissions allowances instead of installing new pollution control systems. In addition, CAIR allowed sources to achieve compliance by surrendering SO_2 allowances issued under EPA's acid rain program (Title IV), which would have allowed sources with excess Title IV emissions allowances to have achieved compliance at relatively low cost.

On July 11, 2008, the United States Court of Appeals for the D.C. Circuit vacated EPA's CAIR regulations, remanding CAIR to EPA to issue new regulations consistent with the Clean Air Act and the court's decision. Pursuant to the court's decision, EPA may be required to expand the CAIR program and make it more stringent, which may require the inclusion of additional states or sources in the program on the basis of adverse effects on downwind states. Among other things, the court found that the regional cap-and-allowance trading programs established by the CAIR did not achieve the intended purpose of ensuring that upwind states did not prevent attainment of National Ambient Air Quality Standards in downwind states because emitters in upwind states could potentially buy large quantities of emissions allowances. The opinion also found that the criteria used by the EPA in setting caps for SO_2 emissions and in allocating NO_X emissions were inconsistent with the statutory criteria and with Title IV of the Clean Air Act. On December 23, 2008, the court modified its remand order so that the existing CAIR regulatory program will remain in place until EPA issues revised regulations that remedy the problems identified in the decision. The court's decision creates uncertainty regarding future NO_X and SO_2 emissions reduction requirements and their timing. As a result of the decision, more stringent regulatory limits could be imposed, or there may be a delay or acceleration in the effective dates of federal requirements to reduce emissions. Based on the court's decision, EPA may not be able to use emissions trading or the surrender of Title IV SO_2 allowances to achieve compliance, and may require sources to install new pollution control systems. EPA initially informed the court that development and finalization of a replacement rule could take approximately two years, but a replacement rule could be proposed as early as spring 2010. Big Rivers is in compliance with the current version of CAIR, but we are unable at this time to determine what impact the replacement rule will have on us.

Mercury. The Clean Air Act also provides for a comprehensive program for the control of hazardous air pollutants, including mercury, unless alternative programs are established that adequately protect health and the environment. In March 2005, the EPA issued the Clean Air Mercury Rule ("CAMR"), which regulated mercury emissions under an alternative program. This rule would have capped total annual mercury emissions from coal-fired plants across the United States through a two-phased program and established a cap-and-trade program similar to the acid rain program, in which the states were encouraged to participate. On February 8, 2008, the United States Court of Appeals for the D.C. Circuit struck down CAMR and returned the issue to EPA for reconsideration and further rulemaking. In connection with such rulemaking, EPA must treat mercury as a "hazardous air pollutant" subject to a more restrictive program requiring the installation of "maximum available control technology" in new and existing units. It is likely that EPA will issue more stringent regulations controlling mercury emissions from coal-fired plants. Regulations for mercury control are uncertain at this time, and will remain so until any future rulemakings. As a result, it is too early to determine what impact, if any, such regulations may have on us. See also "*Multi-Pollutant Legislation*" below for a discussion of recent legislation proposed reductions of mercury emissions from electric utilities.

Multi-Pollutant Legislation. On February 4, 2010, Senators Tom Carper and Lamar Alexander introduced bill number S.2995, the Clean Air Act Amendments of 2010, to the United States Senate. The bill proposes mandatory emission reductions of NO_X, SO_2 and mercury from electric utilities, which would ultimately be more stringent than the emission controls under CAIR and CAMR. This bill is in the early stages of development, so we cannot predict whether it or similar multi-pollutant legislation will ultimately become law. As a result, it is too early to determine what impact, if any, such a law and any implementing regulations may have on us.

Regional Haze. On June 15, 2005, the EPA issued the Clean Air Visibility Rule, amending regulations governing visibility in national parks and wilderness areas throughout the United States. Under the amended rule, certain types of older sources may be required to install best available retrofit technology ("BART"). The amended rules could result in requirements for newer and cleaner technologies and additional controls for particulate matter ("PM"), SO_2 and NO_X emissions from utility sources. Under the Clean Air Visibility Rule, the states were required to develop regional haze plans as part of their SIPs, and identify the facilities that would have to reduce emissions and then set BART emissions limits for those facilities. Kentucky submitted its regional haze SIP revisions to EPA on June 25, 2008. EPA has not yet approved or denied Kentucky's regional haze SIP revisions.

All of Big Rivers' facilities, except the Wilson Plant, were eligible for imposition of BART requirements under the haze SIP revisions. In June 2008, the Kentucky Division of Air Quality ("DAQ") determined that each Big Rivers facility would be exempt from the requirement to install BART for SO_2, NO_X and PM emissions under its regional haze rule. The DAQ determination with respect to SO_2 and NO_X emissions was based on a previous EPA determination that states participating in the CAIR program would not have to require electricity generating facilities to install BART for SO_2 and NO_X emissions. Because the CAIR program is currently under review by EPA, it is possible that EPA's earlier determination could change, requiring states to evaluate SO_2 and NO_X emissions from BART-eligible sources. Therefore it is possible that we will be required to install BART for SO_2 and NO_X emissions at certain facilities. The DAQ determination to exempt Big Rivers facilities from BART with respect to PM emissions was based on air quality modeling information submitted by Big Rivers to DAQ in May 2007. At that time, the modeling information showed that PM emissions from Big Rivers facilities were not contributing to regional haze at any Class I area.

National Ambient Air Quality Standards. The Clean Air Act also requires EPA to establish National Ambient Air Quality Standards ("NAAQS") for certain air pollutants. When a NAAQS has been established, each state must identify areas in its state that do not meet the EPA standard (known as "non-attainment areas") and develop regulatory measures in its state implementation plan ("SIP") to reduce or control the emissions of that air pollutant in order to meet the standard and become an "attainment area." EPA is in the process of reviewing NAAQS for certain air pollutants that are emitted by power plants including nitrogen dioxide, sulfur dioxide, ozone, and particulate matter. For example, on January 19, 2010, EPA published a proposed rule for a stricter NAAQS for ground-level ozone and, on January 25, 2010, EPA released a final rule establishing a stricter primary one-hour NAAQS for nitrogen dioxide. When a stricter NAAQS is finalized and becomes effective, air pollution sources including power plants, could face stricter emission standards. The impact of any new standards under the NAAQS program will depend on the final federal regulations and resulting revisions to Kentucky's SIP, so we cannot determine such impacts at this time.

Opacity. PM emissions from our facilities have, in the past, resulted in notices of violation and occasional complaints from neighbors and local government agencies. The complaints have declined in recent years, following the installation of SCR and/or FGD air pollution controls at the Wilson Plant, the Green Plant, the Henderson Plant and the Coleman Plant. Even though there have been improvements in some of the emissions characteristics, plume opacity and other impacts may continue to arise in connection with the installation and the operation of the SCR and FGD controls. Additionally, the scrubbed units at the Green and Wilson plants are "wet scrubbed" units with "wet stacks." A phenomenon commonly associated with wet scrubbers is the occasional and unexpected appearance of a visible plume that begins some distance after the exhaust exits the stack. The actual cause of the plume is unknown. We continue to monitor the occurrence of the plumes and address Notices of Violations or other agency actions as they arise. Although no material fines or penalties have been assessed against us, we have sought permit amendments to address this issue. It is possible that additional investment or pollution controls may be required to reduce these impacts.

New Source Review. In 1999-2000, the U.S. Justice Department, acting on behalf of the EPA, filed a number of complaints and notices of violation against multiple utilities across the country for alleged violations of the New Source Review ("NSR") provisions of the Clean Air Act. Generally, the government alleged that projects performed at various coal-fired units were major modifications, as defined in the Clean Air Act, and that the utilities violated the Clean Air Act when they undertook these projects without obtaining major source permits under the Prevention of Significant Deterioration ("PSD") and/or Title V programs. As part of the enforcement effort, the EPA also sent requests for information letters to numerous other utilities requesting extensive and detailed information on the repairs and modifications made by those utilities to their coal fired boilers. In 2000, WKE received an information request from EPA, when it was the operator of the Big River facilities, and WKE submitted the requested information to EPA. To date, EPA has not requested any additional information.

In 2007, the U.S. Supreme Court upheld EPA's definition of a major modification as one that increases the actual annual emission of a pollutant from a facility above the actual average for the two prior years, and, under President Obama's administration, EPA has announced plans to enforce the NSR provisions. We cannot predict whether EPA or other governmental authorities will consider any of the past maintenance projects or capital improvements at our facilities to have violated NSR requirements as a result of the uncertain interpretation of this program and recent court decisions. If violations are established, we could be required to install new pollution control equipment in addition to the modifications that have already been completed or planned, and be liable for other payments or penalties.

Global Climate Change

CO_2, a major constituent of emissions from fossil-fuel combustion, and other GHGs are generally believed to be linked to global warming resulting in climate change. Control of such emissions is the subject of debate in the United States, on local, state and national levels. In the United States, no federal legislation limiting GHG emissions has yet been enacted, but there have been significant developments relating to monitoring and regulation of GHG emissions by EPA, certain state governments and regional governmental organizations. In addition, the United States Congress is considering federal legislation that could impose a cap-and-trade system or other measures to reduce GHG emissions, such as carbon tax.

EPA Regulatory Action under the Clean Air Act

On April 2, 2007, the United States Supreme Court issued a decision in *Massachusetts v. EPA* holding that GHG emissions are "air pollutants" under the federal Clean Air Act, thereby requiring EPA to determine whether GHGs pose a threat to public health and welfare. On December 15, 2009, EPA published the final rule for the "endangerment finding" under the Clean Air Act. In the finding, EPA declared that the six identified GHGs – CO_2, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride – cause or contribute to global warming, and that the effects of climate change endanger public health and welfare by increasing the likelihood of severe weather events and the other related consequences of climate change. The issuance of the "endangerment finding" triggered the statutory requirement that EPA regulate emissions of GHGs as air pollutants from motor vehicles. Such regulations were finalized on April 1, 2010, when EPA and the United States Department of Transportation issued a joint final rule imposing GHG emission standards on light-duty vehicles (cars and light trucks). That regulation takes effect on January 2, 2011.

On March 29, 2010, EPA affirmed its position that air pollutants that are actually regulated under the Clean Air Act under any program must be taken into account when considering permits issued under other programs, such as the PSD permit program. A PSD permit is required before commencement of construction of new major stationary sources or major modifications of such sources. As a result of this determination, the effect of the new motor vehicle rule will be to require the analysis of emissions and control options with respect to GHG emissions from new and modified major stationary sources as of January 2, 2011, which is the date the new motor vehicle rule takes effect. Permitting requirements for GHGs will include, but are not limited to, the application of Best Available Control Technology (known as "BACT") for GHG emissions, and monitoring, reporting and recordkeeping for GHGs.

On May 13, 2010, EPA issued a final rule for determining the applicability of the PSD program to GHG emissions from major sources. The rule, known as the "Tailoring Rule," establishes criteria for identifying facilities required to obtain PSD permits and the emissions thresholds at which permitting and other regulatory requirements apply. The applicability threshold levels established by this rule include both a mass-based calculation and a metric known as the carbon dioxide equivalent, or CO_2e, which incorporates the global warming potential for each of the six individual gases the comprise the collective GHG defined in the endangerment finding.

On January 2, 2011, sources that are subject to PSD and/or Title V permits due to their non-GHG emissions (such as fossil-fuel based electric generating facilities for their NO_x, SO_2 and other emissions) will have to address GHG emissions in new permit applications or renewals. Construction or modification of major sources will become subject to PSD requirements for their GHG emissions if the construction or modification results in a net increase in the overall mass of GHG emissions exceeding 75,000 tons per year on a CO_2e basis. New and modified major sources requiring to obtain a PSD permit would be required to conduct a BACT review for their GHG emissions. EPA intends to issue guidance before the end of 2010 on the technologies or operations that would constitute BACT for GHGs. With respect to Title V requirements, as of January 2, 2011, sources that are required to have Title V permits for non-GHG pollutants will be required to address GHGs as part of their Title V permitting. The 75,000 tons per year CO_2e applicability threshold does not apply, so when any source applies for, renews, or revises a Title V permit, then Clean Air Act requirements for monitoring, recordkeeping and reporting will be included. Additional phases of implementation of the Tailoring Rule apply only to sources that are not currently subject to PSD and/or Title V requirements, and are therefore not applicable to our facilities, each of which is subject to one or both of the federal permits.

On October 30, 2009, the EPA published the final rule for mandatory monitoring and annual reporting of greenhouse gas emissions from various categories of facilities including fossil fuel suppliers, industrial gas suppliers, direct greenhouse gas emitters (such as electric generating facilities and industrial processes), and manufacturers of heavy-duty and off-road vehicles and engines. This rule does not require controls or limits on emissions, but requires data collection to beginning January 1, 2010, and the first annual reports due March 31, 2011.

Our costs of compliance with these new regulations are not fully known at this time. The requirements for monitoring, reporting and record keeping with respect to GHG emissions from existing units should not have a material adverse effect, but the consequences of new permit requirements in connection with new units or modifications of existing units could be significant, as could any new proposed regulations affecting permitting and controls for our existing units.

Federal Legislation

The United States Congress is currently considering several energy and climate change-related pieces of legislation that propose, among other things, a cap-and-trade system to regulate and reduce the emission of CO_2 and other GHGs and a federal renewable energy portfolio standard. One such bill, H.R. 2454, known as the American Clean Energy and Security Act of 2009, was passed by the House of Representatives on June 26, 2009. That bill, and several other energy and climate change-related legislative proposals are currently being considered by the Senate. On May 12, 2010, Senators Kerry and Lieberman made public the text of a proposal entitled the American Power Act, which is expected to be considered. The impact that federal GHG cap-and-trade legislation will have on the electric utility industry and our business depends largely on the specific provisions of the legislation that ultimately become law. Some of the important issues that could be addressed in cap-and-trade legislation include: the timing and magnitude of the emissions cap; the extent to which emissions allowances are allocated or auctioned to the highest bidder; and the extent to which emissions may be offset by other actions. The timeline and impact of climate change legislation cannot be accurately assessed at this time, but it is expected that any enactment of statutes to regulate GHG emissions will have a significant impact on fossil-fueled generation facilities.

Litigation

Many of the issues raised by global climate change are being litigated in courts throughout the United States. For example, recent litigation is raising for judicial review the question of whether a federal agency must consider the impact of GHG emissions in the National Environmental Policy Act environmental review process. Pending cases are also alleging that GHG emissions from electric generation are causing a public nuisance and should be abated by electric generation facilities. We cannot currently predict how GHG emissions issues will arise in connection with pending or future permit proceedings or whether litigation based on climate change issues will adversely affect our operations, or our construction and development plans.

Water

The Federal Clean Water Act regulates the discharge of process wastewater and certain storm water under the National Pollutant Discharge Elimination System ("NPDES") permit program. Such permits are issued for five-year periods and continue in effect if renewal applications are timely filed. At the present time, applications for renewal of some of our NPDES permits are awaiting review by the Kentucky Division of Water. We have all other material required permits under the program for all of our electric generating plants. The water quality regulations require us to comply with Kentucky's water quality standards, including sampling and monitoring of the waters discharged from the facilities. We continually sample and monitor the discharges and report the results thereof in accordance with our permits.

Section 316(b) of the Clean Water Act requires the EPA to ensure that the location, design, construction and capacity of cooling water intake structures reflect the best technology available to protect aquatic organisms from being killed or injured by impingement or entrainment. In February 2004, the EPA issued final regulations establishing standards for cooling water intake structures at existing large power plants. The rule provided several compliance alternatives for existing plants such as using existing technologies, adding fish protection systems or using restoration measures.

On January 25, 2007, the United States Second Circuit Court of Appeals remanded key components of the Clean Water Act 316(b) Phase II Rule. The court ruled that EPA could not allow use of restoration measures to satisfy performance standards, nor could it consider cost-benefit analysis in selecting "best technology available." The United States Supreme Court heard the appeal of the Second Circuit decision and held on April 1, 2009, that it is permissible for utility companies and regulators to apply cost-benefit analysis under the Clean Water Act. EPA is in the process of developing a new rule consistent with the Supreme Court's decision.

The impact of Section 316(b) on Big Rivers' is limited to the Reid Plant and the Coleman Plant. The degree of such impact will depend upon the form of the new rule that EPA publishes. If EPA allows a cost-benefit analysis to determine the best technology available, we expect the impact to the Reid Plant and the Coleman Plant will be minimal based on information obtained from previous studies conducted on the quantity and type of fish impinged on the intake screens at Reid Station and Coleman Station.

Other Environmental Matters

The Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA" or "Superfund"), requires cleanup of sites from which there has been a release or threatened release of hazardous substances and authorizes the EPA to take any necessary response action at Superfund sites, including ordering potentially responsible parties ("PRPs") liable for the release to take or pay for such actions. PRPs are broadly defined under CERCLA to include past and present owners and operators of, as well as generators of wastes sent to, a site. We historically have sent wastes, such as coal ash or wastewater that could have included hazardous substances, to third-party disposal sites or treatment plants. Based on such disposal, Big Rivers can become a PRP with respect to such sites. We are not aware of any material liabilities with respect to such disposal, but can provide no assurance that such liabilities will not be asserted in the future. In addition, we have experienced and are likely to continue to experience in the future spills and releases of fuel oil and other materials that could trigger cleanup obligations under CERCLA and result in additional compliance costs. As a result, there can be no assurance that we will not incur liability under CERCLA in the future.

Electro-Magnetic Fields. A number of electrical industry studies have been conducted regarding the potential long-term health effects resulting from exposure to electro-magnetic fields ("EMF") created by high voltage transmission and distribution equipment. At this time, any relationship between EMF and certain adverse health effects appears inconclusive; however, electric utilities have been experiencing challenges in various forms claiming financial damages associated with electrical equipment which creates EMF. In the future, if the scientific community reaches a consensus that EMF presents a health hazard, we may be required to take remedial actions at our facilities. The cost of these actions cannot be estimated with certainty at this time. Such costs, however, could be significant, depending on the particular mitigation measures undertaken, especially if relocation of existing power lines is required.

Coal Ash. Our coal-based generating facilities produce coal ash waste that requires disposal. We dispose of the coal ash in our onsite landfills and impoundments and possess the proper industrial solid waste permits to operate our landfills in accordance with local, state and federal regulations and laws. However, we must continually expand the capacity of our landfills and waste management facilities to accommodate larger amounts of ash. If we become unable to dispose of coal ash on site, our disposal costs may increase considerably. On the other hand, we are continually evaluating methods for beneficial reuse of waste ash. Currently, all of the ash we generate is exempt from regulation as "hazardous waste."

On May 4, 2010, the EPA released the text of a proposed rule describing two possible regulatory options it is considering under the Resource Conservation and Recovery Act ("RCRA") for the disposal of coal ash generated from the combustion of coal by electric utilities and independent power producers. Under either option, EPA would regulate the construction of impoundments and landfills, and seek to ensure the both the physical and environmental integrity of disposal facilities.

Under the first proposed regulatory option, EPA would list coal ash destined for disposal in landfills or surface impoundments as "special wastes" subject to regulation under Subtitle C of RCRA. Subtitle C regulations set forth EPA's hazardous waste regulatory program, which regulate the generation, handling, transport and disposal of wastes. The proposed rule would create a new category of waste under Subtitle C, so that coal ash would not be classified as a hazardous waste, but would be subject to many of the regulatory requirements applicable to such wastes. Under this option, coal ash would be subject to technical and permitting requirements from the point of generation to final disposal. Generators, transporters, and treatment, storage and disposal facilities would be subject to federal requirements and permits. EPA is considering imposing disposal facility requirements such as liners, groundwater monitoring, fugitive dust controls, financial assurance, corrective action, closure of units, and post-closure care. This first option also proposes requirements for dam safety and stability for surface impoundments, land disposal restrictions, treatment standards for coal ash, and a prohibition on the disposal of treated coal ash below the natural water table. The first option would not apply to certain beneficial reuses of coal ash.

Under the second proposed regulatory option, EPA would regulate the disposal of coal ash under Subtitle D of RCRA, the regulatory program for non-hazardous solid wastes. Under this option, EPA is considering issuing national minimum criteria to ensure the safe disposal of coal ash, which would subject disposal units to location standards, composite liner requirements, groundwater monitoring and corrective action standards for releases, closure and post-closure care requirements, and requirements to address the stability of surface impoundments. Existing surface impoundments would not have to close or install composite liners and could continue to operate for their useful life. The second option would not regulate the generation, storage, or treatment of coal ash prior to disposal, and no federal permits would be required.

The proposed rule also states that EPA is considering listing coal ash as a hazardous substance under CERCLA, and includes proposals for alternative methods to adjust the statutory reportable quantity for coal ash. The extension of CERCLA to coal ash could significantly increase our liability for cleanup of past and future coal ash disposal.

EPA has not decided which regulatory approach it will take with respect to the management and disposal of coal ash. We are therefore unable to determine the effects of this proposed rule at this time.

As part of EPA's scrutiny of how ash impoundments are permitted and operated, EPA recently assessed ash impoundments at many facilities throughout the country, including some of our facilities, even though our ash impoundments are not of the same type and construction involved in the Kingston Plant ash spill and therefore do not pose the same kinds of risks. A dam safety assessment report for Reid Station, Green Station and Station Two was prepared for EPA in December 2009. All of the ash ponds at these facilities received "fair" ratings – a rating that reflected EPA's view that our geotechnical information was not complete – but no critical deficiencies were noted. Minor repairs required by EPA during this review will be completed during the 2010 construction season. We have commenced the geotechnical investigation recommended by EPA in connection with the assessment, which is scheduled to be completed for all facilities by the end of 2011. Coal ash waste management and disposal is an evolving issue and we expect to continue to incur costs to upgrade and expand our ash impoundments as regulations change.

FERC Regulation

As a RUS-financed utility, our sale of power at wholesale and certain aspects of our transmission of power in interstate commerce are not regulated by FERC. If we were not a RUS-financed public utility, those functions would be regulated by FERC. FERC has jurisdiction under the Federal Power Act, however, to require us to provide transmission services to third parties at rates and on terms and conditions comparable to our own use of our transmission services. We are a transmitting utility subject to interconnection and transmission orders under Sections 210, 211 and 212 of the Federal Power Act, as amended by the Energy Policy Act of 1992 ("EPAct 1992"). We also are subject to FERC transmission orders to the extent that they apply to non-jurisdictional utilities and to reciprocity tariffs as described below. In the absence of regulation by FERC, the KPSC has asserted jurisdiction over what would otherwise be FERC jurisdictional activities.

EPAct 1992

EPAct 1992 made fundamental changes in the federal regulation of the electric utility industry, particularly in the area of transmission access. The purpose of these changes, in part, was to bring about increased competition in the wholesale electric power supply market. These changes have increased, and will continue to increase, competition in the electric utility industry. Specifically, EPAct 1992 provided that any electric utility, federal power marketing agency or any other person generating electric energy for sale for resale may apply to FERC for an order requiring a transmitting utility like us to provide transmission services to the applicant. After notice and an opportunity for hearing, FERC may issue an order requiring such transmission service to be provided, subject to appropriate compensation to the utility providing such service. However, EPAct 1992 specifically denied FERC authority to require "retail wheeling" under which a retail customer of one utility could obtain electric power and energy from another utility or nonutility power generator and require a transmitting utility to "wheel" it to the retail customer.

Order No. 888 and Successor Orders

In 1996, to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient lower cost power to the nation's electricity consumers, FERC issued Orders Nos. 888 and 889. Orders Nos. 888 and 889, as amended by Orders Nos. 888-A and 889-A in 1997, were intended to deny to public utilities any unfair advantage over competitors resulting from their ownership and control of transmission facilities and required FERC-jurisdictional public utilities to file pro forma, open access, nondiscriminatory transmission tariffs. In Order Nos. 890, 890-A and 890-B, issued (respectively) in February and December 2007 and June 2008, FERC reaffirmed and modified the requirements under Order Nos. 888 and 888-A, specifically, by modifying the transmission tariff provisions on (among other things) calculating available transfer capability, transmission planning, point-to-point transmission service options, energy imbalance service, rollover rights for long-term firm transmission service, and the price caps on capacity reassignments. Under the reciprocity requirement adopted in Order No. 888 and reaffirmed in Order No. 890, non-jurisdictional utilities like us must provide comparable transmission service as a condition of receiving service from jurisdictional utilities under the pro forma tariff. Our transmission facilities located in the Eastern Interconnection are under a transmission tariff that has been approved by FERC. We developed those tariffs to buy and sell electricity using the transmission systems of regulated utilities, as required by FERC's reciprocity requirement.

Energy Policy Act of 2005

On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 ("EPAct 2005"). The significant provisions of EPAct 2005 that could affect us are in the areas of (1) reliability; (2) siting of new transmission facilities; (3) potential FERC authority over transmission service and the rates of non-rate-regulated utilities; (4) native load obligations; and (5) expansion of FERC's enforcement authority. In addition, Congress repealed the Public Utility Holding Company Act of 1935 ("PUHCA 1935"), and replaced it with the Public Utility Holding Company Act of 2005 ("PUHCA 2005"), thereby effectively repealing many of the more onerous provisions of PUHCA 1935. As an electric cooperative, we generally are not subject to the new requirements of PUHCA 2005. EPAct 2005 also created incentives for the construction of transmission facilities; gave FERC authority to establish mandatory reliability standards through a new entity that FERC will certify as the Electric Reliability Organization ("ERO"); authorized the DOE and FERC to grant permits enabling entities, in certain circumstances, to use a federal right of eminent domain to build new transmission lines; and adopted provisions enabling transmission providers to reserve transmission capacity for their native load service obligations. FERC has adopted regulations to implement the new regulations and requirements concerning siting, transmission access, native load preferences and enforcement.

Concerning the expansion of FERC's authority to order transmission access to transmission systems owned or operated by non-rate-regulated utilities, EPAct 2005 added new section 211A to the Federal Power Act. Section 211A authorizes FERC to order non-rate-regulated utilities like us to provide transmission service at rates and terms that are comparable to those by which the non-rate-regulated utility provides transmission service to itself. However, the non-rate-regulated utilities subject to any such requirements are not subject to the full panoply of FERC regulations applicable to transmission-owning public utilities. FERC also is required, with certain limited exceptions, to exempt any non-rate-regulated utility that sells less than 4 million kWh per year. FERC has declined to order transmission access pursuant to Section 211A on a generic basis, and instead will act, if at all, on a case-by-case basis.

NERC has been certified by FERC as the ERO. NERC's mandatory reliability standards, which are subject to FERC review and approval, apply to any entity that owns, operates or uses the bulk power system. EPAct 2005 authorizes FERC and the ERO to impose penalties for violations of the reliability standards. In March and July 2007, FERC issued (respectively) Order Nos. 693 and 693-A largely approving the reliability standards initially filed by NERC for FERC review and approval. FERC also directed NERC to consider revisions to a number of the standards, and other reliability standards and amendments proposed by NERC remain pending before FERC. As an owner and operator of generation and transmission facilities, we are subject to certain of the NERC reliability standards. We are currently scheduled for a routine audit of our compliance with the reliability standards. The audit is scheduled to occur at our facility from May 24 to May 28 of this year. If the auditors identify areas of non-compliance, we could be subject to penalties or sanctions.

EPAct 2005 also added new sections 220, 221 and 222 to the Federal Power Act, which generally prohibit fraud and manipulation in the energy markets and promote price transparency. Under FERC's implementing rules, the anti-fraud rules apply to all entities, including non-jurisdictional utilities, to the extent they engage in activities or transactions in connection with sales and transmission services subject to FERC's public-utility jurisdiction.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Risk Management Policies

We are exposed to significant market risks associated with electricity and coal prices, counter-party credit exposure, interest rates and equity prices. Interest rate risk is associated with the changes in interest rates that impact our variable rate debt instruments and fixed income investments. Our energy related commodity price risks involve changes in the market price of power natural gas, and solid fuels and the impact of such changes on our ability to generate sufficient revenue to cover our operational costs. We have established comprehensive risk management policies to monitor and manage these risks. Our vice president of enterprise risk management is responsible for monitoring and reporting on our risk management policies, including delegation of authority levels. We have an Internal Risk Management Committee that regularly meets and the vice president of enterprise risk management reports to the Board of Directors monthly. The vice president of enterprise risk management is responsible for oversight of market risk, credit risk, etc., including monitoring exposure limits.

To manage our market risks, we may enter into various derivative instruments including swaps, forward contracts, futures contracts and options. Management believes adequate safeguards, reporting mechanisms, and procedures are in place to protect us from unauthorized use of such derivative instruments. We have established certain risk management strategies relating to the sales and purchase prices for the commodities which form our core business, in order to provide insulation from volatile market prices. With respect to our power sales, our Board of Directors has established guidelines which are intended to ensure that derivatives and other financial instruments are used for hedging purposes and not for speculation. Those guidelines provide that hedging activity shall be used only to minimize risk and not to create any greater risk. Risk management status and performance must be reported to our Board of Directors on a monthly basis, and that counterparties must meet capitalization requirements before we will engage with such counterparty.

Electricity and Coal Price Risk

We are exposed to the impact of market fluctuations in the prices of electricity and coal as a result of our ownership and operation of electric generating facilities. Our exposure to coal and purchased power risk is limited by cost-based Member rate recovery through two cost-recovery clauses, namely the fuel adjustment clause ("FAC") and the non-FAC purchased power adjustment. Due to timing of the cost-recovery, there is a two month lag for the FAC between when costs are incurred and when the Member portion is recovered through rates. For the non-FAC purchase power adjustment due to timing of the cost recovery, there is a two month lag between when the costs are incurred and when the Member-Smelter portion is recovered through rates that represent approximately two-thirds of the costs. The remaining one-third of the non-FAC purchase power adjustment cost is deferred as a regulatory account and we will seek recovery from the KPSC during a request to adjust base rate. This request will be presented to the KPSC during 2011 to be effective January 1, 2012.

Price risk represents the potential risk of loss from adverse changes in the market price of electricity or coal. Because we are long on power, both capacity and energy, we are exposed to the illiquidity of the long-term power market and volatility of the market price of electricity and coal. Our long position in the energy market is approximately 150 MWs or 8% of our availability capacity. The excess capacity and energy will be consumed in the future through normal growth. Further, price risk resulting from the volatility in the price of coal is off-set by a month recovery rider for fuel that has been approved by the KPSC.

We generally only enter into market power sales contracts that qualify for the normal sales and purchases exception. Income recognition and realization related to normal sales and normal purchases contracts generally coincide with the physical delivery of the power. For all such contracts, as long as completion of the transaction remains probable, no recognition of the contract's fair value is required to be reported in our financial statements until settlement or physical delivery.

Marketable Securities Price Risk; Pension Plan Assets

We maintain investments to fund the cost of providing our non-contributory defined benefit retirement plans. Those investments are exposed to price fluctuations in equity markets and changes in interest rates. We have established asset allocation targets for our pension plan holdings that take into consideration the investment objectives and the risk profile with respect to the trust in which the assets are held. Our target asset allocation for equity securities is 65% of the value of the plan assets and the holdings are diversified to achieve broad market diversification to reduce exposure to and any adverse impact of a single investment, sector or geographic region. A significant decline in the value of plan asset holdings could require us to increase our funding of the pension plan in future periods, which could adversely affect cash flows in those periods. Additionally, a decline in the fair value of plan assets, absent additional cash contributions to the plan, could increase the amount of pension cost required to be recorded in future periods, which could adversely affect our results of operations in those periods. A 10% decline in the fair value of our plan assets equals $2.2 million.

Interest Rate Risk

We are exposed to risk resulting from changes in interest rates as a result of the use of variable rate debt as a source of financing as well as the fixed income investments in our various portfolios. We manage our interest rate exposure by limiting the total amount of our variable rate exposure to within a particular amount of our total debt and by actively monitoring the effects of market changes in interest rates. As of December 31, 2009, $706.5 million of $848.6 million of outstanding long-term indebtedness secured under the Mortgage Indenture accrued interest at fixed rates to their final maturity. As of December 31, 2009, we had outstanding variable rate debt of $142.1 million. This debt consists of the Refunded Bonds and the Series 1983 Bonds which mature in 2013.

Commodity Price Risk

The average rate to our Members is affected by the price we can obtain in the market for energy produced by our generating facilities in excess of the Members' requirements. Higher prices produce greater Non-Member revenue that is used to offset Member revenue requirements. Our exposure to the risk of fluctuating power prices is declining as our historically high levels of excess generation are being used to meet our increasing Member requirements, including the Smelters. Our excess capacity generation in 2010 is approximately 8%.

Additionally, if one or more of our generating facilities is not able to produce power when required due to operational factors, we may have to forego Non-Member sales opportunities or purchase energy in the wholesale market at higher prices to meet Member requirements.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty failed to perform under its contractual obligations. To reduce credit exposure, we establish credit limits and seek to enter into netting agreements with counterparties that permit it to offset receivables and payables. To control our credit risk associated with credit sales of power we utilize a credit approval process, monitor counterparty limits and require that counterparties have adequate credit ratings. We attempt to further reduce credit risk with certain counterparties by entering into agreements that enable us to obtain collateral or to terminate or reset the terms of transactions after specified time periods or upon the occurrence of credit-related events. Where appropriate, we also obtain cash or letters of credit from counterparties to provide credit support outside of collateral agreements, based on financial analysis of the counterparty and the regulatory or contractual terms and conditions applicable to each transaction.

We generally execute only physical delivery contracts. We frequently use master collateral agreements to mitigate certain credit exposures. The collateral agreements provide for a counterparty to post cash or letters of credit in excess of an established threshold. The threshold amount represents an unsecured credit limit, determined in accordance with our credit policy. Collateral agreements also provide that the inability to post collateral is sufficient cause to terminate contracts and liquidate all positions.

Due to the possibility of extreme volatility in the prices of energy commodities and derivatives, the market value of contractual positions with individual counterparties could exceed established credit limits or collateral provided by those counterparties. If such a counterparty were then to fail to perform its obligations under its contract, we could sustain a loss that could have a material impact on our financial results. The probability of a material impact is lessened by the fact that we only have a relatively small amount of power to sell long-term and presently do not plan on transacting multi-year long-term contracts.

OUR MEMBERS

General

Our Members are local consumer-owned cooperative corporations serving retail residential, commercial and industrial customers on a non-profit basis. The territories served by our Members include portions of 22 counties in western Kentucky. Our Members serve approximately 112,000 consumers. The majority of our Members' customers are individual residences.

Territorial Integrity

Distribution cooperatives generally exercise a monopoly in their service areas. Under a Kentucky statute adopted in 1972, the Members are "Retail Electric Suppliers" that are certified by the KPSC as the exclusive suppliers of energy to their respective certified service areas. Thus, the Members are the exclusive suppliers of energy to electricity consumers located in their respective certified service areas. If a Retail Electric Supplier is providing adequate service within its certified territory, other Retail Electric Suppliers may not sell power to retail customers located within that certified territory. Municipal utilities are not Retail Electric Suppliers under the statute. If a new electric consuming facility locates in two or more adjacent certified territories, the KPSC determines which Retail Electric Supplier may provide retail electric service to that facility based on a number of factors, designed to avoid wasteful duplication of electric generation facilities.

Rate Regulation of Members

The KPSC regulates the retail energy rates of the Members. Under Kentucky law, a utility may revise its rates on 30 days' notice to the KPSC of the proposed changes and the effective date of such changes. The KPSC has the statutory power to suspend such changes pending a hearing for a period not to exceed six months from the proposed effective date of such changes. This suspension period begins with the effective date named by the utility, and thus, the utility may avoid or minimize the effect of such suspension by naming an early effective date in its notice to the KPSC. Rate changes may be placed in effect, in whole or in part, during any such suspension period on a finding by the KPSC that an emergency exists or that the utility's credit or operations will be materially impaired by the suspension. Rates placed into effect on an emergency basis are subject to refund to the extent that the final rates approved by the KPSC are lower than the emergency rates. The KPSC's decision on a new rate schedule filed by a utility must be issued not later than ten months after the filing of the rate schedule.

Member Information

Financial Information

Our Members operate their systems on a not-for-profit basis. Accumulated margins constitute patronage capital for the consumer members. Refunds of accumulated patronage capital to the individual consumer members are made from time to time on a patronage basis subject to limitations contained in Member mortgages to the RUS, if applicable.

Our Members are our owners and not our subsidiaries. Except with respect to the obligations of our Members under their respective wholesale power contracts and the Smelter Agreements, we have no legal interest in, or obligation in respect of, any of the assets, liabilities, equity, revenue or margins of our Members, other than our rights under these contracts. The revenues of our Members are not pledged to us, but their revenues are the source from which they pay for power and energy and transmission services purchased from us. Revenues of our Members are, however, often pledged under their respective mortgages. Tables 1 and 2 in Appendix B present a three-year summary of the balance sheets, statements of operations and selected statistical information with respect to our Members.

Statistical Information

We serve directly and indirectly a diverse customer base that includes farms and residences, commercial and industrial facilities, mining, irrigation and other miscellaneous customers. Farm and residential customers constitute the largest class of customers in terms of numbers throughout the Member service areas. The table below shows energy sales and revenue by customer class for the year 2009 for our Members.

2009 Sales By Members [(1)]

	kWh Sales (in thousands)	kWh Sales (%)	Revenue (in thousands)	Revenue (%)
Farm & Residential	1,433,379	15%	$100,947	24%
Commercial and Industrial (excluding the Smelters)	1,668,503	17%	77,133	18%
Aluminum Smelters	6,672,110	68%	241,379	58%
Mining	--	--	--	--
Other	--	--	--	--
Total	9,773,992	100%	$419,459	100%

(1) The information in this table has been compiled by us from information obtained from the Annual Statistical Report Rural Electric Borrowers (Publication 201.1) and RUS Form 7 prepared by our Members and filed with RUS. We have not independently verified this information.

THE SMELTER AGREEMENTS

We and Kenergy have entered into electric service arrangements with the Smelters. The Smelters have largely identical obligations under the agreements described below, so the following discussion does not distinguish between obligations to a particular Smelter, even though, from a legal perspective, their rights and obligations are separate and not joint.

The principal terms and conditions relating to our sale of electric services to Kenergy for resale to the Smelters are set forth in six agreements, three with respect to service to each Smelter. The basic structure of the sale of electric services is that we sell the electric services to Kenergy and then Kenergy in turns sells those electric services to each Smelter. Because the Smelters are customers of Kenergy, Big Rivers has entered into two, separate wholesale service agreements (each a "Smelter Agreement") with Kenergy. Under each Smelter Agreement, we supply Kenergy with electric service for resale to a particular Smelter. Kenergy has entered into a separate retail electric service agreement (a "Smelter Retail Agreement") with each Smelter. We and each Smelter have also entered into a Smelter Coordination Agreement (a "Smelter Coordination Agreement" and, together with the Smelter Agreements and the Smelter Retail Agreements, the "Smelter Agreements") that sets forth certain direct obligations between us and a Smelter. Due to the pass-through nature of the principal obligations between us and each Smelter, the Smelter Agreement and the Smelter Retail Agreement relating to each Smelter are substantially the same.

The aggregate amount of energy made available to the Smelters under the Smelter Retail Agreements consists of three types of energy referred to as (1) Base Monthly Energy, (2) Supplemental Energy and (3) Back-Up Energy. "Base Monthly Energy" is 368 MW per hour for Alcan and 482 MW per hour for Century. See APPENDIX F – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS – Nature of Service."

The obligation of Kenergy to supply electric service to the Smelters pursuant to the Smelter Retail Agreements will terminate on December 31, 2023, unless terminated earlier pursuant to the terms thereof. A Smelter may terminate its Smelter Retail Agreement upon not less than one year's prior written notice of such termination to Kenergy and us if such Smelter ceases all smelting operations in Kenergy's service territory. See APPENDIX F – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS – Termination Rights."

Pricing under the Smelter Agreements is designed so that the Base Rate for the Smelters will always be 25 cents per MWh over the rate charged to large direct-served industrial customers having an equivalent load factor. The contracts provide that the Smelters are obligated to pay various surcharges, including fuel adjustment surcharges and environmental surcharges. In addition, the Smelter Agreements provide for annual adjustments to rates designed to assist us in achieving positive margins in each year. See APPENDIX F – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS – Smelter Payment Obligations."

For a more detailed summary of the provisions of the Smelter Agreements, see APPENDIX F – "SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS."

POWER SUPPLY PLANNING

Every other year we prepare load forecasts for the three Members. These individual forecasts serve as the basis for Big Rivers' load forecast, which is filed with the RUS. The last forecast was prepared and filed in 2009. Additionally, every three years an Integrated Resource Plan ("IRP") is prepared in accordance with Kentucky Administrative Rule 807 KAR 5:5058 and filed with the KPSC.

The next IRP will be filed with the KPSC in November 2010. Both of these studies examine a future time frame of 15 years.

GENERATION AND TRANSMISSION ASSETS

Generation Resources

General

The following table sets forth certain information about our owned generating facilities and Station Two.

Generating Facility	Type of Fuel	Net Capacity[2] (MW)	Big Rivers' Entitlement Share (MW)	Commercial Operation Date
Kenneth C. Coleman Plant				
Unit 1	Coal	150	150	1969
Unit 2	Coal	138	138	1970
Unit 3	Coal	155	155	1972
Robert D. Green Plant				
Unit 1	Coal	231	231	1979
Unit 2	Coal	223	223	1981
Robert A. Reid Plant				
Unit 1	Coal	65	65	1966
Combustion Turbine	Oil-Natural Gas	65	65	1976
D.B. Wilson Plant Unit No. 1	Coal	417	417	1986
Station Two Facility Units No. 1 and No. 2[1]	Coal	312	212	1973/1974
Total		1,756	1,656	

(1) We operate but do not own the two units at Station Two and not all net capacity of such facility is available to us.
(2) Net capacity means net nameplate as adjusted for parasitic load.

Kenneth C. Coleman Plant

The Coleman Plant is a three unit, coal-fired steam electric generating unit located near Hawesville, Kentucky. Each of the units has a turbine nameplate rating of 160 MW. Units No. 1 has a net capacity of 150 MW, No. 2 has a net nameplate capacity of 138 MW while Unit No. 3 has a net capacity of 155 MW. All three boilers are positive pressure, outdoor units; the turbine generators are semi-outdoor and the station was retrofitted with a FGD system in 2007. The equivalent availability factor for the Coleman Plant for 2009 was 94.9% (post-Unwind).

Environmental controls in place at the Coleman Plant include the use of precipitators (air pollution control devices that collect particles from gaseous emissions) which limit particulate emissions to a maximum of 0.27 pounds per million Btu, and the use of a FGD system which is 97% effective in reducing SO_2 emissions. Coleman Stations permitted SO_2 emissions limit is a maximum of 5.2 pounds per million Btu. NO_X emissions are limited to a maximum of 0.5 pounds per million Btu. This is achievable with the low NO_X burners.

Robert D. Green Plant

The Green Plant is a two unit, coal-fired steam electric generating station located on the same site as the Reid Plant and the Station Two Facility described below. Both boilers at the Green Plant are balanced draft units and they were designed and built with low NO_X burners. The Green Plant is also equipped with a FGD system. Unit No. 1 has a net nameplate capacity of 231 MW while Unit No. 2 has a net capacity of 223 MW. The equivalent availability factor for the Green Plant for 2009 was 94.8% (post-Unwind).

Environmental controls in place at the Green Plant include the use of precipitators which limit particulate emissions to a maximum of 0.1 pounds per million Btu, and the use of a FGD system which limits SO_2 emissions to a maximum of 0.8 pounds per million Btu. NO_X emissions are limited to a maximum of 0.5 pounds per million Btu.

Robert A. Reid Plant

The Robert A. Reid Plant, located near Sebree, Kentucky, is a coal-fired steam electric generating unit with a net capacity of 65 MW and an oil- or natural gas-fired combustion turbine generating unit with a net capacity of 65 MW (the "Reid Plant"). The combustion turbine is used for power emergencies and for peaking purposes. The equivalent availability factor for the Reid Plant for 2009 was 84.7% (post-Unwind).

Environmental controls in place at the Reid Plant include the use of precipitators which limit particulate emissions to a maximum of 0.28 pounds per million Btu, and the use of medium-sulfur coal which limit SO_2 emissions to a maximum of 5.2 pounds per million Btu. NO_X emissions are limited to 0.46 pounds per million Btu.

D.B. Wilson Unit No. 1 Plant

The single unit Wilson Plant is the largest generating unit in our system. The Wilson Plant, located near Centertown, Kentucky on the Green River, is a coal-fired, balanced draft steam electric generating unit equipped with a FGD system. The unit has a net nameplate capacity of 417 MW. The equivalent availability factor for the Wilson Plant for 2009 was 60.7% (post-Unwind). The scheduled fall outage of approximately 60 days lowered the equivalent availability factor for 2009.

Environmental controls in place at the Wilson Plant include the use of a precipitator which limits particulate emissions to a maximum of 0.03 pounds per million Btu, and the use of a FGD system which is 90% effective in removing SO_2 emissions. NO_X emissions are limited to a maximum of 0.6 pounds per million Btu.

Other Power Supply Resources

Station Two Facility

The two units at Station Two have a total net nameplate capacity of 312 MW. Station Two is located on the same site as the Reid Plant and the Green Plant, near Henderson. Station Two consists of two positive pressure outdoor type boilers with scrubbers installed. The equivalent availability factor for Station Two for 2009 was 94.0% (post-Unwind).

In connection with the Unwind, in July 2009, we became responsible for the operation of Station Two in accordance with the terms of the Station Two Operation Agreement and for purchase of capacity and energy in accordance with the terms of the Station Two Power Sales Contract. (See "Station Two Power Sales Contract"). In connection with the Unwind, we and WKEC entered into an Indemnification Agreement (the "Station Two Indemnification Agreement") under which WKEC has agreed to indemnify us against potential lost revenue if the contract provisions of the Station Two Power Sales Contract are interpreted against us (See "Station Two Power Sales Contract").

Station Two Operation Agreement

We operate Station Two in accordance with the Station Two Operation Agreement. The Station Two Operation Agreement provides that we will provide, as an independent contractor, all operating personnel, materials, supplies and technical services for the operation of Station Two. It also provides for the allocation of certain costs of operation and maintenance between Station Two and our Reid Plant which shares some common facilities with Station Two. The Station Two Operation Agreement provides that we prepare an operating budget, including both capital and operating expenditures, for Station Two which is subject to the approval of the City of Henderson. Such budget then becomes the basis for monthly payments by the City of Henderson to us, with an annual reconciliation of such budgeted expenditures and the actual annual expenditures for Station Two. The Station Two Operation Agreement obligates us to maintain property and liability insurance with respect to Station Two and to operate and maintain Station Two in accordance with standards and specifications equal to those provided by the National Electric Safety Code of the United States Bureau of Standards and well as those required by any regulatory authority having jurisdiction. Each party's obligations under the Station Two Operation Agreement are subject to the occurrence of "uncontrollable force" (*e.g.*, events not within control of either party and which by exercise of due diligence and foresight could not reasonably be avoided). The obligations of the City of Henderson under the Station Two Operation Agreement are payable solely from the revenues of the City's electric utility system and do not constitute a general obligation of the City of Henderson. The City of Henderson has covenanted in the Station Two Operation Agreement that it will, subject to any necessary regulatory body approvals, maintain rates for service by its electric system sufficient to pay the costs of ownership, proper operation and maintenance of Station Two. The rates for electric service charged by the City of Henderson are not subject to any regulatory body approval. The term of the Station Two Operation Agreement extends for the operating life of Station Two.

Station Two Power Sales Contract

We purchase a portion of the power and energy produced by Station Two in accordance with a Power Sales Contract between the City of Henderson and us (the "Station Two Power Sales Contract"). The Station Two Power Sales Contract provides for the allocation of the capacity of Station Two between the City of Henderson and us based upon the City's determination of its needs to serve its retail customers. The Station Two Power Sales Contract requires the City of Henderson to give us a rolling five years' advance notice of the allocation of capacity between the City of Henderson and us, but changes of up to 5 MW in the City's allocation are permitted on a yearly basis to serve new commercial or industrial customers of the City. The Station Two Power Sales Contract limits the ability of the City of Henderson to add commercial or industrial customers in excess of 30 MW each to its system if to do so would require the withdrawal of existing capacity from Station Two or any other generating facilities on the City's existing electrical system. The Station Two Power Sales Contract also permits the City of Henderson to utilize up to a total of 25 MW of capacity from capacity otherwise allocated to us from Station Two for "economic development loads" consisting of new customers on the City's system or certain expansions of capacity by an existing customer. Our right to take our reserved portion of the capacity of Station Two is subject to the City of Henderson's prior right to take its allocated capacity. Thus, in the event of an outage or curtailment of the output of Station Two, the City's right to the output has a priority. Each party is entitled to all the energy from Station Two associated with its reserved capacity, subject to our right to "Excess Henderson Energy" described below. The current capacity allocations of the City of Henderson and us are 32% and 68%, respectively.

We and the City of Henderson share capacity costs for Station Two in accordance with our respective allocated capacities. These capacity costs include the costs of operation, maintenance, administration and general expenses for Station Two as well as any amounts paid or payable to us under the terms of the Station Two Operation Agreement. We and the City of Henderson are each responsible for providing our respective portions of the fuel consumed by Station Two based on our respective uses of electric energy from Station Two.

The obligations of each party are subject to "uncontrollable force", having the same definition as in the Station Two Operation Agreement. However, our obligation to make payments for our allocated capacity of Station Two is not excused for any reason including the occurrence of "uncontrollable force".

The Station Two Power Sales Agreement permits the City of Henderson to terminate that Agreement on 30 days' notice for our failure to make any payment properly owing under the Station Two Power Sales Contract and, in such event, to make sales to others of power generated by Station Two and allocated to us on 5 days' notice to us and to apply the proceeds of such sales to the capacity charges we owe.

In accordance with the Station Two Power Sales Contract, we and the City of Henderson have established separate operation and maintenance funds in the amounts of $400,000 and $100,000, respectively, to fund expenditures for operation and maintenance for Station Two, such expenditures to be made from such funds in proportion to the then effective allocation of Station Two capacity between us and the City of Henderson. In accordance with the Station Two Power Sales Contract, we have agreed to fund up to $1.05 million to fund our portion of major renewals or replacements to the Station Two required on an emergency basis.

The term of the Station Two Power Sales Contract extends through the end of the economic operating life of Station Two.

Excess Henderson Energy

The Station Two Power Sales Contract also provides that, to the extent the City of Henderson does not take the full amount of energy associated with its reserved capacity from Station Two (such excess, "Excess Henderson Energy"), we may take and utilize all such energy for a price of $1.50 per MWh plus the cost of all fuel, reagent and sludge disposal costs associated with such Excess Henderson Energy. Furthermore, the Station Two Power Sales Contract precludes the City of Henderson from offering Excess Henderson Energy to a third party without first offering us the opportunity to purchase in accordance with the preceding sentence. Representatives of the City of Henderson have alleged that the Station Two Power Sales Contract permits the City to schedule and take energy from its allocated capacity of Station Two for sales by it to third parties without offering such energy to us. (See "LITIGATION – Litigation with HMP&L under Station Two Power Sales Contract").

SEPA Contract

In addition to our generation resources, we fulfill our power supply responsibilities to our Members with their allocations from SEPA. We normally use entitlement under the SEPA Contract for peaking. However, as a result of problems with certain dams on the Cumberland River hydro system, our capacity entitlement has been suspended and we currently are receiving only energy. Generally, we must schedule and accept 1,500 hours of the contracted 178 MW each fiscal year ending June 30. The maximum amount scheduled in any month shall not exceed 240 hours and the minimum amount scheduled in any month shall not be less than 60 hours. The fee arrangement for generation is a take-or-pay contract, currently we pay a fixed monthly charge in the amount of approximately $280,937 and $12.67 per MWh for energy. These charges will continue until the dam work is completed and the SEPA Contract is restored to full service. The SEPA contract cannot be terminated prior to June 30, 2017, albeit subject to congressional authority.

Transmission

We operate and maintain our transmission facilities and provide transmission services to our Members and Non-Members pursuant to our OATT. As of December 31, 2009, we had in service 827 miles of 69 kilovolt ("kV") transmission lines, 14 miles of 138 kV transmission lines, 353 miles of 161 kV transmission lines, 68 miles of 345 kV transmission lines, and related station land and equipment. We also own 22 substations. We have completed three of the seven system improvements identified as phase two transmission projects. We have construction work orders in progress for two of the remaining four projects and will begin pursuit of the final two projects very soon. All phase two transmission projects are scheduled for completion on or before the end of the third quarter of 2011. Our available transfer capability for exporting power off system is approximately 912 MW prior to the completion of any phase two transmission improvements. The current firm transmission capability is sufficient to allow us to export all available excess generation capacity plus an amount equal to the peak demand of the larger Smelter on our system. With the completion of the phase two projects in 2011, our export capability will be increased to approximately 1380 MW, which will provide the capability to export all of the peak demand for both Smelters.

Contingency Reserve Obligation

We are currently in the process of joining and preparing to integrate our transmission system with Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"), which operates the centralized energy and ancillary services markets in the Midwestern region and administers open access transmission service over the transmission facilities owned by Midwest ISO members. We seek to join Midwest ISO principally to enable us to satisfy the "Contingency Reserve" standard of the NERC reliability standard. That standard is set by NERC, approved by FERC and enforced by the SERC Reliability Corporation, one of NERC's regional entities with responsibility for enforcing the mandatory reliability standards. Our compliance with the NERC Contingency Reserve standard is both an operational necessity and a legal requirement. Under federal law, violations of NERC's Contingency Reserve standard may result in substantial penalties, including potential fines up to $1 million per day per violation. We anticipate that our integration with Midwest ISO will be complete by September 2010. We do not expect any material adverse effect on revenues from that integration.

We previously satisfied the NERC Contingency Reserve standard through membership in certain reserve sharing arrangements, most recently with the Midwest Contingency Reserve Sharing Group ("MCRSG"). The MCRSG arrangements expired December 31, 2009. Upon awareness that the MCRSG would terminate, we began to investigate ways to preserve the MCRSG or find alternate means to satisfy the NERC Contingency Reserve standard. At that time we were not operating our generating assets, but were negotiating and implementing a transaction to terminate or "unwind" a series of agreements entered into in 1998 with subsidiaries or affiliates of E.ON and thereby, regain control of our generating units. The Unwind was approved by the KPSC on March 6, 2009. See "BIG RIVERS ELECTRIC CORPORATION – Bankruptcy and Subsequent Operation," "—Unwind of LG&E Arrangements and Termination of Leveraged Lease Transactions" and "—Summary of Major Provisions of Unwind."

Following the closing of the Unwind, the options available to us to satisfy the NERC Contingency Reserve standard upon the termination of the MCRSG at year end narrowed as a result of legal impediments, cost constraints and a lack of sufficient implementation time. Without alternative feasible options available, on November 20, 2009, our Board of Directors approved joining the Midwest ISO to insure that we would be in compliance with the NERC Contingency Reserve standard on January 1, 2010. Pending full participation in the Midwest ISO, we will satisfy the NERC Contingency Reserve standard under Attachment RR of the Midwest ISO's FERC-approved Open Access Transmission, Energy and Operating Reserve Markets Tariff ("MISO Tariff").

SERC Investigation

We are currently the subject of a preliminary inquiry and non-public investigation initiated by SERC in February 2009. The staff from NERC and FERC are also participating in the investigation. Aside from one minor instance, which has been disclosed to SERC, we believe that we have been, and are, in compliance with all reliability standards and requirements. However, penalties for violations of reliability standards can be substantial. At this time the investigation is still in its preliminary stages and we cannot estimate the amount or range of potential liability, if any.

Approvals for Midwest ISO Membership

On February 1, 2010, we filed an application with the KPSC for authority to transfer functional control of our transmission system to Midwest ISO to be effective September 1, 2010. For this transfer to occur on schedule, all required consents and approvals must be obtained before August 1, 2010. In addition to the authority required from the KPSC to join Midwest ISO, we must also obtain the consent of two of our creditors: the United States of America acting through RUS and CoBank.

Our first full year of participation in Midwest ISO will be 2011. When the KPSC approves our joining Midwest ISO, that approval will allow all prudently incurred expenses to be recovered in rates. We may seek approval of new rates from the KPSC a few months earlier than previously planned once we receive KPSC's approval to join Midwest ISO.

Interconnections

We have several interconnections between our transmission system and those of other power suppliers. These interconnections permit mutual support in emergencies, decrease overall transmission losses, facilitate the arrangement of electric power and energy sales and minimize the duplication of transmission lines. We currently have interconnection agreements with seven power suppliers: HMP&L, Midwest ISO, Southern Illinois Power Cooperative, Hoosier Energy Rural Electric Cooperative, and Southern Indiana Gas and Electric Company – Vectren, E.ON U.S., Kentucky Utilities Company and Louisville Gas and Electric Company ("LG&E"), and TVA. However, we cannot purchase power from TVA due to restrictions on TVA's authority to sell power outside of its service area fixed by statute. An agreement with TVA provides transmission service by TVA to enable us to interchange power and energy with four utilities located in the southern United States.

In addition to interconnections with neighboring transmission systems, we also have received several requests from independent power producers that may determine to locate within our balancing area and interconnect new generators to the transmission system. We have developed certain interconnection procedures and guidelines which we use when generators request interconnection service without a concurrent request for transmission service. Upon our joining Midwest ISO, independent power producers may apply through Midwest ISO to connect to our transmission facilities. Upon receiving an application, Midwest ISO will work with us to study the impacts of such interconnection and to identify the cost of accommodating the interconnection. The allocation of costs will be determined under the MISO Tariff. Interconnections will be effectuated through a standard-form, three-way interconnection agreement among us, Midwest ISO and the independent power producer seeking use of our transmission service.

Open Access Transmission Tariff

We voluntarily agreed to comply with FERC Order No. 888 by filing the OATT with FERC. The OATT also has been filed with the KPSC, and the KPSC has determined to assert jurisdiction over it to the extent FERC does not exert such jurisdiction. FERC Order No. 888 requires utilities regulated by FERC to offer third parties access to, and terms for the use of, their transmission systems on a basis comparable to the access and terms under which such transmission system owners provide transmission service to themselves. FERC Order No. 888 permits such utilities to deny transmission service to a utility which does not have a comparable open access transmission tariff. Although we are not subject to FERC Order No. 888, Big Rivers may require reciprocal access to other utilities' transmission systems in the future in order to meet future obligations to the Members or sell power off-system. To ensure such access, we prepared our OATT consistent with the form of OATT required of FERC-regulated utilities. See "RATE AND ENVIRONMENTAL REGULATIONS – Order No. 888 and Successor Orders" for a discussion of the background of, and proceedings relating to, FERC Order No. 888. We filed the OATT with FERC on May 29, 1998 and subsequently received a letter order from FERC dated September 18, 1998 finding that our OATT met the requirements for reciprocity. On April 22, 2009, we proposed updates to our OATT. FERC issued an order on September 17, 2009, directing certain changes to that proposal. We filed a revised updated OATT on December 16, 2009, and on January 6, 2010, FERC published notice of our proposed updated open access transmission tariff inviting public comments. No comments were filed during the comment period. FERC has not yet acted on the December 16 filing, and FERC is not subject to any deadline for acting on the filing.

Pursuant to the OATT, we will provide firm and non-firm transmission service and network services on our transmission system to parties desiring to purchase available transmission capacity on our transmission system. We will maintain the OASIS on which we post transmission capacity available between certain points of delivery and certain points of receipt on our system. Parties taking service under the OATT reserve transmission capacity on the OASIS on either a firm or non-firm basis for varying periods of time, with requests for longer periods of time taking precedence over those for shorter periods, and with firm service taking precedence over non-firm service. In operating the OASIS, we are subject to certain standards of conduct that prevent our employees in the transmission function from communicating with employees engaging in wholesale sales functions. As part of our OATT, we have implemented certain guidelines for interconnection by generators that seek to interconnect to our transmission system without a concurrent request for transmission services. These generator interconnection procedures are posted on our OASIS.

Upon the effective date of our joining the Midwest ISO, use of our transmission facilities will be governed by the MISO Tariff. We will provide the Midwest ISO with our revenue requirement for use in establishing the rate for transmission services under the MISO Tariff, but our revenue requirement will not be directly reviewed by FERC. As a Midwest ISO transmission owner, we also will participate in the Midwest ISO transmission planning process, and will be responsible for investments in transmission projects assigned to us in accordance with that process. It is impossible to predict what impact our participation in Midwest ISO will have on our operations. At present, we plan for our own transmission needs and participate in regional transmission planning with TVA. Participation in the Midwest ISO planning process will increase the scope of our regional planning process and will subject us to decisions by the Midwest ISO and, ultimately, FERC, concerning allocations of costs for meeting regional transmission needs. Finally, we will be subject to the Midwest ISO reserve requirements established pursuant to Module E of the MISO Tariff.

MANAGEMENT

We are governed by a Board of Directors comprised of six persons. Each Member has two directors on the Board of Directors. Each director is elected by a majority vote of the delegates at the annual membership meeting in September. Each Member designates one delegate to represent it at the annual membership meeting. At least one of the two directors from each Member must be, at the time of their election, a director of such Member. Each term is for a three year period, ending the later of

September 1 or the annual meeting date, and staggered such that two directors from different Members are elected each year.

The following are our principal management personnel with a brief summary of their qualifications:

Mark A. Bailey, President and Chief Executive Officer, received a Bachelor of Science in Electrical Engineering from Ohio Northern University in 1974, and a Master of Science in Management from the Massachusetts Institute of Technology in 1988. He was employed by American Electric Power Company ("AEP") for nearly 30 years, beginning as an Electrical Engineer in 1974. Mr. Bailey was employed as Vice President of AEP subsidiary Indiana Michigan Power Company until AEP's reorganization in 1996, when he became Director-Regions with American Electric Power Service Corporation ("AEPSC"), also a subsidiary of AEP. He was employed as Vice President of Transmission Asset Management for AEPSC from June 2000 until his employment as President and Chief Executive Officer ("CEO") with Kenergy Corp. in 2004. Mr. Bailey was employed as Executive Vice President and Chief Operating Officer beginning in June 2007 until being elected by the Board of Directors to his current position in October 2008.

C. William Blackburn, Senior Vice President Financial & Energy Services and Chief Financial Officer, graduated from Murray State University with a Bachelor of Science in Business and Mathematics in 1972. Mr. Blackburn is a Certified Management Accountant. He has been employed with Big Rivers since 1977. He served in various accounting, finance, and power supply positions including Vice President of Financial Services and Interim Vice President of Power Supply from 1997 through November 2005, prior to assuming his current position in February 2009.

Robert W. Berry, Vice President of Production, graduated from the University of Kentucky Community College system with an Associate degree in Mechanical Engineering Technology and Mid-Continent University with a Bachelor of Science in Business Management. He was employed by Big Rivers from 1981 to 1998 and served in various maintenance positions such as Superintendent of Maintenance and Maintenance Manager. In 1998 he was employed by Western Kentucky Energy and served in various positions such as Maintenance Manager, Plant Manager and General Manager until the Unwind transaction closed in July 2009, at which time he assumed his current position.

David G. Crockett, Vice President of System Operations, graduated from the University of Kentucky with a Bachelor of Science in Electrical Engineering in 1972. He has been employed with Big Rivers since 1972. He served in various engineering positions before assuming the responsibility of Manager of Energy Control in 1998. Mr. Crockett assumed his current position as Vice President System Operations in 2006.

James V. Haner, Vice President of Administrative Services, graduated from the University of Kentucky with a Bachelor of Science in Accounting in 1970. He has been employed with Big Rivers since 1972. He served in various accounting and finance capacities prior to transferring to administrative services in 1991. He assumed duties as Manager Human Resources in 1998. Mr. Haner assumed his current position of Vice President Administrative Services in 2005.

Mark A. Hite, Vice President of Accounting, graduated from the University of Evansville with a Bachelor of Science in Accounting in 1980 and a Master of Business Administration in 1985. He is a licensed CPA. Mr. Hite has been employed with Big Rivers since 1983, and has served in various accounting and finance capacities prior to assuming his current position of Vice President of Accounting.

Albert M. Yockey, Vice President of Governmental Relations & Enterprise Risk Management, graduated from the University of Pittsburgh with a Bachelor of Science in Electrical Engineering in 1972, a Master of Science from Lehigh University in 1979, and a Juris Doctor from Capital University Law School in 1994. He is a registered Professional Engineer in Pennsylvania and a licensed attorney in Ohio. Mr. Yockey was employed in operation and planning positions with Pennsylvania Power and Light Co. from 1972 through 1985. He was employed in planning, regulatory, and compliance positions with American Electric Power Company from 1985 until February 2008. Mr. Yockey joined Big Rivers as Vice President of Enterprise Risk Management and Strategic Planning in 2008 and assumed his current position in July 2009.

The following are the Directors of Big Rivers with a brief summary of their qualifications:

William C. Denton, Chair of the Board, graduated from the University of Evansville with a Bachelor of Liberal Studies. He is the President of the Mortgage Network of America. Mr. Denton represents Kenergy and has served on our board since April 1995. His term expires September 2010 and he is subject to re-election.

James Sills, M.D., Vice Chair of the Board, graduated from Western Kentucky State University with a Bachelor of Chemistry and Biology and the University of Louisville Medical School. He is a retired family physician. Dr. Sills represents Meade County RECC and has served on our board since March 1995. His term expires September 2011 and he is subject to re-election.

Paul Edd Butler, Director, graduated from Breckinridge County High School and then attended Western Kentucky University and Spencerian College. For 31 years, Mr. Butler was a postmaster for the United States Postal Service, Harned, Kentucky. He is now retired. Mr. Butler represents Meade County RECC and has served on our board since July 2002. His term expires September 2012 and he is subject to re-election.

Lee Bearden, Secretary Treasurer, graduated from Lone Oak High School and attended West Kentucky Community College. He is the Vice President of Community Financial Services Bank. Mr. Bearden represents Jackson Purchase and has served on our board since September 1998. His term expires September 2012 and he is subject to re-election.

Larry Elder, Director, graduated from Owensboro Catholic High School, attended two years of college at Brescia College and four years of apprenticeship training at Owensboro Technical School. He is the former President of Dynalectric of Kentucky and is now retired. Mr. Elder represents Kenergy and has served on our board since June 2006. His term expires September 2010 and he is subject to re-election.

Wayne Elliott, Director, graduated from Lone Oak High School and is currently taking college classes. He is a farmer. Mr. Elliott represents Jackson Purchase and has served on our board since September 2007. His term expires September 2010 and he is subject to re-election.

We have 598 full-time employees. The International Brotherhood of Electrical Workers, Local 1701, represents 348 of Big Rivers' generation and transmission operating employees. Our contracts with this union expire on September 14, 2012, and October 14, 2012, respectively. We believe that our relations with labor are good.

LITIGATION

Litigation Involving the County

No litigation is pending or, to our knowledge or to the knowledge of the County (with respect to litigation pertaining to it and the Bonds to be issued by it), threatened in any court, questioning our official existence, the official existence of the County, or the validity of the Bonds, or to restrain or enjoin the issuance or delivery of any of the Bonds or the power of the County to pledge revenues and assets to pay the Bonds.

Litigation with HMP&L under Station Two Power Sales Contract

The Station Two Power Sales Contract also provides that, to the extent the City of Henderson does not take the full amount of energy associated with its reserved capacity from Station Two for the residents of the City of Henderson (such excess, "Excess Henderson Energy"), we may take and utilize all such energy for a price of $1.50 per MWh plus the cost of all fuel, reagent and sludge disposal costs associated with such Excess Henderson Energy. Furthermore, the Station Two Power Sales Contract precludes the City of Henderson from offering Excess Henderson Energy to a third party without first offering us the opportunity to purchase in accordance with the preceding sentence. Representatives of the City of Henderson have alleged that the Station Two Power Sales Contract permits the City to schedule and take energy from its allocated capacity of Station Two for sales by it to third parties without offering such energy to us at the $1.50 MWh price. We disagree with this assertion. Pursuant to an indemnification agreement executed in connection with the Unwind (the "Station Two Indemnity Agreement"), WKEC has agreed to indemnify us, with certain limits, against economic harm to us through 2023 resulting from the City of Henderson's interpretation of the Station Two Power Sales Contract being sustained by a court or other appropriate administrative or judicial tribunal. The obligations of WKEC under the Station Two Indemnification Agreement have been guaranteed by E.ON U.S. LLC. On July 31, 2009, we filed a petition in the Henderson Circuit Court of the Commonwealth of Kentucky, Civil Action No. 09-CI-00693, requesting an order pursuant to the Federal Arbitration Act, 9 U.S.C. § 2 and 4 and Kentucky Revised States 417.060(1) referring the dispute over the Excess Henderson Energy to arbitration. In an Order entered December 17, 2009, the Henderson Circuit Court ruled that the question of our entitlement to Excess Henderson Energy was one for which we are entitled to compel arbitration in accordance with the Station Two Power Sales Contract. By order dated February 10, 2010, the Court denied the City of Henderson's motion to alter, amend or vacate the Court's December 18, 2009 order. The City appealed that order and on February 12, 2010, the Court entered another order finding that the Court had jurisdiction to enforce the arbitration process and that the arbitration should proceed despite the City's appeal.

DESCRIPTION OF THE BONDS

General

The Bonds will be issued in the aggregate principal amount set forth on the front cover of this Offering Statement, will be dated their date of delivery and will mature on July 15, 2031. We will pay interest on the Bonds at the annual rate of 6.00 percent (computed on the basis of a 360-day year of twelve 30-day months), from the date of delivery or from the most recent date to which interest has been paid or provided for, payable in arrears on January 15 and July 15 of each year, commencing January 15, 2011 (each such date is referred to herein as an "Interest Payment Date"). On each Interest Payment Date, interest will be paid to the person in whose name the Bonds are registered at the close of business on the fifteenth (15th) day prior to the applicable Interest Payment Date. If any Interest Payment Date falls on a day which is a legal holiday or a day on which banking institutions in the city in which is located the principal office of the Trustee is authorized by law to remain closed, interest will be paid on the next succeeding day which is not a legal holiday or a day on which such banking institutions are authorized to be closed, with interest accruing only to the originally scheduled Interest Payment Date.

The Bonds will be issued in the form of fully registered Bonds without coupons in minimum denominations of $5,000 and integral multiples thereof. The Bonds will be registered in the name of Cede & Co., as nominee of The Depository Trust Company ("DTC"), pursuant to DTC's Book-Entry Only System. Principal of and interest on the Bonds will be payable, and the transfer of interests in the Bonds will be effected, through the facilities of DTC, as described under "BOOK-ENTRY-ONLY SYSTEM PROCEDURES" below. The Bonds may be transferred only upon the records of the Trustee, as Registrar, kept for that purpose at the principal corporate trust office of the Trustee. The Registrar will not be required to make any exchange or transfer of Bonds during the fifteen days (i) immediately preceding an Interest Payment Date or, (ii) in the case of any proposed redemption of Bonds, immediately preceding the date of the mailing of notice of such redemption. The Registrar will also not be required to make any transfer or exchange of any Bonds called for redemption.

U.S. Bank National Association is the Trustee, Paying Agent and Registrar for the Bonds.

Redemption of Bonds

Optional Redemption

The Bonds are subject to redemption in whole or in part (and if less than all of the Bonds are to be redeemed, by lot in such manner as shall be determined by the Trustee) prior to maturity at any time on or after July 15, 2020 by the County, upon the exercise by us of our option to prepay all or a part of the unpaid balance of the Note, at a redemption price of 100 percent of the principal amount thereof, together with interest accrued thereon to the date fixed for redemption.

Notice of Redemption

Notice of redemption will be given by first-class mail by the Trustee at least thirty (30) days prior to the redemption date to each Holder of such Bonds which are to be redeemed, in whole or in part, at the addresses shown on the registration books of the County maintained by the Trustee, as Registrar. Failure to give notice of redemption by mail, or any defect in such notice, will not affect the validity of the proceedings for the redemption of such Bonds.

If at the time of mailing of notice of an optional redemption we have not deposited with the Trustee moneys sufficient to redeem all of the Bonds called for redemption, then the notice of optional redemption given by the Trustee will so state and will further state that the redemption of such Bonds is conditional upon our providing, or causing to be provided, to the Trustee, by 12:00 noon, New York City time on the redemption date, funds sufficient to effect such redemption, and such Bonds will not be redeemed unless such funds are deposited.

For so long as a book-entry only system is in effect with respect to the Bonds, the Trustee will mail notices of redemption only to The Depository Trust Company, New York, New York ("DTC") or its successor. Any failure of DTC to convey such notice to any DTC participants, any failure of DTC participants to convey such notice to any Indirect Participants or any failure of DTC participants or Indirect Participants to convey such notice to any Beneficial Owner will not affect the validity of the redemption of Bonds. See "BOOK-ENTRY-ONLY SYSTEM PROCEDURES."

BOOK-ENTRY-ONLY SYSTEM PROCEDURES

The Bonds will be available only in book entry form. DTC will act as the initial securities depository for the Bonds. The Bonds will be issued as fully-registered securities registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered bond certificate will be issued for the Bonds, in the aggregate principal amount thereof, and will be deposited with DTC.

DTC, the world's largest depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934. DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments from over 110 countries that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). DTC has Standard & Poor's highest rating of "AAA." The DTC Rules applicable to its Participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com and www.dtc.org.

Purchases of the Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Bonds on DTC's records. The ownership interest of each actual purchaser of the Bonds (a "Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in the Bonds, except in the event that use of the book entry system for the Bonds is discontinued.

To facilitate subsequent transfers, all the Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of the Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. BENEFICIAL OWNERS SHOULD MAKE APPROPRIATE ARRANGEMENTS WITH THEIR BROKER OR DEALER TO RECEIVE NOTICES (INCLUDING NOTICES OF REDEMPTION) AND OTHER INFORMATION REGARDING THE BONDS THAT MAY BE SO CONVEYED TO DIRECT PARTICIPANTS AND INDIRECT PARTICIPANTS.

Redemption notices shall be sent to DTC. If less than all of the Bonds are being redeemed, DTC's practice is to determine by lot amount of the interest of each Direct Participant in the Bonds to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the Bonds unless authorized by a Direct Participant in accordance with DTC's Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the issuer as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts the Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Except as described below, neither DTC nor Cede & Co. will take any action to enforce covenants with respect to any security registered in the name of Cede & Co. Under its current procedures, on the written instructions of a Direct Participant, DTC will cause Cede & Co. to sign a demand to exercise bondholder rights as record holder of the quantity of securities specified in the Direct Participant's instructions, and not as record holder of all the securities of that issue registered in the name of Cede & Co. Also, in accordance with DTC's current procedures, all factual representations to be made by Cede & Co. to the County, the Trustee or any other party must be made to DTC and Cede & Co. by the Direct Participant in its instructions to DTC.

For so long as the Bonds are issued in book-entry form through the facilities of DTC, any Beneficial Owner desiring to cause us or the Trustee to comply with any of its obligations with respect to the Bonds must make arrangements with the Direct Participant or Indirect Participant through whom such Beneficial Owner's ownership interest in the Bonds is recorded in order for the Direct Participant in whose DTC account such ownership interest is recorded to make the instructions to DTC described above.

NEITHER WE NOR THE TRUSTEE NOR THE UNDERWRITER (OTHER THAN IN ITS CAPACITY, IF ANY, AS A DIRECT PARTICIPANT OR AN INDIRECT PARTICIPANT) WILL HAVE ANY OBLIGATION TO THE DIRECT PARTICIPANTS OR THE INDIRECT PARTICIPANTS OR THE PERSONS FOR WHOM THEY ACT AS NOMINEES WITH RESPECT TO DTC'S PROCEDURES OR ANY PROCEDURES OR ARRANGEMENTS BETWEEN DIRECT PARTICIPANTS, INDIRECT PARTICIPANTS AND THE PERSONS FOR WHOM THEY ACT RELATING TO THE MAKING OF ANY DEMAND BY CEDE & CO. AS THE REGISTERED OWNER OF THE BONDS, THE ADHERENCE TO SUCH PROCEDURES OR ARRANGEMENTS OR THE EFFECTIVENESS OF ANY ACTION TAKEN PURSUANT TO SUCH PROCEDURES OR ARRANGEMENTS.

Principal and interest payments and redemption proceeds on the Bonds will be made to Cede & Co., or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts, upon DTC's receipt of funds and corresponding detail information from us or the Trustee, on payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC, the Trustee or us, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal, interest and redemption proceeds to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of us or the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

NEITHER US NOR THE TRUSTEE WILL HAVE ANY RESPONSIBILITY OR OBLIGATION TO PARTICIPANTS, BENEFICIAL OWNERS OR OTHER NOMINEES OF SUCH BENEFICIAL OWNERS FOR (1) SENDING TRANSACTION STATEMENTS; (2) MAINTAINING, SUPERVISING OR REVIEWING, OR THE ACCURACY OF, ANY RECORDS MAINTAINED BY DTC OR ANY PARTICIPANT OR OTHER NOMINEES OF SUCH BENEFICIAL OWNERS; (3) PAYMENT OR THE TIMELINESS OF PAYMENT BY DTC TO ANY PARTICIPANT, OR BY ANY PARTICIPANT OR OTHER NOMINEES OF BENEFICIAL OWNERS TO ANY BENEFICIAL OWNER, OF ANY AMOUNT DUE IN RESPECT OF THE PRINCIPAL OF OR REDEMPTION PREMIUM, IF ANY, INTEREST OR PURCHASE PRICE ON THE BONDS; (4) DELIVERY OR TIMELY DELIVERY BY DTC TO ANY PARTICIPANT, OR BY ANY PARTICIPANT OR OTHER NOMINEES OF BENEFICIAL OWNERS TO ANY BENEFICIAL OWNERS, OF ANY NOTICE (INCLUDING NOTICE OF REDEMPTION) OR OTHER COMMUNICATION WHICH IS REQUIRED OR PERMITTED UNDER THE TERMS OF THE RESOLUTION TO BE GIVEN TO HOLDERS OR OWNERS OF THE BONDS; (5) THE SELECTION OF THE BENEFICIAL OWNERS TO RECEIVE PAYMENT IN THE EVENT OF ANY PARTIAL REDEMPTION OF THE BONDS; OR (6) ANY ACTION TAKEN BY DTC OR ITS NOMINEE AS THE REGISTERED OWNER OF THE BONDS.

So long as Cede & Co. is the registered owner of the Bonds, as nominee for DTC, references in this Offering Statement to the bondholders, holders or registered owners of the Bonds shall mean Cede & Co., as aforesaid, and shall not mean the Beneficial Owners of the Bonds.

When reference is made to any action which is required or permitted to be taken by the Beneficial Owners, such reference shall only relate to those permitted to act (by statute, regulation or otherwise) on behalf of such Beneficial Owners for such purposes. When notices are given, they shall be sent by us or the Trustee to DTC only.

As long as the book-entry system is used for the Bonds, we and the Trustee will give any notices required to be given to holders of the Bonds only to DTC. Any failure of DTC to advise any Direct Participant, or of any Direct Participant to notify any Indirect Participant, or of any Direct Participant or Indirect Participant to notify any Beneficial Owner, of any such notice and its content or effect will not affect the validity of the action premised on such notice.

NEITHER US NOR THE TRUSTEE WILL HAVE ANY RESPONSIBILITY OR OBLIGATION TO SUCH DIRECT PARTICIPANTS, OR THE PERSONS FOR WHOM THEY ACT AS NOMINEES, WITH RESPECT TO THE PAYMENTS TO OR THE PROVIDING OF NOTICE FOR THE DIRECT PARTICIPANTS, THE INDIRECT PARTICIPANTS, OR THE BENEFICIAL OWNERS OF THE BONDS.

For every transfer and exchange of a beneficial ownership interest in the Bonds, the Beneficial Owner may be charged a sum sufficient to cover any tax, fee or other governmental charge, that may be imposed in relation thereto.

Discontinuation of the Book-Entry Only System. DTC may discontinue providing its services as depository with respect to the Bonds at any time by giving reasonable notice to the County or the Trustee. In addition, if the County determines that (i) DTC is unable to discharge its responsibilities with respect to the Bonds, or (ii) continuation of the system of book-entry-only transfers through DTC is not in the County's best interests or in the best interests of the Beneficial Owners of the Bonds, the County may thereupon terminate the services of DTC with respect to the Bonds. Upon the resignation of DTC or determination by the County that DTC is unable to discharge its responsibilities, the County may, within 90 days, appoint a successor depository. If no such successor is appointed or the County determines to discontinue the book-entry-only system, Bond certificates relating to such Bonds will be printed and delivered. Transfers and exchanges of the Bonds shall thereafter be made as described under the caption "DESCRIPTION OF THE BONDS – General."

If the book-entry-only system is discontinued with respect to any of the Bonds, the persons to whom Bond certificates relating to any such Bonds are delivered will be treated as "Holders" for all purposes of the Bond Indenture, including without limitation the payment of principal or redemption price of, and interest on, the Bonds, the redemption of Bonds and the giving to us or the Trustee of any notice, consent, request or demand pursuant to the Bond Indenture for any purpose whatsoever. In such event, principal or redemption price of and interest on, the Bonds will be payable as described under the caption "DESCRIPTION OF THE BONDS – General."

The information in this section concerning DTC and DTC's book-entry only system has been obtained from sources that we believe to be reliable. No representation is made herein by us or the Underwriter as to the accuracy, completeness or adequacy of such information, or as to the absence of material adverse changes in such information subsequent to the date of this Offering Statement.

UNDERWRITING

Goldman, Sachs & Co. (the "Underwriter"), has agreed, subject to certain conditions (including the execution of a continuing disclosure agreements described below) to purchase the Bonds from the County. In consideration of such purchase, we have agreed to pay the Underwriter a fee of $941,505.50. The Underwriter will be obligated to purchase all of the Bonds if any of such Bonds are purchased. The Bonds may be offered and sold to certain dealers (including the Underwriter and other dealers depositing such Bonds into investment trusts) at prices lower than such public offering prices, and such public offering prices may be changed, from time to time, by the Underwriter. Goldman, Sachs & Co. and its affiliates have engaged and may engage in other transactions with and perform services for us from time to time in the ordinary course of business.

CONTINUING DISCLOSURE

To assist the Underwriter in complying with SEC Rule 15c2-12(b)(5) under the Exchange Act, we have authorized the execution and delivery of a Continuing Disclosure Agreement with respect to the Bonds for the benefit of the beneficial owners of the Bonds (the "Continuing Disclosure Agreement"). Under the Continuing Disclosure Agreement, we will be obligated to provide certain financial information and operating data, financial statements, notice of certain events if material, and certain other notices to the Municipal Securities Rulemaking Board, or any other entity authorized or designated by the SEC in the future to receive such information, and such obligations will be enforceable, as described therein. The entry into the Continuing Disclosure Agreement by us is a condition precedent to the obligation of the Underwriter to purchase the Bonds. The proposed form of our Continuing Disclosure Agreement is attached hereto as APPENDIX H.

Our failure to observe or perform any of the obligations under the Continuing Disclosure Agreement will not be deemed an Event of Default under the Mortgage Indenture or the Bond Indenture. If we fail to comply with any provision of the Continuing Disclosure Agreement, any registered owner or beneficial owner of the Bonds may take such actions as may be necessary and appropriate, including seeking mandamus or specific performance by court order, to cause us to comply with our obligations under the Continuing Disclosure Agreement. However, our Continuing Disclosure Agreement provides that no registered owner or beneficial owner of the Bonds will have the right to challenge the content or the adequacy of the information contained in any annual report or any notice of a material event by judicial proceedings unless the registered owners or beneficial owners representing at least 25% in aggregate principal amount of the Bonds then outstanding join in such proceedings.

TAX MATTERS

In the opinion of Orrick, Herrington & Sutcliffe LLP, Bond Counsel, based on an analysis of existing laws, regulations, rulings and court decisions, and assuming, among other matters, the accuracy of certain representations and compliance with certain covenants, interest on the Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code") and Title XIII of the Tax Reform Act of 1986, except that Bond Counsel expresses no opinion as to the status of interest on any Bond for federal income tax purposes during any period that such Bond is held by a "substantial user" of facilities financed or refinanced with the proceeds of the Bonds or by a "related person" within the meaning of Section 103(b)(13) of the 1954 Code. Bond Counsel is of the further opinion that interest on the Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, although Bond Counsel observes that such interest is included in adjusted current earnings in federal corporate alternative minimum taxable income. Interest on the Bonds is exempt from all present Kentucky personal and corporate income taxes. A complete copy of the proposed opinion of Bond Counsel is set forth as APPENDIX F hereto.

Title XIII of the Tax Reform Act of 1986 and Section 103 of the 1954 Code impose various restrictions, conditions and requirements relating to the exclusion from gross income for federal income tax purposes of interest on obligations such as the Bonds. We and the County have made representations related to certain of these requirements and have covenanted to comply with certain restrictions designed to assure that interest on the Bonds will not be included in federal gross income. Inaccuracy of these representations or failure to comply with these covenants may result in interest on the Bonds being included in gross income for federal income tax purposes, possibly from the date of issuance of the Bonds. The opinion of Bond Counsel assumes the accuracy of these representations and compliance with these covenants. Bond Counsel has not undertaken to determine (or to inform any person) whether any actions taken (or not taken) or events occurring (or not occurring) after the date of issuance of the Bonds may adversely affect the tax status of interest on the Bonds. Accordingly, the opinion of Bond Counsel is not intended to, and may not, be relied upon in connection with any such actions, events or matters.

Although Bond Counsel expects to render an opinion that interest on the Bonds is excluded from gross income for federal income tax purposes and is exempt from all present Kentucky personal and corporate income taxes, the ownership or disposition of, or the accrual or receipt of interest on, the Bonds may otherwise affect the tax liability of the holder of the Bonds. The nature and extent of these other tax consequences will depend upon the particular tax status of the holder of the Bonds or its other items of income or deduction. Bond Counsel expresses no opinion regarding any such other tax consequences.

Future legislative proposals, if enacted into law, clarification of the 1954 Code or the 1986 Act, or court decisions may cause interest on the Bonds to be subject, directly or indirectly, to federal income taxation or to be subject to or exempted from state income taxation, or otherwise prevent Beneficial Owners from realizing the full current benefit of the tax status of such interest. The introduction or enactment of any such future legislative proposals, clarification of the 1954 Code or the 1986 Act or court decisions may also affect the market price for, or marketability of, the Bonds. Prospective purchasers of the Bonds should consult their own tax advisers regarding any pending or proposed federal or state tax legislation, regulations or litigation, as to which Bond Counsel expresses no opinion.

The opinion of Bond Counsel is based on current legal authority, covers certain matters not directly addressed by such authorities, and represents Bond Counsel's judgment as to the proper treatment of the Bonds for federal income tax purposes. It is not binding on the IRS or the courts. Furthermore, Bond Counsel cannot give and has not given any opinion or assurance about the future activities of the County or Big Rivers, or about the effect of future changes in the 1954 Code, the 1986 Act, the applicable regulations, the interpretation thereof or the enforcement thereof by the IRS. We and the County have covenanted and agreed for the benefit of Beneficial Owners of the Bonds, however, not directly or indirectly to use or permit the use (to the extent within its control) of proceeds of the Bonds or other funds, or take or omit to take any action, if and to the extent such use, or the taking or omission to take such action, would cause interest on the Bonds to be subject to federal income tax by reason of Section 103 of the 1954 Code or Title XIII of the 1986 Act, and any applicable regulations promulgated thereunder.

Bond Counsel's engagement with respect to the Bonds ends with the issuance of the Bonds, and unless separately engaged, Bond Counsel is not obligated to defend the County or the Beneficial Owners regarding the tax exempt status of the Bonds in the event of an audit examination by the IRS. Under current procedures, parties other than the County, Big Rivers and their appointed counsel, including the Beneficial Owners, would have little, if any, right to participate in the audit examination process. Moreover, because achieving judicial review in connection with an audit examination of tax exempt bonds is difficult, obtaining an independent review of IRS positions with which the County or Big Rivers legitimately disagree may not be practicable. Any action of the IRS, including but not limited to selection of the Bonds for audit, or the course or result of such audit, or an audit of bonds presenting similar tax issues may affect the market price for, or the marketability of, the Bonds, and may cause us, the County or the Beneficial Owners to incur significant expense.

RATINGS

The Bonds are rated "Baa1", "BBB-" and "BBB-" by Moody's, S&P and Fitch, respectively. The respective ratings by Fitch, Moody's and S&P of the Bonds reflect only the views of such organization and any desired explanation of the significance of such ratings and any outlooks or other statements given by the rating agencies with respect thereto should be obtained from the rating agency furnishing the same, at the following addresses: Fitch Ratings, One State Street Plaza, New York, New York 10004; Moody's Investors Service, Inc., 7 World Trade Center, 250 Greenwich Street, New York, New York 10007; and Standard & Poor's Ratings Services, 55 Water Street, New York, New York 10041. Generally, a rating agency bases its rating and outlook (if any) on the information and materials furnished to it on investigations, studies and assumptions of its own. There is no assurance such ratings for the Bonds will continue for any given period of time or that any of such ratings will not be revised downward or withdraw entirely by any of the rating agencies, if, in the judgment of such rating agency or agencies, circumstances so warrant. Any such downward revision or withdrawal of such ratings may have an adverse effect on the market price of the Bonds.

AVAILABLE INFORMATION

Brief descriptions of the County, the Bonds, the Financing Agreement, the Bond Indenture, the Note and the Mortgage Indenture and information about us, including our financial statements, are included in this Offering Statement. Such descriptions do not purport to be comprehensive or definitive.

All references herein to the Financing Agreement, the Bond Indenture, the Note and the Mortgage Indenture are qualified in their entirety by reference to such documents, copies of which are on file at our principal office or the principal office of the Trustee, and are available upon request. References herein to the Bonds are qualified in their entirety by reference to the forms thereof included in the Bond Indenture and the information with respect thereto included in the aforementioned documents.

Any statements made in this Offering Statement involving matters of opinion or of estimates, whether or not so expressly stated, are set forth as such and not as representations of fact, and no representation is made that any of the estimates will be realized.

APPROVAL OF LEGAL PROCEEDINGS

All of the legal proceedings in connection with the authorization and issuance of the Bonds and their validity are subject to the approving opinion of Orrick, Herrington & Sutcliffe LLP, Bond Counsel. A complete copy of the proposed form of Bond Counsel opinion is contained in APPENDIX G hereto. Certain legal matters are subject to the approval of Sutherland Asbill & Brennan LLP, Counsel to the Underwriter. Certain legal matters will be passed upon for us by Sullivan, Mountjoy, Stainback & Miller, P.S.C., Owensboro, Kentucky, its General Counsel. Certain legal matters will be passed upon for the County by Greg Hill, Esq., Counsel to the County.

INDEPENDENT AUDITORS

Our financial statements as of December 31, 2009 and 2008 and for each of the three years in the period ended December 31, 2009, included in APPENDIX A to this Offering Statement have been audited by Deloitte & Touche LLP, independent auditors, as stated in their report appearing herein.

YEAR END FINANCIAL STATEMENTS

Deloitte.

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
Big Rivers Electric Corporation:

We have audited the accompanying balance sheets of Big Rivers Electric Corporation (the "Company") as of December 31, 2009 and 2008, and the related statements of operations, equities (deficit), and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Big Rivers Electric Corporation as of December 31, 2009 and 2008, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

In accordance with *Government Auditing Standards*, we have also issued a report dated March 26, 2010, on our consideration of Big Rivers Electric Corporation's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be read in conjunction with this report in considering the results of our audit.

Deloitte & Touche LLP

March 26, 2010

Member of
Deloitte Touche Tohmatsu

Balance Sheets

As of December 31, 2009 and 2008 — (Dollars in thousands)

Assets

	2009	2008
UTILITY PLANT – Net	$ 1,078,274	$ 912,699
RESTRICTED INVESTMENTS – Member rate mitigation	243,225	–
OTHER DEPOSITS AND INVESTMENTS – At cost	5,342	4,693
CURRENT ASSETS:		
Cash and cash equivalents	60,290	38,903
Accounts receivable	47,493	20,464
Fuel inventory	37,830	–
Non-fuel inventory	20,412	756
Prepaid expenses	3,233	450
Total current assets	169,258	60,573
DEFERRED LOSS FROM TERMINATION OF SALE-LEASEBACK	–	76,001
DEFERRED CHARGES AND OTHER	9,384	20,470
TOTAL	$ 1,505,483	$ 1,074,436

Equities (Deficit) and Liabilities

	2009	2008
CAPITALIZATION:		
Equities (deficit)	$ 379,392	$ (154,602)
Long-term debt	834,367	987,349
Total capitalization	1,213,759	832,747
CURRENT LIABILITIES:		
Current maturities of long-term obligations	14,185	51,771
Purchased power payable	3,362	9,336
Accounts payable	30,657	5,832
Accrued expenses	9,864	3,134
Accrued interest	9,097	8,018
Total current liabilities	67,165	78,091
DEFERRED CREDITS AND OTHER:		
Deferred lease revenue	–	10,955
Residual value payments obligation	–	145,145
Regulatory liabilities – Member rate mitigation	207,348	–
Other	17,211	7,498
Total deferred credits and other	224,559	163,598
COMMITMENTS AND CONTINGENCIES (see note 14)		
TOTAL	$ 1,505,483	$ 1,074,436

See notes to financial statements.

Statements of Operations

For the years ended December 31, 2009, 2008 and 2007 — (Dollars in thousands)

	2009	2008	2007
POWER CONTRACTS REVENUE	$ 341,333	$ 214,758	$ 271,605
LEASE REVENUE	32,027	58,423	58,265
Total operating revenue	373,360	273,181	329,870
OPERATING EXPENSES:			
Operations:			
Fuel for electric generation	80,655	–	–
Power purchased and interchanged	116,883	114,643	169,768
Production, excluding fuel	22,381	–	–
Transmission and other	35,444	28,600	27,196
Maintenance	29,820	4,258	4,240
Depreciation and amortization	32,485	31,041	30,632
Total operating expenses	317,668	178,542	231,836
ELECTRIC OPERATING MARGIN	55,692	94,639	98,034
INTEREST EXPENSE AND OTHER:			
Interest	59,898	65,719	60,932
Interest on obligations related to long-term lease	–	6,991	9,919
Amortization of loss from termination of long-term lease	2,172	811	–
Income tax expense	1,025	5,934	–
Other – net	112	123	103
Total interest expense and other	63,207	79,578	70,954
OPERATING MARGIN	(7,515)	15,061	27,080
NON-OPERATING MARGIN:			
Interest income on restricted investments under long-term lease	–	8,742	12,481
Gain on Unwind transaction (see Note 2)	537,978	–	–
Interest income and other	867	4,013	7,616
Total non-operating margin	538,845	12,755	20,097
NET MARGIN	$ 531,330	$ 27,816	$ 47,177

See notes to financial statements.

Statements of Equities (Deficit)

For the years ended December 31, 2009, 2008 and 2007 — (Dollars in thousands)

	Total Equities (Deficit)	Accumulated Margin (Deficit)	Other Equities: Donated Capital and Memberships	Other Equities: Consumers' Contributions to Debt Service	Accumulated Other Comprehensive Income
BALANCE – December 31, 2006	$ (217,371)	$ (221,816)	$ 764	$ 3,681	$ –
Net margin/ total comprehensive income	47,177	47,177	–	–	–
FAS 158 adoption	(3,943)	–	–	–	(3,943)
BALANCE – December 31, 2007	(174,137)	(174,639)	764	3,681	(3,943)
Comprehensive income:					
Net margin	27,816	27,816	–	–	–
FAS 158 funded status adjustment	(8,281)				(8,281)
Total comprehensive income	19,535				
BALANCE – December 31, 2008	(154,602)	(146,823)	764	3,681	(12,224)
Comprehensive income:					
Net margin	531,330	531,330	–	–	–
FAS 158 funded status adjustment	2,664				2,664
Total comprehensive income	533,994				
BALANCE – December 31, 2009	$ 379,392	$ 384,507	$ 764	$ 3,681	$ (9,560)

See notes to financial statements.

Statements of Cash Flows

For the years ended December 31, 2009, 2008 and 2007 — (Dollars in thousands)

	2009	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net margin	$ 531,330	$ 27,816	$ 47,177
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization	37,084	34,320	33,866
Increase in restricted investments under long-term lease	–	(2,502)	(6,242)
Decrease in deferred AMT Income Taxes	–	5,035	–
Amortization of deferred loss (gain) on sale-leaseback – net	2,172	(1,187)	(2,900)
Deferred lease revenue	(3,768)	(4,582)	(1,779)
Residual value payments obligation gain	(3,881)	(6,748)	(6,591)
Increase in RUS Series B Note	6,136	5,841	5,572
Increase in RUS Series A Note	–	–	15,761
Increase in obligations under long-term lease	–	2,749	6,580
Noncash gain on Unwind transaction	(269,441)	–	–
Cash received for Member Rate Mitigation	217,856	–	–
Noncash Member Rate Mitigation revenue	(12,033)	–	–
Changes in certain assets and liabilities:			
Accounts receivable	(26,049)	6,218	(8,934)
Inventories	(3,497)	12	43
Prepaid expenses	(2,783)	(319)	3,477
Deferred charges	(1,538)	1,871	(2,429)
Purchased power payable	(5,973)	(3,702)	3,818
Accounts payable	24,825	899	1,566
Accrued expenses	7,881	327	1,033
Other – net	6,852	(4,940)	(5,465)
Net cash provided by operating activities	505,173	61,108	84,553
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(58,388)	(22,760)	(18,682)
Proceeds from disposition of investments related to sale-leaseback	–	222,739	–
Proceeds from restricted investments	8,982	–	–
Purchases of restricted investments and other deposits & investments	(252,798)	(401)	(424)
Net cash provided by (used in) investing activities	(302,204)	199,578	(19,106)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Principal payments on long-term obligations	(168,956)	(40,838)	(12,676)
Principal payments on short-term notes payable	(12,380)	–	–
Payments upon termination of sale-leaseback	–	(329,859)	–
Debt issuance cost on bond refunding	(246)	–	–
Net cash used in financing activities	(181,582)	(370,697)	(12,676)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	21,387	(110,011)	52,771
CASH AND CASH EQUIVALENTS—Beginning of year	38,903	148,914	96,143
CASH AND CASH EQUIVALENTS—End of year	$ 60,290	$ 38,903	$ 148,914
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest	$ 51,078	$ 74,819	$ 45,600
Cash paid for income taxes	$ 626	$ 1,220	$ 420

See notes to financial statements.

Notes to Financial Statements

As of December 31, 2009 and 2008, and for each of the three years in the period ended December 31, 2009 — (Dollars in thousands)

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General Information — Big Rivers Electric Corporation ("Big Rivers" or the "Company"), an electric generation and transmission cooperative, supplies wholesale power to its three member distribution cooperatives (Kenergy Corp., Jackson Purchase Energy Corporation, and Meade County Rural Electric Cooperative Corporation) under all requirements contracts, excluding the power needs of two large aluminum smelters (the "Aluminum Smelters"). Additionally, Big Rivers sells power under separate contracts to Kenergy Corp. for the Aluminum Smelters load and markets power to nonmember utilities and power marketers. The members provide electric power and energy to industrial, residential, and commercial customers located in portions of 22 western Kentucky counties. The wholesale power contracts with the members remain in effect until December 31, 2043. Rates to Big Rivers' members are established by the Kentucky Public Service Commission (KPSC) and are subject to approval by the Rural Utilities Service (RUS). The financial statements of Big Rivers include the provisions of FASB ASC 980, *Certain Types of Regulation*, which was adopted by the Company in 2003, and gives recognition to the ratemaking and accounting practices of the KPSC and RUS.

In 1999, Big Rivers Leasing Corporation (BRLC) was formed as a wholly owned subsidiary of Big Rivers. BRLC's principal assets were the restricted investments acquired in connection with the 2000 sale-leaseback transaction discussed in Note 4. The sale-leaseback transaction was terminated on September 30, 2008 and BRLC was dissolved on July 16, 2009, in conjunction with the Unwind Transaction.

Principles of Consolidation — The financial statements of Big Rivers include the accounts of Big Rivers and its wholly owned subsidiary, BRLC. All significant intercompany transactions have been eliminated.

Estimates — The preparation of the financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosure of contingent assets and liabilities. The estimates and assumptions used in the accompanying financial statements are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results may differ from those estimates.

System of Accounts — Big Rivers' maintains its accounting records in accordance with the Uniform System of Accounts as prescribed by the RUS Bulletin 1767B-1, as adopted by the KPSC. These regulatory agencies retain authority and periodically issue orders on various accounting and ratemaking matters. Adjustments to RUS accounting have been made to make the financial statements consistent with generally accepted accounting principles in the United States of America.

Revenue Recognition — Revenues generated from the Company's wholesale power contracts are based on month-end meter readings and are recognized as earned. Prior to its termination, in accordance with FASB ASC 840, *Leases*, Big Rivers' revenue from the Lease Agreement was recognized on a straight-line basis over the term of the lease. The major components of this lease revenue include the annual lease payments and the Monthly Margin Payments (described in Note 2).

Utility Plant and Depreciation — Utility plant is recorded at original cost, which includes the cost of contracted services, materials, labor, overhead, and an allowance for borrowed funds used during construction. Replacements of depreciable property units, except minor replacements, are charged to utility plant.

Allowance for borrowed funds used during construction is included on projects with an estimated total cost of $250 or more before consideration of such allowance. The interest capitalized is determined by applying the effective rate of Big Rivers' weighted-average debt to the accumulated expenditures for qualifying projects included in construction in progress.

Prior to July 17, 2009, the Effective Date of the Unwind Transaction (see Note 2), and in accordance with the terms of the Lease Agreement, the Company generally recorded capital additions for Incremental Capital Costs and Nonincremental Capital Costs expenditures funded by E.ON U.S. (formerly LG&E Energy Corporation) as utility plant to which the Company maintained title. A corresponding obligation to E.ON U.S. was recorded for the estimated portion of these additions attributable to the Residual Value Payments (see Note 2). A portion of this obligation was amortized to lease revenue over the useful life of those assets during the remaining lease term. For the years ended December 31, 2009 and 2008, the Company recorded $5,557 and $10,728, respectively, for such additions in utility plant. The Company recorded $3,881, $6,748, and $6,591 in 2009, 2008, and 2007, respectively, as related lease revenue in the accompanying financial statements. All amounts recorded for 2009 reflect the period prior to the Effective Date of the Unwind Transaction. Under the terms of the Unwind Transaction, E.ON U.S. waived their right to the Residual Value Payment, and the Company recognized a gain.

In accordance with the Lease Agreement, and in addition to the capital costs funded by E.ON U.S. (see Note 2) that were recorded by the Company as utility plant and lease revenue, E.ON U.S also incurred certain Nonincremental Capital Costs and Major Capital Improvements (as defined in the Lease Agreement) for which they waived rights to a Residual Value Payment by Big Rivers upon lease termination. Such amounts were not recorded as utility plant or lease revenue by the Company during the lease. In connection with the Unwind Transaction the Company recognized a gain of $19,679 for the Nonincremental Capital assets for which E.ON had waived rights to.

E.ON U.S. constructed a scrubber (Major Capital Improvement) at Big Rivers' Coleman plant. The scrubber achieved commercial acceptance in January 2007. The Company acquired the Coleman scrubber at no cost under the terms of the Unwind Transaction, recognizing a gain of $98,500 in 2009.

Depreciation of utility plant in service is recorded using the straight-line method over the estimated remaining service lives, as approved by the RUS and KPSC. The annual composite depreciation rates used to compute depreciation expense were as follows:

Electric plant-leased	1.60%–2.47%
Transmission plant	1.76%–3.24%
General plant	1.11%–5.62%

For 2009, 2008, and 2007, the average composite depreciation rates were 1.85%, 1.85%, and 1.85%, respectively. At the time plant is disposed of, the original cost plus cost of removal less salvage value of such plant is charged to accumulated depreciation, as required by the RUS.

Impairment Review of Long-Lived Assets — Long-lived assets are reviewed as facts and circumstances indicate that the carrying amount may be impaired. This review is performed in accordance with FASB ASC 360, *Property, Plant, and Equipment* as it relates to impairment of long-lived assets. FASB ASC 360 establishes one accounting model for all impaired long-lived assets and long-lived assets to be disposed of by sale or otherwise. FASB ASC 360 requires the evaluation of impairment by comparing an asset's carrying value to the estimated future cash flows the asset is expected to generate over its remaining life. If this evaluation were to conclude that the carrying value of the asset is impaired, an impairment charge would be recorded based on the difference between the asset's carrying amount and its fair value (less costs to sell for assets to be disposed of by sale) as a charge to operations or discontinued operations.

Restricted Investments — Investments are restricted under KPSC order to establish certain reserve funds for member rate mitigation in conjunction with the Unwind Transaction. These investments have been classified as held-to-maturity and are carried at amortized cost (see Note 10).

Cash and Cash Equivalents — Big Rivers considers all short-term, highly-liquid investments with original maturities of three months or less to be cash equivalents.

Income Taxes — As a taxable cooperative, Big Rivers is entitled to exclude the amount of patronage allocations to members from taxable income. Income and expenses related to nonmember operations are taxable to Big Rivers. Big Rivers files a Federal income tax return and a Kentucky income tax return.

Patronage Capital — As provided in the bylaws, Big Rivers accounts for each year's patronage-sourced income, both operating and nonoperating, on a patronage basis. Notwithstanding any other provision of the bylaws, the amount to be allocated as patronage capital for a given year shall not be less than the greater of regular taxable patronage-sourced income or alternative minimum taxable patronage-sourced income.

Derivatives — Management has reviewed the requirements of FASB ASC 815, *Derivatives and Hedging*, and has determined that all contracts meeting the definition of a derivative also qualify for the normal purchases and sales exception under FASB ASC 815. The Company has elected the Normal Purchase and Normal Sale exception for these contracts and, therefore, the contracts are not required to be recognized at fair value in the financial statements.

Fair value measurements — The Fair Value Measurements and Disclosures Topic of the FASB ASC 820, *Fair Value Measurements and Disclosures*, defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal, or most advantageous, market for the asset or liability in an orderly transaction between market participants at the measurement date. The Fair Values Measurements Topic establishes a three-Level fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy requires entities to maximize the use of observable inputs when possible. The three levels of inputs used to measure fair value are as follows:

- Level 1 — quoted prices in active markets for identical assets or liabilities

- Level 2 — observable inputs other than quoted prices included in Level 1, such as quoted prices for similar assets and liabilities in active markets; quoted prices for identical or similar assets and liabilities in markets that are not active; or other inputs that are observable or can be corroborated by observable market data; and

- Level 3 — unobservable inputs that are supported by little or no market activity and that are significant to the fair values of the assets or liabilities, including certain pricing models, discounted cash flow methodologies and similar techniques that use significant unobservable inputs.

New Accounting Pronouncements — FASB ASC 815, *Derivatives and Hedging*, issued in March 2008, establishes enhanced disclosure requirements concerning derivative instruments and hedging activities. This enhanced disclosure standard requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation in order to better convey the purpose of derivative use in terms of the risks that the entity is intending to manage. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under FASB ASC 815 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. This standard of FASB ASC 815 is effective for financial statements issued for fiscal years beginning after November 15, 2008. The Company adopted this standard of FASB ASC 815 on January 1, 2009, with no impact to the Company's financial statements.

FASB ASC 855, *Subsequent Events*, establishes a standard for disclosure of events that occur during the period between the balance sheet date and the date on which the financial statements are issued. This standard of FASB ASC 855 is effective for interim or annual financial periods ending after June 15, 2009. The Company has adopted the disclosure requirements for subsequent events as outlined in ASC 855 and management evaluated subsequent events up to and including March 26, 2010, the date the financial statements were available to be issued.

FASB ASC 105, *Generally Accepted Accounting Principles*, provides a Codification of accounting standards that supersedes all previously existing non-SEC accounting and reporting standards and becomes the authoritative source of U.S. generally accepted accounting principles (GAAP). This standard of FASB ASC 105 is effective for annual financial statements issued after September 15, 2009. The Company has adopted the Accounting Standard Codification (ASC) established by FASB ASC 105.

2. LG&E LEASE AGREEMENT

Big Rivers, E.ON U.S. LLC ("E.ON"), Western Kentucky Energy Corporation ("WKEC"), and LG&E Energy Marketing ("LEM"), closed effective July 17, 2009, a transaction resulting in a mutually acceptable early termination of the 1998 LG&E Lease Agreement (referred herein as the "Unwind Transaction" or "Unwind"). E.ON, WKEC, and LEM are collectively referred to in the Notes as "E.ON Entities." This transaction was approved by the KPSC and the RUS. The Unwind Transaction resulted in Big Rivers recognizing a net gain of $537,978. This transaction resulted in the acquisition of assets, the assumption of liabilities, the forgiveness of liabilities, and the establishment of a regulatory reserve prescribed by the KPSC in their approval of the transaction. Assets and liabilities in the unwind transaction were accounted for at fair value or recorded value, as appropriate. The gain from the Unwind Transaction is summarized as follows:

	Unwind Gain
Assets received:	
Cash	$506,675
Coleman scrubber	98,500
Inventory	55,000
Construction in progress	23,074
Utility plant assets	19,679
SO2 allowances	980
Liabilities (assumed) forgiven:	
Economic Reserve	(157,000)
Rural Economic Reserve	(60,856)
Post-retirement benefits liability	(8,768)
Residual value payments obligation	145,251
LEM Settlement Note	15,440
Recognition of (expenses) income:	
Deferred lease income	7,187
Deferred loss from termination of sale/leaseback	(73,829)
Deferred loss from LEM Marketing Payment/Settlement Note	(14,520)
Unwind transaction costs	(18,991)
Other	156
Gain on unwind transaction	$537,978

The terms of the LG&E Lease Agreement as originally structured are outlined in the following text.

On July 15, 1998 ("Effective Date"), a lease was consummated ("Lease Agreement"), whereby Big Rivers leased its generating facilities to Western Kentucky Energy Corporation (WKEC), a wholly owned subsidiary of E.ON U.S. Pursuant to the Lease Agreement, WKEC operated the generating facilities and maintained title to all energy produced. Throughout the lease term, in order for Big Rivers to fulfill its obligation to supply power to its members, the Company purchased substantially all of its power requirements from LG&E Energy Marketing Corporation (LEM), a wholly owned subsidiary of E.ON U.S., pursuant to a power purchase agreement.

Big Rivers continued to operate its transmission facilities and charged LEM tariff rates for delivery of the energy produced by WKEC and consumed by LEM's customers. The significant terms of the Lease Agreement were as follows:

a. WKEC was to lease and operate Big Rivers' generation facilities through 2023.

b. Big Rivers retained ownership of the generation facilities both during and at the end of the lease term.

c. WKEC paid Big Rivers an annual lease payment of $30,965 over the lease term, subject to certain adjustments.

d. On the Effective Date, Big Rivers received $69,100 representing certain closing payments and the first two years of the annual lease payments. In accordance with FASB ASC 840, *Leases*, the Company amortized these payments to revenue on a straight-line basis over the life of the lease.

e. Big Rivers continued to provide power for its members, excluding the member loads serving the Aluminum Smelters, through its power purchase agreements with LEM and the Southeastern Power Administration, based on a pre-determined maximum capacity. When economically feasible, the Company also obtained the power necessary to supply its member loads, excluding the Aluminum Smelters, in the open market. Kenergy Corp.'s retail service for the Aluminum Smelters was served by LEM and other third-party providers that included Big Rivers. To the extent the power purchased from LEM did not reach pre-determined minimums, the Company was required to pay certain penalties. Also, to the extent additional power was available to Big Rivers under the LEM contract, Big Rivers made sales to nonmembers.

f. LEM reimbursed Big Rivers the margins expected from the Aluminum Smelters, defined as the net cash flows that Big Rivers anticipated receiving if the Company had continued to serve the Aluminum Smelters' load, as filed in the Rate Hearing (the "Monthly Margin Payments").

g. WKEC was responsible for the operating costs of the generation facilities; however, Big Rivers was partially responsible for ordinary capital expenditures ("Nonincremental Capital Costs") for the generation facilities over the term of the Lease Agreement, generally up to predetermined annual amounts. At the end of the lease term, Big Rivers was obligated to fund a "Residual Value Payment" to E.ON U.S. for such capital additions during the lease (see Note 1). Adjustments to the Residual Value Payment were made based upon actual capital expenditures. Additionally, WKEC made required capital improvements to the facilities to comply with new laws or a changes to existing laws ("Incremental Capital Costs") over the lease life (the Company was partially responsible for such costs: 20% through 2010) and the Company was required to submit another Residual Value Payment to E.ON U.S. for the undepreciated value of WKEC's 80% share of these costs, at the end of the lease. The Company had title to these assets during the lease and upon lease termination.

h. Big Rivers entered into a note payable with LEM for $19,676 (the "LEM Settlement Note") to be repaid over the term of the Lease Agreement, with an interest rate at 8% per annum, in consideration for LEM's assumption of the risk related to unforeseen costs with respect to power to be supplied to the Aluminum Smelters and the increased responsibility for financing capital improvements. The Company recorded this obligation as a component of deferred charges with the related payable recorded as long-term debt in the accompanying balance sheets. This deferred charge was amortized on a straight-line basis up to the Effective Date of the Unwind Transaction.

i. On the Effective Date, Big Rivers paid a nonrefundable marketing payment of $5,933 to LEM, which was recorded as a component of deferred charges. This amount was amortized on a straight-line basis up to the Effective Date of the Unwind Transaction.

j. During the lease term, Big Rivers was entitled to certain "billing credits" against amounts the Company owed LEM under the power purchase agreement. Each month during the first 55 months of the lease term, Big Rivers received a credit of $89. For the year 2011, Big Rivers was to receive a credit of $2,611 and for the years 2012 through 2023, the Company was to receive a credit of $4,111 annually.

In accordance with the power purchase agreement with LEM, the Company was allowed to purchase power in the open market rather than from LEM, incurring penalties when the power purchased from LEM did not meet certain minimum levels, and to sell excess power (power not needed to supply its jurisdictional load) in the open market (collectively referred to as "Arbitrage"). Pursuant to the New RUS Promissory Note and the RUS ARVP Note, the benefit, net of tax, as defined, derived from Arbitrage had to be divided as follows: one-third, adjusted for capital expenditures, was used to make principal payments on the New RUS Promissory Note; one-third was used to make principal payments on the RUS ARVP Note; and the remaining value was retained by the Company.

3. UTILITY PLANT

At December 31, 2009 and 2008, utility plant is summarized as follows:

	2009	2008
Classified plant in service:		
Production plant	$1,675,733	$ -
Electric plant — leased	-	1,535,004
Transmission plant	236,639	230,800
General plant	18,201	17,240
Other	543	543
	1,931,116	1,783,587
Less accumulated depreciation	908,099	879,073
	1,023,017	904,514
Construction in progress	55,257	8,185
Utility plant — net	$1,078,274	$912,699

Interest capitalized for the years ended December 31, 2009, 2008, and 2007, was $133, $492, and $391, respectively.

The Company has not identified any material legal asset retirement obligations, as defined in FASB ASC 410, *Asset Retirement Obligations*. In accordance with regulatory treatment, the Company records an estimated net cost of removal of its utility plant through normal depreciation. As of December 31, 2009 and 2008, the Company had a regulatory liability of approximately $35,835 and $32,696, respectively, related to nonlegal removal costs included in accumulated depreciation.

4. SALE-LEASEBACK

On April 18, 2000, the Company completed a sale-leaseback of two of its utility plants, including the related facilities and equipment. The sale-leaseback provided Big Rivers a $1,089,000 fixed price purchase option, at the end of each lease term (25 and 27 years), which, together with future contractual interest receipts, would be fully funded.

On September 30, 2008, the Company completed an early termination of the sale-leaseback transaction. The termination was precipitated by the June 2008 downgrade of the claims-paying ability of Ambac Assurance Corporation (Ambac). Ambac served as insurer of Big Rivers' payment obligations, thereby providing credit support under the transaction. Ambac's downgrade exposed the Company to adverse consequences under the contractual terms of the transaction and after consideration of alternative options, Big Rivers ultimately settled on termination as the preferred solution. Proceeds from disposition of the restricted investment and payments required under the termination agreements were $222,739 and $329,559, respectively, reflecting a net cash payment of $107,120. To meet its remaining obligations Big Rivers' entered into a $12,380 promissory note (see Note 5) with Philip Morris Capital Corporation (PMCC). A net loss of $77,001 resulting from the early termination of the sale-leaseback was recorded as a regulatory asset and was amortized up to the Effective Date of the Unwind Transaction; with the balance of the regulatory asset reflected as an offset to the gain recognized from the Unwind Transaction.

Prior to termination the sale-leaseback transaction was recorded as a financing for financial reporting purposes and a sale for Federal income tax purposes. In connection therewith, in 2000, Big Rivers received $866,676 of proceeds and incurred $791,626 of related obligations. Pursuant to a payment undertaking agreement with a financial institution, Big Rivers effectively extinguished $656,029 of these obligations with an equivalent portion of the proceeds. The Company also purchased investments with an initial value of $146,647 to fund the remaining $135,597 of the obligations. Interest received and paid was recorded to these accounts up to the date of lease termination. The Company paid 7.57% interest on its obligations related to long-term lease and received 6.89% on its related investments. The Company made a $64,000 principal payment on the New RUS Promissory Note with the remaining proceeds. The $75,050 gain was deferred and was amortized up to the date of lease termination, with the Company recognizing $1,998, and $2,900, in 2008, and 2007, respectively.

The Amount recognized in the statement of financial position related to the sale-leaseback as of December 31, 2008, is as follows:

Deferred loss from termination of sale-leaseback	$76,001

The unamortized balance of the deferred loss was recognized in 2009 in conjunction with the unwind transaction described in Note 2 based on agreement with the KPSC.

Amounts recognized in the statement of operations related to the sale-leaseback for the years ended December 31, 2008, and 2007, are as follows:

	2008	2007
Power contracts revenue (revenue discount adjustment — see Note 6)	$(2,453)	$(3,680)
Interest on obligations related to long-term lease:		
Interest expense	8,989	12,819
Amortize gain on sale-leaseback	(1,998)	(2,900)
Net interest on obligations related to long-term lease	$6,991	$9,919
Interest income on restricted investments under long-term lease	$8,742	$12,481
Interest income and other	$779	$778

5. DEBT AND OTHER LONG-TERM OBLIGATIONS

A detail of long-term debt at December 31, 2009 and 2008, is as follows:

	2009	2008
RUS Series A Promissory Note, stated amount of, $599,462, stated interest rate of 5.75%, with an interest rate of 5.84%, maturing July 2021	$596,786	$ -
New RUS Promissory Note, stated amount of, $768,391, stated interest rate of 5.75%, with an interest rate of 5.82%, maturing July 2021	-	765,297
RUS Series B Note, stated amount of $245,530, no stated interest rate, with interest imputed at 5.80%, maturing December 2023	109,666	-
RUS ARVP Note, stated amount of $245,899, no stated interest rate, with interest imputed at 5.80%, maturing December 2023	-	103,685
LEM Settlement Note, interest rate of 8.0%, payable in monthly installments	-	15,658
County of Ohio, Kentucky, promissory note, variable interest rate (average interest rate of 10.50% and 8.95% in 2009 and 2008, respectively), maturing in October 2022	83,300	83,300
County of Ohio, Kentucky, promissory note, variable interest rate (average interest rate of 3.22% and 5.14% in 2009 and 2008, respectively), maturing in June 2013	58,800	58,800
PMCC Promissory Note with an interest rate of 8.5%	-	12,380
Total long-term debt	848,552	1,039,120
Current maturities	14,185	51,771
Total long-term debt — net of current maturities	$834,367	$987,349

The following are scheduled maturities of long-term debt at December 31:

Year	Amount
2010	$14,185
2011	14,850
2012	76,081
2013	79,278
2014	21,678
Thereafter	642,480
Total	$848,552

RUS Notes — On July 15, 1998, Big Rivers recorded the New RUS Promissory Note and the RUS ARVP Note at fair value using the applicable market rate of 5.82%. On the Unwind Closing Date, the New RUS Note and the ARVP Note were replaced with the RUS 2009 Promissory Note Series A and the RUS 2009 Promissory Note Series B, respectively. After an Unwind Closing Date payment of $140,181, the RUS 2009 Promissory Note Series A is recorded at an interest rate of 5.84%. The RUS 2009 Series B Note is recorded at an imputed interest rate of 5.80%. The RUS Notes are collateralized by substantially all assets of the Company and secured by the Indenture dated July 1, 2009 between the Company and U.S. Bank National Association.

Pollution Control Bonds — The County of Ohio, Kentucky, issued $83,300 of Pollution Control Periodic Auction Rate Securities, Series 2001, the proceeds of which are supported by a promissory note from Big Rivers, which bears the same interest rate. These bonds bear interest at a variable rate and mature in October 2022.

The County of Ohio, Kentucky, issued $58,800 of Pollution Control Variable Rate Demand Bonds, Series 1983, the proceeds of which are supported by a promissory note from Big Rivers, which bears the same interest rate as the bonds. These bonds bear interest at a variable rate and mature in June 2013.

The Series 1983 bonds are supported by a liquidity facility issued by Credit Suisse First Boston, which was assigned to Dexia Credit in 2006. Both Series are supported by municipal bond insurance and surety policies issued by Ambac Assurance Corporation. Big Rivers has agreed to reimburse Ambac Assurance Corporation for any payments under the municipal bond insurance policies or the surety policies. Both Series are secured by the Indenture dated July 1, 2009 between the company and U.S. Bank National Association.

These instruments are subject to maximum interest rates of 13% and 18%, respectively. The December 31, 2009 interest rates on the Series 1983 and Series 2001 Pollution Control Bonds were 3.25% and 4.50%, respectively.

LEM Settlement Note — On July 15, 1998 Big Rivers executed the Settlement Note with LEM. The Settlement Note required Big Rivers to pay to LEM $19,676, plus interest at 8% per annum over the lease term. The principal and interest payment was approximately $1,822 annually. On the Unwind Closing Date, in connection with the Unwind Transaction the remaining balance on the Settlement Note in the amount of $15,440 was forgiven.

PMCC Promissory Note — On September 30, 2008 in conjunction with the early termination of the sale-leaseback transaction (see Note 4), Big Rivers executed a promissory note with Phillip Morris Capital Corporation (PMCC). The note required Big Rives to pay PMCC $12,380, plus interest at 8.5% per annum. On the Unwind Closing Date Big Rivers repaid the $12,380 principal amount. At December 31, 2009 the Company had no remaining liability associated with this promissory note.

Notes Payable — Notes payable represent the Company's borrowing on its line of credit with the National Rural Utilities Cooperative Finance Corporation (CFC) and CoBank, ACB (CoBank). The maximum borrowing capacity on the lines of credit is $100,000 consisting of $50,000 each for CFC and CoBank. There were no borrowings outstanding on the line of credit at December 31, 2009, however letter of credits issued under an associated Letter of Credit Facility with CFC reduced the borrowing capacity by $5,654. Advances on the CFC line of credit bear interest at a variable rate and outstanding balances are payable in full by the maturity date of July 16, 2014. Advances on the CoBank line of credit bear interest at a variable rate and outstanding balances are payable in full by the maturity date of July 16, 2012.

6. RATE MATTERS

The rates charged to Big Rivers' members consist of a demand charge per kW and an energy charge per kWh consumed as approved by the KPSC. The rates include specific demand and energy charges for its members' two classes of customers, the large industrial customers and the rural customers under its jurisdiction. For the large industrial customers, the demand charge is generally based on each customer's maximum demand during the current month. Each members rural demand charge is based upon the maximum coincident demand of their rural delivery points.

Prior to the Unwind Transaction the demand and energy charges were not subject to adjustments for increases or decreases in fuel or environmental costs. In conjunction with the Unwind Transaction, the KPSC approved the implementation of certain tariff riders; including a fuel adjustment clause and an environmental surcharge, offset by an unwind surcredit (a refund to tariff members of certain charges collected from the Aluminum Smelter in accordance with the contract terms). The net effect of these tariffs is recognized as revenue on a monthly basis with an offset to the regulatory liability – member rate mitigation described below.

The net impact of the tariff riders to members rates is currently mitigated by a Member Rate Stability Mechanism (MRSM) that was funded by certain cash amounts received from the E.ON Entities in connection with the Unwind

Transaction (the Economic and Rural Economic Reserves) and held by Big Rivers as restricted investments. An offsetting regulatory liability – member rate mitigation was established with the funding of these accounts. Big Rivers is required to file a rate case with the KPSC within three years of the unwind or July 2012.

Effective since September 1, 2000, and continuing through August 31, 2008, the KPSC approved Big Rivers' request for a $3,680 annual revenue discount adjustment for its members, effectively passing the benefit of the sale-leaseback transaction (see Note 4) to them. On September 1, 2008, Big Rivers' discontinued the revenue discount adjustment to its members in conjunction with the sale-leaseback termination.

7. **INCOME TAXES**

Big Rivers was formed as a tax-exempt cooperative organization described in Internal Revenue Code Section 501(c)(12). To retain tax-exempt status under this section, at least 85% of the Big Rivers' receipts must be generated from transactions with the Company's members. In 1983, sales to nonmembers resulted in Big Rivers failing to meet the 85% requirement. Until Big Rivers can meet the 85% member income requirement, the Company is a taxable cooperative.

Under the provisions of FASB ASC 740, *Income Taxes*, Big Rivers is required to record deferred tax assets and liabilities for temporary differences between amounts reported for financial reporting purposes and amounts reported for income tax purposes. Deferred tax assets and liabilities are determined based upon these temporary differences using enacted tax rates for the year in which these differences are expected to reverse. Deferred income tax expense or benefit is based on the change in assets and liabilities from period to period, subject to an ongoing assessment of realization. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the more-likely-than-not recognition threshold is satisfied and measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

As a result of the sale-leaseback terminations in 2008 (see Note 4), Big Rivers no longer considers that it is more likely than not that it will recover its net deferred tax assets (which consisted solely of Alternative Minimum Tax (AMT) credit carryforwards). An income statement charge of $5,035 relating the AMT amounts carried forward at January 1, 2008 together with a charge of $900 relating to the 2008 AMT obligation were recorded in the Statement of Operations for 2008. An AMT charge of $1,025 was recorded in the Statement of Operations for 2009.

At December 31, 2009, Big Rivers had a nonpatron net operating loss carryforward of approximately $53,138 expiring through 2012, and an alternative minimum tax credit carryforward of approximately $7,052, which carries forward indefinitely.

The Company has not recorded any regular income tax expense for the years ended December 31, 2009, 2008 and 2007, as the Company has utilized federal net operating losses to offset any regular taxable income during those years. Had the Company not had the benefit of a net operating loss carryforward, the Company would have recorded $19,619, $20,363, and $7,724 in current regular tax expense for the years ended December 31, 2009, 2008 and 2007, respectively.

The components of the net deferred tax assets as of December 31, 2009 and 2008, were as follows:

	2009	2008
Deferred tax assets:		
Net operating loss carryforward	$20,990	$40,609
Alternative minimum tax credit carryforwards	7,052	5,935
Member Rate Mitigation	10,326	-
Fixed asset basis difference	11,420	33,786
Total deferred tax assets	49,788	80,330
Deferred tax liabilities — ARVP Note	(23,793)	(25,384)
Net deferred tax asset (prevaluation allowance)	25,995	54,946
Valuation allowance	(25,995)	(54,946)
Net deferred tax asset	$ -	$ -

A reconciliation of the Company's effective tax rate for 2009, 2008 and 2007, follows:

	2009	2008	2007
Federal rate	35.0 %	35.0 %	35.0 %
State rate — net of federal benefit	4.5	4.5	4.5
Patronage allocation to members	(35.4)	(31.3)	(28.0)
Tax benefit of operating loss carryforwards and other	(4.1)	(8.2)	(11.5)
Alternative minimum tax	0.2	18.0	-
Effective tax rate	0.2 %	18.0 %	- %

The Company files a federal income tax return, as well as several state income tax returns. The years currently open for federal tax examination are 2005 through 2009 and 1990 through 1997, due to unused net operating loss carryforwards. The major state tax jurisdiction currently open for tax examination is Kentucky for years 2002 through 2009 and years 1990 through 1997, also due to unused net operating loss carryforwards. The Company has not recorded any unrecognized tax benefits or liabilities related to federal or state income taxes.

The Company classifies interest and penalties as an operating expense on the income statement and accrued expense in the balance sheet. No interest or penalties have been recorded during 2007, 2008, or 2009.

8. POWER PURCHASED

Prior to the Unwind Transaction and in accordance with the Lease Agreement, Big Rivers supplied all of the members' requirements for power to serve their customers, other than the Aluminum Smelters. Contract limits were established in the Lease Agreement and included minimum and maximum hourly and annual power purchase amounts. Big Rivers could not reduce the contract limits by more than 12 MW in any year or by more than a total of 72 MW over the lease term. In the event Big Rivers failed to take the minimum requirement during any hour or year, Big Rivers was liable to LEM for a certain percentage of the difference between the amount of power actually taken and the applicable minimum requirement.

Although Big Rivers was required by the Lease Agreement to purchase minimum hourly and annual amounts of power from LEM, the lease did not prevent Big Rivers from paying the associated penalty in certain hours to purchase lower cost power, if available, in the open market or reselling a portion of its purchased power to a third party. The power purchases made under this agreement for the years ended December 31, 2009, 2008, and 2007, were $51,592, $99,700, and $96,295, respectively, and are included in power purchased and interchanged on the statement of operations.

9. PENSION PLANS

Defined Benefit Plans — Big Rivers has noncontributory defined benefit pension plans covering substantially all employees who meet minimum age and service requirements and who were employed by the Company prior to the plans closure dates cited below. The plans provide benefits based on the participants' years of service and the five highest consecutive years' compensation during the last ten years of employment. Big Rivers' policy is to fund such plans in accordance with the requirements of the Employee Retirement Income Security Act of 1974.

The salaried employees defined benefit plan was closed to new entrants effective January 1, 2008, and the bargaining employees defined benefit plan was closed to new hires effective November 1, 2008. The Company simultaneously established base contribution accounts in the defined contribution thrift and 401(k) savings plans, which were renamed as the retirement savings plans. The base contribution account for an eligible employee, which is one who meets the minimum age and service requirements, but for whom membership in the defined benefit plan is closed, is funded by employer contributions based on graduated percentages of the employee's pay, depending on his or her age.

The Company has adopted FASB ASC 715, *Defined Benefit Plans*, including the requirement to recognize the funded status of its pension plans and other postretirement plans (see Note 12 — Postretirement Benefits Other Than Pensions). FASB ASC 715 defines the funded status of a defined benefit pension plan as the fair value of its assets less its projected benefit obligation, which includes projected salary increases, and defines the funded status of any other postretirement plan as the fair value of its assets less its accumulated postretirement benefit obligation.

FASB ASC 715 also requires an employer to measure the funded status of a plan as of the date of its year-end balance sheet and requires disclosure in the notes to the financial statements certain additional information related to net periodic benefit costs for the next fiscal year. The Company's pension and other postretirement benefit plans are measured as of December 31, 2009 and 2008.

The following provides an overview of the Company's noncontributory defined benefit pension plans.

A reconciliation of the Company's benefit obligations of its noncontributory defined benefit pension plans at December 31, 2009 and 2008, follows:

	2009	2008
Benefit obligation — beginning of period	$24,253	$19,889
Service cost — benefits earned during the period	1,241	1,072
Interest cost on projected benefit obligation	1,466	1,220
Participant contributions (lump sum repayment)	40	318
Plan settlements	262	-
Benefits paid	(3,945)	(248)
Actuarial loss	2,176	2,002
Benefit obligation — end of period	$25,493	$24,253

The accumulated benefit obligation for all defined benefit pension plans was $18,630 and $18,568 at December 31, 2009 and 2008, respectively.

A reconciliation of the Company's pension plan assets at December 31, 2009 and 2008, follows:

	2009	2008
Fair value of plan assets — beginning of period	$20,295	$21,820
Actual return on plan assets	4,820	(5,095)
Employer contributions	1,060	3,500
Participant contributions (lump sum repayment)	40	318
Benefits paid	(3,945)	(248)
Fair value of plan assets — end of period	$22,270	$20,295

The funded status of the Company's pension plans at December 31, 2009 and 2008, follows:

	2009	2008
Benefit obligation — end of period	$(25,493)	$(24,253)
Fair value of plan assets — end of period	22,270	20,295
Funded status	$(3,223)	$(3,958)

Components of net periodic pension costs for the years ended December 31, 2009, 2008, and 2007, were as follows:

	2009	2008	2007
Service cost	$1,241	$1,072	$958
Interest cost	1,466	1,220	1,058
Expected return on plan assets	(1,332)	(1,516)	(1,167)
Amortization of prior service cost	19	19	19
Amortization of actuarial loss	834	247	285
Settlement loss	1,690	-	-
Net periodic benefit cost	$3,918	$1,042	$1,153

A reconciliation of the pension plan amounts in accumulated other comprehensive income at December 31, 2009 and 2008, follows:

	2009	2008
Prior service cost	$ (59)	$ (78)
Unamortized actuarial (loss)	(9,651)	(13,226)
Accumulated other comprehensive income	$(9,710)	$(13,304)

In 2010, $19 of prior service cost and $560 of actuarial loss is expected to be amortized to periodic benefit cost.

The recognized adjustments to other comprehensive income at December 31, 2009 and 2008, follows:

	2009	2008
Prior service cost	$ 19	$ 19
Unamortized actuarial (loss)	3,575	(8,365)
Other comprehensive income	$3,594	$(8,346)

At December 31, 2009 and 2008, amounts recognized in the statement of financial position were as follows:

	2009	2008
Deferred credits and other	$(3,223)	$(3,958)

Assumptions used to develop the projected benefit obligation and determine the net periodic benefit cost were as follows:

	2009	2008	2007
Discount rate — projected benefit obligation	5.59 %	6.38 %	6.25 %
Discount rate — net periodic benefit cost	6.38	6.25	5.75
Rates of increase in compensation levels	4.00	4.00	4.00
Expected long-term rate of return on assets	7.25	7.25	7.25

The expected long-term rate of return on plan assets for determining net periodic pension cost for each fiscal year is chosen by the Company from a best estimate range determined by applying anticipated long-term returns and long-term volatility for various asset categories to the target asset allocation of the plans, as well as taking into account historical returns.

Using the asset allocation policy adopted by the Company noted in the paragraph below, we determined the expected rate of return at a 50% probablity of achievement Level based on (a) forward-looking rate of return expectations for passively-managed asset categories over a 20-year time horizon and (b) historical rates of return for passively-managed asset categories. Applying an approximately 80%/20% weighting to the rates determined in (a) and (b), respectively, produced an expected rate of return of 7.28%, which was rounded to 7.25%.

Big Rivers utilizes a third party investment manager for the plan assets, and has communicated thereto the Company's Retirement Plan Investment Policy, including a target asset allocation mix of 50% U.S. Equities (an acceptable range of 45-55%), 15% International Equities (an acceptable range of 10-20%), and 35% fixed income (an acceptable range of 30-40%). As of December 31, 2009 and 2008, the investment allocation was 55% and 40%, respectively, in U.S. Equities, 11% and 7%, respectively, in International Equities, and 34% and 53%, respectively, in fixed income. The objective of the investment program seeks to (a) maximize return on investment, (b) minimize volatility, (c) minimize company contributions, and (d) provide the employee benefit in accordance with the plans. The portfolio is well diversified and of high quality. The average quality of the fixed income investments must be "A" or better. The Equity portfolio must also be of investment grade quality. The performance of the investment manager is reviewed semi-annually.

At December 31, 2009, the fair value of Big Rivers' defined benefit pension plan assets by asset category are as follows:

	Level 1	Level 2	Total
Cash and Money Market	$ 815	$ -	$ 815
Equity Securities:			
U.S. large-cap stocks	8,580	-	8,580
U.S. mid-cap stock mutual funds	2,064	-	2,064
U.S. small-cap stock mutual funds	1,282	-	1,282
International stock mutual funds	2,328	-	2,328
Preferred stock	404	-	404
Fixed:			
U.S. Government Agency Bonds	-	2,139	2,139
Taxable U.S. Municipal Bonds	-	2,282	2,282
U.S. Corporate Bonds	-	2,376	2,376
	$15,473	$6,797	$22,270

Expected retiree pension benefit payments projected to be required during the years following 2009 are as follows:

Years Ending December 31	Amount
2010	$ 2,033
2011	1,868
2012	2,911
2013	4,043
2014	2,041
2015–2019	13,642
Total	$26,538

In 2010, the Company expects to contribute $1,096 to its pension plan trusts.

Defined Contribution Plans — Big Rivers has two defined contribution retirement plans covering substantially all employees who meet minimum age and service requirements. Each plan has a thrift and 401(k) savings section allowing employees to contribute up to 75% of pay on a pre-tax and/or after-tax basis, with employer matching contributions equal to 60% of the first 6% contributed by the employee on a pre-tax basis.

A base contribution retirement section was added and the plan name changed from thrift and 401(k) savings to retirement savings, effective January 1, 2008, for the salaried plan and November 1, 2008, for the bargaining plan. The base contribution account is funded by employer contributions based on graduated percentages of pay, depending on the employee's age.

The Company's expense under these plans was $355 and $308 for the years ended December 31, 2009 and 2008, respectively.

Deferred Compensation Plan — Effective May 1, 2008, Big Rivers established a nonqualified deferred compensation plan for its eligible employees who are members of a select group of management or highly compensated employees. The purpose of the plan is to allow participants to receive contributions or make deferrals that they could not receive or make under the salaried employees qualified defined contribution retirement savings plan (formerly the thrift and 401(k) savings plan) as a result of nondiscrimination rules and other limitations applicable to the qualified plan under the Internal Revenue Code. The nonqualified plan also allows a participant to defer a percentage of his or her pay on a pre-tax basis.

The nonqualified deferred compensation plan is unfunded, but the Company has chosen to finance its obligations under the plan, including any employee deferrals, through a rabbi trust. The trust assets remain a part of the Company's general assets, subject to the claims of its creditors. The 2009 employer contribution was $33 and deferred compensation expense was $67. As of December 31, 2009, the trust asset was $94 and the deferred liability was $101.

10. RESTRICTED INVESTMENTS

The amortized costs and fair values of Big Rivers restricted investments held for member rate mitigation at December 31, 2009 are as follows:

	Amortized Costs	Fair Values
Cash and Money Market	$25,186	$25,186
Debt Securities:		
U.S. Treasuries	67,895	67,474
U.S. Government Agency	150,144	150,181
Total	$243,225	$242,841

Gross unrealized gains and losses on restricted investments at December 31, 2009 were as follows:

	Gains	Losses
Cash and Money Market	$ -	$ -
Debt Securities:		
U.S. Treasuries	12	434
U.S. Government Agency	79	41
Total	$91	$475

Debt securities at December 31, 2009 mature, according to their contractual terms, as follows (actual maturities may differ due to call or prepayment rights):

	Amortized Costs	Fair Values
In one year or less	$46,102	$46,112
After one year through five years	197,123	196,729
Total	$243,225	$242,841

Gross unrealized losses on investments and the fair values of the related securities, aggregated by investment category and length of time that individual securities have been in a continuous unrealized loss position at December 31, 2009, were:

	Less Than 12 Months	
	Losses	Fair Values
Debt securities:		
U.S. Treasuries	$434	$59,872
U.S. Government Agency	41	45,026
Total	$475	$104,898

The unrealized loss positions were primarily caused by interest rate fluctuations. The number of investments in an unrealized loss position as of December 31, 2009 was eight. Since the company does not intend to sell and will more likely than not maintain each debt security until its anticipated recovery, and no significant credit risk is deemed to exist, these investments are not considered other-than-temporarily impaired.

The restricted investments related to cash and money market investments are classified as trading securities under ASC 320 and were recorded at fair value using quoted market prices for identical assets without regard to valuation adjustment or block discount (a Level 1 measure), as follows:

Cash and Money Market	$25,186

11. FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

FASB ASC 820, *Fair Value Measurements and Disclosures,* defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measures. It applies under other accounting standards that require or permit fair value measurements and does not require any new fair value measurements. This standard of FASB ASC 820 is effective for fiscal years beginning after November 15, 2007. The adoption of the standards of FASB ASC 820 had no impact on the Company's results of operations and financial condition.

The carrying value of accounts receivable, and accounts payable approximate fair value due to their short maturity. At December 31, the Company's cash and cash equivalents included short-term investments in an institutional money market government portfolio account classified as trading securities under ASC 320 that were recorded at fair value which were determined using quoted market prices for identical assets without regard to valuation adjustment or block discount (a Level 1 measure), as follows:

	2009	2008
Institutional money market government portfolio	$59,887	$38,424

It was not practical to estimate the fair value of patronage capital included within other deposits and investments due to these being untraded companies.

Big Rivers' long-term debt at December 31, 2009 consists of RUS notes totaling $706,452 and variable rate pollution control bonds in the amount of $142,100 (see Note 5). The RUS debt cannot be traded in the market and, therefore, a value other than its outstanding principal amount cannot be determined. The fair value of the Company's variable rate pollution control debt is par value, as each variable rate reset effectively prices such debt to the current market.

12. POSTRETIREMENT BENEFITS OTHER THAN PENSIONS

Big Rivers provides certain postretirement medical benefits for retired employees and their spouses. Generally, except for generation bargaining retirees, Big Rivers pays 85% of the premium cost for all retirees age 62 to 65. The Company pays 25% of the premium cost for spouses under age 62. For salaried retirees age 55 to age 62, Big Rivers pays 25% of the premium cost. Beginning at age 65, the Company pays 25% of the premium cost if the retiree is enrolled in Medicare Part B. For each generation bargaining retiree, Big Rivers establishes a retiree medical account at retirement equal to $1,200 per year of service up to 30 years ($1,250 per year for those retiring on or after 1/1/12). The account balance is credited with interest based on the 10-year treasury rate subject to a minimum of 4% and a maximum of 7%. The account is to be used for the sole purpose of paying the premium cost for the retiree and spouse.

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Medicare Act") was enacted. The Medicare Act created Medicare Part D, a new prescription drug benefit that is available to all Medicare-eligible individuals, effective January 1, 2006. National Rural Electric Cooperative Association (NRECA), the provider of Big Rivers' health plan coverage through the NRECA Group Benefits Trust, chose to become a Medicare Part D provider. Effective January 1, 2006, Part D coverage is the only drug coverage available to Big Rivers' Medicare-eligible retirees.

The discount rates used in computing the postretirement benefit obligation and net periodic benefit cost were as follows:

	2009	2008	2007
Discount rate — projected benefit obligation	5.78 %	6.32 %	5.85 %
Discount rate — net periodic benefit cost	6.32	5.85	5.75

The health care cost trend rate assumptions as of December 31, 2009 and 2008, were as follows:

	2009	2008
Initial trend rate	7.70 %	7.90 %
Ultimate trend rate	4.50 %	4.50 %
Year ultimate trend is reached	2028	2028

A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	2009	2008
One-percentage-point decrease:		
Effect on total service and interest cost components	$(138)	$(37)
Effect on year end benefit obligation	(989)	(290)
One-percentage-point increase:		
Effect on total service and interest cost components	162	44
Effect on year end benefit obligation	1,134	337

A reconciliation of the Company's benefit obligations of its postretirement plan at December 31, 2009 and 2008, follows:

	2009	2008
Benefit obligation — beginning of period	$2,948	$2,862
Service cost — benefits earned during the period	878	129
Interest cost on projected benefit obligation	464	167
Transaction benefit obligation assumed in the unwind	8,768	-
Participant contributions	48	61
Plan amendments	175	-
Benefits paid	(203)	(179)
Actuarial (gain) or loss	786	(92)
Benefit obligation — end of period	$13,864	$2,948

A reconciliation of the Company's postretirement plan assets at December 31, 2009 and 2008, follows:

	2009	2008
Fair value of plan assets — beginning of period	$ -	$ -
Employer contributions	155	118
Participant contributions	48	61
Benefits paid	(203)	(179)
Fair value of plan assets — end of period	$ -	$ -

The funded status of the Company's postretirement plan at December 31, 2009 and 2008, follows:

	2009	2008
Benefit obligation — end of period	$(13,864)	$(2,948)
Fair value of plan assets — end of period	-	-
Funded status	$(13,864)	$(2,948)

The components of net periodic postretirement benefit costs for the years ended December 31, 2009, 2008, and 2007, were as follows:

	2009	2008	2007
Service cost	$ 878	$ 129	$ 85
Interest cost	464	167	153
Amortization of prior service cost	17	2	2
Amortization of actuarial (gain)	(17)	(60)	(70)
Amortization of transition obligation	31	31	31
Net periodic benefit cost	$1,373	$269	$201

A reconciliation of the postretirement plan amounts in accumulated other comprehensive income at December 31, 2009 and 2008, follows:

	2009	2008
Prior service cost	$(165)	$ (7)
Unamortized actuarial gain	407	1,210
Transition obligation	(92)	(123)
Accumulated other comprehensive income	$150	$1,080

In 2010, $18 of prior service cost, $0 of actuarial gain, and $31 of the transition obligation is expected to be amortized to periodic benefit cost.

The recognized adjustments to other comprehensive income at December 31, 2009 and 2008, follows:

	2009	2008
Prior service cost	$(157)	$ 2
Unamortized actuarial gain	(803)	33
Transition obligation	30	30
Other comprehensive income	$(930)	$65

At December 31, 2009 and 2008, amounts recognized in the statement of financial position were as follows:

	2009	2008
Accounts payable	$ (424)	$ (156)
Deferred credits and other	(13,440)	(2,792)
Net amount recognized	$(13,864)	$(2,948)

Expected retiree benefit payments projected to be required during the years following 2009 are as follows:

Year	Amount
2010	$424
2011	599
2012	827
2013	1,014
2014	1,245
2015–2019	8,342
Total	$12,451

In addition to the postretirement plan discussed above, in 1992 Big Rivers began a postretirement benefit plan which vests a portion of accrued sick leave benefits to salaried employees upon retirement or death. To the extent an employee's sick leave hour balance exceeds 480 hours such excess hours are paid at 20% of the employee's base hourly rate at the time of retirement or death. The accumulated obligation recorded for the postretirement sick leave benefit is $375 and $408 at December 31, 2009 and 2008, respectively. The postretirement expense recorded was $45, $63, and $51 for 2009, 2008, and 2007, respectively, and the benefits paid were $78, $0, and $0 for 2009, 2008, and 2007, respectively.

13. RELATED PARTIES

For the years ended December 31, 2009, 2008, and 2007, Big Rivers had tariff sales to its members of $125,826, $114,514, and $113,281, respectively. In addition, for the years ended December 31, 2009, 2008, and 2007, Big Rivers had certain sales to Kenergy for the Aluminum Smelters and Domtar Paper (formerly Weyerhaeuser) loads of $167,885, $55,124, and $123,094, respectively.

At December 31, 2009 and 2008, Big Rivers had accounts receivable from its members of $35,524 and $16,540, respectively.

14. COMMITMENTS AND CONTINGENCIES

Big Rivers is involved in litigation arising in the normal course of business. While the results of such litigation cannot be predicted with certainty, management, based upon advice of counsel, believes that the final outcome will not have a material adverse effect on the financial statements.

* * * * * *

MEMBER FINANCIAL AND STATISTICAL INFORMATION

Our Members operate their systems on a not-for-profit basis. Accumulated margins remaining after payment of expenses and provision for depreciation constitute patronage capital for the consumers of our Members. Refunds of accumulated patronage capital to individual consumers of our Members are made from time to time on a patronage basis subject to limitations contained in each Member's mortgage with RUS, if applicable, or other applicable debt instruments.

Our Members are our owners and not our subsidiaries. Except with respect to the obligations of our Members under their respective wholesale power contracts and the Smelter Agreements, we have no legal interest in, or obligation in respect of, any of the assets, liabilities, equity, revenue or margins of our Members, other than our rights under these contracts. The revenues of our Members are not pledged to us, but their revenues are the source from which they pay for power and energy and transmission services purchased from us. Revenues of our Members are, however, often pledged under their respective mortgages or other debt instruments.

Unaudited financial and statistical information relating to our Members is set forth below. The tables present a three-year summary of the balance sheets, statements of operations and selected statistical information with respect to our Members. The information contained below has been taken from RUS Financial and Statistical Reports (RUS Form 7) provided to us by our Members. This information about our Members may not be indicative of their future results. In addition, the assets, liabilities, equity, revenue and margins should not be attributed to us.

Table 1
Big Rivers' Members
Selected Statistics
for the Years Ended December 31,

	Kenergy	Meade County	Jackson Purchase
2009:			
Average Monthly Residential Revenue ($)	4,195,793	1,940,410	2,273,613
Average Monthly kWh	59,329,974	27,753,017	32,331,404
Average Residential Revenue (cents per kWh)	7.07	6.99	7.03
Times Interest Earned Ratio	1.48	1.57	1.26
Equity/Assets	24%	29%	34%
Equity/Total Capitalization	30%	32%	40%
2008:			
Average Monthly Residential Revenue ($)	4,173,242	2,016,338	2,272,982
Average Monthly kWh	62,689,055	29,421,135	34,638,005
Average Residential Revenue (cents per kWh)	6.66	6.85	6.56
Times Interest Earned Ratio	1.13	2.03	1.34
Equity/Assets	24%	29%	38%
Equity/Total Capitalization	30%	33%	43%
2007:			
Average Monthly Residential Revenue ($)	4,170,143	1,831,843	2,141,500
Average Monthly kWh	64,058,176	29,264,254	34,553,055
Average Residential Revenue (cents per kWh)	6.51	6.26	6.20
Times Interest Earned Ratio	1.59	1.54	1.31
Equity/Assets	25%	29%	39%
Equity/Total Capitalization	30%	31%	43%

Table 2
Big Rivers' Members
Average Number of Customers Served by Each Member
for the Years Ended December 31,

	Kenergy	Meade County	Jackson Purchase
2009:			
Residential Service	45,111	25,940	26,034
Commercial and Industrial	9,652	2,050	3,063
Other	76	6	12
Total Customers Served	54,839	27,996	29,109
2008:			
Residential Service	45,039	25,808	26,038
Commercial and Industrial	9,621	2,052	3,040
Other	76	6	14
Total Customers Served	54,736	27,866	29,092
2007:			
Residential Service	44,758	25,453	25,782
Commercial and Industrial	9,503	2,041	2,952
Other	76	6	13
Total Customers Served	54,337	27,500	28,747

Table 3
Big Rivers' Members
Annual MWh Sales by Customer Class
for the Years Ended December 31,

	Kenergy	Meade County	Jackson Purchase
2009:			
Residential Service	711,960	333,036	387,977
Commercial and Industrial	8,009,814	95,266	232,273
Other	1,598	1,036	1,033
Total MWh Sales	8,723,372	429,338	621,283
2008:			
Residential Service	752,269	353,054	415,656
Commercial and Industrial	8,666,261	98,173	261,187
Other	1,666	1,018	1,034
Total MWh Sales	9,420,196	452,245	677,877
2007:			
Residential Service	768,698	351,171	414,637
Commercial and Industrial	8,602,978	101,494	265,115
Other	1,583	1,003	1,657
Total MWh Sales	9,373,259	453,668	681,409

Table 4
Big Rivers' Members
Annual Revenues by Customer Class
for the Years Ended December 31,

	Kenergy	Meade County	Jackson Purchase
2009:			
Residential Service	$ 50,349,518	$23,284,922	$27,283,351
Commercial and Industrial	297,780,615	6,825,406	13,504,966
Other	252,392	67,802	109,221
Total Electric Sales	$348,382,525	$30,178,130	$40,897,538
Other Operating Revenue	1,400,341	918,510	1,020,934
Total Operating Revenue	$349,782,866	$31,096,640	$41,918,472
2008:			
Residential Service	$ 50,078,902	$24,196,053	$27,275,780
Commercial and Industrial	307,489,509	6,904,260	13,991,782
Other	244,110	66,009	95,499
Total Electric Sales	$357,812,521	$31,166,322	$41,363,061
Other Operating Revenue	1,686,081	928,236	1,019,877
Total Operating Revenue	$359,498,602	$32,094,558	$42,382,938
2007:			
Residential Service	$ 50,041,715	$21,982,113	$25,697,996
Commercial and Industrial	304,081,544	6,857,483	13,587,009
Other	219,014	64,438	87,394
Total Electric Sales	$354,342,273	$28,904,034	$39,372,399
Other Operating Revenue	1,531,503	862,710	993,479
Total Operating Revenue	$355,873,776	$29,766,744	$40,365,878

Table 5
Big Rivers' Members
Summary of Operating Results
for the Years Ended December 31,

	Kenergy	Meade County	Jackson Purchase
2009:			
Operating Revenue and Patronage Capital	$349,782,866	$31,096,640	$41,918,472
Depreciation and Amortization	7,970,349	2,956,264	4,325,554
Other Operating Expenses	332,864,173	24,726,916	34,448,281
Electric Operating Margin	$ 8,948,344	$ 3,413,460	$ 3,144,637
Other Income	985,051	246,919	551,311
Gross Operating Margin	$ 9,933,395	$ 3,660,379	$ 3,695,948
Interest on Long-term Debt (1)	6,063,274	2,284,654	2,787,124
Tax Expenses	363,079	32,462	44,969
Other Deductions	567,124	52,403	153,032
Net Margins	$ 2,939,918	$ 1,290,860	$ 710,823
2008:			
Operating Revenue and Patronage Capital	$359,498,602	$32,094,558	$42,382,938
Depreciation and Amortization	7,726,978	2,842,245	3,881,043
Other Operating Expenses	345,289,107	24,822,687	35,414,883
Electric Operating Margin	$ 6,482,517	$ 4,429,626	$ 3,087,012
Other Income	815,095	298,024	452,538
Gross Operating Margin	$ 7,297,612	$ 4,727,650	$ 3,539,550
Interest on Long-term Debt (1)	5,997,518	2,281,927	2,510,302
Tax Expenses	322,879	32,994	44,038
Other Deductions	192,084	52,519	129,350
Net Margins	$ 785,131	$ 2,360,210	$ 855,860
2007:			
Operating Revenue and Patronage Capital	$355,873,776	$29,766,744	$40,365,878
Depreciation and Amortization	7,415,079	2,702,559	3,433,896
Other Operating Expenses	340,042,623	23,911,521	33,968,199
Electric Operating Margin	$ 8,416,074	$ 3,152,664	$ 2,963,783
Other Income	1,256,081	363,626	597,872
Gross Operating Margin	$ 9,672,155	$ 3,516,290	$ 3,561,655
Interest on Long-term Debt (1)	5,703,124	2,222,123	2,615,535
Tax Expenses	295,302	34,075	43,167
Other Deductions	266,780	49,369	82,890
Net Margins	$ 3,406,949	$ 1,210,723	$ 820,063

(1) Interest on Long-term Debt is net of Interest Charged to Construction.

Table 6
Big Rivers' Members
Condensed of Balance Sheet Information
As of December 31,

	Kenergy	Meade County	Jackson Purchase
2009:			
ASSETS:			
Total Utility Plant (1)	$239,783,186	$91,162,723	$126,585,904
Depreciation	62,290,462	24,560,838	39,314,177
Net Plant	177,492,724	66,601,885	87,271,727
Other Assets	60,673,832	12,737,097	19,302,499
Total Assets	$238,166,556	$79,338,982	$106,574,226
EQUITY AND LIABILITIES:			
Equity	$57,985,783	$23,169,273	$36,395,561
Long-term Debt	133,279,836	48,493,205	54,944,634
Other Liabilities	46,900,937	7,676,504	15,234,031
Total Equity and Liabilities	$238,166,556	$79,338,982	$106,574,226
2008:			
ASSETS:			
Total Utility Plant (1)	$233,759,559	$87,115,338	$119,013,194
Depreciation	59,219,789	22,768,128	37,017,719
Net Plant	174,539,770	64,347,210	81,995,475
Other Assets	49,209,717	10,588,234	10,862,358
Total Assets	$223,749,487	$74,935,444	$ 92,857,833
EQUITY AND LIABILITIES:			
Equity	$54,242,729	$22,006,214	$35,664,571
Long-term Debt	127,078,125	45,582,373	47,469,582
Other Liabilities	42,428,633	7,346,857	9,723,680
Total Equity and Liabilities	$223,749,487	$74,935,444	$ 92,857,833
2007:			
ASSETS:			
Total Utility Plant (1)	$224,786,800	$83,626,010	$113,200,271
Depreciation	53,319,541	20,865,845	34,096,756
Net Plant	171,467,259	62,760,165	79,103,515
Other Assets	53,037,690	8,677,372	9,790,190
Total Assets	$224,504,949	$71,437,537	$ 88,893,705
EQUITY AND LIABILITIES:			
Equity	$55,307,516	$20,828,346	$34,759,030
Long-term Debt	129,556,978	46,264,913	46,768,664
Other Liabilities	39,640,455	4,344,278	7,366,011
Total Equity and Liabilities	$224,504,949	$71,437,537	$ 88,893,705

(1) Including construction work in progress.

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SUMMARY OF CERTAIN PROVISIONS OF THE FINANCING AGREEMENT AND THE NOTE

The following is a summary of certain provisions of the Financing Agreement and the Note and is not to be considered as a full statement of the provisions thereof. This summary is qualified by reference to and is subject to the complete Financing Agreement and the complete Note, copies of which are available for inspection at our principal offices and the principal offices of the Trustee. All capitalized terms used in this APPENDIX C summary and not defined herein or elsewhere in the Offering Statement shall have the meanings given to them in the Financing Agreement.

The Note

Concurrently with the sale and delivery by the County of the Bonds, we will execute and deliver to the Trustee a Note in an aggregate principal amount equal to the aggregate principal amount of the Bonds delivered by the County. Payments required to be made on the Note will be in amounts sufficient to pay the principal of and interest on the Bonds when due.

Other Payment Obligations

We will pay the reasonable fees and actual out-of-pocket expenses (including counsel fees) necessarily incurred by the County in connection with the Bonds, the issuance and sale thereof and the transaction contemplated by the Bond Indenture, the Mortgage Indenture, the Note and the Financing Agreement, and for the services of the Trustee, the Paying Agent and any co-paying agent.

Term of Financing Agreement

The Financing Agreement will continue in full force and effect until the principal of and interest on all of the Bonds, and all other amounts required to be paid by us under the Financing Agreement, have been paid in full or provision for such payment has been made.

Obligations of Big Rivers Unconditional

Our obligations to make the payments pursuant to the Financing Agreement and the Note are absolute and unconditional. Regardless of whether the Facilities are complete, operating or operable, until such time as the principal of and interest on the Bonds shall have been fully paid or provision for the payment thereof shall have been made in accordance with the Bond Indenture, we (1) will not suspend or discontinue any payments pursuant to the Financing Agreement or the Note, (2) will perform and observe all our other agreements contained in the Financing Agreement and in the Note, and (3) except in the case of a prepayment in whole of the Note, will not terminate the Financing Agreement for any cause, including any acts or circumstances that may constitute failure of consideration, destruction of or damage to the applicable Facilities, commercial frustration of purpose, any change in the tax or other laws or administrative rulings of the United States of America or the Commonwealth of Kentucky or any political subdivision thereof or any failure of the County to perform and observe any agreement, whether express or implied, or any duty, liability or obligation arising out of or connected with the Financing Agreement, whether express or implied.

Assignment

Under certain conditions we may assign our interest in the Financing Agreement without the necessity of obtaining the consent of either the County or the Trustee, but such assignment shall not relieve us from primary liability for any of our obligations under the Financing Agreement. Any assignee shall assume our obligations under the Financing Agreement to the extent assigned.

Taxes and Other Governmental Charges

We will pay during the term of the Financing Agreement, as the same become due, all taxes and governmental charges of any kind whatsoever that may at any time be lawfully assessed or levied against or with respect to the Facilities. Compliance with the provisions of the Mortgage Indenture shall constitute compliance with such covenant in the Financing Agreement. The Mortgage Indenture provides that we may, without violating the covenant, withhold payment of any tax or other governmental charge we are contesting the validity thereof by appropriate proceeding in good faith, so long as we shall have set aside on our books adequate reserves with respect thereto.

Tax Covenants

We will covenant that we will not take any action which would adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes pursuant to Section 103 of the Internal Revenue Code of 1954, as amended and Title XIII of the Tax Reform Act of 1986, and the regulations promulgated thereunder (collectively, the "1954 Code"), and will take, or require to be taken, such acts as may be reasonably within our ability and as may from time to time be required under applicable law or regulation to continue the exclusion of the interest on the Bonds from gross income for federal income tax purposes; and in furtherance of such covenants, we will comply with the Tax Certificate and Agreement, dated the date of delivery of the Bonds, executed and delivered by Big Rivers and the Country, as the same may be amended from time to time (the "Tax Certificate") and the provisions of Section 103 of the 1954 Code. We will also covenant that we (1) will not take any action or fail to take any action with respect to the Bonds which would cause the Bonds to be "arbitrage bonds" within the meaning of Section 148 of the Internal Revenue Code of 1986, as incorporated into the 1954 Code by Title XIII of the Tax Reform Act of 1986 and any regulations promulgated or proposed thereunder; and (2) will not use or permit the use of any property financed or refinanced with the proceeds of the Bonds by any person (other than a state or local governmental unit) in such manner or to such extent as would result in loss of the exclusion of the interest on the Bonds from gross income for federal income tax purposes (other than during the period the Bonds are held by a "substantial user" of the facilities financed or refinanced with the proceeds of the Bonds or a "related person" within the meaning of Section 103(b)(13) of the 1954 Code).

Notwithstanding any other provisions of the Financing Agreement to the contrary, so long as necessary in order to maintain the exclusion of interest on the Bonds from gross income for federal income tax purposes under Section 103(a) of the 1954 Code, the covenants described in the preceding paragraph shall survive the payment for the Bonds and the interest thereon, including any payment or defeasance thereof pursuant to the Bond Indenture.

Defaults

Any of the following events will constitute an "event of default" under the Financing Agreement:

(1) Our failure to pay when due any amount required to be paid under the Note to the Trustee for deposit into the Bond Fund.

(2) Acceleration of payment of any Mortgage Indenture Obligation pursuant to an "event of default" as such term is defined in the Mortgage Indenture.

(3) Certain events of bankruptcy, dissolution, liquidation or reorganization relating to us.

Remedies

Upon the happening and continuance of an event of default, the County, or the Trustee, as provided in the Bond Indenture:

(1) shall, by written notice to us, upon the acceleration of the Bonds, declare that an amount equal to the principal of and accrued interest on the Note has matured and is therefore immediately due and payable; and

(2) may take whatever action at law or in equity may appear necessary or desirable to collect the amounts then due and thereafter to become due under the Note and the Financing Agreement, or to enforce performance and observance of any obligation, agreement or covenant of ours under the Financing Agreement or the Note.

Any declaration accelerating amounts due under the Note will be rescinded upon rescission of any declaration of any acceleration of the Bonds (see "SUMMARY OF CERTAIN PROVISIONS OF THE BOND INDENTURE – Events of Default; Remedies"). Any amounts collected pursuant to action taken upon the happening of any event of default shall be paid into the Bond Fund and applied in accordance with the provisions of the Bond Indenture.

No Pecuniary Liability of the County

No provision, covenant or agreement contained in the Financing Agreement or the Note, nor any breach thereof, will constitute or give rise to a pecuniary liability of the County or a charge against its general credit or taxing powers. The County has not obligated itself in making the covenants, agreements or provisions contained in the Financing Agreement, except with respect to the Financing Agreement and the application of the revenues therefrom.

Amendments, Changes and Modifications

No amendment, change, modification, alteration or termination of the Financing Agreement is permissible without the written consent of the Trustee, which consent shall be given in accordance with the Bond Indenture. Pursuant to the provisions of the Bond Indenture, the consent of the Holders of not less than a majority in aggregate principal amount of all Bonds then outstanding is required for any amendment, change or modification of the Financing Agreement. Without the consent or notice of the holders, the County and the Trustee may consent to any amendment, change or modification of the Financing Agreement or Note as may be required (1) by the provisions of the Financing Agreement, the Note and the Bond Indenture, (2) for the purpose of curing any ambiguity or formal defect or omission in the Financing Agreement, (3) to conform to any modifications to or alterations permitted by the Mortgage Indenture or the Bond Indenture, if such provisions are necessary or desirable and do not in the sole opinion of the Trustee materially adversely affect the interest of the Holders or (4) in connection with any other change in the Financing Agreement which, in the judgment of the Trustee, is not to the prejudice of the Trustee or materially adverse to the interests of the Holders of the Bonds. The Trustee may in its discretion determine whether or not in accordance with the foregoing powers of amendment the interests of the Holders of the Bonds would be adversely affected by any such modification or amendment, and any such determination of the Trustee shall be binding and conclusive on us, the County and the Holders of the Bonds. The Trustee shall have no liability as a result of any such determination made in good faith.

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SUMMARY OF CERTAIN PROVISIONS OF THE BOND INDENTURE

The following is a summary of certain provisions of the Bond Indenture and is not to be considered as a full statement of the provisions thereof. This summary is qualified by reference to and is subject to the complete Bond Indenture, copies of which are available for inspection at our principal offices and the principal offices of the Trustee. The Bonds are issued under the Bond Indenture and are payable from and secured by a pledge of the Trust Estate for the Bonds, including revenues derived by the County under the Financing Agreement and the Note. All capitalized terms used in this APPENDIX D and not defined herein or elsewhere in this Offering Statement shall have the meanings given to them in the Bond Indenture.

Limited Pledge

The Bonds issued and at any time Outstanding are in all respects equally and ratably secured by the Bond Indenture, without preference, priority or distinction on account of the date or dates or the actual time or times of the issuance or maturity of the Bonds, so that all Bonds at any time issued and Outstanding under the Bond Indenture have the same right, lien and preference under and by virtue of the Bond Indenture. The principal of and interest on the Bonds is payable solely out of the Receipts and Revenues of the County from the Financing Agreement and other security pledged by the Bond Indenture and are not general obligations of the County and will never constitute nor give rise to a pecuniary liability of the County or a charge against its general credit or taxing powers.

Bond Fund; Application of Revenues

A Bond Fund is established under the Bond Indenture as a trust fund to be used by the Trustee to pay when due the principal of and interest on the Bonds. The payments on the Note are to be remitted directly to the Trustee for the account of the County and deposited in the Bond Fund. The Bond Indenture provides that said payments shall be sufficient in amount to pay the principal of and interest on the Bonds when due. The entire amount of Receipts and Revenues are pledged to the payment of the principal of and interest on the Bonds.

The Receipts and Revenues are the amounts payable by us under the Financing Agreement. These amounts are equal to the principal of the Bonds when due at maturity and interest on the Bonds when due from time to time. Our obligation to pay these amounts is evidenced by the Note under the Financing Agreement.

Under the Financing Agreement, the County has covenanted and agreed that so long as any of the Bonds are Outstanding it will deposit, or cause to be deposited, in the Bond Fund sufficient sums from the Receipts and Revenues promptly to meet and pay the principal of and interest on the Bonds when due. A Bond is "Outstanding" within the meaning of the Bond Indenture if it has been authenticated and delivered, unless (i) such Bond has been cancelled or acquired by the Trustee for cancellation, (ii) cash has been deposited with the Trustee in an amount equal to the principal thereof and interest thereon to maturity, (iii) such Bond has otherwise been paid in accordance with the defeasance provisions of the Bond Indenture, or (iv) another Bond has been authenticated and delivered in exchange or in substitution for such Bond.

Investments

Any moneys held as a part of the Bond Fund shall be invested or reinvested by the Trustee, to the extent permitted by law, and in accordance with the Bond Indenture, in Investment Securities selected by us. Investment Securities are defined as the following securities, maturing or redeemable at the option of the holder thereof at such time or times as to enable disbursements to be made from the Bond Fund, in accordance with the terms of the Bond Indenture, or which shall be marketable prior to the maturities thereof:

(a) Direct obligations of, or obligations guaranteed by, the United States of America;

(b) Obligations of any of the following federal agencies which obligations represent the full faith and credit of the United States of America:

Export-Import Bank
Farm Credit System Financial Assistance Corporation
Farmers Home Administration
General Services Administration
U.S. Maritime Administration
Small Business Administration
Government National Mortgage Association
U.S. Department of Housing & Urban Development; and
Federal Housing Administration;

(c) United States dollar denominated certificates of deposit (whether negotiable or non-negotiable), demand deposits, time deposits and banker's acceptances with any bank or trust company organized under the laws of any state of the United States of America or any national banking association whose deposit obligations on the date of purchase are rated either "A-1" or better by S&P and "P-1" or better by Moody's (provided that a rating on a holding company shall not be deemed to be such rating on a subsidiary bank);

(d) Commercial paper which is rated at the time of purchase either "A-1" or better by S&P and "P-1" or better by Moody's and which matures not more than 270 days after the date of purchase;

(e) Senior debt obligations rated "AAA" by S&P and "Aaa" by Moody's issued by the Federal National Mortgage Association or the Federal Home Loan Mortgage Corporation;

(f) Investments in a money market fund rated "AAAm" or "AAAm-G" or better by S&P;

(g) Pre-refunded Municipal Obligations defined as follows: Any bonds or other obligations of any state of the United States of America or of any agency, instrumentality or local governmental unit of any such state which are not callable at the option of the obligor prior to maturity or as to which irrevocable instructions have been given by the obligor to call on the date specified in the notice; and

(1) which are rated, based on an irrevocable escrow account or fund (the "escrow"), in the highest rating category of S&P and Moody's or any successors thereto; or

(2)(A) which are fully secured as to principal and interest and redemption premium, if any, by an escrow consisting only of cash or obligations described in paragraph (a) above, which escrow may be applied only to the payment of such principal of and interest and redemption premium, if any, on such bonds or other obligations on the maturity date or dates thereof or the specified redemption date or dates pursuant to such irrevocable instructions, as appropriate and (B) which escrow is sufficient, as verified by a nationally recognized firm of independent certified public accountants, to pay principal of and interest and redemption premium, if any, on the bonds or other obligations described in this paragraph on the maturity date or dates specified in the irrevocable instructions referred to above, as appropriate.

Tax Covenant

The County covenants to maintain the exclusion of interest on the Bonds from gross income for federal income tax purposes pursuant to Section 103 of the Internal Revenue Code of 1954, as amended and Title XIII of the Tax Reform Act of 1986 (the "1954 Code"), and will take, or require to be taken, such acts as may be reasonably within its ability and as may from time to time be required under applicable law and regulation to continue the exclusion of the interest on the Bonds from gross income for federal income tax purposes; and in furtherance of such covenants, the County agrees to comply with the Tax Certificate and the provisions of Section 103 of the 1954 Code. The County further covenants that it will not take any action or fail to take any action with respect to the Bonds which would cause the Bonds to be "arbitrage Bonds" within the meaning of such term as used in Section 148 of the Internal Revenue Code of 1986 (the "1986 Code"), as incorporated into the 1954 Code by Title XIII of the Tax Reform Act of 1986, and any regulations promulgated or proposed thereunder. The County shall make any and all payments required to be made to the United States Department of the Treasury in connection with the Bonds pursuant to Section 148(f) of the 1986 Code, as incorporated into the 1954 Code by Title XIII of the Tax Reform Act of 1986, from amounts on deposit in the funds and accounts established under the Bond Indenture and available therefor. The County covenants that it will not use or permit the use of any property financed or refinanced with the proceeds of the Bonds by any person (other than a state or local governmental unit) in such manner or to such extent as would result in a loss of exclusion of the interest on the Bonds from gross income for federal income tax purposes (other than during the period the Bonds are held by a "substantial user" of the facilities financed or refinanced with proceeds of the Bonds or a "related person" within the meaning of Section 103(b)(13) of the 1954 Code).

Notwithstanding any other provisions of the Bond Indenture to the contrary, so long as necessary in order to maintain the exclusion of interest on the Bonds from gross income for federal income tax purposes under Section 103(a) of the 1954 Code, the covenants described in the preceding paragraph shall survive the payment of the Bonds and the interest thereon, including any payment or defeasance thereof pursuant to the Bond Indenture.

Events of Default; Remedies

The following each constitute an "Event of Default" for the purposes the Bond Indenture:

(a) payment of the principal of any of the Bonds (whether maturity, upon a call for redemption or otherwise) or interest on any of the Bonds shall not be made within one Business Day of when due with the result that such principal or interest remains unpaid as of such date; or

(b) failure by us to pay when due any amount required to be paid under the Note to the Trustee for deposit into the Bond Fund; or

(c) acceleration of payment of any Mortgage Indenture Obligations pursuant to an event of default as defined in the Mortgage Indenture; or

(d) we file a petition in bankruptcy or are adjudicated as bankrupt or insolvent; or we make an assignment for the benefit of our creditors, or consent to the appointment of a receiver of ourselves or of our property, or institute proceedings for our reorganization, or proceedings instituted by others for our reorganization are not dismissed within thirty days after the institution thereof, or a receiver or liquidator of us or of any substantial portion of our property is appointed and the order appointing such receiver or liquidator shall not be vacated within thirty days after the entry thereof.

Upon the occurrence and continuance of an Event of Default described in clause (c) above under the Bond Indenture, the Trustee shall, and upon the occurrence and continuance of any other Event of Default under the Bond Indenture, the Trustee may, and upon the written request of the holders of not less than 25.0 percent in aggregate principal amount of the Bonds then Outstanding shall, declare the principal amount of all Bonds then Outstanding and the interest accrued thereon to be immediately due and payable and said principal and interest shall thereupon become immediately due and payable, and the Trustee shall give notice thereof in writing to the County and us, and notice to holders in the same manner as a notice of redemption. Upon any declaration of acceleration under the Bond Indenture, the County and the Trustee shall immediately declare all payments due on the Note to be immediately due and payable as provided in the Financing Agreement.

If at any time after such declaration, but before the Bonds have matured by their terms, all overdue installments of principal and interest upon such Bonds, together with interest on such overdue installments of principal and interest to the extent permitted by law and the reasonable and proper charges, expenses and liabilities of the Trustee, and all other sums then payable by the County under the Bond Indenture (except the principal of, and interest accrued since the next preceding interest payment date on, the Bonds due and payable solely by virtue of such declaration) shall either be paid by or for the account of the County or provision satisfactory to the Trustee shall be made for such payment, and all defaults under such Bonds or under the Bond Indenture (other than the payment of principal and interest due and payable solely by reason of such declaration) shall be made good or be secured to the satisfaction of the Trustee or provision deemed by the Trustee to be adequate shall be made therefor, then and in every such case the holders of fifty percent in aggregate principal amount of the Bonds Outstanding, by written notice to the County and to the Trustee may rescind such declaration and annul such default in its entirety. In such event, the Trustee shall rescind any declaration of acceleration of maturity of principal and interest on the Note, as provided in the Financing Agreement.

In case of any rescission, then and in every such case the County, the Trustee and the holders shall be restored to their former positions and rights under the Bond Indenture, respectively, but no such rescission shall extend to any subsequent or other default or Event of Default or impair any right consequent thereon, nor shall such rescission extend to any instance in which the holder of any Mortgage Indenture Obligation other than the Note has subsequent to a request for rescission declared all unpaid principal of and accrued interest on such other Mortgage Indenture Obligation to be due and payable immediately.

Exercise of Remedies by Trustee

Upon the happening of any Event of Default or upon the failure by the County to observe and perform any covenant, condition, agreement or provision contained in the Bonds or the Bond Indenture, then and in every such case the Trustee in its discretion may, and upon the written request of the holders of not less than twenty-five percent in principal amount of the Bonds then Outstanding and receipt of indemnity to its satisfaction shall, in its own name and as the Trustee of an express trust:

(a) by mandamus, or other suit, action or proceeding at law or in equity, enforce all rights of the holders, and require us or the County to carry out any agreements with or for the benefit of the holders and to perform its or their duties under the Act, the Financing Agreement, the Note and the Bond Indenture;

(b) bring suit upon the Bonds;

(c) by action or suit in equity require the County to account as if it were the trustee of an express trust for the holders; or

(d) by action or suit in equity enjoin any acts or things which may be unlawful or in violation of the rights of the holders.

In case any proceeding taken by the Trustee to enforce any right under the Bond Indenture shall have been discontinued or abandoned for any reason, or shall have been determined adversely to the Trustee, then and in every case the County, the Trustee and the holders shall be restored to their former positions and rights thereunder, respectively, and all rights, remedies and powers of the Trustee shall continue as though no such proceeding had been taken.

Holder Direction of Remedial Proceedings

The holders of a majority in principal amount of the Bonds then Outstanding shall have the right, by an instrument in writing executed and delivered to the Trustee, to direct the time, method and place of conducting all remedial proceedings available to the Trustee under the Bond Indenture or exercising any trust or power conferred on the Trustee by the Bond Indenture.

Limitations on Proceedings by Holders

No holders shall have any right to institute any suit, action or proceeding in equity or at law for the execution of any trust or power under the Bond Indenture, or any other remedy thereunder or on the Bonds, unless such holders previously shall have given to the Trustee written notice of an Event of Default as described above and unless also the holders of not less than twenty-five percent in principal amount of the Bonds then Outstanding shall have made written request of the Trustee to do so, after the right to institute said suit, action or proceeding shall have accrued, and shall have afforded the Trustee a reasonable opportunity to proceed to institute the same in either its or their name, and unless there also shall have been offered to the Trustee security and indemnity satisfactory to it against the costs, expenses and liabilities to be incurred therein or thereby, and the Trustee shall not have complied with such request within a reasonable time; and such notification, request and offer of indemnity are in every such case, at the option of the Trustee, to be conditions precedent to the institution of said suit, action or proceeding; it being understood and intended that no one or more of the holders shall have any right in any manner whatever by its or their action to affect, disturb or prejudice the security of the Bond Indenture, or to enforce any right thereunder or under the Bonds of the applicable series, except in the manner therein provided, and that all suits, actions and proceedings at law or in equity shall be instituted, had and maintained in the manner therein provided and for the equal benefit of all holders.

Application of Moneys Recovered

Any moneys received by the Trustee, by any receiver or by any holder pursuant to any right given or action taken under the Bond Indenture, after payment of the costs and expenses of the proceedings resulting in the collection of such moneys and of the expenses, liabilities and advances incurred or made by the Trustee, shall be deposited in the Bond Fund, and all moneys so deposited in the Bond Fund during the continuance of an Event of Default (other than moneys for the payment of Bonds which had matured or otherwise become payable prior to such Event of Default or for the payment of interest due prior to such Event of Default) shall be applied as follows:

(a) Unless the principal of all the Bonds has become due and payable, all such moneys shall be applied (i) first, to the payment to the persons entitled thereto of all installments of interest then due on the Bonds, with interest on overdue installments, if lawful, at the same rate or rates per annum as specified in such Bonds, in the order of the maturity of the installments of such interest and, if the amount available shall not be sufficient to pay in full any particular installment with such interest, then to the payment ratably, according to the amounts due on such installment, and (ii) second, to the payment to the persons entitled thereto of the unpaid principal of any of such Bonds which shall have become due at maturity (other than Bonds called for redemption for the payment of which money is held pursuant to the provisions of the Bond Indenture), in the order of their due dates, with interest on such Bonds which shall have become due at their respective rates from the respective dates upon which they became due and, if the amount available shall not be sufficient to pay in full such Bonds which shall have become due on any particular date, together with such interest, then to the payment ratably, according to the amount of principal due on such date, in each case to the persons entitled thereto, without any discrimination or privilege.

(b) If the principal of all the Bonds has become due and payable, all such moneys shall be applied to the payment of the principal and interest then due and unpaid upon the such Bonds, with interest on overdue interest and principal, as aforesaid, without preference or priority of principal over interest or of interest over principal or of any installment of interest over any other installment of interest, or of any Bond over any other Bond, ratably, according to the amounts due respectively for principal and interest, to the persons entitled thereto without any discrimination or privilege.

(c) If the principal of all the Bonds has become due and payable, and if such event shall thereafter have been rescinded and annulled under the provisions of the Bond Indenture, then, subject to the provisions of paragraph (b) which shall be applicable in the event that the principal of all the Bonds shall later become due and payable, the moneys shall be applied in accordance with the provisions of paragraph (a).

Whenever moneys are to be applied pursuant to the provisions of the Bond Indenture described above, such moneys shall be applied at such times, and from time to time, as the Trustee shall determine, having due regard to the amount of such moneys available for application and the likelihood of additional moneys becoming available for such application in the future. Whenever the Trustee shall apply such funds, it shall fix the date (which shall be an interest payment date unless it shall deem another date more suitable) upon which such application is to be made and upon such date interest on the amounts of principal, premium and interest to be paid on such dates shall cease to accrue. The Trustee shall give notice, by mailing, of the deposit with it of any such moneys and of the filing of any such date to any holder until such Bond shall be presented to the Trustee for appropriate endorsement or for cancellation if fully paid.

Modifications and Amendments

Supplemental Bond Indenture without Holder Consent

The County and the Trustee may, from time to time and at any time, without the consent of or notice to holders, enter into supplemental Bond Indentures as follows:

(a) To specify and determine any matters and things relative to the Bonds which are not contrary to or inconsistent with the Bond Indenture and which shall not adversely affect the interests of the holders; or

(b) To cure any ambiguity, or to cure, correct or supplement any defect, omission or inconsistent provisions contained in the Bond Indenture, the Financing Agreement, the Mortgage Indenture, or the Note, or to make any provisions with respect to matters arising under the Bond Indenture or for any other purpose if such provisions are necessary or desirable and if such action does not in the sole opinion of the Trustee adversely affect the interests of the holders; or

(c) To grant to or confer upon the Trustee for the benefit of the holders any additional rights, remedies, powers, authority or security which may lawfully be granted or conferred and which are not contrary to or inconsistent with the Bond Indenture as theretofore in effect; or

(d) To add to the covenants and agreements of the County in the Bond Indenture, other covenants and agreements to be observed by the County which are not contrary to or inconsistent with the Bond Indenture as theretofore in effect; or

(e) To add to the limitations and restrictions in the Bond Indenture, other limitations and restrictions to be observed by the County which are not contrary to or inconsistent with the Bond Indenture as theretofore in effect; or

(f) To confirm, as further assurance, any pledge under, and the subjection to any claim, lien or pledge created or to be created by, the Bond Indenture, of the Receipts and Revenues of the County from the Financing Agreement or of any other moneys, securities or funds; or

(g) To comply with the requirements of the Trust Bond Indenture Act of 1939, as from time to time amended; or

(h) To subject to the Bond Indenture additional revenues; or

(i) To make any other changes which do not in the sole opinion of the Trustee materially adversely affect the interest of the holders.

The Trustee may in its discretion determine whether or not in accordance with the foregoing powers of amendment the interest of any holders would be adversely affected by any modification or amendment of the Bond Indenture and any such determination shall be binding and conclusive on us, the County, and all holders. The Trustee shall have no liability as a result of any such determination made in good faith. The interests of a holder shall be deemed to be adversely affected by any modification or amendment of the Bond Indenture if such modification or amendment adversely affects or diminishes the rights of such holder.

Before the County may enter into any supplemental Bond Indenture without the consent of the holders, there shall have been filed with the Trustee an opinion of a nationally recognized bond counsel firm experienced in the financing of pollution control and solid waste disposal and sewage facilities and acceptable to us and the Trustee (such counsel, a "Bond Counsel") stating that such supplemental Bond Indenture is authorized or permitted by the Bond Indenture and complies with its terms, and that it will be valid and binding upon the County in accordance with its terms; provided, however, that such opinion may take exception for the effect of bankruptcy, insolvency, reorganization, moratorium and other similar laws, judicial decisions and principles of equity relating to or affecting creditors' rights or contractual obligations generally.

Supplemental Bond Indentures with Holder Consent

For amendments not described immediately above, (i) the holders of not less than a majority in aggregate principal amount of the Bonds then Outstanding shall have the right, and (ii) in case of a change in the terms of any sinking fund installment (except as provided in clause (A) of the proviso of this paragraph), the holders of not less than a majority in aggregate principal amount of each maturity of Bonds so affected and Outstanding shall have the right, from time to time to consent to and approve the execution by the County and the Trustee of any supplemental Bond Indenture as shall be deemed necessary or desirable by the County for the purposes of modifying, altering, amending, supplementing or rescinding, in any particular, any of the terms or provisions contained in the Bond Indenture; *provided, however*, that, unless approved in writing by the holders of all affected Bonds then Outstanding, nothing in the Bond Indenture shall permit, or be construed as permitting, (A) a change in the times, amounts or currency of payment of the principal of and interest on any Outstanding Bond, or a reduction in the principal amount or redemption price of any Outstanding Bond or the rate of interest thereon or in any maturity with respect thereto or any sinking fund payment with respect to any Bond, or (B) the creation of a claim or lien upon, or a pledge of, the Receipts and Revenues of the County from the Financing Agreement ranking prior to or on a parity with the claim, lien or pledge created by the Bond Indenture, or (C) a preference or priority of any Bond or Bonds over any other Bond or Bonds, or (D) a reduction in the aggregate principal amount of Bonds the consent of the holders of which is required for any such supplemental Bond Indenture.

If at any time the County shall determine to enter into any supplemental Bond Indenture for any of the permitted purposes, it shall cause notice of the proposed supplemental Bond Indenture to be mailed to the holders. Such notice shall briefly set forth the nature of the proposed supplemental Bond Indenture and shall state that a copy thereof is on file at the office of the Trustee for inspection by all holders.

Within one year after the date of such notice, the County may enter into such supplemental Bond Indenture in substantially the form described in such notice only if there shall have first been filed with the Trustee (a) the written consents of holders of not less than a majority in aggregate principal amount of the Bonds then Outstanding, or, if required thereunder, by all holders, and (b) an opinion of Bond Counsel stating that such supplemental Bond Indenture is authorized or permitted by the Bond Indenture and complies with its terms, and that upon execution and delivery it will be valid and binding upon the County in accordance with its terms; *provided, however*, that such opinion may take exception for the effect of bankruptcy, insolvency, reorganization, moratorium and other similar laws, judicial decisions and principles of equity relating to or affecting creditors' rights or contractual obligations generally.

When Big Rivers Consent Required

Any supplemental Bond Indenture which affects any of our rights, powers and authority under the Bond Indenture, the Financing Agreement or the Note or requires a revision of the Financing Agreement, the Note or the Mortgage Indenture shall not become effective unless and until we have consented in writing to such supplemental Bond Indenture.

Amendment of Financing Agreement or the Note without Holder Consent

Without the consent of or notice to the holders, the County and the Trustee may consent to any amendment, change or modification of the Financing Agreement or the Note as may be required (i) by the provisions of the Financing Agreement or the Note, as the case may be, and the Bond Indenture, (ii) for the purpose of curing any ambiguity or formal defect or omission in the Bond Indenture, the Financing Agreement or the Note, (iii) to conform to any modifications to or alterations permitted by the Mortgage Indenture or the Bond Indenture, if such provisions are necessary or desirable and do not in the sole opinion of the Trustee materially adversely affect the interest of the holders or (iv) in connection with any other change therein which, in the judgment of the Trustee, is not to the prejudice of the Trustee, or materially adverse to the holders. The Trustee may in its discretion determine whether or not in accordance with the foregoing powers of amendment the interests of the holders would be adversely affected by any such modification or amendment and any such determination shall be binding and conclusive on us, the County and all holders and the Trustee shall have no liability as a result of any such determination made in good faith.

Amendment of Mortgage Indenture and Note

The Trustee shall not exercise any of the rights of a holder of the Note under the Mortgage Indenture to permit any amendment, modification, supplement or consolidation of the Mortgage Indenture or the Note, whereby any such amendment, modification, supplement or consolidation results in changing the times, amounts or currency of payment of the payments due on the Note, without the prior written consent of the holders of the Bonds adversely affected thereby. The Trustee may otherwise consent to the amendment or modification of the Mortgage Indenture or exercise any other rights thereunder of a holder of the Note either (i) without notice to or consent of any holder if the Trustee, in its sole discretion, deems the effects of such exercise, taken as a whole, to be not materially adverse to the interests of the holders or (ii) in any event, upon notice by the Trustee to the holders of the action proposed to be taken and the consent thereto of the holders of a majority in aggregate principal amount of the Bonds then Outstanding;

provided, however, that no such notice to or consent of the holders shall be required in connection with any supplemental Mortgage Indenture or other instrument as may be required by the provisions of the Mortgage Indenture. The Trustee has agreed, pursuant to the terms of the Bond Indenture, to execute and deliver all such further supplemental Mortgage Indentures and other instruments as may be required by the provisions of the Mortgage. The Trustee may in its discretion determine whether or not in accordance with the foregoing powers of amendment the interests of the holders would be adversely affected by any modification or amendment of the Mortgage Indenture or the Note, and any such determination shall be binding and conclusive on us, the County and all holders and the Trustee shall have no liability as a result of any such determination made in good faith.

Defeasance

Any Bond shall, prior to the maturity or redemption date thereof, be deemed to have been paid and all covenants, agreements and other obligations of the County to the holders shall thereupon cease, terminate and become void if the following conditions are met: (i) in case such Bond is to be redeemed, we and the County shall have given to the Trustee unconditional and irrevocable instructions and notice to give notice of redemption of such Bond on said redemption date, (ii) there shall have been deposited with the Trustee either moneys in an amount which shall be sufficient, or obligations of or guaranteed as to principal and interest by the United States of America, or certificates of an ownership interest in the principal of, premium, if any, or interest on obligations of or guaranteed as to principal and interest by the United States of America, which shall not contain provisions permitting the redemption thereof at the option of the issuer, the principal of, premium, if any, and the interest on which when due, and without any reinvestment thereof, will provide moneys which, together with the moneys, if any, deposited with or held by the Trustee or any co-paying agent at the same time, shall be sufficient to pay when due the principal of and interest due and to become due on such Bond, and (iii) in the event such Bond does not mature or is not by its terms subject to redemption within the next succeeding 60 days, we and the County shall have given the Trustee irrevocable instructions to give, as soon as practicable, a notice to the holders of such Bond that the deposit required by clause (ii) above has been made with the Trustee and that said Bond is deemed to have been paid and stating such maturity or redemption date upon which moneys are to be available for the payment of the principal of and interest on such Bond.

Any cash received from such principal or interest payments on such obligations deposited with the Trustee, (a) to the extent such cash will not be required at any time for the payment of the principal of, premium, if any, and interest on such Bond, shall be paid to us as received by the Trustee, free and clear of any trust, lien or pledge, and (b) to the extent such cash will be required for the payment of the principal of, premium, if any, and interest on such Bond at a later date, shall, to the extent practicable, be reinvested in obligations or certificates of the type described in clause (ii) of the preceding paragraph maturing at times and in amounts sufficient to pay when due the principal of and interest to become due on such Bond on and prior to such redemption date or maturity date thereof, as the case may be, and interest earned from such reinvestments shall be paid to us as received by the Trustee, free and clear of any trust, lien or pledge.

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SUMMARY OF CERTAIN PROVISIONS OF THE MORTGAGE INDENTURE

The Note will be secured under the Mortgage Indenture on a parity basis with other obligations issued or to be issued under the Mortgage Indenture. The following is a summary of the provisions of the Mortgage Indenture. All references to the Mortgage Indenture are qualified by reference to such document, copies of which are on file at our principal office or the principal office of the Trustee, and are available upon request. Capitalized terms used in this APPENDIX E but not otherwise defined in this Offering Statement shall have the meaning set forth in the Mortgage Indenture.

Security for Payment of the Mortgage Indenture Obligations

The Note will be secured equally and ratably with any other obligations issued under the Mortgage Indenture by a lien on substantially all our owned tangible and some of our intangible properties, including our electric generation and transmission facilities and certain of our contracts relating to the purchase, sale or transmission of electricity of more than one year in duration and relating to the ownership, operation or maintenance of electric generation, transmission or distribution facilities owned by us, but excluding all Excepted Property (defined below). The lien of the Mortgage Indenture also extends to revenue generated from the sale or transmission of electricity under certain of these contracts.

The Mortgage Indenture defines Excepted Property to include, among other things:

- Cash on hand or in banks or other financial institutions (excluding such cash to the extent it constitutes proceeds of the Trust Estate in which the security interest created by the Mortgage Indenture is perfected pursuant to the Uniform Commercial Code, for so long as such perfection continues, and also excluding cash deposited or required to be deposited with Trustee pursuant to the Mortgage Indenture);
- Contracts, contract rights and associated general intangibles not specifically subject to the lien of the Mortgage Indenture;
- Equity or debt securities (other than those securities specifically subject to the lien of the Mortgage Indenture), with limited exceptions;
- Allowances for emissions or similar rights granted by any governmental authority;
- Patents, patent licenses, and other patent rights, patent applications, service marks, trade names and trademarks (other than those specifically subject to the lien of the Mortgage Indenture);
- Claims, choses in action and judgments;
- Transportation equipment (including vehicles, vessels, airplanes and barges and all parts and supplies used in connection with that equipment);
- Goods or inventory acquired or produced for the purpose of resale in the ordinary course of business and other personal property consumable in the operation of our business, and all hand and other portable tools, equipment and fuel;

- Office furniture, equipment and supplies and data processing, accounting and other computer equipment, software and supplies;
- Our leasehold interests as lessee (other than for office purposes) under leases for an original term of less than five years;
- Our leasehold interests as lessee for office purposes;
- Timber (separated from the land included in the Trust Estate), coal, ore, gas, oil, minerals, and other natural resources, and all electric energy, gas, steam, water, or other products generated, produced or purchased;
- Non-assignable permits, licenses, franchises, our interest in leases as lessee or lessor, contracts and contractual and other rights not specifically subject to the lien of the Mortgage Indenture;
- Real, personal and mixed property located outside of the Commonwealth of Kentucky not specifically subject to the lien of the Mortgage Indenture;
- Any personal property located outside the Commonwealth of Kentucky in which a security interest cannot be perfected by filing a financing statement under the Uniform Commercial Code; and
- Our interest in other property in which a security interest cannot legally be perfected in the United States.

Our title to the Trust Estate and the lien of the Mortgage Indenture are subject to Permitted Exceptions which include, among other things, restrictions, exceptions, reservations, terms, conditions, agreements, leases, subleases, covenants, limitations, interests and other matters of record on the date of the Mortgage Indenture, or on property we acquire after the date of the Mortgage Indenture as long as those matters do not materially impair the use of our property, reservations contained in U.S. patents, liens for non-delinquent taxes, and liens for delinquent taxes which are being contested in good faith, mechanics', materialmen's or contractors' liens arising in the ordinary course of business which are not delinquent or are being contested in good faith, local improvement district assessments, liens for judgments which are fully covered by insurance or as to which we are prosecuting an appeal and have set aside adequate reserves, leases as a lessor for a term of not more than ten years entered into after the date of the Mortgage Indenture, or, if more than ten years that do not materially impair our use of the leased property in the conduct of our business, easements, rights-of-way and other rights of others in our property for limited purposes to the extent those rights do not in aggregate materially impair the use of the Trust Estate, liens for non-delinquent or contested rent, the undivided or other interests of other owners, liens on those undivided interests and rights of the owners in property owned jointly with us, the pledge of current assets in the ordinary course of business to secure current liabilities, and liens which have been bonded for the amount of obligations secured by those liens or for the payment of which a deposit had been made in the full amount of those liens or privileges of our employees for salary or wages earned but not payable, any right of any municipal or governmental authority and the burdens of any law or regulations, restrictions or other deficiencies of title to easements used by us for pipelines, electric transmission lines or substations or similar facilities if we obtained sufficient right from the apparent owner for the use for which the same are used or we have power of eminent domain to correct the differences or the deficiencies may be remedied without undue effort or expense. The lien of the Mortgage Indenture will also be subject to the lien in favor of Trustee to recover amounts owed to it under the Mortgage Indenture.

The Mortgage Indenture contains provisions subjecting all of our after-acquired property, other than Excepted Property, to the lien of the Mortgage Indenture with limited exceptions relating to purchase money and pre-existing liens (provided, in the case of real property, we file a Supplemental Indenture describing such property). In the case of any consolidation, merger, or conveyance or transfer of the Trust Estate substantially as an entirety, the Mortgage Indenture is not required to be a lien upon any property then owned or thereafter acquired by the successor entity other than upon:

- Betterments, extensions, improvements, additions, repairs, renewals, replacements, substitutions and alterations to or upon the Trust Estate;
- Property made the basis of withdrawal of cash from Trustee or the release of property from the lien of the Mortgage Indenture;
- Property acquired or constructed with the proceeds of (i) insurance on any part of the Trust Estate or (ii) any part of the Trust Estate released from the lien of the Mortgage Indenture or disposed of free from any such lien or taken by eminent domain;
- Property acquired to maintain and repair the property subject to the lien of the Mortgage Indenture in accordance with the requirements of the Mortgage Indenture;
- Property acquired or constructed with Trust Moneys (as defined below) paid upon our request; and
- All property, leases, contracts, rights-of-way, franchises, licenses, permits or easements acquired in alteration, substitution, surrender or modification of those property rights, and all monies deposited with Trustee in connection with the disposition, alteration, or modification of those property rights.

In the event the Mortgage Indenture was not a lien on any such properties then owned or thereafter acquired by the successor entity, no additional Mortgage Indenture Obligations could be issued under the Mortgage Indenture (other than Mortgage Indenture Obligations issued in exchange or substitution for outstanding Mortgage Indenture Obligations).

Release and Substitution of Property

So long as no Event of Default exists under the Mortgage Indenture, we will be able to use and deal with the real and personal property (including licenses, permits, contracts and cash proceeds of the Trust Estate subject to the lien of the Mortgage Indenture, other than cash deposited or required to be deposited with the Indenture Trustee) subject to the lien of the Mortgage Indenture (including releasing, amending, terminating, abandoning or disposing of such property) to facilitate our day-to-day operations. Certain of these transactions will require that we find that such transactions will not adversely affect in any material respect the security afforded by the Mortgage Indenture and are:

- Desirable in the conduct of our business; or
- Made in lieu and reasonable anticipation of the taking by eminent domain or purchase of such property by a governmental entity.

Certain of these transactions also would require the substitution of Bondable Additions, the deposit of cash with the Indenture Trustee or the retirement or defeasance of Mortgage Indenture Obligations, in each case of equivalent value of the fair value of the property to be released. Cash deposited with the Indenture Trustee as a result of the authentication and delivery of Mortgage Indenture Obligations can be withdrawn against 90.91% of Bondable Additions or retired or defeased Mortgage Indenture Obligations of equivalent value. Trust Moneys (as hereinafter defined) can be withdrawn against Bondable Additions or retired or defeased Mortgage Indenture Obligations, in either case of equivalent value, and can, at our option, be used for the redemption of Mortgage Indenture Obligations prior to their maturity, for the payment of principal on Mortgage Indenture Obligations at their maturity or for the purchase of Mortgage Indenture Obligations. To the extent that any Trust Moneys consist of the proceeds of insurance upon any part of the property subject to the lien of the Mortgage Indenture, such Trust Moneys can be withdrawn to reimburse us for costs to repair, rebuild or replace the destroyed or damaged property.

"Trust Moneys" is defined in the Indenture as all money received by the Indenture Trustee:

- Upon the release of any part of the Trust Estate from the lien of the Mortgage Indenture, including all moneys received in respect of the principal of all purchase money obligations deposited with the Indenture Trustee in respect of its release of property;

- As compensation for, or proceeds of the sale of, any part of the Trust Estate subject to the lien of the Mortgage Indenture taken by eminent domain or purchased by, or sold pursuant to an order of, a governmental authority or otherwise disposed of;

- As proceeds of insurance upon any part of the Trust Estate subject to the lien of the Mortgage Indenture required to be paid to the Indenture Trustee pursuant to the Mortgage Indenture; or

- For application as Trust Moneys under the relevant provision of the Mortgage Indenture or whose disposition was not otherwise specifically provided for in the Mortgage Indenture.

Covenants

The Indenture requires us to establish and collect rates, rents, charges, fees and other compensation (collectively, the "Rates") that produce money sufficient, together with other moneys available to us, to enable us to comply with all covenants under the Mortgage Indenture. Subject to the approval or determination of any regulatory or judicial authority with jurisdiction over Rates, the Mortgage Indenture requires us to establish and collect Rates which are reasonably expected, together with our other revenue, to yield a MFI Ratio equal to at least 1.10 for each fiscal year. Promptly upon any material change in the circumstances which were not contemplated at the time such Rates were most recently reviewed but not less frequently than once every 12 months, we will be required to review the Rates so established and, subject to any necessary regulatory approval and the approval of the RUS, if required, promptly establish or revise such Rates as necessary to comply with the foregoing requirements. We will not furnish or supply or cause to be furnished or supplied any use, output, capacity or service of our business with respect to which a charge is regularly or customarily made, free of charge to any Person, and we will use commercially reasonable efforts to enforce the payment of any and all accounts owing to us with respect to the use, output, capacity or service of our business. A failure by us to actually achieve a 1.10 MFI Ratio will not itself constitute an Indenture Event of Default under the Mortgage Indenture. A failure to establish Rates reasonably expected to achieve a 1.10 MFI Ratio, however, will be an Indenture Event of Default if such failure continues for 30 days after we receive notice thereof from either the Indenture Trustee or the holders of not less than 20% in principal amount of the outstanding Mortgage Indenture Obligations, unless such failure results from our inability to obtain regulatory approval.

MFI Ratio, for any period, is (i) the sum of (a) Margins for Interest (as defined below) for such period, plus (b) Interest Charges (as defined below) for such period, divided by (ii) Interest Charges for such period. Margins for Interest means, for any period, the sum of each of the following for such period:

- Our net margins (which include our revenues subject to refund at a later date but exclude provisions for (i) non-recurring charges to income, including the non-recoverability of assets or expenses, except to the extent we determine to recover such charges in Rates and (ii) refunds of revenues collected or accrued in any prior year subject to possible refund; plus

- Any amount included in net margins for accruals for federal and state income and other taxes imposed on income after deduction of interest expense; plus

- Any amount included in net margins for any losses incurred by any subsidiary or affiliate of ours; plus

- Any amount we actually receive in such period as a dividend or other distribution of earnings of any subsidiary or affiliate of ours (whether or not such earnings were for such period or any earlier period); minus

- Any amount included in net margins for any earnings or profits of any subsidiary or affiliate of ours; and minus

- Any amount we actually contribute to the capital of, or actually pay under a guarantee by us of an obligation of, any subsidiary or affiliate in such period to the extent of any accumulated losses incurred by such subsidiary or affiliate (whether or not such losses were for such period or any earlier period), but only to the extent (i) such losses have not otherwise caused other contributions or payments to be included in net margins for purposes of computing Margins for Interest for a prior period and (ii) such amount has not otherwise been included in net margins.

Margins for Interest are determined in accordance with Accounting Requirements; provided, however, that such determination may not be made on a consolidated basis.

"Interest Charges" is defined in the Mortgage Indenture to mean, for any period, the total interest charges (whether capitalized or expensed) for such period (which, except as otherwise provided in this definition, shall be determined in accordance with Accounting Requirements) related to (i) our Outstanding Secured Obligations or (ii) our outstanding Prior Lien Obligations, in all cases including amortization of debt discount and premium on issuance, but excluding all interest charges related to Mortgage Indenture Obligations that have actually been paid by another Person that has agreed to be primarily liable for such Indenture Obligation pursuant to an assumption agreement or similar undertaking, provided such assumption agreement or similar undertaking is not a mechanism by which we continue to make payments to such Person based on payments made by such Person on account of its assumed liability or by which we otherwise seek to avoid having interest related to such Mortgage Indenture Obligations included in the definition of Interest Charges without the economic substance of an assumption of liability on the part of such Person.

The Mortgage Indenture prohibits us from making any distribution, payment or retirement of patronage capital to our members if, at the time thereof or after giving effect thereto:

- An Indenture Event of Default then exists;

- Our aggregate margins and equities as of the end of the immediately preceding fiscal quarter would be less than 20% of our total long-term debt and equities at such time; or

- The aggregate amount expended for all such distributions to our members on and after the date on which our aggregate margins and equities first reached 20% of our long- term debt and equities shall exceed 35% of our aggregate net margins earned after such date.

Notwithstanding such restrictions, so long as no Indenture Event of Default exists, we may make distributions, payments or retirements of patronage capital to members if, after giving effect thereto, our aggregate margins and equities as of the end of our most recent fiscal quarter would have been not less than 30% of our total long-term debt and equities as of such date.

The Mortgage Indenture obligates us to keep all of our property subject to the lien of the Mortgage Indenture free and clear of other liens, subject to Permitted Exceptions and certain purchase money on our after-acquired property not in excess of 80% (or with respect to property that is not necessary to the operations of the remaining portion of our business, 100%) of the lesser of the cost or the fair value of such property and in the aggregate not in excess of 15% of the aggregate principal amount of all Mortgage Indenture Obligations.

Credit Enhancement

The Mortgage Indenture provides that Mortgage Indenture Obligations of any series may have the benefit of an insurance policy, letter of credit, surety bond, or other similar unconditional obligation to pay when due the principal and interest of the Mortgage Indenture Obligations of such series (each, a "Credit Enhancement") issued by a credit enhancer (a "Credit Enhancer").

Additional Mortgage Indenture Obligations

The principal amount of Mortgage Indenture Obligations that can be issued under the Mortgage Indenture is limited to three billion dollars ($3,000,000,000). However, the Mortgage Indenture may be amended to increase such limit without the consent of holders of Mortgage Indenture Obligations. Additional Mortgage Indenture Obligations, ranking equally and ratably with the Mortgage Indenture Obligations issued to refinance or evidence our secured indebtedness outstanding at such time, may be issued from time to time:

- Against:
    - 90.91% of Bondable Additions;
    - 90.91% of Certified Progress Payments;
    - The aggregate principal amount of retired or defeased Mortgage Indenture Obligations;
    - The amount of cash deposited with the Indenture Trustee; and
- To evidence reimbursement Obligations to Credit Enhancers in connection with Credit Enhancement or guarantees of other Mortgage Indenture Obligations.

Bondable Additions are equal to (i) the bondable value of all certified Property Additions (as to which the lien of the Mortgage Indenture shall be subject only to Permitted Exceptions), less (ii) property ("Retirements") subject to the lien of the Mortgage Indenture that is retired after December 31, 2008 (the "Cut-Off Date"). Property Additions are limited under the Mortgage Indenture to certain of our property chargeable to our fixed plant accounts, subject to the lien of the Mortgage Indenture, acquired or constructed by us since the Cut-Off Date, and not subject to pre existing liens securing indebtedness prior to or on a parity with the lien of the Mortgage Indenture. In addition Property Additions include tangible property we acquired from WKEC as part of the Unwind, including the flue gas desulphurization system and associated equipment at our Coleman Mortgage Plant, regardless of when we acquired title to such property. For the purpose of calculating the amount of Property Additions and Retirements, (i) the bondable value of property acquired after the Cut Off Date is the lesser of its cost or fair value to us (determined as of the time of acquisition) and (ii) the bondable value of the tangible property acquired from WKEC in the Unwind is $98.5 million plus the cost of acquisition by WKEC of all such tangible property (other than the flue gas desulphurization system and associated equipment at our Coleman Plant) as reflected on the books of WKEC. The amount of Bondable Additions available for the issuance of additional Mortgage Indenture Obligations is the bondable value of all Property Additions (calculated as described above) after December 31, 2008 plus the bondable value of the tangible property acquired from WKEC in the Unwind on July 16, 2009, minus the bondable value of all property subject to the lien of the Mortgage Indenture that is retired or disposed after December 31, 2008. As a result, as of December 31, 2009, we could have issued approximately $194.6 million of additional Mortgage Indenture Obligations on the basis of Bondable Additions.

In order to finance the construction of generation and related facilities on a contract basis, we can issue additional Mortgage Indenture Obligations in an aggregate principal amount up to 90.91% of the progress payments ("Certified Progress Payments") made under qualified contracts for engineering, construction or procurement services which have been assigned to the Indenture Trustee ("Qualified EPC Contracts"). Such additional Mortgage Indenture Obligations are limited in principal amount to 30% of the Outstanding Secured Obligations under the Mortgage Indenture. As Property Additions are added to the Trust Estate as a consequence of Certified Progress Payments, we can certify such Property Additions as Bondable Additions to (i) issue additional Mortgage Indenture Obligations on the basis of Bondable Additions provided that we use a portion of the proceeds of such additional Mortgage Indenture Obligations to pay a specified portion of the Mortgage Indenture Obligations issued on the basis of Certified Progress Payments or (ii) convert principal amounts outstanding under the Mortgage Indenture Obligations issued on the basis of Certified Progress Payments to principal amounts outstanding under the Mortgage Indenture Obligations issued on the basis of Bondable Additions.

Before we may issue additional Mortgage Indenture Obligations on the basis of Bondable Additions, retirement or defeasance of Mortgage Indenture Obligations, the deposit of cash with the Indenture Trustee or Certified Progress Payments, we must certify that our MFI Ratio was at least 1.10 during the immediately preceding fiscal year (or, if the certification is made within 90 days of the end of a fiscal year, our second preceding fiscal year) or during any consecutive 12-month period within the 15 month period immediately preceding our request for the issuance of additional Mortgage Indenture Obligations.

Events of Default and Remedies

The following are Indenture Events of Default:

- Failure to pay principal of or premium, if any, on any Indenture Obligation when due after any applicable grace period;
- Failure to pay any interest on any Indenture Obligation when due which continues for 5 days;
- Any other breach by us of any of our warranties or covenants contained in the Indenture which continues for 30 days after written notice thereof from the Indenture Trustee or the holders of not less than 25% in principal amount of the outstanding Mortgage Indenture Obligations, unless such default cannot be reasonably cured within such 30 day period in which case, so long as a cure is being

diligently pursued, we shall have a reasonable period of time beyond such 30 day period to complete such cure;

- Failure to pay when due the principal of any other indebtedness for money borrowed, which failure has resulted in the declaration of acceleration of indebtedness in excess of $10 million, if such indebtedness is not discharged or such declaration of acceleration is not rescinded or annulled within 10 days after such acceleration;

- A judgment against us in excess of $10 million which remains unsatisfied or unstayed for 45 days after either entry of judgment or termination of stay, and such judgment remains unstayed or unsatisfied for a period of 10 days after notice thereof from the Indenture Trustee or the holders of not less than 25% in principal amount of the outstanding Mortgage Indenture Obligations; or

- Certain other proceedings in bankruptcy, receivership, insolvency, liquidation or reorganization.

Subject to the provisions of the Mortgage Indenture relating to the duties of the Indenture Trustee, in case an Indenture Event of Default should occur and be continuing, the Indenture Trustee is under no obligation to exercise any of its rights or powers under the Mortgage Indenture at the request or direction of any of the holders, unless such holders shall have offered to the Indenture Trustee a reasonable indemnity. Subject to provisions for the indemnification of the Indenture Trustee, the holders of a majority in aggregate principal amount of the outstanding Mortgage Indenture Obligations have the right to direct the time, method and place of conducting any proceeding for any remedy available to the Indenture Trustee or exercising any trust or power conferred on the Indenture Trustee, except that, so long as it is not in default with respect to its Credit Enhancement for any Mortgage Indenture Obligations, a Credit Enhancer for, and not the actual holders of, Mortgage Indenture Obligations subject to Credit Enhancement would be deemed to be the holder of such Mortgage Indenture Obligations for purposes of, among other things, taking action in connection with the remedies set forth in the Mortgage Indenture.

If an Indenture Event of Default should occur and be continuing, either the Indenture Trustee or the holders of at least 25% in aggregate principal amount of the outstanding Mortgage Indenture Obligations may accelerate the maturity of all Mortgage Indenture Obligations. However, after such declaration of acceleration, but before a sale of any of the property subject to the lien of the Mortgage Indenture or a judgment or decree based on such declaration of acceleration, the holders of a majority in aggregate principal amount of outstanding Mortgage Indenture Obligations may, under certain circumstances, rescind such declaration of acceleration if we have paid or deposited sufficient amounts with the Indenture Trustee and all Events of Default, other than the non-payment of accelerated principal, had been cured or waived as provided in the Mortgage Indenture.

No holder of any Indenture Obligation has any right to institute any proceeding with respect to the Mortgage Indenture or for any remedy thereunder, unless:

- Such holder had previously given to the Indenture Trustee written notice of a continuing Indenture Event of Default;

- The holders of not less than 25% in aggregate principal amount of the outstanding Mortgage Indenture Obligations had made written request and such holders (other than the Government) have offered reasonable indemnity to the Indenture Trustee to institute such proceeding as Indenture Trustee;

- The Indenture Trustee for 60 days after its receipt of such notice, request and indemnity had failed to institute any such proceeding; and

- The Indenture Trustee had not received during such 60 day period from the holders of a majority in aggregate principal amount of the outstanding Mortgage Indenture Obligations a direction inconsistent with such request.

However, such limitations on the holders' rights to institute proceedings would not apply to a suit instituted by a holder of an Indenture Obligation for the enforcement of payment of the principal of, and premium, if any, or interest on such Indenture Obligation on or after the respective due dates expressed in such Indenture Obligation.

The Mortgage Indenture provides that the Indenture Trustee, within 90 days after the occurrence of the Mortgage Indenture Event of Default (but at least 60 days after the occurrence of certain specified Indenture Events of Default), shall give to the holders of Mortgage Indenture Obligations notice of all uncured defaults known to it, provided that, except in the case of an Indenture Event of Default in the payment of principal of, and premium, if any, or interest on Mortgage Indenture Obligations, the Indenture Trustee would be protected in withholding such notice if it in good faith determines that the withholding of such notice is in the interest of the holders of Mortgage Indenture Obligations.

If an Indenture Event of Default should occur and be continuing, the Indenture Trustee may sell the property subject to the lien of the Mortgage Indenture, in either a judicial or nonjudicial proceeding, and the proceeds for disposition of such property, after payment of amounts owing to the Indenture Trustee, shall be applied as follows:

- *First*, to the payment of all amounts due to the Indenture Trustee;
- *Second*,
    - If all Mortgage Indenture Obligations shall have become due and payable, to the payment of outstanding Mortgage Indenture Obligations without preference or priority between interest or principal or among Mortgage Indenture Obligations, or
    - If the principal of all Mortgage Indenture Obligations shall not have become due and payable, then (A) first to interest installments in the order of their maturity and (B) second to principal or redemption price;
- *Third*, to payment of all other amounts due and unpaid on Mortgage Indenture Obligations;
- *Fourth*, to payment of amounts to maintain the value of reserve funds relating to certain tax exempt bonds; and
- *Fifth*, to us or whosoever may be lawfully entitled to receive any remaining amount.

The Indenture requires us to deliver to the Indenture Trustee, within 120 days after the end of each calendar year, a written statement as to our compliance with all our obligations under the Mortgage Indenture. In addition, we are required to deliver to the Indenture Trustee, promptly after any of our officers may be reasonably deemed to have knowledge of a default under the Mortgage Indenture, a written notice specifying the nature and duration of the default and the action we are taking and propose to take with respect thereto.

Amendments and Supplemental Indentures

Waiver of Covenants

Our compliance with the covenants contained in the Mortgage Indenture relating to (i) limitation on liens, (ii) payment of taxes, (iii) maintenance of properties, (iv) insurance, (v) delivery of annual compliance certificates and notice of default under the Mortgage Indenture, (vi) establishing and reviewing certain Rates (other than establishing Rates necessary to comply with the covenants of the Mortgage Indenture), (vii) distributions to our members and (viii) investment of certain moneys, may be waived by a vote of the holders of a majority of the aggregate principal amount of the Mortgage Indenture Obligations outstanding.

Supplemental Indentures Without Consent of Holders

Without the consent of the holders of any Mortgage Indenture Obligations, we, when authorized by a board resolution, and the Indenture Trustee will be able, from time to time, to enter into one or more supplemental Indentures:

- To correct or amplify the description of any property at any time subject to the lien of the Mortgage Indenture;

- To confirm property subject or required to be subjected to the lien of the Mortgage Indenture or to subject additional property to the lien of the Mortgage Indenture;

- To add to the conditions, limitations and restrictions on the authorized amount, terms or purposes of the issue, authentication and delivery of Mortgage Indenture Obligations or of any series of Mortgage Indenture Obligations under the Mortgage Indenture;

- To create any new series of Mortgage Indenture Obligations;

- To modify or eliminate any of the terms of the Mortgage Indenture, provided in the event any such modification or elimination would adversely affect or diminish the rights of any holder, such supplemental Indenture shall state that any such modification or elimination shall become effective only when there are no Mortgage Indenture Obligations outstanding under any series created prior to such supplemental Indenture and provided the Indenture Trustee may decline to execute such supplemental Indenture which does not afford adequate protection to the Indenture Trustee;

- To evidence the succession of another corporation to us and the assumption by any such successor of our covenants;

- To evidence the succession of another Indenture Trustee or the appointment of a co-Indenture Trustee or separate Indenture Trustee;

- To add to our covenants or the Indenture Events of Default for the benefit of all or any series of Mortgage Indenture Obligations or to surrender any of our rights or powers;

- To cure any ambiguity, to correct or supplement any provision in the Mortgage Indenture which may be inconsistent with any other provisions or to make any other provisions, with respect to matters or questions arising under the Mortgage Indenture, which shall not be inconsistent with the provisions of the Mortgage Indenture, provided such action shall not in our opinion, as evidenced by an officer's certificate delivered to the Indenture Trustee, adversely affect the interests of the holders of the Mortgage Indenture Obligations in any material respect;

- To modify, eliminate or add to the provisions of the Mortgage Indenture to the extent necessary to effect the qualification of the Mortgage Indenture under any federal statute, to modify, eliminate or add to the provisions of the Indenture to the extent that any such provisions relating to requirements under the Trust Indenture Act of 1939 (the "TIA") have been modified or eliminated in the TIA after the date of the Mortgage Indenture, to add or change any provisions of the Indenture to the extent necessary to permit or facilitate the issuance of Mortgage Indenture Obligations in bearer or book-entry form;

- To permit the issuance of Mortgage Indenture Obligations in bearer or book-entry form;

- To make any change in the Mortgage Indenture that, in the reasonable judgment of the Indenture Trustee, would not materially and adversely affect the rights of holders of Mortgage Indenture Obligations. A supplemental Indenture will be presumed not to materially and adversely affect the rights of holders if (i) the Mortgage Indenture, as so supplemented and amended, secures equally and ratably the payment of principal of (and premium, if any) and interest on the Mortgage Indenture Obligations which are to remain outstanding and (ii) we shall furnish to the Indenture Trustee written evidence from (x) the nationally recognized statistical rating organization or organizations then rating the Mortgage Indenture Obligations (or other Obligations primarily secured by Mortgage Indenture Obligations) or (y) if there are more than two (2) such organizations, at least two (2) of such organizations, that its ratings of the Mortgage Indenture Obligations (or other Obligations primarily secured by Mortgage Indenture Obligations) will not be withdrawn or reduced as a result of the changes in the Indenture affected by such supplemental Indenture, provided that any changes in the Mortgage Indenture that require the consent of all of the holders of Mortgage Indenture Obligations affected thereby may not be made on the basis that they do not materially and adversely affect the rights of holders. See "Supplemental Indentures With Consent of Holders;" and

- To increase the maximum principal amount of Mortgage Indenture Obligations which may be authenticated and delivered under the Mortgage Indenture.

Supplemental Indentures With Consent of Holders

With the consent of the holders of not less than a majority in principal amount of the Mortgage Indenture Obligations of all series then outstanding affected by such supplemental Indenture, we and the Indenture Trustee will be able, from time to time, to enter into one or more supplemental Indentures to add, change or eliminate any of the provisions of the Mortgage Indenture or modify the rights of the holders of such Mortgage Indenture Obligations, but no such supplemental Indenture will, without the consent of the holder of each outstanding Indenture Obligation affected thereby:

- Change the Stated Maturity (the date specified in each Mortgage Indenture Obligations as the date on which the principal of such Mortgage Indenture Obligations or an installment of interest on any Indenture Obligation is due and payable);

- Reduce the principal of, or any installment of interest on, any Indenture Obligation, or any premium payable upon the redemption thereof;

- Change any Place of Payment (the city or political subdivision thereof in which we are required by the Indenture to maintain an office or agency for payment of the principal of or interest on the Mortgage Indenture Obligations) where any Indenture Obligation, or the interest thereon, is payable;

- Impair the right to institute suits for the enforcement of any such payment on or after the Stated Maturity thereof (or, in the case of redemption, on or after the redemption date);
- Reduce the percentage in principal amount of the outstanding Mortgage Indenture Obligations the consent of the holders of which is required for various purposes;
- Modify certain other provisions of the Mortgage Indenture;
- Permit the creation of any lien (other than as permitted in the Mortgage Indenture) ranking prior to or on a parity with the lien of the Mortgage Indenture with respect to all or substantially all of the property subject to the lien of the Mortgage Indenture; or
- Modify the provisions of any mandatory sinking fund so as to affect the rights of a holder to the benefits thereof.

Defeasance

Subject to certain other conditions, the Mortgage Indenture provides that Mortgage Indenture Obligations will be deemed to have been paid and any of our Obligations to the holders of such Mortgage Indenture Obligations will be discharged, if we deposit with the Indenture Trustee or paying agent cash or Defeasance Securities (as defined below) maturing as to principal and interest in such amounts and at such times as are sufficient, without consideration of reinvestment of such interest, to pay when due the principal or (if applicable) redemption price and interest due and to become due on such Mortgage Indenture Obligations. "Defeasance Securities" is defined in the Mortgage Indenture to include non-callable bonds or other obligations of the principal and interest on which constitute direct obligations of, or are unconditionally guaranteed by the United States of America, or certificates of interest or participation in any such obligations, or in specified portions thereof (which may consist of specified portions of the interest thereon).

SUMMARY OF CERTAIN PROVISIONS OF THE SMELTER AGREEMENTS

The following is a summary of certain provisions of the Smelter Agreements. This summary does not purport to be complete or definitive and is qualified in its entirety by reference to the summarized documents, copies of which are available for inspection at our principal offices and the principal offices of the Trustee. The Smelters have largely identical obligations under the agreements described below, so this summary does not distinguish between obligations to a particular Smelter, even though, from a legal perspective, their rights and obligations are separate and not joint. All capitalized terms used in this APPENDIX F summary and not defined herein or elsewhere in the Offering Statement shall have the meanings given to them in the Smelter Agreements.

Structure

The principal terms and conditions relating to our sale of electric services to Kenergy for resale to the Smelters are set forth in six agreements, three with respect to service to each Smelter. The basic structure of the sale of electric services is that we sell the electric services to Kenergy and then Kenergy in turns sells those electric services to each Smelter. Because the Smelters are customers of Kenergy, Big Rivers has entered into two, separate wholesale service agreements (each a "Smelter Agreement") with Kenergy. Under each Smelter Agreement, we supply Kenergy with electric service for resale to a particular Smelter. Kenergy has entered into a separate retail electric service agreement (a "Smelter Retail Agreement") with each Smelter. We and each Smelter have also entered into a Smelter Coordination Agreement (a "Smelter Coordination Agreement" and, together with the Smelter Agreements and the Smelter Retail Agreements, the "Smelter Agreements") that sets forth certain direct obligations between us and a Smelter. Due to the pass-through nature of the principal obligations between us and each Smelter, the Smelter Agreement and the Smelter Retail Agreement relating to each Smelter are substantially the same.

Nature of Service

The aggregate amount of energy made available to the Smelters under the Smelter Retail Agreements consists of three types of energy referred to as (1) Base Monthly Energy, (2) Supplemental Energy and (3) Back-Up Energy.

Base Monthly Energy

The primary type of energy provided is Base Monthly Energy. "Base Monthly Energy" is the actual amount of energy delivered to the Smelter other than Supplemental Energy provided by Big Rivers or Market Energy provided by third-party suppliers plus energy not delivered as a result of the Smelter's exercise of certain rights to curtail deliveries of energy. Base Monthly Energy is capped at 368 MW per hour for Alcan and 482 MW per hour for Century. The Smelter Retail Agreements do not require the Smelters to schedule Base Monthly Energy but do require each Smelter to use reasonable commercial efforts to inform Kenergy and us promptly of any material change in its intended usage of Base Monthly Energy.

Supplemental Energy

In addition to Base Monthly Energy, the Smelters may purchase Supplemental Energy in certain circumstances. "Supplemental Energy" itself consists of three distinct subsets of energy products in excess of Base Monthly Energy:

Interruptible Energy. Each of the Smelters may purchase up to 10 MW per hour in excess of Base Monthly Energy, from our power supply resources on an interruptible basis ("Interruptible

Energy"). Interruptible Energy may be interrupted if we determine in good faith that our energy resources will be insufficient to supply both the requested Interruptible Energy and our obligations to our Members, all other obligations to the Smelters, and any firm commitments to third parties made prior to our agreement to sell such Interruptive Energy.

Buy-Through Energy. If we interrupt any Interruptible Energy, then we may, at our option, offer energy at a quoted price following the notice of interruption ("Buy-Through Energy"). In practice, we purchase this energy from a third-party supplier in the market and then re-sell it to Kenergy for resale to the Smelter. If the Smelter agrees to purchase Buy-Through Energy, we will have a firm obligation to supply Buy-Through Energy, subject to limited exceptions.

Market Energy. Apart from all other energy, at the request of a Smelter, Kenergy will use reasonable commercial efforts to purchase separately negotiated additional energy and related services ("Market Energy") from either us or third-party suppliers. We have no obligation to provide Market Energy to Kenergy for resale to the Smelters but may elect to do so.

Back-Up Energy

Because the Smelter's receive in each hour energy that meets their actual demand in the hour, the Smelters also purchase and pay for "Back-Up Energy." Back-Up Energy is, for any hour, energy in excess of Base Monthly Energy and Supplemental Energy. Back-Up Energy is intended to be imbalance energy, that is, energy actually used in excess of the Smelter's planned usage in any hour. The Smelters are not required to schedule Back-Up Energy, but the Smelters must use reasonable commercial efforts to inform Kenergy and us promptly of any material change in their intended usage of Back-Up Energy.

Smelter Payment Obligations

Base Monthly Energy Charge

The calculation of the charges for Base Monthly Energy contains numerous components. In sum, the charges are intended to result in the Smelters making payments that help us achieve a net margin so that our net margin plus interest expenses divided by interest expenses is 1.24. This ratio is referred to herein as a "TIER". The charges to reach a TIER of 1.24 are subject to specified limits on the maximum amount payable by the Smelters and certain other adjustments.

Base Energy Charge. The "Base Energy Charge" is the charge for Base Monthly Energy made available to the Smelters. The Base Energy Charge is equal to the Smelter's Base Demand (368 MW or 482 MW, respectively) per hour, assuming a 98% load factor, multiplied by our tariff rate for sales to our Members for resale to large direct-served industrial customers (the "Large Industrial Rate") (inclusive of any surcharges, surcredits and rebates, exclusive of certain fuel adjustment charges and environmental surcharges, the Rebate and the Surcharge (each as defined below)), plus an additional amount of $0.25 per MWh. In addition, the Base Energy Charge includes an adjustment, either positive or negative, for specified variable costs, based on the Smelters' actual energy curtailments.

Supplemental Energy Charges. The charges for Supplemental Energy are the sum of charges for the Interruptible Energy Charge, the Buy-Through Energy Charge, and the Market Energy Charge, calculated as follows:

1. The "Interruptible Energy Charge" is the product of (a) the quantity of Interruptible Energy metered at the point of delivery during the billing month, and (b) the rate or rates for Interruptible Energy proposed by us and accepted by the Smelter with respect to such billing month;

2. The "Buy-Through Energy Charge" is a "pass-through" amount for our costs to purchase such Buy-Through Energy from a third-party supplier for sale to Kenergy for resale to the applicable Smelter, including any amount paid for transmission and ancillary services and all other charges payable by us in connection with Buy-Through Energy; and

3. The "Market Energy Charge" equals the product of the rate agreed to by the supplier of the energy, which may be but is not necessarily us, and the amount of the Market Energy and any amount paid for transmission and ancillary services.

Back-Up Energy Charges. The rates for Back-Up Energy depend on whether we had to purchase that energy in the market. If so, the rate is 110% of the highest price for energy purchased by and delivered to us during that hour. If the Back-Up Energy was not purchased in the market, then the rate is the greater of the locational marginal price at our interface with Midwest Independent System Operator or our system lambda. If Back-Up Energy exceeds 10 MW in any hour, the rate for the excess over 10 MW is computed differently. If this excess Back-Up Energy is required due to a third-party breaching a contract to supply Market Energy (and thereby reducing the energy supplied to a Smelter), then the rate is 110% of the highest price for energy purchased by or sold by us in that hour. If there is no such contractual breach, then the rate for Back-Up Energy in excess of 10 MW is the higher of $250 per MWh or 110% of the highest hourly rate for energy purchased or sold by Big Rivers and delivered to an interconnection with our transmission system in such hour.

TIER Adjustment Charge

Prior to each fiscal year, we determine the expected total amount of additional revenue we will need during the fiscal year to achieve a TIER of 1.24, subject to certain limitations (the "TIER Adjustment"). Each Smelter is obligated to pay a pro rata share (calculated based on its Base Demand) of the TIER Adjustment. If one Smelter's Retail Agreement terminates early, the other Smelter will continue to be obligated to pay only its pro rata share of the TIER Adjustment calculated based on the terminated Smelter's Base Demand, which is 368 MW for Alcan and 482 MW for Century. Each month, one-twelfth of each Smelter's share of the estimated TIER Adjustment for such fiscal year is charged to the Smelter as a "TIER Adjustment Charge". These monthly amounts are further subject to quarterly adjustments based on year-to-date results of operations.

The Smelters' obligations to pay amounts toward our achieving a TIER of 1.24 are not unlimited. Each Smelter's obligation with respect to the TIER Adjustment in any fiscal year may not exceed an amount equal to the product of (a) the Smelters' Based Fixed Energy, for such fiscal year, and (b) the applicable amount set forth below for such year:

Years	Applicable Amount
2009-2011	$0.00195 per kWh
2012-2014	$0.00295 per kWh
2015-2017	$0.00355 per kWh
2018-2020	$0.00415 per kWh
2021-2023	$0.00475 per kWh

Assumptions in the TIER Adjustment. We and Kenergy have agreed with the Smelters to make certain assumptions and adjustments in the calculation of the TIER Adjustment. These assumptions and adjustments are intended to limit the Smelters' obligations in some specified circumstances. Specifically, for purposes of calculating the TIER Adjustment, it will be assumed that:

1. We raise our base rates for service to our Members for their non-Smelter customers by a weighted average of 2.00% in 2010, 2.50% in 2018 and 4.00% in 2021 to the extent we in

fact previously had not increased revenues as a result of rate increases by at least such amount. To date, we have not requested a raise in these base rates.

2. Any entity which becomes a direct-serve customer of a Member after the closing of the Unwind with firm demand in excess of 15 MW paid at least an amount equal to the Smelter Base Rate adjusted for the entity's actual load factor, plus a proportionate share of the TIER Adjustment, if any, and additional amounts relating to the Fuel Adjustment Clause, the Environmental Surcharge, the Purchased Power Adjustment, and the Surcharge. An entity which becomes a direct-serve customer of a Member with a demand of 15 MW or less paid at least an amount equal to the Large Industrial Rate, plus additional amounts relating to the Fuel Adjustment Clause, the Environmental Surcharge, and the Purchased Power Adjustment. This assumption will not be made in the last three years of the term of either Smelter Retail Agreement or following notice of termination of either Smelter Retail Agreement.

3. We will have incurred no expenses that are impermissible for inclusion in rates of electric generation and transmission cooperative utilities subject to the jurisdiction of the KPSC or disallowed by another governmental authority, provided however that a denial by the KPSC or another governmental authority of expense recovery through the Fuel Adjustment Clause or the Environmental Surcharge shall not make such expense impermissible for the purpose of this assumption if the nature of the expense is recoverable in base rates.

4. There are no revenues and expenses associated with our non-regulated businesses.

5. Additional costs related to a change in our depreciation rates may not be included in calculation of the Tier Adjustment unless such changes have been approved, consented to, or accepted by the KPSC, or any other governmental authority if the KPSC no longer has jurisdiction over the change.

In general, these assumptions attempt to ensure that the TIER Adjustment payable by the Smelters is not changed in ways outside the expectations of the parties as a result of known anticipated events.

Other assumptions attempt to net out certain effects of, among other things, (a) patronage capital retirements, (b) interest imputed on debt related to new non-peaking facilities to the extent such new facilities are not included in our revenue requirements for rate-making purposes, (c) interest related to construction-work-in-progress to the extent not included in our revenue requirements for rate-making purposes, (d) possible future indemnification payments under a Smelter Agreement, (e) agreed curtailments, (f) certain penalties, including possible criminal penalties imposed by governmental authorities, (g) penalty interest due to Kenergy or us because of a default by a Smelter, (h) interest on payments made under protest by the Smelters, (i) certain excess reactive demand charges, (j) certain administrative fees paid in connection with certain energy curtailment and resale under a Smelter Agreement.

Rebate. If our TIER in any year exceeds 1.24, as calculated under the Smelter Agreements, then during the next fiscal year we may elect to rebate on a kWh basis a portion of the excess amount, subject to certain limitations, to our Members. Big Rivers has a rider to its tariff to effect this transfer to the Members. Kenergy then would credit to the Smelters a pro rata portion of the amount it received from us on a kWh basis (the "Rebate"). If we do not elect to rebate such excess amount to all our Members, we will still distribute a pro rata portion of the excess to Kenergy for distribution to the Smelters (the "Equity Development Credit"), subject to certain limitations.

Additional Charges

Transmission and Ancillary Services Charge. The Smelters are charged for network transmission service and ancillary services in accordance with our Open Access Transmission Tariff in connection with their purchases of Supplemental Energy..

Variable Charges. The Smelters pay charges under our Fuel Adjustment Clause, and an environmental surcharge (the "Environmental Surcharge") as though they were large industrial tariff customers of one of our Members. The Smelters also pay a charge relating to a purchased power adjustment (the "Purchased Power Adjustment") with respect to purchased power costs not recovered under the Fuel Adjustment Clause.

Surcharge. In addition to any other amounts payable under the Smelter Agreements, the Smelters pay a Surcharge, comprised of four separate components. The first component of the Surcharge is a fixed annual payment, in such amount as follows: (1) an aggregate annual payment of $5,110,000, payable in equal monthly installments through 2011, (2) an aggregate annual payment of $7,300,000, payable in equal monthly installments from 2012 through and including 2016, and (3) an aggregate annual payment of $10,182,816, payable in equal monthly installments from 2017 through 2023. The second component is a fixed reduction to the Surcharge of $86,588 per month for Alcan and $113,412 per month for Century until July 2017. The third and fourth components of the Surcharge are not fixed dollar amounts. The third component is the product of Base Fixed Energy for the billing month (where "Base Fixed Energy" equals the product of the Base Demand (368 MW or 482 MW, respectively), the number of hours in the billing month, and 0.98) multiplied by $0.60 per MWh. The fourth component is the product of Base Fixed Energy for the billing month and the number of cents (between zero and 60) per MW per hour that our budgeted annual average fuel costs for coal-fired generation per MWh for the fiscal year exceed the amounts specified in the Smelter Retail Agreements for that fiscal year, subject to a quarterly true-up based on a comparison of actual fuel costs to budgeted fuel costs and an annual true-up to insure that the Smelters do not pay under this fourth component more than 60 cents per MW per hour of Base Fixed Energy for the fiscal year.

Termination Rights

The obligation of Kenergy to supply electric services to the Smelters pursuant to the Smelter Retail Agreements will terminate on December 31, 2023, unless terminated earlier pursuant to the terms thereof. If no such early termination occurs, we, and Kenergy are obligated, by no later than January 1, 2023, to undertake good faith negotiations with each other and the applicable Smelter for a replacement agreement.

A Smelter may terminate its Smelter Retail Agreement upon not less than one year's prior written notice of such termination to Kenergy and us if it's corporate parent has made a business judgment in good faith to terminate and cease, and has no current intention to re-commence, aluminum smelting operations at the Smelter's Sebree, Kentucky site, in the case of Alcan, or Hawesville, Kentucky site, in the case of Century. Such a termination by a Smelter cannot be effective prior to December 31, 2010; *provided, that* if one Smelter has given notice of termination to be effective on or after December 31, 2010 and improvements to Big Rivers transmission facilities to permit Big Rivers to transmit all Smelter loads to a delivery point of Big Rivers' transmission system have not been completed. A notice of termination by the other Smelter may not be effective prior to December 31, 2011. We have no indication that either Smelter plans to file an early termination notice.

Curtailments

There are five specified circumstances under which the Smelters may curtail their receipt of energy from us. In each case, the Smelters remain obligated to pay for the amount of curtailed energy as though it had been delivered, and receive a credit with respect to the curtailed energy which differs depending on the circumstances of the curtailment.

Surplus Sales. We are required to use reasonable commercial efforts to market amounts of Monthly Energy for Kenergy that a Smelter is obligated to purchase under its Smelter Retail Agreement but which is surplus to such Smelter's needs, with some exceptions. We must credit back to Kenergy, for credit to the applicable Smelter, an amount of net proceeds from such sales which is generally equivalent to the amount of the Smelters' charges otherwise payable with respect thereto.

Undeliverable Energy Sales. If an event occurs that causes damage or destruction to the plant or equipment at a Smelter's facility that limits that Smelter's ability to engage in smelting operations for a period of 48 consecutive hours or longer and the Smelter's demand drops by at least 50 MW (other than as a result of the Smelter's willful or intentional misconduct), the Smelter can request such energy be resold for five or six months ("Undeliverable Energy Sales"). If the Smelter certifies that such condition cannot be remedied with reasonable diligence within six months, such sales may be extended for an additional three months. We must credit back Kenergy, for credit to the Smelter, the net proceeds of the Undeliverable Energy Sales, less an administrative fee of $0.25 per MWh.

Potline Reduction Sales. A Smelter, upon the ceasing of aluminum smelting operations on one of its potlines (a "Potline Reduction"), may request that Kenergy cause us to sell 115 MW (plus or minus 10 MW) per hour on the open market ("Potline Reduction Sales") if certain other conditions are met These conditions include among others: (a) such Smelter is reasonably likely to be able to continue aluminum smelting operations with respect to all of its other potlines; (b) such Smelter reasonably estimates the Potline Reduction will equal or exceed 12 months; and (c) no Potline Reduction Sales have been made for a period of twelve consecutive months prior to the date of such notice. We must credit back Kenergy, for credit to the Smelter, the net proceeds of Potline Reduction Sales, less an administrative fee of $0.25 per MWh.

Economic Sales. Each Smelter may, not more than 12 times in any fiscal year, voluntarily curtail its energy requirements and request that we sell the curtailed energy ("Economic Sales"). Each Economic Sale is subject to our consent, limited to up to 100 MW, and may not be longer than four hours. We must credit back to Kenergy, for credit to the Smelter, 75% of the net proceeds of Economic Sales.

Neither we nor Kenergy have any obligation to market energy as Surplus Sales, Undeliverable Energy Sales, Potline Reduction Sales or Economic Sales until we have sold or chosen not to sell all amounts of its own surplus power, nor do Kenergy or we have any obligation to the Smelters if we are unable to sell this energy as a result of transmission or other constraints.

Other Curtailments. If mutually agreed by a Smelter, Kenergy and us, a Smelter may curtail its energy requirements in an amount and for a period agreed upon by such Smelter, Kenergy and us. Regardless of whether we sell any of such curtailed energy, we must credit back to Kenergy, for credit to the Smelter, an amount equal to the product of (a) the amount of Base Demand per Hour curtailed and (b) the "Market Reference Rate." The Market Reference Rate is the rate (inclusive of all transmission and related charges on any third-party's transmission system) we estimate in good faith we would have paid to purchase energy from a third-party for such amount of curtailed energy to meet our energy delivery obligations under the Smelter Agreements during such period. This curtailment option allows us, if consented to by a Smelter in each instance, to mitigate our exposure to short-terms price spikes in the wholesale power markets during periods when we would otherwise need to purchase power from the market to meet our energy delivery obligations under the Smelter Agreements.

Other Matters

Covenants. We are obligated to our Members to operate our system for the benefit of the Members consistent with prudent utility practices. Under the Smelter Agreements we will apply the same standards to operating decisions that may affect the monthly charges to the Smelters. We will not use a Smelter's payment obligation with respect to the Tier Adjustment as the basis for making an operating decision.

Restructuring. Because of the Smelters' obligations relating to the TIER Adjustment, we have agreed that the effects of certain restructuring transactions (a "Restructuring") on the TIER Adjustment will be implemented over an extended period of time. A restructuring will occur if (i) we, any Affiliate of ours or a Member engages in a merger, consolidation or other combination with another entity, or we admit a new member, and such transaction results in a 5% increase in our sales to our Members on a pro forma basis or (ii) we are acquired. We may, however, seek approval of an increase in the Large Industrial Rate which will increase amounts otherwise payable by the Smelters pursuant to the Smelter Base Rate upon the occurrence of a Restructuring. In connection with such a Restructuring, Big Rivers, Kenergy and the Smelters will determine a good faith estimate of the cumulative increase or decrease in the TIER Adjustment that such a Restructuring would cause over the 24 Billing Month period following the date of the effectiveness of the Restructuring (the "Restructuring Amount") and would increase or decrease the Smelters' charges for 48 months by 1/48th of the Restructuring Amount (subject to a lower limit on the overall MWh rate payable by the Smelters). If we, Kenergy and the Smelters are not able to determine a mutually agreeable estimate of the appropriate economic adjustment according to the procedures set forth in the Smelter Retail Agreements, then Kenergy, Alcan, Century, or we may petition to the KPSC to determine the Restructuring Amount.

Budgets. Each year, we must provide the Smelters with a copy of our then-current projected operating and capital budgets for the following fiscal year. This estimated budget may be reviewed by a mutually agreed independent expert if requested by a Smelter who will evaluate the proposed budgeted operating expense and capital expenditures. The Smelters have the opportunity to present the conclusions and recommendations of the independent expert to the Coordinating Committee (defined below) and to our Board of Directors. We have no duty to take any action based on such report. We must also provide the Smelters with notice of certain significant capital expenditures or operating expenses in excess of our budget made during the fiscal year and allow the Smelters to make a presentation to our Board of Directors in some cases.

Coordinating Committee. The Smelter Agreements provide for the establishment of a committee (the "Coordinating Committee"), consisting of representatives of the Members, Alcan, Century, and our management, organized for the purpose of analyzing information relating to our operational and financial performance, including among others, (i) analysis criteria and procedures for evaluating plans and expenditures, (ii) budgets, (iii) fuel procurement or supply, and (iv) actual budget performance and variances.

Large Industrial Rate Service. We have agreed that if a Smelter's Retail Agreement is terminated pursuant to the termination rights with respect to a cessation of all smelting operations at the Smelter's site, the Smelter will be entitled to be served by Kenergy under our Large Industrial Rate for any non-smelting load up to a maximum load of 15MW.

Smelter Credit Support

The U.S. parent of Alcan and the ultimate parent of Century have entered into agreements guaranteeing the payment and performance of Alcan and Century, respectively, to Kenergy and to us of all obligations under the Smelter Coordination Agreements.

Because the parent guarantor of each Smelter does not have an "A+" or higher credit rating, each Smelter is required to provide and maintain credit support in the form of a letter of credit from a bank rated "A+" or higher, or other credit support acceptable to us and Kenergy, in an amount equal to the amounts estimated to be due for a period of two months under that Smelter's Smelter Retail Agreement and any amount that we estimate reasonably could be due with respect to taxes relating to certain sales of energy on behalf of the Smelters.

Both Smelters have negotiated other credit support acceptable to us and Kenergy. Alcan has pledged its interests in an escrow account. We or Kenergy are permitted to draw amounts from the escrow account at any time to satisfy an overdue Alcan payment obligation up to a specified threshold, initially set at $23 million. Alcan is prohibited from drawing amounts out of the escrow account if the remaining balance would be less than the specified threshold in effect at any time. Century's credit support secures Century's payment obligations to us and Kenergy up to a specified threshold, initially set at $27 million. Century provided its credit support in three parts: (i) a letter of credit issued by E.ON in the amount of $7.5 million, (ii) a cash collateral account in the amount of $7.5 million, and (iii) payments under a swap agreement with E.ON. Under the swap agreement, E.ON pays amounts directly into the lockbox account in which monthly payments under the Smelter Retail Agreement are deposited. The amounts payable by E.ON depend on our cost to produce energy, the sale price for energy not consumed by Century and the amount of aluminum produced by Century. In the event of an early termination of the swap agreement, a termination payment would be directed into the cash collateral account. Both the swap agreement and the letter of credit expire at the end of 2010, and Century is required to provide substitute collateral acceptable to Kenergy and us at that time.

Patronage Capital

Our and Kenergy's allocation and distribution of patronage capital is controlled by our respective by-laws. The Smelter Agreements restrict Kenergy and us from modifying our respective by-laws in a manner that would be adverse to the Smelters with respect to the distribution of patronage capital. The decision to make any payments with respect to the distribution of patronage capital is in the sole discretion of Kenergy or us, as applicable.

PROPOSED FORM OF
OPINION OF BOND COUNSEL

Upon the delivery of the Bonds, Orrick, Herrington & Sutcliffe LLP, New York, New York, Bond Counsel, proposes to render its final approving opinion with respect to such Bonds in substantially the following form:

_________, 2010

Ohio County Fiscal Court
County of Ohio, Kentucky
Hartford, Kentucky

Re: County of Ohio Kentucky
Pollution Control Refunding Revenue Bonds, Series 2010A
(Big Rivers Electric Corporation Project)

Ladies and Gentlemen:

We have acted as bond counsel in connection with issuance by the County, of Ohio, Kentucky (the "Issuer") of $83,300,000 aggregate principal amount of County of Ohio Kentucky Pollution Control Refunding Revenue Bonds, Series 2010A (Big Rivers Electric Corporation Project) (the "Bonds"), issued pursuant to the provisions of the Constitution and laws of the Commonwealth of Kentucky, including Sections 103.200 through 103.285, inclusive, of the Kentucky Revised Statutes, as amended (the "Act"), and pursuant to a Trust Indenture, dated as of June 1, 2010 (the "Bond Indenture"), between the Issuer and U.S. Bank National Association, as Trustee (the "Trustee"). The Bond Indenture provides that the Bonds are issued for the purpose of making a loan of the proceeds thereof to Big Rivers Electric Corporation ("Big Rivers") pursuant to a Loan Agreement, dated as of June 1, 2010 (the "Financing Agreement"), between the Issuer and Big Rivers. Capitalized terms not otherwise defined herein shall have the meanings ascribed thereto in the Bond Indenture.

In such connection, we have reviewed the Bond Indenture, the Financing Agreement, the Big Rivers Indenture, the Note, the Tax Certificate and Agreement, dated the date hereof, between the Issuer and Big Rivers (the "Tax Certificate"), certain resolutions of the Issuer, opinions of counsel to Big Rivers, the Trustee and the Issuer, certificates of the Issuer, the Trustee, Big Rivers and others, and such other documents, opinions and matters to the extent we deemed necessary to render the opinions set forth herein.

The opinions expressed herein are based on an analysis of existing laws, regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. Such opinions may be affected by actions taken or omitted or events occurring after the date hereof. We have not undertaken to determine, or to inform any person, whether any such actions are taken or omitted or events do occur or any other matters come to our attention after the date hereof. Accordingly, this opinion speaks only as of its date and is not intended to, and may not, be relied upon in connection with any such actions, events or matters. Our engagement with respect to the Bonds has concluded with their issuance, and we disclaim any obligation to update this letter. We have assumed the genuineness of all documents and signatures presented to us (whether as originals or as copies) and the due and legal execution and delivery thereof by, and validity against, any parties other than the Issuer. We have assumed, without undertaking to verify, the accuracy of the factual matters represented, warranted or certified in the documents, and of the legal conclusions contained in the opinions, referred to in the second paragraph of this letter. Furthermore, we have assumed compliance with all covenants and agreements contained in the Bond Indenture, the Financing Agreement and the Tax Certificate, including (without limitation) covenants and agreements compliance with which is necessary to assure that future actions, omissions or events will not cause interest on the Bonds to be included in gross income for federal income tax purposes. We call attention to the fact that the rights and obligations under the Bonds, the Bond Indenture, the Financing Agreement and the Tax Certificate and their enforceability may be subject to bankruptcy, insolvency, reorganization, arrangement, fraudulent conveyance, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, to the exercise of judicial discretion in appropriate cases and to the limitations on legal remedies against counties in the Commonwealth of Kentucky. We express no opinion with respect to any indemnification, contribution, penalty, choice of law, choice of forum, choice of venue, waiver or severability provisions contained in the foregoing documents. Finally, we undertake no responsibility for the accuracy, completeness or fairness of the Offering Statement or other offering material relating to the Bonds and express no opinion with respect thereto.

Based on and subject to the foregoing, and in reliance thereon, as of the date hereof, we are of the following opinions:

1. The Issuer is a political subdivision and body politic and corporate of the Commonwealth of Kentucky, created and existing pursuant to the Constitution and laws of such Commonwealth.

2. The Issuer has lawful authority for the issuance of the Bonds, and the Bonds constitute valid and binding limited obligations of the Issuer.

3. The Bond Indenture has been duly executed and delivered by, and constitutes the valid and binding obligation of, the Issuer. The Bond Indenture creates a valid pledge to secure the payment of the principal of and interest on the Bonds (to the extent provided therein). The Bond Indenture also creates a valid assignment to the Trustee, for the benefit of the holders from time to time of the Bonds, of the right, title and interest of the Issuer in the Financing Agreement other than the rights of the Issuer set forth in Sections 5.4 and 9.4 of the Financing Agreement.

4. The Financing Agreement has been duly authorized, executed and delivered by, and constitutes a valid and binding agreement of, the Issuer.

5. All approvals or consents of governmental authorities required to be obtained by the Issuer in connection with the issuance and sale of the Bonds have been obtained.

6. The Bonds are not a lien or charge upon the funds or property of the Issuer except to the extent of the aforementioned pledge and assignment. Neither the faith and credit nor the taxing power of the Commonwealth of Kentucky or any political subdivision thereof is pledged to the payment of the principal of or interest on the Bonds.

7. Interest on the Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1954, as amended (the "1954 Code") and Title XIII of the Tax Reform Act of 1986, except that no opinion is expressed as to the status of interest on any Bond during any period that such Bond is held by a "substantial user" of facilities financed or refinanced by the Bonds or by a "related person" within the meaning of Section 103(b)(13) of the 1954 Code. Further, interest on the Bonds is not a specific preference item for purposes of the federal individual or corporate alternative minimum taxes, nor is it included in adjusted current earnings in calculating federal corporate alternative minimum taxable income.

We express no opinion regarding other tax consequences related to the ownership or disposition of, or the accrual or receipt of interest on, the Bonds.

Faithfully yours,

ORRICK, HERRINGTON & SUTCLIFFE LLP

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CONTINUING DISCLOSURE AGREEMENT

This Continuing Disclosure Agreement (the "Agreement"), dated as of June 1, 2010, by and between Big Rivers Electric Corporation ("Big Rivers") and U.S. Bank National Association, as trustee (the "Trustee") under the Trust Indenture, dated as of June 1, 2010 (the "Indenture"), between the County of Ohio, Kentucky (the "Issuer") and the Trustee, is executed and delivered in connection with the issuance of the Issuer's $83,300,000 principal amount of County of Ohio, Kentucky Pollution Control Refunding Revenue Bonds, Series 2010A (Big Rivers Electric Corporation Project) (the "Bonds"). The proceeds of the sale of the Bonds will be used to refund the entire outstanding principal amount of the Issuer's Pollution Control Refunding Revenue Bonds, Series 2001A (Big Rivers Electric Corporation Project), Periodic Auction Rate Securities. In connection therewith, the Issuer and Big Rivers have entered into a Loan Agreement dated as of June 1, 2010 (the "Financing Agreement"), pursuant to which the Issuer has loaned to Big Rivers the aggregate principal amount of the Bonds. Capitalized terms used in this Agreement shall have the meanings given to them in the Indenture; capitalized terms used in this Agreement which are not otherwise defined in the Indenture shall have the respective meanings specified in Article IV hereof.

ARTICLE I
The Undertaking

Section 1.1. Purpose: No Issuer Responsibility or Liability. This Agreement is being executed and delivered solely to assist the Underwriter in complying with paragraph (b)(5) of the Rule. Big Rivers acknowledges that the Issuer has undertaken no responsibility, and shall not be required to undertake any responsibility, with respect to any reports, notices or disclosures required by or provided pursuant to this Agreement, and shall have no liability to any person, including any holder of the Bonds, with respect to any such reports, notices or disclosures.

Section 1.2. Annual Financial Information.

(a) Big Rivers shall provide Annual Financial Information with respect to each fiscal year, commencing with the fiscal year ending December 31, 2010, by no later than six months after the end of the respective fiscal year to (i) the MSRB and (ii) the Issuer (with copies to the Trustee).

(b) Big Rivers shall provide, in a timely manner, notice of any failure of Big Rivers to provide the Annual Financial Information by the date specified in subsection (a) above to (i) the MSRB and (ii) the Issuer (with copies to the Trustee).

Section 1.3. Audited Financial Statements. If not provided as part of Annual Financial Information by the date required by Section 1.2 hereof because Audited Financial Statements are not available, Big Rivers shall provide Audited Financial Statements, when and if available, to (i) the MSRB and (ii) the Issuer (with copies to the Trustee).

Section 1.4. Material Events Notices.

(a) If a Material Event occurs, Big Rivers shall provide, in a timely manner, a Material Event Notice to (i) the MSRB and (ii) the Issuer (with copies to the Trustee).

(b) Any such notice of a defeasance of Bonds shall state whether the Bonds have been escrowed to maturity or to an earlier redemption and the timing of such maturity or redemption.

(c) The Trustee shall promptly advise Big Rivers and the Issuer whenever, in the course of performing its duties as Trustee under the Indenture, the Trustee has actual notice of an occurrence which, if material, would require Big Rivers to provide a Material Event Notice hereunder; provided, however, that the failure of the Trustee so to advise Big Rivers or the Issuer shall not constitute a breach by the Trustee of any of its duties and responsibilities under this Agreement or the Indenture.

Section 1.5. Information. Nothing in this Agreement shall be deemed to prevent Big Rivers from disseminating any other information, using the means of dissemination set forth in this Agreement or any other means of communication, or including any other information in any Annual Financial Information or Material Event Notice, in addition to that which is required by this Agreement. If Big Rivers chooses to include any information in any Annual Financial Information or Material Event Notice in addition to that which is specifically required by this Agreement, Big Rivers shall have no obligation under this Agreement to update such information or include it in any future Annual Financial Information or Material Event Notice.

Section 1.6. No Previous Non-Compliance. Big Rivers represents that since July 3, 1995, it has not failed to comply in any material respect with any previous undertaking in a written contract or agreement specified in paragraph (b)(5)(i) of the Rule.

ARTICLE II
Operating Rules

Section 2.1. Reference to Other Documents. It shall be sufficient for purposes of Section 1.2 hereof if Big Rivers provides Annual Financial Information by specific reference to documents (i) either (1) provided to the MSRB or (2) filed with the SEC, or (ii) if such document is an offering statement provided in connection with a subsequent financing and meeting the definition of "final official statement" as defined in paragraph (f)(3) of the Rule, available from the MSRB.

Section 2.2. Submission of Information. Annual Financial Information may be provided in one document or multiple documents, and at one time or in part from time to time.

Section 2.3. Material Event Notices. Each Material Event Notice shall be so captioned and shall prominently state the title, date and CUSIP numbers of the Bonds.

Section 2.4. Transmission of Information and Notices. Unless otherwise required by law and, in Big Rivers' sole determination, subject to technical and economic feasibility, Big Rivers shall employ such methods of information and notice transmission as shall be requested or recommended by the herein-designated recipients of Big Rivers' information and notices. Notwithstanding the foregoing, all documents provided to the MSRB shall be in electronic format, accompanied by such identifying information as is prescribed by the MSRB.

Section 2.5. Fiscal Year. Annual Financial Information shall be provided at least annually notwithstanding any fiscal year longer than twelve calendar months. Big Rivers' current fiscal year is January 1 - December 31, and Big Rivers shall promptly notify (i) the MSRB and (ii) the Issuer, of each change in its fiscal year.

ARTICLE III
Effective Date, Termination, Amendment and Enforcement

Section 3.1. Effective Date; Termination.

(a) This Agreement shall be effective upon issuance of the Bonds.

(b) If Big Rivers' obligations under the Financing Agreement are assumed in full by some other entity, such person shall be responsible for compliance with this Agreement in the same manner as if it were Big Rivers, and thereupon Big Rivers shall have no further responsibility hereunder.

(c) Big Rivers' obligations under this Agreement shall terminate upon the legal defeasance pursuant to Section VII of the Indenture, prior redemption or payment in full of all of the Bonds.

(d) This Agreement, or any provision hereof, shall be null and void in the event that Big Rivers delivers to (i) the MSRB, (ii) the Issuer and (iii) the Trustee, an opinion of Counsel, addressed to Big Rivers, the Issuer and the Trustee, to the effect that those portions of the Rule which require this Agreement, or any of such provisions, do not or no longer apply to the Bonds, whether because such portions of the Rule are invalid, have been repealed, or otherwise, as shall be specified in such opinion.

Section 3.2. Amendment.

(a) This Agreement may be amended, by written agreement of the parties, without the consent of the holders of the Bonds (except to the extent required under clause (4) (ii) in this paragraph), if all of the following conditions are satisfied: (1) such amendment is made in connection with a change in circumstances that arises from a change in legal (including regulatory) requirements, a change in law (including rules or regulations) or in interpretations thereof, or a change in the identity, nature or status of Big Rivers or the type of business conducted thereby, (2) this Agreement as so amended would have complied with the requirements of the Rule as of the date of this Agreement, after taking into account any amendments or interpretations of the Rule, as well as any change in circumstances, (3) Big Rivers shall have delivered to the Trustee an opinion of Counsel, addressed to Big Rivers, the Issuer and the Trustee, to the same effect as set forth in clause (2) above, (4) either (i) Big Rivers shall have delivered to the Trustee an opinion of Counsel or a determination by a person, in each case unaffiliated with the Issuer or Big Rivers (such as bond counsel or the Trustee) and acceptable to Big Rivers and the Trustee, addressed to Big Rivers, the Issuer and the Trustee, to the effect that the amendment does not materially impair the interests of the holders of the Bonds or (ii) the holders of the Bonds consent to the amendment to this Agreement pursuant to the same procedures as are required for amendments to the Indenture with consent of holders of Bonds pursuant to Section 11.03 of the Indenture as in effect on the date of this Agreement, and (5) Big Rivers shall have delivered copies of such opinion(s) and amendment to (i) the MSRB, and (ii) the Issuer.

(b) In addition to subsection (a) above, this Agreement may be amended by written agreement of the parties, without the consent of the holders of the Bonds, if all of the following conditions are satisfied: (1) an amendment to the Rule is adopted, or a new or modified official interpretation of the Rule is issued, after the effective date of this Agreement which is applicable to this Agreement, (2) Big Rivers shall have delivered to the Trustee an opinion of Counsel, addressed to Big Rivers, the Issuer and the Trustee, to the effect that performance by Big Rivers under this Agreement as so amended will not result in a violation of the Rule and (3) Big Rivers shall have delivered copies of such opinion and amendment to (i) the MSRB, and (ii) the Issuer.

(c) To the extent any amendment to this Agreement results in a change in the type of financial information or operating data provided pursuant to this Agreement, the first Annual Financial Information provided thereafter shall include a narrative explanation of the reasons for the amendment and the impact of the change in the type of operating data or financial information being provided.

(d) If an amendment is made pursuant to Section 3.2(a) hereof to the accounting principles to be followed by Big Rivers in preparing its financial statements, the Annual Financial Information for the year in which the change is made shall present a comparison between the financial statements or information prepared on the basis of the new accounting principles and those prepared on the basis of the former accounting principles. Such comparison shall include a qualitative and, to the extent reasonably feasible, quantitative discussion of the differences in the accounting principles and the impact of the change in the accounting principles on the presentation of the financial information.

Section 3.3. Benefit; Third-Party Beneficiaries; Enforcement.

(a) The provisions of this Agreement shall constitute a contract with and inure solely to the benefit of the holders from time to time of the Bonds, except that beneficial owners of Bonds shall be third-party beneficiaries of this Agreement. The provisions of this Agreement shall create no rights in any person or entity except as provided in this subsection (a) and subsection (b) of this Section.

(b) The obligations of Big Rivers to comply with the provisions of this Agreement shall be enforceable (i) in the case of enforcement of obligations to provide financial statements, financial information, operating data and notices, by any holder of Outstanding Bonds, or by the Trustee on behalf of the holders of Outstanding Bonds, or (ii), in the case of challenges to the adequacy of the financial statements, financial information and operating data so provided, by the Trustee on behalf of the holders of Outstanding Bonds; *provided, however*, that the Trustee shall not be required to take any enforcement action with respect to the Bonds, except at the direction of the Issuer (but the Issuer shall have no obligation to take any such action), or the holders of not less than twenty-five percent in aggregate principal amount of the Bonds at the time Outstanding, who shall have provided the Trustee with security and indemnity determined by the Trustee to be adequate. The holders' and Trustee's rights to enforce the provisions of this Agreement shall be limited solely to a right, by action in mandamus or for specific performance, to compel performance of Big Rivers' obligations under this Agreement. In recognition of the third-party beneficiary status of beneficial owners of Bonds pursuant to subsection (a) of this Section, beneficial owners shall be deemed to be holders of Bonds for purposes of this subsection (b).

(c) Any failure by Big Rivers or the Trustee to perform in accordance with this Agreement shall not constitute a default or an Event of Default under the Indenture or the Financing Agreement, and the rights and remedies provided by the Indenture or the Financing Agreement, as the case may be, upon the occurrence of a default or an Event of Default shall not apply to any such failure.

(d) This Agreement shall be construed and interpreted in accordance with the laws of the State, and any suits and actions arising out of this Agreement shall be instituted in a court of competent jurisdiction in the State; *provided, however*, that to the extent this Agreement addresses matters of federal securities laws, including the Rule, this Agreement shall be construed in accordance with such federal securities laws and official interpretations thereof.

ARTICLE IV
Definitions

Section 4.1. Definitions. The following terms used in this Agreement shall have the following respective meanings:

(1) "Annual Financial Information" means, collectively, (i) the following financial information and operating data with respect to Big Rivers and the Members, updated on an annual basis (capitalized terms used in this definition of Annual Financial Information and not otherwise defined in this Agreement shall have the meanings set forth in the Offering Statement):

- "BIG RIVERS ELECTRIC CORPORATION – Introduction – General": the numbers set forth in the second and fourth paragraphs thereof;
- "BIG RIVERS ELECTRIC CORPORATION – Introduction – The Members": the numbers set forth therein;
- "SELECTED BIG RIVERS' FINANCIAL DATA";
- "CAPITALIZATION";
- "Management's Discussion and Analysis of Financial Condition and Results of Operations": all of the information contained therein other than forecasted capital expenditures;
- "QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK – Interest Rate Risk and Commodity Price Risk": the numbers or percentages set forth;
- "GENERATION AND TRANSMISSION ASSETS – Generating Resources – General": the table set forth therein;
- "GENERATION AND TRANSMISSION ASSETS – Generating Resources – Kenneth C. Coleman Plant, Robert D. Green Plant, Robert A. Reid Plant, D.B. Wilson Unit No. 1 Plant and Station Two Facility": the numbers set forth under such captions;
- "GENERATION AND TRANSMISSION ASSETS – Transmission": the numbers set forth under such caption;
- "APPENDIX B – Member Financial and Statistical Information": the tables set forth therein;
- "APPENDIX E-1 – SUMMARY OF MORTGAGE INDENTURE – Additional Mortgage Indenture Obligations": the numbers set forth in the second paragraph thereof;

and (ii) the information regarding amendments to this Agreement required pursuant to Sections 3.2(c) and (d) of this Agreement. Annual Financial Information shall include Audited Financial Statements, if available, or Unaudited Financial Statements.

The descriptions contained in clause (i) above of financial information and operating data constituting Annual Financial Information are of general categories of financial information and operating data. When such descriptions include information that no longer can be generated because the operations to which it related have been materially changed or discontinued, a statement to that effect shall be provided in lieu of such information. Any Annual Financial Information containing modified financial information or operating data should explain, in narrative form, the reasons for the modification and the impact of the modification on the type of financial information or operating data being provided.

(2) "Audited Financial Statements" means (i) the annual financial statements, if any, of Big Rivers, audited by such auditor as shall then be required or permitted by State law or the Indenture and (ii) audited financial statements of each of the Members for the prior fiscal year. Audited Financial

Statements shall be prepared in accordance with GAAP; provided, however, that, pursuant to Section 3.2(a) hereof, Big Rivers or the Members, as the case may be, may from time to time, if required by federal or State legal requirements, modify the basis upon which its financial statements are prepared. Written notice of any such modification shall be provided by Big Rivers to the Trustee, pursuant to Section 3.2(d) hereof, and shall include a reference to the specific federal or State law or regulation describing such accounting basis.

(3) "Business Day" means any day other than a Saturday, Sunday, a legal holiday or a day on which banking institutions in the State or the state where the principal office of the Trustee is located are authorized or required by law to remain closed.

(4) "Counsel" means Orrick, Herrington & Sutcliffe LLP or other nationally recognized bond counsel or counsel expert in federal securities laws.

(5) "GAAP" means generally accepted accounting principles as prescribed from time to time by the Financial Accounting Standards Board.

(6) "Material Event" means any of the following events with respect to the Bonds, whether relating to Big Rivers or otherwise, if material:

(i) principal and interest payment delinquencies;

(ii) non-payment related defaults;

(iii) unscheduled draws on debt service reserves reflecting financial difficulties;

(iv) unscheduled draws on credit enhancements reflecting financial difficulties;

(v) substitution of credit or liquidity providers, or their failure to perform;

(vi) adverse tax opinions or events affecting the tax-exempt status of the security;

(vii) modifications to rights of security holders;

(viii) bond calls;

(ix) defeasances;

(x) release, substitution, or sale of property securing repayment of the securities; and

(xi) rating changes.

(7) "Material Event Notice" means notice of a Material Event.

(8) "Members" means the Members.

(9) "MSRB" means the Municipal Securities Rulemaking Board or any other entity designated or authorized by the SEC to receive reports pursuant to the Rule. Until otherwise designated by the MSRB or the SEC, filings with the MSRB are to be made through the Electronic Municipal Market Access (EMMA) website of the MSRB, currently located at http://emma.msrb.org.

(10) "Offering Statement" means the "final official statement," as defined in paragraph (f)(3) of the Rule, relating to the Bonds.

(11) "Rule" means Rule 15c2-12 promulgated by the SEC under the Securities Exchange Act of 1934 (17 CFR Part 240, §240.15c2-12), as in effect on the date of this Agreement, including any official interpretations thereof issued before or after the effective date of this Agreement which are applicable to this Agreement.

(12) "SEC" means the United States Securities and Exchange Commission.

(13) "State" means the Commonwealth of Kentucky.

(14) "Unaudited Financial Statements" means the same as Audited Financial Statements, except that they shall not have been audited.

(15) "Underwriter" means Goldman, Sachs & Co.

ARTICLE V
Miscellaneous

Section 5.1. Duties, Immunities and Liabilities of Trustee. Article IX of the Indenture is hereby made applicable to this Agreement as if this Agreement were (solely for this purpose) contained in the Indenture.

Section 5.2. Counterparts. This Agreement may be executed in several counterparts, each of which shall be an original and all of which shall constitute but one and the same instrument.

IN WITNESS WHEREOF, the parties have each caused this Agreement to be executed by their duly authorized representatives all as of the date first above written.

BIG RIVERS ELECTRIC CORPORATION

____

Attest: U.S. BANK NATIONAL
ASSOCIATION, as Trustee

By:____________________________

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No dealer, salesperson or other person is authorized to give any information or to represent anything not contained in this Offering Statement. You must not rely on any unauthorized information or representations. This Offering Statement is an offer to sell only the Bonds offered hereby, but only under circumstances and in jurisdictions where it is lawful to do so. The information contained in this Offering Statement is current only as of its date.

TABLE OF CONTENTS

$83,300,000

COUNTY OF OHIO, KENTUCKY

POLLUTION CONTROL REFUNDING REVENUE BONDS, SERIES 2010A

(BIG RIVERS ELECTRIC CORPORATION PROJECT)

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

Goldman, Sachs & Co.

Tab No. 31
Filing Requirement
807 KAR 5:001 Section 16(12)(k)
Sponsoring Witness: Billie J. Richert

Description of Filing Requirement:

The most recent Federal Energy Regulatory Commission Form 1 (electric), Federal Energy Regulatory Commission Form 2 (gas), or Public Service Commission Form T (telephone);

Response:

Big Rivers does not file a FERC Form 1, FERC Form 2, or either of the telephone reports listed above. Therefore, this filing requirement is not applicable to Big Rivers' application.

Tab No. 32
Filing Requirement
807 KAR 5:001 Section 16(12)(l)
Sponsoring Witness: Billie J. Richert

Description of Filing Requirement:

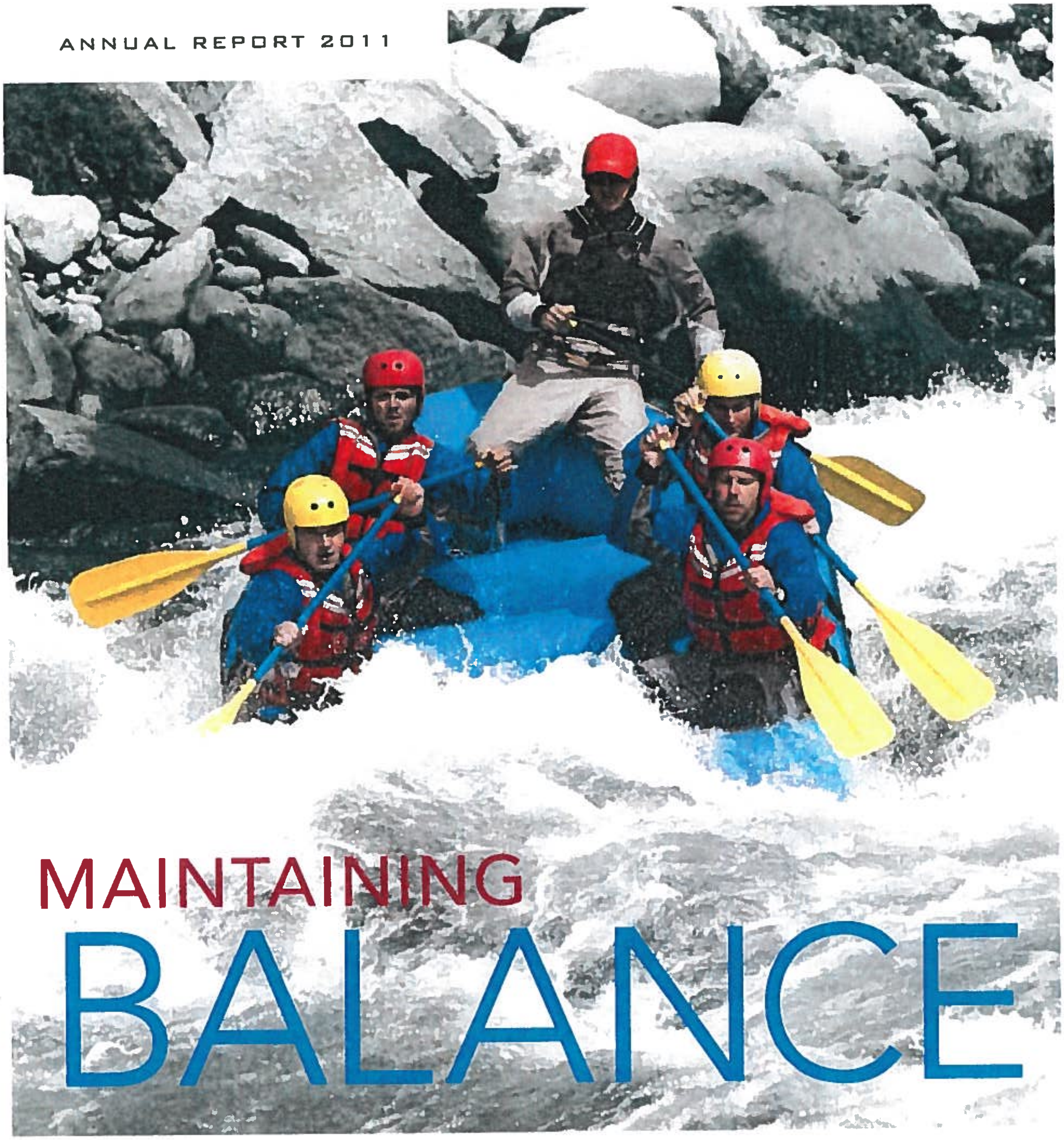
The annual report to shareholders or members and the statistical supplements covering the most recent two (2) years from the application filing date;

Response:

Big Rivers' Annual Reports for 2011 and 2012 (the most recent two years from the application filing date) are provided as attachments to this response.

Big Rivers 2011 Annual Report

ANNUAL REPORT 2011



MAINTAINING BALANCE

Big Rivers

ELECTRIC CORPORATION

Our Mission

Big Rivers will safely deliver low-cost, reliable wholesale power and cost-effective shared services desired by the Members.

Our Vision

Big Rivers will be viewed as one of the top G&Ts in the country and will provide services the Members desire in meeting future challenges.

Our Values

SAFETY
INTEGRITY
EXCELLENCE
MEMBER AND COMMUNITY SERVICE
RESPECT FOR THE EMPLOYEE
TEAMWORK
ENVIRONMENTALLY CONSCIOUS

Financial Highlights

For the years ended Dec. 31. Dollars in thousands.

	2011	2010	2009	2008	2007
Margins	5,600	6,991	531,330	27,816	47,177
Equity	389,820	386,575	379,392	(154,602)	(174,137)
Capital Expenditures*	38,746	42,683	58,388	22,760	18,682
Cash & Investment Balance	44,849	44,780	60,290	38,903	148,914
RUS Series A Note Voluntary Prepayment Status	46,510	23,859	–	–	–
Times Interest Earned Ratio	1.12	1.15	9.85	1.37	1.64
Debt Service Coverage Ratio	1.47	1.47	2.44	1.17	2.04
Cost of Debt	5.69%	5.73%	6.33%	6.33%	5.76%
Cost of Capital	7.98%	7.93%	8.39%	8.33%	7.75%

** Big Rivers' share only.*

Table of Contents

PROFILE

Big Rivers Electric Corporation (Big Rivers) is a Member-owned, not-for-profit, generation and transmission cooperative (G&T). We provide wholesale electric power and services to three distribution cooperative Members across 22 counties in western Kentucky.

The Member cooperatives are Jackson Purchase Energy Corporation, headquartered in Paducah; Kenergy Corp., headquartered in Henderson; and Meade County Rural Electric Cooperative Corporation, headquartered in Brandenburg. Together, the Members distribute retail electric power and provide other services to more than 112,000 homes, farms, businesses and industries.

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

With headquarters in Henderson, Big Rivers owns and operates 1,444 megawatts (MW) of generating capacity in four stations.

Kenneth C. Coleman	443 MW	Hawesville, Ky.
Robert A. Reid	130 MW	Robards, Ky.
Robert D. Green	454 MW	Robards, Ky.
D. B. Wilson	417 MW	Centertown, Ky.
Owned Generation	1,444 MW	

Total generation capacity available is 1,824 MW, including rights to Henderson Municipal Power and Light (HMP&L) Station Two and contracted capacity from Southeastern Power Administration (SEPA).

Owned Generation	1,444 MW
HMP&L Station Two	202 MW
SEPA	178 MW
Total Generation	1,824 MW

High voltage electric power is delivered to the Member cooperatives over a system of 1,266 miles of transmission lines and 22 substations owned by Big Rivers. Twenty-two interconnects link our system with seven surrounding utilities.

Big Rivers is led by an experienced management team and is governed by a six-member board of directors. The board is comprised of two representatives from each distribution cooperative. We employ over 600 people at seven locations in Kentucky, who actively contribute to the communities our Members serve.

Constantly focused on the needs and local priorities of the Member cooperatives, Big Rivers provides assistance in areas such as information technology, mapping and planning, safety programs and training, economic development, education and customer support services.

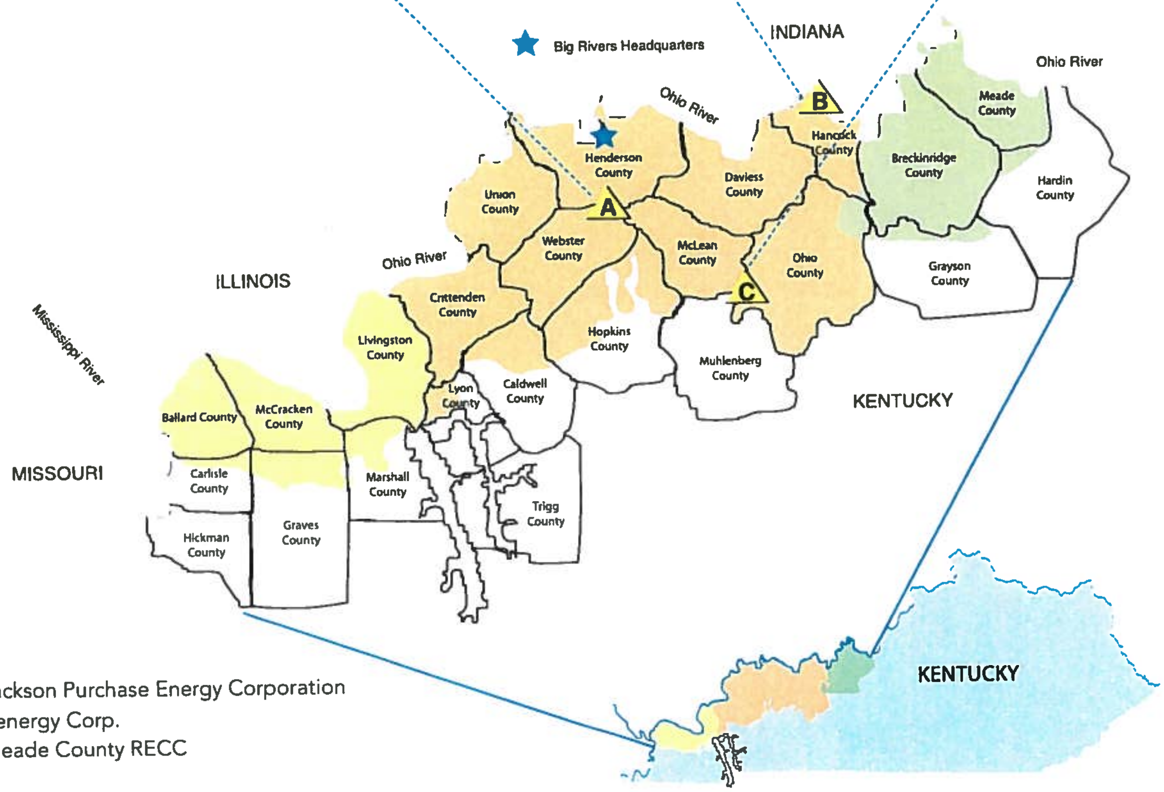
As long-standing members of Touchstone Energy®, Big Rivers and the Member cooperatives pledge to serve western Kentucky with integrity, accountability, innovation and a commitment to community. Keeping the cost of electricity low and the reliability high has always been a priority.

BIG RIVERS ELECTRIC GENERATING STATIONS

A Reid Plant CT
HMP&L Station Two
Reid Plant Unit 1
Green Plant Units 1 & 2

B Coleman Plant
Units 1,2,3

C D.B. Wilson
Unit 1



Jackson Purchase Energy Corporation
Kenergy Corp.
Meade County RECC

MEMBER COOPERATIVES

Kelly Nuckols, *President & CEO*
Jackson Purchase Energy Corporation

JACKSON PURCHASE ENERGY CORPORATION

(270) 442-7321
www.JPEnergy.com

Serves: Ballard, Carlisle, Graves, Livingston, Marshall and McCracken counties

Headquartered:	Paducah, KY
Number of accounts:	29,160
Miles of line:	2,918

Sandy Novick, *President & CEO*
Kenergy Corp.

KENERGY CORP.

(800) 844-4832
www.kenergycorp.com

Serves: Breckinridge, Caldwell, Crittenden, Daviess, Hancock, Henderson, Hopkins, Livingston, Lyon, McLean, Muhlenberg, Ohio, Union and Webster counties

Headquartered:	Henderson, KY
Number of meters:	55,282
Miles of line:	7,047

Burns Mercer, *President & CEO*
Meade County RECC

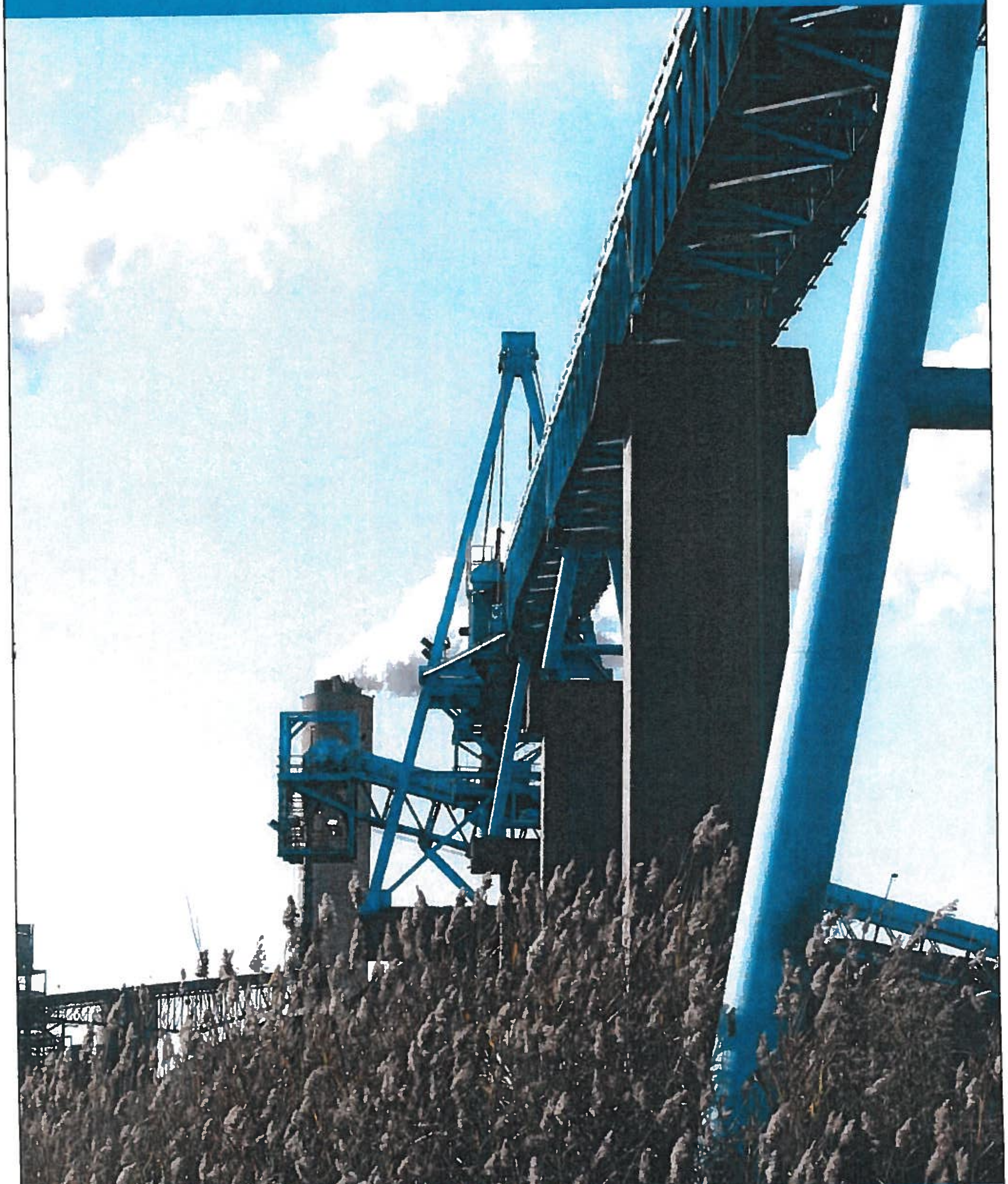
MEADE COUNTY RURAL ELECTRIC COOPERATIVE CORPORATION

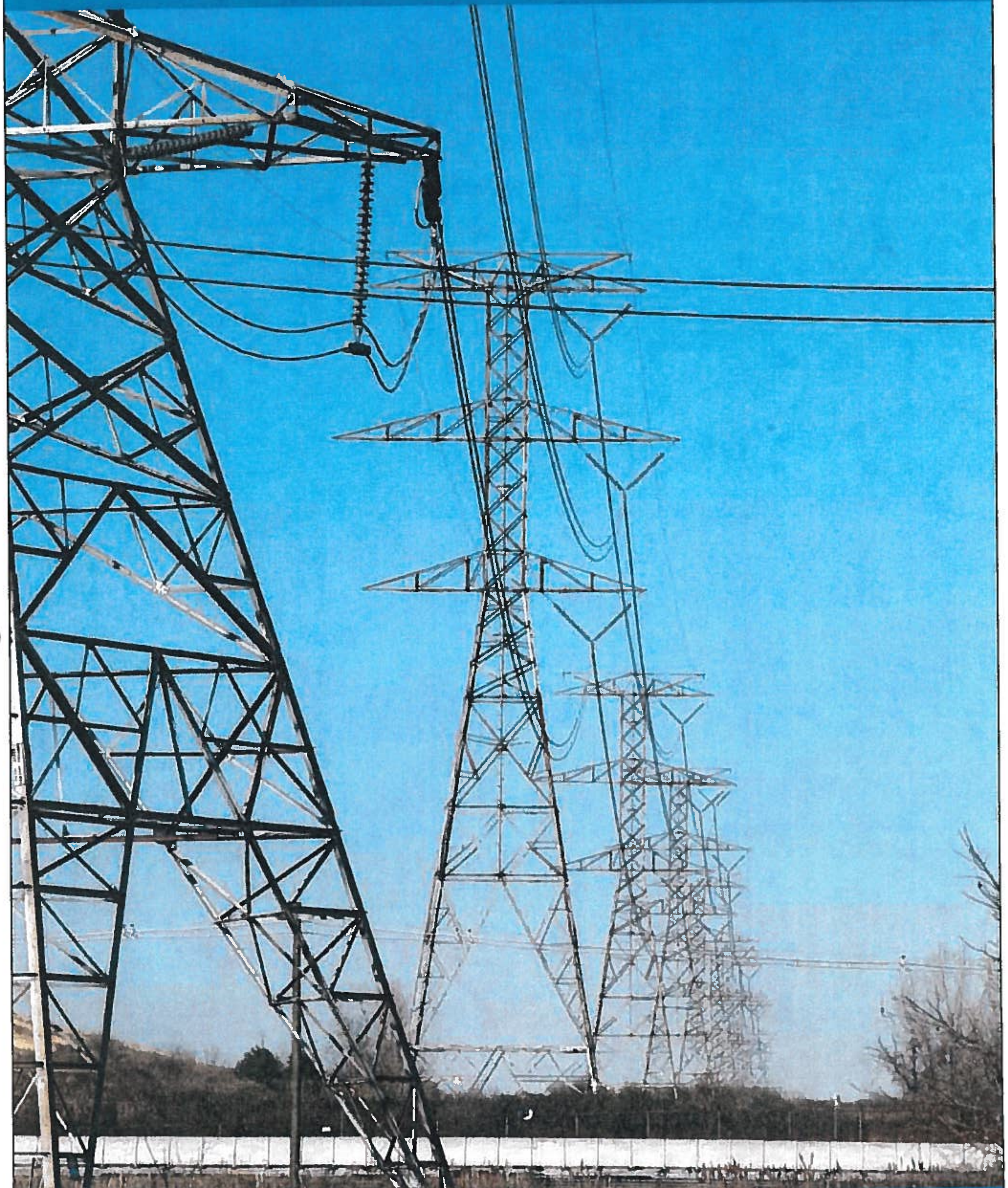
Meade County RECC
Your Touchstone Energy Cooperative

(270) 422-2162
www.mcrecc.coop

Serves: Breckinridge, Grayson, Hancock, Hardin, Meade and Ohio counties

Headquartered:	Brandenburg, KY
Number of meters:	28,478
Miles of line:	2,974





Mark A. Bailey
President and CEO

Dr. James Sills
Chair, Board of Directors

MESSAGE
FROM THE BOARD CHAIR AND CEO

Founded in June of 1961, Big Rivers Electric Corporation celebrated its 50th anniversary in 2011. We are proud of this milestone and owe a significant debt of gratitude to the vision and foresight of our founders. Much of our success today is a tribute to our predecessors' planning and ambition.

Half a century later, we remain dedicated to our mission of safely delivering low-cost, reliable wholesale power and cost-effective services desired by our Members. Our electric rates continue to be some of the lowest in the country, while our generating units remain among the most reliable in our region. Likewise, our employees have continued their commitment to excellence. One of the most visible examples is their record of being some of the safest workers nationally within the electric cooperative program. These accomplishments were no accident, as Big Rivers relies upon dedicated employees committed to serving our Members and the company's success. Teamwork is a core value for Big Rivers, since it is one of the key factors necessary for the company to successfully achieve our mission.

As the times have changed since our creation in 1961, so has the electric utility industry's business climate. Like many electric generation and transmission cooperatives, we have experienced rapid transformation in recent years. This year alone, we faced uncertainty in nearly every sector of our business—the most pressing being a difficult economy and impending environmental regulations. A competent and well-prepared team will be vital to successfully navigating the rough waters ahead. To meet those challenges, Big Rivers' management team is continuously exploring options to successfully balance achievement of our corporate mission, while preparing for emerging environmental regulations and ever-changing utility markets. We are confident our dedicated staff and board of directors are prepared to handle the tough challenges ahead thanks to an experienced leadership team, committed workforce and solid management practices.

To be certain we are equipped to handle the future demands, Big Rivers undertook several long-term initiatives this past year to meet the challenges ahead. At the top of the list was our first wholesale rate increase in 20 years. While no one wants higher electricity rates, Big Rivers' board of directors and management team determined we could no longer continue to defer spending in critical areas and still responsibly operate our generation and transmission system. Although numerous significant cost containment efforts were made prior and subsequent to the rate increase filing, routine and planned maintenance of Big Rivers' transmission and generation assets are necessary to safely deliver low-cost, reliable wholesale power to our Members in western Kentucky.

Big Rivers applied for a 6.85 percent increase in total Member revenue with the Kentucky Public Service Commission on March 1, 2011. On November 17, the Kentucky Public Service Commission granted Big Rivers an increase of $26.7 million annually, a 6.19 percent increase in total Member revenue. Cost containment efforts combined with an increase in revenue were largely responsible for the company achieving net margins of $5.6 million in 2011. This margin achievement satisfied our loan contract requirements. Fortunately, even with this rate increase, Big Rivers will still supply our Members with some of the lowest-priced electricity in the nation.

To satisfy mandated generation reliability requirements set forth by the North American Electric Reliability Corporation (NERC), Big Rivers successfully completed our first full year as a member of the Midwest Independent Transmission System Operator, Inc. (MISO). This move was the most cost-effective alternative for meeting NERC-mandated emergency reserve requirements. Big Rivers is the 35th transmission owning member of MISO, which provided us market access through approximately 57,000 miles of interconnected transmission lines valued at approximately $17 billion. Most importantly, we are happy to report that MISO membership enabled Big Rivers to meet our reliability responsibilities and sell 92 percent of our available generation in 2011—a 4 percent increase from 2010. This helped us keep our rates low.

Another major focus this past year was an analysis of the impacts and costs associated with the Environmental Protection Agency's proposed environmental regulations. This helped determine our compliance strategy. These proposed new environmental compliance rules will create some of the greatest challenges ever faced by electric generators in the U.S. The rules are complex, aggressive and will negatively impact electricity production, availability and rates. Their impact will go well beyond the confines of Kentucky, impacting our U.S. economy and national security.

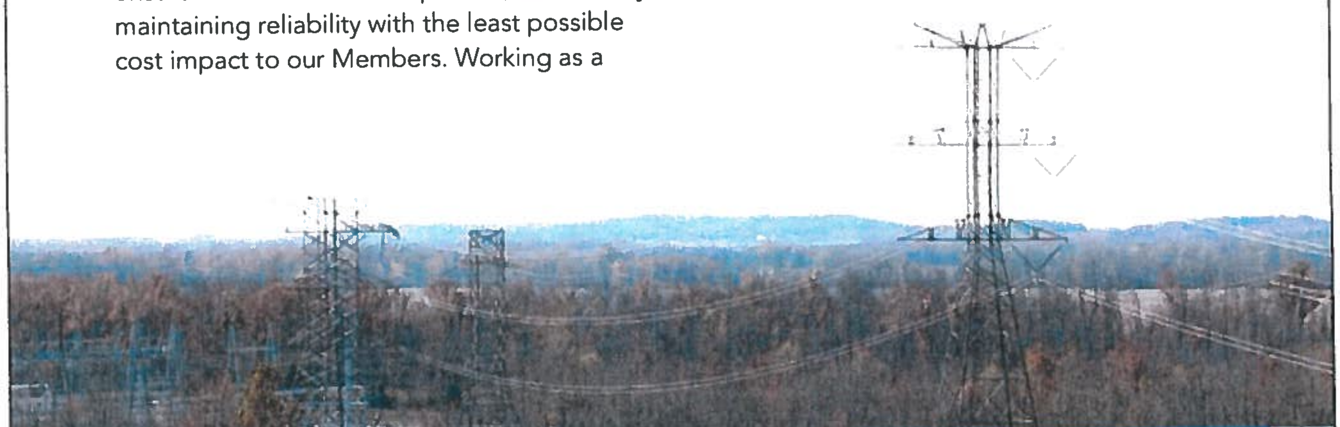
This year, we have taken a proactive approach to inform local officials and community leaders, as well as state and national legislators, regarding our concerns with these burdensome proposals, which come at a time when the economy is still struggling from recession. In April of 2011, we testified before the U.S. Congressional Subcommittee on Energy and Power regarding how these regulations will affect Big Rivers and our Members. We also worked hard to inform our Members' customers how these regulations will ultimately increase electric costs, affect reliability and reduce employment. To help further address these matters, Big Rivers hired Eric Robeson as vice president of plant construction in 2011. Since joining the management team, he has analyzed compliance options, costs and implementation timeframes.

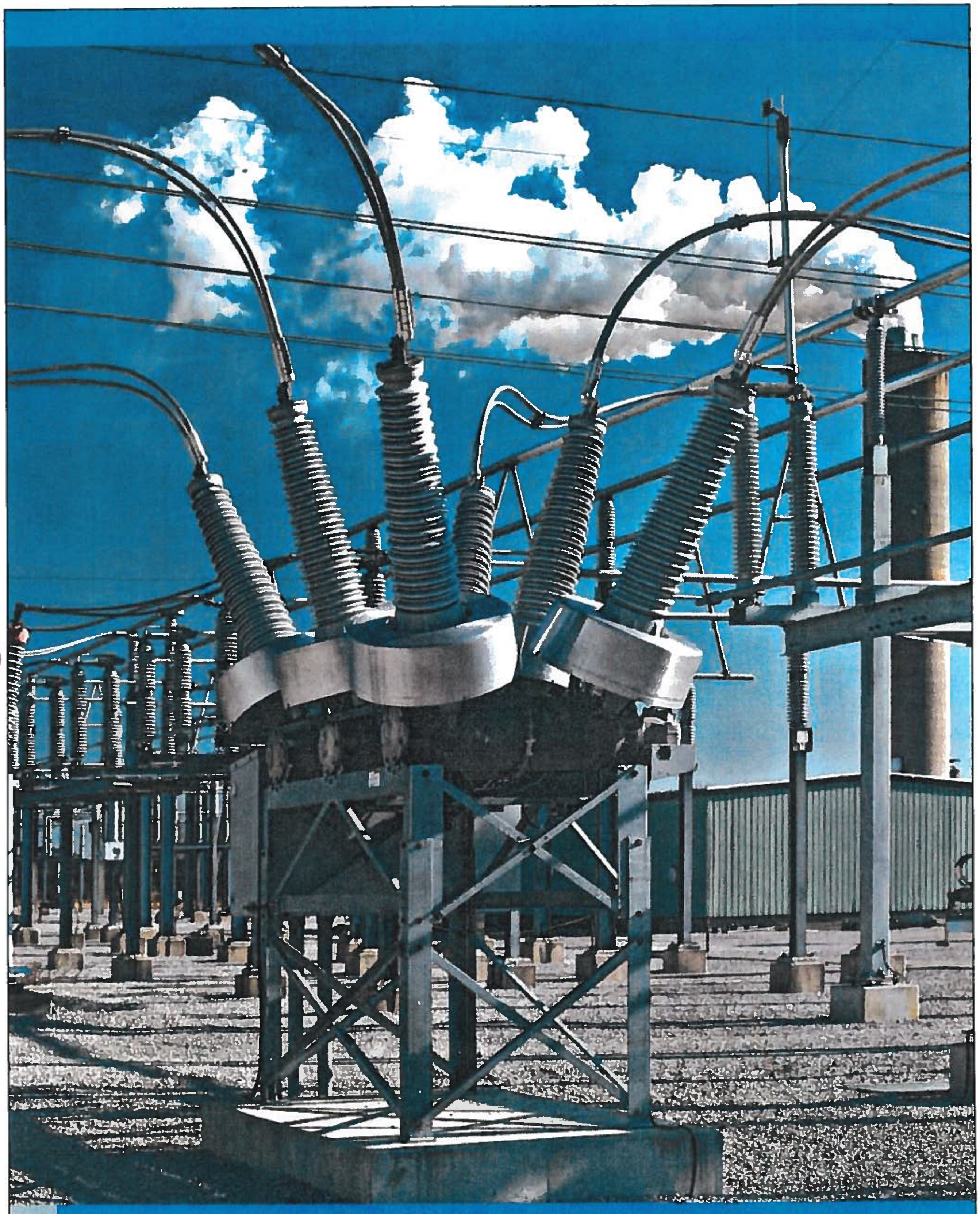
Big Rivers' executive management and board of directors will continue to carefully evaluate all options to optimize our investment and ensure environmental compliance, while safely maintaining reliability with the least possible cost impact to our Members. Working as a

team, Big Rivers' board, management and employees have accomplished major milestones in 2011. We know that maintaining the right balance in the future will be the key to Big Rivers and our Members' continuing success in the coming years. The future holds great challenges, but we are confident in our ability to navigate the uncertain waters ahead. We will continue to add value for Members through excellence in providing reliable and low-cost power for years to come.

Dr. James Sills
Chair, Board of Directors

Mark A. Bailey
President and CEO





BOARD OF DIRECTORS

Standing (left to right):

Dr. James Sills, Chair
Meade County RECC

Wayne Elliott, Vice-Chair
Jackson Purchase Energy Corporation

William Denton
Kenergy Corp.

Seated (left to right):

Lee Bearden
Jackson Purchase Energy Corporation

Paul Edd Butler
Meade County RECC

Larry Elder, Secretary-Treasurer
Kenergy Corp.

MANAGEMENT TEAM

Standing (left to right):

Paula Mitchell, *Executive Assistant*

James Miller, *Corporate Counsel*

Albert Yockey, *V.P. Governmental Relations & Enterprise Risk Management*

David Crockett, *V.P. System Operations*

James Haner, *V.P. Administrative Services*

Marty Littrel, *Communications & Community Relations Manager*

Seated (left to right):

Eric Robeson, *V.P. Environmental Services & Construction*

Robert Berry, *V.P. Power Production*

Mark Bailey, *President & CEO*

Mark Hite, *V.P. Accounting & Interim CFO*

USING TEAMWORK
TO NAVIGATE THE TURBULENT WATERS

On March 1, 2011, Big Rivers Electric Corporation filed with the Kentucky Public Service Commission (KPSC) its first general rate adjustment in 20 years. The filing application requested approval to increase wholesale electric rates by 6.85 percent to our three distribution cooperative Members: Jackson Purchase Energy Corporation, Kenergy Corp., and Meade County Rural Electric Cooperative Corporation.

In the years since Big Rivers last increased wholesale rates in 1991, the Consumer Price Index has risen approximately 64 percent. Prior to and following the rate increase filing, Big Rivers initiated multiple cost containment actions to address decreased wholesale electric revenue resulting from the depressed economy as well as additional expenses required to judiciously operate its business.

Our board of directors and management team constantly strive to safely provide reliable, low-cost service to our Members. However, to address increasing requirements in a challenging environment, we could no longer delay a wholesale electric rate increase.

This rate application process required considerable planning and teamwork among Big Rivers' employees and advisors. Satisfactorily meeting required deadlines for filing testimony and responding to data requests and discovery for the better part of a year was a true demonstration of the leadership and dedication of our employees.

Yet, even with the recent rate change, Big Rivers continues to provide some of the lowest wholesale power rates in Kentucky and in the nation.

Big Rivers conducted a thorough evaluation of the costs of service to determine the revenue contribution each customer class made compared to the cost to serve those customers. This cost of service study revealed that large industrial customers were paying more than their share compared to residential customers. The gap was so significant that even without any rate increase at all, residential rates would have had to be increased 6.7 percent to eliminate the disparity. As a result, Big Rivers proposed to reduce the gap by one-quarter of the difference. In addition, a depreciation study was conducted of all Big Rivers assets as part of the rate case filing.

On November 17, the KPSC authorized Big Rivers to adjust its electric rates approximately $26.7 million annually, a 6.19 percent increase in total Member revenue. Successfully navigating this complex process was a direct result of significant effort and cooperation from a team of employees.

Line crew personnel inspect, treat, and replace transmission poles as part of an ongoing maintenance program.

Energy services personnel plan, schedule, analyze, and forecast use of our generating assets to maximize the benefit to Members.

MOVING THOUGH CHANGING WATERS WITH

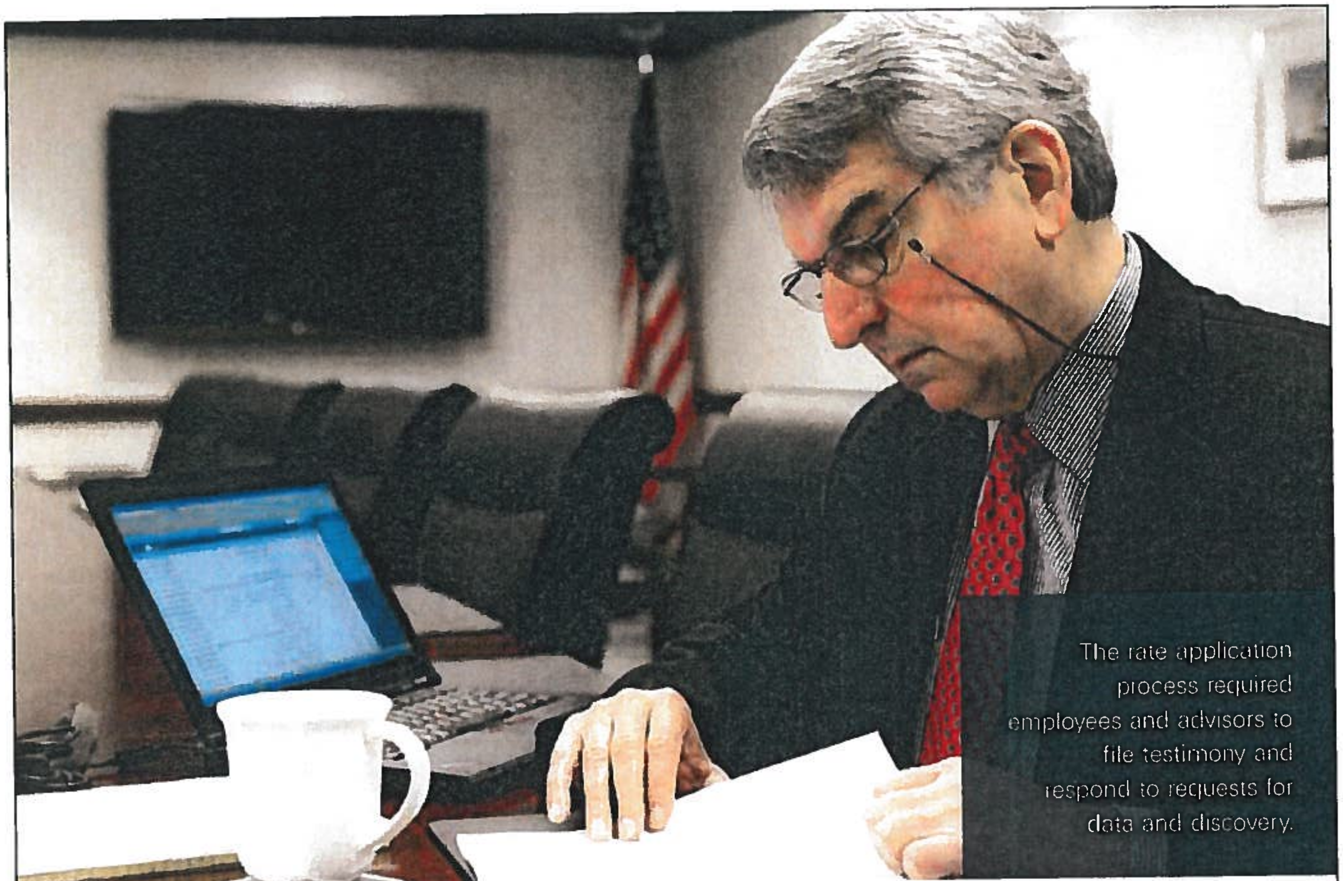
INTEGRITY

Big Rivers has a good working relationship with state and federal legislators. Big Rivers personnel actively monitor legislation and regulations that might impact electric cooperatives and the utility industry. The company is especially vigilant in monitoring a series of regulations recently proposed by the Environmental Protection Agency (EPA), as they will have a significant impact on coal-fired power plants. The regulations, if approved, would ultimately increase the cost of electricity and could affect reliability, at least in the short term.

During much of 2011, Big Rivers personnel analyzed the near and distant impact of pending EPA regulations on company operations and financial metrics. A number of cross-departmental teams are evaluating environmental compliance requirements that will necessitate expensive construction projects at our generating stations, as well as financing, financial modeling, rate case evaluation, and demand side management programs. Although everyone is interested in protecting the environment, the challenge is to balance benefits with costs, while achieving the intended results in the most efficient and cost-effective manner.

Big Rivers also continues to maintain a good working relationship with the Kentucky Public Service Commission. Big Rivers personnel are working with other Kentucky utilities in regulatory advisory groups regarding possible changes to the KPSC's regulations on rules of procedures and tariffs. Big Rivers personnel are also providing input in connection with the implementation of smart grid standards and related investments. Big Rivers received recommendations from KPSC staff on the 2010 filing of its integrated resource plan, which will be incorporated in Big Rivers' next integrated resource plan filing.

Regarding fuel supply, Big Rivers continues to balance the fuel portfolio in accordance with our strategic plan while maintaining transparent fuel procurement processes. Big



The rate application process required employees and advisors to file testimony and respond to requests for data and discovery.

Rivers' generating units are operated in a way that minimizes cost and maximizes efficiency. In light of the low demand for electricity and low market prices for off-system energy sales, Big Rivers has been challenged to meet the needs of Members while still achieving financial objectives. As noted earlier, cost containment measures have enabled Big Rivers to do both.

Big Rivers successfully integrated into Midwest Independent Transmission System Operator, Inc. (MISO) in late 2010 and actively participates in related activities and training to ensure the effectiveness of Big Rivers' operations within the MISO market. Examination of the costs and benefits of MISO membership versus other options is ongoing, and the company filed an annual report to update the KPSC on this matter in 2011. To develop new revenue streams, Big Rivers continues to identify and evaluate power supply business opportunities and strategic partnerships. Now that full integration into MISO is complete, the focus is on optimizing participation and developing strategies designed to maximize Member benefit. Personnel received training in 2011 to gain additional understanding of MISO procedures, as well as oversee transmission-related issues and advocate Big Rivers' position.

By maintaining a balance between risks and benefits, Big Rivers manages Member rate volatility and the impact on net margins. Personnel monitor the effectiveness of enterprise risk management policies and work with the Members to implement depreciation studies, cost of service studies, and rate design to stabilize earnings for Big Rivers and our Members.

PERFORMING WITH EXCELLENCE

Big Rivers' generating stations exceeded all of their key performance indicator targets in 2011. The power plants achieved a near-record equivalent availability factor of 93.3 percent, which is the percentage of time a generating unit is available for power production. The higher the percentage, the more efficiently and productive the generating system is running. Results of 2011 were second only to the year 2010 as the best performance in the company's history.

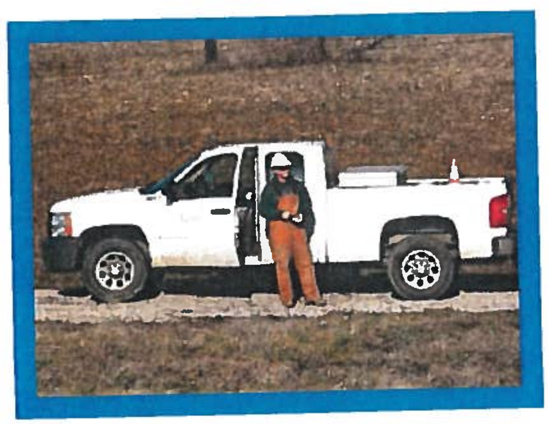
The 2011 equivalent forced outage rate, which measures the percentage of time a generating unit is unexpectedly off-line or unable to obtain its rated capacity, was 4.1 percent, and actual net generation for the year was 12,444,872 MWh.

The fleet-wide net heat rate of our generating fleet was also favorable at 11,001 net Btu/kWh compared to the annual target of 11,067. Net heat rate measures how efficiently the energy contained in coal that is burned is converted to electricity. This favorable heat rate saved Big Rivers' Members more than $1.7 million in fuel costs in 2011.

Coleman Station set records for continuous days in service on all three of its generating units in 2011: Unit 1 – 144 days, Unit 2 – 104 days, and Unit 3 – 140 days. Coleman Station also exceeded its annual generation target by more than 215,000 MWh.

As part of our mission, Big Rivers strives to meet the Members' reliability needs and regulatory compliance requirements in the most cost-effective manner. Employees work with our Members to adopt criteria to evaluate the economic and reliability impact of transmission expansion or improvement projects, as well as monitor the capabilities and expansions of surrounding utility transmission systems. Big Rivers completed or substantially completed 12 capital construction projects in 2011. Regarding transmission service reliability, Big Rivers met the target goal for two member systems as well as system-wide target for average outage duration.

Big Rivers complies with all North American Electric Reliability Corporation (NERC) reliability standards and SERC Reliability Corporation regional guidelines consistent with a corporate culture of compliance. Employees continue to efficiently maintain the transmission system with a focus on Member reliability and power import and export capability. This includes evaluation of shared services that provide value to end-use consumers through economies of scale. Installation of a new two-way radio system



Right-of-way personnel manage vegetation to keep trees from causing outages and to help maintain reliability of our transmission system.

Control room operators are responsible for the safe and efficient operation of our generating units. Personnel improve or maintain performance and trouble-shoot operating issues.

for Big Rivers and all three Members began in 2011 and will be completed in 2012.

As part of an ongoing maintenance program, Energy Transmission & Substation employees inspected and treated 3,375 poles and replaced 62 rejected poles. They performed a ground inspection of 466 miles of transmission line right-of-way as required by NERC, treated 380 miles with herbicide, and performed a full-width cut on 48 miles of right-of-way. In addition, employees tested 43 circuit breakers, 39 transformers, six capacitor banks, 37 line switches, and 78 battery banks. Big Rivers also completed two aerial inspections of the transmission system as required by Kentucky Public Service Commission regulations.

Energy Transmission & Substation employees achieved one year with no lost-time incidents in January 2011.

SHOOTING THE RAPIDS OF POWER DELIVERY WITH
SAFETY

Big Rivers emphasizes safety with employees, Members, contractors, and the public. Team members update, implement, and communicate the comprehensive safety plan on an annual basis and assist the Member systems with their safety needs.

On January 14, Big Rivers employees reached a significant company-wide safety milestone by completing a year without a lost-time incident, which was the first time company employees reached this milestone. This achievement is a credit to all employees, because it could not have been accomplished without each employee doing his or her part to maintain a safe working environment. Also in January, Transmission & Substation employees achieved one year with no lost-time incidents; Coleman Station and Sebree Station completed five years and two years, respectively.

Employees at Sebree Generating Station were awarded their seventh Governor's Safety Award in June. Sebree Station employees received this award for achieving more than one million man-hours without a lost-time injury as of March 31. Safety is a foundation for all decisions and expectations of Big Rivers' workforce, so this milestone is a significant achievement.

Wilson Station employees completed four years with no lost-time incidents on May 15, and they successfully worked 835,667 hours with no lost time as of June 30. As a result, Wilson employees received their eighth Governor's Safety Award. Safety is the most important corporate value at Big Rivers, because it protects the life and well being of our most important asset: our employees.

Big Rivers sent a contingent of employees to Kentucky's 2011 Governor's Safety and Health Conference, including Warren Hust Jr., past president of the Kentucky Safety and Health Network, and Donna Haynes, present board member of the Kentucky Safety and Health Network.

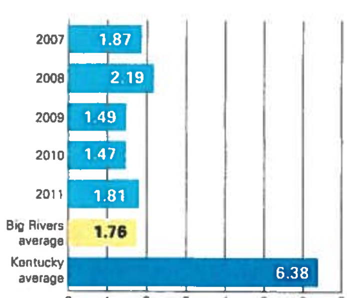
Headquarters employees completed one year with no recordable incidents on June 22, as did Wilson Station employees on October 6, and Transmission & Substation employees on November 17.

Coleman Station employees completed five years with no lost-time incidents in January 2011 and received the Governor's Safety Award at the 2011 Governor's Safety and Health Conference.

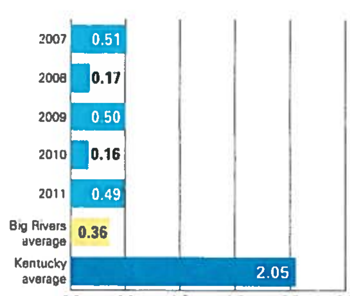
Sebree Station employees completed two years with no lost-time incidents in January 2011 and received the Governor's Safety Award at the 2011 Governor's Safety and Health Conference.

Wilson Station employees completed four years with no lost-time incidents in May 2011 and received their eighth Governor's Safety Award from Kentucky Secretary of Labor Mark Brown.

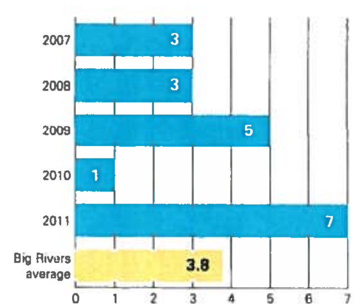
OSHA Recordable Incident Rate



Lost-Time Incident Rate



Number of Vehicle Incidents



MOVING IN SYNC WITH OUR MEMBERS' NEEDS

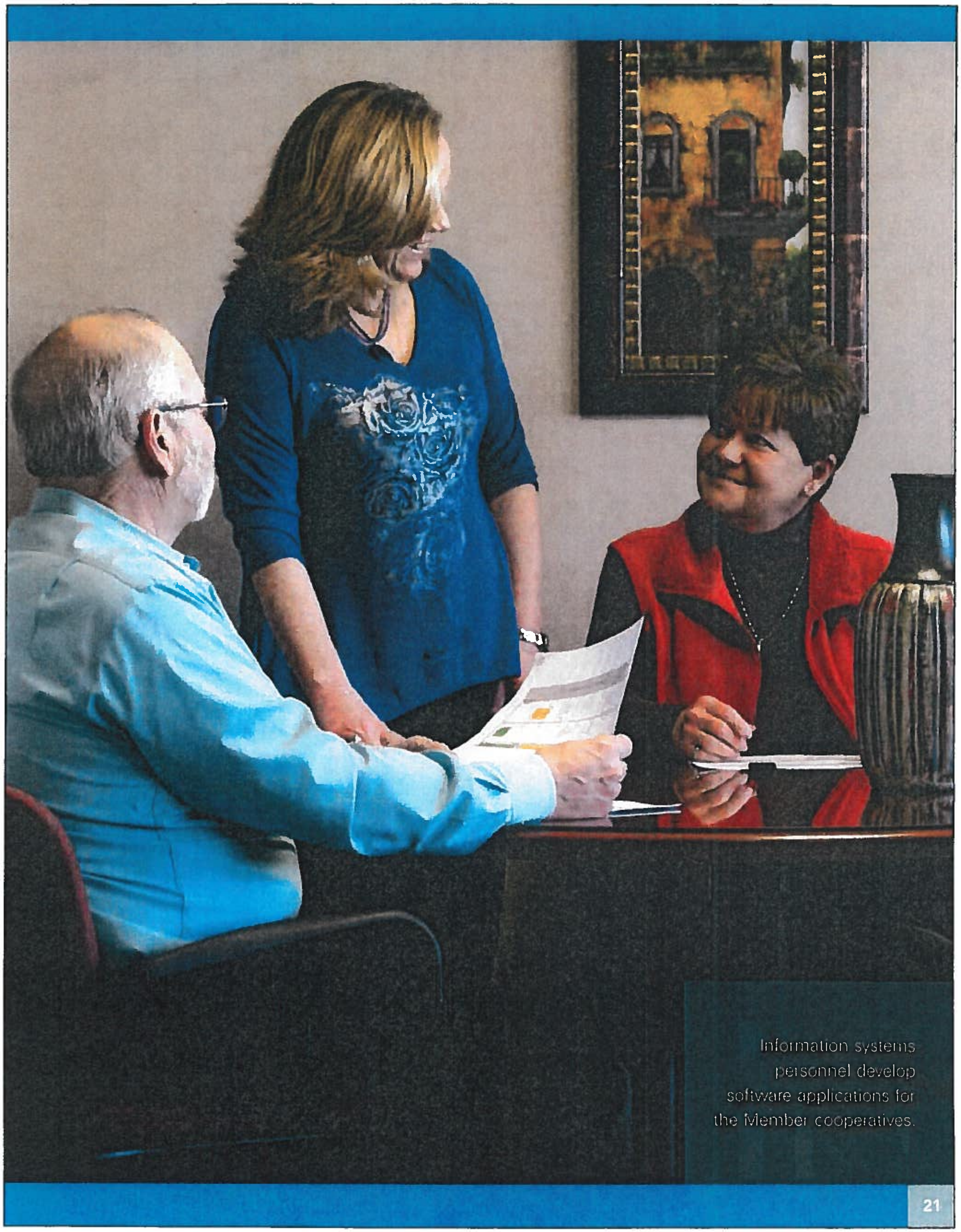
Big Rivers has taken a proactive approach towards advancing Kentucky Governor Steve Beshear's energy plan: Intelligent Energy Choices for Kentucky's Future. Strategy 1 of the plan addresses the energy efficiency of Kentucky's homes, buildings, industries, and transportation fleet by establishing the goal that energy efficiency will offset at least 18 percent of Kentucky's projected 2025 energy demand.

In 2011, Big Rivers worked cooperatively with our Members in developing demand side management programs intended to impact summer and winter demands for electricity, annual kWh sales, and water savings designed to reduce energy consumption at the retail level. These energy efficiency programs provide incentives to both residential and commercial customers of the Member cooperatives to modify energy consumption through purchase, construction, or servicing of electricity-consuming equipment. The following nine programs were launched in October 2011:

- Residential Lighting Program (CFL distribution)
- Residential ENERGY STAR Clothes Washer
- Residential ENERGY STAR Refrigerator Program
- ENERGY STAR Heating, Ventilation and Air Conditioning (HVAC) Program
- Residential Weatherization Program (development still underway)
- Residential Touchstone Energy New Construction Program
- HVAC Tune-Up Program
- Commercial/Industrial Efficient Lighting Program
- Commercial/Industrial Efficient Equipment Program

The KPSC approved an annual budget for the energy efficiency programs of $1 million in 2012 that could result in more than 2.2 MW of reduced demand and save an estimated 6,900 MWh annually for retail Members. Energy efficiency programs have the capability to slow load growth, which may allow Big Rivers to delay the need for purchase of additional generating assets.

Engineering personnel manage construction projects to expand or improve the capabilities of our transmission system.



Information systems personnel develop software applications for the Member cooperatives.

SHOWERING THE

COMMUNITY

WITH CORPORATE AND EMPLOYEE INVOLVEMENT

The United Way committee at Big Rivers is comprised of employee volunteers from each of our locations. These volunteers plan and deliver an annual campaign to generate employee contributions to United Way.

Community service, as part of our corporate values, is a strategic objective at Big Rivers. We persistently support and encourage employee involvement in civic and philanthropic organizations within the communities served by Big Rivers and our Members.

This year, Big Rivers and our employees contributed $208,285 to local United Way agencies. This was a 7 percent increase in employee contributions from the previous year's campaign, which is a testament to the charitable character of our employees. Big Rivers has always encouraged a strong tradition of volunteering and giving back to the communities it serves. This year alone, 77 percent of our employees contributed to United Way, which was one of the highest participation rates in the region. Total employee contributions to the 2011 United Way campaign were $166,285, an average of $326 per employee. Big Rivers stimulates employee participation and giving rates by increasing the corporate contribution based on the percentage increase of employee dollars and participation rates over the previous year. This year, the Big Rivers corporate donation totaled $42,000.

Big Rivers employees are extremely active in a variety of civic and community events. To foster proactive involvement in philanthropic activities, Big Rivers initiated an employee community support program that financially supplements employees' participation in community activities based on their volunteer hours or dollar-for-dollar matching of their financial contributions.

In addition, the company was a major contributor to Junior Achievement, March for Babies, Relay for Life, Habitat for Humanity, Kentucky Governor's Scholars Program, and the Philippine Project (in conjunction with the National Rural

Big Rivers supports a team of employees annually to participate in the March for Babies walk in Henderson, Kentucky.

Electric Cooperative Association International Foundation, which brings electricity to rural villages). Thanks to active participation and a concern for helping others, this year's fundraising efforts were a success and brought value to our communities.

Over the past 50 years, employees at Big Rivers have consistently offered their leadership abilities by serving on numerous committees and boards throughout the area. This year, many of our employees gave back to the local communities in our region by serving in advisory positions for children advocacy groups, economic development organizations, health care foundations, chambers of commerce, and contributing to university and school boards. Helping our local communities grow and prosper is a long tradition for Big Rivers and our Members.

Production employees receive training on power plant operations, equipment maintenance, and safety procedures. Big Rivers stresses the importance of safety, because the company values employees as our most important asset.

RESPECT FOR EVERY EMPLOYEE ON BOARD

Big Rivers is powered by a well-trained, engaged workforce dedicated to teamwork and the success of both the company and our Member cooperatives. The company has:

- Planned to meet current and anticipated staffing needs in recognition of an aging workforce;
- Enhanced the strategy and process for communicating with employees;
- Encouraged teamwork across departments through multi-functional teams;
- Developed tools necessary to track and meet training needs;
- Maintained a positive relationship with the Union;
- Emphasized with employees the importance of Members and helped build employee understanding of how their efforts impact Members; and
- Nurtured and supported employee participation in civic and philanthropic organizations within our local communities.

Maintaining balance is an integral part of the human resources function. Compensation and benefits are adjusted as necessary to attract and retain employees, while minimizing costs to help meet profit or margin requirements for the corporation. A sufficient and well-trained workforce is necessary to keep day-to-day operations running smoothly while preparing for the future. Staffing is made all the more challenging given the number of employees approaching retirement, and the increased pressure on costs due to the depressed power sales market in the current economy.

During 2011, the generating stations lost 16 employees to retirement, taking with them more than 522 years of experience in operating and maintaining power plant equipment. With this in mind, hiring practices have been put into place to prepare for and offset the

Human resources personnel address critical issues in staffing, benefit design, and employee relations.

impact of an aging workforce. This includes temporarily hiring additional employees at the generating stations before they are needed due to upcoming retirements.

In addition, the production department purchased a power plant operator training simulator in 2011 to improve the quality of its control room operator training program and to expedite the training of new operators to replace retirees. In order to continue serving Members with excellence, Big Rivers also sharpens employees' skills through various training activities.

Benefit costs were also a focus in 2011, with the decision made to market the employee health plan. As a result of that effort, Big Rivers is self-insuring its medical plan and moved to a new dental plan provider in 2012 with significant expected savings in the cost of providing employee health plan benefits.

A compensation study was initiated to gauge the competiveness of pay rates and appropriateness in design of the non-bargaining employee salary structure. Adjustments as determined by the study were implemented in early 2012.

ENVIRONMENTALLY CONSCIOUS

OF THE LANDSCAPE THAT SURROUNDS US

This nesting box, installed at Wilson Station, will hopefully house a pair of Peregrine Falcons in the near future.

One of the greatest challenges facing the electric utility industry is finding the proper balance between the public's desire for a cleaner environment and low-cost reliable electricity. To address these challenges, Big Rivers took several proactive steps in 2011 to realize its environmental responsibilities.

In May, Big Rivers hired Eric Robeson as vice president of plant construction to develop an overall compliance strategy to achieve federal EPA requirements of the Cross-State Air Pollution Rule and Mercury and Air Toxics Standards. These regulations will require electric utilities to further reduce their emissions of sulfur dioxide, nitrogen oxides, and mercury from their generating units.

As part of this effort, Big Rivers engaged the engineering firm of Sargent & Lundy to perform a three-phase environmental compliance study. The study measured existing emissions from the generation fleet, identified viable technology solutions to meet the new environmental regulations, and developed a least-cost solution for compliance with these regulations.

In addition, Big Rivers formed an internal team to ensure that all appropriate areas of the company were focused on these new environmental regulations. The primary goal of this team is to develop the required regulatory filings associated with an environmental compliance plan, certificates of public convenience and necessity, and environmental surcharge update by the end of 2012. These filings will allow Big Rivers to receive KPSC approval of its compliance plan.

A ladder structure is assembled onto the front of the nesting box to provide falcons with a perch.

HELPING WILDLIFE

Personnel from the Kentucky Department of Fish and Wildlife Resources installed a Peregrine Falcon nesting box at the top of the Wilson Generating Station stack in mid-September.

Kate Heyden, aviation biologist, offered her thanks to the Wilson crew that helped with the installation. "We greatly appreciate your support of our Peregrine Falcon restoration program. The Peregrine Falcon is a rare species, with only 13 nesting pairs in Kentucky (most of which are in nest boxes)."

Hopefully, this nest box will provide another safe nesting location for these birds in the near future. A similar nesting box was installed at Coleman Generating Station in 2010.

EXPLORING ELECTRIC VEHICLES

Big Rivers purchased the highly-touted Chevy

Environmentally Conscious (continued)

Volt in December 2011 to test its performance and raise public awareness of new electric vehicle technology. This vehicle purchase follows a corporate strategic initiative of proactive asset management, because electric vehicles are typically charged at night when our generating assets are not fully utilized.

The Volt is the first American production vehicle designed to travel extended distances in the electric vehicle mode with full performance and speed. In its simplest form, the Volt operates two ways: short range using only battery power and extended range using gasoline-generated electricity. The Chevy Volt can be charged with a standard 120-volt household outlet, making charging easily available. Initial indications suggest about $1.50 of electricity will permit the vehicle to travel approximately 35 miles using battery power only. Beyond its battery power radius, the Volt's gasoline-powered generator automatically engages to produce electricity that allows the vehicle to be driven an additional 300 miles. Overall, the Volt is allowing Big Rivers to better understand this technology and the opportunities it may present.

Looking to the future, this technology could lead to expansion of our demand side management programs that permit better utilization of our generating assets, while delaying the need to add even more expensive assets to meet our Members' increased electricity needs. As the popularity and economics become more attractive for these electric vehicles, they could provide opportunities for low-cost, off-peak energy programs.

RECYCLING

In order to be better stewards of the environment, Big Rivers launched on-site recycling efforts in 2011. Recycling programs are now operational at three facilities, and the remaining locations will begin participation in 2012.

Sebree Generating Station and Energy Transmission & Substation have partnered with Henderson Recycling to collect cardboard and paper waste. Sebree Station also collects plastic recyclable waste. Big Rivers personnel installed 96-gallon plastic bins in areas such as the control room, offices, and lunch rooms for easy access by employees. These bins collect recyclable items like newspaper, magazines, and plastic bottles.

Sebree warehouse personnel also recycle large cardboard boxes received with material shipments. The program was so successful that Sebree Station is on the waiting list with Henderson Recycling for a second large collection bin. The ultimate goal of this program at our Sebree and Transmission & Substation facilities is to reduce the amount of recyclable material

In partnership with Henderson Recycling, warehouse personnel recycle cardboard boxes received with material shipments.

Big Rivers purchased this Chevy Volt to test its performance and raise awareness of electric vehicle technology.

sent to the Henderson, Kentucky landfill and extend its usable life, which is only about six more years at current usage levels.

As part of another recycling partnership, the city of Hartford, Kentucky delivered a new recycle trailer to Wilson Generating Station, one of six tailor-made trailers Hartford purchased with grant money for recycling. Wilson employees are pleased to join the city of Hartford in this effort to reduce recyclable materials going to landfills.

Thanks to the conscientious efforts of our employees, their waste recycling will not only reduce the volume of material being sent to landfills, it will also reduce the cost associated with traditional garbage removal. These recycling programs at Energy Transmission & Substation, Sebree Station, and Wilson Station exemplify our corporate values of community service, teamwork, and environmental consciousness.

2011 FINANCIAL REVIEW

Big Rivers' mission is to safely provide low-cost, reliable wholesale electricity and cost-effective shared services to three Member distribution cooperatives—Jackson Purchase Energy Corporation, Kenergy Corp. and Meade County Rural Electric Cooperative Corporation. At December 31, 2011, the Members provide service to 112,936 retail customers in 22 western Kentucky counties.

On March 1, 2011, Big Rivers filed an application with the Kentucky Public Service Commission (KPSC) seeking to increase its Member wholesale tariff rates. Per the application, the proposed Member revenue increase was $29.6 million, a 6.85 percent increase in total Member revenue. At the time of the filing, Big Rivers had not obtained a wholesale tariff rate increase in 20 years. The KPSC issued an order on November 17, 2011, approving an increase in electric rates of $26.7 million, a 6.19 percent increase in total Member revenue. The rate increase was retroactively applied for service rendered on September 1, 2011.

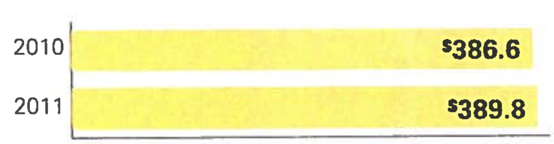
In 2011 Big Rivers also completed its first full year of membership with Midwest Independent Transmission System Operator, Inc. (MISO). MISO coordinates, monitors and controls operation of the electrical power system in this region. ACES Power Marketing continues to market Big Rivers' surplus power.

Big Rivers operates 1,444 MW of owned generating facilities and 312 MW of Henderson Municipal Power & Light Station Two, of which Big Rivers is currently allocated 202 MW. The company also owns transmission assets, principally 1,266 miles of transmission lines and 22 transmission substations. Net utility plant at December 31, 2011 was $1,092.1 million, and total assets were $1,417.9 million.

Big Rivers completed 2011 with a favorable set of key financial metrics, discussed in the pages that follow.

Net Margins
Dollars in millions

Equity
Dollars in millions



NET MARGINS AND EQUITIES

The 2011 net margin was $5.6 million, resulting in a 1.12 times interest earned ratio (TIER) and margins for interest ratio (MFIR), and a 1.47 debt service coverage ratio (DSCR). Equities to total assets were 27.49 percent at December 31, 2011.

The net margin for 2010 was $7.0 million. Three items account for the majority of the $1.4 million decline in the 2011 net margin. First, 2011 reflects additional expense of $4.6 million related to a full year of MISO membership fees versus one month of membership expense in 2010. Second, following a thorough analysis during 2010, the balance of the reserve for obsolescence that was established for certain materials and supplies inventory upon the Unwind closing was written off, resulting in a positive impact of $1.9 million to the 2010 net margin. Third, largely offsetting the unfavorable expense variance is a $5.0 million increase in net sales margin (electric sales revenue less variable cost) in 2011. This is principally due to the Member rate increase and higher smelter and off-system sales volumes in 2011, largely offset by lower market pricing in off-system sales.

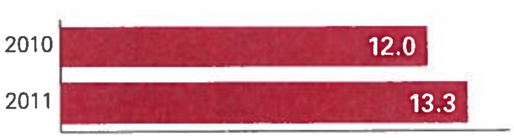
ENERGY SALES AND ELECTRIC REVENUES

Energy sales increased to 13,255,125 MWh in 2011, up from 11,969,420 MWh in 2010. There were two primary reasons for the MWh sales increase. First, an additional 506,389 MWh were sold to the smelters, a 7.98 percent increase over 2010, due to the restarting of an idle potline at Century Aluminum. Second, an additional 846,675 MWh were sold in the off-system market, a 38.32 percent increase over 2010.

Non-smelter Member sales decreased 67,359 MWh in 2011, or 1.98 percent, driven by weather. Electric energy revenue increased to $558.4 million in 2011, up from $514.5 million in 2010, due to a combination of off-system sales, Century Aluminum restarting one of their potlines, and the September 1, 2011, rate increase.

Energy Sales

Megawatt-hours (MWhs) in millions



Electric Revenues

Dollars in millions

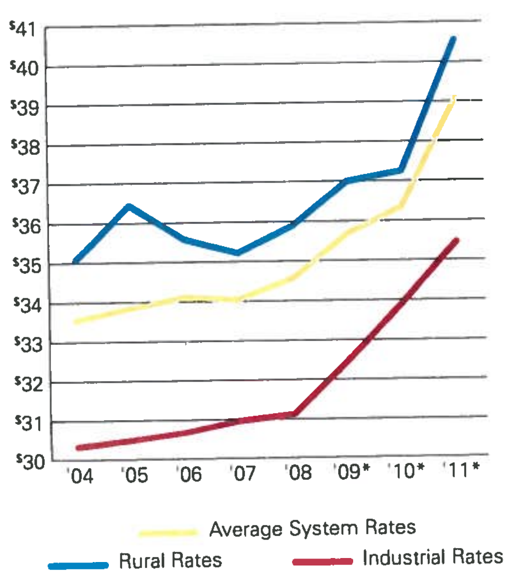
WHOLESALE RATES

Big Rivers has all-requirements wholesale power contracts with its Members through December 31, 2043. Rural Member wholesale revenue per MWh was $46.78 in 2011 versus $45.15 in 2010. Large industrial Member wholesale revenue per MWh was $41.68 in 2011 versus $41.85 in 2010. The aluminum smelter wholesale contracts terminate December 31, 2023. Aluminum smelter wholesale revenue per MWh was $44.48 in 2011 versus $44.05 in 2010. Big Rivers' wholesale Member tariff rate and the aluminum smelter contracts are regulated by the KPSC and the Rural Utilities Service (RUS).

Wholesale Member Rates*

Dollars per megawatt-hour (MWh)

Note that: 2009, 2010 and 2011 rates reflect a reduction due to the Member Rate Stability Mechanism



Wholesale power market prices continue to be depressed, as has been the case since 2008. The revenue per MWh received by Big Rivers for its off-system sales was $33.30 in 2011, down from $37.90 received in 2010, and significantly below the off-system sales rate of $48.03 received in 2007.

LINES OF CREDIT AND LETTERS OF CREDIT

Big Rivers has two $50 million lines of credit available, one with CoBank, ACB, expiring July 16, 2012, and the other with National Rural Utilities Cooperative Finance Corporation (CFC), expiring July 16, 2014. The CFC line of credit contains a $10 million embedded letter of credit facility. At December 31, 2011, letters of credit totaling $5.4 million are outstanding with CFC.

LONG-TERM DEBT

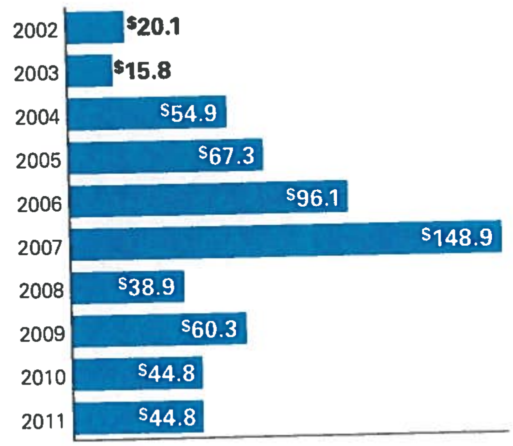
At December 31, 2011, debt to total assets is 55.46 percent. Big Rivers significantly reduced its long-term debt by $252.7 million over the past three years to $786.4 million at December 31, 2011, down from $1,039.1 million at December 31, 2008. The effective interest rate thereon, at December 31, 2011, is 5.75 percent. The RUS Series A Note has a December 31, 2011 fair value of $521.3 million and a stated value of $523.2 million. The non-interest bearing RUS Series B Note, having a December 31, 2011 fair value of $123.0 million and a stated value of $245.5 million, has no payment due until maturity on December 31, 2023.

Big Rivers has two issues of tax-exempt pollution control bonds outstanding, totaling $142.1 million. The larger of the two issues was refinanced June 8, 2010—the $83.3 million County of Ohio, Kentucky, Pollution Control Revenue Bonds, Series 2010A. These Series 2010A Bonds now bear interest at a 6 percent fixed rate, with a maturity date of July 15, 2031. The second issue—the $58.8 million County of Ohio, Kentucky, Pollution Control Revenue Bonds, Series 1983—are variable rate demand bonds currently being held by the liquidity provider, bearing an interest rate of 3.25 percent.

LIQUIDITY

Liquidity is good, as cash and cash equivalents total $44.8 million at December 31, 2011. Additionally, the company has the two lines of credit totaling $100 million discussed earlier. Also of significance, at December 31, 2011, Big Rivers had voluntarily prepaid $11.5 million on its 5.75 percent RUS Series A Note, which the company may claw back by avoiding future quarterly debt service payments. Big Rivers funded all of its operating expenses and capital expenditures in 2011 internally without any new borrowing. Capital expenditures totaled $38.7 million in 2011, versus $42.7 million in 2010.

Cash and
Cash Equivalents
Dollars in millions



KPMG LLP
1601 Market Street
Philadelphia, PA 19103-2499

Independent Auditors' Report

The Board of Directors and Members
Big Rivers Electric Corporation:

We have audited the accompanying balance sheets of Big Rivers Electric Corporation (the Company) as of December 31, 2011 and 2010, and the related statements of operations, equities, and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. The accompanying financial statements of the Company for the year ended December 31, 2009 were audited by other auditors whose report thereon dated March 26, 2010, expressed an unqualified opinion on those statements.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Big Rivers Electric Corporation as of December 31, 2011 and 2010, and the results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

In accordance with *Government Auditing Standards*, we have also issued a report dated March 26, 2012, on our consideration of Big Rivers Electric Corporation's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be read in conjunction with this report in considering the results of our audits.

KPMG LLP

March 26, 2012

BALANCE SHEETS As of December 31, 2011 and 2010 — (Dollars in thousands)

Assets

	2011	2010
UTILITY PLANT – Net	$1,092,063	$ 1,091,566
RESTRICTED INVESTMENTS – Member rate mitigation	163,162	217,562
OTHER DEPOSITS AND INVESTMENTS – At cost	5,911	5,473
CURRENT ASSETS:		
Cash and cash equivalents	44,849	44,780
Accounts receivable	44,287	45,905
Fuel inventory	33,894	37,328
Nonfuel inventory	25,295	23,218
Prepaid expenses	4,217	2,502
Total current assets	152,542	153,733
DEFERRED CHARGES AND OTHER	4,244	3,851
TOTAL	$1,417,922	$ 1,472,185

Equities and Liabilities

	2011	2010
CAPITALIZATION:		
Equities	$ 389,820	$ 386,575
Long-term debt	714,254	809,623
Total capitalization	1,104,074	1,196,198
CURRENT LIABILITIES:		
Current maturities of long-term obligations	72,145	7,373
Notes payable	-	10,000
Purchased power payable	1,878	1,516
Accounts payable	28,446	29,782
Accrued expenses	10,380	10,627
Accrued interest	9,899	11,134
Total current liabilities	122,748	70,432
DEFERRED CREDITS AND OTHER:		
Regulatory liabilities – Member rate mitigation	169,001	185,893
Other	22,099	19,662
Total deferred credits and other	191,100	205,555
COMMITMENTS AND CONTINGENCIES (see Note 14)		
TOTAL	$1,417,922	$ 1,472,185

See accompanying notes to financial statements.

STATEMENTS OF OPERATIONS

For the years ended December 31, 2011, 2010 and 2009 — (Dollars in thousands)

	2011	2010	2009
OPERATING REVENUE	$ 561,989	$ 527,324	$ 341,333
LEASE REVENUE	–	–	32,027
Total operating revenue	561,989	527,324	373,360
OPERATING EXPENSES:			
Operations:			
Fuel for electric generation	226,229	207,749	80,655
Power purchased and interchanged	112,262	99,421	116,883
Production, excluding fuel	50,410	52,507	22,381
Transmission and other	39,085	35,273	35,444
Maintenance	47,718	46,880	29,820
Depreciation and amortization	35,407	34,242	32,485
Total operating expenses	511,111	476,072	317,668
ELECTRIC OPERATING MARGIN	50,878	51,252	55,692
INTEREST EXPENSE AND OTHER:			
Interest	45,226	46,570	59,898
Amortization of loss from termination of long-term lease	–	–	2,172
Income tax expense	100	259	1,025
Other – net	220	166	112
Total interest expense and other	45,546	46,995	63,207
OPERATING MARGIN	5,332	4,257	(7,515)
NON-OPERATING MARGIN:			
Gain on Unwind transaction (see Note 2)	–	–	537,978
Interest income and other	268	2,734	867
Total non-operating margin	268	2,734	538,845
NET MARGIN	$ 5,600	$ 6,991	$ 531,330

See accompanying notes to financial statements.

STATEMENTS OF EQUITIES (Deficit)

For the years ended December 31, 2011, 2010 and 2009 — (Dollars in thousands)

	Total Equities (Deficit)	Accumulated Margin (Deficit)	Other Equities: Donated Capital and Memberships	Other Equities: Consumers' Contributions to Debt Service	Accumulated Other Comprehensive Income
BALANCE – December 31, 2008	$ (154,602)	$ (146,823)	$ 764	$ 3,681	$(12,224)
Comprehensive income:					
Net margin	531,330	531,330	–	–	–
Defined benefit plans	2,664	–	–	–	2,664
Total comprehensive income	533,994	531,330	–	–	2,664
BALANCE – December 31, 2009	379,392	384,507	764	3,681	(9,560)
Comprehensive income:					
Net margin	6,991	6,991	–	–	–
Defined benefit plans	192	–	–	–	192
Total comprehensive income	7,183	6,991	–	–	192
BALANCE – December 31, 2010	386,575	391,498	764	3,681	(9,368)
Comprehensive income:					
Net margin	5,600	5,600	–	–	–
Defined benefit plans	(2,355)	–	–	–	(2,355)
Total comprehensive income	3,245	5,600	–	–	(2,355)
BALANCE – December 31, 2011	$ 389,820	$ 397,098	$ 764	$ 3,681	$(11,723)

See accompanying notes to financial statements.

STATEMENTS OF CASH FLOWS

For the years ended December 31, 2011, 2010 and 2009 — (Dollars in thousands)

	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net margin	$ 5,600	$ 6,991	$ 531,330
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization	37,808	37,650	37,084
Amortization of deferred loss (gain) on sale-leaseback – net	–	–	2,172
Deferred lease revenue	–	–	(3,768)
Residual value payments obligation gain	–	–	(3,881)
Interest compounded - RUS Series A Note	8,398	–	–
Interest compounded - RUS Series B Note	6,884	6,499	6,136
Noncash gain on Unwind transaction	–	–	(269,441)
Cash received for member rate mitigation	–	–	217,856
Noncash member rate mitigation revenue	(18,947)	(23,953)	(12,033)
Changes in certain assets and liabilities:			
Accounts receivable	1,618	1,588	(26,049)
Inventories	1,357	(2,304)	(3,497)
Prepaid expenses	(1,715)	731	(2,783)
Deferred charges	121	1,251	(1,538)
Purchased power payable	362	(1,846)	(5,973)
Accounts payable	(1,336)	(875)	24,825
Accrued expenses	(1,481)	2,800	7,881
Other – net	(70)	555	6,852
Net cash provided by operating activities	38,599	29,087	505,173
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(38,746)	(42,683)	(58,388)
Proceeds from restricted investments	56,095	28,143	8,982
Purchases of restricted investments and other deposits & investments	–	–	(252,798)
Net cash provided by (used in) investing activities	17,349	(14,540)	(302,204)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Principal payments on long-term obligations	(45,879)	(121,355)	(168,956)
Proceeds from long-term obligations	–	83,300	–
Principal payments on short-term notes payable	(10,000)	–	(12,380)
Proceeds from short-term notes payable	–	10,000	–
Debt issuance cost on bond refunding	–	(2,002)	(246)
Net cash used in financing activities	(55,879)	(30,057)	(181,582)
Net increase (decrease) in cash and cash equivalents	69	(15,510)	21,387
CASH AND CASH EQUIVALENTS — Beginning of year	$ 44,780	$ 60,290	$ 38,903
CASH AND CASH EQUIVALENTS — End of year	$ 44,849	$ 44,780	$ 60,290
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest	$ 31,441	$ 37,268	$ 51,078
Cash paid for income taxes	$ 130	$ 260	$ 626

See accompanying notes to financial statements.

NOTES TO FINANCIAL STATEMENTS

As of December 31, 2011 and 2010 (Dollars in thousands)

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) General Information — Big Rivers Electric Corporation (Big Rivers or the Company), an electric generation and transmission cooperative, supplies wholesale power to its three member distribution cooperatives (Kenergy Corp., Jackson Purchase Energy Corporation, and Meade County Rural Electric Cooperative Corporation) under all requirements contracts, excluding the power needs of two large aluminum smelters (the Aluminum Smelters). Additionally, Big Rivers sells power under separate contracts to Kenergy Corp. for the Aluminum Smelters load and markets power to nonmember utilities and power marketers. The members provide electric power and energy to industrial, residential, and commercial customers located in portions of 22 western Kentucky counties. The wholesale power contracts with the members remain in effect until December 31, 2043. Rates to Big Rivers' members are established by the Kentucky Public Service Commission (KPSC) and are subject to approval by the Rural Utilities Service (RUS). The financial statements of Big Rivers include the provisions of the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 980, *Certain Types of Regulation*, which was adopted by the Company in 2003, and gives recognition to the ratemaking and accounting practices of the KPSC and RUS.

Management evaluated subsequent events up to and including March 26, 2012, the date the financial statements were available to be issued.

(b) Principles of Consolidation — The financial statements of Big Rivers include the accounts of Big Rivers and its wholly owned subsidiary, Big Rivers Leasing Corporation (BRLC). All significant intercompany transactions have been eliminated. BRLC was dissolved July 7, 2009.

(c) Estimates — The preparation of the financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosure of contingent assets and liabilities. The estimates and assumptions used in the accompanying financial statements are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results may differ from those estimates.

(d) System of Accounts — Big Rivers' maintains its accounting records in accordance with the Uniform System of Accounts as prescribed by the RUS Bulletin 1767B-1, as adopted by the KPSC. These regulatory agencies retain authority and periodically issue orders on various accounting and ratemaking matters. Adjustments to RUS accounting have been made to make the financial statements consistent with generally accepted accounting principles in the United States of America.

(e) Revenue Recognition — Revenues generated from the Company's wholesale power contracts are based on month-end meter readings and are recognized as earned. Prior to its termination, in accordance with FASB ASC 840, *Leases*, Big Rivers' revenue from the Lease Agreement was recognized on a straight-line basis over the term of the lease. The major components of this lease revenue include the annual lease payments and the Monthly Margin Payments (described in note 2).

(f) Utility Plant and Depreciation — Utility plant is recorded at original cost, which includes the cost of contracted services, materials, labor, overhead, and an allowance for borrowed funds used during construction. Replacements of depreciable property units, except minor replacements, are charged to utility plant.

Allowance for borrowed funds used during construction is included on projects with an estimated total cost of $250 or more before consideration of such allowance. The interest capitalized is determined by applying the effective rate of Big Rivers' weighted average debt to the accumulated expenditures for qualifying projects included in construction in progress.

Depreciation of utility plant in service is recorded using the straight-line method over the estimated remaining service lives, as approved by the RUS and KPSC. During 2010, the Company commissioned a depreciation study to evaluate the remaining economic lives of its assets. In 2011, the study was completed and approved by the RUS and KPSC. The annual composite depreciation rates used to compute depreciation expense were as follows:

	Jan-Nov 2011	Dec 2011
Electric plant	1.60%–2.47%	0.50%–20.22%
Transmission plant	1.76%–3.24%	1.42%–02.23%
General plant	1.11%–5.62%	2.84%–17.12%

For 2011, 2010, and 2009, the average composite depreciation rates were 1.91%, 1.86%, and 1.85%, respectively. At the time plant is disposed of, the original cost plus cost of removal less salvage value of such plant is charged to accumulated depreciation, as required by the RUS.

(g) Impairment Review of Long Lived Assets — Long-lived assets are reviewed as facts and circumstances indicate that the carrying amount may be impaired. FASB ASC 360, *Property, Plant, and Equipment*, requires the evaluation of impairment by comparing an asset's carrying value to the estimated future cash flows the asset is expected to generate over its remaining life. If this evaluation were to conclude that the future cash flows were not sufficient to recover the carrying value of the asset, an impairment charge would be recorded based on the difference between the asset's carrying amount and its fair value (less costs to sell for assets to be disposed of by sale) as a charge to net margin.

(h) Inventory — Inventories are carried at average cost and include coal, petroleum coke, lime, limestone, oil and gas used for electric generation, and materials and supplies used for utility operations. Emission allowances are carried in inventory at a weighted average cost by each vintage year. Issuances of allowances are accounted for on a vintage basis using a monthly weighted average cost.

(i) Restricted Investments — Investments are restricted under KPSC order to establish certain reserve funds for member rate mitigation in conjunction with the Unwind Transaction. These investments have been classified as held-to-maturity and are carried at amortized cost (see note 9).

(j) Cash and Cash Equivalents — Big Rivers considers all short-term, highly liquid investments with original maturities of three months or less to be cash equivalents.

(k) Income Taxes — Big Rivers was formed as a tax-exempt cooperative organization as described in Internal Revenue Code Section 501(c)(12). To retain tax-exempt status under this section, at least 85% of the Big Rivers' receipts must be generated from transactions with the Company's members. In 1983, sales to nonmembers resulted in Big Rivers failing to meet the 85% requirement. Until Big Rivers can meet the 85% member income requirement, the Company will not be eligible for tax exempt status and will be treated as a taxable cooperative.

As a taxable cooperative, Big Rivers is entitled to exclude the amount of patronage allocations to members from taxable income. Income and expenses related to non-patronage sourced operations are taxable to Big Rivers. Big Rivers files a federal income tax return and certain state income tax returns.

Under the provisions of FASB ASC 740, *Income Taxes*, Big Rivers is required to record deferred tax assets and liabilities for temporary differences between amounts reported for financial reporting purposes and amounts reported for income tax purposes. Deferred tax assets and liabilities are determined based upon these temporary differences using enacted tax rates for the year in which these differences are expected to reverse. Deferred income tax expense or benefit is based on the change in assets and liabilities from period to period, subject to an ongoing assessment of realization. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the more-likely than-not recognition threshold is satisfied and measured at the largest amount of benefit that is greater than 50% likely of being realized upon settlement.

(l) Patronage Capital — As provided in the bylaws, Big Rivers accounts for each year's patronage-sourced income, both operating and nonoperating, on a patronage basis. Notwithstanding any other provision of the bylaws, the amount to be allocated as patronage capital for a given year shall not be less than the greater of regular taxable patronage-sourced income or alternative minimum taxable patronage-sourced income.

(m) Derivatives — Management has reviewed the requirements of FASB ASC 815, *Derivatives and Hedging*, and has determined that certain contracts the Company is party to may meet the definition of a derivative under FASB ASC 815. The Company has elected the Normal Purchase and Normal Sale exception for these contracts and, therefore, the contracts are not required to be recognized at fair value in the financial statements.

(n) Fair Value Measurements — FASB ASC 820, *Fair Value Measurements and Disclosures*, defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal, or most advantageous, market for the asset or liability in an orderly transaction between market participants at the measurement date. FASB ASC 820 establishes a three-level fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy requires entities to maximize the use of observable inputs when possible. The three levels of inputs used to measure fair value are as follows:

- Level 1 – quoted prices in active markets for identical assets or liabilities
- Level 2 – observable inputs other than quoted prices included in Level 1, such as quoted prices for similar assets and liabilities in active markets; quoted prices for identical or similar assets and liabilities in markets that are not active; or other inputs that are observable or can be corroborated by observable market data; and
- Level 3 – unobservable inputs that are supported by little or no market activity and that are significant to the fair values of the assets or liabilities, including certain pricing models, discounted cash flow methodologies and similar techniques that use significant unobservable inputs.

2. LG&E LEASE AGREEMENT

Big Rivers, LG&E and KU, Western Kentucky Energy Corporation (WKEC), and LG&E Energy Marketing (LEM), closed effective July 17, 2009, a transaction resulting in a mutually acceptable early termination of the 1998 LG&E Lease Agreement (referred herein as the Unwind Transaction or Unwind). LG&E and KU, WKEC, and LEM are collectively referred to in the notes as "LG&E and KU Entities." This transaction was approved by the KPSC and the RUS. The Unwind Transaction resulted in Big Rivers recognizing a net gain of $537,978. This transaction resulted in the acquisition of assets, the assumption of liabilities, the forgiveness of liabilities, and the establishment of a regulatory reserve prescribed by the KPSC in their approval of the transaction. Assets and liabilities in the Unwind Transaction were accounted for at fair value or recorded value, as appropriate. The gain from the Unwind Transaction is summarized as follows:

	Unwind Gain
Assets received:	
Cash	$506,675
Coleman scrubber	98,500
Inventory	55,000
Construction in progress	23,074
Utility plant assets	19,679
SO2 allowances	980
Liabilities (assumed) forgiven:	
Economic Reserve	(157,000)
Rural Economic Reserve	(60,856)
Post-retirement benefits liability	(8,768)
Residual value payments obligation	145,251
LEM Settlement Note	15,440
Recognition of (expenses) income:	
Deferred lease income	7,187
Deferred loss from termination of sale/leaseback	(73,829)
Deferred loss from LEM Marketing Payment/Settlement Note	(14,520)
Unwind transaction costs	(18,991)
Other	156
Gain on unwind transaction	$537,978

The terms of the LG&E Lease Agreement as originally structured are outlined in the following text.

On July 15, 1998 (Effective Date), a lease was consummated (Lease Agreement), whereby Big Rivers leased its generating facilities to Western Kentucky Energy Corporation (WKEC), a wholly owned subsidiary of LG&E and KU. Pursuant to the Lease Agreement, WKEC operated the generating facilities and maintained title to all energy produced. Throughout the lease term, in order for Big Rivers to fulfill it obligation to supply power to its members, the Company purchased substantially all of its power requirements from LG&E Energy Marketing Corporation (LEM), a wholly owned subsidiary of LG&E and KU, pursuant to a power purchase agreement.

Big Rivers continued to operate its transmission facilities and charged LEM tariff rates for delivery of the energy produced by WKEC and consumed by LEM's customers. The significant terms of the Lease Agreement were as follows:

a. WKEC was to lease and operate Big Rivers' generation facilities through 2023.

b. Big Rivers retained ownership of the generation facilities both during and at the end of the lease term.

c. WKEC paid Big Rivers an annual lease payment of $30,965 over the lease term, subject to certain adjustments.

d. On the Effective Date, Big Rivers received $69,100 representing certain closing payments and the first two years of the annual lease payments. In accordance with FASB ASC 840, *Leases*, the Company amortized these payments to revenue on a straight-line basis over the life of the lease.

e. Big Rivers continued to provide power for its members, excluding the member loads serving the Aluminum Smelters, through its power purchase agreements with LEM and the Southeastern Power Administration, based on a pre-determined maximum capacity. When economically feasible, the Company also obtained the power necessary to supply its member loads, excluding the Aluminum Smelters, in the open market. Kenergy Corp.'s retail service for the Aluminum Smelters was served by LEM and other third party providers that included Big Rivers. To the extent the power purchased from LEM did not reach pre-determined minimums, the Company was required to pay certain penalties. Also, to the extent additional power was available to Big Rivers under the LEM contract, Big Rivers made sales to nonmembers.

f. LEM reimbursed Big Rivers the margins expected from the Aluminum Smelters, defined as the net cash flows that Big Rivers anticipated receiving if the Company had continued to serve the Aluminum Smelters' load, as filed in the Rate Hearing (the Monthly Margin Payments).

g. WKEC was responsible for the operating costs of the generation facilities; however, Big Rivers was partially responsible for ordinary capital expenditures (Nonincremental Capital Costs) for the generation facilities over the term of the Lease Agreement, generally up to predetermined annual amounts. At the end of the lease term, Big Rivers was obligated to fund a "Residual Value Payment" to LG&E and KU for such capital additions during the lease (see note 1). Adjustments to the Residual Value Payment were made based upon actual capital expenditures. Additionally, WKEC made required capital improvements to the facilities to comply with new laws or changes to existing laws (Incremental Capital Costs) over the lease life (the Company was partially responsible for such costs—20% prior to termination of the lease) and the Company was required to submit another Residual Value Payment to LG&E and KU for the undepreciated value of WKEC's 80% share of these costs, at the end of the lease. The Company had title to these assets during the lease and upon lease termination.

h. Big Rivers entered into a note payable with LEM for $19,676 (the LEM Settlement Note) to be repaid over the term of the Lease Agreement, with an interest rate at 8% per annum, in consideration for LEM's assumption of the risk related to unforeseen costs with respect to power to be supplied to the Aluminum Smelters and the increased responsibility for financing capital improvements. The Company recorded this obligation as a component of deferred charges with the related payable recorded as long-term debt in the accompanying balance sheets. This deferred charge was amortized on a straight-line basis up to the Effective Date of the Unwind Transaction.

i. On the Effective Date, Big Rivers paid a nonrefundable marketing payment of $5,933 to LEM, which was recorded as a component of deferred charges. This amount was amortized on a straight-line basis up to the Effective Date of the Unwind Transaction.

j. During the lease term, Big Rivers was entitled to certain "billing credits" against amounts the Company owed LEM under the power purchase agreement. Each month during the first 55 months of the lease term, Big Rivers received a credit of $89. For the year 2011, Big Rivers was to receive a credit of $2,611 and for the years 2012 through 2023, the Company was to receive a credit of $4,111 annually.

In accordance with the power purchase agreement with LEM, the Company was allowed to purchase power in the open market rather than from LEM, incurring penalties when the power purchased from LEM did not meet certain minimum levels, and to sell excess power (power not needed to supply its jurisdictional load) in the open market (collectively referred to as Arbitrage). Pursuant to the New RUS Promissory Note (currently the RUS Series A Note) and the RUS ARVP Note (currently the RUS Series B Note), the benefit, net of tax, as defined, derived from Arbitrage had to be divided as follows: one-third, adjusted for capital expenditures, was used to make principal payments on the New RUS Promissory Note; one-third was used to make principal payments on the RUS ARVP Note; and the remaining value was retained by the Company.

3. UTILITY PLANT

At December 31, 2011 and 2010, utility plant is summarized as follows:

	2011	2010
Classified plant in service:		
Production plant	$1,706,243	$1,689,024
Transmission plant	238,738	237,689
General plant	33,744	18,937
Other	543	543
	1,979,268	1,946,193
Less accumulated depreciation	936,355	909,501
	1,042,913	1,036,692
Construction in progress	49,150	54,874
Utility plant — net	$1,092,063	$1,091,566

Interest capitalized for the years ended December 31, 2011, 2010, and 2009, was $548, $684, and $133, respectively.

The Company has not identified any material legal asset retirement obligations, as defined in FASB ASC 410, *Asset Retirement and Environmental Obligations*. In accordance with regulatory treatment, the Company records an estimated net cost of removal of its utility plant through normal depreciation. As of December 31, 2011 and 2010, the Company had approximately $41,449 and $38,000, respectively, related to nonlegal removal costs included in accumulated depreciation.

4. DEBT AND OTHER LONG-TERM OBLIGATIONS

A detail of long-term debt at December 31, 2011 and 2010 is as follows:

	2011	2010
RUS Series A Promissory Note, stated amount of $523,192, stated interest rate of 5.75%, with an imputed interest rate of 5.84% maturing July 2021	$521,250	$558,731
RUS Series B Promissory Note, stated amount of $245,530, no stated interest rate, with interest imputed at 5.80%, maturing December 2023	123,049	116,165
County of Ohio, Kentucky, promissory note, fixed interest rate of 6.00%, maturing in July 2031	83,300	83,300
County of Ohio, Kentucky, promissory note, variable interest rate (average interest rate of 3.30% and 3.27% in 2011 and 2010, respectively), maturing in June 2013	58,800	58,800
Total long-term debt	786,399	816,996
Current maturities	72,145	7,373
Total long-term debt — net of current maturities	$714,254	$809,623

The following are scheduled maturities of long-term debt at December 31:

Year	Amount
2012	$ 72,145
2013	79,260
2014	21,661
2015	22,955
2016	231,882
Thereafter	358,496
Total	$786,399

(a) *RUS Notes* — On July 15, 1998, Big Rivers recorded the New RUS Promissory Note and the RUS ARVP Note at fair value using the applicable market rate of 5.82%. On the Unwind Closing Date, the New RUS Note and the ARVP Note were replaced with the RUS 2009 Promissory Note Series A and the RUS 2009 Promissory Note Series B, respectively. After an Unwind Closing Date payment of $140,181, the RUS 2009 Promissory Note Series A is recorded at an interest rate of 5.84%. The RUS 2009 Series B Note is recorded at an imputed interest rate of 5.80%. The RUS Notes are collateralized by substantially all assets of the Company and secured by the Indenture dated July 1, 2009 between the Company and U.S. Bank National Association.

(b) *Pollution Control Bonds* — In June 2010, the County of Ohio, Kentucky, issued $83,300 of Pollution Control Refunding Revenue Bonds, Series 2010A (Series 2010A Bonds), the proceeds of which are supported by a promissory note from Big Rivers, which bears the same interest rate. These bonds bear interest at a fixed rate of 6.00% and mature in July 2031.

The County of Ohio, Kentucky, issued $58,800 of Pollution Control Variable Rate Demand Bonds, Series 1983 (Series 1983 Bonds), the proceeds of which are supported by a promissory note from Big Rivers, which bears the same interest rate as the bonds. These bonds bear interest at a variable rate and mature in June 2013.

The Series 1983 Bonds are supported by a liquidity facility issued by Credit Suisse First Boston, which was assigned to Dexia Credit in 2006. In addition, the Series 1983 Bonds are supported by a municipal bond insurance and surety policy issued by Ambac Assurance Corporation. Big Rivers has agreed to reimburse Ambac Assurance Corporation for any payments under the municipal bond insurance policy or the surety policy. Both Series are secured by the Indenture dated July 1, 2009 between the company and U.S. Bank National Association.

The Series 1983 Bonds are subject to a maximum interest rate of 13.00%. The December 31, 2011 interest rate on the Series 1983 Pollution Control Bonds was 3.25%.

(c) *Notes Payable* — Notes payable represent the Company's borrowing on its line of credit with the National Rural Utilities Cooperative Finance Corporation (CFC) and CoBank, ACB (CoBank). The maximum borrowing capacity on the lines of credit is $100,000 consisting of $50,000 each for CFC and CoBank. In March 2011, Big Rivers paid down the $10,000 of borrowings outstanding on the CoBank line of credit at December 31, 2010. The Company had no borrowings outstanding on the lines of credit at December 31, 2011. Letters of credit issued under an associated Letter of Credit Facility with CFC reduced the borrowing capacity on the CFC line of credit by $5,375 and $5,928 at December 31, 2011 and 2010, respectively. Advances on the CFC line of credit bear interest at a variable rate and outstanding balances are payable in full by the maturity date of July 16, 2014. The CFC variable rate is equal to the CFC Line of Credit Rate, which is defined as "the rate published by CFC from time to time, by electronic or other means, for similarly classified lines of credit, but if not published, then the rate determined for such lines of credit by CFC from time to time." Advances on the CoBank line of credit bear interest at a variable rate and outstanding balances are payable in full by the maturity date of July 16, 2012. The CoBank variable rate is a fixed rate per annum (for interest periods of 1, 2, 3 and 6 months) equal to LIBOR plus the Applicable Margin as determined by the Company's credit rating. On February 25, 2011, a $2,500 CFC line of credit, available to the Company to finance storm emergency repairs and expenses related to electric utility operations, matured.

(d) *Covenants* — Big Rivers is in compliance with all debt covenants associated with both long-term and short-term debt. The Company's Indenture and its line of credit with CFC require that a Margins for Interest Ratio (MFIR) of at least 1.10 be maintained for each fiscal year. The CoBank line of credit agreement requires that at the end of each fiscal year the Company have a Debt Service Coverage Ratio (DSCR) of not less than 1.20. Big Rivers' lines of credit with CFC and CoBank require Equity to Asset ratios of 12% and 15%, respectively. Big Rivers' 2011 MFIR was 1.12, its DSCR was 1.47 and the Asset to Equity Ratio was 27%.

5. RATE MATTERS

The rates charged to Big Rivers' members consist of a demand charge per kilowatt (kW) and an energy charge per kilowatt hour (kWh) consumed as approved by the KPSC. The rates include specific demand and energy charges for its members' two classes of customers, the large industrial customers and the rural customers under its jurisdiction. For the large industrial customers, the demand charge is generally based on each customer's maximum demand during the current month. Effective September 1, 2011, the Company received approval from the KPSC to base the member rural demand charge on its Maximum Adjusted Net Local Load (as defined in Big Rivers tariff).

Prior to the Unwind Transaction the demand and energy charges were not subject to adjustments for increases or decreases in fuel or environmental costs. In conjunction with the Unwind Transaction, the KPSC approved the implementation of certain tariff riders, including a fuel adjustment clause and an environmental surcharge, offset by an unwind surcredit (a refund to tariff members of certain charges collected from the Aluminum Smelters in accordance with the contract terms). The net effect of these tariffs is recognized as revenue on a monthly basis with an offset to the regulatory liability – member rate mitigation described below.

The net impact of the tariff riders to members rates is currently mitigated by a Member Rate Stability Mechanism (MRSM) that was funded by certain cash amounts received from the E.ON Entities in connection with the Unwind Transaction (the Economic and Rural Economic Reserves) and held by Big Rivers as restricted investments. An offsetting regulatory liability – member rate mitigation was established with the funding of these accounts.

In its order approving the Unwind Transaction, the KPSC stipulated that Big Rivers file a rate case within three years of the Unwind Closing Date or by July 2012. On March 1, 2011, the company filed an application with the KPSC requesting, among other things, authority to adjust its rates for wholesale electric service. The KPSC entered an order on November 17, 2011, granting Big Rivers an annual revenue increase of $26,745. One of the intervenors in the case has filed an appeal seeking, among other things, an approximate $6,200 reduction in the revenue relief granted in the order, and will presumably ask that any relief obtained be retroactive to the effective date of the rates approved in the order (September 1, 2011). Big Rivers has also sought rehearing on certain matters raised in the order that could increase Big Rivers' annual revenue by $2,735.

The wholesale rates established for the members nonsmelter large direct-served industrial customers (the Large Industrial Rate) provide the basis for pricing the energy consumed by the Aluminum Smelters. The primary component of the pricing used for the Aluminum Smelters is an energy charge in dollars per megawatt hour (MWh) determined by applying the Large Industrial Rate to a load with a 98% load factor, and adding an additional charge of $0.25 per MWh. The other components reflected in the pricing of the Aluminum Smelters' energy usage are certain charges and credits as provided for under the terms of the Aluminum Smelters' wholesale electric service agreements between Big Rivers and Kenergy Corp. (Kenergy Corp. is the retail provider for the Aluminum Smelters load).

6. INCOME TAXES

At December 31, 2011, Big Rivers had a Nonpatron Net Operating Loss Carryforward of approximately $32,434 expiring at various times between 2011 and 2031, and an Alternative Minimum Tax Credit Carryforward of approximately $7,138, which carries forward indefinitely.

The Company has not recorded any regular income tax expense for the years ended December 31, 2011, 2010 and 2009, as the Company has utilized federal net operating losses to offset any regular taxable income during those years. Had the Company not had the benefit of a net operating loss carryforward, the Company would have recorded $3,613, $3,846, and $19,619 in current regular tax expense for the years ended December 31, 2011, 2010 and 2009, respectively.

The components of the net deferred tax assets as of December 31, 2011 and 2010, were as follows:

	2011	2010
Deferred tax assets:		
Net operating loss carryforward	$12,812	$16,730
Alternative minimum tax credit carryforwards	7,138	6,038
Member rate mitigation	10,326	10,326
Fixed asset basis difference	3,980	10,752
RUS Series B Note	19,689	14,767
Total deferred tax assets	53,945	58,613
Deferred tax liabilities:		
RUS Series B Note	–	–
Bond refunding costs	(9)	(8)
Total deferred tax liabilities	(9)	(8)
Net deferred tax asset (prevaluation allowance)	53,936	58,605
Valuation allowance	(53,936)	(58,605)
Net deferred tax asset	$ –	$ –

A reconciliation of the Company's effective tax rate for 2011, 2010 and 2009, follows:

	2011	2010	2009
Federal rate	35.0%	35.0%	35.0%
State rate — net of federal benefit	4.5	4.5	4.5
Permanent differences	0.9	0.5	–
Patronage allocation to members	(40.8)	(38.8)	(35.4)
Tax benefit of operating loss carryforwards and other	0.4	(1.2)	(4.1)
Alternative minimum tax	3.5	3.0	0.2
Effective tax rate	3.5%	3.0%	0.2%

The Company files a federal income tax return, as well as certain state income tax returns. The years currently open for federal tax examination are 2007 through 2011 and 1996 through 1997, due to unused net operating loss carryforwards. The major state tax jurisdiction currently open for tax examination is Kentucky for years 2004 through 2011 and years 2001 through 2003, also due to unused net operating loss carryforwards. The Company has not recorded any unrecognized tax benefits or liabilities related to federal or state income taxes.

The Company classifies interest and penalties as an operating expense on the income statement and accrued expense in the balance sheet. No material interest or penalties have been recorded during 2011, 2010, or 2009.

7. POWER PURCHASED

Prior to the Unwind Transaction and in accordance with the Lease Agreement, Big Rivers supplied all of the members' requirements for power to serve their customers, other than the Aluminum Smelters. Contract limits were established in the Lease Agreement and included minimum and maximum hourly and annual power purchase amounts. Big Rivers could not reduce the contract limits by more than 12 MW in any year or by more than a total of 72 MW over the lease term. In the event Big Rivers failed to take the minimum requirement during any hour or year, Big Rivers was liable to LEM for a certain percentage of the difference between the amount of power actually taken and the applicable minimum requirement.

Although Big Rivers was required by the Lease Agreement to purchase minimum hourly and annual amounts of power from LEM, the lease did not prevent Big Rivers from paying the associated penalty in certain hours to purchase lower cost power, if available, in the open market or reselling a portion of its purchased power to a third party. The power purchases made under this agreement for the year ended December 31, 2009, was $51,592 and is included in power purchased and interchanged on the statement of operations.

8. PENSION PLANS

(a) *Defined Benefit Plans*— Big Rivers has noncontributory defined benefit pension plans covering substantially all employees who meet minimum age and service requirements and who were employed by the Company prior to the plans closure dates cited below. The plans provide benefits based on the participants' years of service and the five highest consecutive years' compensation during the last ten years of employment. Big Rivers' policy is to fund such plans in accordance with the requirements of the Employee Retirement Income Security Act of 1974.

The salaried employees defined benefit plan was closed to new entrants effective January 1, 2008, and the bargaining employees defined benefit plan was closed to new hires effective November 1, 2008. The Company simultaneously established base contribution accounts in the defined contribution thrift and 401(k) savings plans, which were renamed as the retirement savings plans. The base contribution account for an eligible employee, which is one who meets the minimum age and service requirements, but for whom membership in the defined benefit plan is closed, is funded by employer contributions based on graduated percentages of the employee's pay, depending on his or her age.

The Company has adopted FASB ASC 715, *Compensation – Retirement Benefits*, including the requirement to recognize the funded status of its pension plans and other postretirement plans (see note 11 – Postretirement Benefits Other Than Pensions). FASB ASC 715 defines the funded status of a defined benefit pension plan as the fair value of its assets less its projected benefit obligation, which includes projected salary increases, and defines the funded status of any other postretirement plan as the fair value of its assets less its accumulated postretirement benefit obligation.

FASB ASC 715 also requires an employer to measure the funded status of a plan as of the date of its year-end balance sheet and requires disclosure in the notes to the financial statements certain additional information related to net periodic benefit costs for the next fiscal year. The Company's pension and other postretirement benefit plans are measured as of December 31, 2011 and 2010.

The following provides an overview of the Company's noncontributory defined benefit pension plans.

A reconciliation of the Company's benefit obligations of its noncontributory defined benefit pension plans at December 31, 2011 and 2010, follows:

	2011	2010
Benefit obligation — beginning of period	$28,804	$25,493
Service cost — benefits earned during the period	1,279	1,289
Interest cost on projected benefit obligation	1,296	1,368
Benefits paid	(481)	(806)
Actuarial loss	845	1,460
Benefit obligation — end of period	$31,743	$28,804

The accumulated benefit obligation for all defined benefit pension plans was $25,482 and $21,977 at December 31, 2011 and 2010, respectively.

A reconciliation of the Company's pension plan assets at December 31, 2011 and 2010, follows:

	2011	2010
Fair value of plan assets — beginning of period	$25,267	$22,270
Actual return on plan assets	324	2,707
Employer contributions	2,890	1,096
Benefits paid	(481)	(806)
Fair value of plan assets — end of period	$28,000	$25,267

The funded status of the Company's pension plans at December 31, 2011 and 2010, follows:

	2011	2010
Benefit obligation — end of period	$(31,743)	$(28,804)
Fair value of plan assets — end of period	28,000	25,267
Funded status	$ (3,743)	$ (3,537)

Components of net periodic pension costs for the years ended December 31, 2011, 2010, and 2009, were as follows:

	2011	2010	2009
Service cost	$1,279	$1,289	$1,241
Interest cost	1,296	1,368	1,466
Expected return on plan assets	(1,737)	(1,533)	(1,332)
Amortization of prior service cost	14	19	19
Amortization of actuarial loss	461	584	834
Settlement loss	–	–	1,690
Net periodic benefit cost	$1,313	$1,727	$3,918

A reconciliation of the pension plan amounts in accumulated other comprehensive income at December 31, 2011 and 2010, follows:

	2011	2010
Prior service cost	$ (26)	$ (40)
Unamortized actuarial (loss)	(11,151)	(9,354)
Accumulated other comprehensive income	$(11,177)	$(9,394)

In 2012, $14 of prior service cost and $696 of actuarial loss is expected to be amortized to periodic benefit cost.

The recognized adjustments to other comprehensive income (loss) at December 31, 2011 and 2010, follows:

	2011	2010
Prior service cost	$ 14	$ 19
Unamortized actuarial (loss)	(1,797)	297
Other comprehensive income	$(1,783)	$ 316

At December 31, 2011 and 2010, amounts recognized in the balance sheets were as follows:

	2011	2010
Deferred credits and other	$(3,743)	$(3,537)

Assumptions used to develop the projected benefit obligation and determine the net periodic benefit cost were as follows:

	2011	2010	2009
Discount rate — projected benefit obligation	4.26%	4.95%	5.59%
Discount rate — net periodic benefit cost	4.95	5.59	6.38
Rates of increase in compensation levels	4.00	4.00	4.00
Expected long-term rate of return on assets	7.25	7.25	7.25

The expected long-term rate of return on plan assets for determining net periodic pension cost for each fiscal year is chosen by the Company from a best estimate range determined by applying anticipated long-term returns and long-term volatility for various asset categories to the target asset allocation of the plans, as well as taking into account historical returns.

Using the asset allocation policy adopted by the Company noted in the paragraph below, we determined the expected rate of return at a 50% probability of achievement Level based on (a) forward-looking rate of return expectations for passively managed asset categories over a 20-year time horizon and (b) historical rates of return for passively managed asset categories. Applying an approximately 80%/20% weighting to the rates determined in (a) and (b), respectively, produced an expected rate of return of 7.28%, which was rounded to 7.25%.

Big Rivers utilizes a third party investment manager for the plan assets, and has communicated thereto the Company's Retirement Plan Investment Policy, including a target asset allocation mix of 50% U.S. Equities (an acceptable range of 45%-55%), 15% International Equities (an acceptable range of 10%-20%), and 35% fixed income (an acceptable range of 30%-40%). As of December 31, 2011 and 2010, the investment allocation was 56% and 58%, respectively, in U.S. Equities, 8% and 9%, respectively, in International Equities, and 36% and 33%, respectively, in fixed income. The objective of the investment program seeks to (a) maximize return on investment, (b) minimize volatility, (c) minimize company contributions, and (d) provide the employee benefit in accordance with the plans. The portfolio is well diversified and of high quality. The average quality of the fixed income investments must be "A" or better. The equity portfolio must also be of investment grade quality. The performance of the investment manager is reviewed semi-annually.

At December 31, 2011 and 2010, the fair value of Big Rivers' defined benefit pension plan assets by asset category are as follows:

	Level 1	Level 2	December 31, 2011
Cash and money market	$ 2,129	$ –	$ 2,129
Equity Securities:			
U.S. large-cap stocks	10,178	–	10,178
U.S. mid-cap stock mutual funds	3,365	–	3,365
U,S. small-cap stock mutual funds	1,666	–	1,666
International stock mutual funds	2,168	–	2,168
Preferred stock	493	–	493
Fixed:			
TIPS Bond Fund	723	–	723
U.S. Government Agency Bonds	–	1,085	1,085
Taxable U.S. Municipal Bonds	–	3,258	3,258
U.S. Corporate Bonds	–	2,630	2,630
Global bond fund	–	305	305
	$20,722	$7,278	$ 28,000

	Level 1	Level 2	December 31, 2010
Cash and money market	$ 1,517	$ –	$ 1,517
Equity Securities:			
U.S. large-cap stocks	9,731	–	9,731
U.S. mid-cap stock mutual funds	2,926	–	2,926
U,S. small-cap stock mutual funds	1,448	–	1,448
International stock mutual funds	2,194	–	2,194
Preferred stock	490	–	490
Fixed:			
TIPS bond fund	161	–	161
U.S. Government Agency Bonds	–	1,843	1,843
Taxable U.S. Municipal Bonds	–	2,635	2,635
U.S. Corporate Bonds	–	2,322	2,322
	$18,467	$ 6,800	$25,267

Expected retiree pension benefit payments projected to be required during the years following 2011 are as follows:

Years Ending December 31	Amount
2012	$ 2,330
2013	4,386
2014	1,799
2015	3,196
2016	3,265
2017 – 2020	10,986
Total	$25,962

In 2012, the Company expects to contribute $970 to its pension plan trusts.

(b) *Defined Contribution Plans* — Big Rivers has two defined contribution retirement plans covering substantially all employees who meet minimum age and service requirements. Each plan has a thrift and 401(k) savings section allowing employees to contribute up to 75% of pay on a pre-tax and/or after-tax basis, with employer matching contributions equal to 60% of the first 6% contributed by the employee on a pre-tax basis.

A base contribution retirement section was added and the plan name changed from thrift and 401(k) savings to retirement savings, effective January 1, 2008, for the salaried plan and November 1, 2008, for the bargaining plan. The base contribution account is funded by employer contributions based on graduated percentages of pay, depending on the employee's age.

The Company's expense under these plans was $4,464 and $4,389 for the years ended December 31, 2011 and 2010, respectively.

c) *Deferred Compensation Plan* — Big Rivers sponsors a nonqualified deferred compensation plan for its eligible employees who are members of a select group of management or highly compensated employees. The purpose of the plan is to allow participants to receive contributions or make deferrals that they could not receive or make under the salaried employees qualified defined contribution retirement savings plan (formerly the thrift and 401(k) savings plan) as a result of nondiscrimination rules and other limitations applicable to the qualified plan under the Internal Revenue Code. The nonqualified plan also allows a participant to defer a percentage of his or her pay on a pre-tax basis.

The nonqualified deferred compensation plan is unfunded, but the Company has chosen to finance its obligations under the plan, including any employee deferrals, through a rabbi trust. The trust assets remain a part of the Company's general assets, subject to the claims of its creditors. The 2011 employer contribution was $58 and deferred compensation expense was $81. As of December 31, 2011, the trust asset was $283 and the deferred liability was $202.

9. RESTRICTED INVESTMENTS

The amortized costs and fair values of Big Rivers restricted investments held for member rate mitigation at December 31, 2011 and 2010 are as follows:

	2011		2010	
	Amortized Costs	Fair Values	Amortized Costs	Fair Values
Cash and money market	$ 12,765	$ 12,764	$ 12,812	$ 12,812
Debt Securities:				
U.S. Treasuries	62,073	63,917	60,941	62,582
U.S. Government Agency	88,324	88,485	143,809	143,922
Total	$163,162	$165,166	$217,562	$219,316

Gross unrealized gains and losses on restricted investments at December 31, 2011 and 2010 were as follows:

	2011		2010	
	Gains	Losses	Gains	Losses
Cash and money market	$ –	$ –	$ –	$ –
Debt Securities:				
U.S. Treasuries	1,843	–	1,641	–
U.S. Government Agency	161	–	331	217
Total	$ 2,004	$ –	$ 1,972	$ 217

Debt securities at December 31, 2011 and 2010 mature, according to their contractual terms, as follows (actual maturities may differ due to call or prepayment rights):

	2011		2010	
	Amortized Costs	Fair Values	Amortized Costs	Fair Values
In one year or less	$ 43,021	$ 43,092	$ 71,111	$ 71,193
After one year through five years	120,141	122,074	146,451	148,123
Total	$163,162	$165,166	$217,562	$219,316

Gross unrealized losses on investments and the fair values of the related securities, aggregated by investment category and length of time that individual securities have been in a continuous unrealized loss position at December 31, 2011 and 2010, were:

	2011 Less Than 12 Months		2010 Less Than 12 Months	
	Losses	Fair Values	Losses	Fair Values
Debt securities:				
U.S. Treasuries	$ –	$ –	$ –	$ –
U.S. Government Agency	–	–	217	15,783
Total	$ –	$ –	$ 217	$ 15,783

The unrealized loss positions were primarily caused by interest rate fluctuations. The number of investments in an unrealized loss position as of December 31, 2011 and 2010 was zero and one, respectively. Since the company does not intend to sell and will more likely than not maintain each debt security until its anticipated recovery, and no significant credit risk is deemed to exist, these investments are not considered other-than-temporarily impaired.

10. FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

FASB ASC 820 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measures. It applies under other accounting standards that require or permit fair value measurements and does not require any new fair value measurements.

The carrying value of accounts receivable, and accounts payable approximate fair value due to their short maturity. At December 31, the Company's cash and cash equivalents included short-term investments in an institutional money market government portfolio account classified as trading securities under ASC 320, *Investments – Debt and Equity Securities*, that were recorded at fair value which were determined using quoted market prices for identical assets without regard to valuation adjustment or block discount (a Level 1 measure), as follows:

	2011	2010
Institutional money market government portfolio	$44,844	$44,774

It was not practical to estimate the fair value of patronage capital included within other deposits and investments due to It was not practical to estimate the fair value of patronage capital included within other deposits and investments due to these being untraded companies.

Big Rivers' long-term debt at December 31, 2011 consists of RUS notes totaling $644,299, variable rate pollution control bonds in the amount of $58,800, and fixed rate pollution control bonds in the amount of $83,300 (see note 4). The RUS debt cannot be traded in the market and, therefore, a value other than its outstanding principal amount cannot be determined. The fair value of the Company's variable rate pollution control debt is par value, as each variable rate reset effectively prices such debt to the current market. At December 31, 2011, the fair value of Big Rivers' fixed rate pollution control debt was determined based on quoted prices in active markets of identical liabilities (Level 1 measure) and totaled $86,399.

11. POSTRETIREMENT BENEFITS OTHER THAN PENSIONS

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

The discount rates used in computing the postretirement benefit obligation and net periodic benefit cost were as follows:

	2011	2010	2009
Discount rate — projected benefit obligation	4.29%	4.96%	5.78%
Discount rate — net periodic benefit cost	4.96	5.78	6.32

The health care cost trend rate assumptions as of December 31, 2011 and 2010, were as follows:

	2011	2010
Initial trend rate	7.40%	7.60%
Ultimate trend rate	4.50	4.50
Year ultimate trend is reached	2028	2028

A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	2011	2010
One-percentage-point decrease:		
Effect on total service and interest cost components	$ (211)	$ (201)
Effect on year end benefit obligation	(1,056)	(1,131)
One-percentage-point increase:		
Effect on total service and interest cost components	254	236
Effect on year end benefit obligation	1,226	1,306

A reconciliation of the Company's benefit obligations of its postretirement plan at December 31, 2011 and 2010, follows:

	2011	2010
Benefit obligation — beginning of period	$ 15,864	$ 13,864
Service cost — benefits earned during the period	1,253	1,313
Interest cost on projected benefit obligation	754	743
Participant contributions	160	85
Benefits paid	(611)	(313)
Actuarial loss	620	172
Benefit obligation — end of period	$ 18,040	$ 15,864

A reconciliation of the Company's postretirement plan assets at December 31, 2011 and 2010, follows:

	2011	2010
Fair value of plan assets — beginning of period	$ -	$ -
Employer contributions	451	228
Participant contributions	160	85
Benefits paid	(611)	(313)
Fair value of plan assets — end of period	$ -	$ -

The funded status of the Company's postretirement plan at December 31, 2011 and 2010, follows:

	2011	2010
Benefit obligation — end of period	$(18,040)	$(15,864)
Fair value of plan assets — end of period	-	-
Funded status	$(18,040)	$(15,864)

The components of net periodic postretirement benefit costs for the years ended December 31, 2011, 2010, and 2009, were as follows:

	2011	2010	2009
Service cost	$1,253	$1,313	$ 878
Interest cost	754	743	464
Amortization of prior service cost	17	17	17
Amortization of actuarial (gain)	–	–	(17)
Amortization of transition obligation	31	31	31
Net periodic benefit cost	$2,055	$2,104	$1,373

A reconciliation of the postretirement plan amounts in accumulated other comprehensive income (loss) at December 31, 2011 and 2010, follows:

	2011	2010
Prior service cost	$(130)	$(147)
Unamortized actuarial gain (loss)	(385)	235
Transition obligation	(31)	(62)
Accumulated other comprehensive income	$(546)	$ 26

In 2012, $18 of prior service cost, $0 of actuarial gain, and $31 of the transition obligation is expected to be amortized to periodic benefit cost.

The recognized adjustments to other comprehensive loss at December 31, 2011 and 2010, follows:

	2011	2010
Prior service cost	$ 17	$ 18
Unamortized actuarial gain	(620)	(172)
Transition obligation	31	30
Other comprehensive loss	$(572)	$(124)

At December 31, 2011 and 2010, amounts recognized in the balance sheets were as follows:

	2011	2010
Accounts payable	$ (762)	$ (600)
Deferred credits and other	(17,278)	(15,264)
Net amount recognized	$(18,040)	$(15,864)

Expected retiree benefit payments projected to be required during the years following 2011 are as follows:

Year	Amount
2012	$ 761
2013	963
2014	1,148
2015	1,277
2016	1,383
2017–2021	8,754
Total	$14,286

In addition to the postretirement plan discussed above, in 1992 Big Rivers began a postretirement benefit plan, which vests a portion of accrued sick leave benefits to salaried employees upon retirement or death. To the extent an employee's sick leave hour balance exceeds 480 hours such excess hours are paid at 20% of the employee's base hourly rate at the time of retirement or death. The accumulated obligation recorded for the postretirement sick leave benefit is $579 and $391 at December 31, 2011 and 2010, respectively. The postretirement expense recorded was $191, $21, and $45 for 2011, 2010, and 2009, respectively, and the benefits paid were $3, $5, and $78 for 2011, 2010, and 2009, respectively.

12. RELATED PARTIES

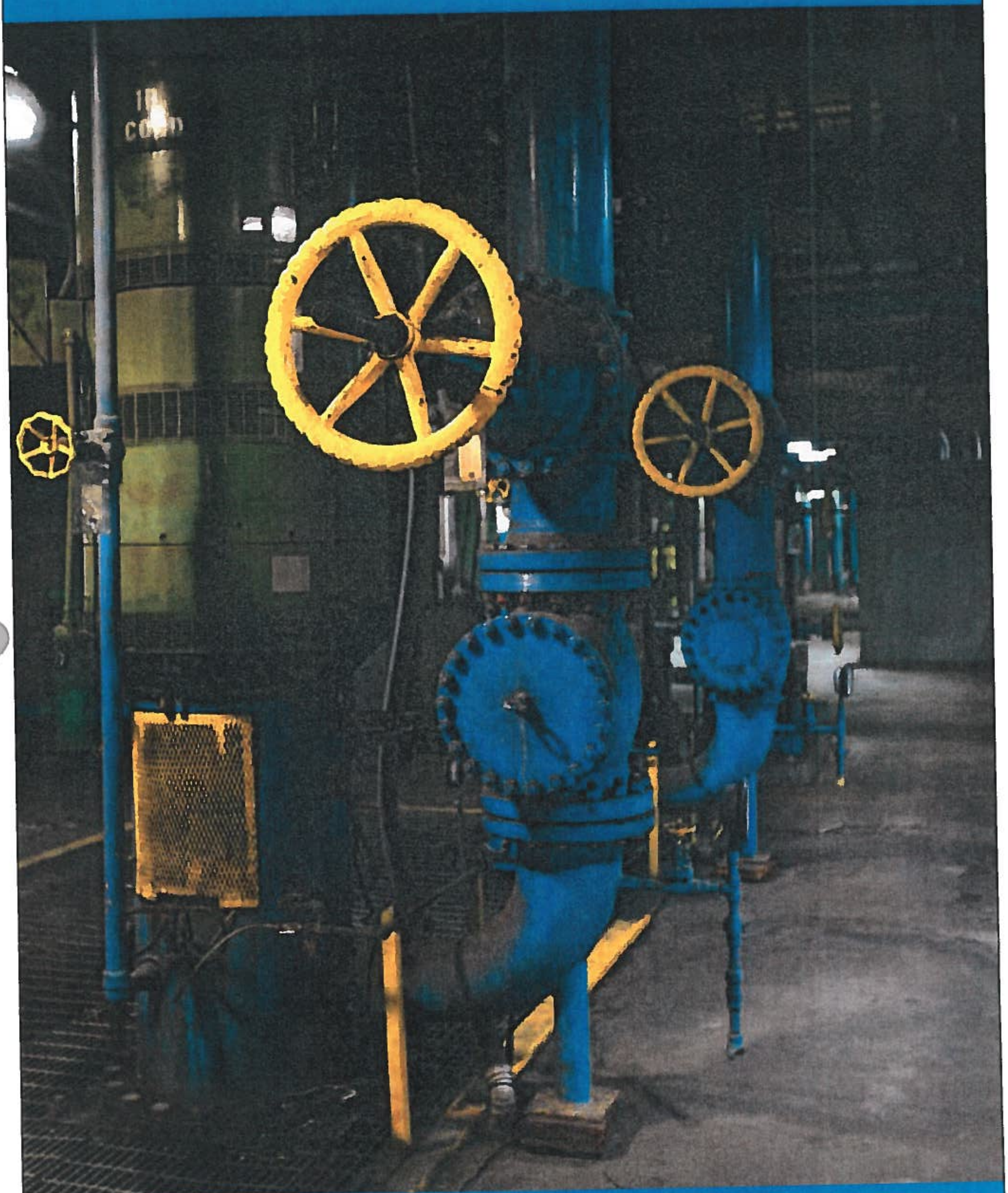
For the years ended December 31, 2011, 2010, and 2009, Big Rivers had tariff sales to its members of $151,472, $151,001, and $125,826, respectively. In addition, for the years ended December 31, 2011, 2010, and 2009, Big Rivers had certain sales to Kenergy for the Aluminum Smelters and Domtar Paper loads of $306,420, $281,473 and $167,885, respectively.

At December 31, 2011 and 2010, Big Rivers had accounts receivable from its members of $40,314 and $36,636, respectively.

13. COMMITMENTS AND CONTINGENCIES

Big Rivers is involved in litigation arising in the normal course of business. While the results of such litigation cannot be predicted with certainty, management, based upon advice of counsel, believes that the final outcome will not have a material adverse effect on the financial statements.

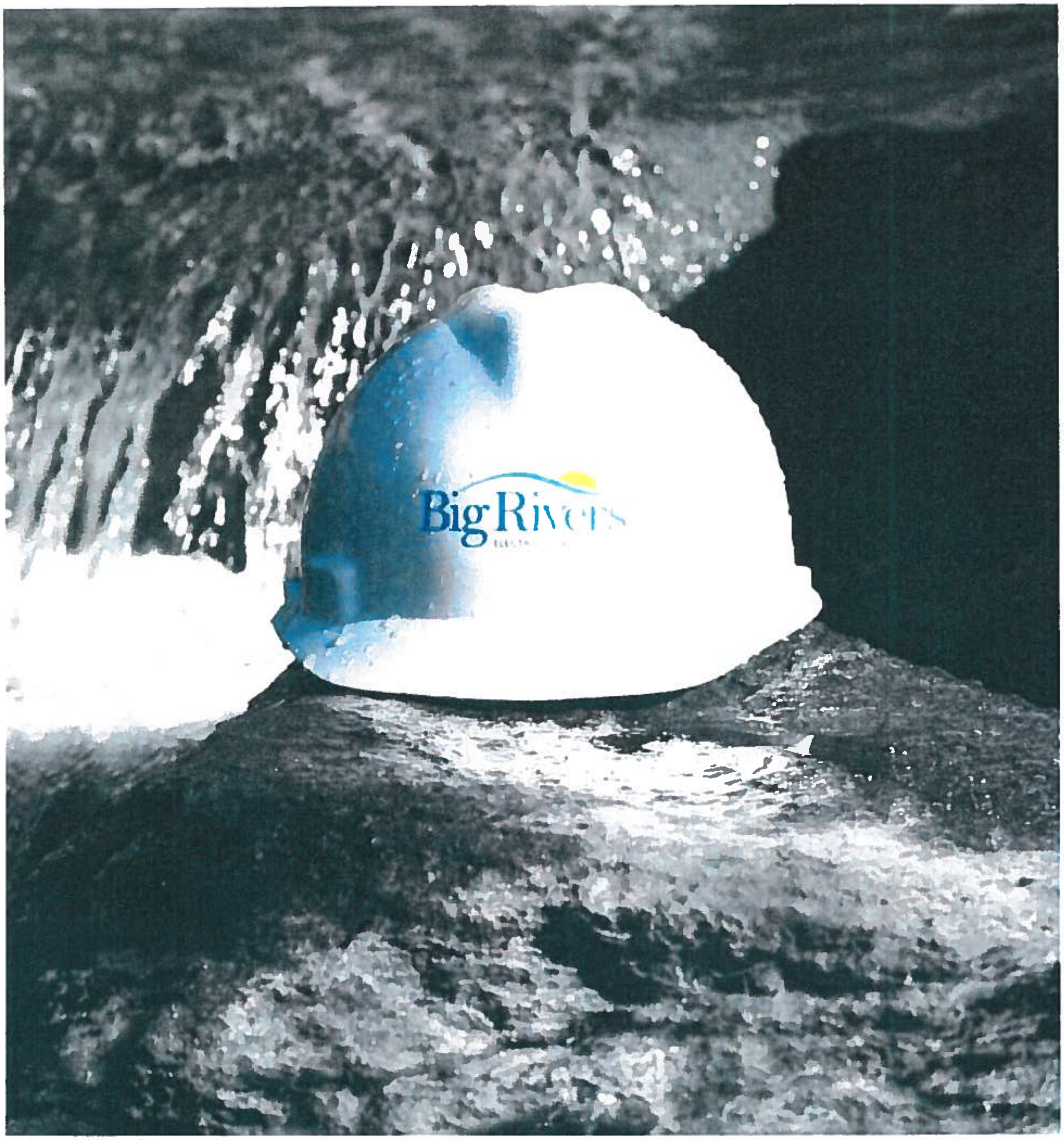
Big Rivers plans to seek KPSC approval for its 2012 environmental compliance plan (ECP) in an April 2012 filing. This ECP will consist of $283,490 of capital projects, primarily for a new scrubber at the D.B. Wilson station and a new selective catalytic reduction facility at the R.D. Green station, and certain additional operations and maintenance costs. The purpose of the ECP is to allow Big Rivers to comply, in the most cost-effective manner, with the U.S. Environmental Protection Agency Cross-State Air Pollution Rule, and Mercury and Other Air Toxics Standards. Among other things, the ECP filing will seek to recover the costs of the ECP through an amendment to Big Rivers' existing environmental surcharge tariff rider, an automatic cost-recovery mechanism that is similar in function to the fuel adjustment clause. The regulatory process is expected to last six months after the filing date.



FIVE-YEAR REVIEW Years Ended December 31 — (Dollars in thousands)

SUMMARY OF OPERATIONS	2011	2010	2009	2008	2007
Operating Revenue:					
Power Contracts Revenue	$561,989	$527,324	$341,333	$214,758	$271,605
Lease Revenue	–	–	32,027	58,423	58,265
Total Operating Revenue	561,989	527,324	373,360	273,181	329,870
Operating Expenses:					
Fuel for Electric Generation	226,229	207,749	80,655	–	–
Power Purchased	112,262	99,421	116,883	114,643	169,768
Operations (Excluding Fuel), Maintenance, Other	137,213	134,660	87,645	32,858	31,436
Depreciation	35,407	34,242	32,485	31,041	30,632
Total Operating Expenses	511,111	476,072	317,668	178,542	231,836
Interest Expense and Other:					
Interest	45,226	46,570	59,898	72,710	70,851
Other – net	320	425	3,309	6,868	103
Total Interest Expense & Other	45,546	46,995	63,207	79,578	70,954
Operating Margin	5,332	4,257	(7,515)	15,061	27,080
Non-Operating Margin	268	2,734	538,845	12,755	20,097
NET MARGIN	$5,600	$6,991	$531,330	$27,816	$47,177
SUMMARY OF BALANCE SHEET					
Total Utility Plant	$2,028,418	$2,001,067	$1,986,373	$1,791,772	$1,764,924
Accumulted Depreciation	936,355	909,501	908,099	879,073	853,290
Net Utility Plant	1,092,063	1,091,566	1,078,274	912,699	911,634
Cash and Cash Equivalents	44,849	44,780	60,290	38,903	148,914
Reserve Account Investments[1]	164,399	218,955	244,641	–	–
Other Assets	116,611	116,884	122,278	122,834	253,610
TOTAL ASSETS	$1,417,922	$1,472,185	$1,505,483	$1,074,436	$1,314,158
Equities (deficit)	$389,820	$386,575	$ 379,392	$ (154,602)	$ (174,137)
Long-term Debt[2]	786,399	816,996	848,552	987,349	1,022,345
Regulatory Liability – Member Rate Mitigation	169,001	185,893	207,348	–	–
Other Liabilities and Deferred Credits	72,702	82,721	70,191	241,689	465,950
TOTAL LIABILITIES AND EQUITY	$1,417,922	$1,472,185	$1,505,483	$1,074,436	$1,314,158
ENERGY SALES (MWh)					
Member Rural	2,371,106	2,481,390	2,239,445	2,386,916	2,406,446
Member Large Industrial	973,093	930,168	919,587	925,793	921,359
Smelter Contracts	6,854,820	6,348,431	2,885,491	–	–
Other	3,056,106	2,209,431	1,746,438	1,844,677	2,835,789
Total Energy Sales	13,255,125	11,969,420	7,790,961	5,157,386	6,163,594
SOURCES OF ENERGY (MWh)					
Generated	10,284,350	9,895,512	3,715,544	–	–
Purchased	2,998,361	2,220,994	4,166,916	5,211,789	6,213,682
Losses and Net Interchange	(27,586)	(147,086)	(91,499)	(54,403)	(50,088)
Total Energy Available	13,255,125	11,969,420	7,790,961	5,157,386	6,163,594
NET CAPACITY (MW)					
Net Generating Capacity Owned	1,444	1,444	1,444	1,459	1,459
Rights to HMP&L Station Two	202	207	212	217	217
Other Net Capacity Available	178	178	178	178	178

[1]Includes investment income receivable.
[2]Includes current maturities of long-term obligations.



BIG RIVERS ELECTRIC CORPORATION

201 Third Street (42420)
PO Box 24 (42419-0024)
Henderson, KY

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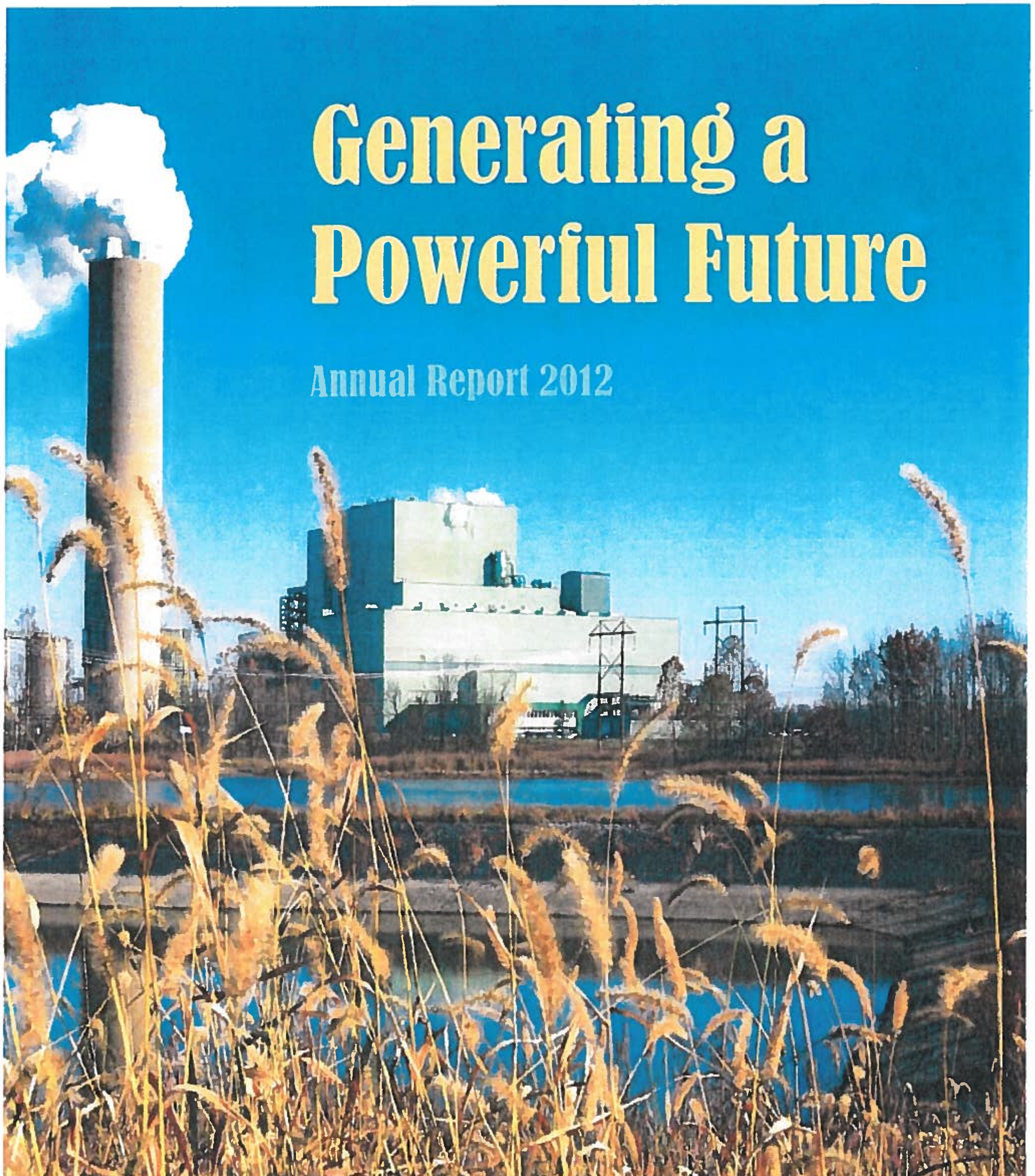
Big Rivers 2012 Annual Report

Generating a Powerful Future

Annual Report 2012



Our Mission

Big Rivers will safely deliver low-cost, reliable wholesale power and cost-effective shared services desired by the Member-Owners.

Our Vision

Big Rivers will be viewed as one of the top G&Ts in the country and will provide services the Member-Owners desire in meeting future challenges.

Our Values

Safety
Excellence
Teamwork
Integrity
Member and Community Service
Respect for the Employee
Environmentally Conscious

Financial Highlights

For the years ended December 31, 2012, 2011, 2010, 2009 and 2008. (Dollars in thousands.)

	2012	2011	2010	2009	2008
Margins	11,277	5,600	6,991	531,330	27,816
Equity	402,882	389,820	386,575	379,392	(154,602)
Capital Expenditures*	39,853	38,746	42,683	58,388	22,760
Cash and Investment Balance	68,860	44,849	44,780	60,290	38,903
RUS Series A Note Voluntary Prepayment Status	-	46,510	23,859	-	-
Times Interest Earned Ratio	1.25	1.12	1.15	9.85	1.37
Debt Service Coverage Ratio	1.58	1.47	1.47	2.44	1.17
Cost of Debt	5.27%	5.69%	5.73%	6.33%	6.33%
Cost of Capital	7.85%	7.98%	7.93%	8.39%	8.33%

* Big Rivers' share only

Generating a Powerful Future

Annual Report 2012

Big Rivers Electric Corporation

a Member-Owned cooperative

Big Rivers Electric Corporation (Big Rivers) is a Member-owned, not-for-profit, generation and transmission cooperative (G&T). We provide wholesale electric power and services to three distribution cooperative Member-Owners across 22 counties in western Kentucky.

The Member-Owners are Jackson Purchase Energy Corporation, headquartered in Paducah; Kenergy Corp., headquartered in Henderson; and Meade County Rural Electric Cooperative Corporation, headquartered in Brandenburg. Together, the Member-Owners distribute retail electric power and provide other services to approximately 113,000 homes, farms, businesses and industries.

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

High voltage electric power is delivered to the Member-Owners over a system of 1,285 miles of transmission lines and 22 substations owned by Big Rivers. Twenty-three interconnects link our system with seven surrounding utilities.

Big Rivers is led by an experienced management team and is governed by a six-member board of directors. The board is comprised of two representatives from each Member-Owner. Big Rivers employs nearly 600 people at seven locations in Kentucky, who actively contribute to the communities our Member-Owners serve.

Constantly focused on the needs and local priorities of the Member-Owners, Big Rivers provides assistance in areas such as information technology, mapping and planning, safety programs and training, economic development, education and customer support services.

As long-standing members of Touchstone Energy®, Big Rivers and the Member-Owners pledge to serve western Kentucky with integrity, accountability, innovation and a commitment to community. Keeping the cost of electricity low and the reliability high has always been a priority.

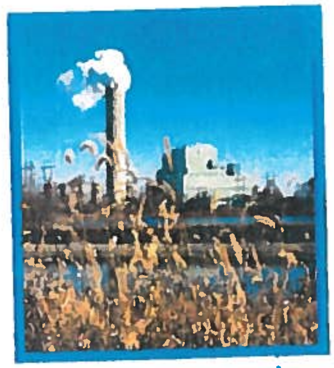
With headquarters in Henderson, Big Rivers owns and operates 1,444 megawatts (MW) of generating capacity in four stations.

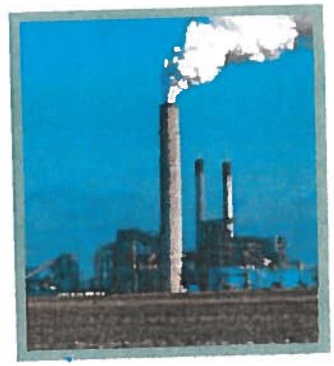
Station	Capacity	Location
Kenneth C. Coleman	443 MW	Hawesville, Ky.
Robert A. Reid	130 MW	Robards, Ky.
Robert D. Green	454 MW	Robards, Ky.
D. B. Wilson	417 MW	Centertown, Ky.
Owned Generation	1,444 MW	

Total generation available is 1,819 MW, including rights to Henderson Municipal Power and Light (HMP&L) Station Two and contracted capacity from Southeastern Power Administration (SEPA).

Owned Generation	1,444 MW
HMP&L Station Two	197 MW
SEPA	178 MW
Total Generation	1,819 MW

Big Rivers Generating Stations





Sebree Station

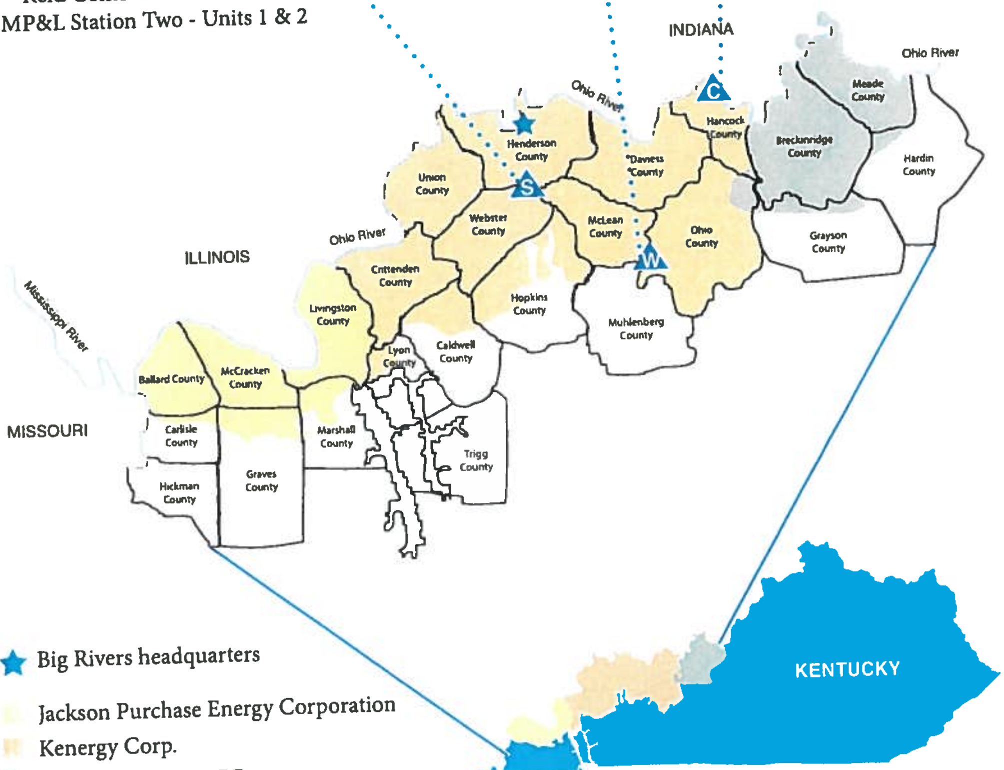
Green Units 1 & 2
Reid Unit 1
Reid Combustion Turbine
HMP&L Station Two - Units 1 & 2

Wilson Station

Wilson Unit 1

Coleman Station

Coleman Units 1, 2, 3



Big Rivers headquarters
Jackson Purchase Energy Corporation
Kenergy Corp.
Meade County RECC

Member-Owner Cooperatives

Kelly Nuckols, President & CEO
Jackson Purchase Energy Corporation

Jackson Purchase Energy Corporation

(270) 442-7321
www.JPEnergy.com

Serves: Ballard, Carlisle, Graves, Livingston, Marshall and McCracken counties

Headquartered: Paducah, Ky.

Number of accounts: 29,301

Miles of line: 2,923

Greg Starheim, President & CEO
Kenergy Corp.

Kenergy Corp.

(800) 844-4832
www.kenergycorp.com

Serves: Breckinridge, Caldwell, Crittenden, Daviess, Hancock, Henderson, Hopkins, Livingston, Lyon, McLean, Muhlenberg, Ohio, Union and Webster counties

Headquartered: Henderson, Ky.

Number of meters: 55,282

Miles of line: 7,047

Burns Mercer, President & CEO
Meade County RECC

Meade County Rural Electric Cooperative Corporation

Meade County RECC
Your Touchstone Energy® Cooperative

(270) 422-2162
www.mcrecc.coop

Serves: Breckinridge, Grayson, Hancock, Hardin, Meade and Ohio counties

Headquartered: Brandenburg, Ky.

Number of meters: 28,622

Miles of line: 2,971

Board of Directors

Back row (left to right):

Dr. James Sills, Chair
Meade County RECC

Wayne Elliott, Vice-Chair
Jackson Purchase Energy Corporation

William Denton
Kenergy Corp.

Front row (left to right):

Lee Bearden
Jackson Purchase Energy Corporation

Paul Edd Butler
Meade County RECC

Larry Elder, Secretary-Treasurer
Kenergy Corp.

Management Team

Back row (left to right):

Albert Yockey, V.P. Governmental Relations & Enterprise Risk Management (retired January 2013)

Marty Littrel, Managing Director Communications & Community Relations

James Haner,
V.P. Administrative Services

Paula Mitchell, Executive Assistant

Eric Robeson, V.P. Environmental Services and Construction

David Crockett,
V.P. System Operations

Front row (left to right):

Billie Richert, V.P. Accounting, Rates, and Chief Financial Officer

Robert Berry, Chief Operating Officer

Mark Bailey, President & Chief Executive Officer

James Miller, Corporate Counsel

Not pictured:

Lindsay Barron, V.P. Energy Services (as of February 2013)

John Talbert, Director Governmental Relations

MESSAGE from the Board Chair and CEO

Mark A. Bailey
President and CEO

Dr. James Sills
Chair, Board of Directors

Big Rivers is proud as a not-for-profit electric cooperative to be owned by the consumers (Members) we serve, which is why we refer to our customers as Member-Owners.

The three distribution cooperatives that own Big Rivers are democratically-controlled organizations just like Big Rivers and are also owned by the customers (Members) they serve. This business model is unique to electric cooperatives and sets us apart from other electric utilities. This distinction has served us well and has driven Big Rivers to be one of the lowest-cost electricity producers in the country for many years.

Big Rivers, like other cooperatives, makes decisions that are in the best interests of ALL our Member-Owners, instead of making business decisions that are shareholder-driven by owners who may not live in the area or be served by us. Following this cooperative model enables Big Rivers to stay focused on our mission of safely providing low cost and reliable electricity and our vision to be viewed as one of the top generation and transmission cooperatives in the country.

With another challenging year past, we are pleased to highlight several notable 2012 achievements of the Big Rivers team.

Overall, 2012 was a very successful year. Through a collaborative effort, Big Rivers provided our Member-Owners net incremental value of over $26 million in 2012 through successful completion of initiatives involving safety, plant operations, financing and transmission reliability.

On August 27, 2012, Navigant Consulting, a nationally recognized benchmarking firm, presented its annual Operational Excellence Award to Big Rivers' Coleman Station located in Hawesville, Kentucky for its first place ranking in the small coal plant category. This is significant because 78 percent of all U.S. coal-fired plants participate in this benchmarking study including plants owned by a number of large utilities. The award is based on cost, operational efficiency and safety performance. To be eligible, plants submit five consecutive years of most recent data. Receipt of this award by our Coleman plant is a credit not only to all plant employees, but also to the entire Big Rivers production group. All three plant locations collectively and collaboratively work as a team, along with our procurement and environmental staff, to help the organization meet its operational and financial goals.

All three Big Rivers plant locations earned Governor

Safety Awards in 2012. The award is presented by the Kentucky Department of Labor to employers in the state whose employees work a specified period without a recordable injury or illness. The entire company reached 12 consecutive months without a lost-time incident in July, which is the second time since 2009 Big Rivers attained that milestone, and completed all of 2012 without a lost-time incident, the first time that feat has been accomplished.

In an effort to continue to keep electric rates as low as possible, Big Rivers production employees made continuous improvements in generating unit operating efficiency which saved Big Rivers' Member-Owners approximately $5.3 million in 2012. Our production group takes pride in their ability to improve plant performance and pass the savings along to our Member-Owners.

In addition, Big Rivers employees renegotiated fuel and pollution control equipment reagent contracts while also taking advantage of a depressed wholesale power market to purchase inexpensive off-peak electricity when it was available rather than generating it ourselves to save an additional $3 per megawatt hour for our Member-Owners in 2012. These successes are a result of the vision and long-term planning of our board of directors and senior leadership team to actively manage expenses and enhance operating efficiency.

Big Rivers' finance and accounting department remained committed to strengthening our financial performance by taking advantage of Big Rivers' stronger balance sheet that resulted from the Unwind transaction. We successfully closed $537 million in loans from National Rural Utilities Cooperative Finance Corporation (CFC) and CoBank, ACB (CoBank) to refinance Rural Utilities Service (RUS) debt and provide capital for ongoing operations. Of this total, $235 million came from CoBank at an all-in effective interest rate of approximately 3.7 percent and $302 million came from CFC at an all-in effective interest rate of approximately 4.5 percent

These efforts enabled Big Rivers to pay down $442 million of RUS debt that carried higher interest expense of 5.75 percent. The lower all-in effective cost of the CFC and CoBank term loans are estimated to save approximately $4.3 million annually for Big Rivers and its Member-Owners. Reducing costs and saving our Member-Owners money is a strategic objective for Big Rivers. As we plan for the future, we will remain vigilant in seeking methods to reduce expenses.

However, our business, like many other entities, continues to face a myriad of challenges. Looming environmental regulation has been on every coal-fired generating utility's radar for a number of years. On April 2, 2012, Big Rivers filed its Environmental Compliance Plan with the Kentucky Public Service Commission (PSC). The total estimated compliance cost for just two of five potential pending environmental regulations, the Cross State Air Pollution Rule (CSAPR) and the Mercury and Air Toxics Standards (MATS), was $283.5 million.

The day before the Environmental Compliance Plan hearing was scheduled to be heard before the PSC in August 2012, the District of Columbia Court of Appeals overturned EPA's CSAPR rule. The vacatur of the CSAPR ruling by the court reduced Big Rivers' required environmental capital expenditure by $225.5 million. As a result, Big Rivers now needs to spend approximately $59 million instead of the originally planned $283.5 million. Big Rivers anticipates this to increase electric rates by nearly four percent; but the increase will not appear on wholesale Member-Owners customers' bills until early 2018.

The greatest challenge in dealing with the current environmental regulatory situation is the uncertainty it creates in planning and operating Big Rivers' generating resources. We are committed to ensuring that environmental policy makers understand the impact proposed regulations have on electric bills to help shape the final regulations so they are fair, attainable and affordable for our Member-Owners' customers. Our team has been advocating with regulators and legislators to maintain a proper balance between a clean environment and low-cost reliable electricity.

This is especially important as the economy is still in the early stages of recovery from recession.

Over the course of the year, new challenges emerged as Big Rivers' and Member-Owner Kenergy's two largest customers, Century Aluminum and Rio Tinto Alcan, initiated efforts to seek electric rate discounts from Big Rivers at the expense of our remaining Member-Owners. These two aluminum smelters account for nearly 850 megawatts of combined electricity demand and approximately 64 percent of Big Rivers' annual revenue. Big Rivers' senior management and its Member-Owners dedicated countless hours to meet, evaluate and propose equitable solutions in an effort to address both smelters' requests for relief.

However, as a not-for-profit Member-Owned electric cooperative, there are limits as to the financial relief we can provide without harming our other Member-Owners. It's likely that Big Rivers is the only electric generation and transmission utility in the country that serves two aluminum smelters and has such a high percentage of its load dedicated to just two customers. They have both been valued customers of Big Rivers and Kenergy for decades, but as international entities they have been facing competitive global pressure for some time due to depressed world-wide aluminum prices. Given that several U.S. smelters have closed operations in the last few years, in 2012 Big Rivers developed a Load Concentration Mitigation Strategy to deal with this possibility should it occur.

It is disappointing that only three years earlier Big Rivers, its Member-Owners and the aluminum smelters completed a major (Unwind) transaction that provided both smelters with long-term, predictable and affordable electric rates that averaged approximately $48 per megawatt hour in 2012, less than what was projected for 2012 when the Unwind agreements were signed in mid-2009. Even though our board and senior management team tried to help both aluminum smelters with their latest request for concessions, it was not enough to prevent Century Aluminum from submitting a Termination Notice to Big Rivers and Kenergy on August 20, 2012.

This decision by Century Aluminum has driven Big Rivers to execute its Load Mitigation Plan, which among other actions called for working aggressively to attract new customers to our Member-Owners' service territory through economic development efforts and through energy services initiatives to sell to other electric utilities the power the smelter has been taking. Additionally, Big Rivers' board and management have begun evaluating options of idling or selling generating unit(s) to offset the impending smelter revenue loss.

Concurrently, Big Rivers' rate case team began efforts to file a $74.5 annual rate increase request with the PSC after identifying and implementing significant cost reductions to offset the revenue deficiency contributed by the departure of our largest customer. For years, Big Rivers has had a successful track record of supplying our Members-Owners with some of the lowest-priced electricity in the nation. Even with this latest rate increase, Big Rivers will continue to offer some of the lowest electric rates in the country. Eventually, as our load mitigation strategy is implemented, we will be able to lower rates as additional revenue is received from new and expanding industry or other electric utilities that buy Big Rivers' power.

Big Rivers and its Member-Owners will continue to work with Century Aluminum in an attempt to develop a reasonable solution that will avoid the closure of the smelter while not imposing additional financial burdens on the homes and businesses served by our Member-Owners. As a not-for-profit electric cooperative, we care about the communities we serve and the economic vitality of our region. Big Rivers' board, senior management and Member-Owners remain dedicated to negotiating a successful resolution that will be mutually beneficial for all parties in western Kentucky.

At Big Rivers, we remain committed to responding to the challenges we face to fulfill our mission of safely delivering low-cost reliable wholesale electricity to our Member-Owners. We are

confident our senior leadership team and board of directors are well equipped to strategize and implement initiatives to meet that mission. In the process, Big Rivers will continue to evaluate and execute strategies to reduce costs and provide additional financial and service benefits to our Member-Owners. Our staff is committed to excellence as our accomplishments in 2012 demonstrate. We will remain committed to our cooperative principles and in the process will Generate A Powerful Future. We are confident our best days are ahead of us.

Dr. James Sills
Chair, Board of Directors

Mark A. Bailey
President and CEO

Maintaining power production EXCELLENCE and transmission system RELIABILITY

Generating Resources

Big Rivers currently owns and operates 1,444 MW of net generating capacity in four stations:

- Kenneth C. Coleman Station (443 MW) Hawesville, Kentucky
- Robert A. Reid Station (130 MW) Robards, Kentucky
- Robert D. Green Station (454 MW) Robards, Kentucky
- D. B. Wilson Station (417 MW) Centertown, Kentucky.

Big Rivers also has contractual rights to 197 MW from the Station Two plant owned by Henderson Municipal Power and Light (HMP&L) and 178 MW of hydro capacity from the Southeastern Power Administration (SEPA), for a total net capacity availability of 1,819 MW.

The SEPA contract is currently in force majeure due to safety issues at the Wolf Creek and Center Hill dams, so Big Rivers is only receiving run-of-the-river output that the company has the right to refuse. The Wolf Creek dam and hydro units are expected to return to normal operation in January 2015, at which time the full 178 MW of rated capacity will be available to Big Rivers.

Big Rivers' share of the Station Two capacity was 207 MW on March 1, 2011. HMP&L has the contractual right to increase or decrease its capacity reservation from Station Two up to 5 MW each year to meet the needs of the City of Henderson and its residents. HMP&L exercised that right in June 2011 and June 2012, reducing Big Rivers' share of Station Two capacity from 207 MW to 197 MW.

Generating Unit Reliability

A commonly used industry standard for measuring the reliability of generating units is the Equivalent Forced Outage Rate (EFOR). Big Rivers determines EFOR for its generating fleet using the North American Electric Reliability Corporation (NERC) generator availability data system and compares its EFOR against other utilities. Big Rivers also relies on Equivalent Availability Factor (EAF) and Net Capacity Factor (NCF) in monitoring reliability versus other utilities. Big Rivers uses Navigant Consulting's "Generation Knowledge Service" for these comparisons.

Overall, Big Rivers' generating fleet has been very reliable since closing of the Unwind Transaction in July 2009, and has consistently performed in the top quartile in EFOR, EAF, and NCF.

More specifically, in a five-year benchmarking study completed in August 2012, for the period from April 2007 through March 2012, the statistics for Big Rivers' units were in the best quartile for the units in their respective peer group.

As the data contained in the table at the bottom of this page demonstrates, the reliability of Big Rivers' generating facilities compares quite favorably to others in the industry.

Coleman Station Wins Operational Excellence Award

Coleman Station ranked first and won the 2012 Operational Excellence Award in the small coal plant category by Navigant Consulting, based on its performance in cost, reliability, and employee safety. Navigant Consulting, the industry's premier benchmarking service for fossil-fired generation plants, measures and evaluates the operational performance and cost of generating units and compares them to their peers. Roughly 78 percent of the North American electric generating coal fleet are clients with Navigant Consulting.

The small plant category includes generating stations with an average unit size of 200 MW or less. Coleman Station produces 443 MW from its three generating units, which equates to an average unit size of about 148 MW. Plants were evaluated over the five-year period in the following areas:

- Efficient cost management of non-fuel operations and maintenance
- High availability measured by equivalent availability factor, which is the percentage of time a generating unit is available for power production
- Predictable reliability measured by the percentage of time a generating unit is unexpectedly off-line
- Improving reliability
- Safety performance based on Occupational Safety and Health Administration standards

Big Rivers is proud of its Coleman Station employees for earning this national award, which symbolizes successful pursuit of three of our seven corporate values: **safety**, **excellence** and **teamwork**. The award is also a tribute to the entire production group, given the team approach they use in making investment and maintenance decisions. Big Rivers is excited for Coleman Station to be ranked first

For the comparative period April 2007 through March 2012, the reliability metrics for Big Rivers' generating units compared to their peer group are as follows:

Metric	Big Rivers Units		Best Quartile
EFOR	4.18 %	(lower is better)	4.55 %
EAF	90.07 %	(higher is better)	88.70 %
NCF	81.55 %	(higher is better)	78.24 %

In a one-year comparison from April 2011 through March 2012, Big Rivers' units performed slightly better than the same peer group:

Metric	Big Rivers Units		Best Quartile
EFOR	3.69 %	(lower is better)	3.84%
EAF	92.92 %	(higher is better)	92.04%
NCF	82.29 %	(higher is better)	76.15%

nationally for operational excellence compared to similar-sized power plants operated by some of the largest utilities in the United States.

Generating Facility Maintenance

Outage planning is an important element of Big Rivers' reliability strategy. Planners at each generating station use formal outage planning processes to ensure work is optimized during each unit's scheduled outage. Big Rivers' capital work plan includes more than $212 million in capital improvements and asset replacement for its generating units necessary to keep the reliability of its fleet consistently within the top quartile of their respective peer group. These actions ensure Big Rivers continues to fulfill its strategy of reliable, safe, and economic generation fleet performance.

Transmission System Overview

Big Rivers owns, operates, and maintains a 1,285-mile transmission system and 22 substations. In addition, 23 interconnects link the Big Rivers transmission system with seven neighboring utilities. Big Rivers is required to satisfy a contingency (unplanned event) reserve standard mandated by the North American Electric Reliability Corporation (NERC). Failure to satisfy the requirements can result in fines up to $1 million per day for each violation.

Big Rivers became fully integrated as a transmission-owning member of MISO, formerly known as Midwest Independent System Operator, effective December 1, 2010. Big Rivers joined MISO because it was the least-cost alternative to satisfy contingency reserve obligations and avoid potential penalties for non-compliance from NERC. Big Rivers has also realized benefits from reduced transmission system congestion since joining MISO. This resulted in improvements in Big Rivers' ability to both purchase and sell electricity in the wholesale power market.

MISO operates three competitive markets and acts as a financial clearinghouse for market participants' electric energy supply, load, and financial transmission rights. These markets facilitate competition

among market participants, dispatch least cost generation resources, optimize use of the transmission system, and provide market participants the ability to hedge transmission system congestion costs.

Big Rivers has been a member-owner of ACES, formerly known as ACES Power Marketing, since January 2003. ACES acts as Big Rivers' agent to assist in managing the company's energy portfolio through generation dispatch, energy trading, and optimization of financial transmission rights. ACES also provides support services such as energy risk management, portfolio modeling, contract administration, and regulatory support.

New 345 kV Interconnect

Vectren Corporation and Big Rivers constructed a new extra high voltage 345 kV transmission interconnect between the company's Robert A. Reid substation in Robards, Kentucky and Vectren's A.B. Brown substation in Posey County, Indiana. This project, proposed and led by Vectren, involved a system analysis by MISO. Although Vectren was responsible for construction of the line itself and all project costs, Big Rivers was responsible for construction at the Reid substation.

Big Rivers relocated an existing 345 kV line termination in the Reid substation to make room for termination of the new Vectren line. In addition, Big Rivers added a ring bus, consisting of four 345 kV breakers with disconnect switches, which allows the transmission system to remain operational while sections of the ring bus are de-energized to enable preventative maintenance. With the addition of this new 345 kV line, Big Rivers now has two extra high voltage transmission lines leaving the Reid substation, which greatly improves the ability to transfer power into and from the Big Rivers transmission system to help maintain system reliability.

Two-Way Radio System

Big Rivers completed installation of a new digital two-way radio system in 2012. The new radio system replaced aging equipment and met new Federal Communication Commission rules that became effective January 1, 2013. The 13-site Motorola network supports truck radio communications for Big Rivers and the Member-Owners. The radio system's high tech design allows each company to have its own independent dispatch operations while sharing the network and electronics that make it operate.

In addition to highly reliable voice communication, the system provides better geographic coverage than previous systems, and its shared network architecture allows for improved interoperability and resource sharing during storms or emergencies.

Keeping SAFETY as a primary focus every day

Big Rivers employees set new records in working safely

Big Rivers completed 2012 with zero lost-time incidents and seven recordables—the lowest totals ever in company history.

- Coleman Station employees completed six years without a lost-time incident at midnight on January 5.
- Transmission employees completed two years without a lost-time incident at midnight on January 14.
- Wilson Station employees completed five years without a lost-time incident at midnight on May 15.
- Sebree Station employees completed one year without a lost-time incident at midnight on May 19.
- Production employees completed one year without a lost-time incident at midnight on May 19.
- Headquarters employees completed one year without a lost-time incident at midnight on July 20.
- The company completed one year without a lost-time incident at midnight on July 20.

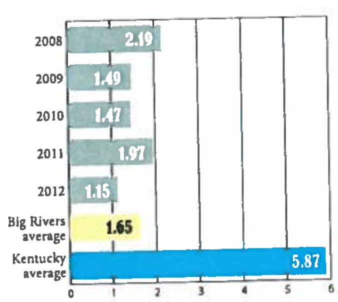
All generating stations receive Governor's Safety Awards

The Governor's Safety and Health Award recognizes outstanding safety performance. This award is given to employers and employees who together achieve a required number of hours worked without experiencing a work-related lost-time injury or illness which prevents an individual from performing his/her regular duties on a subsequent scheduled workday or shift.

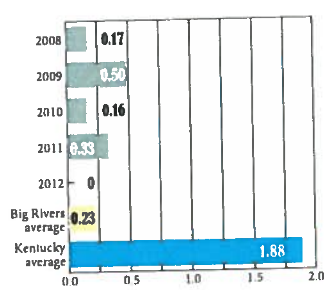
Wilson Station earned its 11th Governor's Safety Award on March 31 for working over 1,000,000 hours without a lost-time injury. Mark Brown, secretary of the Kentucky Labor Cabinet, presented Wilson Station employees with their award on June 14.

Sebree Station earned its 8th Governor's Safety Award on May 28 for working 502,411

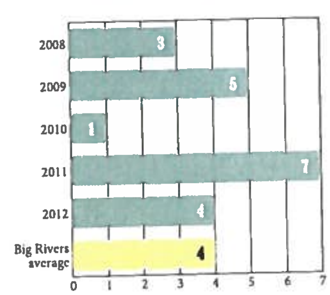
OSHA Recordable Incident Rate



Lost-Time Incident Rate



Number of Vehicle Incidents



hours without a lost-time injury. Mark Brown, secretary of the Kentucky Labor Cabinet, presented Sebree Station employees with their award on June 22.

Coleman Station earned its 10th Governor's Safety Award for working 1,338,041 hours without a lost-time injury. This represents 6.5 years worked without experiencing a lost-time injury. Mark Brown, secretary of the Kentucky Labor Cabinet, presented Coleman Station employees with their award on August 15.

Safety is one of seven core values at Big Rivers and is a foundation for all decisions and expectations of the workforce.

Three safety awards from the Kentucky Association of Electric Cooperatives

Coleman Station, Wilson Station, and Energy Transmission & Substation received safety awards on May 22 from the Kentucky Association of Electric Cooperatives for hours worked with no lost time incidents: Coleman - 1,263,102; Wilson - 956,543; ET&S - 119,800. Mark Bailey, president and CEO, accepted the awards at the KAEC board meeting on behalf of Big Rivers employees.

Two awards from the Kentucky Safety & Health Network

The Kentucky Safety & Health Network (KSHN) presented Troy Stovall, Big Rivers corporate safety administrator, with an award for Outstanding Individual in Occupational Safety & Health in the business category. Troy received the award May 10 in recognition of his dedication to the field of occupational safety and health in Kentucky. Big Rivers was also recognized by KSHN in appreciation of its sponsorship of the Governor's Safety and Health Conference. KSHN represents individuals from all facets of Kentucky's workplaces, and the organization draws on the knowledge of members in four sectors: business, education, government and labor. Membership is open to any and all individuals with an interest in occupational safety and health.

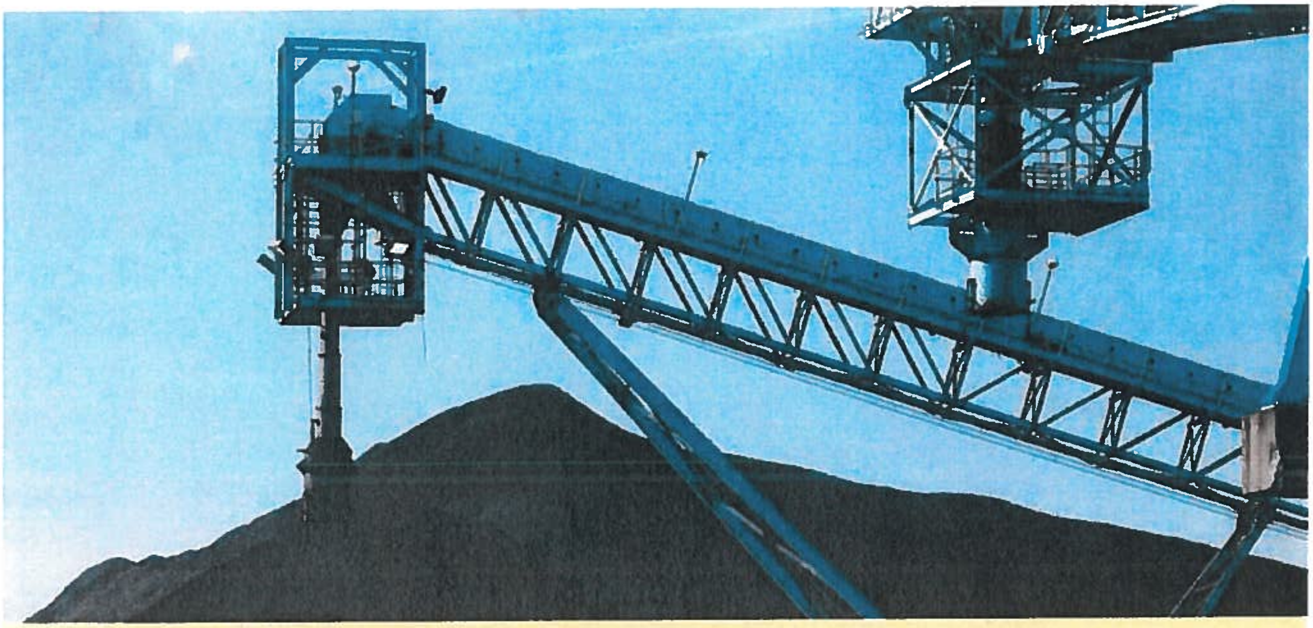
Big Rivers hosts annual contractor safety meeting

Big Rivers held its annual contractor safety meeting in January 2012. Attendees at the packed event included contractors who work at Big Rivers facilities, Big Rivers employees and personnel from East Kentucky Power Cooperative. Participants received information on why Big Rivers values safety, expectations of contractors, and hearing loss prevention. The keynote speaker, a safety instructor for Indiana Statewide Association of Rural Electric Cooperatives, emphasized the true cost of being injured while working on the job.

Wilson Station earned its 11th Governor's Safety Award on March 31.

Sebree Station earned its 8th Governor's Safety Award on May 28.

Coleman Station earned its 10th Governor's Safety Award on July 11.



Using TEAMWORK to develop and implement strategic risk management

Load Forecast

Big Rivers is required by the U.S. Department of Agriculture Rural Utilities Services (RUS) to update its load forecast every two years and to submit the forecast to RUS for review and approval. The load forecast is a projection of future energy usage and peak demand that reflects changes in usage per customer and customer growth based on economic and demographic trends, consumer end-usage and weather data. The forecast is an input to production cost and Big Rivers' financial models, and it drives calculation of operational expenses and projected revenues. The current forecast was approved by RUS on July 16, 2012. Big Rivers' load forecasting process is a team effort involving Big Rivers and its Member-Owners. Member-Owner input is an integral part of the load forecast development process, as Big Rivers' load forecast is built by aggregating its individual Member-Owners' forecasts. Big Rivers' Member-Owners provide input during development of the load forecast and review results prior to finalization.

As a result of the Century contract termination, beginning on August 20, 2013, Big Rivers reduced its peak demand forecast by 482 MW and its energy forecast by 4,138 GWh/year. The demand reduction represents Century's full contract demand specified in the Smelter (Contract) Agreement, and the energy reduction represents the full contract demand at 98% load factor, consistent with the terms and conditions for billing as specified in the Smelter Agreement. These reductions result in the elimination of one hundred percent of the Century load from Big Rivers' load forecast.

Rate Case

On January 15, 2013, Big Rivers filed with the PSC a request seeking approval for an annual increase of $74,476,120 in rates. The vast majority of this amount—approximately $63 million—stems from Century's contract termination. Additional major drivers (which Big Rivers estimates have a net impact of approximately $11 million) include declining off-system sales margins and increasing depreciation expense. Offsetting these increase drivers are the effects of the July 2012 refinancing of RUS debt and cost cutting measures.

Big Rivers' mission is to provide safe, reliable, low-cost power to its Member-Owners. The pending rate increase is necessary to allow Big Rivers to meet its financial obligations to its creditors so that it can continue to attract the necessary capital to provide service to its Member-Owners in 2013 and beyond. While the pending rate increase is aimed at mitigating 100 percent of the revenue impact to Big Rivers resulting from the Century contract termination, Big Rivers worked very hard to ensure the increase can be reduced over time.

Plan for Reducing Production Costs

Since it is unlikely that Big Rivers will replace the Century load before August 20, 2013, the company intends to continue to implement its Load Concentration Mitigation Plan and curtail electricity production to reduce the expense of full production in a depressed wholesale power market. The current plan is to idle generating units to eliminate variable production costs and reduce fixed expenses. In its 2013 budget, Big Rivers assumed Wilson Station will be idled; however, company management continues to evaluate a range of options to identify the most cost-effective alternatives for Big Rivers' Member-Owners.

Since Big Rivers received Century's Notice of Termination on August 20, 2012, the company has deferred filling most production employment vacancies in anticipation of a workforce reduction due to the potential idling of generating units. Big Rivers has only filled vacant positions that could not be covered by overtime work. This has created a significant amount of overtime; however, it is Big Rivers' belief this is a prudent approach to reduce the number of involuntary work force reductions after Century exits the system on August 20, 2013.

As a transmission-owning member of MISO, Big Rivers must secure MISO's approval prior to layup of any generating unit to ensure that action does not have an adverse impact on the reliability of the transmission grid. Because of the physical proximity of the Coleman Station to Century's Hawesville smelting facility, and given the possibility that Century could ultimately begin purchasing power from the wholesale market, Big Rivers assumed that if the Century facility continues to operate in any substantial way on or after August 20, 2013, MISO would require Big Rivers to continue to operate the Coleman Station for system reliability reasons. Since no such constraint applies to the Wilson Station, it is Big Rivers' belief that idling Wilson Station will have less negative impact on transmission system reliability.

Big Rivers continues to look for additional ways to reduce expenses, to improve the efficiency of its generating units, and to offer a robust set of demand side management and energy efficiency programs to help its Member-Owners deal with the rate increase necessary when Century no longer buys Big Rivers' power. Big Rivers carefully monitors costs and has engaged in corporate-wide cost cutting.

Transmission Projects to Mitigate Risk of Smelter Load Loss

The Phase 2 Transmission Projects were an essential component of Big Rivers' efforts to mitigate the risks associated with providing electric service for two aluminum smelters: Century Aluminum of Kentucky General Partnership (Century) and Alcan Primary Product Corporation (Alcan). In the Unwind transaction, Big Rivers entered into contracts to provide electric service to Kenergy Corp. (one of Big Rivers' three electric distribution cooperative Member-Owners) for resale to the smelters. The Phase 2 Transmission Projects were designed to enable Big Rivers to withstand the loss of load from both smelters, should they cease operation, by increasing the power export capacity of the Big Rivers transmission system to cover not only the 850 MW smelter load, but also the additional generating capacity that would be available when the remaining Big Rivers' Member-Owners' loads are at their lowest levels.

Big Rivers has completed or substantially completed all of the system improvements associated with the Phase 2 Transmission Projects except one. Big Rivers entered into a construction work agreement with the Tennessee Valley Authority (TVA) under which TVA will complete work on its transmission system at an existing interconnection point with Big Rivers at TVA's Paradise switchyard, which addresses the final project. TVA contemplates this work will be completed in the 2014-2015 timeframe. Until the TVA system improvements are completed, Big Rivers can reconfigure its transmission system on a temporary basis to export the entire 850 MW of power consumed by both smelters.

From a transmission standpoint, Big Rivers is meeting its mission of delivering safe and reliable transmission service to its customers. Big Rivers is satisfying its NERC reliability obligations and is working to optimize its membership in MISO. Big Rivers is also satisfying its commitments to the PSC regarding the Phase 2 Transmission Projects.

Working with INTEGRITY to overcome obstacles

Mitigation of the Century Aluminum contract termination

Since receiving Century's Notice of Termination on August 20, 2012, Big Rivers staff has been implementing its Load Concentration Mitigation Plan, which calls for several steps.

First, the plan calls for Big Rivers to petition the PSC to increase rates to address forecasted net revenue shortfall stemming from Century's contract termination. Big Rivers has addressed this in the rate case filing.

Second, the plan calls for Big Rivers to market all available power not consumed by internal customers when the market price is greater than avoidable generation cost. Forecasted MISO market prices in 2013 and 2014 indicate that off-system sales margins will remain depressed due to the depressed economy, so this mitigation step is not expected to be an effective mitigation method for the next few years.

Third, the plan calls for Big Rivers to idle or reduce generation when the market price does not support the cost of generating power. Big Rivers plans to address this measure with curtailed production by temporarily idling one or more of its generating units.

Fourth, the plan calls for Big Rivers to evaluate options to execute forward two-party sales contracts, enter into wholesale power agreements, and/or participate in organized power capacity markets. Big Rivers is actively exploring all these alternatives. To that end, efforts are underway to find load replacement options for the 482 MW currently being utilized by Century. So far, Big Rivers has provided proposals as a result of requests from two other utilities. Big Rivers has informally initiated discussions with other potential counterparties, on a strictly confidential basis, to explore possible opportunities for Big Rivers to sell the power Century has been buying.

Big Rivers is also taking a multi-pronged approach, with Big Rivers' Member-Owners focusing on economic development opportunities. Most new economic development opportunities—for example, the attraction of a new industrial facility to a greenfield or brownfield site—often take six months for the outside party to finalize site selection, with another 18 to 24 months for environmental assessment/ mitigation, construction, and ramp-up to full load.

Big Rivers will continue evaluating all ways available to mitigate the effects of the Century contract termination. As those mitigation efforts are successful, Big Rivers' Member-Owners will benefit through rate reduction, but those benefits are not expected to materialize for several years. Under current wholesale market conditions, Big Rivers' best option at this time to mitigate the negative impact of the Century contract termination appears to be idling a generating plant to reduce expenses.

Remaining conscious of the ENVIRONMENT

Environmental compliance plan approved

In a case of coincidental timing, a federal appeals court struck down an EPA air regulation one day before a Big Rivers hearing was scheduled with the PSC related to the company's environmental compliance plan. There were several intervenors in the case; however, Big Rivers reached a stipulation agreement with those parties.

In an order issued October 1, the PSC granted Big Rivers permission to move forward with the agreed upon environmental compliance plan. Big Rivers was granted certificates of public convenience and necessity to complete conversion of Reid Unit 1 from coal to natural gas and to install additional equipment to reduce mercury emission controls at Coleman, Wilson, and Green stations. Big Rivers will invest about $58 million in environmental controls to comply with the EPA-mandated MATS, which has a compliance deadline of April 2015.

These environmental projects will enable Big Rivers to comply with MATS only, due to the federal appeals court's vacatur of CSAPR. Big Rivers will continue to operate under EPA's 2005 Clean Air Interstate Rule, until the EPA promulgates a new rule.

Coleman Station conducting clear carbon test program

Big Rivers is conducting a test program at Coleman Unit 1 to explore mercury removal from stack gasses. Big Rivers has partnered with Clear Carbon Innovations for this test program, which began November 2012 and is expected to run approximately six months.

Activated carbon is injected both upstream and downstream of the unit's air heater to determine which location is better for optimal mercury removal. Mercury levels will be measured at the precipitator outlet. These injections are made about one week per month during the testing period. Big Rivers anticipates using results of this study to optimize its MATS compliance plan to reduce the cost impact to its Member-Owners.

Renewable Energy

Big Rivers is well positioned in the national renewable energy movement. Power supplies of the future will include a growing emphasis on renewable energy as these sources gain more attention, popularity and commercial viability.

In the tradition of working together, cooperatives across the country have formed the National Renewables Cooperative Organization (NRCO) to promote and facilitate development of renewable energy resources. Membership in the NRCO is open to G&Ts and distribution cooperatives with the legal ability to buy power in the wholesale market. Big Rivers was one of 24 founding members of the organization, which formed in November 2008.

The NRCO allows cooperatives to pool their expertise so the knowledge base of cooperatives with experience in developing renewable energy will be available to all. At the outset, the NRCO served in a consulting capacity, evaluating renewable resource opportunities, facilitating member participation in renewable energy projects and assisting in creating optimal arrangements for members like Big Rivers. The NRCO also assists cooperatives in ongoing management of renewable resources.

Big Rivers continues to evaluate renewable energy sources along with the regulatory and legislative efforts that impact development of additional sources of generation.

Coleman Station launches recycling program

In February 2012, Coleman Station established a new recycling program in partnership with the City of Hawesville. The plant is utilizing two large compartment trailers for recycling plastics, metal/aluminum cans, white paper, and newspapers/magazines.

The City of Hawesville also provided a smaller trailer for recycling cardboard. Coleman Station employees are pleased to participate alongside the City of Hawesville to minimize the volume of recyclable material going to landfills, as well as reducing costs associated with regular garbage removal.

Continuing COMMUNITY service

Big Rivers has a workforce of competent, hardworking individuals who contribute daily to the success of the organization. In addition, Big Rivers is also fortunate to have employees who are dedicated to the success and wellbeing of the communities we serve.

Big Rivers and its employees pledge $194,713 to United Way

Big Rivers employees pledged $154,713 to United Way in 2012. The employee participation rate was 73 percent, and 54 percent of employees pledged one hour of pay or more per month. The corporate donation was $40,000, making a total Big Rivers/ employee pledge of $194,713.

United Way and its partner agencies believe education is the cornerstone of individual and community success. United Way helps Americans achieve financial stability and works for a healthier America. Whether it is a neighbor without health insurance, a victim of abuse, or someone struggling with mental illness or an addiction, local United Ways are working to ensure everyone has access to affordable and quality care.

Big Rivers raises $3,360 towards March for Babies

Big Rivers and its employees raised $3,360 in 2012 for the Henderson/Union County March for Babies. Every donation received helps fight premature birth and birth defects. Collectively, the efforts of Big Rivers employees garnered several awards, including fourth place in team donations. Two Big Rivers employees were recognized individually—one for raising the highest amount of donations prior to the event and the other for turning in the largest amount of donations on the day of the event. The Henderson/Union County walk collected over $25,000 total in donations.

Sebree Station employees provide energy education to students

Union County High School brought a group of students to Big Rivers' Sebree Station for a power plant tour. The student group consisted of sophomores, juniors and seniors who visited with the goal of learning how energy is converted from coal to electricity.

Their two-hour session began with a classroom presentation that covered the basics of electricity generation, electricity transmission and power plant operations. In addition, the students learned about various fuel transportation mechanisms and the quantity of homes electrified from Big Rivers' generating capabilities.

The presentation also included information on the volume of coal required to fuel Sebree Station along with a discussion about the various components and diverse skill sets needed by employees to efficiently operate a generation and transmission company.

This tour provided an opportunity to explain the benefits of the electricity generated by Big Rivers and our environmental stewardship concerning air, soil and water.

Coleman Station food drive

Coleman Station employees collected non-perishable food, personal hygiene items, and cleaning supplies, and a monetary contribution for the Hancock County Food Pantry. The pantry provides for approximately 100 families ranging in size from two to eight who are struggling with basic necessities.

Headquarters employees Clothe-A-Kid for school

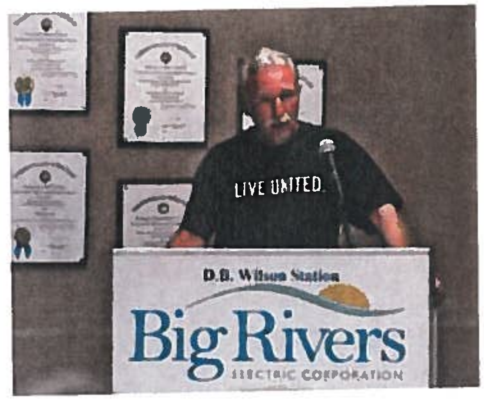
Headquarters employees raised money to help five needy school children begin the 2012 school year with new clothes. This "Clothe-A-Kid" program, an effort by the Volunteer and Information Center in Henderson, is based on a belief that education is key in breaking the cycle of poverty.

Wilson Station collects 540 pounds of non-perishable items

Wilson Station employees collected 540 pounds of non-perishable items near the end of November for the Friends of Sinners agency, a long-term substance recovery program that focuses on restoration from addictions.

Headquarters employees help area families have a bountiful Thanksgiving

Headquarters employees donated funds to the Henderson Volunteer and Information Center for its Bountiful Thanksgiving program. These dollars were enough to provide a Thanksgiving meal for six area families. Because Thanksgiving meals are not the same for every family, the Volunteer and Information Center provided families with vouchers from a local grocery store to purchase food items specific to their tastes.



Big Rivers and its employees pledged $194,713 to United Way in 2012.

Big Rivers and its employees raised $3,360 for the March for Babies.

Coleman and Wilson stations held food drives for local organizations.

Wilson Station employees donated clothing and toys to a local shelter.

Headquarters employees adopted two families for Christmas.

Sebree Station employees delivered Christmas gifts to eight families.

Wilson Station employees help 16 children celebrate Christmas

Wilson Station employees donated clothing and toys to provide a Merry Christmas for 16 children staying at the Daniel Pitino Shelter in Owensboro. The shelter offers both emergency and transitional housing, nutritional food, primary physical and mental health care, essential services, and educational enhancement. It has the capacity to serve 65 individuals—50 transitional and 15 emergency.

Headquarters employees adopt five children for Christmas

Headquarters employees donated money to the Henderson Volunteer and Information Center's Adopt-A-Family for Christmas program. This year Big Rivers adopted two families and provided two outfits of new clothing, undergarments, shoes, and a special gift for five children.

Sebree Station employees deliver Christmas Wish to eight families

Eight families had a much brighter Christmas because of Sebree Station employee participation in a Christmas Wish project. Employees who donated toys, clothing, food and hard-earned cash made a difference for these families.

NRECA honors the Philippine Project in recent video

In 1966, with a grant from the U.S. Agency of International Development and an invitation from the government of the Philippines, the National Rural Electric Cooperative Association (NRECA) International Programs began a long journey to electrify rural areas of the Philippines.

Starting with a feasibility study that established two pilot electric cooperatives, a national rural electrification program was initiated.

Since the first days of the program, 119 electric cooperatives have been established in the Philippines with assistance and guidance from NRECA International Programs, making the Philippines electrification effort one of the most successful over the International Programs' 50-year history. NRECA International highlighted the Philippine Project in a 12-minute video entitled "Light to Their Beloved Land: NRECA in the Philippines."

In the video, Travis Housley, retired Big Rivers vice president, discusses his planning, engineering and project facilitation efforts during more than 17 trips to the Philippines.

Providing shared services desired by our MEMBER-OWNERS

Energy Efficiency Programs available to customers

Big Rivers is working to advance the goals put forth by Governor Steve Beshear in his plan for Kentucky's energy independence. Strategy 1 of the governor's plan, Intelligent Energy Choices for Kentucky's Future, calls for Kentucky to improve energy efficiency in the residential, commercial, industrial, and transportation sectors by offsetting at least 18 percent of Kentucky's projected 2025 energy demand.

Big Rivers is committed to developing a robust set of cost-effective energy efficiency programs to help eliminate or delay the need for costly additional generating resources.

After the Unwind Transaction closed in 2009 and Big Rivers regained control of its generating units, Big Rivers and its three Member-Owners began taking steps to increase energy efficiency programs available to customers on the Big Rivers system beyond distribution of compact fluorescent light bulbs (CFLs). Big Rivers and its Member-Owners established a multicompany energy efficiency team to evaluate, design, and implement cost-effective energy efficiency programs.

The energy efficiency team evaluated over 200 residential and commercial energy efficiency measures and recommended cost-effective programs to be offered to customers as pilots in 2011. On March 16, 2012, Big Rivers filed tariffs with the PSC for nine energy efficiency programs developed based on the 2011 pilot programs. Subsequently, on April 20, 2012, Big Rivers filed a tariff for one additional energy efficiency program, bringing the total energy efficiency portfolio to 10 programs.

Residential energy efficiency programs include:

- Lighting replacement using CFL distribution
- ENERGY STAR clothes washer replacement
- ENERGY STAR refrigerator replacement
- ENERGY STAR heating/ ventilation/air conditioning equipment upgrades
- Weatherization of electric and gas heating systems
- Heating/ventilation/ air conditioning and refrigeration tune-up
- Touchstone Energy new home construction standards

Commerical/industrial energy efficiency programs include:

- Lighting replacement
- Equipment replacement
- Heating/ventilation/ air conditioning and refrigeration tune-up

Big Rivers and its Member-Owners spent more than $600,000 toward these energy efficiency programs in 2012. It is estimated the programs saved retail Members a total of 4,967 MWh. Winter peak demand was estimated to be reduced by 1.25 MW, and summer peak demand was reduced by 0.9 MW.

Big Rivers anticipates that its slate of energy efficiency programs will expand in the future as the multicompany energy efficiency team continues to evaluate other potential measures to offer, including demand response opportunities.

Financial Review: 2012

Big Rivers' mission is to safely provide low-cost, reliable wholesale electricity and cost-effective shared services to three Member-Owner distribution cooperatives—Jackson Purchase Energy Corporation, Kenergy Corp. and Meade County Rural Electric Cooperative Corporation. As of December 31, 2012, the Member-Owners provide service to approximately 113,000 retail customers in 22 western Kentucky counties.

Big Rivers operates 1,444 MW of owned generating facilities and has contractual rights to 197 MW from the Station Two unit owned by Henderson Municipal Power & Light and to 178 MW from the Southeastern Power Administration (SEPA). The company also owns transmission assets, principally 1,285 miles of transmission lines and 22 transmission substations. Net utility plant at December 31, 2012 was $1,087.2 million, and total assets were $1,546.7 million.

The two aluminum smelter wholesale contracts with Kenergy Corp. were scheduled to terminate December 31, 2023. On August 20, 2012, Big Rivers as wholesale power supplier, and Kenergy Corp. (Kenergy) as retail power supplier, received a letter from Century Aluminum of Kentucky General Partnership (Century), serving its one-year Notice of Termination of its Retail Service Agreement with Kenergy, effective August 20, 2013. On January 31, 2013, Alcan Primary Products Corporation (Alcan) provided its one-year Notice of Termination of its Kenergy Retail Service Agreement to Big Rivers and Kenergy, effective January 31, 2014. Both smelters indicated they were ceasing all smelter operations at their Hawesville, Kentucky and Robards, Kentucky facilities, respectively.

Upon receipt of the first Notice of Termination, Big Rivers began implementing its formal Load Concentration Mitigation Plan. This plan encompasses, in part, the filing of a general rate increase with the PSC which was done on January 15, 2013. In addition, Big Rivers is actively pursuing replacement load for the 850 MW currently used by Century and Alcan. Big Rivers also anticipates a second general rate case filing with the PSC in June 2013 as a result of Alcan's departure.

Big Rivers completed 2012 with a favorable set of key financial metrics, discussed in the pages that follow.

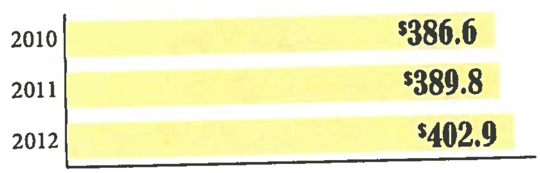
Net Margins and Equities

The 2012 net margin was $11.3 million, resulting in a 1.25 times interest earned ratio (TIER) and margins for interest ratio (MFIR), and a 1.58 debt service coverage ratio (DSCR). Equities to total assets were 26 percent at December 31, 2012, and equities to total capitalization were 30 percent.

Several items account for the majority of the $5.7 million improvement in the 2012 net margin compared with the 2011 net margin of $5.6 million. Firstly, net sales margins (electric sales revenue less variable operations costs) for 2012 reflect a $10.1 million improvement. This is principally due to a full year of the Member-Owner base rate increase that became effective in September 2011, higher smelter sales volumes, and lower reagent, fuel and purchased power variable operations costs—offset by depressed off-system market prices and lower sales volumes. Maintenance expense reflects a favorable variance of $1.8 million to offset depressed off-system market prices. Interest expense reflects a favorable variance of $0.8 million on long-term debt, and interest income reflects

Net Margins
Dollars in millions

Equity
Dollars in millions



Energy Sales
Megawatt-hours (MWhs) in millions

Electric Energy Revenues
Dollars in millions

a favorable variance of $0.8 million—both as a result of the July 2012 refinancing. Offsetting the improvement is a $5.7 million increase in depreciation expense in 2012. This is due to a full year of higher depreciation rates resulting from the 2010 depreciation study implemented in December 2011 following PSC approval.

Energy Sales and Electric Energy Revenues

Energy sales decreased to 12,244,082 MWh in 2012, down from 13,255,125 MWh in 2011. The primary reason for the MWh sales decrease was a reduction of 1,519,273 MWh or 49.71 percent in off-system sales volume, driven by lower market pricing. Smelter sales volumes increased 569,653 MWh or 8.31 percent in 2012, providing some offset.

Non-smelter Member sales decreased 61,421 MWh in 2012, or 1.84 percent, driven by weather. Electric energy revenue increased to $563.4 million in 2012, up from $558.4 million in 2011. The increase in revenue is due to a full year of the base rate increase coupled with higher smelter sales volumes and lower variable operations costs, partly offset by lower off-system sales revenue.

Wholesale Rates

Big Rivers has all-requirements wholesale power contracts with its Member-Owners through December 31, 2043. Rural Member wholesale revenue per

MWh was $50.58 in 2012 versus $46.78 in 2011. Large industrial Member wholesale revenue per MWh was $43.15 in 2012 versus $41.68 in 2011. The non-smelter Member revenue per MWh increase in 2012 is primarily due to a full year of increased base rates. Aluminum smelter wholesale revenue per MWh was $48.52 in 2012 versus $44.48 in 2011. Big Rivers' wholesale Member tariff rate and the aluminum smelter contracts are regulated by the PSC and RUS.

Wholesale power market prices continue to be depressed, as has been the case since 2008. The revenue per MWh received by Big Rivers for its off-system sales was $28.81 in 2012, down from $33.38 received in 2011, and significantly below the off-system sales rate of $48.03 received in 2007.

Lines of Credit and Letters of Credit

Big Rivers has two $50 million lines of credit—one with CoBank, expiring July 2017, and the other with CFC, expiring July 2014. The CFC line of credit contains a $10 million embedded letter of credit facility. At December 31, 2012, letters of credit totaling $5.4 million are outstanding with CFC.

As the result of the contract termination notice rendered by Century on August 20, 2012, Big Rivers, based on current language in its line of credit agreements, does not have access to borrow under the CoBank line of credit as of December 31, 2012, and will lose access to the CFC line of credit on August 20, 2013 (the date on which Century's contract terminates). Big Rivers is currently in negotiations with CoBank and CFC to modify the language in the line of credit agreements to ensure it has access to the lines of credit upon termination of the Century agreement. Amendments to these agreements are subject to approval by the PSC.

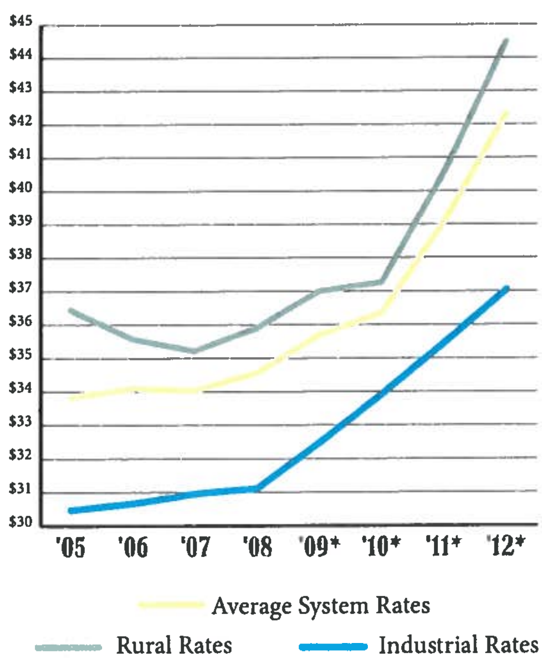
Long-term Debt

At December 31, 2012, debt to total assets is 60 percent. During July 2012, Big Rivers refinanced $442 million of existing debt under its RUS Series A Note with new secured term loans, at lower interest rates, through CFC and CoBank. The CFC term loans consist of a Refinance Note, with an all-in effective interest rate of 4.50 percent, and an Equity Note, with a fixed interest rate 5.35 percent, which was used to purchase interest-bearing Capital Term Certificates (CTC). Both term loans and the CTC

Wholesale Member-Owner Rates*

Dollars per megawatt-hour (MWh)

** Note that: 2009, 2010, 2011 and 2012 rates reflect a reduction due to the Member Rate Stability Mechanism*



have final maturity dates of July 2032. As of December 31, 2012, the CFC Refinance and Equity Notes have outstanding principal balances of $298.5 million and $42.8 million, respectively. The CoBank secured term loan has a fixed interest rate of 4.30% and an outstanding principal balance of $231.4 million as of December 31, 2012, with a final maturity date of June 2032. The RUS Series A Note has a fair value of $80 million at December 31, 2012 and a stated value of $80.4 million, with a final maturity date of July 2021. The non-interest bearing RUS Series B Note, having a December 31, 2012 fair value of $130.3 million and a stated value of $245.5 million, has no payment due until maturity in December 2023.

Big Rivers has two issues of tax-exempt pollution control bonds outstanding, totaling $142.1 million. The larger of the two issues was refinanced June 8, 2010— the $83.3 million County of Ohio, Kentucky, Pollution Control Revenue Bonds, Series 2010A. These Series 2010A Bonds bear interest at a 6 percent fixed rate, with a maturity date of July 2031.

The second issue—the $58.8 million County of Ohio, Kentucky, Pollution Control Revenue Bonds, Series 1983 (1983 Bonds)—are variable rate demand bonds currently being held by the liquidity provider, bearing an interest rate of 3.25 percent. These bonds have a maturity date of June 2013.

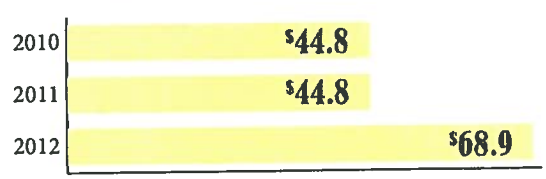
Liquidity

Big Rivers' liquidity position remains strong, as cash and cash equivalents total $68.9 million and restricted cash totals $41.3 million at December 31, 2012. This amount is restricted by a PSC order and is to be used for capital expenditures in the ordinary course of business. Additionally, Big Rivers has access to the existing CFC line of credit totaling $50 million discussed earlier, until August 19, 2013.

In November 2012, Big Rivers filed a financing application with the PSC requesting access to the $35 million Transition Reserve, held in restricted investments at December 31, 2012, and approval to repay the 1983 Bonds from repurposed funds currently restricted by previously issued orders of the PSC. The PSC issued an order on March 26, 2013, granting the approval sought by Big Rivers in this matter.

Capital expenditures totaled $39.8 million in 2012, versus $38.7 million in 2011.

Cash and Cash Equivalents
Dollars in millions



KPMG LLP
1601 Market Street
Philadelphia, PA 19103-2499

Independent Auditors' Report

The Board of Directors and Members
Big Rivers Electric Corporation:

Report on the Financial Statements

We have audited the accompanying financial statements of Big Rivers Electric Corporation, which comprise the balance sheets as of December 31, 2012 and 2011, and the related statements of operations, comprehensive income, equities (deficit), and cash flows for each of the years in the three-year period ended December 31, 2012, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with U.S. generally accepted accounting principles; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial statement audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

KPMG

Opinion

In our opinion, the financial statements referred to above present fairly in all material respects, the financial position of Big Rivers Electric Corporation as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2012, in accordance with U.S. generally accepted accounting principles.

Report on Other Legal and Regulatory Requirements

In accordance with *Government Auditing Standards*, we have also issued a report dated March 29, 2013, on our consideration of Big Rivers Electric Corporations' internal control over financial reporting and our tests of their compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. The report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be read in conjunction with this report in assessing the results of our audits.

KPMG LLP

Philadelphia, Pennsylvania
March 29, 2013

Balance Sheets

As of December 31, 2012 and 2011 — (Dollars in thousands)

	2012	2011
Assets		
Utility plant – net	$1,087,227	$1,092,063
Restricted investments – Member rate mitigation	144,514	163,162
Restricted investments – Transition reserve	35,009	-
Restricted investments – NRUCFC Capital Term Certificates	43,156	-
Other deposits and investments – at cost	6,092	5,911
Current assets:		
Cash and cash equivalents	68,860	44,849
Restricted cash	41,313	-
Accounts receivable	48,376	44,287
Fuel inventory	34,146	33,894
Nonfuel inventory	24,957	25,295
Prepaid expenses	4,093	4,217
Total current assets	221,745	152,542
Deferred charges and other	8,935	4,244
Total	$1,546,678	$1,417,922
Equities and Liabilities		
Capitalization:		
Equities	$ 402,882	$ 389,820
Long-term debt	845,317	714,254
Total capitalization	1,248,199	1,104,074
Current liabilities:		
Current maturities of long-term obligations	79,926	72,145
Purchased power payable	1,402	1,878
Accounts payable	31,611	28,446
Accrued expenses	10,955	10,380
Accrued interest	4,925	9,899
Total current liabilities	128,819	122,748
Deferred credits and other:		
Regulatory liabilities – Member rate mitigation	147,732	169,001
Other	21,928	22,099
Total deferred credits and other	169,660	191,100
Commitments and Contingencies (see Note 12)		
Total	$1,546,678	$1,417,922

See accompanying notes to financial statements.

Statements of Operations

For the years ended December 31, 2012, 2011, and 2010 — (Dollars in thousands)

	2012	2011	2010
Operating revenue	$ 568,342	$ 561,989	$ 527,324
Total operating revenue	568,342	$ 561,989	$ 527,324
Operating expenses:			
Operations:			
Fuel for electric generation	226,369	226,229	207,749
Power purchased and interchanged	111,465	112,262	99,421
Production, excluding fuel	48,055	50,410	52,507
Transmission and other	40,189	39,085	35,273
Maintenance	45,962	47,718	46,880
Depreciation and amortization	41,090	35,407	34,242
Total operating expenses	513,130	511,111	476,072
Electric operating margin	55,212	50,878	51,252
Interest expense and other:			
Interest	44,414	45,226	46,570
Income tax expense	—	100	259
Other – net	546	220	166
Total interest expense and other	44,960	45,546	46,995
Operating margin	10,252	5,332	4,257
Non-operating margin:			
Interest income and other	1,025	268	2,734
Total nonoperating margin	1,025	268	2,734
Net margin	$ 11,277	$ 5,600	$ 6,991

See accompanying notes to financial statements.

Statements of Comprehensive Income

For the years ended December 31, 2012, 2011, and 2010 — (Dollars in thousands)

	2012	2011	2010
Net margin	$ 11,277	$ 5,600	$ 6,991
Other comprehensive income:			
Defined benefit plans:			
Prior service cost	14	14	19
Unamortized actuarial gain (loss)	1,035	(1,797)	297
Defined benefit plans	1,049	(1,783)	316
Postretirement benefits other than pensions			
Prior service cost	1,974	17	17
Unamortized actuarial gain (loss)	(1,269)	(620)	(172)
Transition obligation	31	31	31
Postretirement benefits other than pensions	736	(572)	(124)
Other comprehensive income (loss)	1,785	(2,355)	192
Comprehensive income	$ 13,062	$ 3,245	$ 7,183

Statements of Equities (Deficit)

For the years ended December 31, 2012, 2011, and 2010 — (Dollars in thousands)

	Total equities	Retained margin (deficit)	Other equities: Donated capital and memberships	Other equities: Consumers' contributions to debt service	Accumulated other comprehensive loss
Balance – December 31, 2009	$ 379,392	$ 384,507	$ 764	$ 3,681	$ (9,560)
Net margin	6,991	6,991	–	–	–
Pension and postretirement benefit plans	192	–	–	–	192
Balance – December 31, 2010	386,575	391,498	764	3,681	(9,368)
Net margin	5,600	5,600	–	–	–
Pension and postretirement benefit plans	(2,355)	–	–	–	(2,355)
Balance – December 31, 2011	$ 389,820	$ 397,098	$ 764	$ 3,681	$(11,723)
Net margin	11,277	11,277	–	–	–
Pension and postretirement benefit plans	1,785	–	–	–	1,785
Balance – December 31, 2012	$ 402,882	408,375	764	3,681	(9,938)

See accompanying notes to financial statements.

Statements of Cash Flows

For the years ended December 31, 2012, 2011, and 2010 — (Dollars in thousands)

	2012	2011	2010
Cash flows from operating activities:			
Net margin	$ 11,277	$ 5,600	$ 6,991
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization	44,733	37,808	37,650
Interest compounded - RUS Series A Note	7,603	8,398	-
Interest compounded - RUS Series B Note	7,291	6,884	6,499
Noncash Member rate mitigation revenue	(22,873)	(18,947)	(23,953)
Changes in certain assets and liabilities:			
Accounts receivable	(4,090)	1,618	1,588
Inventories	87	1,357	(2,304)
Prepaid expenses	124	(1,715)	731
Deferred charges	(1,278)	121	1,251
Purchased power payable	(476)	362	(1,846)
Accounts payable	3,164	(1,336)	(875)
Accrued expenses	(4,399)	(1,481)	2,800
Other – net	278	(70)	555
Net cash provided by operating activities	41,441	38,599	29,087
Cash flows from investing activities:			
Capital expenditures	(39,853)	(38,746)	(42,683)
Proceeds from restricted investments	(58,094)	56,095	28,143
Purchases of restricted investments and other deposits & investments	146	-	-
Change in restricted cash	(41,313)	-	-
Net cash provided by (used in) investing activities	(139,114)	17,349	(14,540)
Cash flows from financing activities:			
Principal payments on long-term obligations	(456,206)	(45,879)	(121,355)
Proceeds from long-term obligations	580,156	-	83,300
Principal payments on short-term notes payable	-	(10,000)	-
Proceeds from short-term notes payable	-	-	10,000
Debt issuance cost on bond refunding	(2,266)	-	(2,002)
Net cash provided by (used in) financing activities	121,684	(55,879)	(30,057)
Net increase in cash and cash equivalents	24,011	69	(15,510)
Cash and cash equivalents — beginning of year	44,849	$ 44,780	$ 60,290
Cash and cash equivalents — end of year	$ 68,860	$ 44,849	$ 44,780
Supplemental cash flow information:			
Cash paid for interest	$ 34,893	$ 31,441	$ 37,268
Cash paid for income taxes	-	$ 130	$ 260

See accompanying notes to financial statements.

Notes to Financial Statements

As of December 31, 2012 and 2011 — (Dollars in thousands)

1. Organization and Summary of Significant Accounting Policies

(a) General Information

Big Rivers Electric Corporation (Big Rivers or the Company), an electric generation and transmission cooperative, supplies wholesale power to its three member distribution cooperatives (Kenergy Corp., Jackson Purchase Energy Corporation, and Meade County Rural Electric Cooperative Corporation) under all requirements contracts, excluding the power needs of two large aluminum smelters (the Aluminum Smelters). Additionally, Big Rivers sells power under separate contracts to Kenergy Corp. for the Aluminum Smelters load and markets power to nonmember utilities and power marketers. The members provide electric power and energy to industrial, residential, and commercial customers located in portions of 22 western Kentucky counties. The wholesale power contracts with the members remain in effect until December 31, 2043. Rates to Big Rivers' members are established by the Kentucky Public Service Commission (KPSC) and are subject to approval by the Rural Utilities Service (RUS). The financial statements of Big Rivers include the provisions of the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 980, *Regulated Operations*, which was adopted by the Company in 2003, and gives recognition to the ratemaking and accounting practices of the KPSC and RUS.

Management evaluated subsequent events up to and including March 29, 2013, the date the financial statements were available to be issued.

(b) Estimates

The preparation of the financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and disclosure of contingent assets and liabilities. The estimates and assumptions used in the accompanying financial statements are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results may differ from those estimates.

(c) System of Accounts

Big Rivers' maintains its accounting records in accordance with the Uniform System of Accounts as prescribed by the RUS Bulletin 1767B 1, as adopted by the KPSC. These regulatory agencies retain authority and periodically issue orders on various accounting and ratemaking matters. Adjustments to RUS accounting have been made to make the financial statements consistent with generally accepted accounting principles in the United States of America.

(d) Revenue Recognition

Revenues generated from the Company's wholesale power contracts are based on month-end meter readings and are recognized as earned.

(e) Utility Plant and Depreciation

Utility plant is recorded at original cost, which includes the cost of contracted services, materials, labor, overhead, and an allowance for borrowed funds used during construction. Replacements of depreciable property units, except minor replacements, are charged to utility plant.

Allowance for borrowed funds used during construction is included on projects with an estimated total cost of $250 or more before consideration of such allowance. The interest capitalized is determined by applying the effective rate of Big Rivers' weighted average debt to the accumulated expenditures for qualifying projects included in construction in progress.

Depreciation of utility plant in service is recorded using the straight-line method over the estimated remaining service lives, as approved by the RUS and KPSC. During 2010, the Company commissioned a depreciation study to evaluate the remaining economic lives of its assets. In 2011, the study was completed and approved by the RUS and KPSC. The annual composite depreciation rates used to compute depreciation expense were as follows:

Electric plant	0.50%–20.22%
Transmission plant	1.42%–02.23%
General plant	2.84%–17.12%

For 2012, 2011, and 2010, the average composite depreciation rates were 2.23%, 1.91%, and 1.86%, respectively. At the time plant is disposed of, the original cost plus cost of removal less salvage value of such plant is charged to accumulated depreciation, as required by the RUS.

(f) Impairment Review of Long-Lived Assets

Long-lived assets are reviewed as facts and circumstances indicate that the carrying amount may be impaired. FASB ASC 360, *Property, Plant, and Equipment*, requires the evaluation of impairment by comparing an asset's carrying value to the estimated future cash flows the asset is expected to generate over its remaining life. If this evaluation were to conclude that the future cash flows were not sufficient to recover the carrying value of the asset, an impairment charge would be recorded based on the difference between the asset's carrying amount and its fair value (less costs to sell for assets to be disposed of by sale) as a charge to net margin.

(g) Inventory

Inventories are carried at average cost and include coal, petroleum coke, lime, limestone, oil and gas used for electric generation, and materials and supplies used for utility operations. Emission allowances are carried in inventory at a weighted average cost by each vintage year. Issuances of allowances are accounted for on a vintage basis using a monthly weighted average cost.

(h) Restricted Investments

Investments are restricted under KPSC order to establish certain reserve funds for member rate mitigation and a Transition Reserve as described in note 5. These investments have been classified as held to maturity and are carried at amortized cost. In addition, Big Rivers was required to purchase investments in National Rural Utilities Cooperative Finance Corporation's (CFC) Capital Term Certificates (CTCs) in connection with a secured term loan agreement with CFC (note 8), which are also classified as held-to-maturity.

(i) Cash and Cash Equivalents

Big Rivers considers all short term, highly liquid investments with original maturities of three months or less to be cash equivalents.

(j) Restricted Cash

Certain cash amounts are restricted under KPSC order for capital expenditures in the ordinary course of business (note 9).

(k) Income Taxes

Big Rivers was formed as a tax-exempt cooperative organization as described in Internal Revenue Code Section 501(c)(12). To retain tax-exempt status under this section, at least 85% of the Big Rivers' receipts must be generated from transactions with the Company's members. In 1983, sales to nonmembers resulted in Big Rivers failing to meet the 85% requirement. Until Big Rivers can meet the 85% member income requirement, the Company will not be eligible for tax-exempt status and will be treated as a taxable cooperative.

As a taxable cooperative, Big Rivers is entitled to exclude the amount of patronage allocations to members from taxable income. Income and expenses related to nonpatronage-sourced operations are taxable to Big Rivers. Big Rivers files a federal income tax return and certain state income tax returns.

Under the provisions of FASB ASC 740, *Income Taxes*, Big Rivers is required to record deferred tax assets and liabilities for temporary differences between amounts reported for financial reporting purposes and amounts reported for income tax purposes. Deferred tax assets and liabilities are determined based upon these temporary differences using enacted tax rates for the year in which these differences are expected to reverse. Deferred income tax expense or benefit is based on the change in assets and liabilities from period to period, subject to an ongoing assessment of realization. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the more likely than not recognition threshold is satisfied and measured at the largest amount of benefit that is greater than 50% likely of being realized upon settlement.

(l) Patronage Capital

As provided in the bylaws, Big Rivers accounts for each year's patronage sourced income, both operating and nonoperating, on a patronage basis. Notwithstanding any other provision of the bylaws, the amount to be allocated as patronage capital for a given year shall not be less than the greater of regular taxable patronage-sourced income or alternative minimum taxable patronage sourced income.

(m) Derivatives

Management has reviewed the requirements of FASB ASC 815, *Derivatives and Hedging*, and has determined that certain contracts the Company is party to may meet the definition of a derivative under FASB ASC 815. The Company has elected the Normal Purchase and Normal Sale exception for these contracts, and therefore, the contracts are not required to be recognized at fair value in the financial statements.

(n) Fair Value Measurements

FASB ASC 820, *Fair Value Measurement*, defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal, or most advantageous, market for the asset or liability in an orderly transaction between market participants at the measurement date. FASB ASC 820 establishes a three level fair value hierarchy that prioritizes the inputs used to measure fair value. This hierarchy requires entities to maximize the use of observable inputs when possible. The three levels of inputs used to measure fair value are as follows:

- Level 1 – quoted prices in active markets for identical assets or liabilities;
- Level 2 – observable inputs other than quoted prices included in Level 1, such as quoted prices for similar assets and liabilities in active markets; quoted prices for identical or similar assets and liabilities in markets that are not active; or other inputs that are observable or can be corroborated by observable market data; and
- Level 3 – unobservable inputs that are supported by little or no market activity and that are significant to the fair values of the assets or liabilities, including certain pricing models, discounted cash flow methodologies, and similar techniques that use significant unobservable inputs.

2. Utility Plant

At December 31, 2012 and 2011, utility plant is summarized as follows:

	2012	2011
Classified plant in service:		
Production plant	$1,715,486	$1,706,243
Transmission plant	248,276	238,738
General plant	35,103	33,744
Other	543	543
	1,999,408	1,979,268
Less accumulated depreciation	962,994	936,355
	1,036,414	1,042,913
Construction in progress	50,813	49,150
Utility plant — net	$1,087,227	$1,092,063

Interest capitalized for the years ended December 31, 2012, 2011, and 2010, was $767, $548, and $684, respectively.

The Company has not identified any material legal asset retirement obligations, as defined in FASB ASC 410, *Asset Retirement and Environmental Obligations*. In accordance with regulatory treatment, the Company records an estimated net cost of removal of its utility plant through normal depreciation. As of December 31, 2012 and 2011, the Company had approximately $43,559 and $41,449, respectively, related to nonlegal removal costs included in accumulated depreciation.

3. Debt and Other Long-Term Obligations

A detail of long-term debt at December 31, 2012 and 2011 is as follows:

	2012	2011
CFC Refinance Promissory Note, Series 2012 B, serial note pricing, all-in effective interest rate of 4.50%, final maturity date of July 2032	$298,513	-
CFC Equity Note, Series 2012B, stated interest rate of 5.35%, final maturity date of July 2032	42,845	-
CoBank Promissory Note, Series 2012A, stated interest rate of 4.30%, final maturity date of June 2032	231,426	-
RUS Series A Promissory Note, stated amount of $80,456, stated interest rate of 5.75%, with an imputed interest rate of 5.84% maturing July 2021	$80,019	521,250
RUS Series B Promissory Note, stated amount of $245,530, no stated interest rate, with interest imputed at 5.80%, maturing December 2023	130,340	123,049
County of Ohio, Kentucky, promissory note, fixed interest rate of 6.00%, maturing in July 2031	83,300	83,300
County of Ohio, Kentucky, promissory note, variable interest rate (average interest rates of 3.25% and 3.30% in 2012 and 2011, respectively), maturing in June 2013	58,800	58,800
Total long-term debt	925,243	786,399
Current maturities	79,926	72,145
Total long-term debt — net of current maturities	$845,317	714,254

The following are scheduled maturities of long-term debt at December 31:

Year	Amount
2013	79,926
2014	20,127
2015	20,903
2016	21,717
2017	22,576
Thereafter	759,994
Total	$925,243

(a) National Rural Utilities Cooperative Finance Corporation (CFC) Refinance and Equity Promissory Notes, 2012B

In July 2012, Big Rivers issued new debt with CFC in the form of a secured term loan in the amount of $302,000 (the Refinance Note) and a CFC Equity Note in the amount of $43,156. The Refinance Note consists of 20 individual notes with different fixed interest rates ranging from 3.05% to 5.35%. The Refinance Note has an all-in effective interest rate of 4.50% and a final maturity date of July 2032. The Equity Note has a fixed interest rate of 5.35% and a final maturity date of July 2032. The proceeds of the Refinance Note were used to prepay $302,000 of the RUS Series A Note. The proceeds of the CFC Equity Note were used to purchase interest-bearing Capital Term Certificates (CTCs), as required in connection with the Refinance Note (note 8).

(b) CoBank, ACB (CoBank) Promissory Note, Series 2012A

In July 2012, Big Rivers issued new debt with CoBank in the form of a secured term loan in the amount of $235,000. The loan has a fixed interest rate of 4.30% per annum and a final maturity date of June 2032. Proceeds from the CoBank term loan were used to prepay $140,000 of the RUS Series A Note and replenish the $35,000 Transition Reserve fund (depleted on April 1, 2011 to prepay the RUS Series A Note and realize a net interest expense reduction). The remaining $60,000 will be used to fund capital expenditures in the ordinary course of business or to refinance existing debt (note 5).

(c) RUS Notes

On July 15, 2009, Big Rivers' previous RUS debt was replaced with the RUS 2009 Promissory Note Series A (the RUS Series A Note) and the RUS 2009 Promissory Note Series B (the RUS Series B Note). The RUS Series A Note is recorded at an interest rate of 5.84%. The RUS Series B Note is recorded at an imputed interest rate of 5.80%. The RUS Notes are secured under the Indenture dated July 1, 2009 between the Company and U.S. Bank National Association.

In July 2012, Big Rivers prepaid $442,000 of the RUS Series A Note from proceeds of the CFC and CoBank term loans as described above.

(d) Pollution Control Bonds

In June 2010, the County of Ohio, Kentucky, issued $83,300 of Pollution Control Refunding Revenue Bonds, Series 2010A (Series 2010A Bonds), the proceeds of which are supported by a promissory note from Big Rivers, which bears the same interest rate. These bonds bear interest at a fixed rate of 6.00% and mature in July 2031.

The County of Ohio, Kentucky, issued $58,800 of Pollution Control Variable Rate Demand Bonds, Series 1983 (Series 1983 Bonds), the proceeds of which are supported by a promissory note from Big Rivers, which bears the same interest rate as the bonds. These bonds bear interest at a variable rate, subject to a maximum interest rate of 13.00%, and mature in June 2013. As of December 31, 2012, the interest rate on the Series 1983 Bonds was 3.25%.

The Series 1983 Bonds are supported by a liquidity facility issued by Credit Suisse First Boston, which was assigned to Dexia Credit in 2006. In addition, the Series 1983 Bonds are supported by a municipal bond insurance and surety policy issued by Ambac Assurance Corporation. Big Rivers has agreed to reimburse Ambac Assurance Corporation for any payments under the municipal bond insurance policy or the surety policy. Both Series are secured by the Indenture dated July 1, 2009 between the Company and U.S. Bank National Association.

(e) Lines of Credit

The Company has lines of credit with the National Rural Utilities Cooperative Finance Corporation (CFC) and CoBank, ACB (CoBank). In July 2012, a new unsecured CoBank line-of-credit facility (the CoBank Revolver),with a five-year term, was established to replace the line-of-credit facility dated July 2009, having a three-year term. The CFC line-of-credit facility (the CFC Revolver) is for a five-year term and will terminate in July 2014. The maximum borrowing capacity on the Revolvers is $100,000 consisting of $50,000 each for CFC and CoBank. In March 2011, Big Rivers paid down the $10,000 of borrowings outstanding on the CoBank Revolver at December 31, 2010. The Company had no borrowings outstanding on the Revolvers at December 31, 2012 and 2011. Letters of credit issued under an associated Letter of Credit Facility with CFC reduced the borrowing capacity on the CFC Revolver by $5,375 for years ended December 31, 2012 and 2011.

As the result of a contract termination notice rendered by Century Aluminum Company on August 20, 2012 (note 5), Big Rivers, based on current language in its line-of-credit agreements, does not have access to borrow under the CoBank Revolver and will lose access to the CFC Revolver on August 20, 2013 (the date on which Century indicated it will terminate and cease aluminum smelting operations at the Hawesville Smelter). The Company is currently in negotiations with both CoBank and CFC to modify the language in the line-of-credit agreements to ensure it has access to the Revolvers upon termination of the Century agreement. Amendments to these agreements are subject to approval by the KPSC.

Advances on the CFC Revolver bear interest at a variable rate and outstanding balances are payable in full by the maturity date of July 16, 2014. The CFC variable rate is equal to the CFC Line-of-Credit Rate, which is defined as "the rate published by CFC from time to time, by electronic or other means, for similarly classified lines of credit, but if not published, then the rate determined for such lines of credit by CFC from time to time." Advances on the CoBank Revolver may be made as either London Interbank Offered Rate Loans or Base Rate Loans. LIBOR Loans bear interest at a rate per annum equal to the LIBOR Rate determined for such day plus the Applicable Margin for each day during the Interest Period. The Applicable Margin is determined based on the Company's credit rating. The Interest Period commences on the borrowing, continuation, or conversion date and ends on the numerically corresponding day, either one, two, three, six, nine, or twelve months thereafter, as selected by the Company. Base Rate Loans bear interest at a rate per annum equal to the Base Rate plus the Applicable Margin. The Base Rate is defined as "the rate of interest in effect from day to day defined as a rate per annum announced by the Administrative Agent on the first Banking Day of each week equal to the greatest of (A) 100 basis points greater than the LIBOR or (B) the Prime Rate."

On February 25, 2011, a $2,500 CFC line of credit, available to the Company to finance storm emergency repairs and expenses related to electric utility operations, matured.

(f) Covenants

Big Rivers is in compliance with all debt covenants associated with both long-term and short-term debt. The Company's Indenture and other debt agreements require that a Margins for Interest Ratio (MFIR) of at least 1.10 be maintained for each fiscal year. The CoBank line-of-credit agreement requires that the Company have a Total Debt to Total Capitalization Ratio of no greater than 80% at the end of each fiscal year, and the CFC line-of-credit agreement requires an Equity to Asset Ratio of no less than 12%. Big Rivers' MFIR for the fiscal year ended December 31, 2012 was 1.25. Big Rivers' Total Debt to Total Capitalization Ratio, as of December 31, 2012, was 70% and its Equity to Asset Ratio was 26%. The CoBank Revolver that expired and was replaced in July 2012 included a Debt Service Coverage Ratio reporting requirement. Big Rivers existing debt agreements do not have a Debt Service Coverage Ratio requirement.

A MFIR less than 1.10, per the Indenture and other debt agreements, results in the following actions, restrictions or consequences: Big Rivers cannot secure additional debt under the Indenture; the Company must seek rates that are reasonably expected to yield a 1.10 MFIR; in consultation with RUS, the Company must provide a written plan satisfactory to the RUS setting forth actions to be taken to achieve the specified MFIR on a timely basis; can result in an event of default and increased interest rates; termination of lines of credit and acceleration of outstanding amounts under the lines of credit.

4. Rate Matters

The rates charged to Big Rivers' members consist of a demand charge per kilowatt (kW) and an energy charge per kilowatt-hour (kWh) consumed as approved by the KPSC. The rates include specific demand and energy charges for its members' two classes of customers, the large industrial customers, and the rural customers under its jurisdiction. For the large industrial customers, the demand charge is generally based on each customer's maximum demand during the current month. Effective September 1, 2011, the Company received approval from the KPSC to base the member rural demand charge on its Maximum Adjusted Net Local Load (as defined in Big Rivers tariff).

Effective July 17, 2009, the KPSC approved the implementation of certain tariff riders; including a fuel adjustment clause and an environmental surcharge, offset by an unwind surcredit (a refund to tariff members of certain charges collected from the Aluminum Smelters in accordance with the contract terms). The net effect of these tariffs is recognized as revenue on a monthly basis with a partial offset to the regulatory liability – member rate mitigation described below.

The net impact of the tariff riders to members' rates is currently mitigated by a Member Rate Stability Mechanism (MRSM) that is funded by certain cash reserves (the Economic and Rural Economic Reserves) established and held by Big Rivers as restricted investments. An offsetting regulatory liability – member rate mitigation reflects the obligation associated with the funding of these reserve accounts.

On March 1, 2011, the Company filed an application with the KPSC requesting, among other things, authority to adjust its rates for wholesale electric service. The KPSC entered an order on November 17, 2011, granting Big Rivers an annual revenue increase of $26,745. Big Rivers petitioned for and was granted a rehearing by the KPSC to address certain issues. The KPSC later expanded the scope of the rehearing to include other issues raised by one of the intervenors in the case. An evidentiary hearing was held by the KPSC in September 2012 and an order was issued January 29, 2013. The KPSC order granted the Company an additional increase in annual revenues of approximately $1,043 effective retroactive to September 1, 2011 (the effective date of the rates granted on November 17, 2011 order).

Under the Aluminum Smelters' agreements, the wholesale rates established for the members' nonsmelter large direct-served industrial customers (the Large Industrial Rate) provide the basis for pricing the energy consumed by the Aluminum Smelters (Century Aluminum Company and Alcan Primary Products Corporation). The primary component of the pricing used for the Aluminum Smelters is an energy charge in dollars per megawatt hour (MWh) determined by applying the Large Industrial Rate to a load with a 98% load factor, and adding an additional charge of $0.25 per MWh. The other components reflected in the pricing of the Aluminum Smelters' energy usage are certain charges and credits as provided for under the terms of the Aluminum Smelters' wholesale electric service agreements between Big Rivers and Kenergy Corp. (Kenergy Corp. is the retail provider for the Aluminum Smelters load).

5. Aluminum Smelters Termination Notices

On August 20, 2012, Big Rivers as wholesale power supplier, and Kenergy Corp. (Kenergy) as retail power supplier, received a letter from Century Aluminum Company (Century) serving Notice of Termination of its Retail Service Agreement with Kenergy. Big Rivers provided notification to the three credit rating agencies and certain creditors, in accordance with its debt covenant requirements, of the Century termination notice. As a result of Century's notice, two credit rating agencies revised their Outlook for Big Rivers to negative from stable and the other revised Outlook from stable to under review for further downgrade during late August of 2012. Standard & Poor's Rating Services (Standard & Poor's) and Fitch Ratings (Fitch) maintained their credit ratings at BBB-, while Moody's Investors Service, Inc. (Moody's) downgraded its rating of Big Rivers' Series 2010A Bonds (in the amount of $83,300) to Baa2 from Baa1 and placed the rating under review. Big Rivers has developed and is in the process of implementing its Load Concentration Mitigation Plan (LCMP) to preserve its financial position notwithstanding Century's termination, which will become effective August 20, 2013. On January 15, 2013, Big Rivers filed an application for a $74,500 increase in rates with the KPSC — the first phase of its mitigation plan. Big Rivers' rate request represents a base retail rate increase of approximately: 19% for rural customers; 17% for large industrial customers; and 15.6% for the remaining aluminum smelter (Alcan Primary Products Corporation).

On January 31, 2013, Alcan Primary Products Corporation (Alcan) provided a Notice of Termination of its Kenergy Retail Service Agreement to Big Rivers and Kenergy. Alcan stated in its notice that with the proposed rate increase of 15.6% its smelter was "unprofitable and therefore unsustainable." Big Rivers provided notification to the three credit rating agencies and its creditors of the Alcan termination notice. As a result of Alcan's notice, the three credit rating agencies downgraded Big Rivers' credit ratings in early February 2013 as follows: Standard & Poor's to BB- from BBB-; Fitch to BB from BBB-; and Moody's to Ba1 from Baa2. In addition, all three credit rating agencies maintained their Outlooks. Big Rivers' continues to implement its LCMP, which includes the filing of an application requesting approval of a second rate increase to become effective January 31, 2014. The Company expects to file this application no later than June 28, 2013. In addition, Big Rivers is actively pursuing replacement load for the 850 MW currently being utilized by Century and Alcan.

In accordance with the Amended and Consolidated Loan Contract between Big Rivers and the United States of America (acting by and through the RUS Administrator), Big Rivers provided notification to the RUS Administrator via letter dated February 7, 2013 of a failure to maintain two Credit Ratings of Investment Grade. Based on this, the Company is required to provide a corrective plan to the RUS. Big Rivers in consultation with RUS is in the process of developing a corrective plan setting forth the actions that will be taken by management that are reasonably expected to achieve two Credit Ratings of Investment Grade.

As a result of the termination notice from Century, as of December 31, 2012 Big Rivers does not have access to draw on its $50,000 line of credit with CoBank. In addition, in order for Big Rivers to have access to the $50,000 line of credit with CFC after August 20, 2014, that agreement must be amended. Big Rivers is currently negotiating with CFC and CoBank to modify certain terms of the Company's line-of-credit agreements to ensure access to the lines of credit, given receipt of the two Smelter termination notices. Amendments to these agreements are subject to approval by the KPSC.

On November 14, 2012, Big Rivers filed an application with the KPSC seeking approval to issue new debt to be used to refund the $58,800 Series 1983 Bonds (note 3) that mature in June 2013. However, with the uncertainty created by the Aluminum Smelters' termination notices, and potential cumulative impact on prospective bond purchasers, the Company has decided to seek KPSC approval to repay the bonds from repurposed funds currently restricted by previously issued orders of the KPSC. The restricted funds consist of CoBank borrowings to be used for capital expenditures in the ordinary course of business; and a Transition Reserve established for use upon the loss of one or both of the Aluminum Smelter loads (the December 31, 2012 balances were $41,313 and $35,009, respectively). On March 26, 2013, the KPSC issued an Order granting the approval sought by the Company in this matter.

Certain legislators in Western Kentucky have filed companion bills in the Kentucky General Assembly (HB 211 and SB 71) in an attempt to legislate power supply pricing options for the Aluminum Smelters on Big Rivers' system that will encourage the smelters to continue operating their facilities. Big Rivers does not support those legislative proposals, and cannot predict whether the efforts will be successful.

While the ultimate outcome of the filings with the KPSC, discussions with lenders, and possible legislation are all uncertain, management of Big Rivers believes that the Company's results of operations and cash flows will provide sufficient liquidity for the Company to operate its business and meet its obligations as they come due for the foreseeable future. However, negative outcomes in one or more of these matters could potentially have a material impact on the Company's results of operations, cash flows, and liquidity.

6. Income Taxes

At December 31, 2012, Big Rivers had a Nonpatron Net Operating Loss Carryforward of approximately $31,933 expiring at various times between 2012 and 2031, and an Alternative Minimum Tax Credit Carryforward of approximately $7,028, which carries forward indefinitely.

The Company has not recorded any regular income tax expense for the years ended December 31, 2012, 2011, and 2010, as the Company has utilized federal net operating losses to offset any regular taxable income during those years. Had the Company not had the benefit of a net operating loss carryforward, the Company would have recorded $0, $3,613, and $3,846 in current regular tax expense for the years ended December 31, 2012, 2011, and 2010, respectively.

The components of the net deferred tax assets as of December 31, 2012 and 2011 were as follows:

	2012	2011
Deferred tax assets:		
Net operating loss carryforward	$12,614	$12,812
Alternative minimum tax credit carryforwards	7,028	7,138
Member rate mitigation	10,326	10,326
Fixed asset basis difference	3,352	3,980
RUS Series B Note	19,689	19,689
Total deferred tax assets	53,009	53,945
Deferred tax liabilities:		
RUS Series B Note	-	-
Bond refunding costs	(9)	(9)
Total deferred tax liabilities	(9)	(9)
Net deferred tax asset (prevaluation allowance)	53,000	53,936
Valuation allowance	(53,000)	(53,936)
Net deferred tax asset	$ -	-

A reconciliation of the Company's effective tax rate for 2012, 2011, and 2010 is as follows:

	2012	2011	2010
Federal rate	35.0%	35.0%	35.0%
State rate — net of federal benefit	4.5	4.5	4.5
Permanent differences	0.9	0.9	0.5
Patronage allocation to members	(40.4)	(40.8)	(38.8)
Tax benefit of operating loss carryforwards and other	-	(0.4)	(1.2)
Alternative minimum tax	-	3.5	3.0
Effective tax rate	- %	3.5%	3.0%

The Company files a federal income tax return, as well as certain state income tax returns. The years currently open for federal tax examination are 2007 through 2011 and 1996 through 1997, due to unused net operating loss carryforwards. The major state tax jurisdiction currently open for tax examination is Kentucky for years 2004 through 2012 and years 2001 through 2003, also due to unused net operating loss carryforwards. The Company has not recorded any unrecognized tax benefits or liabilities related to federal or state income taxes.

The Company classifies interest and penalties as an operating expense on the income statement and accrued expense in the balance sheet. No material interest or penalties have been recorded during 2012, 2011, or 2010.

7. Pension Plans

(a) Defined-Benefit Plans

Big Rivers has noncontributory defined-benefit pension plans covering substantially all employees who meet minimum age and service requirements and who were employed by the Company prior to the plans closure dates cited below. The plans provide benefits based on the participants' years of service and the five highest consecutive years' compensation during the last ten years of employment. Big Rivers' policy is to fund such plans in accordance with the requirements of the Employee Retirement Income Security Act of 1974.

The salaried employees defined-benefit plan was closed to new entrants effective January 1, 2008, and the bargaining employees defined-benefit plan was closed to new hires effective November 1, 2008. The Company simultaneously established base contribution accounts in the defined-contribution thrift and 401(k) savings plans, which were renamed as the retirement savings plans. The base contribution account for an eligible employee, which is one who meets the minimum age and service requirements, but for whom membership in the defined-benefit plan is closed, is funded by employer contributions based on graduated percentages of the employee's pay, depending on his or her age.

The Company has adopted FASB ASC 715, *Compensation – Retirement Benefits*, including the requirement to recognize the funded status of its pension plans and other postretirement plans (note 10 – Postretirement Benefits Other Than Pensions). FASB ASC 715 defines the funded status of a defined-benefit pension plan as the fair value of its assets less its projected benefit obligation, which includes projected salary increases, and defines the funded status of any other postretirement plan as the fair value of its assets less its accumulated postretirement benefit obligation.

FASB ASC 715 also requires an employer to measure the funded status of a plan as of the date of its year-end balance sheet and requires disclosure in the notes to the financial statements certain additional information related to net periodic benefit costs for the next fiscal year. The Company's pension and other postretirement benefit plans are measured as of December 31, 2012 and 2011.

The following provides an overview of the Company's noncontributory defined-benefit pension plans.

A reconciliation of the Company's benefit obligations of its noncontributory defined-benefit pension plans at December 31, 2012 and 2011 is as follows:

	2012	2011
Benefit obligation — beginning of period	$31,743	$28,804
Service cost — benefits earned during the period	1,428	1,279
Interest cost on projected benefit obligation	1,304	1,296
Benefits paid	(6,499)	(481)
Actuarial loss	2,931	845
Benefit obligation — end of period	$30,907	$31,743

Big Rivers' defined-benefit pension plans provide retirees with a lump-sum payment option. Benefits paid in 2012 include lump-sum payments in the amounts of $6,462 – the result of ten retirees electing the lump-sum payment option. In 2011, only one retiree elected the lump-sum payment option for an amount of $441.

The accumulated benefit obligation for all defined-benefit pension plans was $24,211 and $25,482 at December 31, 2012 and 2011, respectively.

A reconciliation of the Company's pension plan assets at December 31, 2012 and 2011 is as follows:

	2012	2011
Fair value of plan assets — beginning of period	$28,000	$25,267
Actual return on plan assets	3,020	324
Employer contributions	4,810	2,890
Benefits paid	(6,499)	(481)
Fair value of plan assets — end of period	$29,331	$28,000

The funded status of the Company's pension plans at December 31, 2012 and 2011 is as follows:

	2012	2011
Benefit obligation — end of period	$(30,907)	$(31,743)
Fair value of plan assets — end of period	29,331	28,000
Funded status	$ (1,576)	$ (3,743)

Components of net periodic pension costs for the years ended December 31, 2012, 2011, and 2010 were as follows:

	2012	2011	2010
Service cost	$1,428	$1,279	$1,289
Interest cost	1,304	1,296	1,368
Expected return on plan assets	(1,897)	(1,737)	(1,533)
Amortization of prior service cost	14	14	19
Amortization of actuarial loss	779	461	584
Settlement loss	2,064	-	-
Net periodic benefit cost	$3,692	$1,313	$1,727

As a result of the 2012 lump-sum payments there was a settlement required to the defined-benefit pension plans as provided in FASB ASC 715. The 2012 settlement loss of $2,064 reflects an accelerated amortization of unrecognized losses existing at the settlement date of December 31, 2012. The settlement loss is determined by multiplying the total unrecognized losses as of the settlement date by the projected benefit obligation that was settled or eliminated due to the lump-sum payments.

A reconciliation of the pension plan amounts in accumulated other comprehensive income at December 31, 2012 and 2011 is as follows:

	2012	2011
Prior service cost	$ (12)	$ (26)
Unamortized actuarial (loss)	(10,116)	(11,151)
Accumulated other comprehensive income	$(10,128)	$(11,177)

In 2013, $11 of prior service cost and $635 of actuarial loss is expected to be amortized to periodic benefit cost.

The recognized adjustments to other comprehensive income (loss) at December 31, 2012 and 2011 are as follows:

	2012	2011
Prior service cost	$ 14	$ 14
Unamortized actuarial (loss)	1,035	(1,797)
Other comprehensive income (loss)	$ 1,049	$(1,783)

At December 31, 2012 and 2011, amounts recognized in the balance sheets were as follows:

	2012	2011
Deferred credits and other	$(1,576)	$(3,743)

Assumptions used to develop the projected benefit obligation and determine the net periodic benefit cost were as follows:

	2012	2011	2010
Discount rate — projected benefit obligation	3.57%	4.26%	4.95%
Discount rate — net periodic benefit cost	4.26	4.95	5.59
Rates of increase in compensation levels	4.00	4.00	4.00
Expected long-term rate of return on assets	7.25	7.25	7.25

The expected long-term rate of return on plan assets for determining net periodic pension cost for each fiscal year is chosen by the Company from a best estimate range determined by applying anticipated long-term returns and long-term volatility for various asset categories to the target asset allocation of the plans, as well as taking into account historical returns.

Using the asset allocation policy adopted by the Company noted in the paragraph below, we determined the expected rate of return at a 50% probability of achievement level based on (a) forward-looking rate of return expectations for passively managed asset categories over a 20-year time horizon and (b) historical rates of return for passively managed asset categories. Applying an approximately 80%/20% weighting to the rates determined in (a) and (b), respectively, produced an expected rate of return of 7.28%, which was rounded to 7.25%.

Big Rivers utilizes a third-party investment manager for the plan assets, and has communicated thereto the Company's Retirement Plan Investment Policy, including a target asset allocation mix of 50% U.S. Equities (an acceptable range of 45% – 55%), 15% International Equities (an acceptable range of 10% – 20%), and 35% fixed income (an acceptable range of 30% – 40%). As of December 31, 2012 and 2011, the investment allocation was 49% and 56%, respectively, in U.S. Equities, 6% and 8%, respectively, in International Equities, and 45% and 36%, respectively, in fixed income. The objective of the investment program seeks to (a) maximize return on investment, (b) minimize volatility, (c) minimize company contributions, and (d) provide the employee benefit in accordance with the plans. The portfolio is well diversified and of high quality. The average quality of the fixed income investments must be "A" or better. The equity portfolio must also be of investment grade quality. The performance of the investment manager is reviewed semiannually.

At December 31, 2012 and 2011, the fair value of Big Rivers' defined-benefit pension plan assets by asset category are as follows:

	Level 1	Level 2	December 31, 2012
Cash and money market	$ 5,820	$ –	$ 5,820
Equity securities:			
U.S. Large-Cap Stocks	9,839	–	9,839
U.S. Mid-Cap Stock Mutual Funds	2,796	–	2,796
U.S. Small-Cap Stock Mutual Funds	1,513	–	1,513
International Stock Mutual Funds	1,888	–	1,888
Preferred stock	228	–	228
Fixed:			
Short-Term Bond Fund	–	300	300
U.S. Government Agency Bonds	–	921	921
Taxable U.S. Municipal Bonds	–	3,109	3,109
U.S. Corporate Bonds	–	2,617	2,617
Global Bond Fund	–	300	300
	$22,084	$7,247	$ 29,331

	Level 1	Level 2	December 31, 2011
Cash and money market	$ 2,129	$ –	$ 2,129
Equity securities:			
U.S. Large-Cap Stocks	10,178	–	10,178
U.S. Mid-Cap Stock Mutual Funds	3,365	–	3,365
U.S. Small-Cap Stock Mutual Funds	1,666	–	1,666
International Stock Mutual Funds	2,168	–	2,168
Preferred stock	493	–	493
Fixed:			
TIPS Bond Fund	723	–	723
U.S. Government Agency Bonds	–	1,085	1,085
Taxable U.S. Municipal Bonds	–	3,258	3,258
U.S. Corporate Bonds	–	2,630	2,630
Global Bond Fund	–	305	305
	$20,722	$7,278	$ 28,000

Expected retiree pension benefit payments projected to be required during the years following 2012 are as follows:

Year(s) Ending December 31	Amount
2013	$ 4,718
2014	1,682
2015	3,034
2016	3,573
2017	1,865
2018 – 2022	13,563
Total	$28,435

In 2013, the Company expects to contribute $924 to its pension plan trusts.

(b) Defined-Contribution Plans

Big Rivers has two defined-contribution retirement plans covering substantially all employees who meet minimum age and service requirements. Each plan has a thrift and 401(k) savings section allowing employees to contribute up to 75% of pay on a pretax and/or after-tax basis, with employer matching contributions equal to 60% of the first 6% contributed by the employee on a pretax basis.

A base contribution retirement section was added and the plan name changed from thrift and 401(k) savings to retirement savings, effective January 1, 2008, for the salaried plan and November 1, 2008, for the bargaining plan. The base contribution account is funded by employer contributions based on graduated percentages of pay, depending on the employee's age.

The Company's expense under these plans was $4,808 and $4,464 for the years ended December 31, 2012 and 2011, respectively.

(c) Deferred Compensation Plan

Big Rivers sponsors a nonqualified deferred compensation plan for its eligible employees who are members of a select group of management or highly compensated employees. The purpose of the plan is to allow participants to receive contributions or make deferrals that they could not receive or make under the salaried employees qualified defined-contribution retirement savings plan (formerly, the thrift and 401(k) savings plan) as a result of nondiscrimination rules and other limitations applicable to the qualified plan under the Internal Revenue Code. The nonqualified plan also allows a participant to defer a percentage of his or her pay on a pretax basis.

The nonqualified deferred compensation plan is unfunded, but the Company has chosen to finance its obligations under the plan, including any employee deferrals, through a rabbi trust. The trust assets remain a part of the Company's general assets, subject to the claims of its creditors. The 2012 employer contribution was $60 and deferred compensation expense was $122. As of December 31, 2012, the trust asset was $404 and the deferred liability was $263.

8. Restricted Investments

The amortized costs and fair values of Big Rivers restricted investments held for member rate mitigation and the Transition Reserve at December 31, 2012 and 2011 are as follows:

	2012		2011	
	Amortized costs	Fair values	Amortized costs	Fair values
Cash and money market	$ 1,292	$ 1,292	$ 12,765	$ 12,764
Debt securities:				
U.S. Treasuries	63,208	64,097	62,073	63,917
U.S. government agency	115,023	115,040	88,324	88,485
Total	$179,523	$180,429	$163,162	$165,166

Gross unrealized gains and losses on restricted investments at December 31, 2012 and 2011 were as follows:

	2012		2011	
	Gains	Losses	Gains	Losses
Debt securities:				
U.S. Treasuries	$ 889	$ -	$ 1,843	$ -
U.S. government agency	20	3	161	-
Total	$ 909	$ 3	$ 2,004	$ -

Debt securities at December 31, 2012 and 2011 mature, according to their contractual terms, are as follows (actual maturities may differ due to call or prepayment rights):

	2012		2011	
	Amortized costs	Fair values	Amortized costs	Fair values
In one year or less	$ 56,315	$ 56,330	$ 43,021	$ 43,092
After one year through five years	123,208	124,099	120,141	122,074
Total	$179,523	$180,429	$163,162	$165,166

Gross unrealized losses on investments and the fair values of the related securities, aggregated by investment category and length of time that individual securities have been in a continuous unrealized loss position at December 31, 2012 and 2011 were as follows:

	2012 Less than 12 months		2011 Less than 12 months	
	Losses	Fair values	Losses	Fair values
Debt securities:				
U.S. Treasuries	$ -	$ -	$ -	$ -
U.S. government agency	3	34,997	-	-
Total	$ 3	$ 34,997	$ -	$ -

The unrealized loss positions were primarily caused by interest rate fluctuations. The number of investments in an unrealized loss position as of December 31, 2012 and 2011 was two and zero, respectively. Since the Company does not intend to sell and will more likely than not maintain each debt security until its anticipated recovery, and no significant credit risk is deemed to exist, these investments are not considered other-than-temporarily impaired.

In conjunction with the CFC $302,000 secured term loan (note 3), Big Rivers was required to invest in Capital Term Certificates (CTCs) equal to 14.29% of the Refinance Note. Proceeds of the Equity Note were used to purchase the investments in CTCs as required under the loan agreement. The interest rate on the CTCs is fixed at 4.28% and is equal to 80% of the Equity Note rate of 5.35%. The CTCs cannot be traded in the market, and therefore, a value other than their outstanding principal amount cannot be determined.

9. Fair Value of Other Financial Instruments

FASB ASC 820 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measures. It applies under other accounting standards that require or permit fair value measurements and does not require any new fair value measurements.

The carrying value of accounts receivable and accounts payable approximate fair value due to their short maturity. At December 31, the Company's cash, cash equivalents, and restricted cash included short-term investments in an institutional money market government portfolio account classified as trading securities under ASC 320, *Investments – Debt and Equity Securities*, that were recorded at fair value which were determined using quoted market prices for identical assets without regard to valuation adjustment or block discount (a Level 1 measure), as follows:

	2012	2011
Institutional money market government portfolio	$110,165	$44,844

It was not practical to estimate the fair value of patronage capital included within other deposits and investments due to these being untraded companies.

Big Rivers' long-term debt at December 31, 2012 consists of CFC loans totaling $341,358, a CoBank loan in the amount of $231,426, RUS notes totaling $210,359, variable rate pollution control bonds in the amount of $58,800, and fixed-rate pollution control bonds in the amount of $83,300 (note 3). The RUS, CFC, and CoBank debt cannot be traded in the market, and therefore, a value other than their outstanding principal amount cannot be determined. The fair value of the Company's variable rate pollution control debt is par value, as each variable rate reset effectively prices such debt to the current market. At December 31, 2012, the fair value of Big Rivers' fixed-rate pollution control debt was determined based on quoted prices in active markets of similar instruments (Level 1 measure) and totaled $86,778.

10. Postretirement Benefits Other than Pensions

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

The discount rates used in computing the postretirement benefit obligation and net periodic benefit cost were as follows:

	2012	2011	2010
Discount rate — projected benefit obligation	3.72%	4.29%	4.96%
Discount rate — net periodic benefit cost	4.29	4.96	5.78

The healthcare cost trend rate assumptions as of December 31, 2012 and 2011 were as follows:

	2012	2011
Initial trend rate	7.30%	7.40%
Ultimate trend rate	4.50	4.50
Year ultimate trend is reached	2028	2028

A one-percentage-point change in assumed healthcare cost trend rates would have the following effects:

	2012	2011
One-percentage-point decrease:		
Effect on total service and interest cost components	$ (209)	$ (211)
Effect on year-end benefit obligation	(1,454)	(1,056)
One-percentage-point increase:		
Effect on total service and interest cost components	253	254
Effect on year-end benefit obligation	1,723	1,226

A reconciliation of the Company's benefit obligations of its postretirement plan at December 31, 2012 and 2011 is as follows:

	2012	2011
Benefit obligation — beginning of period	$ 18,040	$ 15,864
Service cost — benefits earned during the period	1,169	1,253
Interest cost on projected benefit obligation	766	754
Participant contributions	177	160
Amendments	(1,957)	-
Benefits paid	(796)	(611)
Actuarial loss	1,270	620
Benefit obligation — end of period	$ 18,669	$ 18,040

Big Rivers revised the eligibility requirements for postretirement medical with regard to age and service. Beginning January 1, 2014, eligibility for retirement is age 62 with 10 years of service. The service requirement is waived for active employees on December 31, 2012 who will not have 10 years of service at age 62. These amendments to the plan represent a $1,957 reduction in the accrued liability as of December 31, 2012.

A reconciliation of the Company's postretirement plan assets at December 31, 2012 and 2011 is as follows:

	2012	2011
Fair value of plan assets — beginning of period	$ -	$ -
Employer contributions	619	451
Participant contributions	177	160
Benefits paid	(796)	(611)
Fair value of plan assets — end of period	$ -	$ -

The funded status of the Company's postretirement plan at December 31, 2012 and 2011 is as follows:

	2012	2011
Benefit obligation — end of period	$(18,669)	$(18,040)
Fair value of plan assets — end of period	-	-
Funded status	$(18,669)	$(18,040)

The components of net periodic postretirement benefit costs for the years ended December 31, 2012, 2011, and 2010 were as follows:

	2012	2011	2010
Service cost	$1,169	$1,253	$1,313
Interest cost	766	754	743
Amortization of prior service cost	17	17	17
Amortization of transition obligation	31	31	31
Net periodic benefit cost	$1,983	$2,055	$2,104

A reconciliation of the postretirement plan amounts in accumulated other comprehensive income (loss) at December 31, 2012 and 2011 is as follows:

	2012	2011
Prior service cost	$1,844	$ (130)
Unamortized actuarial loss	(1,655)	(385)
Transition obligation	-	(31)
Accumulated other comprehensive income (loss)	$ 189	$ (546)

In 2013, $17 of prior service cost and $0 of actuarial gain is expected to be amortized to periodic benefit cost.

The recognized adjustments to other comprehensive loss at December 31, 2012 and 2011 are as follows:

	2012	2011
Prior service cost	$1,974	$ 17
Unamortized actuarial loss	(1,269)	(620)
Transition obligation	31	31
Other comprehensive income (loss)	$ 736	$(572)

At December 31, 2012 and 2011, amounts recognized in the balance sheets were as follows:

	2012	2011
Accounts payable	$ (992)	$ (762)
Deferred credits and other	(17,677)	(17,278)
Net amount recognized	$(18,669)	$(18,040)

Expected retiree benefit payments projected to be required during the years following 2012 are as follows:

Year(s)	Amount
2013	$ 992
2014	1,160
2015	1,231
2016	1,330
2017	1,488
2018–2022	8,033
Total	$14,234

In addition to the postretirement plan discussed above, Big Rivers has another postretirement benefit plan, which vests a portion of accrued sick leave benefits to salaried employees upon retirement or death. To the extent, an employee's sick leave hour balance exceeds 480 hours such excess hours are paid at 20% of the employee's base hourly rate at the time of retirement or death. The accumulated obligation recorded for the postretirement sick leave benefit is $589 and $579 at December 31, 2012 and 2011, respectively. The postretirement expense recorded was $57, $191, and $21 for 2012, 2011, and 2010, respectively, and the benefits paid were $47, $3, and $5 for 2012, 2011, and 2010, respectively.

11. Related Parties

For the years ended December 31, 2012, 2011, and 2010, Big Rivers had tariff sales to its members of $158,893, $151,472, and $151,001, respectively. In addition, for the years ended December 31, 2012, 2011, and 2010, Big Rivers had certain sales to Kenergy for the Aluminum Smelters and Domtar Paper loads of $366,758, $306,420, and $281,473, respectively.

At December 31, 2012 and 2011, Big Rivers had accounts receivable from its members of $42,759 and $40,314, respectively.

12. Commitments and Contingencies

Big Rivers is involved in litigation arising in the normal course of business. While the results of such litigation cannot be predicted with certainty, management, based upon advice of counsel, believes that the final outcome will not have a material adverse effect on the financial statements.

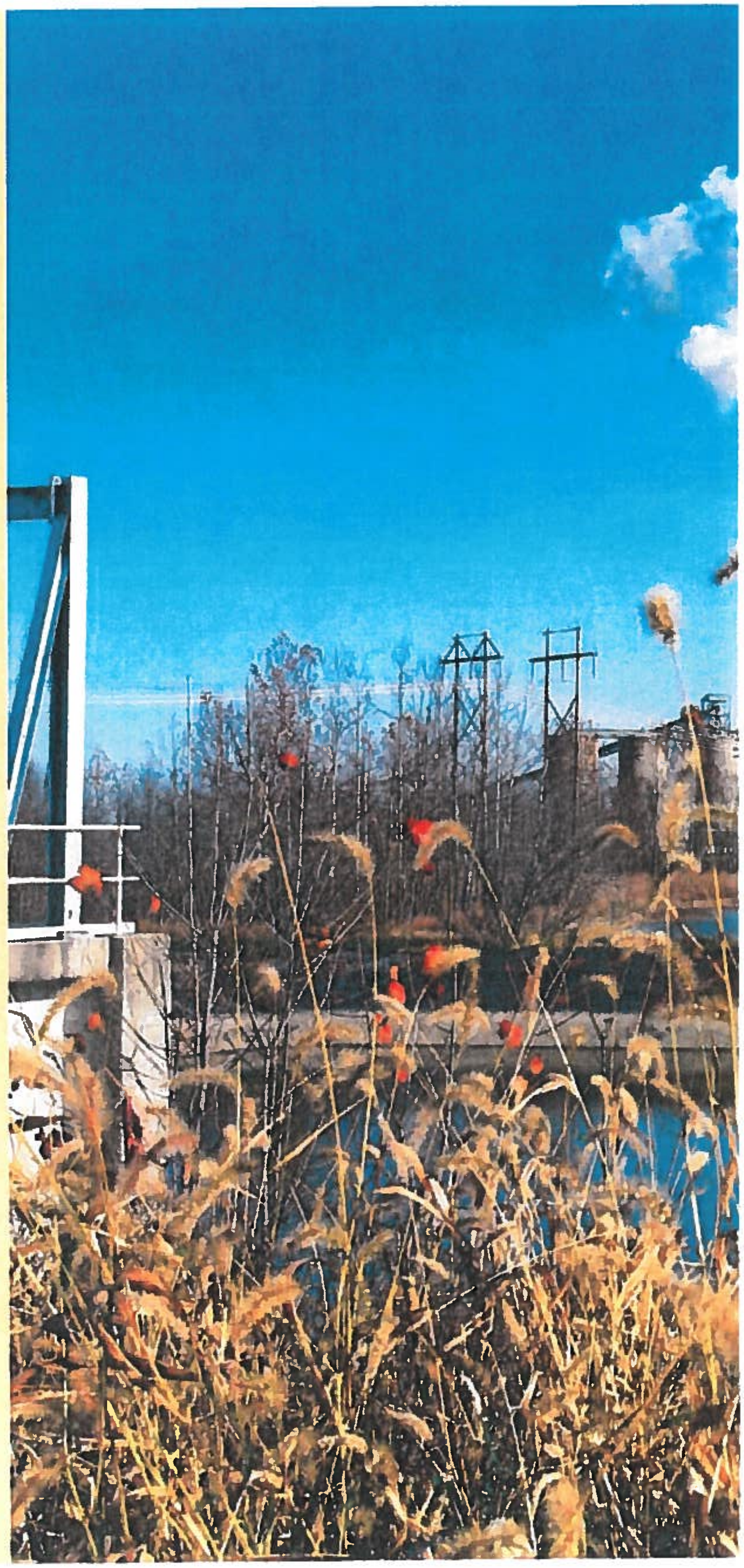
On April 2, 2012, Big Rivers filed an application with the KPSC seeking approval of its 2012 environmental compliance plan (ECP). As filed, the ECP requested KPSC approval to install certain equipment allowing Big Rivers to comply, in the most cost-effective manner, with the U.S. Environmental Protection Agency Cross State Air Pollution Rule (CSAPR), and Mercury and Air Toxics Standards (MATS). In addition, the ECP filing requested approval to recover the costs of the ECP through an amendment to Big Rivers' existing environmental surcharge tariff rider, an automatic cost recovery mechanism that is similar in function to the fuel adjustment clause. Prior to the evidentiary hearing conducted on August 22 and 23, 2012 at the KPSC's offices, a ruling by the United States Court of Appeals for the District of Columbia Circuit resulted in CSAPR being vacated. On August 22, 2012, with CSAPR vacated and only MATS compliance remaining (at an estimated cost of $58,440), the parties to the KPSC hearing were able to reach a full and unanimous settlement of all issues related to the ECP case. On October 1, 2012, the KPSC issued an order approving Big Rivers' ECP.

Five-Year Review

Years ended December 31 — (Dollars in thousands)

SUMMARY OF OPERATIONS	2012	2011	2010	2009	2008
Operating Revenue:					
Power Contracts Revenue	$568,342	$561,989	$527,324	$341,333	$214,758
Lease Revenue	-	-	-	32,027	58,423
Total Operating Revenue	568,342	561,989	527,324	373,360	273,181
Operating Expenses:					
Fuel for Electric Generation	226,369	226,229	207,749	80,655	-
Power Purchased	111,465	112,262	99,421	116,883	114,643
Operations (Excluding Fuel), Maintenance, Other	134,206	137,213	134,660	87,645	32,858
Depreciation	41,090	35,407	34,242	32,485	31,041
Total Operating Expenses	513,130	511,111	476,072	317,668	178,542
Interest Expense and Other:					
Interest	44,414	45,226	46,570	59,898	72,710
Other – net	546	320	425	3,309	6,868
Total Interest Expense & Other	44,960	45,546	46,995	63,207	79,578
Operating Margin	10,252	5,332	4,257	(7,515)	15,061
Non-Operating Margin	1,025	268	2,734	538,845	12,755
Net Margin	$11,277	$5,600	$6,991	$531,330	$27,816
SUMMARY OF BALANCE SHEET					
Total Utility Plant	$2,050,221	$2,028,418	$2,001,067	$1,986,373	$1,791,772
Accumulated Depreciation	962,994	936,355	909,501	908,099	879,073
Net Utility Plant	1,087,227	1,092,063	1,091,566	1,078,274	912,699
Cash and Cash Equivalents	68,860	44,849	44,780	60,290	38,903
Restricted Cash	41,313	-	-	-	-
Reserve Account Investments[1]	182,994	164,399	218,955	244,641	-
Other Assets	166,284	116,611	116,884	122,278	122,834
Total Assets	$1,546,678	$1,417,922	$1,472,185	$1,505,483	$1,074,436
Equities (deficit)	$402,882	$389,820	$386,575	$ 379,392	$ (154,602)
Long-term Debt[2]	925,243	786,399	816,996	848,552	987,349
Regulatory Liability – Member Rate Mitigation	147,732	169,001	185,893	207,348	-
Other Liabilities and Deferred Credits	70,821	72,702	82,721	70,191	241,689
Total Liabilities and Equity	$1,546,678	$1,417,922	$1,472,185	$1,505,483	$1,074,436
ENERGY SALES (MWh)					
Member Rural	2,321,477	2,371,106	2,481,390	2,239,445	2,386,916
Member Large Industrial	961,298	973,093	930,168	919,587	925,793
Smelter Contracts	7,424,473	6,854,820	6,348,431	2,885,491	-
Other	1,536,834	3,056,106	2,209,431	1,746,438	1,844,677
Total Energy Sales	12,244,082	13,255,125	11,969,420	7,790,961	5,157,386
Sources of Energy (MWh)					
Generated	9,143,111	10,284,350	9,895,512	3,715,544	-
Purchased	3,162,489	2,998,361	2,220,994	4,166,916	5,211,789
Losses and Net Interchange	(61,518)	(27,586)	(147,086)	(91,499)	(54,403)
Total Energy Available	12,244,082	13,255,125	11,969,420	7,790,961	5,157,386
NET CAPACITY (MW)					
Net Generating Capacity Owned	1,444	1,444	1,444	1,444	1,459
Rights to HMP&L Station Two	197	202	207	212	217
Other Net Capacity Available	178	178	178	178	178

[1] Includes investment income receivable.
[2] Includes current maturities of long-term obligations.



Big Rivers
ELECTRIC CORPORATION

Big Rivers Electric Corporation

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42419-0024

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Tab No. 33
Filing Requirement
807 KAR 5:001 Section 16(12)(m)
Sponsoring Witness: Billie J. Richert

Description of Filing Requirement:

The current chart of accounts if more detailed than the Uniform System of Accounts chart prescribed by the commission.

Response:

Please see the attachment to this response for Big Rivers' current chart of accounts.

Big Rivers Electric Corporation
Case No. 2013-00199
Chart of Accounts

Account #	Description	Type
10000000	ELECTRIC PLANT IN SERVICE	Asset
10100000	ELECTRIC PLANT IN SERVICE	Asset
10100099	ELECTRIC PLANT IN SERVICE CONV	Asset
10100100	PLT IN SERV-EXCL 289	Asset
10103010	ORGANIZATION	Asset
10103020	FRANCHISES AND CONSENTS	Asset
10103101	LAND AND LAND RIGHTS REID	Asset
10103102	LAND AND LAND RIGHTS COLEMAN	Asset
10103103	LAND AND LAND RIGHTS GREEN	Asset
10103104	LAND AND LAND RIGHTS WILSON	Asset
10103111	STRUCTURES AND IMROVEMENTS REID	Asset
10103112	STRUCTURES AND IMROVEMENTS COLEMAN	Asset
10103113	STRUCTURES AND IMROVEMENTS GREEN	Asset
10103114	STRUCTURES AND IMROVEMENTS WILSON	Asset
10103115	HMP&L STATION 2-STRUCTURES	Asset
10103116	COMMON FOR REID & STATION 2-STRUCTURES	Asset
10103117	COMMON FOR REID, GREEN & STATION 2	Asset
10103119	STRUCTURES-CENTRAL MACHINE SHOP	Asset
10103120	CENTRAL LAB EQUIPMENT-COAL ANALYSIS	Asset
10103121	BOILER PLANT EQUIPMENT REID	Asset
10103122	BOILER PLANT EQUIPMENT COLEMAN	Asset
10103123	BOILER PLANT EQUIPMENT GREEN	Asset
10103124	BOILER PLANT EQUIPMENT WILSON	Asset
10103125	HMP&l STATION II-BOILER PLANT EQUIPMENT	Asset
10103126	BOILER PLANT EQUIPMENT-REID/STATION TWO	Asset
10103127	BOILER PLANT EQUIPMENT-REID/GREEN/STA 2	Asset
10103128	BOILER PLANT EQUIPMENT-BARGES	Asset
1010312A	CENTRAL LAB EQUIP-COAL-CLEAN AIR	Asset
1010312B	BOILER PLANT EQUIP-CLEAN AIR-REID	Asset
1010312C	BOILER PLANT EQUIP-CLEAN AIR-COLEMAN	Asset
1010312D	BOILER PLANT EQUIP-CLEAN AIR-GREEN	Asset
1010312E	BOILER PLANT EQUIP-CLEAN AIR-WILSON	Asset
1010312F	BOILER PLANT EQUIP-CLEAN AIR-HMP&L	Asset
1010312G	BOILER PLANT EQUIP-CLEAN AIR-REID/HMP&L	Asset
1010312J	BOILER PLANT EQUIP-CLEAN AIR-GREEN/HMP&L	Asset
1010312K	BOILER PLANT EQUIP-CLEAN AIR-HMP&L SCRUB	Asset
1010312L	BOILER-SHORT LIFE-CLEAN AIR-RE	Asset
1010312M	BOILER-SHORT LIFE-CLEAN AIR-CO	Asset
1010312N	BOILER-SHORT LIFE-CLEAN AIR-GR	Asset

Account #	Description	Type
1010312P	BOILER-SHORT LIFE-CLEAN AIR-WI	Asset
1010312Q	BOILER-SHORT LIFE-CLEAN AIR-HM	Asset
1010312V	BOILER-SHORT LIFE-REID	Asset
1010312W	BOILER-SHORT LIFE-COLEMAN	Asset
1010312X	BOILER-SHORT LIFE-GREEN	Asset
1010312Y	BOILER-SHORT LIFE-WILSON	Asset
1010312Z	BOILER-SHORT LIFE-HMPL	Asset
10103141	TURBO-GENERATOR UNITS REID	Asset
10103142	TURBO-GENERATOR UNITS COLEMAN	Asset
10103143	TURBO-GENERATOR UNITS GREEN	Asset
10103144	TURBO-GENERATOR UNITS WILSON	Asset
10103145	TURBO GENERATOR UNITS-HMP&L-STATION TWO	Asset
10103146	COMMON FOR REID & STATION 2	Asset
10103147	COMMON FOR REID, GREEN & STATION 2	Asset
10103151	ACCESSORY ELECTRIC EQUIPMENT REID	Asset
10103152	ACCESSORY ELECTRIC EQUIPMENT COLEMAN	Asset
10103153	ACCESSORY ELECTRIC EQUIPMENT GREEN	Asset
10103154	ACCESSORY ELECTRIC EQUIPMENT WILSON	Asset
10103155	HMP&L STATION 2-ACCESS,ELECTRIC EQUIP.	Asset
10103157	COMMON FOR REID,GREEN,STATION II	Asset
10103159	CENTRAL MACHINE SHOP	Asset
10103160	CENTRAL LAB EQUIPMENT-GENERAL	Asset
10103161	MISC. POWER PLANT EQUIPMENT REID	Asset
10103162	MISC. POWER PLANT EQUIPMENT COLEMAN	Asset
10103163	MISC. POWER PLANT EQUIPMENT GREEN	Asset
10103164	MISC. POWER PLANT EQUIPMENT WILSON	Asset
10103165	HMP&L STATION 2-MISC PLANT EQUIPMENT	Asset
10103166	COMMON FOR REID & STATION 2	Asset
10103167	COMMON FOR REID, GREEN & STATION TWO	Asset
10103169	MISC EQUIPMENT-CENTRAL MACHINE SHOP	Asset
10103410	STRUCTURES AND IMPROVEMENTS-GAS TURBINE	Asset
10103420	FUEL HOLDERS, PRODUCERS & ACCESSORIES-GAS T	Asset
10103430	PRIME MOVERS-GAS TURBINE	Asset
10103440	GENERATORS-GAS TURBINE	Asset
10103450	ACCESSORY ELECTRIC EQUIPMENT-GAS TURBINE	Asset
10103460	MISC POWER PLANT EQUIPMENT-GAS TURBINE	Asset
10103500	LAND RIGHT OF WAYS-TRANSMISSION	Asset
10103501	LAND-TRANSMISSION	Asset
10103520	STRUCTURES AND IMPROVEMENTS TRANSMISSION	Asset

Big Rivers Electric Corporation
Case No. 2013-00199
Chart of Accounts

Account #	Description	Type
10103521	STRUCTURES-REID SWITCHYARD	Asset
10103522	STRUCTURES-COLEMAN SWITCHYARD	Asset
10103524	STRUCTURES-WILSON SWITCHYARD	Asset
10103530	STATION EQUIPMENT	Asset
10103531	STATION EQUIPMENT-REID SWITCHYARD	Asset
10103532	STATION EQUIPMENT-COLEMAN SWITCHYARD	Asset
10103533	STATION EQUIPMENT-GREEN SWITCHYARD	Asset
10103534	STATION EQUIPMENT-WILSON SWITCHYARD	Asset
10103540	TOWERS AND FIXTURES	Asset
10103541	TOWERS-REID SWITCHYARD	Asset
10103550	POLES AND FIXTURES	Asset
10103551	POLES AND FIXTURES - SPECIAL	Asset
10103560	OVERHEAD CONDUCTOR AND DEVICES	Asset
10103561	OVERHEAD CONDUCTOR AND DEVICES - SPECIAL	Asset
10103890	LAND AND LAND RIGHTS GENERAL PLANT	Asset
10103900	STRUCTURES AND IMPROVEMENTS GENERAL PLT	Asset
10103910	OFFICE FURNITURE AND EQUIPMENT	Asset
10103912	COMPUTER EQUIPMENT AND SOFTWARE	Asset
10103913	ENGINEERING COMPUTER	Asset
10103916	OFFICE FURN & EQUIP-REID, STATION TWO	Asset
10103917	OFFICE FURN & EQUIP-REID, GREEN, STA TWO	Asset
10103922	TRANSPORTATION EQUIPMENT-AUTO	Asset
10103923	TRANSPORTATION EQUIP-TRANSMISSION	Asset
10103930	STORES EQUIPMENT	Asset
10103940	TOOLS, SHOP, AND GARAGE EQUIPMENT	Asset
10103950	LABORATORY EQUIPMENT	Asset
10103960	POWER OPERATED EQUIPMENT	Asset
10103961	GO-TRACT VEHICLE #103	Asset
10103970	COMMUNICATION EQUIPMENT	Asset
10103980	MISCELLANEOUS EQUIPMENT	Asset
10103986	MISC EQUIPMENT-REID, STATION TWO	Asset
10103987	MISC EQUIPMENT-REID, GREEN, STATION TWO	Asset
10108000	ELECTRIC PLANT IN SERVICE-ORACLE	Asset
10110000	ELECTRIC PLANT IN SERVICE-OTHER	Asset
10110099	ELECTRIC PLANT IN SERVICE-OTHER CONVERSION	Asset
10113525	STRUCTURES AND IMPROVEMENTS-KU	Asset
10113535	STATION EQUIPMENT-KU	Asset
10113545	TOWERS-KU	Asset
10113555	POLES AND FIXTURES-KU	Asset

Account #	Description	Type
10113565	OVHD CONDUCTORS AND DEVICES-KU	Asset
10400000	ELECTRIC PLANT LEASED TO OTHER	Asset
10400099	ELECTRIC PLANT LEASED TO OTHER CONVERSION	Asset
10403101	LAND/LAND RIGHTS REID-LEASE	Asset
10403102	LAND/LAND RIGHTS COLEMAN-LEASE	Asset
10403103	LAND/LAND RIGHTS GREEN-LEASE	Asset
10403104	LAND/LAND RIGHTS WILSON-LEASE	Asset
10403111	STRUCTURES/IMROVEMENTS REID-LEASE	Asset
10403112	STRUCTURES/IMROVEMENTS COLEMAN-LEASE	Asset
10403113	STRUCTURES/IMROVEMENTS GREEN-LEASE	Asset
10403114	STRUCTURES/IMROVEMENTS WILSON-LEASE	Asset
10403115	STRUCTURES/IMROVEMENTS HMP&L-LEASE	Asset
10403116	STRUCTURES/IMROVEMENTS H/HMP&L-LEASE	Asset
10403117	STRUCTURES/IMROVEMENTS R/G/HMP&L-LEASE	Asset
10403119	STRUCTURES/IMROVEMENTS CMS-LEASE	Asset
10403121	BOILER PLANT EQUIPMENT REID-LEASE	Asset
10403122	BOILER PLANT EQUIPMENT COLEMAN-LEASE	Asset
10403123	BOILER PLANT EQUIPMENT GREEN-LEASE	Asset
10403124	BOILER PLANT EQUIPMENT WILSON-LEASE	Asset
10403125	BOILER PLANT EQUIPMENT HMPL-LEASE	Asset
10403126	BOILER PLANT EQUIPMENT R/HMPL-LEASE	Asset
10403127	BOILER PLANT EQUIPMENT R/G/HMPL-LEASE	Asset
1040312A	BOILER PLANT EQUIP-CLEAN AIR-CENTRAL LAB	Asset
1040312B	BOILER PLANT EQUIP-CLEAN AIR-REID-LEASE	Asset
1040312C	BOILER PLANT EQUIP-CLEAN AIR-COLEMAN-LEASE	Asset
1040312D	BOILER PLANT EQUIP-CLEAN AIR-GREEN-LEASE	Asset
1040312E	BOILER PLANT EQUIP-CLEAN AIR-WILSON-LEASE	Asset
1040312F	BOILER PLANT EQUIP-CLEAN AIR-HMP&L-LEASE	Asset
1040312G	BOILER PLANT EQUIP-CLEAN AIR-R/HMP&L-LEASE	Asset
1040312J	BOILER PLANT EQUIP-CLEAN AIR-G/HMP&L-LEASE	Asset
1040312K	BOILER PLANT EQUIP-CLEAN AIR-HMP&L SCRUB	Asset
10403141	TURBO -GENERATOR UNITS-REID-LEASE	Asset
10403142	TURBO -GENERATOR UNITS-COLEMAN-LEASE	Asset
10403143	TURBO -GENERATOR UNITS-GREEN-LEASE	Asset
10403144	TURBO -GENERATOR UNITS-WILSON-LEASE	Asset
10403145	TURBO -GENERATOR UNITS-HMPL-LEASE	Asset
10403146	TURBO -GENERATOR UNITS-R/HMPL-LEASE	Asset
10403147	TURBO -GENERATOR UNITS-R/G/HMPL-LEASE	Asset
10403151	ACCESS ELECTRIC EQUIP-REID-LEASE	Asset

Big Rivers Electric Corporation
Case No. 2013-00199
Chart of Accounts

Account #	Description	Type
10403152	ACCESS ELECTRIC EQUIP-COLEMAN-LEASE	Asset
10403153	ACCESS ELECTRIC EQUIP-GREEN-LEASE	Asset
10403154	ACCESS ELECTRIC EQUIP-WILSON-LEASE	Asset
10403155	ACCESS ELECTRIC EQUIP-HMPL-LEASE	Asset
10403159	ACCESS ELECTRIC EQUIP-CMS-LEASE	Asset
10403410	STRUCTURES/IMPROVEMENTS-GAS TURBINE-LEASE	Asset
10403420	FUEL HOLDERS, ACCESS-GAS TURBINE-LEASE	Asset
10403430	PRIME MOVERS-GAS TURBINE-LEASE	Asset
10403440	GENERATORS-GAS TURBINE-LEASE	Asset
10403450	ACCESS ELECTRIC EQUIP-GAS TURBINE-LEASE	Asset
10500000	ELECTRIC PLANT HELD FOR FUTURE	Asset
10500099	ELECTRIC PLANT HELD FOR FUTURE CONVERSION	Asset
10503401	LAND/LAND RIGHTS-COMBUSTION TURBINE	Asset
10600000	COMPLETED CONST NOT CLASSIFIED	Asset
10600099	COMPLETED CONST NOT CLASSIFIED-ELECTRIC CONVERSION	Asset
10600919	WILSON 161 KV LINE 19-F	Asset
10600930	WHITE OAK SUBSTATION	Asset
10600946	OIL SPILL PREVENTION CONTROL	Asset
10600955	HEADQUARTERS REMODEL	Asset
10600960	ORACLE SYSTEM	Asset
10608600	MEADE COUNTY 161 KV LINE TERMINAL	Asset
10608700	OIL SPILL PREVENTION CONTROL	Asset
10608850	RECONDUCTOR LINE 6-A	Asset
10608930	SKILLMAN TAP/MEADE COUNTY 161 KV LINE	Asset
10609030	DAVIESS COUNTY SUBSTATION	Asset
10609080	DIGITAL MICROWAVE RADIO SYSTEM	Asset
10609120	HENDERSON/VECTREN LINE 16-B	Asset
10609170	OLIVET CHURCH RD TAP LINE	Asset
10609240	PATRIOT FREEDOM MINE NIAGRA PORTAL LINE	Asset
10609260	RECONDUCTOR LINES 4-K & 5-D	Asset
10700000	CONSTRUCTION WORK IN PROGRESS	Asset
10705000	CONSTRUCTION WORK IN PROGRESS-DIRECT ADDITIONS	Asset
10708000	CONSTRUCTION WORK IN PROGRESS-ORACLE	Asset
10708900	CONSTRUCTION WIP-ORACLE-CONTRA	Asset
10710000	CWIP-NONINCR CAPITAL-BIG RIVER	Asset
10711000	CWIP-INCREMENTAL CAPITAL-BIG RIVERS CONTR	Asset
10720000	CWIP-NONINCR CAPITAL-WKE CONTR	Asset
10721000	CWIP-INCREMENTAL CAPITAL-WKE CONTR	Asset
10730000	CONSTRUCTION WIP-BR W/O CITY SHARE	Asset

Big Rivers Electric Corporation
Case No. 2013-00199
Chart of Accounts

Account #	Description	Type
10800000	ACCUM DEPR-PLANT	Asset
10800100	ACCUM DEPR-PLANT-HMPL BOOKS	Asset
10810000	ACCUM PROV FOR DEPRECIATION-STEAM PLANT	Asset
10810099	ACCUM PROV FOR DEPRECIATION-STEAM PLANT CONVERSION	Asset
10813111	STRUCTURES & IMPROVEMENTS-REID	Asset
10813112	STRUCTURES & IMPROVEMENTS-COLEMAN	Asset
10813113	STRUCTURES & IMPROVEMENTS-GREEN	Asset
10813114	STRUCTURES & IMPROVEMENTS-WILSON	Asset
10813116	COMMON FOR REID & STATION 2-STRUCTURES	Asset
10813117	COMMON FOR REID, GREEN, & STATION 2	Asset
10813119	STRUCTURES & IMPROVEMENTS-CENTRAL MACHIN	Asset
10813120	CENTRAL LAB EQUIPMENT-COAL ANALYSIS	Asset
10813121	BOILER PLANT EQUIPMENT-REID	Asset
10813122	BOILER PLANT EQUIPMENT-COLEMAN	Asset
10813123	BOILER PLANT EQUIPMENT-GREEN	Asset
10813124	BOILER PLANT EQUIPMENT-WILSON	Asset
10813126	BOILER PLANT EQUIPMENT-REID/STATION TWO	Asset
10813127	BOILER PLANT EQUIPMENT-REID/GREEN/STATION TWO	Asset
10813128	BOILER PLANT EQUIPMENT-BARGES	Asset
1081312A	BOILER PLANT EQUIP-CLEAN AIR-CENTRAL LAB	Asset
1081312B	BOILER PLANT EQUIP-CLEAN AIR-REID	Asset
1081312C	BOILER PLANT EQUIP-CLEAN AIR-COLEMAN	Asset
1081312D	BOILER PLANT EQUIP-CLEAN AIR-GREEN	Asset
1081312E	BOILER PLANT EQUIP-CLEAN AIR-WILSON	Asset
1081312G	BOILER PLANT EQUIP-CLEAN AIR-REID/HMP&L	Asset
1081312J	BOILER PLANT EQUIP-CLEAN AIR-GREEN/HMP&L	Asset
1081312L	BOILER-SHORT LIFE-CLEAN AIR-RE	Asset
1081312M	BOILER-SHORT LIFE-CLEAN AIR-CO	Asset
1081312N	BOILER-SHORT LIFE-CLEAN AIR-GR	Asset
1081312P	BOILER-SHORT LIFE-CLEAN AIR-WI	Asset
1081312Q	BOILER-SHORT LIFE-CLEAN AIR-HM	Asset
1081312V	BOILER-SHORT LIFE-REID	Asset
1081312W	BOILER-SHORT LIFE-COLEMAN	Asset
1081312X	BOILER-SHORT LIFE-GREEN	Asset
1081312Y	BOILER-SHORT LIFE-WILSON	Asset
1081312Z	BOILER-SHORT LIFE-HMPL	Asset
10813141	TURBO-GENERATOR EQUIPMENT-REID	Asset
10813142	TURBO-GENERATOR EQUIPMENT-COLEMAN	Asset
10813143	TURBO-GENERATOR EQUIPMENT-GREEN	Asset

Account #	Description	Type
10813144	TURBOGENERATOR UNITS-WILSON	Asset
10813146	TURBOGENERATOR UNITS-REID & STATION 2	Asset
10813147	TURBOGENERATOR UNITS-R/G/STA 2	Asset
10813151	ACCESSORY ELECTRIC EQUIPMENT-R	Asset
10813152	ACCESSORY ELECTRIC EQUIPMENT-COLEMAN	Asset
10813153	ACCESSORY ELECTRIC EQUIPMENT-GREEN	Asset
10813154	ACCESSORY ELECTRIC EQUIPMENT-WILSON	Asset
10813157	COMMON FOR REID,GREEN,STATION II	Asset
10813159	ELECTRIC EQUIPMENT-CENTRAL MACHINE SHOP	Asset
10813160	CENTRAL LAB EQUIPMENT-GENERAL	Asset
10813161	MISC POWER PLANT EQUIPMENT-REID	Asset
10813162	MISC POWER PLANT EQUIPMENT-COLEMAN	Asset
10813163	MISC POWER PLANT EQUIPMENT-GREEN	Asset
10813164	MISC POWER PLANT EQUIPMENT-WILSON	Asset
10813166	COMMON FOR REID & STATION 2	Asset
10813167	COMMON FOR REID, GREEN, & STATION 3	Asset
10813169	MISC POWER PLANT EQUIP-CENTRAL MACHINE	Asset
10840000	ACCUM PROV FOR DEPRECIATION-GAS TURBINE	Asset
10840099	ACCUM PROV FOR DEPRECIATION-GAS TURBINE CONVERSION	Asset
10843410	STRUCTURES & IMPROVEMENTS-GAS TURBINE	Asset
10843420	FUEL HANDLING EQUIPMENT-GAS TURBINE	Asset
10843430	PRIME MOVERS-GAS TURBINE	Asset
10843440	GENERATOR-GAS TURBINE	Asset
10843450	ACCESSORY ELECTRIC EQUIPMENT-GAS TURBINE	Asset
10843460	MISC POWER PLANT EQUIPMENT-GAS TURBINE	Asset
10850000	ACCUM PROV FOR DEPRECIATION-TRANSMISSION	Asset
10850099	ACCUM PROV FOR DEPRECIATION-TRANS CONVERSION	Asset
10851060	UNCLASSIFIED PLANT	Asset
10853520	STRUCTURES & IMPROVEMENTS-TRAN	Asset
10853521	STRUCTURES-ACCUM DEPR-REID SWITCHYARD	Asset
10853522	STRUCTURES-ACCUM DEPR-REID SWITCHYARD	Asset
10853524	STRUCTURES-ACCUM DEPR-WILSON SWITCHYARD	Asset
10853530	STATION EQUIPMENT-TRANS	Asset
10853531	STATION EQUIP-ACCUM DEPR-REID SWITCHYARD	Asset
10853532	STATION EQUIP-ACCUM DEPR-COLEMAN SWITCHY	Asset
10853533	STATION EQUIP-ACCUM DEPR-GREEN SWITCHYAR	Asset
10853534	STATION EQUIP-ACCUM DEPR-WILSON SWITCHYA	Asset
10853540	TOWERS & FIXTURES-TRANS	Asset
10853541	TOWERS-ACCUM DEPR-REID SWITCHYARD	Asset

Big Rivers Electric Corporation
Case No. 2013-00199
Chart of Accounts

Account #	Description	Type
10853550	POLES & FIXTURES-TRANS	Asset
10853551	POLES & FIXTURES-SPECIAL	Asset
10853560	OVERHEAD CONDUCTORS & DEVICES-TRANS	Asset
10853561	OVERHEAD CONDUCTORS & DEVICES-SPECIAL	Asset
10870000	ACCUM PROV FOR DEPRECIATION-GENERAL PLT	Asset
10870099	ACCUM PROV FOR DEPRECIATION-GENERAL PLT CONVERSION	Asset
10871060	UNCLASSIFIED GENERAL PLANT	Asset
10873900	STRUCTURES & IMPROVEMENTS-GENERAL	Asset
10873910	OFFICE FURNITURE & EQUIPMENT	Asset
10873912	DATA PROCESSING SYSTEM/34 COMPUTER EQUIP	Asset
10873916	OFFICE FURN & EQUIP @ REID/HMP&L	Asset
10873917	OFFICE FURN & EQUIP @ REID/GREEN/HMP&L	Asset
10873922	TRANSPORTATION EQUIPMENT-AUTOS	Asset
10873923	TRANSPORTATION EQUIP-TRANSMISSION	Asset
10873930	STORES EQUIPMENT	Asset
10873940	TOOL & GARAGE EQUIPMENT	Asset
10873950	LABORATORY EQUIPMENT	Asset
10873960	POWER OPERATED EQUIPMENT	Asset
10873961	GO-TRACT VEHICLE #103	Asset
10873970	COMMUNICATION EQUIPMENT-GENERAL	Asset
10873980	MISCELLANEOUS EQUIPMENT-GENERAL	Asset
10873987	MISC EQUIPMENT @ REID/GREEN/HMP&L	Asset
10880000	RETIREMENT FOR WORK IN PROGRESS	Asset
10890000	ACCUM PROV FOR DEPRECIATION-RETIREMENTS	Asset
10890099	ACCUM PROV FOR DEPRECIATION-RETIREMENTS CONVERSION	Asset
10893111	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893112	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893113	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893114	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893116	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893117	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893119	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893120	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893121	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893122	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893123	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893124	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893126	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893127	DEPRECIATION RESERVE ADJUSTMENT	Asset

Account #	Description	Type
10893128	DEPRECIATION RESERVE ADJUSTMENT	Asset
1089312B	BOILER PLANT EQUIP-CLEAN AIR-REID	Asset
1089312C	BOILER PLANT EQUIP-CLEAN AIR-COLEMAN	Asset
1089312D	BOILER PLANT EQUIP-CLEAN AIR-GREEN	Asset
1089312E	BOILER PLANT EQUIP-CLEAN AIR-WILSON	Asset
1089312G	BOILER PLANT EQUIP-CLEAN AIR-REID/HMP&L	Asset
1089312L	DEPRECIATION RESERVE ADJUSTMENT	Asset
1089312M	DEPRECIATION RESERVE ADJUSTMENT	Asset
1089312N	DEPRECIATION RESERVE ADJUSTMENT	Asset
1089312P	DEPRECIATION RESERVE ADJUSTMENT	Asset
1089312Q	DEPRECIATION RESERVE ADJUSTMENT	Asset
1089312V	DEPRECIATION RESERVE ADJUSTMENT	Asset
1089312W	DEPRECIATION RESERVE ADJUSTMENT	Asset
1089312X	DEPRECIATION RESERVE ADJUSTMENT	Asset
1089312Y	DEPRECIATION RESERVE ADJUSTMENT	Asset
1089312Z	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893141	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893142	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893143	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893144	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893146	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893147	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893151	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893152	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893153	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893154	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893157	DEPRECIATION RESERVE ADJSTMENT	Asset
10893159	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893162	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893163	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893164	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893166	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893410	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893420	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893430	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893440	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893450	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893520	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893521	DEPRECIATION RESERVE ADJUSTMENT	Asset

Account #	Description	Type
10893522	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893524	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893530	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893531	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893532	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893533	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893534	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893540	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893551	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893561	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893900	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893910	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893912	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893913	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893922	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893923	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893930	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893940	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893950	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893960	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893961	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893970	DEPRECIATION RESERVE ADJUSTMENT	Asset
10893980	DEPRECIATION RESERVE ADJUSTMENT	Asset
11110000	ACCUM PROV FOR AMORT-STATION TWO ASSETS	Asset
11110099	ACCUM PROV FOR AMORT-STATION TWO CONVERSION	Asset
11113115	ACCUM PROV FOR AMORT OF STATION TWO	Asset
11113125	ACCUM PROV FOR AMORT OF STATION TWO	Asset
1111312F	BOILER PLANT EQUIP-CLEAN AIR-HMP&L	Asset
1111312K	BOILER PLANT EQUIP-CLEAN AIR-HMP&L SCRUB	Asset
1111312Q	BOILER-SHORT LIFE-CLEAN AIR-HM	Asset
1111312Z	BOILER-SHORT LIFE-HMPL	Asset
11113145	ACCUM PROV FOR AMORT OF STATION TWO	Asset
11113155	ACCUM PROV FOR AMORT OF STATION TWO	Asset
11113165	ACCUM PROV FOR AMORT OF STATION TWO	Asset
11150000	ACCUM PROV FOR AMORT-TRANSMISSION OTHER	Asset
11150099	ACCUM PROV FOR AMORT-TRANS OTHER CONVERSION	Asset
11153525	ACCUM PROV FOR AMORT-STRUCTURES-KU	Asset
11153535	ACCUM PROV FOR AMORT-STATION EQUIP-KU	Asset
11153545	ACCUM PROV FOR AMORT-TOWERS-KU	Asset

Account #	Description	Type
11153555	ACCUM PROV FOR AMORT-POLES-KU	Asset
11153565	ACCUM PROV FOR AMORT-OVHD CONDUCTOR-KU	Asset
11190000	ACCUM PROV FOR AMORT-RETIREMENTS	Asset
11190099	ACCUM PROV FOR AMORT-RETIREMENTS CONVERSION	Asset
11193115	AMORTIZATION RESERVE ADJUSTMENT	Asset
11193125	AMORTIZATION RESERVE ADJUSTMENT	Asset
1119312F	AMORTIZATION RESERVE ADJUSTMENT	Asset
1119312K	AMORTIZATION RESERVE ADJUSTMENT	Asset
1119312Q	AMORTIZATION RESERVE ADJUSTMENT	Asset
1119312Z	AMORTIZATION RESERVE ADJUSTMENT	Asset
11193145	AMORTIZATION RESERVE ADJUSTMENT	Asset
11193155	AMORTIZATION RESERVE ADJUSTMENT	Asset
12300000	PATRONAGE CAPITAL FROM ASSOC COOPERATIVES AND OTHER	Asset
12310000	PATRONAGE CAPITAL FROM ASSOC COOPERATIVE	Asset
12322000	INVESTMENTS IN CAPITAL TERM CERT-CFC	Asset
12323000	OTHER INVESTMENTS IN ASSOC ORGANIZATIONS	Asset
12400000	OTHER INVESTMENTS	Asset
12800000	OTHER SPECIAL FUNDS	Asset
12810000	OTHER SPECIAL FUNDS-DEFERRED INCOME	Asset
12820000	OTHER SPECIAL FUNDS-ECONOMIC RESERVE	Asset
12820001	OTHER SPECIAL FUNDS-ECONOMIC RES-PRINC	Asset
12820002	OTHER SPECIAL FUNDS-ECONOMIC RES-PREMIUM	Asset
12820099	OTHER SPECIAL FUNDS-ECONOMIC RESERVE CONVERSION	Asset
12830000	OTHER SPECIAL FUNDS-RURAL ECONOMIC RES	Asset
12830001	OTHER SPECIAL FUNDS-RURAL ER-PRINCIPAL	Asset
12830002	OTHER SPECIAL FUNDS-RURAL ER-PREMIUM	Asset
12830099	OTHER SPECIAL FUNDS-RURAL ECONOMIC RES CONVERSION	Asset
12840000	OTHER SPECIAL FUNDS-TRANSITION RESERVE	Asset
12840001	OTHER SPECIAL FUNDS-TRANS RES-PRINCIPAL	Asset
12840002	OTHER SPECIAL FUNDS-TRANS RES-PREMIUM	Asset
12840099	OTHER SPECIAL FUNDS-TRANSITION RESERVE CONVERSION	Asset
12850000	OTHER SPECIAL FUNDS-STATION TWO O&M FUND	Asset
12860000	OTHER SPECIAL FUNDS-CAFETERIA PLAN-ORACLE	Asset
12870000	OTHER SPECIAL FUNDS-LIBERTY MUTUAL-LOC	Asset
12880000	OTHER SPECIAL FUNDS-CAPEX RESERVE	Asset
12880001	OTHER SPECIAL FUNDS-CAPEX RES-PRINCIPAL	Asset
12880002	OTHER SPECIAL FUNDS-CAPEX RES-PREMIUM	Asset
12885000	OTHER SPECIAL FUNDS-RUS COUNSEL-UNWIND	Asset

Account #	Description	Type
12886000	OTHER SPECIAL FUNDS-MARITIME COM.	Asset
13100000	CASH	Asset
13106000	CASH CLEARING	Asset
13106100	CASH CLEARING - BREC STATION TW	Asset
13107300	CASH-OM FUND HMPL ONLY	Asset
13107400	CASH-R R FUND HMPL ONLY	Asset
13107700	CASH-INTERIM SCR ACCT (HMPL ONLY)	Asset
13110000	CASH-GENERAL	Asset
13111000	CASH-RIGHT OF WAY	Asset
13118000	CASH-ORACLE AP CLEARING	Asset
13400000	SPECIAL DEPOSITS	Asset
13410000	SPECIAL DEPOSIT-TVA TRANS RESERVATION	Asset
13420000	SPECIAL DEP-ADM/ICE MARGIN CALL	Asset
13500000	WORKING FUNDS	Asset
13600000	TEMPORARY CASH INVESTMENTS	Asset
13607300	INVESTMENTS-OM FUNDHMPL ONLY	Asset
13607400	INVESTMENTS-R R FUNDHMPL ONLY	Asset
14200000	CUSTOMER ACCOUNTS RECEIVABLE	Asset
14210000	CUSTOMER ACCOUNTS RECEIVABLE-ELECTRIC	Asset
14210300	CUSTOMER ACCOUNTS RECEIVABLE-MISO	Asset
14219900	CUSTOMER ACCOUNTS RECEIVABLE-CLEARING	Asset
14300000	ACCOUNTS RECEIVABLE	Asset
14313000	ACCTS REC-EMPLOYEES-OTHER	Asset
14313200	ACCTS REC-EMP COMPUTER ASSISTANCE PROGRAM	Asset
14318000	ACCTS REC-OTHER-ORACLE	Asset
14318200	ACCTS REC-EMP COMPUTER ASSIST PROG-ORACLE	Asset
14320000	OTHER ACCOUNTS RECEIVABLE-MISCELLANEOUS	Asset
14329900	OTHER ACCOUNTS RECEIVABLE-MISCELLANEOUS-CLEARING	Asset
14342000	ACCTS REC-WKE/TRANSMISSION	Asset
14350000	ACCTS REC-HMP&L-STA TWO OPERATION BILL	Asset
14350001	ACCTS REC-HMP&L-STA TWO AMORT EXP	Asset
14350002	ACCTS REC-HMP&L-STA TWO AMORT EXP-CLEAN AIR	Asset
14350003	ACCTS REC-HMP&L-STA TWO INTEREST CHARGED-CONST CR	Asset
14350004	ACCTS REC-HMP&L-STA TWO OPER SUPERVISION/ENGIN	Asset
14350005	ACCTS REC-HMP&L-STA TWO FUEL	Asset
14350006	ACCTS REC-HMP&L-STA TWO FUEL HANDLING	Asset
14350007	ACCTS REC-HMP&L-STA TWO BOTTOM ASH DISPOSAL	Asset
14350008	ACCTS REC-HMP&L-STA TWO FLY ASH DISPOSAL	Asset
14350009	ACCTS REC-HMP&L-STA TWO STEAM EXPENSES	Asset

Account #	Description	Type
14350010	ACCTS REC-HMP&L-STA TWO STEAM EXPENSES-CLEAN AIR	Asset
14350011	ACCTS REC-HMP&L-STA TWO SO2 REAGENTS	Asset
14350012	ACCTS REC-HMP&L-STA TWO ELECTRIC EXPENSES	Asset
14350013	ACCTS REC-HMP&L-STA TWO MISC STEAM PWR EXPENSES	Asset
14350014	ACCTS REC-HMP&L-STA TWO MISC STEAM PWR-SCR/NOX	Asset
14350015	ACCTS REC-HMP&L-STA TWO NOX REAGENTS	Asset
14350016	ACCTS REC-HMP&L-STA TWO RENTS-STEAM POWER	Asset
14350017	ACCTS REC-HMP&L-STA TWO ALLOWANCES-CLEAN AIR	Asset
14350018	ACCTS REC-HMP&L-STA TWO MAINT SUPERVISION/ENGIN	Asset
14350019	ACCTS REC-HMP&L-STA TWO MAINT STRUCTURES	Asset
14350020	ACCTS REC-HMP&L-STA TWO MAINT BOILER PLANT	Asset
14350021	ACCTS REC-HMP&L-STA TWO MAINT BOILER PLANT-CLEAN AIR	Asset
14350022	ACCTS REC-HMP&L-STA TWO MAINT SCRUBBER/SOLID WASTE	Asset
14350023	ACCTS REC-HMP&L-STA TWO BOILER PLANT-REAGENT PREP	Asset
14350024	ACCTS REC-HMP&L-STA TWO BOILER PLANT WASTE TREAT	Asset
14350025	ACCTS REC-HMP&L-STA TWO MAINT ELECTRIC PLANT	Asset
14350026	ACCTS REC-HMP&L-STA TWO MAINT MISC STEAM PLANT	Asset
14350027	ACCTS REC-HMP&L-STA TWO ADMIN & GENERAL SALARIES	Asset
14350028	ACCTS REC-HMP&L-STA TWO OFFICE SUPPLIES & EXPENSES	Asset
14350029	ACCTS REC-HMP&L-STA TWO OUTSIDE SERVICES EMPLOYED	Asset
14350030	ACCTS REC-HMP&L-STA TWO PROPERTY INSURANCE	Asset
14350031	ACCTS REC-HMP&L-STA TWO PROPERTY INSURANCE-CLEAN AIR	Asset
14350032	ACCTS REC-HMP&L-STA TWO INJURIES & DAMAGES	Asset
14350033	ACCTS REC-HMP&L-STA TWO EMPLOYEE PENSIONS/BENEFITS	Asset
14350034	ACCTS REC-HMP&L-STA TWO MISC GENERAL EXPENSES	Asset
14350035	ACCTS REC-HMP&L-STA TWO MAINT GENERAL PLANT	Asset
14350036	ACCTS REC-HMP&L-STA TWO SYSTEM CONTROL/LOAD DISPATCH	Asset
14350037	ACCTS REC-HMP&L-STA TWO STATION EXPENSES	Asset
14350038	ACCTS REC-HMP&L-STA TWO OPER SUPERVISION & ENGINEERING-LINES	Asset
14350039	ACCTS REC-HMP&L-STA TWO OPER SUPERVISION & ENGINEERING-STATIONS	Asset
14350040	ACCTS REC-HMP&L-STA TWO MAINT SUPERVISION & ENGINEERING-LINES	Asset
14350041	ACCTS REC-HMP&L-STA TWO MAINT SUPERVISION & ENGINEERING-STATIONS	Asset

Big Rivers Electric Corporation
Case No. 2013-00199
Chart of Accounts

Account #	Description	Type
14350042	ACCTS REC-HMP&L-STA TWO ADMINISTRATIVE AND GENERAL SALARIES-GENERATION	Asset
14350043	ACCTS REC-HMP&L-STA TWO OFFICE SUPPLIES AND EXPENSES-GENERATION	Asset
14350044	ACCTS REC-HMP&L-STA TWO OUTSIDE SERVICES EMPLOYED-GENERATION	Asset
14350045	ACCTS REC-HMP&L-STA TWO-MAINT OVERHEAD LINES	Asset
14350046	ACCTS REC-HMP&L-STA TWO-MAINTENANCE STATION EQUIPMENT	Asset
14350047	ACCTS REC-HMP&L-STA TWO-MAINTENANCE MISC TRANSMISSION PLANT-LINES	Asset
14350048	ACCTS REC-HMP&L-STA TWO-MAINTENANCE MISC TRANSMISSION PLANT-STATIONS	Asset
14350049	ACCTS REC-HMP&L-STA TWO REGULATORY COMMISSION EXPENSES-ECP	Asset
14350050	ACCTS REC-HMPL&L-STA TWO MISC STEAM PWR-EMISSION FEES	Asset
14350099	ACCTS REC-HMP&L-STA TWO OPERATION BILL CONVERSION	Asset
14350100	A/R - SII BILLING BREC/HMPL ONLY	Asset
14350300	A/R-SII INVENTORY HMPL ONLY	Asset
14360000	ACCTS REC-HMP&L-STA TWO OTHER	Asset
14370000	ACCTS REC-L G & E LEASE	Asset
14371000	ACCTS REC-WKE MEDICAL PREM	Asset
14372000	ACCTS REC-E.ON-US-UNWIND	Asset
14372500	ACCTS REC-E.ON-US-UNWIND-ADD'L	Asset
14373000	ACCTS REC-E.ON-US-HMP&L LITIGATION	Asset
14373500	ACCTS REC-HMP&L MISO COSTS	Asset
14374000	ACCTS REC-HMP&L LEM REIMB	Asset
14374500	ACCTS REC-MISC-LEM	Asset
14375000	ACCTS REC-WESTLAKE CHEMICAL CORP	Asset
14376000	ACCTS REC-SMITHLAND HYDRO POWER	Asset
14377000	ACCTS REC-KU-MATANZAS SUBSTATION	Asset
14378000	ACCTS REC-KYTC TL 18-G	Asset
14378500	ACCTS REC-KYTC GARRETT T-LINE	Asset
14378600	ACCTS REC-KYTC TL 4-A	Asset
14379000	ACCTS REC-CENTURY ESCROW	Asset
14379500	ACCTS REC-ALCAN ESCROW	Asset
14380000	ACCTS REC-WKE PROPERTY TAXES ON LEASED ASSET	Asset
14440000	ACCUM PROV FOR OTHER UNCOLLECTIBLE ACCTS-CREDIT	Asset

Account #	Description	Type
15100000	FUEL STOCK	Asset
15111000	FUEL STOCK-COAL-REID	Asset
15111100	FUEL STOCK-COAL-IN TRANSIT-REID	Asset
15112000	FUEL STOCK-COAL-COLEMAN	Asset
15112100	FUEL STOCK-COAL-IN TRANSIT-COLEMAN	Asset
15113000	FUEL STOCK-COAL-GREEN	Asset
15113100	FUEL STOCK-COAL-IN TRANSIT-GREEN	Asset
15114000	FUEL STOCK-COAL-WILSON	Asset
15114100	FUEL STOCK-COAL-IN TRANSIT-WILSON	Asset
15115000	FUEL STOCK-COAL-STATION TWO	Asset
15115100	FUEL STOCK-COAL-IN TRANSIT-STATION TWO	Asset
15131000	FUEL STOCK-OIL-REID/STATION TWO	Asset
15132000	FUEL STOCK-OIL-GAS TURBINE	Asset
15133000	FUEL STOCK-OIL-GREEN	Asset
15134000	FUEL STOCK-OIL-WILSON	Asset
15135000	FUEL STOCK-OIL-STATION TWO	Asset
15138000	FUEL STOCK-OIL-GAS TURBINE	Asset
15139000	FUEL STOCK-NATURAL GAS-GAS TURBINE	Asset
15152000	FUEL STOCK-PROPANE-COLEMAN	Asset
15173000	FUEL STOCK-PETROL COKE-GREEN	Asset
15173100	FUEL STOCK-PET COKE-IN TRANSIT-GREEN	Asset
15174000	FUEL STOCK-PETROL COKE-WILSON	Asset
15174100	FUEL STOCK-PET COKE-IN TRANSIT-WILSON	Asset
15175000	FUEL STOCK-PETROL COKE-STATION TWO	Asset
15400000	MATERIALS & SUPPLIES	Asset
15410000	MATERIALS & SUPPLIES-TRANSMISSION	Asset
15420000	MATERIALS & SUPPLIES-PRODUCTION	Asset
15422000	MATERIALS & SUPPLIES-PROD-VENDOR FAB-WIP	Asset
15423000	MATERIALS & SUPPLIES-PROD-SELF FAB PARTS	Asset
15423500	MATERIALS & SUPPLIES-STAT TWO-SELF FAB PARTS	Asset
15424000	MATERIALS & SUPPLIES-OBSOLESCENCE RESERVE	Asset
15424500	MATERIALS & SUPPLIES-OBSOLESCENCE RES-ST	Asset
15425000	MATERIALS & SUPPLIES-PRODUCTION-CLEARING	Asset
15432000	LIME STOCK-COLEMAN	Asset
15433000	LIME STOCK-GREEN	Asset
15434000	LIME STOCK-WILSON	Asset
15490000	MATERIALS & SUPPLIES-STATION TWO	Asset
15491000	MATERIALS & SUPPLIES-STATION TWO-CITY	Asset
15492500	MATERIALS & SUPPLIES-STAT TWO-VENDOR FAB	Asset

Big Rivers Electric Corporation
Case No. 2013-00199
Chart of Accounts

Account #	Description	Type
15499900	INVENTORY OBSOLESCENCE RESERVE	Asset
15811000	ALLOWANCE INVENTORY-SO2	Asset
15812000	ALLOWANCE INVENTORY-NOX	Asset
15820000	ALLOWANCES WITHHELD	Asset
16308000	STORES EXPENSE-UNDISTRIBUTED	Asset
16500000	PREPAYMENTS	Asset
16510000	PREPAYMENTS-INSURANCE	Asset
16510099	PREPAYMENTS-INSURANCE CONVERSION	Asset
16511000	PREPAID INS-PROPERTY COMP ALL RISK	Asset
16512000	PREPAID INS-SPECIAL MULTI-PERIL	Asset
16514000	PREPAID INS-DIRECTOR & OFFICER LIABILITY	Asset
16516000	PREPAID INS-GROUP TRAVEL ACCIDENT	Asset
16517000	PREPAID INS-OCEAN MARINE	Asset
16518000	PREPAID INS-UMBRELLA LIABILITY	Asset
16519000	PREPAID INS-CRIME	Asset
16520000	PREPAID INS-FIDUCIARY	Asset
16521000	PREPAID INS-WORKERS COMPENSATION	Asset
16521090	PREPAID INS-WORKERS COMPENSATION-CLEARING	Asset
16521800	PREPD INS-WRKS COMP-ORACLE	Asset
16523000	PREPAID INS-LONG TERM DISABILITY	Asset
16523090	PREPAID INS-LONG TERM DISABILITY-CLEARING	Asset
16523800	PREPD INS-LTD-ORACLE	Asset
16524000	PREPAID INS-AD&D EMPLOYEE & DEPEND LIFE	Asset
16524090	PREPAID INS-AD&D EMPLOYEE & DEPEND LIFE-CLEARING	Asset
16524800	PREPD INS-LIFE-ORACLE	Asset
16526000	PREPAID INS-AUTOMOBILE LIABILITY	Asset
16527000	DIRECTORS GROUP LIFE	Asset
16529800	PREPAYMENTS-CAFETERIA PLAN	Asset
16530000	PREPAYMENTS-EMPLOYER CONTRIB-RETIREMENT	Asset
16531000	PREPAYMENTS-AMBAC INSURANCE PREMIUMS	Asset
16533000	PREPAYMENTS-PURCHASING CARD ELAN	Asset
16533500	PREPAYMENTS-PURCHASING CARD ELAN-PLANT	Asset
16534000	PREPAYMENTS-STATE TAX	Asset
16535000	PREPAYMENTS-FEDERAL INCOME TAX	Asset
16538000	PREPAYMENTS-OTHER-ORACLE	Asset
17100000	INTEREST & DIVIDENDS RECEIVABLE	Asset
17120000	INTEREST & DIVIDENDS REC-ECONOMIC RESERVE	Asset
17122000	INTEREST & DIVIDENDS REC-CFC 2012 CTCs	Asset
17130000	INTEREST & DIVIDENDS REC-RURAL ECONOMIC RES	Asset

Big Rivers Electric Corporation
Case No. 2013-00199
Chart of Accounts

Account #	Description	Type
17140000	INTEREST & DIVIDENDS REC-TRANSITION RESERVE	Asset
17150000	INTEREST & DIVIDENDS REC-CFC 2012 CTCs	Asset
17310000	ACCRUED UTILITY REVENUE-LEM TRANS	Asset
17320000	ACCRUED UTILITY REVENUE-OTHER	Asset
17420000	ACCRUED MISC REVENUE-V WACLAWEK	Asset
17430000	ACCRUED MISC ASSET-SECURITY DEPOSIT	Asset
18100000	UNAMORTIZED DEBT EXPENSE	Asset
18110000	UNAMORT DEBT EXP-2001 PCB REFUND'G $83.3	Asset
18120000	UNAMORT DEBT EXP-2010 PCB REFUND'G $83.3	Asset
18125000	UNAMORTIZED BOND DISCOUNT-REFUND	Asset
18125100	ACCUM AMORTIZATION-BOND DISCOUNT	Asset
18125200	UNAMORTIZED FINANCING EXP-REFUND	Asset
18125300	ACCUM AMORTIZATION-FINANCING EX	Asset
18130000	UNAMORT DEBT EXP-RUS SERIES A NOTE REFINANCING	Asset
18140000	UNAMORT DEBT EXP-COBANK REVOLVER	Asset
18150000	UNAMORT DEBT EXP-CFC SYN REVOLV	Asset
18160000	UNAMORT DEBT EXP-2013 PCB $58.8	Asset
18235000	OTHER REG ASSET-NON-SMELTER NON-FAC PPA	Asset
18236000	OTHER REG ASSET-ENV COMP PLAN	Asset
18300000	PRELIM SURVEY & INVESTIGATION	Asset
18410000	TRANSPORTATION EXPENSE-GAS & OIL	Asset
18420000	TRANSPORTATION EXPENSE-OTHER	Asset
18430000	TRANSPORTATION EXPENSE-LARGE TRUCKS	Asset
18430100	TRANSPORTATION EXPENSE-VEHICLE 1	Asset
18430300	TRANSPORTATION EXPENSE-VEHICLE 103	Asset
18431600	TRANSPORTATION EXPENSE-VEHICLE 316	Asset
18432000	TRANSPORTATION EXPENSE-VEHICLE 120	Asset
18433800	TRANSPORTATION EXPENSE-VEHICLE 238	Asset
18433900	TRANSPORTATION EXPENSE-VEHICLE 239	Asset
18434800	TRANSPORTATION EXPENSE-VEHICLE 248	Asset
18435300	TRANSPORTATION EXPENSE-VEHICLE 253	Asset
18437500	TRANSPORTATION EXPENSE-VEHICLE 275	Asset
18437600	TRANSPORTATION EXPENSE-VEHICLE 76	Asset
18440000	CLEARING ACCOUNT-PURCHASING CARD	Asset
18450000	CLEARING ACCOUNT-STAT TWO SWITCHYARD	Asset
18460000	CLEARING ACCOUNT-MASS ALLOCATIONS	Asset
18481600	CLEARING ACCOUNT-INVENTORIES	Asset
18481900	CLEARING ACCOUNT-SYNMAT CREDIT	Asset
18482000	CLEARING ACCOUNT-HMP&L FUEL OIL	Asset

Big Rivers Electric Corporation
Case No. 2013-00199
Chart of Accounts

Account #	Description	Type
18489900	OUT-OF-BALANCE JOURNALS CLEARING	Asset
18498000	OTHER-ALLC CLEARING WKE ONLY-ORACLE	Asset
18600000	DEFERRED DEBIT	Asset
18608000	DEFERRED DEBIT-UNWIND	Asset
18610000	DEFERRED DEBIT-COBANK LINE OF CREDIT	Asset
18615000	DEFERRED DEBIT-NRUCFC LINE OF CREDIT	Asset
18620000	DEFERRED DEBIT-SEPAENERGY USAGE	Asset
18630000	DEFERRED DEBIT-POSTRETIREMENT BENEFITS	Asset
18640000	DEFERRED DEBIT-PROFESSIONAL SERVICES	Asset
18645000	DEFERRED DEBIT-CENTURY ESCROW	Asset
18650000	DEFERRED DEBIT-MARKETING PMT/SETTLEMENT	Asset
18660000	DEFERRED DEBIT-2012RATECASE EXP	Asset
18665000	DEFERRED DEBIT-2013RATECASE EXP	Asset
18670000	DEFERRED DEBIT-HANSON SITE LEASE	Asset
18680000	DEFERRED DEBIT-MISO RSG CHARGES	Asset
18685000	DEFERRED DEBIT-ICE STORM REPAIR	Asset
18905000	DEFERRED DEBIT-UNAMORTIZED LOSS DEF S/L	Asset
18910000	DEFERRED DEBIT-UNAMORTIZED LOSS 2001 PCB	Asset
18920000	DEFERRED DEBIT-UNAMORTIZED LOSS RUS SERIES A NOTE	Asset
19010000	ACCUMULATED DEFERRED INCOME TAXES	Asset
20000000	MEMBERSHIPS ISSUED	Liability
20010000	MEMBERSHIPS ISSUED	Liability
20100000	PATRONS CAPITAL-CREDITS, ASSIGNABLE AND DONATED	Owners' equity
20110000	PATRONS CAPITAL CREDITS	Liability
20120000	PATRONAGE CAPITAL ASSIGNABLE	Liability
20800000	DONATED CAPITAL	Liability
20911000	AOCI-POSTRETIREMENT BENEFITS	Liability
21100000	CONSUMERS CONSTRIBUTION FOR DEBT SERVICE	Liability
21600700	EQUITY IN CONSTRUCTION HMPL ONLY	Owners' equity
21600800	EQUITY IN INVESTMENTS HMPL ONLY	Owners' equity
21600900	EQUITY IN SCR HMPL ONLY	Owners' equity
21910000	OPERATING MARGINS	Owners' equity
21911000	AOCI-POSTRETIREMENT BENEFITS	Owners' equity
21918000	OPERATING MARGINS & OCI PENSION LIABILITY	Owners' equity
21920000	NONOPERATING MARGINS	Owners' equity
21940000	OTHER MARGINS & EQUITIES-PRIOR PERIODS	Owners' equity
22410000	LONG TERM DEBT	Liability
22412100	COBANK TERM LOAN-SERIES 2012A	Liability
22412200	CFC TERM LOAN	Liability

Account #	Description	Type
22412300	CFC EQUITY LOAN-2012 CTC	Liability
22414100	LEM SETTLEMENT PROMISSORY NOTE	Liability
22414700	LONG-TERM DEBT-OHIO COUNTY NOTE	Liability
22414800	PMCC PROMISSORY NOTE	Liability
22430000	LONG TERM DEBT-RUS	Liability
22435000	RUS SERIES A NOTE	Liability
22436000	RUS SERIES B NOTE	Liability
22800000	ACCUMULATED PROVISION-BENEFITS	Liability
22830000	ACCUMULATED PROVISION-DEF COMP	Liability
22830090	ACCUMULATED PROVISION-DEF COMP-CLEARING	Liability
22831000	ACCUMULATED PROVISION-SICK LEAVE BENEFIT	Liability
22831090	ACCUMULATED PROVISION-SICK LEAVE BENEFIT-CLEARING	Liability
22832000	ACCUM PROV-POST RETIREMENT BENEFITS	Liability
22832090	ACCUM PROV-POST RETIREMENT BENEFITS-CLEARING	Liability
22832500	ACCUM PROV-EMPLOYER CONTRIB-RETIREMENT	Liability
22832800	ACCUM PROV-POST RET BENEFITS-ORACLE	Liability
22833000	ACCUM PROV-MEDICAL INSURANCE	Liability
22833090	ACCUM PROV-MEDICAL INSURANCE-CLEARING	Liability
22833800	ACCUM PROV-MEDICAL INSURANCE-ORACLE	Liability
22834000	ACCUM PROV-DENTAL INSURANCE	Liability
22834090	ACCUM PROV-DENTAL INSURANCE-CLEARING	Liability
22834800	ACCUM PROV-DENTAL INSURANCE-ORACLE	Liability
22835000	ACCUM PROV-POSTEMPLOYMENT BENEFITS	Liability
22835090	ACCUM PROV-POSTEMPLOYMENT BENEFITS-CLEARING	Liability
22835800	ACCUM PROV-POSTEMPLOYMENT BENEFITS-ORACLE	Liability
22836000	ACCUM PROV-VISION INSURANCE	Liability
22836090	ACCUM PROV-VISION INSURANCE-CLEARING	Liability
23100000	NOTES PAYABLE	Liability
23110000	NOTES PAYABLE-NRUCFC	Liability
23120000	NOTES PAYABLE-COBANK	Liability
23200000	ACCOUNTS PAYABLE	Liability
23200900	PURCHASING ACCRUAL	Liability
23201200	ACCOUNTS PAYABLE-SHOP FLOOR	Liability
23201250	ACCOUNTS PAYABLE-SHOP FLOOR-DISCOUNTS	Liability
23201400	ACCOUNTS PAYABLE-INVENTORY	Liability
23201500	ACCOUNTS PAYABLE-COAL PURCHASES	Liability
23201600	ACCOUNTS PAYABLE-LIME PURCHASES	Liability
23201700	ACCOUNTS PAYABLE-COMBUSTION BY-PRODUCTS	Liability
23201800	ACCOUNTS PAYABLE-PETCOKE	Liability

Account #	Description	Type
23209900	SUSPENSE ACCOUNT	Liability
23210000	VOUCHERS PAYABLE-GENERAL FUND	Liability
23215000	ACCOUNTS PAYABLE-UNRECORDED LIABILITY	Liability
23218000	ACCOUNTS PAYABLE-GENERAL-ORACLE	Liability
23230000	ACCOUNTS PAYABLE-OTHER	Liability
23230100	ACCOUNTS PAYABLE-PURCHASED POWER	Liability
23230200	ACCOUNTS PAYABLE-PWR SCHEDULED-ECAR-ARS	Liability
23230300	ACCOUNTS PAYABLE-MISO	Liability
23230500	ACCOUNTS PAYABLE-CONSOLIDATED SERVICES	Liability
23230600	VOUCHERS PAYABLE-PHILIPPINE PROJECT	Liability
23230700	VOUCHERS PAYABLE-E.ON-UNWIND	Liability
23231000	ACCOUNTS PAYABLE-LANDFILL CAPPING/COVER	Liability
23238000	ACCOUNTS PAYABLE-OTHER-ORACLE	Liability
23240000	ACCTS PAY-HLMP&L-STA TWO POWER BILLING	Liability
23250200	HMPANDL OTHER A/P	Liability
23250300	A/P BREC BREC PORTION	Liability
23250400	A/P BREC CITY PORTION	Liability
23260000	ACCTS PAY-DEFINED BENEFIT-RETIREMENT	Liability
23260090	ACCTS PAY-DEFINED BENEFIT-RETIREMENT-CLEARING	Liability
23260100	ACCTS PAY-DEFINED CONTRIB-RETIREMENT	Liability
23260190	ACCTS PAY-DEFINED CONTRIB-RETIREMENT-CLEARING	Liability
23260200	ACCTS PAY-EMPLOYER CONTRIB-401K PLAN	Liability
23260290	ACCTS PAY-EMPLOYER CONTRIB-401(K) PLAN-CLEARING	Liability
23260500	ACCTS PAY-POSTRETIREMENT BENEFITS	Liability
23260800	ACCTS PAY-EMPLOYER CONTRIB-RETIREMENT-ORACLE	Liability
23268100	ACCTS PAY-DEFINED CONTRIB-RETIRE-ORACLE	Liability
23268200	ACCTS PAY-EMPLOYER CONTRIB-401K-ORACLE	Liability
23268500	ACCTS PAY-EMPLOYER-RETIRMENT INCOME-ORACLE	Liability
23270000	ACCTS PAY-L G & E LEASE	Liability
23271000	ACCTS PAY-INCREMENTAL O&M	Liability
23275000	ACOUNTS PAYABLE-CAPITAL ASSETS	Liability
23275100	ACCOUNTS PAYABLE-INCREMENTAL C	Liability
23280090	ACCOUNTS PAYABLE-MISCELLANEOUS	Liability
23290000	ACCTS PAY-RETAINAGE	Liability
23500000	CUSTOMER DEPOSITS	Liability
23500099	CUSTOMER DEPOSITS CONVERSION	Liability
23510000	CUSTOMER DEPOSITS-MARGIN CALL-EDF	Liability
23520000	CUSTOMER DEP-MARGIN CALL-AMEREN UNION	Liability
23525502	CUSTOMER DEPOSITS-BREC POWER SUPPLY RELIANT	Liability

Big Rivers Electric Corporation
Case No. 2013-00199
Chart of Accounts

Account #	Description	Type
23525592	CUSTOMER DEP-BREC POWER SUPPLY RELIANT	Liability
23527002	CUSTOMER DEPOSITS-LEM	Liability
23600000	TAXES ACCRUED	Liability
23610000	TAXES ACCRUED-PROPERTY	Liability
23618000	TAXES ACCRUED-PROPERTY-ORACLE	Liability
23620000	TAXES ACCRUED-FEDERAL UNEMPLOYMENT	Liability
23620090	TAXES ACCRUED-FEDERAL UNEMPLOYMENT-CLEARING	Liability
23628000	TAXES ACCRUED-FEDERAL UNEMPLOYMENT-ORACLE	Liability
23630000	TAXES ACCRUED-FICA	Liability
23630090	TAXES ACCRUED-FICA-CLEARING	Liability
23638000	TAXES ACCRUED-FICA-ORACLE	Liability
23640000	TAXES ACCRUED-STATE UNEMPLOYMENT	Liability
23640090	TAXES ACCRUED-STATE UNEMPLOYMENT-CLEARING	Liability
23648000	TAXES ACCRUED-STATE UNEMPLOYMENT-ORACLE	Liability
23650000	TAXES ACCRUED-SALES & USE	Liability
23658000	TAXES ACCRUED-SALES & USE-ORACLE	Liability
23670000	TAXES ACCRUED-FEDERAL INCOME	Liability
23700000	ACCRUED INTEREST	Liability
23710000	ACCRUED INTEREST-NRUCFC	Liability
23712100	ACCRUED INTEREST-COBANK TERM LOAN SERIES 2012A	Liability
23712200	ACCRUED INTEREST-CFC TERM LOAN	Liability
23712300	ACCRUED INTEREST-CFC EQUITY LOAN-2012 CTCS	Liability
23714100	ACCRUED INTEREST-SETTLEMENT PROMISSORY NOTE	Liability
23714800	ACCRUED INTEREST-PMCC PROMISSORY NOTE	Liability
23715000	ACCRUED INTEREST-RUS SERIES A NOTE	Liability
23716000	ACCRUED INTEREST-RUS SERIES B NOTE	Liability
23720000	ACCRUED INTEREST-COBANK	Liability
23760000	ACCRUED INTEREST-OHIO COUNTY NOTES	Liability
24100000	TAX COLLECTIONS PAYABLE	Liability
24110000	TAX COLLECTIONS PAYABLE-FEDERAL INCOME	Liability
24118000	TAX COLLECTIONS PAYABLE-FED INCOME-ORACLE	Liability
24120000	TAX COLLECTIONS PAYABLE-STATE INCOME-KY	Liability
24121000	TAX COLLECTIONS PAYABLE-STATE INCOME-IND	Liability
24121800	TAX COLLECTIONS PAYABLE-STATE INC-IND-ORACLE	Liability
24128000	TAX COLLECTIONS PAYABLE-STATE INC-KY-ORACLE	Liability
24130000	TAX COLLECTIONS PAYABLE-FICA	Liability
24138000	TAX COLLECTIONS PAYABLE-FICA-O	Liability
24140000	TAX COLLECTIONS PAYABLE-HANCOCK CO-OCCP	Liability
24141000	TAX COLLECTIONS PAYABLE-OHIO CO-OCCP	Liability

Big Rivers Electric Corporation
Case No. 2013-00199
Chart of Accounts

Account #	Description	Type
24142000	TAX COLLECTIONS PAYABLE-MCCRACKEN CO-OCCP	Liability
24143000	TAX COLLECTIONS PAYABLE-HENDERSON-CITY	Liability
24143800	TAX COLLECTIONS PAYABLE-HENDERSON CITY-ORAC	Liability
24144000	TAX COLLECTIONS PAYABLE-MARION-CITY	Liability
24145000	TAX COLLECTIONS PAYABLE-PADUCAH-CITY	Liability
24146000	TAX COLLECTIONS PAYABLE-BALLARD-COUNTY	Liability
24147000	TAX COLLECTIONS PAYABLE-CALDWELL-COUNTY	Liability
24148000	TAX COLLECTIONS PAYABLE-DAVIESS-COUNTY	Liability
24149000	TAX COLLECTIONS PAYABLE-GRAVES-COUNTY	Liability
24150000	TAX COLLECTIONS PAYABLE-GRAYSON-COUNTY	Liability
24151000	TAX COLLECTIONS PAYABLE-LIVINGSTON-CNTY	Liability
24152000	TAX COLLECTIONS PAYABLE-MARSHALL-COUNTY	Liability
24153000	TAX COLLECTIONS PAYABLE-MCLEAN-COUNTY	Liability
24154000	TAX COLLECTIONS PAYABLE-UNION-COUNTY	Liability
24155000	TAX COLLECTIONS PAYABLE-FRANKFORT-CITY	Liability
24158000	TAX COLLECTIONS PAY CITY/COUNTY ORACLE	Liability
24161000	TAX COLLECTIONS PAY IN-HARRISON CTY	Liability
24162000	TAX COLLECTIONS PAY IN-PERRY CTY	Liability
24163000	TAX COLLECTIONS PAY IN-POSEY CTY	Liability
24164000	TAX COLLECTIONS PAY IN-SPENCER CTY	Liability
24165000	TAX COLLECTIONS PAY IN-VANDERBURGH	Liability
24166000	TAX COLLECTIONS PAY IN-WARRICK CTY	Liability
24220000	ACCRUED PAYROLL	Liability
24220090	ACCRUED PAYROLL CLEARING ACCOUNT	Liability
24221000	ACCRUED PAYROLL CLEARING ACCOUNT	Liability
24228000	ACCRUED PAYROLL-ORACLE	Liability
24231000	ACCRUED VACATIONS	Liability
24231090	ACCRUED VACATIONS-CLEARING	Liability
24231800	ACCRUED VACATIONS-ORACLE	Liability
24232000	ACCRUED HOLIDAYS	Liability
24232090	ACCRUED HOLIDAYS-CLEARING	Liability
24232800	ACCRUED HOLIDAYS-ORACLE	Liability
24233190	ACCRUED WORKERS COMP-CLEARING	Liability
24233200	ACCRUED OTHER OFF-DUTY	Liability
24233290	ACCRUED OTHER OFF-DUTY-CLEARING	Liability
24233300	ACCRUED PREMIUM PAY	Liability
24233390	ACCRUED PREMIUM PAY-CLEARING	Liability
24233400	ACCRUED INCENTIVE	Liability
24233490	ACCRUED INCENTIVE-CLEARING	Liability

Account #	Description	Type
24233500	ACCRUED BONUS	Liability
24233590	ACCRUED BONUS-CLEARING	Liability
24233600	ACCRUED SICK	Liability
24233690	ACCRUED SICK-CLEARING	Liability
24233800	ACCRUED SICK-ORACLE	Liability
24234000	ACCRUED PERSONAL DAYS	Liability
24234090	ACCRUED PERSONAL DAYS-CLEARING	Liability
24240000	ACCRUED INSURANCE	Liability
24241000	ACCRUED SUPPLEMENTAL LIFE INSURANCE	Liability
24241800	ACCRUED SUPPLEMENTAL LIFE INS-ORACLE	Liability
24242000	ACCRUED CANCER PLAN	Liability
24243000	ACCRUED AFLAC INSURANCE	Liability
24251000	ACCRUED CAFETERIA PLAN	Liability
24251800	ACCRUED CAFETERIA PLAN-ORACLE	Liability
24252000	ACCRUED CREDIT UNION	Liability
24252800	ACCRUED CREDIT UNION-ORACLE	Liability
24253000	ACCRUED UNITED FUND	Liability
24253800	ACCRUED UNITED FUND-ORACLE	Liability
24255000	ACCRUED SURE & ACRE	Liability
24260800	ACCRUED EMPLOYEE-401K-ORACLE	Liability
24261000	ACCRUED EMPLOYEE CONTRI-SAVING	Liability
24262000	ACCRUED EMPLOYEE CONTRI-401K PLAN	Liability
24263000	ACCRUED EMPLOYEE-401K PLAN LOANS	Liability
24263800	ACCRUED EMPLOYEE-401(K) PLAN LOANS-ORACLE	Liability
24265000	ACCRUED EMPLOYEE CONTRI-DEF COMP	Liability
24270000	ACCRUED UNION DUES	Liability
24280000	ACCRUED MISC LIABILITY-EMPLOYEES	Liability
24280800	ACCRUED MISC LIABILITY-EMPLOYEES-ORACLE	Liability
24295000	ACCRUED LIABILITY-EMISSION FEES	Liability
24298800	ACCRUED LIABILITY-OTHER-ORACLE	Liability
24299000	ACCRUED LIABILITY-OTHER	Liability
25300000	DEFERRED CREDIT	Liability
25302000	DEFERRED CREDIT-SEPA ENERGY USAGE	Liability
25320000	DEFERRED CREDIT-LEASE INCOME	Liability
25320001	DEFERRED CR-LEASE INCOME-NONTRANSMISSION	Liability
25320002	DEFERRED CR-LEASE INCOME-TRANSMISSION	Liability
25320099	DEFERRED CREDIT-LEASE INCOME CONVERSION	Liability
25325000	DEFERRED CREDIT-CAP ASSET RESIDUAL VALUE	Liability
25325100	DEFERRED CREDIT-INCRMNTL RESIDUAL VALUE	Liability

Big Rivers Electric Corporation
Case No. 2013-00199
Chart of Accounts

Account #	Description	Type
25335000	DEFERRED CREDIT-CEN EXCESS REACTIVE PWR	Liability
25336000	DEFERRED CREDIT-ALCAN EXCESS REACTIVE PWR	Liability
25340000	DEFERRED CREDIT-UNWIND CLOSING PAYMENT	Liability
25345000	DEFERRED CREDIT-CENTURY ESCROW	Liability
25350000	DEFERRED CREDIT-OTHER	Liability
25420000	OTHER REG LIAB-ECONOMIC RESERVE	Liability
25430000	OTHER REG LIAB-RURAL ECONOMIC RESERVE	Liability
25435000	OTHER REG LIAB-NON-SMELTER NON-FAC PPA	Liability
25435500	OTHER REG LIAB-NSNFP FACTOR-AMORT	Liability
25436000	OTHER REG LIAB-NSNFP FACTOR-AMORT-2	Liability
40300000	DEPRECIATION EXPENSE	Expense
40311000	DEPRECIATION EXPENSE-STEAM PLANT	Expense
40311100	DEPRECIATION EXPENSE-STEAM PLANT-CLEAN AIR	Expense
40340000	DEPRECIATION EXPENSE-GAS TURBINE	Expense
40350000	DEPRECIATION EXPENSE-TRANSMISSION	Expense
40370000	DEPRECIATION EXPENSE-GENERAL PLANT	Expense
40411000	AMORTIZATION EXPENSE	Expense
40411100	AMORTIZATION EXPENSE-CLEAN AIR	Expense
40800000	TAXES	Expense
40811000	TAXES-PROPERTY	Expense
40811100	TAXES-PROPERTY-CLEAN AIR	Expense
40811900	TAXES-PROPERTY-CONTRA	Expense
40820000	TAXES OTHER THAN INCOME TAXES	Expense
40910000	TAXES-FEDERAL INCOME	Expense
40911000	TAXES-STATE INCOME/FRANCHISE	Expense
40920000	TAXES-FEDERAL INCOME-OTHER INC/DEDUCT	Expense
41020000	DEFERRED INCOME TAXES-OTHER INC/DEDUCT	Expense
41110000	PROVISION FOR DEFERRED INCOME TAXES-CR	Expense
41180000	GAIN FROM DISPOSITION OF ALLOWANCES	Revenue
41200000	REVENUES FROM ELECTRIC PLANT LEASED TO WKEC	Revenue
41200001	REVENUE FROM LG&E LEASE-NONTRANSMISSION	Revenue
41200002	REVENUE FROM LG&E LEASE-TRANSMISSION	Revenue
41200099	REVENUES - ELEC PLANT LEASED TO WKED CONVERSION	Revenue
41210000	WKEC CONTRIBUTION TO CAP AMORT TO INCOME	Revenue
41210001	WKEC CONTR TO CAP AMORT TO INC-NONTRAN	Revenue
41210002	WKEC CONTR TO CAP AMORT TO INC-INCRMNTL	Revenue
41210099	WKEC CONTRIB TO CAP AMORT TO INCOME CONVERSION	Revenue
41290000	REVENUES FROM ELECTRIC PLANT	Expense
412X0000	MISC INCOME	Revenue

Account #	Description	Type
41310000	OPERATION EXPENSES-ELECTRIC PLANT LEASED	Expense
41320000	MAINTENANCE EXPENSES-ELECTRIC PLANT LEASED	Expense
41330000	DEPR EXP-ELECTRIC PLANT LEASED TO WKE	Expense
41340000	AMORT EXP-ELECTRIC PLANT LEASED TO WKEC	Expense
41808000	REVENUES FROM NONOPERATING RENTAL INC-OR	Revenue
41900000	INTEREST & DIVIDEND INCOME	Revenue
41904000	INTEREST & DIVIDEND INCOME-TRANSITION RES	Revenue
41908000	INTEREST & DIVIDEND INCOME-ORACLE	Revenue
41922000	INTEREST & DIVIDEND INCOME-CFC 2012 CTCS	Revenue
41950000	INTEREST & DIVIDEND INCOME-CFC CAP TERM CERT	Revenue
419X0000	INTEREST & DIVIDEND INCOME	Revenue
42100000	MISCELLANEOUS NONOPERATING INCOME	Revenue
42110000	GAIN ON DISPOSITION OF PROPERTY	Revenue
42120000	LOSS ON DISPOSITION OF PROPERTY	Expense
421X0000	OTHER OPERATING REVENUE AND INCOME	Revenue
42400000	OTHER CAPITAL CREDITS & PATRONAGE ALLOC	Revenue
42610000	DONATIONS	Expense
42630000	PENALTIES	Expense
42640000	CIVIC, POLITICAL, RELATED ACT.-EXPENSE	Expense
42650000	OTHER DEDUCTIONS	Expense
426X0000	DONATIONS, PENALTIES, CIVIC	Expense
42710000	INTEREST ON LONG TERM DEBT	Expense
42711000	INTEREST ON LONG-TERM DEBT	Expense
42711100	INTEREST LONG-TERM DEBT-CLEAN AIR	Expense
42730000	INTEREST CHARGED TO CONSTRUCTION	Expense
42731000	INTEREST CHARGED TO CONST-CR	Expense
42731100	INTEREST CHARGED TO CONST-CR-CLEAN AIR	Expense
42800000	AMORTIZATION-DEBT EXPENSE	Expense
42810000	AMORTIZE LOSS - REACQUIRED DEBT 2001 BONDS	Expense
42811000	AMORTIZE LOSS - REACQUIRED DEBT RUS A NOTE	Expense
42815000	AMORTIZE LOSS - DEFEASED SALE/LEASEBACK	Expense
43100000	INTEREST EXPENSE	Expense
43110000	INTEREST EXPENSE-NRUCFC	Expense
43120000	INTEREST EXPENSE-COBANK	Expense
43130000	INTEREST EXPENSE-OTHER	Expense
43300200	CLOSED 09/08 - RETAINED EARNING	Revenue
43400000	EXTRAORDINARY INCOME	Revenue
434X0000	EXTRAORDINARY INCOME & DEDUCTIONS	Expense
43500000	EXTRAORDINARY DEDUCTIONS	Expense

Big Rivers Electric Corporation
Case No. 2013-00199
Chart of Accounts

Account #	Description	Type
44700000	SALES FOR RESALE	Revenue
44701000	FIRM SALES - ENERGY-OTHER - KWH	Revenue
44710100	SALES FOR RESALE-RUS-KE-RURAL	Revenue
44710101	SFR-RUS-KE-NONTRANS-RURAL	Revenue
44710102	SFR-RUS-KE-TRANS-RURAL	Revenue
44710199	SALES FOR RESALE-RUS-KE-RURAL CONVERSION	Revenue
44711000	SALES FOR RESALE-RUS-KE-ROLL COATER, INC	Revenue
44711001	SFR-RUS-KE-NONTRANS-ROLL COATER, INC	Revenue
44711002	SFR-RUS-KE-TRANS-ROLL COATER, INC	Revenue
44711099	SALES FOR RESALE-RUS-KE-ROLL COATER CONVERSION	Revenue
44711200	SALES FOR RESALE-RUS-KE-KIMBERLU-CLARK	Revenue
44711201	SFR-RUS-KE-NONTRANS-KIMBERLY-CLARK	Revenue
44711202	SFR-RUS-KE-TRANS-KIMBERLY-CLARK	Revenue
44711299	SALES FOR RESALE-RUS-KE-KIMBERLY-CLARK CONVERSION	Revenue
44711300	SALES FOR RESALE-RUS-KE-DOMTAR PAPER CO	Revenue
44711301	SFR-RUS-KE-NONTRANS-DOMTAR PAPER CO	Revenue
44711302	SFR-RUS-KE-TRANS-DOMTAR PAPER CO	Revenue
44711399	SALES FOR RESALE-RUS-KE-DOMTAR PAPER CONVERSION	Revenue
44711400	SALES FOR RESALE-RUS-KE-ALERIS INTERNAT	Revenue
44711401	SFR-RUS-KE-NONTRANS-ALERIS INTERNAT	Revenue
44711402	SFR-RUS-KE-TRANS-ALERIS INTERNAT	Revenue
44711499	SALES FOR RESALE-RUS-KE-ALERIS CONVERSION	Revenue
44711600	SALES FOR RESALE-RUS-KE-SOUTHWIRE COMPAN	Revenue
44711601	SFR-RUS-KE-NONTRANS-SOUTHWIRE COMPAN	Revenue
44711602	SFR-RUS-KE-TRANS-SOUTHWIRE COMPAN	Revenue
44711699	SALES FOR RESALE-RUS-KE-SOUTHWIRE CONVERSION	Revenue
44711700	SALES FOR RESALE-RUS-KE-ALCOA AUTOMOTIVE	Revenue
44711701	SFR-RUS-KE-NONTRANS-ALCOA AUTOMOTIVE	Revenue
44711702	SFR-RUS-KE-TRANS-ALCOA AUTOMOTIVE	Revenue
44711799	SALES FOR RESALE-RUS-KE-ALCOA AUTO CONVERSION	Revenue
44711800	SALES FOR RESALE-RUS-KE-ARMSTRONG BIG RUN	Revenue
44711801	SFR-RUS-KE-NONTRANS-ARMSTRONG BIG RUN	Revenue
44711802	SFR-RUS-KE-TRANS-ARMSTRONG BIG RUN	Revenue
44711899	SALES FOR RESALE-RUS-KE-ARMSTRONG CONVERSION	Revenue
44711900	SALES FOR RESALE-RUS-KE-ARMSTRONG-MIDWAY	Revenue
44711901	SFR-RUS-KE-NONTRANS-ARMSTRONG-MIDWAY	Revenue
44711902	SFR-RUS-KE-TRANS-ARMSTRONG-MIDWAY	Revenue
44711999	SALES FOR RESALE-RUS-KE-ARMSTRONG-MID CONVERSION	Revenue
44712400	SALES FOR RESALE-RUS-KE-ACCURIDE	Revenue

Big Rivers Electric Corporation
Case No. 2013-00199
Chart of Accounts

Account #	Description	Type
44712401	SFR-RUS-KE-NONTRANS-ACCURIDE	Revenue
44712402	SFR-RUS-KE-TRANS-ACCURIDE	Revenue
44712499	SALES FOR RESALE-RUS-KE-ACCURIDE CONVERSION	Revenue
44712600	SALES FOR RESALE-RUS-KE-KB ALLOYS	Revenue
44712601	SFR-RUS-KE-NONTRANS-KB ALLOYS	Revenue
44712602	SFR-RUS-KE-TRANS-KB ALLOYS	Revenue
44712699	SALES FOR RESALE-RUS-KE-KB ALLOYS CONVERSION	Revenue
44712800	SALES FOR RESALE-RUS-KE-ARMSTRONG-DOCK	Revenue
44712801	SFR-RUS-KE-NONTRANS-ARMSTRONG-DOCK	Revenue
44712802	SFR-RUS-KE-TRANS-ARMSTRONG-DOCK	Revenue
44712899	SALES FOR RESALE-RUS-KE-ARMSTRG-DOCK CONVERSION	Revenue
44712900	SALES FOR RESALE-RUS-KE-ARMSTRONG EQUALITY	Revenue
44712901	SFR-RUS-KE-NONTRANS-ARMSTRONG EQUALITY	Revenue
44712902	SFR-RUS-KE-TRANS-ARMSTRONG EQUALITY	Revenue
44712999	SALES FOR RESALE-RUS-KE-ARMSTRG EQUAL CONVRSION	Revenue
44713000	SALES FOR RESALE-RUS-KE-ARMSTRONG-LEWIS CREEK	Revenue
44713001	SFR-RUS-KE-NONTRANS-ARMSTRONG-LEWIS CREEK	Revenue
44713002	SFR-RUS-KE-TRANS-ARMSTRONG-LEWIS CREEK	Revenue
44713200	SALES FOR RESALE-RUS-KE-ALLIED RESOURCES	Revenue
44713201	SFR-RUS-KE-NONTRANS-ALLIED RESOURCES	Revenue
44713202	SFR-RUS-KE-TRANS-ALLIED RESOURCES	Revenue
44713299	SALES FOR RESALE-RUS-KE-ALLIED CONVERSION	Revenue
44713300	SALES FOR RESALE-RUS-KE-HOPKIN CO COAL	Revenue
44713301	SFR-RUS-KE-NONTRANS-HOPKINS CO COAL	Revenue
44713302	SFR-RUS-KE-TRANS-HOPKINS CO COAL	Revenue
44713399	SALES FOR RESALE-RUS-KE-HOPKINS COAL CONVERSION	Revenue
44713400	SALES FOR RESALE-RUS-KE-KMMC, L.L.C.	Revenue
44713401	SFR-RUS-KE-NONTRANS-KMMC, L.L.C.	Revenue
44713402	SFR-RUS-KE-TRANS-KMMC, L.L.C.	Revenue
44713499	SALES FOR RESALE-RUS-KE-KMMC, L.L.C CONVERSION	Revenue
44713500	SALES FOR RESALE-RUS-KE-TYSON FOODS	Revenue
44713501	SFR-RUS-KE-NONTRANS-TYSON FOODS	Revenue
44713502	SFR-RUS-KE-TRANS-TYSON FOODS	Revenue
44713599	SALES FOR RESALE-RUS-KE-TYSON FOODS CONVERSION	Revenue
44713600	SALES FOR RESALE-RUS-KE-HCC-ELK CREEK	Revenue
44713601	SFR-RUS-KE-NONTRANS-HCC-ELK CREEK	Revenue
44713700	SALES FOR RESALE-RUS-KE-PATRIOT COAL	Revenue
44713701	SFR-RUS-KE-NONTRANS-PATRIOT COAL	Revenue
44713702	SFR-RUS-KE-TRANS-PATRIOT COAL	Revenue

Account #	Description	Type
44713799	SALES FOR RESALE-RUS-KE-PATRIOT COAL CONVERSION	Revenue
44713800	SALES FOR RESALE-RUS-KE-VALLEY GRAIN	Revenue
44713801	SFR-RUS-KE-NONTRANS-VALLEY GRAIN	Revenue
44713802	SFR-RUS-KE-TRANS-VALLEY GRAIN	Revenue
44713899	SALES FOR RESALE-RUS-KE-VALLEY GRAIN CONVERSION	Revenue
44713900	SALES FOR RESALE-RUS-KE-DOTIKI #4	Revenue
44713901	SFR-RUS-KE-NONTRANS-DOTIKI #4	Revenue
44713902	SFR-RUS-KE-TRANS-DOTIKI #4	Revenue
44713999	SALES FOR RESALE-RUS-KE-DOTIKI #4 CONVERSION	Revenue
44714000	SALES FOR RESALE-RUS-MC-RURAL	Revenue
44714001	SFR-RUS-MC-NONTRANS-RURAL	Revenue
44714002	SFR-RUS-MC-TRANS-RURAL	Revenue
44714099	SALES FOR RESALE-RUS-MC-RURAL CONVERSION	Revenue
44715100	SALES FOR RESALE-RUS-JP-RURAL	Revenue
44715101	SFR-RUS-JP-NONTRANS-RURAL	Revenue
44715102	SFR-RUS-JP-TRANS-RURAL	Revenue
44715199	SALES FOR RESALE-RUS-JP-RURAL CONVERSION	Revenue
44715300	SALES FOR RESALE-RUS-JP-SHELL OIL	Revenue
44715301	SFR-RUS-JP-NONTRANS-SHELL OIL	Revenue
44715302	SFR-RUS-JP-TRANS-SHELL OIL	Revenue
44715399	SALES FOR RESALE-RUS-JP-SHELL OIL CONVERSION	Revenue
44715400	SALES FOR RESALE-RUS-ECONOMIC RESERVE MEMBERS	Revenue
44715401	SFR-RUS-NONTRANS-ECONOMIC RESERVE-MEMBERS	Revenue
44715402	SFR-RUS-TRANS-ECONOMIC RESERVE-MEMBERS	Revenue
44715499	SALES FOR RESALE-RUS-ECON RES MEMBERS CONVERSION	Revenue
44717100	SALES FOR RESALE-RUS-POWERSOUTH ENERGY	Revenue
44717101	SFR-RUS-NONTRANS-POWERSOUTH ENERGY	Revenue
44717199	SALES FOR RESALE-RUS-POWERSOUTH CONVERSION	Revenue
44717500	SALES FOR RESALE-RUS-OGLETHORPE POWER	Revenue
44717501	SFR-RUS-NONTRANS-OGLETHORPE POWER	Revenue
44717599	SALES FOR RESALE-RUS-OGLETHORPE CONVERSION	Revenue
44718300	SALES FOR RESALE-RUS-ASSOC ELEC COOP	Revenue
44718301	SFR-RUS-NONTRANS-ASSOC ELEC COOP	Revenue
44718399	SALES FOR RESALE-RUS-ASSOC ELEC CONVERSION'	Revenue
44718500	SALES FOR RESALE-RUS-EAST KENTUCKY	Revenue
44718501	SFR-RUS-NONTRANS-EAST KENTUCKY	Revenue
44718599	SALES FOR RESALE-RUS-EAST KENTTUCKY CONVERSION	Revenue
44719100	SALES FOR RESALE-RUS-KE-CENTURY/ALCAN	Revenue
44719101	SFR-RUS-KE-NONTRANS-CENTURY/ALCAN	Revenue

Account #	Description	Type
44719199	SALES FOR RESALE-RUS-KE-CENTURY/ALCAN CONVERSION	Revenue
44719300	SALES FOR RESALE-RUS-KE-DOMTAR COGEN	Revenue
44719301	SFR-RUS-KE-NONTRANS-DOMTAR COGDN	Revenue
44719399	SALES FOR RESALE-RUS-KE-DOMTAR COGEN CONVERSION	Revenue
44719400	SALES FOR RESALE-RUS-KE-DOMTAR COGEN-ARS	Revenue
44719401	SFR-RUS-KE-NONTRANS-DOMTAR COGEN-ARS	Revenue
44719499	SALES FOR RESALE-RUS-KE-DOMTAR-ARS CONVERSION	Revenue
44719500	SALES FOR RESALE-RUS-KE-ALCAN	Revenue
44719501	SFR-RUS-KE-NONTRANS-ALCAN	Revenue
44719600	SALES FOR RESALE-RUS-KE-CENTURY	Revenue
44719601	SFR-RUS-KE-NONTRANS-CENTURY	Revenue
44721000	SALES FOR RESALE-OTHER-AMERICAN ELECTRIC POWER SERVICE	Revenue
44721001	SFR-OTHER-NONTRANS-AMERICAN ELECTRIC POWER SERVICE CORP	Revenue
44721500	SALES FOR RESALE-OTHER-TVA	Revenue
44721501	SFR-OTHER-NONTRANS-TVA	Revenue
44721599	SALES FOR RESALE-OTHER-TVA CONVERSION	Revenue
44722000	SALES FOR RESALE-OTHER-HMP&L	Revenue
44722001	SFR-OTHER-NONTRANS-HMP&L	Revenue
44722099	SALES FOR RESALE-OTHER-HMP&L CONVERSION	Revenue
44723500	SALES FOR RESALE-OTHER-LEM	Revenue
44723501	SFR-OTHER-NONTRANS-LEM	Revenue
44723599	SALES FOR RESALE-OTHER-LEM CONVERSION	Revenue
44723600	SALES FOR RESALE-OTHER-AMEREN UE	Revenue
44723601	SFR-OTHER-NONTRANS-AMEREN UE	Revenue
44723699	SALES FOR RESALE-OTHER-AMEREN UE CONVERSION	Revenue
44723700	SALES FOR RESALE-OTHER-KENTUCKY UTILITIES	Revenue
44723701	SFR-OTHER-NONTRANS-KENTUCKY UTILITIES	Revenue
44723800	SALES FOR RESALE-OTHER-LG&E	Revenue
44723801	SFR-OHTER-NONTRANS-LG&E	Revenue
44724100	SALES FOR RESALE-OTHER-ENERGY AUTHORITY	Revenue
44724101	SFR-OTHER-NONTRANS-ENERGY AUTHORITY	Revenue
44724199	SALES FOR RESALE-OTHER-ENERGY AUTH CONVERSION	Revenue
44724200	SALES FOR RESALE-OTHER-MISO	Revenue
44724201	SFR-OTHER-NONTRANS-MISO	Revenue
44724299	SALES FOR RESALE-OTHER-MISO CONVERSION	Revenue
44724300	SALES FOR RESALE-OTHER-MISO-ARS	Revenue
44724301	SFR-OTHER-NONTRANS-MISO-ARS	Revenue

Big Rivers Electric Corporation
Case No. 2013-00199
Chart of Accounts

Account #	Description	Type
44724399	SALES FOR RESALE-OTHER-MISO-ARS CONVERSION	Revenue
44724400	SALES FOR RESALE-OTHER-PJM	Revenue
44724401	SFR-OTHER-NONTRANS-PJM	Revenue
44724499	SALES FOR RESALE-OTHER-PJM CONVERSION	Revenue
44724600	SALES FOR RESALE-OTHER-EDF TRADING NAME	Revenue
44724601	SFR-OTHER-NONTRANS-EDF TRADING NAME	Revenue
44724699	SALES FOR RESALE-OTHER-EDF TRADING CONVERSION	Revenue
44724800	SALES FOR RESALE-OTHER-DTE ENERGY TRADIN	Revenue
44724801	SFR-OTHER-NONTRANS-DTE ENERGY TRADIN	Revenue
44724899	SALES FOR RESALE-OTHER-DTE ENERGY CONVERSION	Revenue
44725300	SALES FOR RESALE-OTHER-WESTAR ENERGY, INC	Revenue
44725301	SFR-OTHER-NONTRANS-WESTAR ENERGY, INC	Revenue
44725399	SALES FOR RESALE-OTHER-WESTAR ENERGY CONVERSION	Revenue
44725500	SALES FOR RESALE-OTHER-SOUTHERN CO SVCS	Revenue
44725501	SFR-OTHER-NONTRANS-SOUTHERN CO SVCS	Revenue
44725599	SALES FOR RESALE-OTHER-SOUTHERN CO CONVERSION	Revenue
44727000	SALES FOR RESALE-OTHER-LEM	Revenue
44727001	SFR-OTHER-NONTRANS-LEM	Revenue
44727099	SALES FOR RESALE-OTHER-LEM CONVERSION	Revenue
44728700	SALES FOR RESALE-OTHER-CARGILL POWER MKT	Revenue
44728701	SFR-OTHER-NONTRANS-CARGILL POWER MKT	Revenue
44728799	SALES FOR RESALE-OTHER-CARGILL POWER CONVERSION	Revenue
44729000	SALES FOR RESALE-OTHER-ADM INVESTOR SERVICES	Revenue
44729001	SFR-OTHER-NONTRANS-ADM INVESTOR SERVICES	Revenue
44729500	SALES FOR RESALE-OTHER-CONSTELLATION PWR	Revenue
44729501	SFR-OTHER-NONTRANS-CONSTELLATION PWR	Revenue
44729599	SALES FOR RESALE-OTHER-CONSTELLATION CONVERSION	Revenue
44729600	SALES FOR RESALE-OTHER-EAGLE ENERGY	Revenue
44729601	SFR-OTHER-NONTRANS-EAGLE ENERGY	Revenue
44729699	SALES FOR RESALE-OTHER-EAGLE ENERGY CONVERSION	Revenue
44729900	SALES FOR RESALE-OTHER-TENASKA POWER SVC	Revenue
44729901	SFR-OTHER-NONTRANS-TENASKA POWER SVC	Revenue
44729999	SALES FOR RESALE-OTHER-TENASKA POWER CONVERSION	Revenue
45000000	RENT FROM ELECTRIC PROPERTY AND OTHER ELECTRIC REVENUES	Revenue
45400000	RENT FROM ELECTRIC PROPERTY	Revenue
45400001	RENT FROM ELEC PROPERTY-NONTRASMISSION	Revenue
45400002	RENT FROM ELEC PROPERTY-TRANSMISSION	Revenue
45400099	RENT FROM ELECTRIC PROPERTY CONVERSION	Revenue

Account #	Description	Type
45600000	OTHER ELECTRIC REVENUES	Revenue
45605000	OTHER ELEC REV-DOMTAR COGEN-ANCILLARIES	Revenue
45608000	OTHER ELECTRIC REVENUES-ORACLE	Revenue
45610000	OTHER ELEC REV-POWER SUPPLY	Revenue
45610002	OTHER ELEC REV-POWER SUPPLY-TRANS	Revenue
45610099	OTHER ELEC REV-POWER SUPPLY CONVERSION	Revenue
45610100	OTHER ELEC REV-KENERGY	Revenue
45610102	OTHER ELEC REV-KENERGY-TRANS	Revenue
45610199	OTHER ELEC REV-KENERGY CONVERSION	Revenue
45616000	OTHER ELEC REV-SIPC	Revenue
45616002	OTHER ELEC REV-SIPC-TRANS	Revenue
45616099	OTHER ELEC REV-SIPC CONVERSION	Revenue
45619300	OTHER ELEC REV-DOMTAR PAPER COGEN	Revenue
45619302	OTHER ELEC REV-DOMTAR PAPER COGEN-TRANS	Revenue
45619399	OTHER ELEC REV-DOMTAR PAPER CONVERSION	Revenue
45622000	OTHER ELEC REV-HMP&L	Revenue
45622002	OTHER ELEC REV-HMP&L-TRANS	Revenue
45622099	OTHER ELEC REV-HMP&L CONVERSION	Revenue
45624200	OTHER ELEC REV-MISO	Revenue
45624202	OTHER ELEC REV-MISO TRANS	Revenue
45625000	OTHER ELEC REV-OMU	Revenue
45625002	OTHER ELEC REV-OMU-TRANS	Revenue
45625099	OTHER ELEC REV-OMU CONVERSION	Revenue
45626000	OTHER ELEC REV-EDF TRADING	Revenue
45626002	OTHER ELEC REV-EDF TRADING-TRANS	Revenue
45627000	OTHER ELEC REV-LEM	Revenue
45627002	OTHER ELEC REV-LEM-TRANS	Revenue
45627099	OTHER ELEC REV-LEM CONVERSION	Revenue
45629900	OTHER ELEC REV-CARGILL POWER MARKETS LLC	Revenue
45629902	OTHER ELEC REV-CARGILL POWER MARKETS LLC-TRANS	Revenue
50000000	OPERATION SUPERVISION AND ENGINEERING	Expense
50010000	OPER SUPERVISION & ENGINEERING	Expense
50100000	FUEL	Expense
50110000	FUEL	Expense
50120000	FUEL HANDLING	Expense
50130000	BOTTOM ASH DISPOSAL	Expense
50135000	FLY ASH DISPOSAL	Expense
50210000	STEAM EXPENSES	Expense
50211000	STEAM EXPENSES-CLEAN AIR	Expense

Account #	Description	Type
50230000	SO2 REAGENTS	Expense
50510000	ELECTRIC EXPENSES	Expense
50610000	MISC STEAM POWER EXPENSE	Expense
50610500	MISC STEAM PWR EXP-SCR/NOX	Expense
50610600	MISC STEAM PWR-EMISSION FEES	Expense
50630000	NOX REAGENTS	Expense
50710000	RENTS-STEAM POWER	Expense
50910000	ALLOWANCES-CLEAN AIR	Expense
51000000	MAINTENANCE SUPERVISION AND ENGINEERING	Expense
51010000	MAINT SUPERVISION & ENGINEERING	Expense
51110000	MAINTENANCE STRUCTURES	Expense
51210000	MAINTENANCE BOILER PLANT	Expense
51211000	MAINTENANCE BOILER PLANT-CLEAN AIR	Expense
51212000	MAINT SCRUBBER/SOLID WASTE	Expense
51213000	MAINTENANCE BOILER PLANT-REAGENT PREP	Expense
51214000	MAINTENANCE BOILER PLANT-WASTE TREATMENT	Expense
51310000	MAINTENANCE ELECTRIC PLANT	Expense
51410000	MAINTENANCE MISC STEAM PLANT	Expense
54710000	FUEL-GAS TURBINE	Expense
54810000	GENERATION EXPENSES-GAS TURBINE	Expense
55310000	MAINT GENERATING & ELEC PLT-GAS TURBINE	Expense
55500000	PURCHASED POWER	Expense
55511000	PURCHASED POWER-SEPA	Expense
55513500	PURCHASED POWER-LEM	Expense
55513600	PURCHASED POWER-LEM-ARBITRAGE	Expense
55513700	PURCHASED POWER-LG&E/KU	Expense
55514100	PURCHASED POWER-ENERGY AUTHORITY	Expense
55514200	PURCHASED POWER-MISO	Expense
55514300	PURCHASED POWER-MISO ARS	Expense
55514400	PURCHASED POWER-PJM INTERCONNECTION	Expense
55515000	PURCHASED POWER-HMP&L STATION TWO	Expense
55515001	HMP&L STATION TWO AMORT EXP	Expense
55515002	HMP&L STATION TWO AMORT EXP-CLEAN AIR	Expense
55515003	HMP&L STATION TWO INTEREST CHARGED TO CONST CR	Expense
55515004	HMP&L STATION TWO OPER SUPERVISON & ENGINEERING	Expense
55515005	HMP&L STATION TWO FUEL	Expense
55515006	HMP&L STATION TWO FUEL HANDLING	Expense
55515007	HMP&L STATION TWO BOTTOM ASH DISPOSAL	Expense
55515008	HMP&L STATION TWO FLY ASH DISPOSAL	Expense

Account #	Description	Type
55515009	HMP&L STATION TWO STEAM EXPENSES	Expense
55515010	HMP&L STATION TWO SO2 REAGENTS	Expense
55515011	HMP&L STATION TWO ELECTRIC EXPENSES	Expense
55515012	HMP&L STATION TWO STEAM POWER EXPENSES	Expense
55515013	HMP&L STATION TWO NOX REAGENTS	Expense
55515014	HMP&L STATION TWO RENTS-STEAM POWER	Expense
55515015	HMP&L STATION TWO MAINT SUPERVISION & ENGINEERING	Expense
55515016	HMP&L STATION TWO MAINT STRUCTURES	Expense
55515017	HMP&L STATION TWO MAINT BOILER PLANT	Expense
55515018	HMP&L STATION TWO MAINT ELECTRIC PLANT	Expense
55515019	HMP&L STATION TWO MAINTENANCE MISC STEAM PLANT	Expense
55515020	HMP&L STATION TWO ADMIN & GENERAL SALARIES	Expense
55515021	HMP&L STATION TWO OFFICE SUPPLIES & EXPENSE	Expense
55515022	HMP&L STATION TWO OUTSIDE SERVICES EMPLOYED	Expense
55515023	HMP&L STATION TWO PROPERTY INSURANCE	Expense
55515024	HMP&L STATION TWO INJURIES & DAMAGES	Expense
55515025	HMP&L STATION TWO EMPLOYEE PENSIONS & BENEFITS	Expense
55515026	HMP&L STATION TWO MISC GENERAL EXPENSES	Expense
55515027	HMP&L STATION TWO MAINT OF GENERAL PLANT	Expense
55515028	HMP&L STATION TWO SYSTEM CONTROL & LOAD DISPATCH	Expense
55515029	HMP&L STATION TWO STATION EXPENSES	Expense
55515030	HMP&L STATION TWO OPER SUPERVISION & ENGINEERING-LINES	Expense
55515031	HMP&L STATION TWO OPER SUPERVISION & ENGINEERING-STATIONS	Expense
55515032	HMP&L STATION TWO MAINT SUPERVISION & ENGINEERING-LINES	Expense
55515033	HMP&L STATION TWO MAINT SUPERVISION & ENGINEERING-STATIONS	Expense
55515034	HMP&L STATION TWO ADMINISTRATIVE AND GENERAL SALARIES-GENERATION	Expense
55515035	HMP&L STATION TWO OFFICE SUPPLIES AND EXPENSES-GENERATION	Expense
55515036	HMP&L STATION TWO OUTSIDE SERVICES EMPLOYED-GENERATION	Expense
55515037	HMP&L STATION TWO OFF SUP & EXP-HMPL EXP	Expense
55515038	HMP&L STATION TWO OUTSIDE SVCS-HMPL EXP	Expense
55515039	HMP&L STATION TWO MISC GEN EXP-HMPL EXP	Expense

Account #	Description	Type
55515040	HMP&L STATION TWO REGULATORY COMMISSION EXPENSES-ECP	Expense
55515041	HMP&L STATION TWO MISC STEAM PWR-EMISSION FEES	Expense
55515099	PURCHASED POWER-HMP&L STATION TWO CONVERSION	Expense
555150XX	PURCHASED POWER-HMP&L STATION TWO	Expense
55515200	PURCHASED POWER-HMP&L-CLEAN AI	Expense
55515201	HMP&L-STEAM EXPENSES CLEAN AIR	Expense
55515202	HMP&L-MISC STEAM PWR EXP-SCR/NOX	Expense
55515203	HMP&L-ALLOWANCES CLEAN AIR	Expense
55515204	HMP&L-MAINT BOILER PLANT CLEAN AIR	Expense
55515205	HMP&L-MAINT SCRUBBER/SOLID WASTE	Expense
55515206	HMP&L-MAINT BOILER PLANT-REAGENT PREP	Expense
55515207	HMP&L-MAINT BOILER PLANT-WASTE TREATMENT	Expense
55515208	HMP&L-PROPERTY INSURANCE CLEAN AIR	Expense
55515299	PURCHASED POWER-HMP&L-CLEAN AIR CONVERSION	Expense
555152XX	PURCHASED POWER-HMP&L-CLEAN AIR	Expense
55515500	PURCHASED POWER-SOUTHERN COMPANY	Expense
55517700	PURCHASED POWER-SIPC	Expense
55518300	PURCHASED POWER-ASSOC ELEC COOP	Expense
55518500	PURCHASED POWER-EAST KY POWER COOP	Expense
55518700	PURCHASED POWER-CARGILL POWER MKT	Expense
55518800	PURCHASED POWER-RELIANT	Expense
55519100	PURCHASED POWER-SMELTERS	Expense
55519300	PURCHASED POWER-DOMTAR PAPER COGEN	Expense
55519600	PURCHASED POWER-EDF TRADING N AMERICA	Expense
55519800	PURCHASED POWER-CONSTELLATION ENERGY	Expense
55519900	PURCHASED POWER-TENASKA POWER SERVICES	Expense
55521000	PURCHASED POWER-AMERICAN ELECTRIC POWER SERVICE CORP	Expense
55523600	PURCHASED POWER-AMEREN MISSOURI	Expense
55525000	PURCHASED POWER-MISO RESERVATION FEE	Expense
55599900	PURCHASED POWER ADJ-REGULATORY ASSET	Expense
55610000	SYSTEM CONTROL & LOAD DISPATCHING	Expense
55711000	OTHER EXPENSE-POWER SUPPLY-ARBITRAGE	Expense
55711009	OTHER EXPENSE-POWER SUPPLY-ARBITRAGE CONTRA	Expense
55711100	OTHER EXPENSE-POWER SUPPLY	Expense
55711200	OTHER EXPENSE-POWER SUPPLY-MEMBER	Expense
55711300	OTHER EXPENSE-POWER SUPPLY-DOMTAR CURTAIL	Expense
55711400	OTHER EXPENSE-POWER SUPPLY-SMELTER CURTAIL	Expense

Account #	Description	Type
55711900	OTHER EXPENSE-POWER SUPPLY-ARBITRAGE CONTRA	Expense
55735000	OTHER EXPENSE-NON-SMELTER NON-FAC PPA	Expense
56000000	OPERATION SUPERVISION AND ENGINEERING-LINES AND STATIONS	Expense
56010000	OPER SUPERVISION & ENGINEERING-LINES	Expense
56020000	OPER SUPERVISION & ENGINEERING-STATIONS	Expense
56110000	LOAD DISPATCHING	Expense
56140000	SCHEDULING, SYSTEM CONTROL & DISPATCHING SERVICES	Expense
56180000	RELIABILITY PLANNING & STANDARDS DEVELOPMENT SERV	Expense
56210000	STATION EXPENSES	Expense
56310000	OVERHEAD LINE EXPENSES	Expense
56510000	TRANSMISSION OF ELECTRICITY BY OTHERS	Expense
56610000	MISC TRANSMISSION EXPENSE-LINE	Expense
56620000	MISC TRANSMISSION EXPENSE-STATIONS	Expense
56720000	RENTS-STATIONS	Expense
56800000	MAINTENANCE SUPERVISION AND ENGINEERING-LINES AND STATIONS	Expense
56810000	MAINT SUPERVISION & ENGINEERING-LINES	Expense
56820000	MAINT SUPERVISION & ENGINEERING-STATIONS	Expense
56910000	MAINTENANCE STRUCTURES	Expense
57010000	MAINTENANCE STATION EQUIPMENT	Expense
57110000	MAINTENANCE OVERHEAD LINES	Expense
57310000	MAINTENANCE MISC TRANSMISSION PLANT-LINES	Expense
57320000	MAINTENANCE MISC TRANSMISSION PLANT-STATIONS	Expense
57570000	MARKET FACILITATION, MONITORING & COMPLIANCE SERV	Expense
60112000	FUEL-EXPENSE	Expense
60210000	STEAM EXPENSES	Expense
60610000	MISC STEAM POWER EXPENSE	Expense
61010000	MAINTENANCE SUPERVISION & ENGINEERING	Expense
62410000	PROPERTY INSURANCE-PRODUCTION	Expense
62510000	INJURIES & DAMAGES-O&M	Expense
70010000	OPER SUPERVISION & ENGINEERING	Expense
70110000	FUEL EXPENSE	Expense
70210000	STEAM EXPENSES	Expense
70211000	STEAM EXPENSES-CLEAN AIR	Expense
70510000	ELECTRIC EXPENSES	Expense
70610000	MSC STEAM POWER EXPENSES	Expense
71010000	MAINTENANCE SUPERVISION & ENGINEERING EXP	Expense
71111000	MAINTENANCE STRUCTURES-EXPENSE	Expense

Big Rivers Electric Corporation
Case No. 2013-00199
Chart of Accounts

Account #	Description	Type
71210000	MAINTENANCE BOILER PLANT	Expense
72010000	ADMINISTRATIVE AND GENERAL EXPENSE	Expense
72310000	OUTSIDE SERVICES EMPLOYED	Expense
72410000	PROPERTY INSURANCE	Expense
72411000	PROPERTY INSURANCE-CLEAN AIR	Expense
72510000	INJURIES & DAMAGES-O&M	Expense
72517000	INJURIES & DAMAGES-A&G	Expense
72620000	EMPLOYEE PENSIONS & BENEFITS	Expense
73510000	MAINTENANCE OF GENERAL PLANT	Expense
75610000	SYSTEM CONTROL & LOAD DISPATCHING	Expense
76210000	STATION EXPENSES	Expense
90400000	UNCOLLECTIBLE ACCOUNT	Expense
90800000	CUSTOMER ASSISTANCE EXPENSES	Expense
90810000	CUSTOMER ASSISTANCE EXPENSES	Expense
90910000	INFORMATION & INSTRUCTION ADV EXP	Expense
91010000	MISC CUSTOMER SERV & INFORMATIONAL EXP	Expense
91300000	ADVERTISING EXPENSE	Expense
91310000	ADVERTISING EXPENSE	Expense
92000000	ADMINISTRATIVE GENERAL	Expense
92010000	ADMINISTRATIVE AND GENERAL SALARIES	Expense
92010100	ADMIN & GENERAL SALARIES-POWER SUPPLY	Expense
92010200	ADMIN & GENERAL SALARIES-CUSTOMER SERV	Expense
92010300	ADMIN & GENERAL SALARIES-GENERATION	Expense
92110000	OFFICE SUPPLIES AND EXPENSES	Expense
92110100	OFFICE SUPPLIES & EXPENSES-POWER SUPPLY	Expense
92110200	OFFICE SUPPLIES & EXPENSES-CUSTOMER SER	Expense
92110300	OFFICE SUPPLIES & EXPENSES-GENERATION	Expense
92110500	OFFICE SUPPLIES & EXPENSES-HMPL EXPENSES	Expense
92118300	OFFICE SUPPLIES & EXPENSES-ORACLE	Expense
92310000	OUTSIDE SERVICES EMPLOYED	Expense
92310100	OUTSIDE SERVICES-POWER SUPPLY	Expense
92310200	OUTSIDE SERVICES-CUSTOMER SERVICE	Expense
92310300	OUTSIDE SERVICES-GENERATION	Expense
92310400	OUTSIDE SERVICES-TRANSMISSION	Expense
92310500	OUTSIDE SERVICES-HMPL EXPENSES	Expense
92310600	OUTSIDE SERVICES-RATE CASE 2013	Expense
92310700	OUTSIDE SERVICES-AMORT PROF FEES	Expense
92318300	OUTSIDE SERVICES-ORACLE	Expense
92325000	OUTSIDE SERVICES-MISO MEMBERSHIP	Expense

Account #	Description	Type
92411000	PROPERTY INSURANCE	Expense
92411100	PROPERTY INSURANCE-CLEAN AIR	Expense
92510000	INJURIES & DAMAGES	Expense
92610000	EMPLOYEE PENSIONS & BENEFITS	Expense
92810000	REGULATORY COMMISSION EXPENSES	Expense
92820000	REGULATORY COMMISSION EXPENSES-RATE CASE	Expense
92822500	REGULATORY COMMISSION EXPENSES-RATE CASE 2011	Expense
92823000	REGULATORY COMMISSION EXPENSES-ECP (ENVIRON COMPL PLAN)	Expense
92824000	REGULATORY COMMISSION EXPENSES-DSM (DEMAND SIDE MGMT)	Expense
92825000	REGULATORY COMMISSION EXPENSES-MISO	Expense
92826000	REGULATORY COMMISSION EXPENSES-CFC FINANCING CASE	Expense
93010000	GENERAL ADVERTISING EXPENSES	Expense
93011200	GENERAL ADVERTISING EXP-CUSTOM SERVICE	Expense
93020000	MISCELLANEOUS GENERAL EXPENSES	Expense
93021100	MISC GENERAL EXPENSES-POWER SUPPLY	Expense
93021200	MISC GENERAL EXPENSES-CUSTOMER SERV	Expense
93021400	MISC GENERAL EXPENSES-TRANSMISSION	Expense
93021500	MISC GENERAL EXPENSES-HMPL EXPENSES	Expense
93028300	MISC GENERAL EXPENSES-ORACLE	Expense
93110000	RENTS-ADMINISTRATIVE & GENERAL	Expense
93500000	MAINTENANCE OF GENERAL PLANT	Expense
93510000	MAINTENANCE OF GENERAL PLANT	Expense
93511100	MAINT OF GENERAL PLANT-EXP-POWER SUPPLY	Expense
93511200	MAINT OF GENERAL PLANT-EXP-CUSTOMER SER	Expense

Tab No. 34
Filing Requirement
807 KAR 5:001 Section 16(12)(n)
Sponsoring Witness: Billie J. Richert

Description of Filing Requirement:

The latest twelve (12) months of the monthly managerial reports providing financial results of operations in comparison to the forecast.

Response:

The monthly managerial reports for May 2012 through April 2013 are attached.

RUS Form 12 – April 2013

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0572-0032. The time required to complete this information collection is estimated to average 21 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT** **ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062
	PERIOD ENDED April -2013
INSTRUCTIONS - See help in the online application *This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C. 552).*	BORROWER NAME **Big Rivers Electric Corporation**

CERTIFICATION

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7 CFR CHAPTER XVII

(check one of the following)

X All of the obligations under the RUS loan documents have been fulfilled in all material respects.

__ There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part A Section C of this report.

Mark A. Bailey 5/20/13

SIGNATURE OF PRESIDENT AND CEO DATE

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART A - FINANCIAL**	BORROWER DESIGNATION KY0062
	PERIOD ENDED Apr-13
INSTRUCTIONS - See help in the online application.	

SECTION A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	THIS YEAR (b)	BUDGET (c)	THIS MONTH (d)
1. Electric Energy Revenues	178,433,780.13	198,100,021.11	190,356,612.00	47,913,943.00
2. Income From Leased Property (Net)	0.00	0.00	0.00	0.00
3. Other Operating Revenue and Income	1,526,825.12	1,337,952.55	1,235,168.00	305,551.66
4. **Total Operation Revenues & Patronage Capital** *(1 thru 3)*	179,960,605.25	199,437,973.66	191,591,780.00	48,219,494.66
5. Operating Expense - Production - Excluding Fuel	15,806,738.99	16,934,734.08	18,244,032.00	4,323,290.09
6. Operating Expense - Production - Fuel	67,077,494.71	81,325,404.31	84,045,565.00	20,293,782.53
7. Operating Expense - Other Power Supply	41,435,907.87	36,383,534.08	30,838,511.00	8,958,452.27
8. Operating Expense - Transmission	3,266,048.49	3,818,095.86	3,064,739.00	984,735.04
9. Operating Expense - RTO/ISO	848,574.26	898,593.63	760,432.00	200,151.06
10. Operating Expense - Distribution	0.00	0.00	0.00	0.00
11. Operating Expense - Customer Accounts	0.00	62,966.24	0.00	62,966.24
12. Operating Expense - Customer Service & Information	130,748.92	202,087.18	402,996.00	69,533.43
13. Operating Expense - Sales	5,873.98	14,718.75	35,933.00	4,906.25
14. Operating Expense - Administrative & General	8,600,796.79	8,631,156.45	9,453,023.00	2,031,129.99
15. **Total Operation Expense** *(5 thru 14)*	137,172,184.01	148,271,290.58	146,845,231.00	36,928,946.90
16. Maintenance Expense - Production	15,120,822.58	11,821,366.82	13,360,557.00	2,617,968.75
17. Maintenance Expense - Transmission	1,403,422.24	1,261,122.98	1,564,831.00	315,172.67
18. Maintenance Expense - RTO/ISO	0.00	0.00	0.00	0.00
19. Maintenance Expense - Distribution	0.00	0.00	0.00	0.00
20. Maintenance Expense - General Plant	46,622.56	86,803.90	73,327.00	9,659.18
21. **Total Maintenance Expense** *(16 thru 20)*	16,570,867.38	13,169,293.70	14,998,715.00	2,942,800.60
22. Depreciation and Amortization Expense	13,580,162.24	13,715,721.15	13,779,668.00	3,428,381.04
23. Taxes	4,060.88	2,461.92	885.00	2,366.92
24. Interest on Long-Term Debt	14,963,524.32	14,787,749.24	15,061,615.00	3,693,582.62
25. Interest Charged to Construction - Credit	<263,200.00>	<135,070.00>	<77,016.00>	<28,155.00>
26. Other Interest Expense	162.17	45.65	0.00	22.83
27. Asset Retirement Obligations	0.00	0.00	0.00	0.00
28. Other Deductions	82,895.64	169,542.08	177,919.00	30,321.51
29. **Total Cost Of Electric Service** *(15 + 21 thru 28)*	182,110,656.64	189,981,034.32	190,787,017.00	46,998,267.42
30. **Operating Margins** *(4 less 29)*	<2,150,051.39>	9,456,939.34	804,763.00	1,221,227.24
31. Interest Income	23,174.89	665,036.87	680,087.00	162,106.18
32. Allowance For Funds Used During Construction	0.00	0.00	0.00	0.00
33. Income (Loss) from Equity Investments	0.00	0.00	0.00	0.00
34. Other Non-operating Income (Net)	0.00	0.00	0.00	0.00
35. Generation & Transmission Capital Credits	0.00	0.00	0.00	0.00
36. Other Capital Credits and Patronage Dividends	44,874.64	783,330.28	1,263,325.00	0.00
37. Extraordinary Items	0.00	0.00	0.00	0.00
38. **Net Patronage Capital Or Margins** *(30 thru 37)*	<2,082,001.86>	10,905,306.49	2,748,175.00	1,383,333.42

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE	BORROWER DESIGNATION KY0062
FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART A - FINANCIAL	PERIOD ENDED Apr-13
INSTRUCTIONS - See help in the online application.	

SECTION B. BALANCE SHEET

ASSETS AND OTHER DEBITS		LIABILITIES AND OTHER CREDITS	
1. Total Utility Plant in Service	2,005,296,651.80	33. Memberships	75.00
2. Construction Work in Progress	50,750,758.00	34. Patronage Capital	
3. Total Utility Plant *(1 + 2)*	**2,056,047,409.80**	a. Assigned and Assignable	
4. Accum. Provision for Depreciation and Amort.	974,528,978.86	b. Retired This year	
		c. Retired Prior years	
5. Net Utility Plant *(3 - 4)*	**1,081,518,430.94**	**d. Net Patronage Capital (a-b-c)**	0.00
6. Non-Utility Property (Net)	0.00	35. Operating Margins - Prior Years	<231,584,391.53>
7. Investments in Subsidiary Companies	0.00	36. Operating Margin - Current Year	10,240,269.62
8. Invest. in Assoc. Org. - Patronage Capital	3,894,189.99	37. Non-Operating Margins	640,625,704.39
9. Invest, in Assoc. Org. - Other - General Funds	43,840,793.00	38. Other Margins and Equities	<5,494,663.80>
10. Invest. in Assoc. Org. - Other - Nongeneral Funds	0.00	**39. Total Margins & Equities *(33 + 34d thru 38)***	**413,786,993.68**
11. Investments in Economic Development Projects	10,000.00	40. Long-Term Debt - RUS (Net)	212,244,447.55
		41. Long-Term Debt - FFB - RUS Guaranteed	0.00
12. Other Investments	5,333.85	42. Long-Term Debt - Other - RUS Guaranteed	0.00
13. Special Funds	174,104,817.99	43. Long-Term Debt - Other (Net)	629,997,166.83
14. Total Other Property And Investments *(6 thru 13)*	**221,855,134.83**	44. Long-Term Debt - RUS - Econ. Devel. (Net)	0.00
		45. Payments - Unapplied	0.00
15. Cash - General Funds	5,711.75	**46. Total Long-Term Debt *(40 thru 44-45)***	**842,241,614.38**
16. Cash - Construction Funds - Trustee	0.00	47. Obligations Under Capital Leases - Noncurrent	0.00
17. Special Deposits	598,619.93		
18. Temporary Investments	124,602,977.78	48. Accumulated Operating Provisions and Asset Retirement Obligations	22,511,733.08
19. Notes Receivable (Net)	0.00		
20. Accounts Receivable - Sales of Energy (Net)	43,774,721.63	**49. Total Other NonCurrent Liabilities *(47 +48)***	**22,511,733.08**
21. Accounts Receivable - Other (Net)	1,036,357.50	50. Notes Payable	0.00
22. Fuel Stock	32,595,958.36	51. Accounts Payable	33,695,085.62
23. Renewable Energy Credits	0.00		
24. Materials and Supplies - Other	26,254,166.06	52. Current Maturities Long-Term Debt	79,240,736.44
25. Prepayments	2,882,921.80		
26. Other Current and Accrued Assets	1,435,129.12	53. Current Maturities Long-Term Debt - Rural Development	0.00
27. Total Current And Accrued Assets *(15 thru 26)*	**233,186,563.93**	54. Current Maturities Capital Leases	0.00
		55. Taxes Accrued	1,566,400.76
28. Unamortized Debt Discount & Extraor. Prop. Losses	4,137,303.98	56. Interest Accrued	6,645,626.47
		57. Other Current and Accrued Liabilities	7,159,063.52
29. Regulatory Assets	619,849.34		
30. Other Deferred Debits	5,467,557.48	**58. Total Current & Accrued Liabilities *(50 thru 57)***	**128,306,912.81**
31. Accumulated Deferred Income Taxes	0.00	59. Deferred Credits	139,937,586.55
		60. Accumulated Deferred Income Taxes	0.00
32. Total Assets And Other Debits *(5+14+27 thru 31)*	**1,546,784,840.50**	**61. Total Liabilities and Other Credits *(39 + 46 + 49 + 58 thru 60)***	**1,546,784,840.50**

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Apr-13

Part B SE - Sales of Electricity

Sale No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Fuel Type (e)	Average Monthly Billing Demand (MW) (f)	Actual Average Monthly NCP Demand (g)	Actual Average Monthly CP Demand (h)
	Ultimate Consumer(s)							
	Distribution Borrowers							
1	Jackson Purchase Energy Corp.	KY0020	RQ			114	128	112
2	Kenergy Corporation	KY0065	IF					
3	Kenergy Corporation	KY0065	LF					
4	Kenergy Corporation	KY0065	RQ			354	377	353
5	Meade County Rural ECC	KY0018	RQ			100	105	100
	G&T Borrowers							
	Others							
6	Midcontinent Independent Trans. Sys. Op.		OS					
7	PJM Interconnection		OS					
8								

	(f)	(g)	(h)
Total for Ultimate Consumer(s)	0	0	0
Total for Distribution Borrowers	568	610	565
Total for G&T Borrowers	0	0	0
Total for Others	0	0	0
Grand Total	568	610	565

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Apr-13

INSTRUCTIONS - See help in the online application.

Part B SE - Sales of Electricity

Sale No.	Electricity Sold (MWh) (i)	Revenue Demand Charges (j)	Revenue Energy Charges (k)	Revenue Other Charges (l)	Revenue Total (j + k + l) (m)
1	223,826.533	4,798,741.51	6,912,049.96		11,710,791.47
2	68,929.799		2,583,657.67		2,583,657.67
3	2,449,767.731		119,818,855.01		119,818,855.01
4	726,271.693	14,918,644.75	20,724,904.13		35,643,548.88
5	175,315.563	4,159,326.27	5,443,725.29		9,603,051.56
6	615,678.700		18,740,165.63		18,740,165.63
7			<49.11>		<49.11>
8			0.00		
	0	0	0	0	0
	3,644,111.319	23,876,712.53	155,483,192.06	0.00	179,359,904.59
	0.000	0.00	0.00	0.00	0.00
	615,678.700	0.00	18,740,116.52	0.00	18,740,116.52
	4,259,790.019	23,876,712.53	174,223,308.58	0.00	198,100,021.11

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD NAME Apr-13
INSTRUCTIONS - See help in the online application.	

PART B PP - Purchased Power

Purchase No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Energy Type (e)	Average Monthly Billing Demand (MW) (f)	Average Monthly NCP Demand (g)	Average Monthly CP Demand (h)
	Distribution Borrowers							
	G&T Borrowers							
	Others							
1	Henderson Municipal Power & Light		RQ					
2	Midcontinent Independent Trans. Sys. Op.		OS					
3	Southeastern Power Admin.		LF					
Total for Distribution Borrowers						0	0	0
Total for G&T Borrowers						0	0	0
Total for Others						0	0	0
Grand Total						0	0	0

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD NAME Apr-13
INSTRUCTIONS - See help in the online application.	

PART B PP - Purchased Power

Purchase No.	Electricity Purchased (MWh) (i)	Electricity Received (MWh) (j)	Electricity Delivered (MWh) (k)	Demand Charges (l)	Energy Charges (m)	Other Charges (n)	Total (l + m + n) (o)
1	459,157.110				21,839,179.26		21,839,179.26
2	346,420.500				9,302,914.84		9,302,914.84
3	187,624.000				4,362,816.84		4,362,816.84
	0.000				0.00		0.00
	0.000				0.00		0.00
	993,201.610				35,504,910.94		35,504,910.94
	993,201.610				35,504,910.94		35,504,910.94

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART C - SOURCES AND DISTRIBUTION OF ENERGY	BORROWER DESIGNATION KY0062 PERIOD ENDED Apr-13
INSTRUCTIONS - See help in the online application.	

SOURCES OF ENERGY (a)	NO. OF PLANTS (b)	CAPACITY (kW) (c)	NET ENERGY RECEIVED BY SYSTEM (MWh) (d)	COST ($) (e)
Generated In Own Plant *(Details on Parts D and F IC)*				
1. Fossil Steam	4	1,489,000	3,286,145.021	133,287,688.05
2. Nuclear				
3. Hydro				
4. Combined Cycle				
5. Internal Combustion	1	70,000	<71.180>	229,129.12
6. Other				
7. Total In Own Plant ***(1 thru 6)***	5	1,559,000	3,286,073.841	133,516,817.17
Purchased Power				
8. Total Purchased Power			993,201.610	35,504,910.94
Interchanged Power				
9. Received into System (Gross)			1,515,954.000	
10. Delivered Out of System (Gross)			1,459,463.000	
11. Net Interchange ***(9 minus 10)***			56,491.000	
Transmission For or By Others - (Wheeling)				
12. Received into System			0.000	
13. Delivered Out of System			0.000	
14. Net Energy Wheeled ***(12 minus 13)***			0.000	
15. Total Energy Available for Sale (7 + 8 + 11 + 14)			4,335,766.451	
Distribution of Energy				
16. Total Sales			4,259,790.019	
17. Energy Furnished to Others Without Charge				
18. Energy Used by Borrower *(Excluding Station Use)*				
19. Total Energy Accounted For ***(16 thru 18)***			4,259,790.019	
Losses				
20. Energy Losses - MWh ***(15 minus 19)***			75,976.432	
21. Energy Losses - Percentage ((20 divided by 15) * 100)			1.75 %	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART D - STEAM PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062
PLANT
COLEMAN
PERIOD ENDED
Apr-13

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	7	322,889.8	0.000	9,016.2			2,612.0	25.0	0.0	242.0
2.	2	2	330,278.9	0.000	3,468.9			2,742.0	0.0	0.0	137.0
3.	3	2	348,233.9	0.000	8,590.0			2,754.7	0.0	0.0	124.3
4.											
5.											
6.	Total	11	1,001,402.6	0.000	21,075.1			8,108.7	25.0	0.0	503.3
7.	Average BTU		11,345	0	1,000						
8.	Total BTU(10^6)		11,360,912	0	21,075		11,381,988				
9.	Total Del.Cost ($)		27,658,829.99	700.12	105,631.76						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (1)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	160,000	363,702.000	
2.	2	160,000	382,130.000	
3.	3	165,000	405,290.000	
4.				
5.				
6.	Total	485,000	1,151,122.000	9,888
7.	Station Service (MWh)		101,914.000	
8.	Net Generation (MWh)		1,049,208.000	10,848
9.	Station Service (%)		8.85	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	105
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	81.75
2.	Plant Factor (%)	82.44
3.	Running Plant Capacity Factor (%)	87.79
4.	15 Minute Gross Maximum Demand (kW)	489,077
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/$10^6$ BTU (c)
1.	Operation, Supervision and Engineering	500	591,471.10		
2.	Fuel, Coal	501.1	28,692,550.08		2.53
3.	Fuel, Oil	501.2	700.12		
4.	Fuel, Gas	501.3	105,631.76		5.01
5.	Fuel, Other	501.4			
6.	**Fuel Sub Total (2 thru 5)**	501	28,798,881.96	27.45	2.53
7.	Steam Expenses	502	1,940,032.20		
8.	Electric Expenses	505	694,085.29		
9.	Miscellaneous Steam Power Expenses	506	769,278.37		
10.	Allowances	509	8,880.32		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub Total (1 + 7 thru 11)**		4,003,747.28	3.82	
13.	**Operation Expense (6 + 12)**		32,802,629.24	31.26	
14.	Maintenance, Supervision and Engineering	510	489,939.25		
15.	Maintenance of Structures	511	337,451.75		
16.	Maintenance of Boiler Plant	512	2,473,083.35		
17.	Maintenance of Electric Plant	513	352,733.89		
18.	Maintenance of Miscellaneous Plant	514	481,281.78		
19.	**Maintenance Expense (14 thru 18)**		4,134,490.02	3.94	
20.	**Total Production Expense (13 + 19)**		36,937,119.26	35.20	
21.	Depreciation	403.1	1,851,491.32		
22.	Interest	427	2,288,248.64		
23.	**Total Fixed Cost (21 + 22)**		4,139,739.96	3.95	
24.	**Power Cost (20 + 23)**		41,076,859.22	39.15	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PLANT D - STEAM PLANT

BORROWER DESIGNATION: KY0062
PLANT: REID
PERIOD ENDED: Apr-13

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	0	.0	.000	.0			.0	2,879.0	.0	.0
2.											
3.											
4.											
5.											
6.	Total	0	.0	.000	.0			.0	2,879.0	.0	.0
7.	Average BTU		0	0	0						
8.	Total BTU(10^6)		0	0	0		0				
9.	Total Del..Cost ($)		0.00	265.34	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	72,000	.000	
2.				
3.				
4.				
5.				
6.	Total	72,000	.000	0
7.	Station Service (MWh)		6,310.000	
8.	Net Generation (MWh)		<6,310.000>	0
9.	Station Service (%)		0	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	17
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	.00
2.	Plant Factor (%)	.00
3.	Running Plant Capacity Factor (%)	.00
4.	15 Minute Gross Maximum Demand (kW)	0
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	95,954.49		
2.	Fuel, Coal	501.1	107,441.85		0
3.	Fuel, Oil	501.2	265.34		0
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	Fuel Sub Total (2 thru 5)	501	107,707.19		0
7.	Steam Expenses	502	168,128.14		
8.	Electric Expenses	505	93,695.61		
9.	Miscellaneous Steam Power Expenses	506	74,609.90		
10.	Allowances	509	142.14		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		432,530.28		
13.	Operation Expense (6 + 12)		540,237.47		
14.	Maintenance, Supervision and Engineering	510	82,525.92		
15.	Maintenance of Structures	511	30,131.78		
16.	Maintenance of Boiler Plant	512	252,154.49		
17.	Maintenance of Electric Plant	513	39,871.56		
18.	Maintenance of Miscellaneous Plant	514	41,550.55		
19.	Maintenance Expense (14 thru 18)		446,234.30		
20.	Total Production Expense (13 + 19)		986,471.77		
21.	Depreciation	403.1	136,362.73		
22.	Interest	427	235,892.53		
23.	Total Fixed Cost (21 + 22)		372,255.26	0	
24.	Power Cost (20 + 23)		1,358,727.03		

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION	KY0062
PLANT	GREEN
PERIOD ENDED	Apr-13

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE Scheduled (j)	Unsched (k)
1.	1	3	537,345.4	54.577	.0			2,779.0	.0	.0	100.0
2.	2	0	542,383.9	27.660	.0			2,879.0	.0	.0	.0
3.											
4.											
5.											
6.	Total	3	1,079,729.3	82.237	.0			5,658.0	.0	.0	100.0
7.	Average BTU		11,719	138,000	0						
8.	Total BTU(10⁶)		12,653,348	11,349	0		12,664,696				
9.	Total Del..Cost ($)		26,406,748.72	263,810.04	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	250,000	628,304.380	
2.	2	242,000	631,430.500	
3.				
4.				
5.				
6.	Total	492,000	1,259,734.880	10,053
7.	Station Service (MWh)		117,061.810	
8.	Net Generation (MWh)		1,142,673.070	11,083
9.	Station Service (%)		9.29	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	110
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	87.21
2.	Plant Factor (%)	88.93
3.	Running Plant Capacity Factor (%)	90.53
4.	15 Minute Gross Maximum Demand (kW)	501,732
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10⁶ BTU (c)
1.	Operation, Supervision and Engineering	500	505,806.97		
2.	Fuel, Coal	501.1	27,212,256.80		
3.	Fuel, Oil	501.2	263,810.04		2.15
4.	Fuel, Gas	501.3	0.00		23.25
5.	Fuel, Other	501.4			0
6.	Fuel Sub Total (2 thru 5)	501	27,476,066.84	24.05	2.17
7.	Steam Expenses	502	5,005,465.79		
8.	Electric Expenses	505	1,054,433.28		
9.	Miscellaneous Steam Power Expenses	506	493,583.57		
10.	Allowances	509	6,935.65		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		7,066,225.26	6.18	
13.	Operation Expense (6 + 12)		34,542,292.10	30.23	
14.	Maintenance, Supervision and Engineering	510	512,691.97		
15.	Maintenance of Structures	511	340,806.30		
16.	Maintenance of Boiler Plant	512	2,290,334.99		
17.	Maintenance of Electric Plant	513	403,439.67		
18.	Maintenance of Miscellaneous Plant	514	295,987.88		
19.	Maintenance Expense (14 thru 18)		3,843,260.81	3.36	
20.	Total Production Expense (13 + 19)		38,385,552.91	33.59	
21.	Depreciation	403.1	2,657,572.45		
22.	Interest	427	2,665,078.17		
23.	Total Fixed Cost (21 + 22)		5,322,650.62	4.66	
24.	Power Cost (20 + 23)		43,708,203.53	38.25	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION
KY0062
PLANT
WILSON
PERIOD ENDED
Apr-13

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	2	995,495.0	124.063	.0			2,834.8	.0	.0	44.2
2.											
3.											
4.											
5.											
6.	Total	2	995,495.0	124.063	.0			2,834.8	.0	.0	44.2
7.	Average BTU		11,661	138,000	0						
8.	Total BTU(10^6)		11,608,467	17,121	0		11,625,588				
9.	Total Del..Cost ($)		23,515,631.60	391,314.53	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	440,000	1,181,033.570	
2.				
3.				
4.				
5.				
6.	Total	440,000	1,181,033.570	9,844
7.	Station Service (MWh)		80,459.619	
8.	Net Generation (MWh)		1,100,573.951	10,563
9.	Station Service (%)		6.81	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	105
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	90.25
2.	Plant Factor (%)	93.23
3.	Running Plant Capacity Factor (%)	94.69
4.	15 Minute Gross Maximum Demand (kW)	454,558
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	628,282.03		
2.	Fuel, Coal	501.1	24,532,933.81		
3.	Fuel, Oil	501.2	391,314.53		2.11
4.	Fuel, Gas	501.3	0.00		22.86
5.	Fuel, Other	501.4			0
6.	Fuel Sub-Total (2 thru 5)	501	24,924,248.34	22.65	0
7.	Steam Expenses	502	3,320,176.55		2.14
8.	Electric Expenses	505	485,255.57		
9.	Miscellaneous Steam Power Expenses	506	973,630.76		
10.	Allowances	509	11,930.17		
11.	Rents	507	0.00		
12.	Non-Fuel Sub-Total (1 + 7 thru 11)		5,419,275.08	4.92	
13.	Operation Expense (6 + 12)		30,343,523.42	27.57	
14.	Maintenance, Supervision and Engineering	510	472,894.80		
15.	Maintenance of Structures	511	275,277.44		
16.	Maintenance of Boiler Plant	512	2,203,091.01		
17.	Maintenance of Electric Plant	513	243,254.86		
18.	Maintenance of Miscellaneous Plant	514	171,433.17		
19.	Maintenance Expense (14 thru 18)		3,365,951.28	3.06	
20.	Total Production Expense (13 + 19)		33,709,474.70	30.63	
21.	Depreciation	403.1	6,395,325.18		
22.	Interest	427	7,039,098.39		
23.	Total Fixed Cost (21 + 22)		13,434,423.57	12.21	
24.	Power Cost (20 + 23)		47,143,898.27	42.84	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART F IC - INTERNAL COMBUSTION PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION: KY0062
PLANT: REID
PERIOD ENDED: Apr-13

SECTION A. INTERNAL COMBUSTION GENERATING UNITS

NO.	UNIT NO. (a)	SIZE (kW) (b)	FUEL CONSUMPTION OIL (1000 Gals.) (c)	GAS (1000 C.F.) (d)	OTHER (e)	TOTAL (f)	OPERATING HOURS IN SERVICE (g)	ON STANDBY (h)	OUT OF SERVICE Sche. (i)	Unsched (j)	GROSS GENERATION (MWh) (k)	BTU PER kWh (l)
1.	1	70,000	.000	3,807			10.4	2,784.9	.0	83.7	160.630	
2.												
3.												
4.												
5.												
6.	Total	70,000	.000	3,807			10.4	2,784.9	.0	83.7	160.630	23,700
7.	Average BTU		0	1,000			Station Service (MWh)				231.810	
8.	Total BTU(10^6)		0	3,807		3,807	Net Generation (MWh)				<71.180>	0
9.	Total Del..Cost ($)		0.00	18,499.98			Station Service % of Gross				144.31	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	0	5.	Maint. Plant Payroll ($)	
2.	No. Employees Part-Time		6.	Other Accounts. Plant Payroll ($)	
3.	**Total Empl. - Hrs. Worked**				
4.	Oper. Plant Payroll ($)		7.	**Total Plant Payroll ($)**	

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	.54
2.	Plant Factor (%)	.08
3.	Running Plant Capacity Factor (%)	22.06
4.	15 Minute Gross Maximum Demand (kW)	10,308
5.	Indicated Gross Maximum Demand kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	546	0.00		
2.	Fuel, Oil	547.1	0.00		
3.	Fuel, Gas	547.2	18,499.98		
4.	Fuel, Other	547.3			4.86
5.	Energy for Compressed Air	547.4			
6.	**Fuel Sub-Total *(2 thru 5)***	547	18,499.98		
7.	Generation Expenses	548	12,956.18		4.86
8.	Miscellaneous Other Power Generation Expenses	549	0.00		
9.	Rents	550	0.00		
10.	**Non-Fuel Sub-Total *(1 + 7 thru 9)***		12,956.18		
11.	**Operation Expense *(6+ 10)***		31,456.16		
12.	Maintenance, Supervision and Engineering	551	0.00		
13.	Maintenance of Structures	552	0.00		
14.	Maintenance of Generating and Electric Plant	553	31,430.41		
15.	Maintenance of Miscellaneous Other Power Generating Plant	554	0.00		
16.	**Maintenance Expense *(12 thru 15)***		31,430.41		
17.	**Total Production Expense *(11 + 16)***		62,886.57		
18.	Depreciation	403.1,411.10	98,204.92		
19.	Interest	427	68,037.63		
20.	**Total Fixed Cost *(18+ 19)***		166,242.55		
21.	**Power Cost *(17 + 20)***		229,129.12		

REMARKS *(including Unscheduled Outages)*

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART I - LINES AND STATIONS	BORROWER DESIGNATION KY0062 PERIOD ENDED Apr-13
INSTRUCTIONS - See help in the online application.	

SECTION A. EXPENSE AND COSTS

ITEM	ACCOUNT NUMBER	LINES (a)	STATIONS (b)
Transmission Operation			
1. Supervision and Engineering	560	86,054.08	103,789.68
2. Load Dispatching	561	1,251,206.17	
3. Station Expenses	562		293,738.72
4. Overhead Line Expenses	563	412,650.33	
5. Underground Line Expenses	564	0.00	
6. Miscellaneous Expenses	566	94,321.89	118,989.40
7. **Subtotal *(1 thru 6)***		1,844,232.47	516,517.78
8. Transmission of Electricity by Others	565	1,454,389.67	
9. Rents	567	0.00	2,955.94
10. **Total Transmission Operation *(7 thru 9)***		3,298,622.14	519,473.72
Transmission Maintenance			
11. Supervision and Engineering	568	75,512.98	80,314.29
12. Structures	569		4,988.05
13. Station Equipment	570		468,233.61
14. Overhead Lines	571	445,746.51	
15. Underground Lines	572	0.00	
16. Miscellaneous Transmission Plant	573	80,996.87	105,330.67
17. **Total Transmission Maintenance *(11 thru 16)***		602,256.36	658,866.62
18. **Total Transmission Expense *(10 + 17)***		3,900,878.50	1,178,340.34
19. *RTO/ISO Expense - Operation*	575	898,593.63	
20. RTO/ISO Expense - Maintenance	576	0.00	
21. **Total RTO/ISO Expense *(19 + 20)***		898,593.63	
22. Distribution Expense - Operation	580-589	0.00	0.00
23. Distribution Expense - Maintenance	590-598	0.00	0.00
24. **Total Distribution Expense *(22 + 23)***		0.00	0.00
25. **Total Operation And Maintenance *(18 + 21 +24)***		4,799,472.13	1,178,340.34
Fixed Costs			
26. Depreciation - Transmission	403.5	588,044.58	961,672.77
27. Depreciation - Distribution	403.6	0.00	0.00
28. Interest - Transmission	427	938,190.23	1,107,955.60
29. Interest - Distribution	427	0.00	0.00
30. **Total Transmission *(18 + 26 + 28)***		5,427,113.31	3,247,968.71
31. **Total Distribution *(24 +27 +29)***		0.00	0.00
32. **Total Lines And Stations *(21 + 30 + 31)***		6,325,706.94	3,247,968.71

SECTION B. FACILITIES IN SERVICE

TRANSMISSION LINES		SUBSTATIONS	
VOLTAGE (kV)	MILES	TYPE	CAPACITY (kVA)
1.69 kV	839.20	13. Distr. Lines	0
2.345 kV	68.40		
3.138 kV	14.40		
4.161 kV	362.80	14. Total *(12 + 13)*	1,284.80
5.		15. Step up at Generating Plants	1,879,800
6.			
7.			
8.		16. Transmission	3,595,000
9.			
10.		17. Distribution	0
11.			
12. Total *(1 thru 11)*	1,284.80	18. Total *(15 thru 17)*	5,474,800

SECTION C. LABOR AND MATERIAL SUMMARY

1. Number of Employees		53
ITEM	LINES	STATIONS
2. Oper. Labor	537,315.33	305,658.15
3. Maint. Labor	439,004.47	449,204.92
4. Oper. Material	3,659,900.44	213,815.57
5. Maint. Material	163,251.89	209,661.70

SECTION D. OUTAGES

1. Total	5,257.50
2. Avg. No. Dist. Cons. Served	113,252.00
3. Avg. No. Hours Out Per Cons.	0.05

RUS Form 12 – March 2013

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0572-0032. The time required to complete this information collection is estimated to average 21 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062
	PERIOD ENDED March -2013
INSTRUCTIONS - See help in the online application *This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C 552).*	BORROWER NAME **Big Rivers Electric Corporation**

CERTIFICATION

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7 CFR CHAPTER XVII

(check one of the following)

X All of the obligations under the RUS loan documents have been fulfilled in all material respects.

__ There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part A Section C of this report.

Mark A. Bailey 4/18/13

SIGNATURE OF PRESIDENT AND CEO DATE

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART A - FINANCIAL

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Mar-13

INSTRUCTIONS - See help in the online application.

SECTION A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	YEAR-TO-DATE BUDGET (c)	THIS MONTH (d)
1. Electric Energy Revenues	134,099,606.98	150,186,078.11	146,549,306.00	50,322,100.30
2. Income From Leased Property (Net)	0.00	0.00	0.00	0.00
3. Other Operating Revenue and Income	1,205,412.07	1,032,400.89	927,501.00	320,517.61
4. **Total Operation Revenues & Patronage Capital** *(1 thru 3)*	135,305,019.05	151,218,479.00	147,476,807.00	50,642,617.91
5. Operating Expense - Production - Excluding Fuel	11,819,929.11	12,611,443.99	13,745,801.00	4,125,212.99
6. Operating Expense - Production - Fuel	49,722,308.47	61,031,621.78	63,377,014.00	19,606,606.97
7. Operating Expense - Other Power Supply	31,526,081.60	27,425,081.81	23,135,520.00	10,156,987.46
8. Operating Expense - Transmission	2,409,490.80	2,833,360.82	2,328,441.00	895,408.62
9. Operating Expense - RTO/ISO	658,671.95	698,442.57	584,283.00	244,383.02
10. Operating Expense - Distribution	0.00	0.00	0.00	0.00
11. Operating Expense - Customer Accounts	0.00	0.00	0.00	0.00
12. Operating Expense - Customer Service & Information	104,308.62	132,553.75	318,530.00	61,547.11
13. Operating Expense - Sales	5,873.98	9,812.50	28,675.00	4,906.25
14. Operating Expense - Administrative & General	6,722,249.06	6,600,026.46	7,233,326.00	2,212,879.27
15. **Total Operation Expense** *(5 thru 14)*	102,968,913.59	111,342,343.68	110,751,590.00	37,307,931.69
16. Maintenance Expense - Production	12,134,496.52	9,203,398.07	9,423,935.00	3,268,530.57
17. Maintenance Expense - Transmission	1,055,272.45	945,950.31	1,192,855.00	331,359.59
18. Maintenance Expense - RTO/ISO	0.00	0.00	0.00	0.00
19. Maintenance Expense - Distribution	0.00	0.00	0.00	0.00
20. Maintenance Expense - General Plant	39,723.17	77,144.72	55,052.00	18,958.57
21. **Total Maintenance Expense** *(16 thru 20)*	13,229,492.14	10,226,493.10	10,671,842.00	3,618,848.73
22. Depreciation and Amortization Expense	10,175,830.45	10,287,340.11	10,327,895.00	3,459,257.39
23. Taxes	885.00	95.00	85.00	95.00
24. Interest on Long-Term Debt	11,256,593.45	11,094,166.62	11,224,951.00	3,793,702.11
25. Interest Charged to Construction - Credit	<200,566.00>	<106,915.00>	<30,889.00>	<36,879.00>
26. Other Interest Expense	162.17	22.82	0.00	10.75
27. Asset Retirement Obligations	0.00	0.00	0.00	0.00
28. Other Deductions	40,436.24	139,220.57	132,405.00	33,952.39
29. **Total Cost Of Electric Service** *(15 + 21 thru 28)*	137,471,747.04	142,982,766.90	143,077,879.00	48,176,919.06
30. **Operating Margins** *(4 less 29)*	<2,166,727.99>	8,235,712.10	4,398,928.00	2,465,698.85
31. Interest Income	18,339.76	502,930.69	510,611.00	168,356.69
32. Allowance For Funds Used During Construction	0.00	0.00	0.00	0.00
33. Income (Loss) from Equity Investments	0.00	0.00	0.00	0.00
34. Other Non-operating Income (Net)	0.00	0.00	0.00	0.00
35. Generation & Transmission Capital Credits	0.00	0.00	0.00	0.00
36. Other Capital Credits and Patronage Dividends	44,874.64	783,330.28	1,238,325.00	783,330.28
37. Extraordinary Items	0.00	0.00	0.00	0.00
38. **Net Patronage Capital Or Margins** *(30 thru 37)*	<2,103,513.59>	9,521,973.07	6,147,864.00	3,417,385.82

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART A - FINANCIAL

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Mar-13

INSTRUCTIONS - See help in the online application.

SECTION B. BALANCE SHEET

ASSETS AND OTHER DEBITS

1. Total Utility Plant in Service	2,005,031,797.93
2. Construction Work in Progress	47,789,799.11
3. **Total Utility Plant *(1 + 2)***	2,052,821,597.04
4. Accum. Provision for Depreciation and Amort.	971,356,276.60
5. **Net Utility Plant *(3 - 4)***	1,081,465,320.44
6. Non-Utility Property (Net)	0.00
7. Investments in Subsidiary Companies	0.00
8. Invest. in Assoc. Org. - Patronage Capital	3,894,189.99
9. Invest, in Assoc. Org. - Other - General Funds	43,840,793.00
10. Invest. in Assoc. Org. - Other - Nongeneral Funds	0.00
11. Investments in Economic Development Projects	10,000.00
12. Other Investments	5,333.85
13. Special Funds	176,183,902.85
14. **Total Other Property And Investments *(6 thru 13)***	223,934,219.69
15. Cash - General Funds	5,778.97
16. Cash - Construction Funds - Trustee	0.00
17. Special Deposits	598,583.21
18. Temporary Investments	116,374,045.17
19. Notes Receivable (Net)	0.00
20. Accounts Receivable - Sales of Energy (Net)	45,529,718.41
21. Accounts Receivable - Other (Net)	357,296.21
22. Fuel Stock	29,508,660.11
23. Renewable Energy Credits	0.00
24. Materials and Supplies - Other	25,929,071.64
25. Prepayments	3,228,069.65
26. Other Current and Accrued Assets	2,335,706.52
27. **Total Current And Accrued Assets *(15 thru 26)***	223,866,929.89
28. Unamortized Debt Discount & Extraor. Prop. Losses	4,157,628.99
29. Regulatory Assets	640,908.77
30. Other Deferred Debits	5,019,429.43
31. Accumulated Deferred Income Taxes	0.00
32. **Total Assets And Other Debits *(5+14+27 thru 31)***	1,539,084,437.21

LIABILITIES AND OTHER CREDITS

33. Memberships	75.00
34. Patronage Capital a. Assigned and Assignable b. Retired This year c. Retired Prior years **d. Net Patronage Capital (a-b-c)**	0.00
35. Operating Margins - Prior Years	<231,584,391.53>
36. Operating Margin - Current Year	9,019,042.38
37. Non-Operating Margins	640,463,598.21
38. Other Margins and Equities	<5,494,663.80>
39. **Total Margins & Equities *(33 + 34d thru 38)***	412,403,660.26
40. Long-Term Debt - RUS (Net)	212,233,698.00
41. Long-Term Debt - FFB - RUS Guaranteed	0.00
42. Long-Term Debt - Other - RUS Guaranteed	0.00
43. Long-Term Debt - Other (Net)	629,997,166.83
44. Long-Term Debt - RUS - Econ. Devel. (Net)	0.00
45. Payments - Unapplied	0.00
46. **Total Long-Term Debit *(40 thru 44-45)***	842,230,864.83
47. Obligations Under Capital Leases - Noncurrent	0.00
48. Accumulated Operating Provisions and Asset Retirement Obligations	22,170,052.37
49. **Total Other NonCurrent Liabilities *(47 +48)***	22,170,052.37
50. Notes Payable	0.00
51. Accounts Payable	29,204,435.91
52. Current Maturities Long-Term Debt	79,240,736.44
53. Current Maturities Long-Term Debt - Rural Development	0.00
54. Current Maturities Capital Leases	0.00
55. Taxes Accrued	1,307,640.72
56. Interest Accrued	4,107,909.61
57. Other Current and Accrued Liabilities	6,793,005.76
58. **Total Current & Accrued Liabilities *(50 thru 57)***	120,653,728.44
59. Deferred Credits	141,626,131.31
60. Accumulated Deferred Income Taxes	0.00
61. **Total Liabilities and Other Credits *(39 + 46 + 49 + 58 thru 60)***	1,539,084,437.21

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Mar-13

Part B SE - Sales of Electricity

Sale No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Fuel Type (e)	Average Monthly Billing Demand (MW) (f)	Actual Average Monthly NCP Demand (g)	Actual Average Monthly CP Demand (h)
	Ultimate Consumer(s)							
	Distribution Borrowers							
1	Jackson Purchase Energy Corp.	KY0020	RQ			121	135	121
2	Kenergy Corporation	KY0065	IF					
3	Kenergy Corporation	KY0065	LF					
4	Kenergy Corporation	KY0065	RQ			369	380	365
5	Meade County Rural ECC	KY0018	RQ			107	112	107
	G&T Borrowers							
	Others							
6	Midwest Independent Trans. Sys. Op.		OS					

	(f)	(g)	(h)
Total for Ultimate Consumer(s)	0	0	0
Total for Distribution Borrowers	597	627	593
Total for G&T Borrowers	0	0	0
Total for Others	0	0	0
Grand Total	597	627	593

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Mar-13

Part B SE - Sales of Electricity

Sale No.	Electricity Sold (MWh) (i)	Revenue Demand Charges (j)	Revenue Energy Charges (k)	Revenue Other Charges (l)	Revenue Total (j + k + l) (m)
1	178,990.853	3,910,230.42	5,526,419.28		9,436,649.70
2	50,974.313		1,821,380.70		1,821,380.70
3	1,836,846.591		89,802,600.99		89,802,600.99
4	568,961.137	11,825,129.58	16,283,516.42		28,108,646.00
5	143,955.234	3,393,971.15	4,465,356.42		7,859,327.57
6	460,077.600		13,157,473.15		13,157,473.15
	0	0	0	0	0
	2,779,728.128	19,129,331.15	117,899,273.81	0.00	137,028,604.96
	0.000	0.00	0.00	0.00	0.00
	460,077.600	0.00	13,157,473.15	0.00	13,157,473.15
	3,239,805.728	19,129,331.15	131,056,746.96	0.00	150,186,078.11

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE	BORROWER DESIGNATION KY0062
FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	PERIOD NAME Mar-13
INSTRUCTIONS - See help in the online application.	

PART B PP - Purchased Power

Purchase No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Energy Type (e)	Average Monthly Billing Demand (MW) (f)	Average Monthly NCP Demand (g)	Average Monthly CP Demand (h)
	Distribution Borrowers							
	G&T Borrowers							
	Others							
1	Henderson Municipal Power & Light		RQ					
2	Midwest Independent Trans. Sys. Op.		OS					
3	Southeastern Power Admin.		LF					
Total for Distribution Borrowers						0	0	0
Total for G&T Borrowers						0	0	0
Total for Others						0	0	0
Grand Total						0	0	0

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD NAME Mar-13
INSTRUCTIONS - See help in the online application.	

PART B PP - Purchased Power

Purchase No.	Electricity Purchased (MWh) (i)	Electricity Received (MWh) (j)	Electricity Delivered (MWh) (k)	Demand Charges (l)	Energy Charges (m)	Other Charges (n)	Total (l + m + n) (o)
1	400,684.380				17,004,458.76		17,004,458.76
2	252,762.300				6,398,067.83		6,398,067.83
3	147,794.000				3,397,287.07		3,397,287.07
	0.000				0.00		0.00
	0.000				0.00		0.00
	801,240.680				26,799,813.66		26,799,813.66
	801,240.680				26,799,813.66		26,799,813.66

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART C - SOURCES AND DISTRIBUTION OF ENERGY

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Mar-13

INSTRUCTIONS - See help in the online application.

SOURCES OF ENERGY (a)	NO. OF PLANTS (b)	CAPACITY (kW) (c)	NET ENERGY RECEIVED BY SYSTEM (MWh) (d)	COST ($) (e)
Generated in Own Plant *(Details on Parts D and F IC)*				
1. Fossil Steam	4	1,489,000	2,451,688.184	100,256,589.83
2. Nuclear				
3. Hydro				
4. Combined Cycle				
5. Internal Combustion	1	70,000	<157.510>	171,581.74
6. Other				
7. Total in Own Plant *(1 thru 6)*	5	1,559,000	2,451,530.674	100,428,171.57
Purchased Power				
8. Total Purchased Power			801,240.680	26,799,813.66
Interchanged Power				
9. Received Into System (Gross)			1,212,560.000	
10. Delivered Out of System (Gross)			1,165,522.000	
11. Net Interchange *(9 minus 10)*			47,038.000	
Transmission For or By Others - (Wheeling)				
12. Received Into System			0.000	
13. Delivered Out of System			0.000	
14. Net Energy Wheeled *(12 minus 13)*			0.000	
15. Total Energy Available for Sale (7 + 8 + 11 + 14)			3,299,809.354	
Distribution of Energy				
16. Total Sales			3,239,805.728	
17. Energy Furnished to Others Without Charge				
18. Energy Used by Borrower *(Excluding Station Use)*				
19. Total Energy Accounted For *(16 thru 18)*			3,239,805.728	
Losses				
20. Energy Losses - MWh *(15 minus 19)*			60,003.626	
21. Energy Losses - Percentage ((20 divided by 15) * 100)			1.82 %	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART D - STEAM PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062
PLANT
COLEMAN
PERIOD ENDED
Mar-13

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	5	230,126.5	0.000	7,103.6			1,906.7	25.0	0.0	227.3
2.	2	1	249,837.7	0.000	2,279.6			2,090.4	0.0	0.0	68.6
3.	3	2	254,156.5	0.000	7,207.7			2,034.7	0.0	0.0	124.3
4.											
5.											
6.	Total	8	734,120.7	0.000	16,590.9			6,031.8	25.0	0.0	420.2
7.	Average BTU		11,336	0	1,000						
8.	Total BTU(10^6)		8,321,992	0	16,591						
9.	Total Del.Cost ($)		20,205,046.10	0.00	74,796.44		8,338,583				

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	160,000	258,203.000	
2.	2	160,000	288,745.000	
3.	3	165,000	294,837.000	
4.				
5.				
6.	Total	485,000	841,785.000	9,906
7.	Station Service (MWh)		75,672.000	
8.	Net Generation (MWh)		766,113.000	10,884
9.	Station Service (%)		8.99	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	105
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	79.72
2.	Plant Factor (%)	80.39
3.	Running Plant Capacity Factor (%)	86.31
4.	15 Minute Gross Maximum Demand (kW)	489,077
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10⁶ BTU (c)
1.	Operation, Supervision and Engineering	500	447,301.53		
2.	Fuel, Coal	501.1	20,946,607.05		
3.	Fuel, Oil	501.2	0.00		2.52
4.	Fuel, Gas	501.3	74,796.44		
5.	Fuel, Other	501.4			4.51
6.	Fuel Sub Total (2 thru 5)	501	21,021,403.49	27.44	2.52
7.	Steam Expenses	502	1,489,736.85		
8.	Electric Expenses	505	526,257.74		
9.	Miscellaneous Steam Power Expenses	506	579,081.99		
10.	Allowances	509	5,855.84		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		3,048,233.95	3.98	
13.	Operation Expense (6 + 12)		24,069,637.44	31.42	
14.	Maintenance, Supervision and Engineering	510	374,772.03		
15.	Maintenance of Structures	511	241,976.13		
16.	Maintenance of Boiler Plant	512	2,063,737.58		
17.	Maintenance of Electric Plant	513	277,514.11		
18.	Maintenance of Miscellaneous Plant	514	359,832.27		
19.	Maintenance Expense (14 thru 18)		3,317,832.12	4.33	
20.	Total Production Expense (13 + 19)		27,387,469.56	35.75	
21.	Depreciation	403.1	1,388,487.28		
22.	Interest	427	1,716,366.27		
23.	Total Fixed Cost (21 + 22)		3,104,853.55	4.05	
24.	Power Cost (20 + 23)		30,492,323.11	39.80	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION
KY0062

PLANT
REID

PERIOD ENDED
Mar-13

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE Scheduled (j)	Unsched (k)
1.	1	0	.0	.000	.0						
2.								.0	2,159.0	.0	.0
3.											
4.											
5.											
6.	Total	0	.0	.000	.0						
7.	Average BTU		0	0	0			.0	2,159.0	.0	.0
8.	Total BTU(10^6)		0	0	0						
9.	Total Del. Cost ($)		0.00	265.34	0.00		0				

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (1)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	72,000	.000	
2.				
3.				
4.				
5.				
6.	Total	72,000	.000	0
7.	Station Service (MWh)		4,833.000	
8.	Net Generation (MWh)		<4,833.000>	0
9.	Station Service (%)		0	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	17
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	.00
2.	Plant Factor (%)	.00
3.	Running Plant Capacity Factor (%)	.00
4.	15 Minute Gross Maximum Demand (kW)	0
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10⁶ BTU (c)
1.	Operation, Supervision and Engineering				
2.	Fuel, Coal	500	71,012.05		
3.	Fuel, Oil	501.1	88,997.27		0
4.	Fuel, Gas	501.2	265.34		0
5.	Fuel, Other	501.3	0.00		0
6.	Fuel Sub Total (2 thru 5)	501.4			0
7.	Steam Expenses	501	89,262.61		0
8.	Electric Expenses	502	129,612.16		
9.	Miscellaneous Steam Power Expenses	505	70,670.43		
10.	Allowances	506	55,425.16		
11.	Rents	509	139.63		
12.	Non-Fuel Sub Total (1 + 7 thru 11)	507	0.00		
13.	Operation Expense (6 + 12)		326,859.43		
14.	Maintenance, Supervision and Engineering		416,122.04		
15.	Maintenance of Structures	510	58,738.07		
16.	Maintenance of Boiler Plant	511	25,155.34		
17.	Maintenance of Electric Plant	512	246,577.03		
18.	Maintenance of Miscellaneous Plant	513	32,150.48		
19.	Maintenance Expense (14 thru 18)	514	32,784.22		
20.	Total Production Expense (13 + 19)		395,405.14		
21.	Depreciation		811,527.18		
22.	Interest	403.1	102,273.84		
23.	Total Fixed Cost (21 + 22)	427	176,333.60		
24.	Power Cost (20 + 23)		278,607.44	0	
			1,090,134.62		

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION	KY0062
PLANT	GREEN
PERIOD ENDED	Mar-13

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	3	403,102.3	49.328	.0			2,059.0	.0	.0	100.0
2.	2	0	413,195.6	24.354	.0			2,159.0	.0	.0	.0
3.											
4.											
5.											
6.	Total	3	816,297.9	73.682	.0			4,218.0	.0	.0	100.0
7.	Average BTU		11,711	138,000	0						
8.	Total BTU(10^6)		9,559,665	10,168	0		9,569,833				
9.	Total Del. Cost ($)		20,112,631.94	236,534.03	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	250,000	470,087.380	
2.	2	242,000	478,363.400	
3.				
4.				
5.				
6.	Total	492,000	948,450.780	10,090
7.	Station Service (MWh)		87,711.880	
8.	Net Generation (MWh)		860,738.900	11,118
9.	Station Service (%)		9.26	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	112
2.	No. Employees Part-Time	
3.	**Total Empl. - Hrs. Worked**	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	**Total Plant Payroll ($)**	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	87.56
2.	Plant Factor (%)	89.29
3.	Running Plant Capacity Factor (%)	91.44
4.	15 Minute Gross Maximum Demand (kW)	501,732
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10⁶ BTU (c)
1.	Operation, Supervision and Engineering	500	376,763.43		
2.	Fuel, Coal	501.1	20,714,682.51		2.17
3.	Fuel, Oil	501.2	236,534.03		23.26
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			
6.	**Fuel Sub Total (2 thru 5)**	501	20,951,216.54	24.34	2.19
7.	Steam Expenses	502	3,728,497.52		
8.	Electric Expenses	505	790,059.69		
9.	Miscellaneous Steam Power Expenses	506	383,972.12		
10.	Allowances	509	4,640.86		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub Total (1 + 7 thru 11)**		5,283,933.62	6.14	
13.	**Operation Expense (6 + 12)**		26,235,150.16	30.48	
14.	Maintenance, Supervision and Engineering	510	386,886.10		
15.	Maintenance of Structures	511	263,337.21		
16.	Maintenance of Boiler Plant	512	1,721,805.46		
17.	Maintenance of Electric Plant	513	310,613.72		
18.	Maintenance of Miscellaneous Plant	514	228,943.64		
19.	**Maintenance Expense (14 thru 18)**		2,911,586.13	3.38	
20.	**Total Production Expense (13 + 19)**		29,146,736.29	33.86	
21.	Depreciation	403.1	1,993,595.80		
22.	Interest	427	1,999,341.37		
23.	**Total Fixed Cost (21 + 22)**		3,992,937.17	4.64	
24.	**Power Cost (20 + 23)**		33,139,673.46	38.50	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION
KY0062
PLANT
WILSON
PERIOD ENDED
Mar-13

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	2	753,767.3	104.467	.0			2,114.8	.0	.0	44.2
2.											
3.											
4.											
5.											
6.	Total	2	753,767.3	104.467	.0			2,114.8	.0	.0	44.2
7.	Average BTU		11,627	138,000	0						
8.	Total BTU(10^6)		8,764,052	14,416	0		8,778,468				
9.	Total Del..Cost ($)		17,883,450.34	329,503.15	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	440,000	890,559.480	
2.				
3.				
4.				
5.				
6.	Total	440,000	890,559.480	9,857
7.	Station Service (MWh)		60,890.196	
8.	Net Generation (MWh)		829,669.284	10,681
9.	Station Service (%)		6.84	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	106
2.	No. Employees Part-Time	
3.	**Total Empl. - Hrs. Worked**	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	**Total Plant Payroll ($)**	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	90.74
2.	Plant Factor (%)	93.75
3.	Running Plant Capacity Factor (%)	95.71
4.	15 Minute Gross Maximum Demand (kW)	454,558
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	475,907.37		
2.	Fuel, Coal	501.1	18,638,732.76		2.13
3.	Fuel, Oil	501.2	329,503.15		22.86
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	**Fuel Sub-Total (2 thru 5)**	501	18,968,235.91	22.86	2.16
7.	Steam Expenses	502	2,391,644.22		
8.	Electric Expenses	505	366,682.65		
9.	Miscellaneous Steam Power Expenses	506	699,367.76		
10.	Allowances	509	9,156.46		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub-Total (1 + 7 thru 11)**		3,942,758.46	4.75	
13.	**Operation Expense (6 + 12)**		22,910,994.37	27.61	
14.	Maintenance, Supervision and Engineering	510	355,712.88		
15.	Maintenance of Structures	511	214,107.35		
16.	Maintenance of Boiler Plant	512	1,651,790.15		
17.	Maintenance of Electric Plant	513	209,091.98		
18.	Maintenance of Miscellaneous Plant	514	112,178.63		
19.	**Maintenance Expense (14 thru 18)**		2,542,880.99	3.06	
20.	**Total Production Expense (13 + 19)**		25,453,875.36	30.68	
21.	Depreciation	403.1	4,796,558.35		
22.	Interest	427	5,284,024.93		
23	**Total Fixed Cost (21 + 22)**		10,080,583.28	12.15	
24.	**Power Cost (20 + 23)**		35,534,458.64	42.83	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART F IC - INTERNAL COMBUSTION PLANT

BORROWER DESIGNATION: KY0062
PLANT: REID
PERIOD ENDED: Mar-13

INSTRUCTIONS - See help in the online application.

SECTION A. INTERNAL COMBUSTION GENERATING UNITS

NO.	UNIT NO. (a)	SIZE (kW) (b)	FUEL CONSUMPTION: OIL (1000 Gals.) (c)	GAS (1000 C.F.) (d)	OTHER (e)	TOTAL (f)	OPERATING HOURS: IN SERVICE (g)	ON STANDBY (h)	OUT OF SERVICE: Sche. (i)	Unsched (j)	GROSS GENERATION (MWh) (k)	BTU PER kWh (1)
1.	1	70,000	.000	367			2.2	2,083.2	.0	73.6	4.010	
2.												
3.												
4.												
5.												
6.	Total	70,000	.000	367			2.2	2,083.2	.0	73.6	4.010	91,521
7.	Average BTU		0	1,000			Station Service (MWh)				161.520	
8.	Total BTU(10^6)		0	367		367	Net Generation (MWh)				<157.510>	0
9.	Total Del. Cost ($)		0.00	1,503.23			Station Service % of Gross				4,027.93	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	0	5.	Maint. Plant Payroll ($)	
2.	No. Employees Part-Time		6.	Other Accounts. Plant Payroll ($)	
3.	**Total Empl. - Hrs. Worked**				
4.	Oper. Plant Payroll ($)		7.	**Total Plant Payroll ($)**	

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	.02
2.	Plant Factor (%)	.00
3.	Running Plant Capacity Factor (%)	2.60
4.	15 Minute Gross Maximum Demand (kW)	10,308
5.	Indicated Gross Maximum Demand kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10⁶ BTU (c)
1.	Operation, Supervision and Engineering	546	0.00		
2.	Fuel, Oil	547.1	0.00		
3.	Fuel, Gas	547.2	1,503.23		4.10
4.	Fuel, Other	547.3			
5.	Energy for Compressed Air	547.4			
6.	**Fuel Sub-Total *(2 thru 5)***	547	1,503.23		4.10
7.	Generation Expenses	548	9,658.53		
8.	Miscellaneous Other Power Generation Expenses	549	0.00		
9.	Rents	550	0.00		
10.	**Non-Fuel Sub-Total *(1 + 7 thru 9)***		9,658.53		
11.	**Operation Expense *(6+ 10)***		11,161.76		
12.	Maintenance, Supervision and Engineering	551	0.00		
13.	Maintenance of Structures	552	0.00		
14.	Maintenance of Generating and Electric Plant	553	35,693.69		
15.	Maintenance of Miscellaneous Other Power Generating Plant	554	0.00		
16.	**Maintenance Expense *(12 thru 15)***		35,693.69		
17.	**Total Production Expense *(11 + 16)***		46,855.45		
18.	Depreciation	403.1,411.10	73,653.69		
19.	Interest	427	51,072.60		
20.	**Total Fixed Cost *(18+ 19)***		124,726.29		
21.	**Power Cost *(17 + 20)***		171,581.74		

REMARKS *(including Unscheduled Outages)*

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART I - LINES AND STATIONS

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Mar-13

SECTION A. EXPENSE AND COSTS

ITEM	ACCOUNT NUMBER	LINES (a)	STATIONS (b)
Transmission Operation			
1. Supervision and Engineering	560	65,161.10	84,237.54
2. Load Dispatching	561	915,357.29	
3. Station Expenses	562		218,537.71
4. Overhead Line Expenses	563	317,675.11	
5. Underground Line Expenses	564	0.00	
6. Miscellaneous Expenses	566	52,437.07	88,271.95
7. **Subtotal *(1 thru 6)***		1,350,630.57	391,047.20
8. Transmission of Electricity by Others	565	1,089,026.28	
9. Rents	567	0.00	2,656.77
10. **Total Transmission Operation *(7 thru 9)***		2,439,656.85	393,703.97
Transmission Maintenance			
11. Supervision and Engineering	568	57,533.12	62,827.50
12. Structures	569		4,809.53
13. Station Equipment	570		324,406.94
14. Overhead Lines	571	344,838.45	
15. Underground Lines	572	0.00	
16. Miscellaneous Transmission Plant	573	60,668.42	91,086.35
17. **Total Transmission Maintenance *(11 thru 16)***		463,039.99	482,910.32
18. **Total Transmission Expense *(10 + 17)***		2,902,696.84	876,614.29
19. RTO/ISO Expense - Operation	575	698,442.57	
20. RTO/ISO Expense - Maintenance	576	0.00	
21. **Total RTO/ISO Expense *(19 + 20)***		698,442.57	
22. Distribution Expense - Operation	580-589	0.00	0.00
23. Distribution Expense - Maintenance	590-598	0.00	0.00
24. **Total Distribution Expense *(22 + 23)***		0.00	0.00
25. **Total Operation And Maintenance *(18 + 21 + 24)***		3,601,139.41	876,614.29
Fixed Costs			
26. Depreciation - Transmission	403.5	440,782.24	721,923.34
27. Depreciation - Distribution	403.6	0.00	0.00
28. Interest - Transmission	427	702,275.71	826,316.09
29. Interest - Distribution	427	0.00	0.00
30. **Total Transmission *(18 + 26 + 28)***		4,045,754.79	2,424,853.72
31. **Total Distribution *(24 + 27 + 29)***		0.00	0.00
32. **Total Lines And Stations *(21 + 30 + 31)***		4,744,197.36	2,424,853.72

SECTION B. FACILITIES IN SERVICE

TRANSMISSION LINES		SUBSTATIONS	
VOLTAGE (kV)	MILES	TYPE	CAPACITY (kVA)
1.69 kV	839.20	13. Distr. Lines	0
2.345 kV	68.40		
3.138 kV	14.40		
4.161 kV	362.80	14. Total *(12 + 13)*	1,284.80
5.		15. Step up at Generating Plants	1,879,800
6.			
7.			
8.		16. Transmission	3,595,000
9.			
10.		17. Distribution	0
11.			
12. Total *(1 thru 11)*	1,284.80	18. Total *(15 thru 17)*	5,474,800

SECTION C. LABOR AND MATERIAL SUMMARY

1. Number of Employees: 51

ITEM	LINES	STATIONS
2. Oper. Labor	414,191.60	235,785.06
3 Maint. Labor	329,149.61	321,507.66
4. Oper. Material	2,723,907.82	157,918.91
5. Maint Material	133,890.38	161,402.66

SECTION D. OUTAGES

1. Total	1,962.50
2. Avg. No. Dist. Cons. Served	113,252.00
3 Avg. No. Hours Out Per Cons.	0.02

RUS Form 12 – February 2013

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0572-0032. The time required to complete this information collection is estimated to average 21 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD ENDED February -2013
INSTRUCTIONS - See help in the online application *This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C. 552).*	BORROWER NAME **Big Rivers Electric Corporation**

CERTIFICATION

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7 CFR CHAPTER XVII

(check one of the following)

X All of the obligations under the RUS loan documents have been fulfilled in all material respects.

__ There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part A Section C of this report.

Mark A. Bailey 3/25/13

SIGNATURE OF PRESIDENT AND CEO DATE

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT** **ELECTRIC POWER SUPPLY** **PART A - FINANCIAL**	BORROWER DESIGNATION KY0062 PERIOD ENDED Feb-13
INSTRUCTIONS - See help in the online application.	

SECTION A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	THIS YEAR (b)	BUDGET (c)	THIS MONTH (d)
1. Electric Energy Revenues	88,954,042.58	99,863,977.81	97,814,573.00	49,226,444.84
2. Income From Leased Property (Net)	0.00	0.00	0.00	0.00
3. Other Operating Revenue and Income	856,710.80	711,883.28	619,834.00	350,148.01
4. **Total Operation Revenues & Patronage Capital** *(1 thru 3)*	89,810,753.38	100,575,861.09	98,434,407.00	49,576,592.85
5. Operating Expense - Production - Excluding Fuel	7,474,262.65	8,486,231.00	8,981,164.00	4,111,416.06
6. Operating Expense - Production - Fuel	33,211,481.67	41,425,014.81	41,943,978.00	19,894,279.14
7. Operating Expense - Other Power Supply	19,567,911.58	17,268,094.35	14,757,094.00	7,940,327.78
8. Operating Expense - Transmission	1,610,970.13	1,937,952.20	1,530,564.00	1,166,729.77
9. Operating Expense - RTO/ISO	425,677.65	454,059.55	389,296.00	215,774.42
10. Operating Expense - Distribution	0.00	0.00	0.00	0.00
11. Operating Expense - Customer Accounts	0.00	0.00	0.00	0.00
12. Operating Expense - Customer Service & Information	36,383.76	71,006.64	130,066.00	22,948.58
13. Operating Expense - Sales	<3,938.52>	4,906.25	10,406.00	4,906.25
14. Operating Expense - Administrative & General	4,145,694.64	4,387,147.19	4,355,733.00	2,636,294.78
15. **Total Operation Expense** *(5 thru 14)*	66,468,443.56	74,034,411.99	72,098,301.00	35,992,676.78
16. Maintenance Expense - Production	6,452,585.34	5,934,867.50	5,948,144.00	2,630,616.78
17. Maintenance Expense - Transmission	619,462.50	614,590.72	746,130.00	335,954.94
18. Maintenance Expense - RTO/ISO	0.00	0.00	0.00	0.00
19. Maintenance Expense - Distribution	0.00	0.00	0.00	0.00
20. Maintenance Expense - General Plant	29,177.93	58,186.15	37,446.00	35,504.22
21. **Total Maintenance Expense** *(16 thru 20)*	7,101,225.77	6,607,644.37	6,731,720.00	3,002,075.94
22. Depreciation and Amortization Expense	6,786,122.04	6,828,082.72	6,882,137.00	3,414,042.41
23. Taxes	0.00	0.00	0.00	0.00
24. Interest on Long-Term Debt	7,430,257.06	7,300,464.51	7,296,170.00	3,496,431.22
25. Interest Charged to Construction - Credit	<134,100.00>	<70,036.00>	<8,437.00>	<36,474.00>
26. Other Interest Expense	23.76	12.07	0.00	0.00
27. Asset Retirement Obligations	0.00	0.00	0.00	0.00
28. Other Deductions	25,125.60	105,268.18	84,653.00	70,128.51
29. **Total Cost Of Electric Service** *(15 + 21 thru 28)*	87,677,097.79	94,805,847.84	93,084,544.00	45,938,880.86
30. **Operating Margins** *(4 less 29)*	2,133,655.59	5,770,013.25	5,349,863.00	3,637,711.99
31. Interest Income	11,364.72	334,574.00	340,830.00	165,144.63
32. Allowance For Funds Used During Construction	0.00	0.00	0.00	0.00
33. Income (Loss) from Equity Investments	0.00	0.00	0.00	0.00
34. Other Non-operating Income (Net)	0.00	0.00	0.00	0.00
35. Generation & Transmission Capital Credits	0.00	0.00	0.00	0.00
36. Other Capital Credits and Patronage Dividends	0.00	0.00	0.00	0.00
37. Extraordinary Items	0.00	0.00	0.00	0.00
38. **Net Patronage Capital Or Margins** *(30 thru 37)*	2,145,020.31	6,104,587.25	5,690,693.00	3,802,856.62

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART A - FINANCIAL**	BORROWER DESIGNATION KY0062 PERIOD ENDED Feb-13
INSTRUCTIONS - See help in the online application.	

SECTION B. BALANCE SHEET

ASSETS AND OTHER DEBITS		LIABILITIES AND OTHER CREDITS	
1. Total Utility Plant in Service	1,999,408,279.79	33. Memberships	75.00
2. Construction Work in Progress	53,628,696.15	34. Patronage Capital	
3. Total Utility Plant (1 + 2)	**2,053,036,975.94**	a. Assigned and Assignable	
4. Accum. Provision for Depreciation and Amort.	970,351,964.00	b. Retired This year	
		c. Retired Prior years	
5. Net Utility Plant (3 - 4)	**1,082,685,011.94**	**d. Net Patronage Capital (a-b-c)**	0.00
6. Non-Utility Property (Net)	0.00	35. Operating Margins - Prior Years	<231,584,391.53>
7. Investments in Subsidiary Companies	0.00	36. Operating Margin - Current Year	5,770,013.25
8. Invest. in Assoc. Org. - Patronage Capital	3,680,644.42	37. Non-Operating Margins	640,295,241.52
9. Invest, in Assoc. Org. - Other - General Funds	43,840,793.00	38. Other Margins and Equities	<5,494,663.80>
10. Invest. in Assoc. Org. - Other - Nongeneral Funds	0.00	**39. Total Margins & Equities (33 + 34d thru 38)**	**408,986,274.44**
11. Investments in Economic Development Projects	10,000.00	40. Long-Term Debt - RUS (Net)	210,370,089.31
		41. Long-Term Debt - FFB - RUS Guaranteed	0.00
12. Other Investments	5,333.85	42. Long-Term Debt - Other - RUS Guaranteed	0.00
13. Special Funds	178,223,769.69	43. Long-Term Debt - Other (Net)	631,903,545.83
14. Total Other Property And Investments (6 thru 13)	**225,760,540.96**	44. Long-Term Debt - RUS - Econ. Devel. (Net)	0.00
		45. Payments - Unapplied	0.00
15. Cash - General Funds	5,771.83	**46. Total Long-Term Debt (40 thru 44-45)**	**842,273,635.14**
16. Cash - Construction Funds - Trustee	0.00	47. Obligations Under Capital Leases - Noncurrent	0.00
17. Special Deposits	598,537.97		
18. Temporary Investments	116,720,184.82	48. Accumulated Operating Provisions and Asset Retirement Obligations	22,213,978.74
19. Notes Receivable (Net)	0.00		
20. Accounts Receivable - Sales of Energy (Net)	42,958,401.87	**49. Total Other NonCurrent Liabilities (47 +48)**	**22,213,978.74**
21. Accounts Receivable - Other (Net)	537,765.49	50. Notes Payable	0.00
22. Fuel Stock	29,646,075.59	51. Accounts Payable	30,216,735.82
23. Renewable Energy Credits	0.00		
24. Materials and Supplies - Other	25,521,791.45	52. Current Maturities Long-Term Debt	79,152,809.44
25. Prepayments	3,469,705.58	53. Current Maturities Long-Term Debt - Rural Development	0.00
26. Other Current and Accrued Assets	2,293,040.50		
27. Total Current And Accrued Assets (15 thru 26)	**221,751,275.10**	54. Current Maturities Capital Leases	0.00
		55. Taxes Accrued	1,093,610.01
28. Unamortized Debt Discount & Extraor. Prop. Losses	4,159,049.86	56. Interest Accrued	4,697,801.51
		57. Other Current and Accrued Liabilities	7,071,539.86
29. Regulatory Assets	662,670.19		
30. Other Deferred Debits	4,483,792.51	**58. Total Current & Accrued Liabilities (50 thru 57)**	**122,232,496.64**
31. Accumulated Deferred Income Taxes	0.00	59. Deferred Credits	143,795,955.60
		60. Accumulated Deferred Income Taxes	0.00
32. Total Assets And Other Debits (5+14+27 thru 31)	**1,539,502,340.56**	**61. Total Liabilities and Other Credits (39 + 46 + 49 + 58 thru 60)**	**1,539,502,340.56**

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD ENDED Feb-13
INSTRUCTIONS - See help in the online application.	

Part B SE - Sales of Electricity

Sale No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Fuel Type (e)	Average Monthly Billing Demand (MW) (f)	Actual Average Monthly NCP Demand (g)	Actual Average Monthly CP Demand (h)
	Ultimate Consumer(s)							
	Distribution Borrowers							
1	Jackson Purchase Energy Corp.	KY0020	RQ			126	137	125
2	Kenergy Corporation	KY0065	IF					
3	Kenergy Corporation	KY0065	LF					
4	Kenergy Corporation	KY0065	RQ			378	387	374
5	Meade County Rural ECC	KY0018	RQ			113	116	112
	G&T Borrowers							
	Others							
6	Midwest Independent Trans. Sys. Op.		OS					

	(f)	(g)	(h)
Total for Ultimate Consumer(s)	0	0	0
Total for Distribution Borrowers	617	640	611
Total for G&T Borrowers	0	0	0
Total for Others	0	0	0
Grand Total	617	640	611

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Feb-13

Part B SE - Sales of Electricity

Sale No.	Electricity Sold (MWh) (i)	Revenue Demand Charges (j)	Revenue Energy Charges (k)	Revenue Other Charges (l)	Revenue Total (j + k + l) (m)
1	120,541.093	2,816,745.00	3,706,525.02		6,523,270.02
2	33,311.782		1,078,754.60		1,078,754.60
3	1,200,877.273		58,687,476.28		58,687,476.28
4	379,039.179	8,278,800.97	10,810,164.74		19,088,965.71
5	97,060.974	2,458,831.26	3,000,475.64		5,459,306.90
6	334,470.800		9,026,204.30		9,026,204.30
	0	0	0	0	0
	1,830,830.301	13,554,377.23	77,283,396.28	0.00	90,837,773.51
	0.000	0.00	0.00	0.00	0.00
	334,470.800	0.00	9,026,204.30	0.00	9,026,204.30
	2,165,301.101	13,554,377.23	86,309,600.58	0.00	99,863,977.81

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE	BORROWER DESIGNATION KY0062
FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	PERIOD NAME Feb-13
INSTRUCTIONS - See help in the online application.	

PART B PP - Purchased Power

Purchase No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Energy Type (e)	Average Monthly Billing Demand (MW) (f)	Average Monthly NCP Demand (g)	Average Monthly CP Demand (h)
	Distribution Borrowers							
	G&T Borrowers							
	Others							
1	Henderson Municipal Power & Light		RQ					
2	Midwest Independent Trans. Sys. Op.		OS					
3	Southeastern Power Admin.		LF					
Total for Distribution Borrowers						0	0	0
Total for G&T Borrowers						0	0	0
Total for Others						0	0	0
Grand Total						0	0	0

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE	BORROWER DESIGNATION KY0062
FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	PERIOD NAME Feb-13
INSTRUCTIONS - See help in the online application.	

PART B PP - Purchased Power

Purchase No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Energy Type (e)	Average Monthly Billing Demand (MW) (f)	Average Monthly NCP Demand (g)	Average Monthly CP Demand (h)
	Distribution Borrowers							
	G&T Borrowers							
	Others							
1	Henderson Municipal Power & Light		RQ					
2	Midwest Independent Trans. Sys. Op.		OS					
3	Southeastern Power Admin.		LF					
Total for Distribution Borrowers						0	0	0
Total for G&T Borrowers						0	0	0
Total for Others						0	0	0
Grand Total						0	0	0

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART C - SOURCES AND DISTRIBUTION OF ENERGY

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Feb-13

INSTRUCTIONS - See help in the online application.

SOURCES OF ENERGY (a)	NO. OF PLANTS (b)	CAPACITY (kW) (c)	NET ENERGY RECEIVED BY SYSTEM (MWh) (d)	COST ($) (e)
Generated in Own Plant *(Details on Parts D and F IC)*				
1. Fossil Steam	0	1,489,000	1,662,923.382	67,350,666.39
2. Nuclear				
3. Hydro				
4. Combined Cycle				
5. Internal Combustion	0	70,000	<99.810>	124,473.62
6. Other				
7. Total in Own Plant *(1 thru 6)*	0	1,559,000	1,662,823.572	67,475,140.01
Purchased Power				
8. Total Purchased Power			511,274.500	16,899,003.92
Interchanged Power				
9. Received Into System (Gross)			808,381.000	
10. Delivered Out of System (Gross)			778,552.000	
11. Net Interchange *(9 minus 10)*			29,829.000	
Transmission For or By Others - (Wheeling)				
12. Received Into System			0.000	
13. Delivered Out of System			0.000	
14. Net Energy Wheeled *(12 minus 13)*			0.000	
15. Total Energy Available for Sale (7 + 8 + 11 + 14)			2,203,927.072	
Distribution of Energy				
16. Total Sales			2,165,301.101	
17. Energy Furnished to Others Without Charge				
18. Energy Used by Borrower *(Excluding Station Use)*				
19. Total Energy Accounted For *(16 thru 18)*			2,165,301.101	
Losses				
20. Energy Losses - MWh *(15 minus 19)*			38,625.971	
21. Energy Losses - Percentage ((20 divided by 15) * 100)			1.75 %	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART D - STEAM PLANT

BORROWER DESIGNATION
KY0062
PLANT
COLEMAN
PERIOD ENDED
Feb-13

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	4	150,991.8	0.000	5,633.9			1,223.3	25.0	0.0	167.7
2.	2	1	163,435.1	0.000	1,984.9			1,347.4	0.0	0.0	68.6
3.	3	0	178,766.5	0.000	4,786.5			1,416.0	0.0	0.0	0.0
4.											
5.											
6.	Total	5	493,193.4	0.000	12,405.3			3,986.7	25.0	0.0	236.3
7.	Average BTU		11,323	0	1,000						
8.	Total BTU(10^6)		5,584,429	0	12,405		5,596,834				
9.	Total Del.Cost ($)		13,515,374.36	0.00	58,734.64						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	160,000	169,490.000	
2.	2	160,000	188,713.000	
3.	3	165,000	206,688.000	
4.				
5.				
6.	Total	485,000	564,891.000	9,908
7.	Station Service (MWh)		50,255.000	
8.	Net Generation (MWh)		514,636.000	10,875
9.	Station Service (%)		8.90	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	105
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	81.66
2.	Plant Factor (%)	82.25
3.	Running Plant Capacity Factor (%)	87.59
4.	15 Minute Gross Maximum Demand (kW)	488,548
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/$10^6$ BTU (c)
1.	Operation, Supervision and Engineering	500	297,548.29		
2.	Fuel, Coal	501.1	14,026,820.31		2.51
3.	Fuel, Oil	501.2	0.00		
4.	Fuel, Gas	501.3	58,734.64		4.73
5.	Fuel, Other	501.4			
6.	Fuel Sub Total (2 thru 5)	501	14,085,554.95	27.37	2.52
7.	Steam Expenses	502	1,023,131.13		
8.	Electric Expenses	505	348,952.55		
9.	Miscellaneous Steam Power Expenses	506	348,977.99		
10.	Allowances	509	4,062.18		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		2,022,672.14	3.93	
13.	Operation Expense (6 + 12)		16,108,227.09	31.30	
14.	Maintenance, Supervision and Engineering	510	248,926.59		
15.	Maintenance of Structures	511	146,600.95		
16.	Maintenance of Boiler Plant	512	1,233,999.55		
17.	Maintenance of Electric Plant	513	155,828.75		
18.	Maintenance of Miscellaneous Plant	514	226,866.60		
19.	Maintenance Expense (14 thru 18)		2,012,222.44	3.91	
20.	Total Production Expense (13 + 19)		18,120,449.53	35.21	
21.	Depreciation	403.1	922,550.76		
22.	Interest	427	1,129,193.86		
23.	Total Fixed Cost (21 + 22)		2,051,744.62	3.99	
24.	Power Cost (20 + 23)		20,172,194.15	39.20	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION: KY0062
PLANT: REID
PERIOD ENDED: Feb-13

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	0	.0	.000	.0			.0	1,416.0	.0	.0
2.											
3.											
4.											
5.											
6.	Total	0	.0	.000	.0			.0	1,416.0	.0	.0
7.	Average BTU		0	0	0						
8.	Total BTU(10^6)		0	0	0		0				
9.	Total Del..Cost ($)		0.00	265.34	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (1)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	72,000	.000	
2.				
3.				
4.				
5.				
6.	Total	72,000	.000	0
7.	Station Service (MWh)		3,193.000	
8.	Net Generation (MWh)		<3,193.000>	0
9.	Station Service (%)		0	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	17
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	.00
2.	Plant Factor (%)	.00
3.	Running Plant Capacity Factor (%)	.00
4.	15 Minute Gross Maximum Demand (kW)	0
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	47,842.80		
2.	Fuel, Coal	501.1	68,544.38		0
3.	Fuel, Oil	501.2	265.34		0
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	**Fuel Sub Total (2 thru 5)**	501	68,809.72		0
7.	Steam Expenses	502	83,214.68		
8.	Electric Expenses	505	46,589.34		
9.	Miscellaneous Steam Power Expenses	506	37,876.46		
10.	Allowances	509	139.63		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub Total (1 + 7 thru 11)**		215,662.91		
13.	**Operation Expense (6 + 12)**		284,472.63		
14.	Maintenance, Supervision and Engineering	510	39,754.16		
15.	Maintenance of Structures	511	17,146.06		
16.	Maintenance of Boiler Plant	512	127,392.75		
17.	Maintenance of Electric Plant	513	21,638.81		
18.	Maintenance of Miscellaneous Plant	514	24,135.08		
19.	**Maintenance Expense (14 thru 18)**		230,066.86		
20.	**Total Production Expense (13 + 19)**		514,539.49		
21.	Depreciation	403.1	67,556.74		
22.	Interest	427	115,998.92		
23.	**Total Fixed Cost (21 + 22)**		183,555.66	0	
24.	**Power Cost (20 + 23)**		698,095.15		

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION	KY0062
PLANT	GREEN
PERIOD ENDED	Feb-13

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	2	278,269.4	31.605	.0			1,363.9	.0	.0	52.1
2.	2	0	278,220.0	20.740	.0			1,416.0	.0	.0	.0
3.											
4.											
5.											
6.	Total	2	556,489.4	52.345	.0			2,779.9	.0	.0	52.1
7.	Average BTU		11,852	138,000	0						
8.	Total BTU(10^6)		6,595,512	7,224	0		6,602,736				
9.	Total Del..Cost ($)		13,883,032.42	168,533.39	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	250,000	327,988.440	
2.	2	242,000	325,371.890	
3.				
4.				
5.				
6.	Total	492,000	653,360.330	10,106
7.	Station Service (MWh)		58,392.695	
8.	Net Generation (MWh)		594,967.635	11,098
9.	Station Service (%)		8.94	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	113
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	91.96
2.	Plant Factor (%)	93.78
3.	Running Plant Capacity Factor (%)	95.57
4.	15 Minute Gross Maximum Demand (kW)	501,732
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	259,334.08		
2.	Fuel, Coal	501.1	14,277,426.55		2.16
3.	Fuel, Oil	501.2	168,533.39		23.33
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			
6.	Fuel Sub Total (2 thru 5)	501	14,445,959.94	24.28	2.19
7.	Steam Expenses	502	2,647,485.72		
8.	Electric Expenses	505	510,674.73		
9.	Miscellaneous Steam Power Expenses	506	274,191.02		
10.	Allowances	509	2,991.68		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		3,694,677.23	6.21	
13.	Operation Expense (6 + 12)		18,140,637.17	30.49	
14.	Maintenance, Supervision and Engineering	510	256,959.11		
15.	Maintenance of Structures	511	171,814.65		
16.	Maintenance of Boiler Plant	512	1,249,127.33		
17.	Maintenance of Electric Plant	513	148,005.41		
18.	Maintenance of Miscellaneous Plant	514	106,349.92		
19.	Maintenance Expense (14 thru 18)		1,932,256.42	3.25	
20.	Total Production Expense (13 + 19)		20,072,893.59	33.74	
21.	Depreciation	403.1	1,322,575.76		
22.	Interest	427	1,316,141.22		
23.	Total Fixed Cost (21 + 22)		2,638,716.98	4.44	
24.	Power Cost (20 + 23)		22,711,610.57	38.17	

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PLANT D - STEAM PLANT	BORROWER DESIGNATION KY0062
	PLANT WILSON
	PERIOD ENDED Feb-13

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	2	504,631.1	79.221	.0			1,371.8	.0	.0	44.2
2.											
3.											
4.											
5.											
6.	Total	2	504,631.1	79.221	.0			1,371.8	.0	.0	44.2
7.	Average BTU		11,654	138,000	0						
8.	Total BTU(10^6)		5,880,971	10,932	0		5,891,903				
9.	Total Del..Cost ($)		12,077,143.10	249,873.69	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	440,000	597,271.140	
2.				
3.				
4.				
5.				
6.	Total	440,000	597,271.140	9,865
7.	Station Service (MWh)		40,758.393	
8.	Net Generation (MWh)		556,512.747	10,587
9.	Station Service (%)		6.82	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	104
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	92.79
2.	Plant Factor (%)	95.86
3.	Running Plant Capacity Factor (%)	98.95
4.	15 Minute Gross Maximum Demand (kW)	454,558
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10⁶ BTU (c)
1.	Operation, Supervision and Engineering	500	319,470.59		
2.	Fuel, Coal	501.1	12,573,577.01		2.14
3.	Fuel, Oil	501.2	249,873.69		22.86
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	Fuel Sub-Total (2 thru 5)	501	12,823,450.70	23.04	2.18
7.	Steam Expenses	502	1,486,878.10		
8.	Electric Expenses	505	240,916.64		
9.	Miscellaneous Steam Power Expenses	506	493,249.04		
10.	Allowances	509	6,359.81		
11.	Rents	507	0.00		
12.	Non-Fuel Sub-Total (1 + 7 thru 11)		2,546,874.18	4.58	
13.	Operation Expense (6 + 12)		15,370,324.88	27.62	
14.	Maintenance, Supervision and Engineering	510	241,799.38		
15.	Maintenance of Structures	511	152,167.66		
16.	Maintenance of Boiler Plant	512	1,105,791.05		
17.	Maintenance of Electric Plant	513	142,911.98		
18.	Maintenance of Miscellaneous Plant	514	83,462.08		
19.	Maintenance Expense (14 thru 18)		1,726,132.15	3.10	
20.	Total Production Expense (13 + 19)		17,096,457.03	30.72	
21.	Depreciation	403.1	3,195,011.94		
22.	Interest	427	3,477,297.55		
23.	Total Fixed Cost (21 + 22)		6,672,309.49	11.99	
24.	Power Cost (20 + 23)		23,768,766.52	42.71	

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART F IC - INTERNAL COMBUSTION PLANT**	BORROWER DESIGNATION KY0062 PLANT REID PERIOD ENDED Feb-13
INSTRUCTIONS - See help in the online application.	

SECTION A. INTERNAL COMBUSTION GENERATING UNITS

NO.	UNIT NO. (a)	SIZE (kW) (b)	FUEL CONSUMPTION: OIL (1000 Gals.) (c)	GAS (1000 C.F.) (d)	OTHER (e)	TOTAL (f)	OPERATING HOURS: IN SERVICE (g)	ON STANDBY (h)	OUT OF SERVICE: Sche. (i)	Unsched (j)	GROSS GENERATION (MWh) (k)	BTU PER kWh (1)
1.	1	70,000	.000	319			.2	1,346.8	.0	69.0	4.010	
2.												
3.												
4.												
5.												
6.	Total	70,000	.000	319			.2	1,346.8	.0	69.0	4.010	79,551
7.	Average BTU		0	1,000			Station Service (MWh)				103.820	
8.	Total BTU(10^6)		0	319		319	Net Generation (MWh)				<99.810>	0
9.	Total Del..Cost ($)		0.00	1,239.50			Station Service % of Gross				2,589.03	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	0	5.	Maint. Plant Payroll ($)	
2.	No. Employees Part-Time		6.	Other Accounts. Plant Payroll ($)	
3.	**Total Empl. - Hrs. Worked**				
4.	Oper. Plant Payroll ($)		7.	**Total Plant Payroll ($)**	

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	.03
2.	Plant Factor (%)	.00
3.	Running Plant Capacity Factor (%)	28.64
4.	15 Minute Gross Maximum Demand (kW)	10,308
5.	Indicated Gross Maximum Demand kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	546	0.00		
2.	Fuel, Oil	547.1	0.00		
3.	Fuel, Gas	547.2	1,239.50		3.89
4.	Fuel, Other	547.3			
5.	Energy for Compressed Air	547.4			
6.	**Fuel Sub-Total *(2 thru 5)***	547	1,239.50		3.89
7.	Generation Expenses	548	6,344.54		
8.	Miscellaneous Other Power Generation Expenses	549	0.00		
9.	Rents	550	0.00		
10.	**Non-Fuel Sub-Total *(1 + 7 thru 9)***		6,344.54		
11.	**Operation Expense *(6+ 10)***		7,584.04		
12.	Maintenance, Supervision and Engineering	551	0.00		
13.	Maintenance of Structures	552	0.00		
14.	Maintenance of Generating and Electric Plant	553	34,189.63		
15.	Maintenance of Miscellaneous Other Power Generating Plant	554	0.00		
16.	**Maintenance Expense *(12 thru 15)***		34,189.63		
17.	**Total Production Expense *(11 + 16)***		41,773.67		
18.	Depreciation	403.1,411.10	49,102.46		
19.	Interest	427	33,597.49		
20.	**Total Fixed Cost *(18+ 19)***		82,699.95		
21.	**Power Cost *(17 + 20)***		124,473.62		

REMARKS *(including Unscheduled Outages)*

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART I - LINES AND STATIONS	BORROWER DESIGNATION KY0062 PERIOD ENDED Feb-13
INSTRUCTIONS - See help in the online application.	

SECTION A. EXPENSE AND COSTS

ITEM	ACCOUNT NUMBER	LINES (a)	STATIONS (b)
Transmission Operation			
1. Supervision and Engineering	560	43,351.33	62,179.80
2. Load Dispatching	561	634,383.31	
3. Station Expenses	562		149,267.35
4. Overhead Line Expenses	563	226,010.40	
5. Underground Line Expenses	564	0.00	
6. Miscellaneous Expenses	566	37,041.65	59,253.38
7. **Subtotal *(1 thru 6)***		940,786.69	270,700.53
8. Transmission of Electricity by Others	565	724,107.38	
9. Rents	567	0.00	2,357.60
10. **Total Transmission Operation *(7 thru 9)***		1,664,894.07	273,058.13
Transmission Maintenance			
11. Supervision and Engineering	568	39,062.66	43,493.14
12. Structures	569		1,031.06
13. Station Equipment	570		236,096.71
14. Overhead Lines	571	178,903.69	
15. Underground Lines	572	0.00	
16. Miscellaneous Transmission Plant	573	49,593.80	66,409.66
17. **Total Transmission Maintenance *(11 thru 16)***		267,560.15	347,030.57
18. **Total Transmission Expense *(10 + 17)***		1,932,454.22	620,088.70
19. RTO/ISO Expense - Operation	575	454,059.55	
20. RTO/ISO Expense - Maintenance	576	0.00	
21. **Total RTO/ISO Expense *(19 + 20)***		454,059.55	
22. Distribution Expense - Operation	580-589	0.00	0.00
23. Distribution Expense - Maintenance	590-598	0.00	0.00
24. **Total Distribution Expense *(22 + 23)***		0.00	0.00
25. **Total Operation And Maintenance *(18 + 21 +24)***		2,386,513.77	620,088.70
Fixed Costs			
26. Depreciation - Transmission	403.5	294,557.12	476,774.30
27. Depreciation - Distribution	403.6	0.00	0.00
28. Interest - Transmission	427	462,106.45	543,789.70
29. Interest - Distribution	427	0.00	0.00
30. **Total Transmission *(18 + 26 + 28)***		2,689,117.79	1,640,652.70
31. **Total Distribution *(24 +27 +29)***		0.00	0.00
32. **Total Lines And Stations *(21 + 30 + 31)***		3,143,177.34	1,640,652.70

SECTION B. FACILITIES IN SERVICE

TRANSMISSION LINES VOLTAGE (kV)	MILES	SUBSTATIONS TYPE	CAPACITY (kVA)
1.69 kV	839.20		
2.345 kV	68.40	13. Distr. Lines	0
3.138 kV	14.40		
4.161 kV	362.80	14. Total *(12 + 13)*	1,284.80
5.			
6.		15. Step up at Generating Plants	1,879,800
7.			
8.		16. Transmission	3,595,000
9.			
10.		17. Distribution	0
11.			
12. Total *(1 thru 11)*	1,284.80	18. Total *(15 thru 17)*	5,474,800

SECTION C. LABOR AND MATERIAL SUMMARY

ITEM	LINES	STATIONS
1. Number of Employees		52
2. Oper. Labor	283,723.42	165,173.86
3. Maint. Labor	210,758.79	214,417.72
4. Oper. Material	1,835,230.20	107,884.27
5. Maint. Material	56,801.36	132,612.85

SECTION D. OUTAGES

1. Total	331.00
2. Avg. No. Dist. Cons. Served	113,252.00
3. Avg. No. Hours Out Per Cons.	0.00

RUS Form 12 – January 2013

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0572-0032. The time required to complete this information collection is estimated to average 21 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	BORROWER DESIGNATION KY0062
	PERIOD ENDED January -2013
INSTRUCTIONS - See help in the online application *This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C. 552).*	BORROWER NAME Big Rivers Electric Corporation

CERTIFICATION

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7 CFR CHAPTER XVII

(check one of the following)

X All of the obligations under the RUS loan documents have been fulfilled in all material respects.

__ There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part A Section C of this report.

Mark A. Bailey 4/27/13

SIGNATURE OF PRESIDENT AND CEO DATE

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART A - FINANCIAL

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Jan-13

SECTION A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	THIS YEAR (b)	BUDGET (c)	THIS MONTH (d)
1. Electric Energy Revenues	46,502,203.58	50,637,532.97	51,456,924.00	50,637,532.97
2. Income From Leased Property (Net)	0.00	0.00	0.00	0.00
3. Other Operating Revenue and Income	373,872.96	361,735.27	312,167.00	361,735.27
4. **Total Operation Revenues & Patronage Capital** *(1 thru 3)*	46,876,076.54	50,999,268.24	51,769,091.00	50,999,268.24
5. Operating Expense - Production - Excluding Fuel	3,972,740.12	4,374,814.94	4,620,091.00	4,374,814.94
6. Operating Expense - Production - Fuel	16,903,878.80	21,530,735.67	22,037,483.00	21,530,735.67
7. Operating Expense - Other Power Supply	10,234,058.03	9,327,766.57	7,630,830.00	9,327,766.57
8. Operating Expense - Transmission	818,025.74	771,222.43	787,567.00	771,222.43
9. Operating Expense - RTO/ISO	208,911.34	238,285.13	207,423.00	238,285.13
10. Operating Expense - Distribution	0.00	0.00	0.00	0.00
11. Operating Expense - Customer Accounts	0.00	0.00	0.00	0.00
12. Operating Expense - Customer Service & Information	15,200.89	48,058.06	68,227.00	48,058.06
13. Operating Expense - Sales	<3,938.52>	0.00	5,514.00	0.00
14. Operating Expense - Administrative & General	2,026,264.87	1,750,852.41	2,251,334.00	1,750,852.41
15. **Total Operation Expense** *(5 thru 14)*	34,175,141.27	38,041,735.21	37,608,469.00	38,041,735.21
16. Maintenance Expense - Production	3,158,935.04	3,304,250.72	2,735,208.00	3,304,250.72
17. Maintenance Expense - Transmission	315,086.59	278,635.78	384,048.00	278,635.78
18. Maintenance Expense - RTO/ISO	0.00	0.00	0.00	0.00
19. Maintenance Expense - Distribution	0.00	0.00	0.00	0.00
20. Maintenance Expense - General Plant	17,409.28	22,681.93	19,697.00	22,681.93
21. **Total Maintenance Expense** *(16 thru 20)*	3,491,430.91	3,605,568.43	3,138,953.00	3,605,568.43
22. Depreciation and Amortization Expense	3,396,407.46	3,414,040.31	3,440,168.00	3,414,040.31
23. Taxes	0.00	0.00	0.00	0.00
24. Interest on Long-Term Debt	3,823,910.12	3,804,033.29	3,801,778.00	3,804,033.29
25. Interest Charged to Construction - Credit	<69,840.00>	<33,562.00>	<2,288.00>	<33,562.00>
26. Other Interest Expense	13.80	12.07	0.00	12.07
27. Asset Retirement Obligations	0.00	0.00	0.00	0.00
28. Other Deductions	13,077.18	35,139.67	46,160.00	35,139.67
29. **Total Cost Of Electric Service** *(15 + 21 thru 28)*	44,830,140.74	48,866,966.98	48,033,240.00	48,866,966.98
30. **Operating Margins** *(4 less 29)*	2,045,935.80	2,132,301.26	3,735,851.00	2,132,301.26
31. Interest Income	5,655.03	169,429.37	170,736.00	169,429.37
32. Allowance For Funds Used During Construction	0.00	0.00	0.00	0.00
33. Income (Loss) from Equity Investments	0.00	0.00	0.00	0.00
34. Other Non-operating Income (Net)	0.00	0.00	0.00	0.00
35. Generation & Transmission Capital Credits	0.00	0.00	0.00	0.00
36. Other Capital Credits and Patronage Dividends	0.00	0.00	0.00	0.00
37. Extraordinary Items	0.00	0.00	0.00	0.00
38. **Net Patronage Capital Or Margins** *(30 thru 37)*	2,051,590.83	2,301,730.63	3,906,587.00	2,301,730.63

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART A - FINANCIAL**	BORROWER DESIGNATION KY0062 PERIOD ENDED Jan-13
INSTRUCTIONS - See help in the online application.	

SECTION B. BALANCE SHEET

ASSETS AND OTHER DEBITS

1. Total Utility Plant in Service	1,999,408,055.99
2. Construction Work in Progress	52,786,617.84
3. **Total Utility Plant *(1 + 2)***	**2,052,194,673.83**
4. Accum. Provision for Depreciation and Amort.	966,671,647.02
5. **Net Utility Plant *(3 - 4)***	**1,085,523,026.81**
6. Non-Utility Property (Net)	0.00
7. Investments in Subsidiary Companies	0.00
8. Invest. in Assoc. Org. - Patronage Capital	3,680,750.51
9. Invest, in Assoc. Org. - Other - General Funds	43,840,793.00
10. Invest. in Assoc. Org. - Other - Nongeneral Funds	0.00
11. Investments in Economic Development Projects	10,000.00
12. Other Investments	5,333.85
13. Special Funds	180,110,896.71
14. **Total Other Property And Investments *(6 thru 13)***	**227,647,774.07**
15. Cash - General Funds	5,794.81
16. Cash - Construction Funds - Trustee	0.00
17. Special Deposits	598,519.51
18. Temporary Investments	112,281,637.63
19. Notes Receivable (Net)	0.00
20. Accounts Receivable - Sales of Energy (Net)	45,469,059.83
21. Accounts Receivable - Other (Net)	1,047,541.90
22. Fuel Stock	27,956,905.73
23. Renewable Energy Credits	0.00
24. Materials and Supplies - Other	25,174,844.21
25. Prepayments	3,803,370.32
26. Other Current and Accrued Assets	678,643.79
27. **Total Current And Accrued Assets *(15 thru 26)***	**217,016,317.73**
28. Unamortized Debt Discount & Extraor. Prop. Losses	4,169,822.44
29. Regulatory Assets	682,325.66
30. Other Deferred Debits	4,091,174.65
31. Accumulated Deferred Income Taxes	0.00
32. **Total Assets And Other Debits *(5+14+27 thru 31)***	1,539,130,441.36

LIABILITIES AND OTHER CREDITS

33. Memberships	75.00
34. Patronage Capital	
a. Assigned and Assignable	
b. Retired This year	
c. Retired Prior years	
d. **Net Patronage Capital (a-b-c)**	0.00
35. Operating Margins - Prior Years	<231,584,391.53>
36. Operating Margin - Current Year	2,132,301.26
37. Non-Operating Margins	640,130,096.89
38. Other Margins and Equities	<5,494,663.80>
39. **Total Margins & Equities *(33 + 34d thru 38)***	**405,183,417.82**
40. Long-Term Debt - RUS (Net)	210,370,089.31
41. Long-Term Debt - FFB - RUS Guaranteed	0.00
42. Long-Term Debt - Other - RUS Guaranteed	0.00
43. Long-Term Debt - Other (Net)	634,958,421.53
44. Long-Term Debt - RUS - Econ. Devel. (Net)	0.00
45. Payments - Unapplied	0.00
46. **Total Long-Term Debit *(40 thru 44-45)***	**845,328,510.84**
47. Obligations Under Capital Leases - Noncurrent	0.00
48. Accumulated Operating Provisions and Asset Retirement Obligations	21,730,349.78
49. **Total Other NonCurrent Liabilities *(47 +48)***	**21,730,349.78**
50. Notes Payable	0.00
51. Accounts Payable	27,358,919.11
52. Current Maturities Long-Term Debt	79,926,462.99
53. Current Maturities Long-Term Debt - Rural Development	0.00
54. Current Maturities Capital Leases	0.00
55. Taxes Accrued	817,138.58
56. Interest Accrued	5,025,800.31
57. Other Current and Accrued Liabilities	7,822,123.51
58. **Total Current & Accrued Liabilities *(50 thru 57)***	**120,950,444.50**
59. Deferred Credits	145,937,718.42
60. Accumulated Deferred Income Taxes	0.00
61. **Total Liabilities and Other Credits *(39 + 46 + 49 + 58 thru 60)***	1,539,130,441.36

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Jan-13

Part B SE - Sales of Electricity

Sale No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Fuel Type (e)	Average Monthly Billing Demand (MW) (f)	Actual Average Monthly NCP Demand (g)	Actual Average Monthly CP Demand (h)
	Ultimate Consumer(s)							
	Distribution Borrowers							
1	Jackson Purchase Energy Corp.	KY0020	RQ			125	137	123
2	Kenergy Corporation	KY0065	IF					
3	Kenergy Corporation	KY0065	LF					
4	Kenergy Corporation	KY0065	RQ			375	383	365
5	Meade County Rural ECC	KY0018	RQ			111	115	108
	G&T Borrowers							
	Others							
6	Midwest Independent Trans. Sys. Op.		OS					
	Total for Ultimate Consumer(s)					0	0	0
	Total for Distribution Borrowers					611	635	596
	Total for G&T Borrowers					0	0	0
	Total for Others					0	0	0
	Grand Total					611	635	596

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD ENDED Jan-13
INSTRUCTIONS - See help in the online application.	

Part B SE - Sales of Electricity

Sale No.	Electricity Sold (MWh) (i)	Revenue Demand Charges (j)	Revenue Energy Charges (k)	Revenue Other Charges (l)	Revenue Total (j + k + l) (m)
1	65,138.920	1,210,730.18	1,964,906.60		3,175,636.78
2	18,269.428		566,434.01		566,434.01
3	630,196.618		30,473,436.61		30,473,436.61
4	201,071.048	3,770,578.15	5,622,436.78		9,393,014.93
5	51,773.650	1,073,409.42	1,569,621.15		2,643,030.57
6	169,789.100		4,385,980.07		4,385,980.07
	0	0	0	0	0
	966,449.664	6,054,717.75	40,196,835.15	0.00	46,251,552.90
	0.000	0.00	0.00	0.00	0.00
	169,789.100	0.00	4,385,980.07	0.00	4,385,980.07
	1,136,238.764	6,054,717.75	44,582,815.22	0.00	50,637,532.97

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE	BORROWER DESIGNATION KY0062
FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	PERIOD NAME Jan-13
INSTRUCTIONS - See help in the online application.	

PART B PP - Purchased Power

Purchase No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Energy Type (e)	Average Monthly Billing Demand (MW) (f)	Average Monthly NCP Demand (g)	Average Monthly CP Demand (h)
	Distribution Borrowers							
	G&T Borrowers							
	Others							
1	Henderson Municipal Power & Light		RQ					
2	Midwest Independent Trans. Sys. Op.		OS					
3	Southeastern Power Admin.		LF					
Total for Distribution Borrowers						0	0	0
Total for G&T Borrowers						0	0	0
Total for Others						0	0	0
Grand Total						0	0	0

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE	BORROWER DESIGNATION KY0062
FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	PERIOD NAME Jan-13
INSTRUCTIONS - See help in the online application.	

PART B PP - Purchased Power

Purchase No.	Electricity Purchased (MWh) (i)	Electricity Received (MWh) (j)	Electricity Delivered (MWh) (k)	Demand Charges (l)	Energy Charges (m)	Other Charges (n)	Total (l + m + n) (o)
1	139,280.540				5,707,895.27		5,707,895.27
2	94,983.100				2,276,283.01		2,276,283.01
3	53,790.000				1,212,482.17		1,212,482.17
	0.000				0.00		0.00
	0.000				0.00		0.00
	288,053.640				9,196,660.45		9,196,660.45
	288,053.640				9,196,660.45		9,196,660.45

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART C - SOURCES AND DISTRIBUTION OF ENERGY	BORROWER DESIGNATION KY0062 PERIOD ENDED Jan-13
INSTRUCTIONS - See help in the online application.	

SOURCES OF ENERGY (a)	NO. OF PLANTS (b)	CAPACITY (kW) (c)	NET ENERGY RECEIVED BY SYSTEM (MWh) (d)	COST ($) (e)
Generated in Own Plant *(Details on Parts D and F IC)*				
1. Fossil Steam	0	1,489,000	853,363.488	35,106,280.45
2. Nuclear				
3. Hydro				
4. Combined Cycle				
5. Internal Combustion	0	70,000	<53.190>	46,567.58
6. Other				
7. Total in Own Plant *(1 thru 6)*	0	1,559,000	853,310.298	35,152,848.03
Purchased Power				
8. Total Purchased Power			288,053.640	9,196,660.45
Interchanged Power				
9. Received Into System (Gross)			374,049.000	
10. Delivered Out of System (Gross)			359,323.000	
11. Net Interchange *(9 minus 10)*			14,726.000	
Transmission For or By Others - (Wheeling)				
12. Received Into System			0.000	
13. Delivered Out of System			0.000	
14. Net Energy Wheeled *(12 minus 13)*			0.000	
15. Total Energy Available for Sale (7 + 8 + 11 + 14)			1,156,089.938	
Distribution of Energy				
16. Total Sales			1,136,238.764	
17. Energy Furnished to Others Without Charge				
18. Energy Used by Borrower *(Excluding Station Use)*				
19. Total Energy Accounted For *(16 thru 18)*			1,136,238.764	
Losses				
20. Energy Losses - MWh *(15 minus 19)*			19,851.174	
21. Energy Losses - Percentage ((20 divided by 15) * 100)			1.72 %	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART D - STEAM PLANT

BORROWER DESIGNATION	KY0062
PLANT	COLEMAN
PERIOD ENDED	Jan-13

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	4	65,840.6	0.000	5,247.1			551.3	25.0	0.0	167.7
2.	2	1	83,744.4	0.000	1,534.8			675.4	0.0	0.0	68.6
3.	3	0	94,568.3	0.000	3,886.5			744.0	0.0	0.0	0.0
4.											
5.											
6.	Total	5	244,153.3	0.000	10,668.4			1,970.7	25.0	0.0	236.3
7.	Average BTU		11,285	0	1,000						
8.	Total BTU(10^6)		2,755,270	0	10,668		2,765,938				
9.	Total Del.Cost ($)		6,652,725.74	0.00	49,621.73						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (1)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	160,000	73,380.000	
2.	2	160,000	95,795.000	
3.	3	165,000	109,194.000	
4.				
5.				
6.	Total	485,000	278,369.000	9,936
7.	Station Service (MWh)		25,284.000	
8.	Net Generation (MWh)		253,085.000	10,929
9.	Station Service (%)		9.08	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	106
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	76.58
2.	Plant Factor (%)	77.14
3.	Running Plant Capacity Factor (%)	87.25
4.	15 Minute Gross Maximum Demand (kW)	488,548
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	154,310.05		
2.	Fuel, Coal	501.1	6,919,894.47		2.51
3.	Fuel, Oil	501.2	0.00		
4.	Fuel, Gas	501.3	49,621.73		4.65
5.	Fuel, Other	501.4			
6.	Fuel Sub Total (2 thru 5)	501	6,969,516.20	27.54	2.52
7.	Steam Expenses	502	534,940.15		
8.	Electric Expenses	505	176,597.02		
9.	Miscellaneous Steam Power Expenses	506	171,465.48		
10.	Allowances	509	1,880.07		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		1,039,192.77	4.11	
13.	Operation Expense (6 + 12)		8,008,708.97	31.64	
14.	Maintenance, Supervision and Engineering	510	127,388.04		
15.	Maintenance of Structures	511	85,313.98		
16.	Maintenance of Boiler Plant	512	798,664.27		
17.	Maintenance of Electric Plant	513	86,630.38		
18.	Maintenance of Miscellaneous Plant	514	120,759.18		
19.	Maintenance Expense (14 thru 18)		1,218,755.85	4.82	
20.	Total Production Expense (13 + 19)		9,227,464.82	36.46	
21.	Depreciation	403.1	461,274.33		
22.	Interest	427	588,797.79		
23.	Total Fixed Cost (21 + 22)		1,050,072.12	4.15	
24.	Power Cost (20 + 23)		10,277,536.94	40.61	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PLANT D - STEAM PLANT

BORROWER DESIGNATION
KY0062
PLANT
REID
PERIOD ENDED
Jan-13

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	0	.0	.000	.0			.0	744.0	.0	.0
2.											
3.											
4.											
5.											
6.	Total	0	.0	.000	.0			.0	744.0	.0	.0
7.	Average BTU		0	0	0						
8.	Total BTU(10^6)		0	0	0		0				
9.	Total Del..Cost ($)		0.00	265.34	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	72,000	.000	
2.				
3.				
4.				
5.				
6.	Total	72,000	.000	0
7.	Station Service (MWh)		1,690.000	
8.	Net Generation (MWh)		<1,690.000>	0
9.	Station Service (%)		0	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	17
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	.00
2.	Plant Factor (%)	.00
3.	Running Plant Capacity Factor (%)	.00
4.	15 Minute Gross Maximum Demand (kW)	0
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	23,876.20		
2.	Fuel, Coal	501.1	58,019.31		0
3.	Fuel, Oil	501.2	265.34		0
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	Fuel Sub Total (2 thru 5)	501	58,284.65		0
7.	Steam Expenses	502	44,771.94		
8.	Electric Expenses	505	24,258.31		
9.	Miscellaneous Steam Power Expenses	506	18,973.96		
10.	Allowances	509	0.16		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		111,880.57		
13.	Operation Expense (6 + 12)		170,165.22		
14.	Maintenance, Supervision and Engineering	510	19,277.44		
15.	Maintenance of Structures	511	8,963.22		
16.	Maintenance of Boiler Plant	512	82,969.23		
17.	Maintenance of Electric Plant	513	11,643.06		
18.	Maintenance of Miscellaneous Plant	514	10,130.56		
19.	Maintenance Expense (14 thru 18)		132,983.51		
20.	Total Production Expense (13 + 19)		303,148.73		
21.	Depreciation	403.1	33,778.37		
22.	Interest	427	60,485.20		
23.	Total Fixed Cost (21 + 22)		94,263.57	0	
24.	Power Cost (20 + 23)		397,412.30		

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION
KY0062
PLANT
GREEN
PERIOD ENDED
Jan-13

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	2	145,056.5	29.300	.0			691.9	.0	.0	52.1
2.	2	0	152,005.3	17.800	.0			744.0	.0	.0	.0
3.											
4.											
5.											
6.	Total	2	297,061.8	47.100	.0			1,435.9	.0	.0	52.1
7.	Average BTU		11,745	138,000	0						
8.	Total BTU(10^6)		3,488,991	6,500	0		3,495,491				
9.	Total Del..Cost ($)		7,396,561.70	151,884.72	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	250,000	169,238.740	
2.	2	242,000	175,376.910	
3.				
4.				
5.				
6.	Total	492,000	344,615.650	10,143
7.	Station Service (MWh)		30,537.160	
8.	Net Generation (MWh)		314,078.490	11,129
9.	Station Service (%)		8.86	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	115
2.	No. Employees Part-Time	
3.	**Total Empl. - Hrs. Worked**	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	**Total Plant Payroll ($)**	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	93.89
2.	Plant Factor (%)	94.14
3.	Running Plant Capacity Factor (%)	97.62
4.	15 Minute Gross Maximum Demand (kW)	493,346
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	130,843.41		
2.	Fuel, Coal	501.1	7,603,839.90		2.18
3.	Fuel, Oil	501.2	151,884.72		23.37
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			
6.	**Fuel Sub Total (2 thru 5)**	501	7,755,724.62	24.69	2.22
7.	Steam Expenses	502	1,383,918.19		
8.	Electric Expenses	505	262,650.33		
9.	Miscellaneous Steam Power Expenses	506	150,835.54		
10.	Allowances	509	1,453.64		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub Total (1 + 7 thru 11)**		1,929,701.11	6.14	
13.	**Operation Expense (6 + 12)**		9,685,425.73	30.84	
14.	Maintenance, Supervision and Engineering	510	124,741.18		
15.	Maintenance of Structures	511	81,211.23		
16.	Maintenance of Boiler Plant	512	705,321.23		
17.	Maintenance of Electric Plant	513	91,243.69		
18.	Maintenance of Miscellaneous Plant	514	51,376.88		
19.	**Maintenance Expense (14 thru 18)**		1,053,894.21	3.36	
20.	**Total Production Expense (13 + 19)**		10,739,319.94	34.19	
21.	Depreciation	403.1	661,287.88		
22.	Interest	427	686,135.77		
23.	**Total Fixed Cost (21 + 22)**		1,347,423.65	4.29	
24.	**Power Cost (20 + 23)**		12,086,743.59	38.48	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION	KY0062
PLANT	WILSON
PERIOD ENDED	Jan-13

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	2	263,042.4	75.400	.0			699.8	.0	.0	44.2
2.											
3.											
4.											
5.											
6.	Total	2	263,042.4	75.400	.0			699.8	.0	.0	44.2
7.	Average BTU		11,626	138,000	0						
8.	Total BTU(10^6)		3,058,131	10,405	0		3,068,536				
9.	Total Del..Cost ($)		6,256,137.62	237,745.29	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (1)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	440,000	309,302.340	
2.				
3.				
4.				
5.				
6.	Total	440,000	309,302.340	9,921
7.	Station Service (MWh)		21,412.342	
8.	Net Generation (MWh)		287,889.998	10,659
9.	Station Service (%)		6.92	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	107
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	91.46
2.	Plant Factor (%)	94.48
3.	Running Plant Capacity Factor (%)	100.45
4.	15 Minute Gross Maximum Demand (kW)	454,558
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	168,871.54		
2.	Fuel, Coal	501.1	6,508,228.08		2.13
3.	Fuel, Oil	501.2	237,745.29		22.85
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	Fuel Sub-Total (2 thru 5)	501	6,745,973.37	23.43	2.20
7.	Steam Expenses	502	780,420.10		
8.	Electric Expenses	505	118,937.77		
9.	Miscellaneous Steam Power Expenses	506	219,137.89		
10.	Allowances	509	3,482.12		
11.	Rents	507	0.00		
12.	Non-Fuel Sub-Total (1 + 7 thru 11)		1,290,849.42	4.48	
13.	Operation Expense (6 + 12)		8,036,822.79	27.92	
14.	Maintenance, Supervision and Engineering	510	121,885.50		
15.	Maintenance of Structures	511	121,337.71		
16.	Maintenance of Boiler Plant	512	530,430.70		
17.	Maintenance of Electric Plant	513	82,699.16		
18.	Maintenance of Miscellaneous Plant	514	42,194.34		
19.	Maintenance Expense (14 thru 18)		898,547.41	3.12	
20.	Total Production Expense (13 + 19)		8,935,370.20	31.04	
21.	Depreciation	403.1	1,597,505.97		
22.	Interest	427	1,811,711.45		
23.	Total Fixed Cost (21 + 22)		3,409,217.42	11.84	
24.	Power Cost (20 + 23)		12,344,587.62	42.88	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART F IC - INTERNAL COMBUSTION PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062
PLANT
REID
PERIOD ENDED
Jan-13

SECTION A. INTERNAL COMBUSTION GENERATING UNITS

NO.	UNIT NO. (a)	SIZE (kW) (b)	FUEL CONSUMPTION: OIL (1000 Gals.) (c)	GAS (1000 C.F.) (d)	OTHER (e)	TOTAL (f)	OPERATING HOURS: IN SERVICE (g)	ON STANDBY (h)	OUT OF SERVICE: Sche. (i)	Unsched (j)	GROSS GENERATION (MWh) (k)	BTU PER kWh (l)
1.	1	70,000	.000	311			.2	737.4	.0	6.4	4.010	
2.												
3.												
4.												
5.												
6.	Total	70,000	.000	311			.2	737.4	.0	6.4	4.010	77,556
7.	Average BTU		0	1,000			Station Service (MWh)				57.200	
8.	Total BTU(10^6)		0	311		311	Net Generation (MWh)				<53.190>	0
9.	Total Del..Cost ($)		0.00	1,236.83			Station Service % of Gross				1,426.43	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	0	5.	Maint. Plant Payroll ($)	
2.	No. Employees Part-Time				
3.	Total Empl. - Hrs. Worked		6.	Other Accounts. Plant Payroll ($)	
4.	Oper. Plant Payroll ($)		7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	.05
2.	Plant Factor (%)	.01
3.	Running Plant Capacity Factor (%)	28.64
4.	15 Minute Gross Maximum Demand (kW)	10,308
5.	Indicated Gross Maximum Demand kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10⁶ BTU (c)
1.	Operation, Supervision and Engineering	546	0.00		
2.	Fuel, Oil	547.1	0.00		
3.	Fuel, Gas	547.2	1,236.83		3.98
4.	Fuel, Other	547.3			
5.	Energy for Compressed Air	547.4			
6.	**Fuel Sub-Total *(2 thru 5)***	547	1,236.83		3.98
7.	Generation Expenses	548	3,191.07		
8.	Miscellaneous Other Power Generation Expenses	549	0.00		
9.	Rents	550	0.00		
10.	**Non-Fuel Sub-Total *(1 + 7 thru 9)***		3,191.07		
11.	**Operation Expense *(6+ 10)***		4,427.90		
12.	Maintenance, Supervision and Engineering	551	0.00		
13.	Maintenance of Structures	552	0.00		
14.	Maintenance of Generating and Electric Plant	553	69.74		
15.	Maintenance of Miscellaneous Other Power Generating Plant	554	0.00		
16.	**Maintenance Expense *(12 thru 15)***		69.74		
17.	**Total Production Expense *(11 + 16)***		4,497.64		
18.	Depreciation	403.1,411.10	24,551.23		
19.	Interest	427	17,518.71		
20.	**Total Fixed Cost *(18+ 19)***		42,069.94		
21.	**Power Cost *(17 + 20)***		46,567.58		

REMARKS *(including Unscheduled Outages)*

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART I - LINES AND STATIONS	BORROWER DESIGNATION KY0062 PERIOD ENDED Jan-13
INSTRUCTIONS - See help in the online application.	

SECTION A. EXPENSE AND COSTS

ITEM	ACCOUNT NUMBER	LINES (a)	STATIONS (b)
Transmission Operation			
1. Supervision and Engineering	560	21,920.23	33,190.62
2. Load Dispatching	561	323,863.13	
3. Station Expenses	562		74,380.16
4. Overhead Line Expenses	563	111,679.48	
5. Underground Line Expenses	564	0.00	
6. Miscellaneous Expenses	566	21,579.59	31,580.55
7. **Subtotal** *(1 thru 6)*		479,242.43	139,151.33
8. Transmission of Electricity by Others	565	150,770.24	
9. Rents	567	0.00	2,058.43
10. **Total Transmission Operation** *(7 thru 9)*		630,012.67	141,209.76
Transmission Maintenance			
11. Supervision and Engineering	568	19,106.15	22,233.28
12. Structures	569		24.51
13. Station Equipment	570		106,776.91
14. Overhead Lines	571	84,184.13	
15. Underground Lines	572	0.00	
16. Miscellaneous Transmission Plant	573	25,984.40	20,326.40
17. **Total Transmission Maintenance** *(11 thru 16)*		129,274.68	149,361.10
18. **Total Transmission Expense** *(10 + 17)*		759,287.35	290,570.86
19. RTO/ISO Expense - Operation	575	238,285.13	
20. RTO/ISO Expense - Maintenance	576	0.00	
21. **Total RTO/ISO Expense** *(19 + 20)*		238,285.13	
22. Distribution Expense - Operation	580-589	0.00	0.00
23. Distribution Expense - Maintenance	590-598	0.00	0.00
24. **Total Distribution Expense** *(22 + 23)*		0.00	0.00
25. **Total Operation And Maintenance** *(18 + 21 + 24)*		997,572.48	290,570.86
Fixed Costs			
26. Depreciation - Transmission	403.5	147,276.56	238,387.15
27. Depreciation - Distribution	403.6	0.00	0.00
28. Interest - Transmission	427	241,498.13	284,908.67
29. Interest - Distribution	427	0.00	0.00
30. **Total Transmission** *(18 + 26 + 28)*		1,148,064.04	813,866.88
31. **Total Distribution** *(24 + 27 + 29)*		0.00	0.00
32. **Total Lines And Stations** *(21 + 30 + 31)*		1,386,349.17	813,866.88

SECTION B. FACILITIES IN SERVICE

TRANSMISSION LINES		SUBSTATIONS	
VOLTAGE (kV)	MILES	TYPE	CAPACITY (kVA)
1.69 kV	839.20		
2.345 kV	68.40	13. Distr. Lines	0
3.138 kV	14.40		
4.161 kV	362.80	14. Total *(12 + 13)*	1,284.80
5.			
6.		15. Step up at Generating Plants	1,879,800
7.			
8.			
9.		16. Transmission	3,595,000
10.			
11.		17. Distribution	0
12. Total *(1 thru 11)*	1,284.80	18. Total *(15 thru 17)*	5,474,800

SECTION C. LABOR AND MATERIAL SUMMARY

ITEM	LINES	STATIONS
1. Number of Employees		52
2. Oper. Labor	143,390.52	86,861.77
3. Maint. Labor	98,264.02	114,935.81
4. Oper. Material	724,907.28	54,347.99
5. Maint. Material	31,010.66	34,425.29

SECTION D. OUTAGES

1. Total	309.70
2. Avg. No. Dist. Cons. Served	113,252.00
3. Avg. No. Hours Out Per Cons.	0.00

RUS Form 12 – December 2012

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0572-0032. The time required to complete this information collection is estimated to average 21 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD ENDED December, 2012
INSTRUCTIONS - See help in the online application.	BORROWER NAME Big Rivers Electric Corporation

This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C. 552)

CERTIFICATION

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7 CFR CHAPTER XVII

(check one of the following)

[X] All of the obligations under the RUS loan documents have been fulfilled in all material respects.

[ ] There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part A Section C of this report.

Mark Bailey

3/27/2013
DATE

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART A - FINANCIAL**	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2012

SECTION A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE			THIS MONTH (*d*)
	LAST YEAR (*a*)	THIS YEAR (*b*)	BUDGET (*c*)	
1. Electric Energy Revenues	558,372,354	563,385,132	614,725,050	47,925,748
2. Income From Leased Property (Net)				
3. Other Operating Revenue and Income	3,616,878	4,957,104	4,011,500	361,084
4. **Total Operation Revenues & Patronage Capital *(1 thru 3)***	561,989,232	568,342,236	618,736,550	48,286,832
5. Operating Expense – Production - Excluding Fuel	50,410,485	48,054,671	54,962,438	3,943,268
6. Operating Expense – Production - Fuel	226,229,050	226,368,922	240,841,163	21,249,081
7. Operating Expense – Other Power Supply	112,261,892	111,465,357	126,165,163	8,645,661
8. Operating Expense – Transmission	9,183,058	10,118,766	10,722,952	1,034,389
9. Operating Expense – RTO/ISO	2,529,532	2,262,435	2,470,652	193,127
10. Operating Expense – Distribution				
11. Operating Expense – Customer Accounts		297,191		297,191
12. Operating Expense – Customer Service & Information	631,535	886,168	723,774	255,809
13. Operating Expense – Sales	185,004	191,205	1,101,600	44,997
14. Operating Expense – Administrative & General	26,557,242	26,428,745	25,925,640	2,622,045
15. **Total Operation Expense *(5 thru 14)***	427,987,798	426,073,460	462,913,382	38,285,568
16. Maintenance Expense – Production	42,896,418	41,169,862	58,889,721	3,284,827
17. Maintenance Expense – Transmission	4,680,625	4,607,998	3,933,069	301,844
18. Maintenance Expense – RTO/ISO				
19. Maintenance Expense – Distribution				
20. Maintenance Expense – General Plant	140,534	184,301	101,538	31,440
21. **Total Maintenance Expense *(16 thru 20)***	47,717,577	45,962,161	62,924,328	3,618,111
22. Depreciation and Amortization Expense	35,406,806	41,090,391	41,910,892	3,425,586
23. Taxes	98,389	3,811	885	
24. Interest on Long-Term Debt	45,715,144	45,032,787	44,647,132	3,798,588
25. Interest Charged to Construction – Credit	(548,206)	(766,677)	(678,117)	(44,584)
26. Other Interest Expense	59,249	147,499		46,673
27. Asset Retirement Obligations				
28. Other Deductions	220,434	546,328	415,812	121,400
29. **Total Cost Of Electric Service *(15 + 21 thru 28)***	556,657,191	558,089,760	612,134,314	49,251,342
30. **Operating Margins *(4 less 29)***	5,332,041	10,252,476	6,602,236	(964,510)
31. Interest Income	150,516	963,130	61,860	213,476
32. Allowance For Funds Used During Construction				
33. Income (Loss) from Equity Investments				
34. Other Non-operating Income (Net)	9,288			
35. Generation & Transmission Capital Credits				
36. Other Capital Credits and Patronage Dividends	108,536	61,485	33,000	2,811
37. Extraordinary Items				
38. **Net Patronage Capital Or Margins *(30 thru 37)***	5,600,381	11,277,091	6,697,096	(748,223)

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

**FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART A - FINANCIAL**

INSTRUCTIONS – See help in the online application.

BORROWER DESIGNATION: KY0062

PERIOD ENDED: December, 2012

SECTION B. BALANCE SHEET

ASSETS AND OTHER DEBITS			LIABILITIES AND OTHER CREDITS	
1.	Total Utility Plant in Service	1,999,408,056	33. Memberships	75
2.	Construction Work in Progress	50,813,643	34. Patronage Capital	
3.	**Total Utility Plant (1 + 2)**	2,050,221,699	a. Assigned and Assignable	0
4.	Accum. Provision for Depreciation and Amortization	962,994,278	b. Retired This year	0
5.	**Net Utility Plant (3 - 4)**	1,087,227,421	c. Retired Prior years	0
			d. **Net Patronage Capital (a - b - c)**	0
6.	Non-Utility Property (Net)	0	35. Operating Margins - Prior Years	(241,898,352)
7.	Investments in Subsidiary Companies	0	36. Operating Margin - Current Year	10,313,961
8.	Invest. in Assoc. Org. - Patronage Capital	3,682,912	37. Non-Operating Margins	639,960,667
9.	Invest. in Assoc. Org. - Other - General Funds	43,840,793	38. Other Margins and Equities	(5,494,664)
10.	Invest. in Assoc. Org. - Other - Nongeneral Funds	0	39. **Total Margins & Equities (33 +34d thru 38)**	402,881,687
11.	Investments in Economic Development Projects	10,000		
12.	Other Investments	5,334	40. Long-Term Debt - RUS (Net)	210,359,050
13.	Special Funds	180,633,439	41. Long-Term Debt - FFB - RUS Guaranteed	0
14.	**Total Other Property And Investments (6 thru 13)**	228,172,478	42. Long-Term Debt - Other - RUS Guaranteed	0
			43. Long-Term Debt - Other (Net)	634,958,422
15.	Cash - General Funds	7,311	44. Long-Term Debt - RUS - Econ. Devel. (Net)	0
16.	Cash - Construction Funds - Trustee	0	45. Payments – Unapplied	0
17.	Special Deposits	598,486	46. **Total Long-Term Debt (40 thru 44 - 45)**	845,317,472
18.	Temporary Investments	110,165,436	47. Obligations Under Capital Leases Noncurrent	0
19.	Notes Receivable (Net)	0	48. Accumulated Operating Provisions and Asset Retirement Obligations	21,571,187
20.	Accounts Receivable - Sales of Energy (Net)	44,758,033	49. **Total Other NonCurrent Liabilities (47 + 48)**	21,571,187
21.	Accounts Receivable - Other (Net)	2,345,621		
22.	Fuel Stock	34,145,612	50. Notes Payable	0
23.	Renewable Energy Credits	0	51. Accounts Payable	33,012,925
24.	Materials and Supplies - Other	24,957,073	52. Current Maturities Long-Term Debt	79,926,463
25.	Prepayments	4,175,474	53. Current Maturities Long-Term Debt - Rural Devel.	0
26.	Other Current and Accrued Assets	1,276,192	54. Current Maturities Capital Leases	0
27.	**Total Current And Accrued Assets (15 thru 26)**	222,429,238	55. Taxes Accrued	967,206
			56. Interest Accrued	4,925,038
28.	Unamortized Debt Discount & Extraordinary Property Losses	4,163,615	57. Other Current and Accrued Liabilities	9,987,629
29.	Regulatory Assets	704,087	58. **Total Current & Accrued Liabilities (50 thru 57)**	128,819,261
30.	Other Deferred Debits	3,981,082	59. Deferred Credits	148,088,314
31.	Accumulated Deferred Income Taxes	0	60. Accumulated Deferred Income Taxes	0
32.	**Total Assets and Other Debits (5+14+27 thru 31)**	1,546,677,921	61. **Total Liabilities and Other Credits (39 + 46 + 49 + 58 thru 60)**	1,546,677,921

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2012

SECTION C. NOTES TO FINANCIAL STATEMENTS

Footnote to RUS Financial and Operating Report Electric Power Supply - Part A

Financial Ratios: 2012

Margins For Interest Ratio (MFIR) 1.25

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2012

SECTION C. CERTIFICATION LOAN DEFAULT NOTES

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2012

PART B SE - SALES OF ELECTRICITY

Sale No.	Name Of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Fuel Type (e)	Average Monthly Billing Demand (MW) (f)	Actual Average Monthly NCP Demand (g)	Actual Average Monthly CP Demand (h)
1	Ultimate Consumer(s)							
2	Jackson Purchase Energy Corp (KY0020)	KY0020	RQ			124	137	123
3	Kenergy Corporation (KY0065)	KY0065	IF					
4	Kenergy Corporation (KY0065)	KY0065	LF					
5	Kenergy Corporation (KY0065)	KY0065	RQ			359	372	355
6	Meade County Rural E C C (KY0018)	KY0018	RQ			87	96	86
7	PowerSouth Energy Cooperative (AL0042)	AL0042	OS					
8	ADM Investor Services, Inc. (IL)		OS					
9	Henderson Munic Power & Light		OS					
10	Louisville Gas & Electric Co		OS					
11	Midwest Independent Transmission System Operator, Inc. (IN)		OS					
12	PJM Interconnection (PA)		OS					
UC	Total for Ultimate Consumer(s)							
Dist	Total for Distribution Borrowers					570	605	564
G&T	Total for G&T Borrowers					0	0	0
Other	Total for Other					0	0	0
Total	Grand Total					570	605	564

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2012

PART B SE - SALES OF ELECTRICITY

Sale No	Electricity Sold (MWh) (i)	Revenue Demand Charges (j)	Revenue Energy Charges (k)	Revenue Other Charges (l)	Revenue Total (j + k + l) (m)
1					
2	668,864	14,140,485	19,735,293		33,875,778
3	206,140		6,549,580		6,549,580
4	7,424,473		360,208,261		360,208,261
5	2,148,250	42,979,816	58,406,006		101,385,822
6	465,662	9,883,714	13,748,137		23,631,851
7	460		17,325		17,325
8			(24,460)		(24,460)
9	16,240		457,677		457,677
10	180		6,961		6,961
11	1,313,813		37,261,252		37,261,252
12			15,085		15,085
UC					
Dist	10,913,389	67,004,015	458,647,277	0	525,651,292
G&T	460	0	17,325	0	17,325
Other	1,330,233	0	37,716,515	0	37,716,515
Total	12,244,082	67,004,015	496,381,117	0	563,385,132

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2012

PART B SE - SALES OF ELECTRICITY

Sale No	Comments
1	
2	
3	
4	
5	
6	
7	
8	
9	
10	
11	
12	
UC	

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2012

PART B PP - PURCHASED POWER

Purchase No.	Name Of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Fuel Type (e)	Average Monthly Billing Demand (MW) (f)	Actual Average Monthly NCP Demand (g)	Actual Average Monthly CP Demand () (h)
1	Cargill-Alliant LLC		OS					
2	Henderson Munic Power & Light		RQ					
3	Louisville Gas & Electric Co		OS					
4	Midwest Independent Transmission System Operator, Inc. (IN)		OS					
5	Southeastern Power Admin		LF					
Dist	Total for Distribution Borrowers					0	0	0
G&T	Total for G&T Borrowers					0	0	0
Other	Total for Other					0	0	0
Total	Grand Total					0	0	0

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY

BORROWER DESIGNATION
KY0062

INSTRUCTIONS - See help in the online application.

PERIOD ENDED
December, 2012

PART B PP - PURCHASED POWER

Purchase No	Electricity Purchased (MWh) (i)	Electricity Received (MWh) (j)	Electricity Delivered (MWh) (k)	Demand Charges (l)	Energy Charges (m)	Other Charges (n)	Total (l + m + n) (o)
1	36,000				993,600		993,600
2	1,417,205				63,633,745		63,633,745
3	4,410				165,608		165,608
4	1,426,648				35,844,767		35,844,767
5	278,226				8,053,063		8,053,063
Dist	0	0	0	0	0	0	0
G&T	0	0	0	0	0	0	0
Other	3,162,489	0	0	0	108,690,783	0	108,690,783
Total	3,162,489	0	0	0	108,690,783	0	108,690,783

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2012

PART B PP - PURCHASED POWER

Purchase No	Comments
1	
2	
3	
4	
5	

reUNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART C - SOURCES AND DISTRIBUTION OF ENERGY	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2012

SOURCES OF ENERGY *(a)*	NO. OF PLANTS *(b)*	CAPACITY (kW) *(c)*	NET ENERGY RECIEVED BY SYSTEM (MWh) *(d)*	COST ($) *(e)*
Generated in Own Plant (*Details on Parts D, E, F IC, F CC, and G*)				
1. Fossil Steam	4	1,489,000	9,136,472	385,384,562
2. Nuclear	0	0	0	0
3. Hydro	0	0	0	0
4. Combined Cycle	0	0	0	0
5. Internal Combustion	1	70,000	6,639	1,177,586
6. Other	0	0	0	0
7. **Total in Own Plant (*1 thru 6*)**	5	1,559,000	9,143,111	386,562,148
Purchased Power				
8. **Total Purchased Power**			3,162,489	108,690,783
Interchanged Power				
9. Received Into System (Gross)			2,530,109	0
10. Delivered Out of System (Gross)			2,375,205	0
11. **Net Interchange (*9 - 10*)**			154,904	0
Transmission For or By Others - (Wheeling)				
12. Received Into System			19,103	28,658
13. Delivered Out of System			19,103	28,658
14. **Net Energy Wheeled (*12 - 13*)**			0	0
15. **Total Energy Available for Sale (*7 + 8 + 11 + 14*)**			12,460,504	
Distribution of Energy				
16. Total Sales			12,244,082	
17. Energy Furnished to Others Without Charge			0	
18. Energy Used by Borrower (*Excluding Station Use*)			0	
19. **Total Energy Accounted For (*16 thru 18*)**			12,244,082	
Losses				
20. **Energy Losses - MWh (*15 - 19*)**			216,422	
21. **Energy Losses - Percentage ((*20 / 15*) * *100*)**			1.73 %	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART D - STEAM PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION KY0062

PLANT Coleman

PERIOD ENDED December, 2012

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: SCHED. (j)	UNSCH. (k)
1.	1	14	929,004.20		27,263.40			7,930	139		715
2.	2	6	1,005,539.00		18,992.10			8,501	63		220
3.	3	4	1,055,763.90		31,081.00			8,642			142
4.											
5.											
6.	Total	24	2,990,307	0.00	77,336.50	0.00		25,073	202	0	1,077
7.	Average BTU		11,317		1,000.00						
8.	Total BTU (10^6)		33,841,305.00		77,337.00		33,918,642				
9.	Total Del. Cost ($)		78,905,097	2,266.00	250,716.00						

SECTION A. BOILERS/TURBINES (Continued)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	160,000	1,061,238.00	
2.	2	160,000	1,150,211.00	
3.	3	165,000	1,218,405.00	
4.				
5.				
6.	Total	465,000	3,429,854.00	9,889
7.	Station Service (MWh)		312,648.20	
8.	Net Generation (MWh)		3,117,205.80	10,881.10
9.	Station Service (%)		9.12	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1.	No. Employees Full-Time (Include Superintendent)	106
2.	No. Employees Part-Time	
3.	**Total Employee Hours Worked**	222,307
4.	Operating Plant Payroll ($)	7,669,267
5.	Maintenance Plant Payroll ($)	4,670,649
6.	Other Accts. Plant Payroll ($)	
7.	**Total Plant Payroll ($)**	12,339,916

SEC. C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	79.21%
2.	Plant Factor (%)	80.51%
3.	Running Plant Capacity Factor (%)	84.59%
4.	15 Minute Gross Max. Demand (kW)	492,950
5.	Indicated Gross Max. Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/$10^6$ BTU (c)
1.	Operation, Supervision and Engineering	500	1,717,705		
2.	Fuel, Coal	501.1	82,341,624		
3.	Fuel, Oil	501.2	2,266		
4.	Fuel, Gas	501.3	250,716		
5.	Fuel, Other	501.4			
6.	**Fuel SubTotal (*2 thru 5*)**		82,594,606	26.50	
7.	Steam Expenses	502	5,554,308		
8.	Electric Expenses	505	2,036,170		
9.	Miscellaneous Steam Power Expenses	506	1,906,808		
10.	Allowances	509	38,959		
11.	Rents	507			
12.	**Non-Fuel SubTotal (*1 + 7 thru 11*)**		11,253,950	3.61	
13.	**Operation Expense (*6 + 12*)**		93,848,556	30.11	
14.	Maintenance, Supervision and Engineering	510	1,512,903		
15.	Maintenance of Structures	511	1,229,166		
16.	Maintenance of Boiler Plant	512	6,382,429		
17.	Maintenance of Electric Plant	513	1,126,536		
18.	Maintenance of Miscellaneous Plant	514	1,519,262		
19.	**Maintenance Expense (*14 thru 18*)**		11,770,296	3.78	
20.	**Total Production Expense (*13 + 19*)**		105,618,852	33.88	
21.	Depreciation	403.1, 411.10	5,534,490		
22.	Interest	427	6,977,048		
23.	**Total Fixed Cost (*21 + 22*)**		12,511,546	4.01	
24.	**Power Cost (*20 + 23*)**		118,130,398	37.90	

Remarks

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART D - STEAM PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION KY0062

PLANT Green

PERIOD ENDED December, 2012

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: SCHED. (j)	UNSCH. (k)
1.	1	8	1,475,386.70	213.00				8,007	604		173
2.	2	8	1,236,496.90	216.39				6,829	1,318		637
3.											
4.											
5.											
6.	Total	16	2,711,884	429.39	0.00	0.00		14,836	1,922	0	810
7.	Average BTU		11,810	138,000.41							
8.	Total BTU (10^6)		32,027,345.00	59,256			32,086,601				
9.	Total Del. Cost ($)		67,662,565	1,355,317.00							

SECTION A. BOILERS/TURBINES (*Continued*)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	250,000	1,769,282.50	
2.	2	242,000	1,456,898.80	
3.				
4.				
5.				
6.	Total	492,000	3,226,181.30	9,946
7.	Station Service (MWh)		309,595.80	
8.	Net Generation (MWh)		2,916,585.50	11,001.43
9.	Station Service (%)		9.60	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1.	No. Employees Full-Time (Include Superintendent)	114
2.	No. Employees Part-Time	
3.	**Total Employee Hours Worked**	227,208
4.	Operating Plant Payroll ($)	8,103,324
5.	Maintenance Plant Payroll ($)	5,354,346
6.	Other Accts. Plant Payroll ($)	
7.	**Total Plant Payroll ($)**	13,457,670

SEC. C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	73.58%
2.	Plant Factor (%)	74.65%
3.	Running Plant Capacity Factor (%)	88.28%
4.	15 Minute Gross Max. Demand (kW)	499,181
5.	Indicated Gross Max. Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	1,592,418		
2.	Fuel, Coal	501.1	70,228,455		2.19
3.	Fuel, Oil	501.2	1,355,316		22.87
4.	Fuel, Gas	501.3			
5.	Fuel, Other	501.4			
6.	**Fuel SubTotal (*2 thru 5*)**	501	71,583,771	24.54	2.23
7.	Steam Expenses	502	12,484,073		
8.	Electric Expenses	505	3,281,025		
9.	Miscellaneous Steam Power Expenses	506	1,361,695		
10.	Allowances	509	20,697		
11.	Rents	507			
12.	**Non-Fuel SubTotal (*1 + 7 thru 11*)**		18,739,908	6.42	
13.	**Operation Expense (*6 + 12*)**		90,323,679	30.96	
14.	Maintenance, Supervision and Engineering	510	1,577,077		
15.	Maintenance of Structures	511	1,141,279		
16.	Maintenance of Boiler Plant	512	7,823,112		
17.	Maintenance of Electric Plant	513	1,298,040		
18.	Maintenance of Miscellaneous Plant	514	907,969		
19.	**Maintenance Expense (*14 thru 18*)**		12,747,477	4.37	
20.	**Total Production Expense (*13 + 19*)**		103,071,156	35.33	
21.	Depreciation	403.1, 411.10	7,984,437		
22.	Interest	427	8,032,504		
23.	**Total Fixed Cost (*21 + 22*)**		16,016,941	5.49	
24.	**Power Cost (*20 + 23*)**		119,088,097	40.83	

Remarks

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART D - STEAM PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION KY0062

PLANT Reid

PERIOD ENDED December, 2012

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: SCHED. (j)	UNSCH. (k)
1.	1	6	28,599.60	34.41				571	7,690		523
2.											
3.											
4.											
5.											
6.	Total	6	28,600	34.41	0.00	0.00					
7.	Average BTU		12,206	137,983.14				571	7,690	0	523
8.	Total BTU (10^6)		349,087.00	4,748							
9.	Total Del. Cost ($)		872,499	110,069.00			353,835				

SECTION A. BOILERS/TURBINES (Continued)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	72,000	29,068.00	
2.				
3.				
4.				
5.				
6.	Total	72,000	29,068.00	12,173
7.	Station Service (MWh)		19,823.00	
8.	Net Generation (MWh)		9,245.00	38,273.12
9.	Station Service (%)		68.20	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1.	No. Employees Full-Time (Include Superintendent)	17
2.	No. Employees Part-Time	
3.	**Total Employee Hours Worked**	30,310
4.	Operating Plant Payroll ($)	1,130,501
5.	Maintenance Plant Payroll ($)	605,059
6.	Other Accts. Plant Payroll ($)	
7.	**Total Plant Payroll ($)**	1,735,560

SEC. C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	5.73%
2.	Plant Factor (%)	4.60%
3.	Running Plant Capacity Factor (%)	70.70%
4.	15 Minute Gross Max. Demand (kW)	57,776
5.	Indicated Gross Max. Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	275,299		
2.	Fuel, Coal	501.1	1,140,074		
3.	Fuel, Oil	501.2	110,069		
4.	Fuel, Gas	501.3			
5.	Fuel, Other	501.4			
6.	**Fuel SubTotal (*2 thru 5*)**	501	1,250,143	135.22	
7.	Steam Expenses	502	542,947		
8.	Electric Expenses	505	272,554		
9.	Miscellaneous Steam Power Expenses	506	261,558		
10.	Allowances	509	5,469		
11.	Rents	507			
12.	**Non-Fuel SubTotal (*1 + 7 thru 11*)**		1,357,827	146.87	
13.	**Operation Expense (*6 + 12*)**		2,607,970	282.10	
14.	Maintenance, Supervision and Engineering	510	246,160		
15.	Maintenance of Structures	511	120,928		
16.	Maintenance of Boiler Plant	512	775,249		
17.	Maintenance of Electric Plant	513	216,839		
18.	Maintenance of Miscellaneous Plant	514	182,998		
19.	**Maintenance Expense (*14 thru 18*)**		1,542,174	166.81	
20.	**Total Production Expense (*13 + 19*)**		4,150,144	448.91	
21.	Depreciation	403.1, 411.10	447,509		
22.	Interest	427	718,613		
23.	**Total Fixed Cost (*21 + 22*)**		1,166,122	126.14	
24.	**Power Cost (*20 + 23*)**		5,316,266	575.04	

Remarks

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART D - STEAM PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION KY0062

PLANT Wilson

PERIOD ENDED December, 2012

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: SCHED. (j)	UNSCH. (k)
1.	1	15	2,728,242.90	481.65							
2.								8,047	21	336	380
3.											
4.											
5.											
6.	Total	15	2,728,243	481.65							
7.	Average BTU		11,944	138,000.62	0.00	0.00		8,047	21	336	380
8.	Total BTU (10^6)		32,586,133.00	66,468							
9.	Total Del. Cost ($)		66,082,314	1,508,015.00			32,652,601				

SECTION A. BOILERS/TURBINES (Continued)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	440,000	3,317,746.30	
2.				
3.				
4.				
5.				
6.	Total	440,000	3,317,746.30	9,842
7.	Station Service (MWh)		224,310.60	
8.	Net Generation (MWh)		3,093,435.70	10,555.45
9.	Station Service (%)		6.76	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1.	No. Employees Full-Time (Include Superintendent)	107
2.	No. Employees Part-Time	
3.	Total Employee Hours Worked	216,656
4.	Operating Plant Payroll ($)	7,357,480
5.	Maintenance Plant Payroll ($)	4,990,077
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	12,347,557

SEC. C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	81.77%
2.	Plant Factor (%)	85.84%
3.	Running Plant Capacity Factor (%)	93.70%
4.	15 Minute Gross Max. Demand (kW)	461,911
5.	Indicated Gross Max. Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering				
2.	Fuel, Coal	500	2,014,988		
3.	Fuel, Oil	501.1	69,041,281		
4.	Fuel, Gas	501.2	1,508,015		2.11
5.	Fuel, Other	501.3			22.68
6.	**Fuel SubTotal (*2 thru 5*)**	501.4			
7.	Steam Expenses	501	70,549,296	22.80	2.16
8.	Electric Expenses	502	9,865,479		
9.	Miscellaneous Steam Power Expenses	505	1,271,925		
10.	Allowances	506	3,462,852		
11.	Rents	509	51,037		
12.	**Non-Fuel SubTotal (*1 + 7 thru 11*)**	507			
13.	**Operation Expense (*6 + 12*)**		16,666,281	5.38	
14.	Maintenance, Supervision and Engineering		87,215,577	28.19	
15.	Maintenance of Structures	510	1,465,468		
16.	Maintenance of Boiler Plant	511	1,086,908		
17.	Maintenance of Electric Plant	512	10,850,340		
18.	Maintenance of Miscellaneous Plant	513	818,286		
19.	**Maintenance Expense (*14 thru 18*)**	514	644,694		
20.	**Total Production Expense (*13 + 19*)**		14,865,696	4.80	
21.	Depreciation		102,081,273	32.99	
22.	Interest	403.1, 411.10	19,164,687		
23.	**Total Fixed Cost (*21 + 22*)**	427	21,603,841		
24.	**Power Cost (*20 + 23*)**		40,768,528	13.17	
Remarks			142,849,801	46.17	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART F IC - INTERNAL COMBUSTION PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION: KY0062

PLANT: Reid

PERIOD ENDED: December, 2012

SECTION A. INTERNAL COMBUSTION GENERATING UNITS

NO.	UNIT NO. (a)	SIZE (kW) (b)	FUEL CONSUMPTION: OIL (1000 Gals.) (c)	GAS (1000 C.F.) (d)	OTHER (e)	TOTAL (f)	OPERATING HOURS: IN SERVICE (g)	ON STANDBY (h)	OUT OF SERVICE: SCHED. (i)	UNSCH. (j)	GROSS GENER. (MWh) (k)	BTU PER kWh (l)
1.	1	70,000		128.39			243	8,395		146	7,651	
2.												
3.												
4.												
5.												
6.	Total	70,000	0.00	128.39	0.00		243	8,395	0	146	7,651	
7.	Average BTU			999,976.63								
8.	Total BTU (10^6)			128,387.00		128,387.00	Station Service (MWh)				1,011.30	16,781.30
9.	Total Del. Cost ($)			390,604.00			Net Generation (MWh)				6,639.30	
							Station Service % of Gross				13.22	[illegible]

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1.	No. Employees Full Time (Include Superintendent)		5.	Maintenance Plant Payroll ($)	56,932
2.	No. Employees Part Time		6.	Other Accounts Plant Payroll ($)	
3.	**Total Employee Hours Worked**	1,021	7.	**Total Plant Payroll ($)**	58,453
4.	Operating Plant Payroll ($)	1,521			

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	1.36%
2.	Plant Factor (%)	1.24%
3.	Running Plant Capacity Factor (%)	44.98%
4.	15 Min. Gross Max. Demand (kW)	63,895
5.	Indicated Gross Max. Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET (kWh) (b)	$/10⁶ BTU (c)
1.	Operation, Supervision and Engineering	546	0		
2.	Fuel, Oil	547.1	0		0.00
3.	Fuel, Gas	547.2	391,106		3.04
4.	Fuel, Other	547.3	0		0.00
5.	Energy for Compressed Air	547.4	0	0.00	
6.	**Fuel SubTotal *(2 thru 5)***	547	391,106	58.90	3.04
7.	Generation Expenses	548	36,705		
8.	Miscellaneous Other Power Generation Expenses	549	0		
9.	Rents	550	0		
10.	**Non-Fuel SubTotal *(1 + 7 thru 9)***		36,705	5.52	
11.	**Operation Expense *(6 + 10)***		427,811	64.43	
12.	Maintenance, Supervision and Engineering	551	0		
13.	Maintenance of Structures	552	0		
14.	Maintenance of Generating and Electric Plant	553	244,219		
15.	Maintenance of Miscellaneous Other Power Generating Plant	554	0		
16.	**Maintenance Expense *(12 thru 15)***		244,219	36.78	
17.	**Total Production Expense *(11 + 16)***		672,030	101.22	
18.	Depreciation	403.4, 411.10	296,464		
19.	Interest	427	209,092		
20.	**Total Fixed Cost *(18 + 19)***		505,556	76.14	
21.	**Power Cost *(17 + 20)***		1,177,586	177.36	

Remarks (including Unscheduled Outages)

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART H - ANNUAL SUPPLEMENT

BORROWER DESIGNATION KY0062

PERIOD ENDED December, 2012

INSTRUCTIONS - See help in the online application.

SECTION A. UTILITY PLANT

ITEM	BALANCE BEGINNING OF YEAR (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS AND TRANSFERS (d)	BALANCE END OF YEAR (e)
1. Total Intangible Plant (301 thru 303)	66,895				66,895
2. Total Steam Production Plant (310 thru 317)	1,698,243,573	22,506,189	13,240,619	(29,117)	1,707,480,026
3. Total Nuclear Production Plant (320 thru 326)	0				0
4. Total Hydro Production Plant (330 thru 337)	0				0
5. Total Other Production Plant (340 thru 347)	7,998,989	36,238	44,699	15,754	8,006,282
6. **Total Production Plant (2 thru 5)**	1,706,242,562	22,542,427	13,285,318	(13,363)	1,715,486,308
7. Land and Land Rights (350)	13,858,902	448,209			14,307,111
8. Structures and Improvements (352)	6,872,307	55,851	17,639		6,910,519
9. Station Equipment (353)	123,005,427	3,987,596	448,926		126,544,097
10. Other Transmission Plant (354 thru 359.1)	95,001,641	2,279,286	142,277		97,138,650
11. **Total Transmission Plant (7 thru 10)**	238,738,277	6,770,942	608,842		244,900,377
12. Land and Land Rights (360)	0	0	0	0	0
13. Structures and Improvements (361)	0	0	0	0	0
14. Station Equipment (362)	0	0	0	0	0
15. Other Distribution Plant (363 thru 374)	0	0	0	0	0
16. **Total Distribution Plant (12 thru 15)**	0	0	0	0	0
17. RTO/ISO Plant (380 thru 386)		0	0	0	0
18. Total General Plant (389 thru 399.1)	33,744,022	1,683,715	319,711	(4,665)	35,103,361
19. **Electric Plant in Service (1+6+11+16 thru 18)**	1,978,791,756	30,997,084	14,213,871	(18,028)	1,995,556,941
20. Electric Plant Purchased or Sold (102)	0	0	0	0	0
21. Electric Plant Leased to Others (104)	0	0	0	0	0
22. Electric Plant Held for Future Use (105)	475,968	0	0	0	475,968
23. Completed Construction Not Classified (106)	0	3,375,147	0	0	3,375,147
24. Acquisition Adjustments (114)	0				0
25. Other Utility Plant (118)	0				0
26. Nuclear Fuel Assemblies (120.1 thru 120.4)	0				0
27. **Total Utility Plant in Service (19 thru 26)**	1,979,267,724	34,372,231	14,213,871	(18,028)	1,999,408,056
28. Construction Work in Progress (107)	49,150,583	1,663,060	0	0	50,813,643
29. **Total Utility Plant (27+28)**	2,028,418,307	36,035,291	14,213,871	(18,028)	2,050,221,699

SECTION B. ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION - UTILITY PLANT

ITEM	COMP. RATE (%) (a)	BALANCE BEGINNING OF YEAR (b)	ANNUAL ACCRUALS (c)	RETIREMENTS LESS NET SALVAGE (d)	ADJUSTMENTS AND TRANSFERS (e)	BALANCE END OF YEAR (f)
1. Depr. of Steam Prod. Plant (108.1)		789,264,252	33,230,561	12,544,246	(9,748)	809,940,819
2. Depr. of Nuclear Prod. Plant (108.2)		0	0	0	0	0
3. Depr. of Hydraulic Prod. Plant (108.3)		0	0	0	0	0
4. Depr. of Other Prod. Plant (108.4)		5,726,582	294,869	44,700	0	5,976,751
5. Depr. of Transmission Plant (108.5)		113,364,146	4,645,024	868,231	(242)	117,140,697
6. Depr. of Distribution Plant (108.6)		0	0	0	0	0
7. Depr. of General Plant (108.7)		6,780,236	2,864,360	294,170	(650)	9,349,776
8. Retirement Work in Progress (108.8)		(1,265,779)	0	1,055,699	0	(2,321,478)
9. **Total Depr. for Elec. Plant in Serv. (1 thru 8)**		913,869,437			(10,640)	940,086,565
10. Depr. of Plant Leased to Others (109)		0	0	0	0	0
11. Depr. of Plant Held for Future Use (110)		0	0	0	0	0
12. Amort. of Elec. Plant in Service (111)		22,485,516	3,251,446	2,486,610	(342,639)	22,907,713
13. Amort. of Leased Plant (112)		0	0	0	0	0
14. Amort. of Plant Held for Future Use		0	0	0	0	0
15. Amort. of Acquisition Adj. (115)		0	0	0	0	0
16. Depr. & Amort. Other Plant (119)		0	0	0	0	0
17. Amort. of Nuclear Fuel (120.5)		0				0
18. **Total Prov. for Depr. & Amort. (9 thru 17)**		936,354,953	44,286,260	17,293,656	(353,279)	962,994,278

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART H - ANNUAL SUPPLEMENT

BORROWER DESIGNATION: KY0062

PERIOD ENDED: December, 2012

INSTRUCTIONS - See help in the online application.

SECTION B. ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION - UTILITY PLANT (*Continued*)

19. Amount of Annual Accrual Charged to Expense $ 41,090,391	20. Amount of Annual Accrual Charged to Other Accounts $ 3,195,219	21. Book Cost of Property Retired $ 14,213,871
22. Removal Cost of Property Retired $ 3,667,261	23. Salvage Material from Property Retired $ 392,652	24. Renewal and Replacement Cost $ 17,987,767

SECTION C. NON-UTILITY PLANT

ITEM	BALANCE BEGINNING OF YEAR (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS AND TRANSFERS (d)	BALANCE END OF YEAR (e)
1. NonUtility Property (121)					
2. Provision For Depr. & Amort. (122)					

SECTION D. DEMAND AND ENERGY AT POWER SOURCES

MONTH	PEAK DEMAND (MW) (a)	MONTHLY PEAKS DATE (b)	TIME (c)	TYPE OF READING (d)	ENERGY OUTPUT (MWh) (e)
1. January	1,422	01/12/2012	20	Coincident	1,039,519
2. February	1,384	02/13/2012	7	Coincident	933,820
3. March	1,337	03/05/2012	7	Coincident	1,014,152
4. April	1,320	04/02/2012	18	Coincident	974,526
5. May	1,422	05/25/2012	17	Coincident	1,069,765
6. June	1,505	06/29/2012	16	Coincident	1,019,977
7. July	1,507	07/18/2012	15	Coincident	1,105,153
8. August	1,489	08/02/2012	15	Coincident	1,033,312
9. September	1,422	09/07/2012	17	Coincident	1,000,969
10. October	1,287	10/31/2012	7	Coincident	1,003,740
11. November	1,378	11/28/2012	7	Coincident	1,118,677
12. December	1,391	12/13/2012	7	Coincident	1,146,895
13. **Annual Peak**	1,507			**Annual Total**	12,460,505

SECTION E. DEMAND AND ENERGY AT DELIVERY POINTS

MONTH	DELIVERED TO RUS BORROWERS DEMAND (MW) (a)	ENERGY (MWh) (b)	DELIVERED TO OTHERS DEMAND (MW) (c)	ENERGY (MWh) (d)	TOTAL DELIVERED DEMAND (MW) (e)	ENERGY (MWh) (f)
1. January	575	931,031	968	89,365	1,543	1,020,396
2. February	533	864,990	979	50,476	1,512	915,466
3. March	470	910,610	1,003	85,324	1,473	995,934
4. April	451	877,892	1,013	75,106	1,464	952,998
5. May	557	913,398	1,015	143,932	1,572	1,057,330
6. June	647	904,177	998	95,460	1,645	999,637
7. July	661	982,585	1,008	101,780	1,669	1,084,365
8. August	632	946,275	1,019	67,798	1,651	1,014,073
9. September	574	875,950	1,010	108,947	1,584	984,897
10. October	433	881,111	978	107,195	1,411	988,306
11. November	511	889,792	986	212,414	1,497	1,102,206
12. December	529	936,038	976	192,436	1,505	1,128,474
13. **Peak or Total**	661	10,913,849	1,019	1,330,233	1,669	12,244,082

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT	BORROWER DESIGNATION KY0062 PERIOD ENDED December, 2012

INSTRUCTIONS - Reporting of investments is required by 7 CFR 1717, Subpart N. Investment categories reported on this Part correspond to Balance Sheet items in Part A Section B. Identify all investments in Rural Development with an 'X' in column (c). Both 'Included' and 'Excluded' Investments must be reported. See help in the online application.

SECTION F. INVESTMENTS, LOAN GUARANTEES AND LOANS
SUB SECTION I. INVESTMENTS

No	Description (a)	Included ($) (b)	Excluded ($) (c)	Income Or Loss ($) (d)	Rural Development (e)
2	**Investments in Associated Organizations**				
	United Utility Supply Capital	31,773			
	Ky Assn for Electric Coops Capital Credit	15,200			
	Jackson Purchase Capital Credit		4,291		
	Kenergy Capital Credit		22,598		
	Meade County Capital Credit		1,470		
	Rural Cooperatives Credit Union Deposit	5			
	Touchstone Energy (NRECA) Capital Credit	1,742			
	CoBank Capital Credit		3,510,199		
	NRUCFC Capital Credit		2,039		
	Cooperative Membership Fees	2,280			
	ACES Power Marketing Membership Fees	678,000			
	Federated Rural Electric Insurance Exchange Capital Credit	4,713	80,855		
	National Renewables Cooperative Organization Capital Credit		12,740		
	Capital Term Certificates - NRUCFC		43,155,800		
	Totals	733,713	46,789,992		
3	**Investments in Economic Development Projects**				
	Breckinridge Co. Development Corp. Stock	5,000			
	Hancock Co. Industrial Foundation Stock	5,000			X
	Totals	10,000			X
4	**Other Investments**				
	Southern States Coop Capital Credit	5,334			
	Totals	5,334			
5	**Special Funds**				
	Other Special Funds-Deferred Compensation		404,051		
	Other Special Funds-Economic Reserve	486,254	80,024,675		
	Other Special Funds-Rural Economic Reserve	794,769	63,208,234		
	Other Special Funds-Transition Reserve	10,859	34,997,841		
	Other Special Funds-Station Two O&M Fund	150,000	250,000		
	Other Special Funds-Liberty Mutual	0	306,756		
	Totals	1,441,882	179,191,557		
6	**Cash - General**				
	General Fund	0	2,586		
	Right of Way Fund	0	1,000		
	Working Fund	3,725	0		
	Totals	3,725	3,586		
7	**Special Deposits**				
	TVA Transmission Reservation	572,946	0		
	ADM/ICE Margin Call	25,540			
	Totals	598,486	0		
8	**Temporary Investments**				
	Fidelity-U.S. Treasury Only (#057)	0	110,165,436		
	Totals	0	110,165,436		
9	**Accounts and Notes Receivable - NET**				
	Accts Receivable-Employees - Other	2,954			

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART H - ANNUAL SUPPLEMENT

BORROWER DESIGNATION
KY0062

PERIOD ENDED
December, 2012

INSTRUCTIONS - Reporting of investments is required by 7 CFR 1717, Subpart N. Investment categories reported on this Part correspond to Balance Sheet items in Part A Section B. Identify all investments in Rural Development with an 'X' in column (e). Both 'Included' and 'Excluded' Investments must be reported. See help in the online application.

SECTION F. INVESTMENTS, LOAN GUARANTEES AND LOANS
SUB SECTION I. INVESTMENTS

	Accts Receivable-Employees-Computer Assist Program	28,910			
	Other Accts Receivable-Misc.	1,139,710			
	Accts Receivable-HMP&L Sta Two Operation	283,111			
	Accts Receivable-HMP&L Sta Two Other	630,884			
	Accts Receivable-HMP&L Litigation	18,161			
	Accts Receivable-HMP&L MISO Costs	565,901			
	Accts Receivable-Smithland Hydro Power	(306,682)			
	Accts Receivable-KU-Matanzas Substation	6,339			
	Accts Receivable-KYTC TL 18-G	290			
	Accts Receivable-Century Escrow	273,234			
	Accumulated Provision for Other Uncollectible Accts - Credit	(297,191)			
	Totals	2,345,621			
11	TOTAL INVESTMENTS (1 thru 10)	5,138,761	336,150,571		

RUS Financial and Operating Report Electric Power Supply – Part H - Annual Supplement

Revision Date 2010

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT	BORROWER DESIGNATION KY0062 PERIOD ENDED December, 2012

INSTRUCTIONS - Reporting of investments is required by 7 CFR 1717, Subpart N. Investment categories reported on this Part correspond to Balance Sheet items in Part A Section B. Identify all investments in Rural Development with an 'X' in column (e). Both 'Included' and 'Excluded' Investments must be reported. See help in the online application.

SECTION F. INVESTMENTS, LOAN GUARANTEES AND LOANS
SUB SECTION II. LOAN GUARANTEES

No	Organization (a)	Maturity Date (b)	Original Amount ($) (c)	Loan Balance ($) (d)	Rural Development (e)
	TOTAL				
	TOTAL (Included Loan Guarantees Only)				

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT	BORROWER DESIGNATION KY0062 PERIOD ENDED December, 2012

INSTRUCTIONS - Reporting of investments is required by 7 CFR 1717, Subpart N. Investment categories reported on this Part correspond to Balance Sheet items in Part A Section B. Identify all investments in Rural Development with an "X" in column (e). Both "Included" and "Excluded" Investments must be reported. See help in the online application.

SECTION F. INVESTMENTS, LOAN GUARANTEES AND LOANS
SUB SECTION III. RATIO

RATIO OF INVESTMENTS AND LOAN GUARANTEES TO UTILITY PLANT [Total of Included Investments (Sub Section I, 11b) and Loan Guarantees - Loan Balance (Sub Section II, 5d) to Total Utility Plant (Part A, Section B, Line 3 of this report)]	0.25 %

SECTION F. INVESTMENTS, LOAN GUARANTEES AND LOANS
SUB SECTION IV. LOAN

No	Organization (a)	Maturity Date (b)	Original Amount ($) (c)	Loan Balance ($) (d)	Rural Development (e)
	TOTAL				

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART H - ANNUAL SUPPLEMENT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION

KY0062

PERIOD ENDED

December, 2012

SECTION G. MATERIALS AND SUPPLIES INVENTORY

ITEM	BALANCE BEGINNING OF YEAR (a)	PURCHASED & SALVAGED (b)	USED & SOLD (c)	BALANCE END OF YEAR (d)
1. Coal	30,130,701	218,735,885	222,747,900	26,118,686
2. Other Fuel	3,763,312	36,064,270	31,800,656	8,026,926
3. Production Plant Parts and Supplies	22,273,445	7,790,022	7,756,077	22,307,390
4. Station Transformers and Equipment	0			0
5. Line Materials and Supplies	761,000	492,440	404,790	848,650
6. Other Materials and Supplies	2,260,820	15,422,296	15,882,083	1,801,033
7. Total (*1 thru 6*)	59,189,278	278,504,913	278,591,506	59,102,685

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART H - ANNUAL SUPPLEMENT

BORROWER DESIGNATION
KY0062

INSTRUCTIONS - See help in the online application.

PERIOD ENDED
December, 2012

SECTION H. LONG-TERM DEBT AND DEBT SERVICE REQUIREMENTS

No	Item	Balance End Of Year (a)	Interest (Billed This Year) (b)	Principal (Billed This Year) (c)	Total (Billed This Year) (d)
1	RUS (Excludes RUS - Economic Development Loans)	210,359,050	18,089,278	448,821,876	466,911,154
2	National Rural Utilities Cooperative Finance Corporation	341,358,017	5,406,678	3,797,783	9,204,461
3	CoBank, ACB	231,426,868	4,386,962	3,573,132	7,960,094
4	Federal Financing Bank				
5	RUS - Economic Development Loans				
6	Payments Unapplied				
7	Ohio County Kentucky Bonds-Series 1983	58,800,000	2,022,181		2,022,181
8	Ohio County Kentucky Bonds-Series 2001A	83,300,000	4,998,000		4,998,000
	TOTAL	925,243,935	34,803,099	456,192,791	491,095,890

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT**	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2012

SECTION I. ANNUAL MEETING AND BOARD DATA

1. Date of Last Annual Meeting 9/20/2012	2. Total Number of Members 3	3. Number of Members Present at Meeting 3	4. Was Quorum Present? Yes
5. Number of Members Voting by Proxy or Mail 0	6. Total Number of Board Members 6	7. Total Amount of Fees and Expenses for Board Members $ 197,387	8. Does Manager Have Written Contract? No

SECTION J. MAN-HOUR AND PAYROLL STATISTICS

1. Number of Full Time Employees	601	4. Payroll Expensed	45,079,561
2. Man-Hours Worked - Regular Time	1,074,163	5. Payroll Capitalized	1,002,012
3. Man-Hours Worked – Overtime	134,738	6. Payroll Other	3,203,003

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT**	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2012

SECTION K. LONG-TERM LEASES

No	Name Of Lessor (a)	Type Of Property (b)	Rental This Year (c)
1	Louisville Gas & Electric Company	Interconnect Facilities - Cloverport Sub	21,111
	TOTAL		21,111

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2012

SECTION L. RENEWABLE ENERGY CREDITS

ITEM	BALANCE BEGINNING OF YEAR (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS AND TRANSFER (d)	BALANCE END OF YEAR (e)
1. Renewable Energy Credits					

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART I - LINES AND STATIONS

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION: KY0062

PERIOD ENDED: December, 2012

SECTION A. EXPENSES AND COSTS

ITEM	ACCOUNT NUMBER	LINES (a)	STATIONS (b)
Transmission Operation			
1. Supervision and Engineering	560	265,236	360,606
2. Load Dispatching	561	3,966,746	
3. Station Expenses	562		773,022
4. Overhead Line Expenses	563	975,572	
5. Underground Line Expenses	564		
6. Miscellaneous Expenses	566	257,941	412,849
7. **Subtotal (*1 thru 6*)**		5,465,495	1,546,477
8. Transmission of Electricity by Others	565	3,082,093	
9. Rents	567		24,701
10. **Total Transmission Operation (*7 thru 9*)**		8,547,588	1,571,178
Transmission Maintenance			
11. Supervision and Engineering	568	239,483	244,791
12. Structures	569		22,426
13. Station Equipment	570		1,554,891
14. Overhead Lines	571	1,805,126	
15. Underground Lines	572		
16. Miscellaneous Transmission Plant	573	296,087	445,194
17. **Total Transmission Maintenance (*11 thru 16*)**		2,340,696	2,267,302
18. **Total Transmission Expense (*10 + 17*)**		10,888,284	3,838,480
19. RTO/ISO Expense – Operation	575.1-575.8	2,262,435	
20. RTO/ISO Expense – Maintenance	576.1-576.5		
21. **Total RTO/ISO Expense (*19 + 20*)**		2,262,435	
22. Distribution Expense - Operation	580-589		
23. Distribution Expense - Maintenance	590-598		
24. **Total Distribution Expense (*22 + 23*)**			
25. **Total Operation And Maintenance (*18 + 21 + 24*)**		13,150,719	3,838,480
Fixed Costs			
26. Depreciation – Transmission	403.5	1,841,075	2,803,949
27. Depreciation – Distribution	403.6		
28. Interest – Transmission	427	2,732,554	3,230,274
29. Interest – Distribution	427		
30. **Total Transmission (*18 + 26 + 28*)**		15,461,913	9,872,703
31. **Total Distribution (*24 + 27 + 29*)**			
32. **Total Lines And Stations (*21 + 30 + 31*)**		17,724,348	9,872,703

SECTION B. FACILITIES IN SERVICE

TRANSMISSION LINES

VOLTAGE (kV)	MILES
1. 161 KV	362.80
2. 345 KV	68.40
3. 138 KV	14.40
4. 69 KV	839.20
5.	
6.	
7.	
8.	
9.	
10.	
11.	
12. **Total (*1 thru 11*)**	1,284.80

SUBSTATIONS

TYPE	CAPACITY(kVA)
13. Distribution Lines	
14. **Total (*12 + 13*)**	1,284.80
15. Stepup at Generating Plants	1,879,800
16. Transmission	3,595,000
17. Distribution	
18. **Total (*15 thru 17*)**	5,474,800

SECTION C. LABOR AND MATERIAL SUMMARY

1. Number of Employees: 52

ITEM	LINES	STATIONS
2. Oper. Labor	1,555,834	936,457
3. Maint. Labor	1,326,549	1,468,675
4. Oper. Material	9,254,189	634,721
5. Maint. Material	1,014,146	798,627

SECTION D. OUTAGES

1. Total	66,290.60
2. Avg. No. of Distribution Consumers Served	113,252.00
3. Avg. No. of Hours Out Per Consumer	.60

RUS Form 12 – November 2012

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0572-0032. The time required to complete this information collection is estimated to average 21 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	BORROWER DESIGNATION KY0062 PERIOD ENDED November -2012
INSTRUCTIONS - See help in the online application *This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C. 552).*	BORROWER NAME Big Rivers Electric Corporation

CERTIFICATION

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7 CFR CHAPTER XVII

(check one of the following)

X All of the obligations under the RUS loan documents have been fulfilled in all material respects.

__ There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part A Section C of this report.

Mark A. Bailey 12/18/12

SIGNATURE OF PRESIDENT AND CEO DATE

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART A - FINANCIAL

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Nov-12

INSTRUCTIONS - See help in the online application.

SECTION A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	YEAR-TO-DATE BUDGET (c)	THIS MONTH (d)
1. Electric Energy Revenues	510,961,044.35	515,459,383.23	560,167,999.00	50,275,789.91
2. Income From Leased Property (Net)	0.00	0.00	0.00	0.00
3. Other Operating Revenue and Income	3,237,001.53	4,596,020.01	3,677,587.00	328,255.55
4. **Total Operation Revenues & Patronage Capital** *(1 thru 3)*	**514,198,045.88**	**520,055,403.24**	**563,845,586.00**	**50,604,045.46**
5. Operating Expense - Production - Excluding Fuel	45,737,497.94	44,111,403.21	50,420,358.00	4,037,383.15
6. Operating Expense - Production - Fuel	207,154,640.29	205,119,841.29	217,462,236.00	21,115,850.46
7. Operating Expense - Other Power Supply	102,532,953.50	102,819,695.91	117,972,756.00	7,678,556.44
8. Operating Expense - Transmission	8,341,720.53	9,084,376.64	9,818,219.00	818,185.67
9. Operating Expense - RTO/ISO	2,317,681.27	2,069,307.83	2,242,407.00	215,006.88
10. Operating Expense - Distribution	0.00	0.00	0.00	0.00
11. Operating Expense - Customer Accounts	0.00	0.00	0.00	0.00
12. Operating Expense - Customer Service & Information	438,304.90	630,359.03	671,828.00	143,637.12
13. Operating Expense - Sales	140,925.58	146,208.41	1,028,639.00	4,906.25
14. Operating Expense - Administrative & General	23,702,723.58	23,806,699.57	23,960,444.00	2,097,586.17
15. **Total Operation Expense** *(5 thru 14)*	**390,366,447.59**	**387,787,891.89**	**423,576,887.00**	**36,111,112.14**
16. Maintenance Expense - Production	39,001,742.46	37,885,035.04	56,251,376.00	3,251,549.10
17. Maintenance Expense - Transmission	4,116,732.03	4,306,153.23	3,627,791.00	237,404.75
18. Maintenance Expense - RTO/ISO	0.00	0.00	0.00	0.00
19. Maintenance Expense - Distribution	0.00	0.00	0.00	0.00
20. Maintenance Expense - General Plant	133,524.06	152,862.02	93,926.00	11,016.52
21. **Total Maintenance Expense** *(16 thru 20)*	**43,251,998.55**	**42,344,050.29**	**59,973,093.00**	**3,499,970.37**
22. Depreciation and Amortization Expense	32,154,621.93	37,664,804.87	38,363,446.00	3,416,737.66
23. Taxes	128,389.00	3,810.88	885.00	<250.00>
24. Interest on Long-Term Debt	41,926,404.48	41,234,198.88	40,908,315.00	3,706,477.74
25. Interest Charged to Construction - Credit	<507,834.00>	<722,093.00>	<569,513.00>	<73,475.00>
26. Other Interest Expense	59,240.58	100,826.11	0.00	45,833.83
27. Asset Retirement Obligations	0.00	0.00	0.00	0.00
28. Other Deductions	202,783.38	424,927.67	373,251.00	166,722.44
29. **Total Cost Of Electric Service** *(15 + 21 thru 28)*	**507,582,051.51**	**508,838,417.59**	**562,626,364.00**	**46,873,129.18**
30. **Operating Margins** *(4 less 29)*	**6,615,994.37**	**11,216,985.65**	**1,219,222.00**	**3,730,916.28**
31. Interest Income	144,337.54	749,654.48	58,959.00	171,966.52
32. Allowance For Funds Used During Construction	0.00	0.00	0.00	0.00
33. Income (Loss) from Equity Investments	0.00	0.00	0.00	0.00
34. Other Non-operating Income (Net)	9,288.48	0.00	0.00	0.00
35. Generation & Transmission Capital Credits	0.00	0.00	0.00	0.00
36. Other Capital Credits and Patronage Dividends	104,653.04	58,674.04	33,000.00	0.00
37. Extraordinary Items	0.00	0.00	0.00	0.00
38. **Net Patronage Capital Or Margins** *(30 thru 37)*	6,874,273.43	12,025,314.17	1,311,181.00	3,902,882.80

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE	BORROWER DESIGNATION KY0062
FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART A - FINANCIAL	PERIOD ENDED Nov-12
INSTRUCTIONS - See help in the online application.	

SECTION B. BALANCE SHEET

ASSETS AND OTHER DEBITS

1. Total Utility Plant in Service	1,998,739,597.24
2. Construction Work in Progress	51,284,124.36
3. Total Utility Plant *(1 + 2)*	**2,050,023,721.60**
4. Accum. Provision for Depreciation and Amort.	962,036,997.48
5. Net Utility Plant *(3 - 4)*	1,087,986,724.12
6. Non-Utility Property (Net)	0.00
7. Investments in Subsidiary Companies	0.00
8. Invest. in Assoc. Org. - Patronage Capital	3,680,691.11
9. Invest, in Assoc. Org. - Other - General Funds	43,840,793.00
10. Invest. in Assoc. Org. - Other - Nongeneral Funds	0.00
11. Investments in Economic Development Projects	10,000.00
12. Other Investments	5,333.85
13. Special Funds	182,146,513.15
14. Total Other Property And Investments *(6 thru 13)*	**229,683,331.11**
15. Cash - General Funds	5,789.98
16. Cash - Construction Funds - Trustee	0.00
17. Special Deposits	598,439.73
18. Temporary Investments	112,017,886.54
19. Notes Receivable (Net)	0.00
20. Accounts Receivable - Sales of Energy (Net)	44,963,536.05
21. Accounts Receivable - Other (Net)	1,300,219.04
22. Fuel Stock	34,451,929.38
23. Renewable Energy Credits	0.00
24. Materials and Supplies - Other	24,928,709.89
25. Prepayments	933,700.09
26. Other Current and Accrued Assets	1,011,572.86
27. Total Current And Accrued Assets *(15 thru 26)*	**220,211,783.56**
28. Unamortized Debt Discount & Extraor. Prop. Losses	4,151,321.55
29. Regulatory Assets	725,848.50
30. Other Deferred Debits	3,507,947.69
31. Accumulated Deferred Income Taxes	0.00
32. Total Assets And Other Debits *(5+14+27 thru 31)*	1,546,266,956.53

LIABILITIES AND OTHER CREDITS

33. Memberships	75.00
34. Patronage Capital a. Assigned and Assignable b. Retired This year c. Retired Prior years **d. Net Patronage Capital (a-b-c)**	0.00
35. Operating Margins - Prior Years	<241,898,352.19>
36. Operating Margin - Current Year	11,275,659.69
37. Non-Operating Margins	639,747,191.68
38. Other Margins and Equities	<7,278,744.80>
39. Total Margins & Equities *(33 + 34d thru 38)*	**401,845,829.38**
40. Long-Term Debt - RUS (Net)	208,486,526.69
41. Long-Term Debt - FFB - RUS Guaranteed	0.00
42. Long-Term Debt - Other - RUS Guaranteed	0.00
43. Long-Term Debt - Other (Net)	636,842,427.53
44. Long-Term Debt - RUS - Econ. Devel. (Net)	0.00
45. Payments - Unapplied	0.00
46. Total Long-Term Debit *(40 thru 44-45)*	**845,328,954.22**
47. Obligations Under Capital Leases - Noncurrent	0.00
48. Accumulated Operating Provisions and Asset Retirement Obligations	25,269,178.37
49. Total Other NonCurrent Liabilities *(47 +48)*	**25,269,178.37**
50. Notes Payable	0.00
51. Accounts Payable	27,366,476.52
52. Current Maturities Long-Term Debt	79,839,567.99
53. Current Maturities Long-Term Debt - Rural Development	0.00
54. Current Maturities Capital Leases	0.00
55. Taxes Accrued	1,232,871.98
56. Interest Accrued	6,575,891.95
57. Other Current and Accrued Liabilities	9,274,270.38
58. Total Current & Accrued Liabilities *(50 thru 57)*	**124,289,078.82**
59. Deferred Credits	149,533,915.74
60. Accumulated Deferred Income Taxes	0.00
61. Total Liabilities and Other Credits *(39 + 46 + 49 + 58 thru 60)*	1,546,266,956.53

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Nov-12

INSTRUCTIONS - See help in the online application.

Part B SE - Sales of Electricity

Sale No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Fuel Type (e)	Average Monthly Billing Demand (MW) (f)	Actual Average Monthly NCP Demand (g)	Actual Average Monthly CP Demand (h)
	Ultimate Consumer(s)							
	Distribution Borrowers							
1	Jackson Purchase Energy Corp	KY0020	RQ			125	137	123
2	Kenergy Corporation	KY0065	IF					
3	Kenergy Corporation	KY0065	LF					
4	Kenergy Corporation	KY0065	RQ			360	372	355
5	Meade County Rural ECC	KY0018	RQ			86	96	86
	G&T Borrowers							
6	PowerSouth Energy Coop	AL0042	OS					
	Others							
7	ADM Investor Services		OS					
8	Henderson Muncipal Power & Light		OS					
9	Louisville Gas & Electric		OS					
10	Midwest Independent Trans. Sys. Op.		OS					
11	PJM Interconnection		OS					
12								
	Total for Ultimate Consumer(s)					0	0	0
	Total for Distribution Borrowers					571	605	564
	Total for G&T Borrowers					0	0	0
	Total for Others					0	0	0
	Grand Total					571	605	564

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD ENDED Nov-12
INSTRUCTIONS - See help in the online application.	

Part B SE - Sales of Electricity

Sale No.	Electricity Sold (MWh) (i)	Revenue Demand Charges (j)	Revenue Energy Charges (k)	Revenue Other Charges (l)	Revenue Total (j + k + l) (m)
1	611,174.321	13,040,452.00	18,053,561.06		31,094,013.06
2	188,452.671		5,966,997.28		5,966,997.28
3	6,790,125.169		331,414,982.37		331,414,982.37
4	1,966,434.598	39,467,375.67	53,519,389.29		92,986,764.96
5	421,163.690	9,027,223.00	12,447,984.48		21,475,207.48
6	460.000		17,325.40		17,325.40
7			<24,460.00>		<24,460.00>
8	16,240.176		457,677.04		457,677.04
9	180.000		6,960.60		6,960.60
10	1,121,377.600		32,067,920.63		32,067,920.63
11			<4,005.59>		<4,005.59>
12			0.00		
	0	0	0	0	0
	9,977,350.449	61,535,050.67	421,402,914.48	0.00	482,937,965.15
	460.000	0.00	17,325.40	0.00	17,325.40
	1,137,797.776	0.00	32,504,092.68	0.00	32,504,092.68
	11,115,608.225	61,535,050.67	453,924,332.56	0.00	515,459,383.23

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062

PERIOD NAME
Nov-12

PART B PP - Purchased Power

Purchase No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Energy Type (e)	Average Monthly Billing Demand (MW) (f)	Average Monthly NCP Demand (g)	Average Monthly CP Demand (h)
	Distribution Borrowers							
	G&T Borrowers							
	Others							
1	Cargill Power Markets		OS					
2	Henderson Municipal Power & Light		RQ					
3	Louisville Gas & Electric		OS					
4	Midwest Independent Trans. Sys. Op.		OS					
5	Southeastern Power Admin.		LF					
6								
Total for Distribution Borrowers						0	0	0
Total for G&T Borrowers						0	0	0
Total for Others						0	0	0
Grand Total						0	0	0

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD NAME Nov-12
INSTRUCTIONS - See help in the online application.	

PART B PP - Purchased Power

Purchase No.	Electricity Purchased (MWh) (i)	Electricity Received (MWh) (j)	Electricity Delivered (MWh) (k)	Demand Charges (l)	Energy Charges (m)	Other Charges (n)	Total (l + m + n) (o)
1	36,000.000				993,600.00		993,600.00
2	1,284,071.490				58,077,622.11		58,077,622.11
3	4,410.000				165,608.38		165,608.38
4	1,327,574.600				33,771,215.64		33,771,215.64
5	245,518.000				7,213,521.19		7,213,521.19
6					0.00		
	0.000				0.00		0.00
	0.000				0.00		0.00
	2,897,574.090				100,221,567.32		100,221,567.32
	2,897,574.090				100,221,567.32		100,221,567.32

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART C - SOURCES AND DISTRIBUTION OF ENERGY

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Nov-12

INSTRUCTIONS - See help in the online application.

SOURCES OF ENERGY (a)	NO. OF PLANTS (b)	CAPACITY (kW) (c)	NET ENERGY RECEIVED BY SYSTEM (MWh) (d)	COST ($) (e)
Generated in Own Plant ***(Details on Parts D and F IC)***				
1. Fossil Steam	4	1,489,000	8,267,642.259	351,022,164.28
2. Nuclear				
3. Hydro				
4. Combined Cycle				
5. Internal Combustion	1	70,000	6,703.060	1,126,204.80
6. Other				
7. Total in Own Plant ***(1 thru 6)***	5	1,559,000	8,274,345.319	352,148,369.08
Purchased Power				
8. Total Purchased Power			2,897,574.090	100,221,567.32
Interchanged Power				
9. Received Into System (Gross)			2,209,202.000	
10. Delivered Out of System (Gross)			2,067,512.000	
11. Net Interchange ***(9 minus 10)***			141,690.000	
Transmission For or By Others - (Wheeling)				
12. Received Into System			0.000	
13. Delivered Out of System			0.000	
14. Net Energy Wheeled ***(12 minus 13)***			0.000	
15. Total Energy Available for Sale (7 + 8 + 11 + 14)			11,313,609.409	
Distribution of Energy				
16. Total Sales			11,115,608.225	
17. Energy Furnished to Others Without Charge				
18. Energy Used by Borrower *(Excluding Station Use)*				
19. Total Energy Accounted For ***(16 thru 18)***			11,115,608.225	
Losses				
20. Energy Losses - MWh ***(15 minus 19)***			198,001.184	
21. Energy Losses - Percentage ((20 divided by 15) * 100)			1.75 %	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART D - STEAM PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION: KY0062
PLANT: COLEMAN
PERIOD ENDED: Nov-12

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	14	835,213.7	0.000	25,928.2			7,186.3	138.9	0.0	714.8
2.	2	5	914,852.0	0.000	17,501.5			7,775.7	63.3	0.0	201.0
3.	3	4	960,044.4	0.000	29,870.8			7,897.5	0.0	0.0	142.5
4.											
5.											
6.	Total	23	2,710,110.1	0.000	73,300.5			22,859.5	202.2	0.0	1,058.3
7.	Average BTU		11,318	0	1,000						
8.	Total BTU(10^6)		30,673,026	0	73,301		30,746,327				
9.	Total Del.Cost ($)		71,436,866.20	2,265.59	230,711.53						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	160,000	954,389.000	
2.	2	160,000	1,046,564.000	
3.	3	165,000	1,107,269.000	
4.				
5.				
6.	Total	485,000	3,108,222.000	9,892
7.	Station Service (MWh)		284,857.180	
8.	Net Generation (MWh)		2,823,364.820	10,890
9.	Station Service (%)		9.16	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	107
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	78.42
2.	Plant Factor (%)	79.71
3.	Running Plant Capacity Factor (%)	84.07
4.	15 Minute Gross Maximum Demand (kW)	492,950
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	1,537,412.10		
2.	Fuel, Coal	501.1	74,624,698.95		2.43
3.	Fuel, Oil	501.2	2,265.59		
4.	Fuel, Gas	501.3	230,711.53		3.15
5.	Fuel, Other	501.4			
6.	**Fuel Sub Total (2 thru 5)**	501	74,857,676.07	26.51	2.43
7.	Steam Expenses	502	5,132,264.92		
8.	Electric Expenses	505	1,895,694.75		
9.	Miscellaneous Steam Power Expenses	506	1,832,986.72		
10.	Allowances	509	35,727.14		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub Total (1 + 7 thru 11)**		10,434,085.63	3.70	
13.	**Operation Expense (6 + 12)**		85,291,761.70	30.21	
14.	Maintenance, Supervision and Engineering	510	1,370,060.82		
15.	Maintenance of Structures	511	1,106,036.60		
16.	Maintenance of Boiler Plant	512	5,938,814.56		
17.	Maintenance of Electric Plant	513	1,046,263.01		
18.	Maintenance of Miscellaneous Plant	514	1,384,889.04		
19.	**Maintenance Expense (14 thru 18)**		10,846,064.03	3.84	
20.	**Total Production Expense (13 + 19)**		96,137,825.73	34.05	
21.	Depreciation	403.1	5,069,827.86		
22.	Interest	427	6,389,238.09		
23.	**Total Fixed Cost (21 + 22)**		11,459,065.95	4.06	
24.	**Power Cost (20 + 23)**		107,596,891.68	38.11	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION	KY0062
PLANT	REID
PERIOD ENDED	Nov-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	6	28,599.6	34.405	.0			571.2	6,962.6	.0	506.2
2.											
3.											
4.											
5.											
6.	Total	6	28,599.6	34.405	.0			571.2	6,962.6	.0	506.2
7.	Average BTU		12,206	138,000	0						
8.	Total BTU(10^6)		349,087	4,748	0		353,835				
9.	Total Del..Cost ($)		872,499.36	110,069.50	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	72,000	29,068.000	
2.				
3.				
4.				
5.				
6.	Total	72,000	29,068.000	12,173
7.	Station Service (MWh)		18,267.000	
8.	Net Generation (MWh)		10,801.000	32,759
9.	Station Service (%)		62.84	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	17
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	6.26
2.	Plant Factor (%)	5.02
3.	Running Plant Capacity Factor (%)	70.68
4.	15 Minute Gross Maximum Demand (kW)	57,776
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	247,397.47		
2.	Fuel, Coal	501.1	1,119,539.01		3.21
3.	Fuel, Oil	501.2	110,069.50		23.18
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	**Fuel Sub Total (2 thru 5)**	501	1,229,608.51	113.84	3.48
7.	Steam Expenses	502	502,417.89		
8.	Electric Expenses	505	252,930.88		
9.	Miscellaneous Steam Power Expenses	506	199,542.65		
10.	Allowances	509	5,468.67		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub Total (1 + 7 thru 11)**		1,207,757.56	111.82	
13.	**Operation Expense (6 + 12)**		2,437,366.07	225.66	
14.	Maintenance, Supervision and Engineering	510	221,586.07		
15.	Maintenance of Structures	511	108,761.35		
16.	Maintenance of Boiler Plant	512	729,228.21		
17.	Maintenance of Electric Plant	513	201,912.75		
18.	Maintenance of Miscellaneous Plant	514	156,735.83		
19.	**Maintenance Expense (14 thru 18)**		1,418,224.21	131.30	
20.	**Total Production Expense (13 + 19)**		3,855,590.28	356.97	
21.	Depreciation	403.1	413,376.80		
22.	Interest	427	658,345.23		
23.	**Total Fixed Cost (21 + 22)**		1,071,722.03	99.22	
24.	**Power Cost (20 + 23)**		4,927,312.31	456.19	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PLANT D - STEAM PLANT

BORROWER DESIGNATION	KY0062
PLANT	GREEN
PERIOD ENDED	Nov-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	8	1,321,367.2	210.779	.0			7,263.3	603.5	.0	173.2
2.	2	8	1,087,330.5	214.081	.0			6,084.9	1,318.1	.0	637.0
3.											
4.											
5.											
6.	Total	16	2,408,697.7	424.860	.0			13,348.2	1,921.6	.0	810.2
7.	Average BTU		11,819	138,000	0						
8.	Total BTU(10^6)		28,468,398	58,631	0		28,527,029				
9.	Total Del..Cost ($)		60,379,803.79	1,340,894.33	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	250,000	1,587,797.390	
2.	2	242,000	1,281,935.100	
3.				
4.				
5.				
6.	Total	492,000	2,869,732.490	9,941
7.	Station Service (MWh)		278,538.343	
8.	Net Generation (MWh)		2,591,194.147	11,009
9.	Station Service (%)		9.71	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	114
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	71.50
2.	Plant Factor (%)	72.55
3.	Running Plant Capacity Factor (%)	87.27
4.	15 Minute Gross Maximum Demand (kW)	499,181
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	1,422,214.98		
2.	Fuel, Coal	501.1	62,666,544.60		2.20
3.	Fuel, Oil	501.2	1,340,894.33		22.87
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			
6.	Fuel Sub Total (2 thru 5)	501	64,007,438.93	24.70	2.24
7.	Steam Expenses	502	11,271,386.54		
8.	Electric Expenses	505	3,067,478.42		
9.	Miscellaneous Steam Power Expenses	506	1,301,913.02		
10.	Allowances	509	18,901.61		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		17,081,894.57	6.59	
13.	Operation Expense (6 + 12)		81,089,333.50	31.29	
14.	Maintenance, Supervision and Engineering	510	1,404,463.87		
15.	Maintenance of Structures	511	1,003,133.92		
16.	Maintenance of Boiler Plant	512	7,189,334.44		
17.	Maintenance of Electric Plant	513	1,241,869.40		
18.	Maintenance of Miscellaneous Plant	514	804,815.91		
19.	Maintenance Expense (14 thru 18)		11,643,617.54	4.49	
20.	Total Production Expense (13 + 19)		92,732,951.04	35.79	
21.	Depreciation	403.1	7,316,781.97		
22.	Interest	427	7,360,661.60		
23.	Total Fixed Cost (21 + 22)		14,677,443.57	5.66	
24.	Power Cost (20 + 23)		107,410,394.61	41.45	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION: KY0062
PLANT: WILSON
PERIOD ENDED: Nov-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	10	2,503,636.6	377.120	.0						
2.								7,428.1	21.2	335.7	255.0
3.											
4.											
5.											
6.	Total	10	2,503,636.6	377.120	.0			7,428.1	21.2	335.7	255.0
7.	Average BTU		11,954	138,000	0						
8.	Total BTU(10^6)		29,928,472	52,043	0		29,980,515				
9.	Total Del..Cost ($)		60,720,055.72	1,178,297.38	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	440,000	3,047,270.260	
2.				
3.				
4.				
5.				
6.	Total	440,000	3,047,270.260	9,838
7.	Station Service (MWh)		204,987.968	
8.	Net Generation (MWh)		2,842,282.292	10,548
9.	Station Service (%)		6.73	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	105
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	82.05
2.	Plant Factor (%)	86.14
3.	Running Plant Capacity Factor (%)	93.24
4.	15 Minute Gross Maximum Demand (kW)	461,911
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	1,807,553.76		
2.	Fuel, Coal	501.1	63,454,846.51		
3.	Fuel, Oil	501.2	1,178,297.38		2.12
4.	Fuel, Gas	501.3	0.00		22.64
5.	Fuel, Other	501.4			0
6.	Fuel Sub-Total (2 thru 5)	501	64,633,143.89	22.74	0
7.	Steam Expenses	502	9,123,344.44		2.16
8.	Electric Expenses	505	1,178,532.65		
9.	Miscellaneous Steam Power Expenses	506	3,197,816.73		
10.	Allowances	509	46,559.27		
11.	Rents	507	0.00		
12.	Non-Fuel Sub-Total (1 + 7 thru 11)		15,353,806.85	5.40	
13.	Operation Expense (6 + 12)		79,986,950.74	28.14	
14.	Maintenance, Supervision and Engineering	510	1,316,506.11		
15.	Maintenance of Structures	511	963,528.39		
16.	Maintenance of Boiler Plant	512	10,137,099.92		
17.	Maintenance of Electric Plant	513	758,153.65		
18.	Maintenance of Miscellaneous Plant	514	564,940.72		
19.	Maintenance Expense (14 thru 18)		13,740,228.79	4.83	
20.	Total Production Expense (13 + 19)		93,727,179.53	32.98	
21.	Depreciation	403.1	17,566,605.87		
22.	Interest	427	19,793,780.28		
23.	Total Fixed Cost (21 + 22)		37,360,386.15	13.14	
24.	Power Cost (20 + 23)		131,087,565.68	46.12	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART F IC - INTERNAL COMBUSTION PLANT

BORROWER DESIGNATION
KY0062
PLANT
REID
PERIOD ENDED
Nov-12

INSTRUCTIONS - See help in the online application.

SECTION A. INTERNAL COMBUSTION GENERATING UNITS

NO.	UNIT NO. (a)	SIZE (kW) (b)	FUEL CONSUMPTION OIL (1000 Gals.) (c)	GAS (1000 C.F.) (d)	OTHER (e)	TOTAL (f)	OPERATING HOURS IN SERVICE (g)	ON STANDBY (h)	OUT OF SERVICE Sche. (i)	Unsched (j)	GROSS GENERATION (MWh) (k)	BTU PER kWh (1)
1.	1	70,000	.000	128,359			243.1	7,724.2	.0	72.7	7,650.580	
2.												
3.												
4.												
5.												
6.	Total	70,000	.000	128,359			243.1	7,724.2	.0	72.7	7,650.580	16,778
7.	Average BTU		0	1,000			Station Service (MWh)				947.520	
8.	Total BTU(10^6)		0	128,359		128,359	Net Generation (MWh)				6,703.060	19,149
9.	Total Del..Cost ($)		0.00	391,529.89			Station Service % of Gross				12.38	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	0	5.	Maint. Plant Payroll ($)	
2.	No. Employees Part-Time				
3.	**Total Empl. - Hrs. Worked**		6.	Other Accounts. Plant Payroll ($)	
4.	Oper. Plant Payroll ($)		7.	**Total Plant Payroll ($)**	

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	1.49
2.	Plant Factor (%)	1.36
3.	Running Plant Capacity Factor (%)	44.96
4.	15 Minute Gross Maximum Demand (kW)	63,895
5.	Indicated Gross Maximum Demand kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	546	0.00		
2.	Fuel, Oil	547.1	0.00		
3.	Fuel, Gas	547.2	391,973.89		3.05
4.	Fuel, Other	547.3			
5.	Energy for Compressed Air	547.4			
6.	**Fuel Sub-Total *(2 thru 5)***	547	391,973.89	58.48	3.05
7.	Generation Expenses	548	33,858.60		
8.	Miscellaneous Other Power Generation Expenses	549	0.00		
9.	Rents	550	0.00		
10.	**Non-Fuel Sub-Total *(1 + 7 thru 9)***		33,858.60	5.05	
11.	**Operation Expense *(6+ 10)***		425,832.49	63.53	
12.	Maintenance, Supervision and Engineering	551	0.00		
13.	Maintenance of Structures	552	0.00		
14.	Maintenance of Generating and Electric Plant	553	236,900.47		
15.	Maintenance of Miscellaneous Other Power Generating Plant	554	0.00		
16.	**Maintenance Expense *(12 thru 15)***		236,900.47	35.34	
17.	**Total Production Expense *(11 + 16)***		662,732.96	98.87	
18.	Depreciation	403.1,411.10	271,912.41		
19.	Interest	427	191,559.43		
20.	**Total Fixed Cost *(18+ 19)***		463,471.84	69.14	
21.	**Power Cost *(17 + 20)***		1,126,204.80	168.01	

REMARKS *(including Unscheduled Outages)*

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART I - LINES AND STATIONS

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Nov-12

INSTRUCTIONS - See help in the online application.

SECTION A. EXPENSE AND COSTS

ITEM	ACCOUNT NUMBER	LINES (a)	STATIONS (b)
Transmission Operation			
1. Supervision and Engineering	560	242,200.16	329,341.45
2. Load Dispatching	561	3,639,642.29	
3. Station Expenses	562		711,513.68
4. Overhead Line Expenses	563	910,867.29	
5. Underground Line Expenses	564	0.00	
6. Miscellaneous Expenses	566	235,030.42	384,119.99
7. **Subtotal *(1 thru 6)***		5,027,640.16	1,424,975.12
8. Transmission of Electricity by Others	565	2,609,118.63	
9. Rents	567	0.00	22,642.73
10. **Total Transmission Operation *(7 thru 9)***		7,636,758.79	1,447,617.85
Transmission Maintenance			
11. Supervision and Engineering	568	218,363.12	224,404.72
12. Structures	569		22,235.75
13. Station Equipment	570		1,461,306.51
14. Overhead Lines	571	1,707,600.52	
15. Underground Lines	572	0.00	
16. Miscellaneous Transmission Plant	573	247,369.75	424,672.86
17. **Total Transmission Maintenance *(11 thru 16)***		2,173,333.39	2,132,619.84
18. **Total Transmission Expense *(10 + 17)***		9,810,092.18	3,580,437.69
19. RTO/ISO Expense - Operation	575	2,069,307.83	
20. RTO/ISO Expense - Maintenance	576	0.00	
21. **Total RTO/ISO Expense *(19 + 20)***		2,069,307.83	
22. Distribution Expense - Operation	580-589	0.00	0.00
23. Distribution Expense - Maintenance	590-598	0.00	0.00
24. **Total Distribution Expense *(22 + 23)***		0.00	0.00
25. **Total Operation And Maintenance *(18 + 21 +24)***		11,879,400.01	3,580,437.69
Fixed Costs			
26. Depreciation - Transmission	403.5	1,693,796.88	2,565,422.91
27. Depreciation - Distribution	403.6	0.00	0.00
28. Interest - Transmission	427	2,491,859.12	2,943,812.22
29. Interest - Distribution	427	0.00	0.00
30. **Total Transmission *(18 + 26 + 28)***		13,995,748.18	9,089,672.82
31. **Total Distribution *(24 +27 +29)***		0.00	0.00
32. **Total Lines And Stations *(21 + 30 + 31)***		16,065,056.01	9,089,672.82

SECTION B. FACILITIES IN SERVICE

TRANSMISSION LINES		SUBSTATIONS	
VOLTAGE (kV)	MILES	TYPE	CAPACITY (kVA)
1.69 kV	833.20		
2.345 kV	68.40	13. Distr. Lines	0
3.138 kV	14.40		
4.161 kV	349.60	14. Total *(12 + 13)*	1,265.60
5.			
6.		15. Step up at Generating Plants	1,679,800
7.			
8.		16. Transmission	3,540,000
9.			
10.		17. Distribution	0
11.			
12. Total *(1 thru 11)*	1,265.60	18. Total *(15 thru 17)*	5,419,800

SECTION C. LABOR AND MATERIAL SUMMARY

1. Number of Employees		53
ITEM	LINES	STATIONS
2. Oper. Labor	1,408,935.58	865,987.87
3. Maint. Labor	1,230,699.40	1,377,327.84
4. Oper. Material	8,297,131.04	581,629.98
5. Maint. Material	942,633.99	755,492.00

SECTION D. OUTAGES

1. Total	40,881.20
2. Avg. No. Dist. Cons. Served	112,887.00
3. Avg. No. Hours Out Per Cons.	0.36

RUS Forma 12 – October 2012

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0572-0032. The time required to complete this information collection is estimated to average 21 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD ENDED October -2012
INSTRUCTIONS - See help in the online application *This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C. 552).*	BORROWER NAME **Big Rivers Electric Corporation**

CERTIFICATION

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7 CFR CHAPTER XVII

(check one of the following)

X All of the obligations under the RUS loan documents have been fulfilled in all material respects.

__ There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part A Section C of this report.

Mark A. Bailey 11/15/12

SIGNATURE OF PRESIDENT AND CEO   DATE

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART A - FINANCIAL

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Oct-12

INSTRUCTIONS - See help in the online application.

SECTION A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	THIS YEAR (b)	BUDGET (c)	THIS MONTH (d)
1. Electric Energy Revenues	466,987,484.25	465,183,593.32	514,859,370.00	46,000,856.28
2. Income From Leased Property (Net)	0.00	0.00	0.00	0.00
3. Other Operating Revenue and Income	2,981,670.76	4,267,764.46	3,343,670.00	408,787.19
4. **Total Operation Revenues & Patronage Capital** *(1 thru 3)*	**469,969,155.01**	**469,451,357.78**	**518,203,040.00**	**46,409,643.47**
5. Operating Expense - Production - Excluding Fuel	41,534,846.90	40,074,020.06	46,162,891.00	3,681,565.82
6. Operating Expense - Production - Fuel	190,762,094.89	184,003,990.83	199,522,886.00	18,170,579.05
7. Operating Expense - Other Power Supply	92,142,983.76	95,141,139.47	109,417,904.00	10,860,362.39
8. Operating Expense - Transmission	7,637,817.55	8,266,190.97	8,993,047.00	903,023.44
9. Operating Expense - RTO/ISO	2,055,560.20	1,854,300.95	2,058,205.00	191,310.65
10. Operating Expense - Distribution	0.00	0.00	0.00	0.00
11. Operating Expense - Customer Accounts	0.00	0.00	0.00	0.00
12. Operating Expense - Customer Service & Information	371,713.07	486,721.91	614,088.00	95,629.46
13. Operating Expense - Sales	131,113.08	141,302.16	956,476.00	39,287.22
14. Operating Expense - Administrative & General	21,871,138.00	21,709,113.40	22,093,684.00	1,331,250.47
15. **Total Operation Expense** *(5 thru 14)*	**356,507,267.45**	**351,676,779.75**	**389,819,181.00**	**35,273,008.50**
16. Maintenance Expense - Production	33,221,278.88	34,633,485.94	51,782,905.00	3,761,208.05
17. Maintenance Expense - Transmission	3,783,424.46	4,068,748.48	3,348,143.00	333,187.78
18. Maintenance Expense - RTO/ISO	0.00	0.00	0.00	0.00
19. Maintenance Expense - Distribution	0.00	0.00	0.00	0.00
20. Maintenance Expense - General Plant	117,462.49	141,845.50	86,380.00	13,689.69
21. **Total Maintenance Expense** *(16 thru 20)*	**37,122,165.83**	**38,844,079.92**	**55,217,428.00**	**4,108,085.52**
22. Depreciation and Amortization Expense	28,872,655.57	34,248,067.21	34,824,050.00	3,396,022.12
23. Taxes	128,389.00	4,060.88	885.00	0.00
24. Interest on Long-Term Debt	38,246,446.93	37,527,721.14	37,241,114.00	3,808,835.93
25. Interest Charged to Construction - Credit	<475,923.00>	<648,618.00>	<481,171.00>	<69,999.00>
26. Other Interest Expense	58,989.26	54,992.28	0.00	23.24
27. Asset Retirement Obligations	0.00	0.00	0.00	0.00
28. Other Deductions	171,305.63	258,205.23	331,070.00	71,257.10
29. **Total Cost Of Electric Service** *(15 + 21 thru 28)*	**460,631,296.67**	**461,965,288.41**	**516,952,557.00**	**46,587,233.41**
30. **Operating Margins** *(4 less 29)*	**9,337,858.34**	**7,486,069.37**	**1,250,483.00**	**<177,589.94>**
31. Interest Income	138,407.95	577,687.96	54,199.00	174,358.78
32. Allowance For Funds Used During Construction	0.00	0.00	0.00	0.00
33. Income (Loss) from Equity Investments	0.00	0.00	0.00	0.00
34. Other Non-operating Income (Net)	9,288.48	0.00	0.00	0.00
35. Generation & Transmission Capital Credits	0.00	0.00	0.00	0.00
36. Other Capital Credits and Patronage Dividends	104,653.04	58,674.04	33,000.00	0.00
37. Extraordinary Items	0.00	0.00	0.00	0.00
38. **Net Patronage Capital Or Margins** *(30 thru 37)*	**9,590,207.81**	**8,122,431.37**	**1,337,682.00**	**<3,231.16>**

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART A - FINANCIAL

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Oct-12

INSTRUCTIONS - See help in the online application.

SECTION B. BALANCE SHEET

ASSETS AND OTHER DEBITS	
1. Total Utility Plant in Service	1,998,490,213.69
2. Construction Work in Progress	47,402,754.93
3. Total Utility Plant (1 + 2)	**2,045,892,968.62**
4. Accum. Provision for Depreciation and Amort.	958,897,679.36
5. Net Utility Plant (3 - 4)	**1,086,995,289.26**
6. Non-Utility Property (Net)	0.00
7. Investments in Subsidiary Companies	0.00
8. Invest. in Assoc. Org. - Patronage Capital	3,680,691.11
9. Invest, in Assoc. Org. - Other - General Funds	43,840,793.00
10. Invest. in Assoc. Org. - Other - Nongeneral Funds	0.00
11. Investments in Economic Development Projects	10,000.00
12. Other Investments	5,333.85
13. Special Funds	183,594,826.46
14. Total Other Property And Investments (6 thru 13)	**231,131,644.42**
15. Cash - General Funds	5,639.07
16. Cash - Construction Funds - Trustee	0.00
17. Special Deposits	598,394.53
18. Temporary Investments	117,329,395.78
19. Notes Receivable (Net)	0.00
20. Accounts Receivable - Sales of Energy (Net)	40,253,528.04
21. Accounts Receivable - Other (Net)	2,283,471.76
22. Fuel Stock	37,301,107.75
23. Renewable Energy Credits	0.00
24. Materials and Supplies - Other	25,578,123.30
25. Prepayments	1,214,147.67
26. Other Current and Accrued Assets	710,873.91
27. Total Current And Accrued Assets (15 thru 26)	**225,274,681.81**
28. Unamortized Debt Discount & Extraor. Prop. Losses	3,990,428.43
29. Regulatory Assets	768,669.35
30. Other Deferred Debits	3,151,799.11
31. Accumulated Deferred Income Taxes	0.00
32. Total Assets And Other Debits (5+14+27 thru 31)	1,551,312,512.38

LIABILITIES AND OTHER CREDITS	
33. Memberships	75.00
34. Patronage Capital a. Assigned and Assignable b. Retired This year c. Retired Prior years **d. Net Patronage Capital (a-b-c)**	0.00
35. Operating Margins - Prior Years	<241,898,352.19>
36. Operating Margin - Current Year	7,544,743.41
37. Non-Operating Margins	639,575,225.16
38. Other Margins and Equities	<7,278,744.80>
39. Total Margins & Equities (33 + 34d thru 38)	**397,942,946.58**
40. Long-Term Debt - RUS (Net)	208,486,526.69
41. Long-Term Debt - FFB - RUS Guaranteed	0.00
42. Long-Term Debt - Other - RUS Guaranteed	0.00
43. Long-Term Debt - Other (Net)	639,871,979.94
44. Long-Term Debt - RUS - Econ. Devel. (Net)	0.00
45. Payments - Unapplied	0.00
46. Total Long-Term Debt (40 thru 44-45)	**848,358,506.63**
47. Obligations Under Capital Leases - Noncurrent	0.00
48. Accumulated Operating Provisions and Asset Retirement Obligations	25,134,016.89
49. Total Other NonCurrent Liabilities (47 +48)	**25,134,016.89**
50. Notes Payable	0.00
51. Accounts Payable	32,008,662.04
52. Current Maturities Long-Term Debt	80,607,799.06
53. Current Maturities Long-Term Debt - Rural Development	0.00
54. Current Maturities Capital Leases	0.00
55. Taxes Accrued	436,848.14
56. Interest Accrued	6,761,080.34
57. Other Current and Accrued Liabilities	8,873,214.30
58. Total Current & Accrued Liabilities (50 thru 57)	**128,687,603.88**
59. Deferred Credits	151,189,438.40
60. Accumulated Deferred Income Taxes	0.00
61. Total Liabilities and Other Credits (39 + 46 + 49 + 58 thru 60)	1,551,312,512.38

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD ENDED Oct-12

INSTRUCTIONS - See help in the online application.

Part B SE - Sales of Electricity

Sale No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Fuel Type (e)	Average Monthly Billing Demand (MW) (f)	Actual Average Monthly NCP Demand (g)	Actual Average Monthly CP Demand (h)
	Ultimate Consumer(s)							
	Distribution Borrowers							
1	Jackson Purchase Energy Corp	KY0020	RQ			126	139	125
2	Kenergy Corporation	KY0065	IF					
3	Kenergy Corporation	KY0065	LF					
4	Kenergy Corporation	KY0065	RQ			362	375	357
5	Meade County Rural ECC	KY0018	RQ			86	96	86
	G&T Borrowers							
6	PowerSouth Energy Coop	AL0042	OS					
	Others							
7	ADM Investor Services		OS					
8	Henderson Muncipal Power & Light		OS					
9	Louisville Gas & Electric		OS					
10	Midwest Independent Trans. Sys. Op.		OS					
11	PJM Interconnection		OS					
12								

	(f)	(g)	(h)
Total for Ultimate Consumer(s)	0	0	0
Total for Distribution Borrowers	574	610	568
Total for G&T Borrowers	0	0	0
Total for Others	0	0	0
Grand Total	574	610	568

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD ENDED Oct-12
INSTRUCTIONS - See help in the online application.	

Part B SE - Sales of Electricity

Sale No.	Electricity Sold (MWh) (i)	Revenue Demand Charges (j)	Revenue Energy Charges (k)	Revenue Other Charges (l)	Revenue Total (j + k + l) (m)
1	559,728.881	11,986,272.50	16,495,692.01		28,481,964.51
2	170,798.736		5,330,350.99		5,330,350.99
3	6,178,295.988		300,720,213.72		300,720,213.72
4	1,797,223.478	36,113,001.02	48,810,131.12		84,923,132.14
5	381,511.460	8,187,157.00	11,243,709.77		19,430,866.77
6	460.000		17,325.40		17,325.40
7			<24,460.00>		<24,460.00>
8	16,240.176		457,677.04		457,677.04
9	180.000		6,960.60		6,960.60
10	908,963.900		25,843,573.32		25,843,573.32
11			<4,011.17>		<4,011.17>
12			0.00		
	0	0	0	0	0
	9,087,558.543	56,286,430.52	382,600,097.61	0.00	438,886,528.13
	460.000	0.00	17,325.40	0.00	17,325.40
	925,384.076	0.00	26,279,739.79	0.00	26,279,739.79
	10,013,402.618	56,286,430.52	408,897,162.80	0.00	465,183,593.32

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062

PERIOD NAME
Oct-12

PART B PP - Purchased Power

Purchase No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Energy Type (e)	Average Monthly Billing Demand (MW) (f)	Average Monthly NCP Demand (g)	Average Monthly CP Demand (h)
	Distribution Borrowers							
	G&T Borrowers							
	Others							
1	Cargill Power Markets		OS					
2	Henderson Municipal Power & Light		RQ					
3	Louisville Gas & Electric		OS					
4	Midwest Independent Trans. Sys. Op.		OS					
5	Southeastern Power Admin.		LF					
6								
Total for Distribution Borrowers						0	0	0
Total for G&T Borrowers						0	0	0
Total for Others						0	0	0
Grand Total						0	0	0

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY

BORROWER DESIGNATION
KY0062

PERIOD NAME
Oct-12

INSTRUCTIONS - See help in the online application.

PART B PP - Purchased Power

Purchase No.	Electricity Purchased (MWh) (i)	Electricity Received (MWh) (j)	Electricity Delivered (MWh) (k)	Demand Charges (l)	Energy Charges (m)	Other Charges (n)	Total (l + m + n) (o)
1	36,000.000				993,600.00		993,600.00
2	1,133,827.060				52,358,414.81		52,358,414.81
3	4,410.000				165,608.38		165,608.38
4	1,259,016.500				32,235,229.53		32,235,229.53
5	234,304.000				6,754,208.46		6,754,208.46
6					0.00		
	0.000				0.00		0.00
	0.000				0.00		0.00
	2,667,557.560				92,507,061.18		92,507,061.18
	2,667,557.560				92,507,061.18		92,507,061.18

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART C - SOURCES AND DISTRIBUTION OF ENERGY

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Oct-12

INSTRUCTIONS - See help in the online application.

SOURCES OF ENERGY (a)	NO. OF PLANTS (b)	CAPACITY (kW) (c)	NET ENERGY RECEIVED BY SYSTEM (MWh) (d)	COST ($) (e)
Generated in Own Plant ***(Details on Parts D and F IC)***				
1. Fossil Steam	4	1,489,000	7,390,137.205	316,885,645.76
2. Nuclear				
3. Hydro				
4. Combined Cycle				
5. Internal Combustion	1	70,000	6,608.110	1,007,901.92
6. Other				
7. Total in Own Plant ***(1 thru 6)***	5	1,559,000	7,396,745.315	317,893,547.68
Purchased Power				
8. Total Purchased Power			2,667,557.560	92,507,061.18
Interchanged Power				
9. Received Into System (Gross)			1,920,015.000	
10. Delivered Out of System (Gross)			1,789,385.000	
11. Net Interchange ***(9 minus 10)***			130,630.000	
Transmission For or By Others - (Wheeling)				
12. Received Into System			0.000	
13. Delivered Out of System			0.000	
14. Net Energy Wheeled ***(12 minus 13)***			0.000	
15. Total Energy Available for Sale (7 + 8 + 11 + 14)			10,194,932.875	
Distribution of Energy				
16. Total Sales			10,013,402.619	
17. Energy Furnished to Others Without Charge				
18. Energy Used by Borrower *(Excluding Station Use)*				
19. Total Energy Accounted For ***(16 thru 18)***			10,013,402.619	
Losses				
20. Energy Losses - MWh ***(15 minus 19)***			181,530.256	
21. Energy Losses - Percentage ((20 divided by 15) * 100)			1.78 %	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART D - STEAM PLANT

BORROWER DESIGNATION
KY0062
PLANT
COLEMAN
PERIOD ENDED
Oct-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	14	738,945.6	0.000	25,125.0			6,465.3	138.9	0.0	714.8
2.	2	4	824,079.6	0.000	16,127.7			7,068.9	63.3	0.0	186.8
3.	3	4	865,155.6	0.000	28,531.0			7,176.5	0.0	0.0	142.5
4.											
5.											
6.	Total	22	2,428,180.8	0.000	69,783.7			20,710.7	202.2	0.0	1,044.1
7.	Average BTU		11,324	0	1,000						
8.	Total BTU(10^6)		27,496,719	0	69,784		27,566,503				
9.	Total Del.Cost ($)		63,841,831.82	2,265.59	214,500.36						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	160,000	844,302.000	
2.	2	160,000	941,363.000	
3.	3	165,000	997,500.000	
4.				
5.				
6.	Total	485,000	2,783,165.000	9,905
7.	Station Service (MWh)		257,266.180	
8.	Net Generation (MWh)		2,525,898.820	10,914
9.	Station Service (%)		9.24	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	110
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	77.46
2.	Plant Factor (%)	78.41
3.	Running Plant Capacity Factor (%)	83.09
4.	15 Minute Gross Maximum Demand (kW)	490,933
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	1,393,795.38		
2.	Fuel, Coal	501.1	66,619,186.68		2.42
3.	Fuel, Oil	501.2	2,265.59		
4.	Fuel, Gas	501.3	214,500.36		3.07
5.	Fuel, Other	501.4			
6.	**Fuel Sub Total (2 thru 5)**	501	66,835,952.63	26.46	2.42
7.	Steam Expenses	502	4,686,207.57		
8.	Electric Expenses	505	1,718,688.22		
9.	Miscellaneous Steam Power Expenses	506	1,712,731.88		
10.	Allowances	509	32,655.91		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub Total (1 + 7 thru 11)**		9,544,078.96	3.78	
13.	**Operation Expense (6 + 12)**		76,380,031.59	30.24	
14.	Maintenance, Supervision and Engineering	510	1,263,481.53		
15.	Maintenance of Structures	511	1,039,597.85		
16.	Maintenance of Boiler Plant	512	5,600,414.66		
17.	Maintenance of Electric Plant	513	978,425.29		
18.	Maintenance of Miscellaneous Plant	514	1,219,655.92		
19.	**Maintenance Expense (14 thru 18)**		10,101,575.25	4.00	
20.	**Total Production Expense (13 + 19)**		86,481,606.84	34.24	
21.	Depreciation	403.1	4,608,874.20		
22.	Interest	427	5,816,554.82		
23.	**Total Fixed Cost (21 + 22)**		10,425,429.02	4.13	
24.	**Power Cost (20 + 23)**		96,907,035.86	38.37	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION	KY0062
PLANT	REID
PERIOD ENDED	Oct-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

			FUEL CONSUMPTION					OPERATING HOURS			
										OUT OF SERVICE	
NO.	UNIT NO. (a)	TIMES STARTED (b)	COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	IN SERVICE (h)	ON STANDBY (i)	Scheduled (j)	Unsched (k)
1.	1	6	28,599.6	34.405	.0			571.2	6,241.6	.0	506.2
2.											
3.											
4.											
5.											
6.	Total	6	28,599.6	34.405	.0			571.2	6,241.6	.0	506.2
7.	Average BTU		12,206	138,000	0						
8.	Total BTU(10^6)		349,087	4,748	0		353,835				
9.	Total Del..Cost ($)		872,499.36	109,808.76	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	72,000	29,068.000	
2.				
3.				
4.				
5.				
6.	Total	72,000	29,068.000	12,173
7.	Station Service (MWh)		16,754.000	
8.	Net Generation (MWh)		12,314.000	28,734
9.	Station Service (%)		57.64	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	17
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	6.87
2.	Plant Factor (%)	5.52
3.	Running Plant Capacity Factor (%)	70.68
4.	15 Minute Gross Maximum Demand (kW)	57,776
5	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	225,023.74		
2.	Fuel, Coal	501.1	1,107,585.37		3.17
3.	Fuel, Oil	501.2	109,808.76		23.13
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	Fuel Sub Total (2 thru 5)	501	1,217,394.13	98.86	3.44
7.	Steam Expenses	502	457,020.39		
8.	Electric Expenses	505	229,031.47		
9.	Miscellaneous Steam Power Expenses	506	180,706.05		
10.	Allowances	509	5,468.00		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		1,097,249.65	89.11	
13.	Operation Expense (6 + 12)		2,314,643.78	187.97	
14.	Maintenance, Supervision and Engineering	510	202,587.50		
15.	Maintenance of Structures	511	99,339.07		
16.	Maintenance of Boiler Plant	512	681,563.76		
17.	Maintenance of Electric Plant	513	193,445.24		
18.	Maintenance of Miscellaneous Plant	514	145,452.38		
19.	Maintenance Expense (14 thru 18)		1,322,387.95	107.39	
20.	Total Production Expense (13 + 19)		3,637,031.73	295.36	
21.	Depreciation	403.1	374,837.50		
22.	Interest	427	599,538.87		
23.	Total Fixed Cost (21 + 22)		974,376.37	79.13	
24.	Power Cost (20 + 23)		4,611,408.10	374.48	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION: KY0062
PLANT: GREEN
PERIOD ENDED: Oct-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	7	1,192,432.0	190.808	.0			6,607.5	598.2	.0	113.3
2.	2	8	953,062.7	212.376	.0			5,363.8	1,318.2	.0	637.0
3.											
4.											
5.											
6.	Total	15	2,145,494.7	403.184	.0			11,971.3	1,916.4	.0	750.3
7.	Average BTU		11,816	138,000	0						
8.	Total BTU(10^6)		25,351,165	55,639	0		25,406,805				
9.	Total Del..Cost ($)		53,917,406.03	1,270,158.68	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	250,000	1,431,822.760	
2.	2	242,000	1,120,020.100	
3.				
4.				
5.				
6.	Total	492,000	2,551,842.860	9,956
7.	Station Service (MWh)		249,879.974	
8.	Net Generation (MWh)		2,301,962.886	11,037
9.	Station Service (%)		9.79	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	113
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	69.85
2.	Plant Factor (%)	70.87
3.	Running Plant Capacity Factor (%)	86.51
4.	15 Minute Gross Maximum Demand (kW)	499,181
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	1,297,594.68		
2.	Fuel, Coal	501.1	56,018,609.63		2.21
3.	Fuel, Oil	501.2	1,270,158.68		22.83
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			
6.	Fuel Sub Total (2 thru 5)	501	57,288,768.31	24.89	2.25
7.	Steam Expenses	502	10,151,740.59		
8.	Electric Expenses	505	2,798,459.22		
9.	Miscellaneous Steam Power Expenses	506	1,140,152.00		
10.	Allowances	509	17,011.16		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		15,404,957.65	6.69	
13.	Operation Expense (6 + 12)		72,693,725.96	31.58	
14.	Maintenance, Supervision and Engineering	510	1,273,382.38		
15.	Maintenance of Structures	511	965,289.66		
16.	Maintenance of Boiler Plant	512	6,447,466.08		
17.	Maintenance of Electric Plant	513	926,796.99		
18.	Maintenance of Miscellaneous Plant	514	737,464.22		
19.	Maintenance Expense (14 thru 18)		10,350,399.33	4.50	
20.	Total Production Expense (13 + 19)		83,044,125.29	36.08	
21.	Depreciation	403.1	6,658,223.37		
22.	Interest	427	6,705,405.93		
23.	Total Fixed Cost (21 + 22)		13,363,629.30	5.81	
24.	Power Cost (20 + 23)		96,407,754.59	41.88	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION	KY0062
PLANT	WILSON
PERIOD ENDED	Oct-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

			FUEL CONSUMPTION					OPERATING HOURS			
NO.	UNIT NO. (a)	TIMES STARTED (b)	COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE Scheduled (j)	OUT OF SERVICE Unsched (k)
1.	1	10	2,249,233.3	369.650	.0			6,707.1	21.2	335.7	255.0
2.											
3.											
4.											
5.											
6.	Total	10	2,249,233.3	369.650	.0			6,707.1	21.2	335.7	255.0
7.	Average BTU		11,944	138,000	0						
8.	Total BTU(10^6)		26,864,843	51,012	0		26,915,855				
9.	Total Del..Cost ($)		54,572,853.42	1,154,714.70	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (1)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	440,000	2,734,830.860	
2.				
3.				
4.				
5.				
6.	Total	440,000	2,734,830.860	9,842
7.	Station Service (MWh)		184,869.361	
8.	Net Generation (MWh)		2,549,961.499	10,555
9.	Station Service (%)		6.76	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	106
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	80.89
2.	Plant Factor (%)	84.92
3.	Running Plant Capacity Factor (%)	92.67
4.	15 Minute Gross Maximum Demand (kW)	461,911
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	1,650,025.57		
2.	Fuel, Coal	501.1	57,131,075.81		2.13
3.	Fuel, Oil	501.2	1,154,714.70		22.64
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	**Fuel Sub-Total (2 thru 5)**	501	58,285,790.51	22.86	2.17
7.	Steam Expenses	502	8,353,798.69		
8.	Electric Expenses	505	1,080,842.84		
9.	Miscellaneous Steam Power Expenses	506	2,870,475.97		
10.	Allowances	509	41,538.27		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub-Total (1 + 7 thru 11)**		13,996,681.34	5.49	
13.	**Operation Expense (6 + 12)**		72,282,471.85	28.35	
14.	Maintenance, Supervision and Engineering	510	1,212,499.00		
15.	Maintenance of Structures	511	868,885.11		
16.	Maintenance of Boiler Plant	512	9,334,464.83		
17.	Maintenance of Electric Plant	513	710,703.50		
18.	Maintenance of Miscellaneous Plant	514	553,579.18		
19.	**Maintenance Expense (14 thru 18)**		12,680,131.62	4.97	
20.	**Total Production Expense (13 + 19)**		84,962,603.47	33.32	
21.	Depreciation	403.1	15,969,327.03		
22.	Interest	427	18,027,516.71		
23.	**Total Fixed Cost (21 + 22)**		33,996,843.74	13.33	
24.	**Power Cost (20 + 23)**		118,959,447.21	46.65	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART F IC - INTERNAL COMBUSTION PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION	KY0062
PLANT	REID
PERIOD ENDED	Oct-12

SECTION A. INTERNAL COMBUSTION GENERATING UNITS

			FUEL CONSUMPTION				OPERATING HOURS					
									OUT OF SERVICE			
NO.	UNIT NO. (a)	SIZE (kW) (b)	OIL (1000 Gals.) (c)	GAS (1000 C.F.) (d)	OTHER (e)	TOTAL (f)	IN SERVICE (g)	ON STANDBY (h)	Sche. (i)	Unsched (j)	GROSS GENERATION (MWh) (k)	BTU PER kWh (l)
1.	1	70,000	.000	124,926			235.4	7,020.0	.0	63.6	7,492.900	
2.												
3.												
4.												
5.												
6.	Total	70,000	.000	124,926			235.4	7,020.0	.0	63.6	7,492.900	16,673
7.	Average BTU		0	1,000			Station Service (MWh)				884.790	
8.	Total BTU(10^6)		0	124,926		124,926	Net Generation (MWh)				6,608.110	18,905
9.	Total Del..Cost ($)		0.00	375,701.25			Station Service % of Gross				11.81	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1	No. Employees Full-Time (inc. Superintendent)	0	5.	Maint. Plant Payroll ($)	
2.	No. Employees Part-Time		6.	Other Accounts. Plant Payroll ($)	
3.	Total Empl. - Hrs. Worked				
4.	Oper. Plant Payroll ($)		7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	1.60
2.	Plant Factor (%)	1.46
3.	Running Plant Capacity Factor (%)	45.47
4.	15 Minute Gross Maximum Demand (kW)	63,895
5.	Indicated Gross Maximum Demand kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	546	0.00		
2.	Fuel, Oil	547.1	0.00		
3.	Fuel, Gas	547.2	376,085.25		3.01
4.	Fuel, Other	547.3			
5.	Energy for Compressed Air	547.4			
6.	**Fuel Sub-Total** *(2 thru 5)*	547	376,085.25	56.91	3.01
7.	Generation Expenses	548	31,052.46		
8.	Miscellaneous Other Power Generation Expenses	549	0.00		
9.	Rents	550	0.00		
10.	**Non-Fuel Sub-Total** *(1 + 7 thru 9)*		31,052.46	4.70	
11.	**Operation Expense** *(6+ 10)*		407,137.71	61.61	
12.	Maintenance, Supervision and Engineering	551	0.00		
13.	Maintenance of Structures	552	0.00		
14.	Maintenance of Generating and Electric Plant	553	178,991.79		
15.	Maintenance of Miscellaneous Other Power Generating Plant	554	0.00		
16.	**Maintenance Expense** *(12 thru 15)*		178,991.79	27.09	
17.	**Total Production Expense** *(11 + 16)*		586,129.50	88.70	
18.	Depreciation	403.1,411.10	247,309.27		
19.	Interest	427	174,463.15		
20.	**Total Fixed Cost** *(18+ 19)*		421,772.42	63.83	
21.	**Power Cost** *(17 + 20)*		1,007,901.92	152.52	

REMARKS *(including Unscheduled Outages)*

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART I - LINES AND STATIONS

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Oct-12

INSTRUCTIONS - See help in the online application.

SECTION A. EXPENSE AND COSTS

ITEM	ACCOUNT NUMBER	LINES (a)	STATIONS (b)
Transmission Operation			
1. Supervision and Engineering	560	224,023.81	306,231.13
2. Load Dispatching	561	3,284,089.59	
3. Station Expenses	562		651,302.30
4. Overhead Line Expenses	563	855,136.32	
5. Underground Line Expenses	564	0.00	
6. Miscellaneous Expenses	566	220,535.06	351,050.39
7. **Subtotal *(1 thru 6)***		4,583,784.78	1,308,583.82
8. Transmission of Electricity by Others	565	2,353,238.07	
9. Rents	567	0.00	20,584.30
10. **Total Transmission Operation *(7 thru 9)***		6,937,022.65	1,329,168.12
Transmission Maintenance			
11. Supervision and Engineering	568	200,876.61	207,863.21
12. Structures	569		21,414.80
13. Station Equipment	570		1,403,503.48
14. Overhead Lines	571	1,608,845.47	
15. Underground Lines	572	0.00	
16. Miscellaneous Transmission Plant	573	227,865.93	397,378.98
17. **Total Transmission Maintenance *(11 thru 16)***		2,036,588.01	2,030,160.47
18. **Total Transmission Expense *(10 + 17)***		8,975,610.86	3,359,328.59
19. RTO/ISO Expense - Operation	575	1,854,300.95	
20. RTO/ISO Expense - Maintenance	576	0.00	
21. **Total RTO/ISO Expense *(19 + 20)***		1,854,300.95	
22. Distribution Expense - Operation	580-589	0.00	0.00
23. Distribution Expense - Maintenance	590-598	0.00	0.00
24. **Total Distribution Expense *(22 + 23)***		0.00	0.00
25. **Total Operation And Maintenance *(18 + 21 + 24)***		10,829,911.81	3,359,328.59
Fixed Costs			
26. Depreciation - Transmission	403.5	1,546,518.34	2,326,901.90
27. Depreciation - Distribution	403.6	0.00	0.00
28. Interest - Transmission	427	2,257,120.40	2,693,172.67
29. Interest - Distribution	427	0.00	0.00
30. **Total Transmission *(18 + 26 + 28)***		12,779,249.60	8,379,403.16
31. **Total Distribution *(24 + 27 + 29)***		0.00	0.00
32. **Total Lines And Stations *(21 + 30 + 31)***		14,633,550.55	8,379,403.16

SECTION B. FACILITIES IN SERVICE

TRANSMISSION LINES		SUBSTATIONS	
VOLTAGE (kV)	MILES	TYPE	CAPACITY (kVA)
1. 69 kV	833.20		
2. 345 kV	68.40	13. Distr. Lines	0
3. 138 kV	14.40		
4. 161 kV	349.60	14. Total *(12 + 13)*	1,265.60
5.			
6.		15. Step up at Generating Plants	1,879,800
7.			
8.			
9.		16. Transmission	3,540,000
10.			
11.		17. Distribution	0
12. Total *(1 thru 11)*	1,265.60	18. Total *(15 thru 17)*	5,419,800

SECTION C. LABOR AND MATERIAL SUMMARY

ITEM	LINES	STATIONS
1. Number of Employees		50
2. Oper. Labor	1,292,843.91	799,643.21
3. Maint. Labor	1,140,413.39	1,304,056.67
4. Oper. Material	7,498,479.89	529,524.91
5. Maint. Material	898,174.68	726,103.80

SECTION D. OUTAGES

1. Total	37,980.50
2. Avg. No. Dist. Cons. Served	112,887.00
3. Avg. No. Hours Out Per Cons.	0.34

RUS Form 12 – September 2012

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0572-0032. The time required to complete this information collection is estimated to average 21 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062
	PERIOD ENDED September-2012
INSTRUCTIONS - See help in the online application *This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C. 552).*	BORROWER NAME **Big Rivers Electric Corporation**

CERTIFICATION

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7 CFR CHAPTER XVII

(check one of the following)

X All of the obligations under the RUS loan documents have been fulfilled in all material respects.

__ There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part A Section C of this report.

Mark A. Bailey 10/19/12

SIGNATURE OF PRESIDENT AND CEO DATE

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART A - FINANCIAL

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Sep-12

INSTRUCTIONS - See help in the online application.

SECTION A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	YEAR-TO-DATE BUDGET (c)	THIS MONTH (d)
1. Electric Energy Revenues	422,320,923.10	419,182,737.04	454,928,509.00	46,263,638.90
2. Income From Leased Property (Net)	0.00	0.00	0.00	0.00
3. Other Operating Revenue and Income	2,167,762.77	3,858,977.27	3,009,753.00	351,245.81
4. **Total Operation Revenues & Patronage Capital** *(1 thru 3)*	**424,488,685.87**	**423,041,714.31**	**457,938,262.00**	**46,614,884.71**
5. Operating Expense - Production - Excluding Fuel	37,000,721.75	36,392,454.24	41,510,560.00	4,038,049.95
6. Operating Expense - Production - Fuel	173,106,985.46	165,833,411.78	181,106,198.00	18,170,079.56
7. Operating Expense - Other Power Supply	83,178,821.74	84,280,777.08	90,265,834.00	8,973,386.39
8. Operating Expense - Transmission	6,919,691.09	7,363,167.53	8,092,840.00	625,547.93
9. Operating Expense - RTO/ISO	1,832,483.01	1,662,990.30	1,872,825.00	170,181.42
10. Operating Expense - Distribution	0.00	0.00	0.00	0.00
11. Operating Expense - Customer Accounts	0.00	0.00	0.00	0.00
12. Operating Expense - Customer Service & Information	344,618.55	391,092.45	551,368.00	60,673.76
13. Operating Expense - Sales	129,850.48	102,014.94	871,298.00	4,906.25
14. Operating Expense - Administrative & General	19,979,650.48	20,377,862.93	19,871,127.00	2,107,485.34
15. **Total Operation Expense** *(5 thru 14)*	**322,492,822.56**	**316,403,771.25**	**344,142,050.00**	**34,150,310.60**
16. Maintenance Expense - Production	29,181,571.13	30,872,277.89	45,097,378.00	2,999,837.88
17. Maintenance Expense - Transmission	3,347,673.93	3,735,560.70	2,994,692.00	337,995.46
18. Maintenance Expense - RTO/ISO	0.00	0.00	0.00	0.00
19. Maintenance Expense - Distribution	0.00	0.00	0.00	0.00
20. Maintenance Expense - General Plant	93,378.73	128,155.81	78,080.00	17,232.01
21. **Total Maintenance Expense** *(16 thru 20)*	**32,622,623.79**	**34,735,994.40**	**48,170,150.00**	**3,355,065.35**
22. Depreciation and Amortization Expense	26,373,902.54	30,852,045.09	31,298,645.00	3,563,617.13
23. Taxes	128,389.00	4,060.88	885.00	0.00
24. Interest on Long-Term Debt	34,450,455.53	33,718,885.21	33,472,584.00	3,704,032.49
25. Interest Charged to Construction - Credit	<449,625.00>	<578,619.00>	<404,165.00>	<70,061.00>
26. Other Interest Expense	58,956.39	54,969.04	0.00	12.35
27. Asset Retirement Obligations	0.00	0.00	0.00	0.00
28. Other Deductions	158,454.44	186,948.13	288,512.00	23,588.38
29. **Total Cost Of Electric Service** *(15 + 21 thru 28)*	**415,835,979.25**	**415,378,055.00**	**456,968,661.00**	**44,726,565.30**
30. **Operating Margins** *(4 less 29)*	**8,652,706.62**	**7,663,659.31**	**969,601.00**	**1,888,319.41**
31. Interest Income	131,802.42	403,329.18	49,390.00	347,353.18
32. Allowance For Funds Used During Construction	0.00	0.00	0.00	0.00
33. Income (Loss) from Equity Investments	0.00	0.00	0.00	0.00
34. Other Non-operating Income (Net)	9,288.48	0.00	0.00	0.00
35. Generation & Transmission Capital Credits	0.00	0.00	0.00	0.00
36. Other Capital Credits and Patronage Dividends	104,653.04	58,674.04	33,000.00	0.00
37. Extraordinary Items	0.00	0.00	0.00	0.00
38. **Net Patronage Capital Or Margins** *(30 thru 37)*	**8,898,450.56**	**8,125,662.53**	**1,051,991.00**	**2,235,672.59**

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART A - FINANCIAL**	BORROWER DESIGNATION KY0062 PERIOD ENDED Sep-12
INSTRUCTIONS - See help in the online application.	

SECTION B. BALANCE SHEET

ASSETS AND OTHER DEBITS

1. Total Utility Plant in Service	1,997,624,468.12
2. Construction Work in Progress	44,936,428.33
3. Total Utility Plant *(1 + 2)*	**2,042,560,896.45**
4. Accum. Provision for Depreciation and Amort.	955,854,941.29
5. Net Utility Plant *(3 - 4)*	**1,086,705,955.16**
6. Non-Utility Property (Net)	0.00
7. Investments in Subsidiary Companies	0.00
8. Invest. in Assoc. Org. - Patronage Capital	3,680,691.11
9. Invest. in Assoc. Org. - Other - General Funds	43,840,793.00
10. Invest. in Assoc. Org. - Other - Nongeneral Funds	0.00
11. Investments in Economic Development Projects	10,000.00
12. Other Investments	5,333.85
13. Special Funds	184,966,321.11
14. Total Other Property And Investments *(6 thru 13)*	**232,503,139.07**
15. Cash - General Funds	5,487.70
16. Cash - Construction Funds - Trustee	0.00
17. Special Deposits	598,347.83
18. Temporary Investments	113,244,033.84
19. Notes Receivable (Net)	0.00
20. Accounts Receivable - Sales of Energy (Net)	42,902,258.24
21. Accounts Receivable - Other (Net)	1,221,298.17
22. Fuel Stock	32,352,421.05
23. Renewable Energy Credits	0.00
24. Materials and Supplies - Other	26,016,994.36
25. Prepayments	1,548,947.34
26. Other Current and Accrued Assets	712,273.32
27. Total Current And Accrued Assets *(15 thru 26)*	**218,602,061.85**
28. Unamortized Debt Discount & Extraor. Prop. Losses	3,982,616.10
29. Regulatory Assets	0.00
30. Other Deferred Debits	2,988,348.61
31. Accumulated Deferred Income Taxes	0.00
32. Total Assets And Other Debits *(5+14+27 thru 31)*	1,544,782,120.79

LIABILITIES AND OTHER CREDITS

33. Memberships	75.00
34. Patronage Capital a. Assigned and Assignable b. Retired This year c. Retired Prior years **d. Net Patronage Capital (a-b-c)**	0.00
35. Operating Margins - Prior Years	<241,898,352.19>
36. Operating Margin - Current Year	7,722,333.35
37. Non-Operating Margins	639,400,866.38
38. Other Margins and Equities	<7,278,744.80>
39. Total Margins & Equities *(33 + 34d thru 38)*	**397,946,177.74**
40. Long-Term Debt - RUS (Net)	208,478,774.65
41. Long-Term Debt - FFB - RUS Guaranteed	0.00
42. Long-Term Debt - Other - RUS Guaranteed	0.00
43. Long-Term Debt - Other (Net)	639,871,979.94
44. Long-Term Debt - RUS - Econ. Devel. (Net)	0.00
45. Payments - Unapplied	0.00
46. Total Long-Term Debit *(40 thru 44-45)*	**848,350,754.59**
47. Obligations Under Capital Leases - Noncurrent	0.00
48. Accumulated Operating Provisions and Asset Retirement Obligations	25,211,763.08
49. Total Other NonCurrent Liabilities *(47 +48)*	**25,211,763.08**
50. Notes Payable	0.00
51. Accounts Payable	26,999,758.72
52. Current Maturities Long-Term Debt	80,607,799.06
53. Current Maturities Long-Term Debt - Rural Development	0.00
54. Current Maturities Capital Leases	0.00
55. Taxes Accrued	824,402.73
56. Interest Accrued	3,811,881.15
57. Other Current and Accrued Liabilities	8,292,111.08
58. Total Current & Accrued Liabilities *(50 thru 57)*	**120,535,952.74**
59. Deferred Credits	152,737,472.64
60. Accumulated Deferred Income Taxes	0.00
61. Total Liabilities and Other Credits *(39 + 46 + 49 + 58 thru 60)*	1,544,782,120.79

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD ENDED Sep-12
INSTRUCTIONS - See help in the online application.	

Part B SE - Sales of Electricity

Sale No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Fuel Type (e)	Average Monthly Billing Demand (MW) (f)	Actual Average Monthly NCP Demand (g)	Actual Average Monthly CP Demand (h)
	Ultimate Consumer(s)							
	Distribution Borrowers							
1	Jackson Purchase Energy Corp	KY0020	RQ			130	143	112
2	Kenergy Corporation	KY0065	IF					
3	Kenergy Corporation	KY0065	LF					
4	Kenergy Corporation	KY0065	RQ			368	383	362
5	Meade County Rural ECC	KY0018	RQ			88	98	77
	G&T Borrowers							
6	PowerSouth Energy Coop	AL0042	OS					
	Others							
7	ADM Investor Services		OS					
8	Henderson Muncipal Power & Light		OS					
9	Louisville Gas & Electric		OS					
10	Midwest Independent Trans. Sys. Op.		OS					
11	PJM Interconnection		OS					
12								

	(f)	(g)	(h)
Total for Ultimate Consumer(s)	0	0	0
Total for Distribution Borrowers	586	624	551
Total for G&T Borrowers	0	0	0
Total for Others	0	0	0
Grand Total	586	624	551

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD ENDED Sep-12
INSTRUCTIONS - See help in the online application.	

Part B SE - Sales of Electricity

Sale No.	Electricity Sold (MWh) (i)	Revenue Demand Charges (j)	Revenue Energy Charges (k)	Revenue Other Charges (l)	Revenue Total (j + k + l) (m)
1	514,730.389	11,134,557.00	15,135,058.79		26,269,615.79
2	153,240.877		4,691,257.60		4,691,257.60
3	5,552,923.111		269,914,026.81		269,914,026.81
4	1,635,850.187	33,069,338.59	44,365,135.24		77,434,473.83
5	349,703.530	7,522,784.00	10,276,218.58		17,799,002.58
6	460.000		17,325.40		17,325.40
7			<24,460.00>		<24,460.00>
8	16,240.176		457,677.04		457,677.04
9	180.000		6,960.60		6,960.60
10	801,768.500		22,620,900.97		22,620,900.97
11			<4,043.58>		<4,043.58>
12			0.00		
	0	0	0	0	0
	8,206,448.094	51,726,679.59	344,381,697.02	0.00	396,108,376.61
	460.000	0.00	17,325.40	0.00	17,325.40
	818,188.676	0.00	23,057,035.03	0.00	23,057,035.03
	9,025,096.770	51,726,679.59	367,456,057.45	0.00	419,182,737.04

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE	BORROWER DESIGNATION KY0062
FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	PERIOD NAME Sep-12
INSTRUCTIONS - See help in the online application.	

PART B PP - Purchased Power

Purchase No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Energy Type (e)	Average Monthly Billing Demand (MW) (f)	Average Monthly NCP Demand (g)	Average Monthly CP Demand (h)
	Distribution Borrowers							
	G&T Borrowers							
	Others							
1	Cargill Power Markets		OS					
2	Henderson Municipal Power & Light		RQ					
3	Louisville Gas & Electric		OS					
4	Midwest Independent Trans. Sys. Op.		OS					
5	Southeastern Power Admin.		LF					
6								
Total for Distribution Borrowers						0	0	0
Total for G&T Borrowers						0	0	0
Total for Others						0	0	0
Grand Total						0	0	0

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY

BORROWER DESIGNATION
KY0062

PERIOD NAME
Sep-12

INSTRUCTIONS - See help in the online application.

PART B PP - Purchased Power

Purchase No.	Electricity Purchased (MWh) (i)	Electricity Received (MWh) (j)	Electricity Delivered (MWh) (k)	Demand Charges (l)	Energy Charges (m)	Other Charges (n)	Total (l + m + n) (o)
1	36,000.000				993,600.00		993,600.00
2	1,005,308.550				46,675,410.99		46,675,410.99
3	4,410.000				165,608.38		165,608.38
4	1,121,382.600				27,824,142.15		27,824,142.15
5	219,037.000				6,223,198.16		6,223,198.16
6					0.00		
	0.000				0.00		0.00
	0.000				0.00		0.00
	2,386,138.150				81,881,959.68		81,881,959.68
	2,386,138.150				**81,881,959.68**		**81,881,959.68**

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART C - SOURCES AND DISTRIBUTION OF ENERGY	BORROWER DESIGNATION KY0062 PERIOD ENDED Sep-12
INSTRUCTIONS - See help in the online application.	

SOURCES OF ENERGY (a)	NO. OF PLANTS (b)	CAPACITY (kW) (c)	NET ENERGY RECEIVED BY SYSTEM (MWh) (d)	COST ($) (e)
Generated in Own Plant *(Details on Parts D and F IC)*				
1. Fossil Steam	4	1,489,000	6,678,497.238	285,463,372.80
2. Nuclear				
3. Hydro				
4. Combined Cycle				
5. Internal Combustion	1	70,000	5,702.200	892,156.97
6. Other				
7. Total in Own Plant *(1 thru 6)*	5	1,559,000	6,684,199.438	286,355,529.77
Purchased Power				
8. Total Purchased Power			2,386,138.150	81,881,959.68
Interchanged Power				
9. Received Into System (Gross)			1,692,308.000	
10. Delivered Out of System (Gross)			1,571,453.000	
11. Net Interchange *(9 minus 10)*			120,855.000	
Transmission For or By Others - (Wheeling)				
12. Received Into System			0.000	
13. Delivered Out of System			0.000	
14. Net Energy Wheeled *(12 minus 13)*			0.000	
15. Total Energy Available for Sale (7 + 8 + 11 + 14)			9,191,192.588	
Distribution of Energy				
16. Total Sales			9,025,096.770	
17. Energy Furnished to Others Without Charge				
18. Energy Used by Borrower *(Excluding Station Use)*				
19. Total Energy Accounted For *(16 thru 18)*			9,025,096.770	
Losses				
20. Energy Losses - MWh *(15 minus 19)*			166,095.818	
21. Energy Losses - Percentage ((20 divided by 15) * 100)			1.81 %	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART D - STEAM PLANT

BORROWER DESIGNATION
KY0062
PLANT
COLEMAN
PERIOD ENDED
Sep-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	10	666,861.2	0.000	21,652.9			5,897.5	138.9	0.0	538.6
2.	2	4	731,260.5	0.000	15,416.4			6,324.9	63.3	0.0	186.8
3.	3	4	776,892.4	0.000	26,922.5			6,432.5	0.0	0.0	142.5
4.											
5.											
6.	Total	18	2,175,014.1	0.000	63,991.8			18,654.9	202.2	0.0	867.9
7.	Average BTU		11,334	0	1,000						
8.	Total BTU(10^6)		24,651,610	0	63,992		24,715,602				
9.	Total Del.Cost ($)		56,946,836.75	2,265.59	192,007.66						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	160,000	761,479.000	
2.	2	160,000	834,856.000	
3.	3	165,000	895,421.000	
4.				
5.				
6.	Total	485,000	2,491,756.000	9,919
7.	Station Service (MWh)		230,551.180	
8.	Net Generation (MWh)		2,261,204.820	10,930
9.	Station Service (%)		9.25	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	110
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	77.36
2.	Plant Factor (%)	78.14
3.	Running Plant Capacity Factor (%)	82.59
4.	15 Minute Gross Maximum Demand (kW)	489,901
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	1,259,758.67		
2.	Fuel, Coal	501.1	59,468,482.82		2.41
3.	Fuel, Oil	501.2	2,265.59		
4.	Fuel, Gas	501.3	192,007.66		3.00
5.	Fuel, Other	501.4			
6.	Fuel Sub Total (2 thru 5)	501	59,662,756.07	26.39	2.41
7.	Steam Expenses	502	4,246,299.36		
8.	Electric Expenses	505	1,544,855.71		
9.	Miscellaneous Steam Power Expenses	506	1,549,660.18		
10.	Allowances	509	30,789.72		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		8,631,363.64	3.82	
13.	Operation Expense (6 + 12)		68,294,119.71	30.20	
14.	Maintenance, Supervision and Engineering	510	1,125,456.96		
15.	Maintenance of Structures	511	928,319.93		
16.	Maintenance of Boiler Plant	512	5,228,615.17		
17.	Maintenance of Electric Plant	513	914,521.18		
18.	Maintenance of Miscellaneous Plant	514	1,124,443.28		
19.	Maintenance Expense (14 thru 18)		9,321,356.52	4.12	
20.	Total Production Expense (13 + 19)		77,615,476.23	34.32	
21.	Depreciation	403.1	4,149,054.21		
22.	Interest	427	5,227,759.52		
23.	Total Fixed Cost (21 + 22)		9,376,813.73	4.15	
24.	Power Cost (20 + 23)		86,992,289.96	38.47	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062
PLANT
REID
PERIOD ENDED
Sep-12

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	6	28,599.6	34.404	.0			571.2	5,497.6	.0	506.2
2.											
3.											
4.											
5.											
6.	Total	6	28,599.6	34.404	.0			571.2	5,497.6	.0	506.2
7.	Average BTU		12,206	138,000	0						
8.	Total BTU(10^6)		349,087	4,748	0		353,835				
9.	Total Del..Cost ($)		872,499.36	109,808.76	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (1)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	72,000	29,068.000	
2.				
3.				
4.				
5.				
6.	Total	72,000	29,068.000	12,173
7.	Station Service (MWh)		15,231.000	
8.	Net Generation (MWh)		13,837.000	25,572
9.	Station Service (%)		52.40	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	17
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	7.65
2.	Plant Factor (%)	6.14
3.	Running Plant Capacity Factor (%)	70.68
4.	15 Minute Gross Maximum Demand (kW)	57,776
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	203,202.90		
2.	Fuel, Coal	501.1	1,071,567.57		3.07
3.	Fuel, Oil	501.2	109,808.76		23.13
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	Fuel Sub Total (2 thru 5)	501	1,181,376.33	85.38	3.34
7.	Steam Expenses	502	415,540.04		
8.	Electric Expenses	505	204,992.91		
9.	Miscellaneous Steam Power Expenses	506	164,173.91		
10.	Allowances	509	5,464.63		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		993,374.39	71.79	
13.	Operation Expense (6 + 12)		2,174,750.72	157.17	
14.	Maintenance, Supervision and Engineering	510	179,617.57		
15.	Maintenance of Structures	511	86,014.54		
16.	Maintenance of Boiler Plant	512	658,265.76		
17.	Maintenance of Electric Plant	513	193,637.06		
18.	Maintenance of Miscellaneous Plant	514	134,598.78		
19.	Maintenance Expense (14 thru 18)		1,252,133.71	90.49	
20.	Total Production Expense (13 + 19)		3,426,884.43	247.66	
21.	Depreciation	403.1	342,063.55		
22.	Interest	427	539,080.63		
23.	Total Fixed Cost (21 + 22)		881,144.18	63.68	
24.	Power Cost (20 + 23)		4,308,028.61	311.34	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062
PLANT
GREEN
PERIOD ENDED
Sep-12

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	6	1,060,203.0	166.513	.0			5,922.9	598.2	.0	53.9
2.	2	7	913,768.8	184.685	.0			5,147.5	1,318.2	.0	109.3
3.											
4.											
5.											
6.	Total	13	1,973,971.8	351.198	.0			11,070.4	1,916.4	.0	163.2
7.	Average BTU		11,815	138,000	0						
8.	Total BTU(10^6)		23,322,477	48,465	0		23,370,942				
9.	Total Del..Cost ($)		49,367,132.48	1,107,478.72	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	250,000	1,272,978.850	
2.	2	242,000	1,072,430.200	
3.				
4.				
5.				
6.	Total	492,000	2,345,409.050	9,965
7.	Station Service (MWh)		230,229.002	
8.	Net Generation (MWh)		2,115,180.048	11,049
9.	Station Service (%)		9.82	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	113
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	71.46
2.	Plant Factor (%)	72.50
3.	Running Plant Capacity Factor (%)	86.03
4.	15 Minute Gross Maximum Demand (kW)	499,181
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10⁶ BTU (c)
1.	Operation, Supervision and Engineering	500	1,164,161.32		
2.	Fuel, Coal	501.1	51,221,538.89		2.20
3.	Fuel, Oil	501.2	1,107,478.72		22.85
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			
6.	Fuel Sub Total (2 thru 5)	501	52,329,017.61	24.74	2.24
7.	Steam Expenses	502	9,239,652.82		
8.	Electric Expenses	505	2,483,753.71		
9.	Miscellaneous Steam Power Expenses	506	1,047,464.45		
10.	Allowances	509	15,506.89		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		13,950,539.19	6.60	
13.	Operation Expense (6 + 12)		66,279,556.80	31.34	
14.	Maintenance, Supervision and Engineering	510	1,111,241.54		
15.	Maintenance of Structures	511	869,993.65		
16.	Maintenance of Boiler Plant	512	5,602,688.61		
17.	Maintenance of Electric Plant	513	697,263.08		
18.	Maintenance of Miscellaneous Plant	514	667,683.13		
19.	Maintenance Expense (14 thru 18)		8,948,870.01	4.23	
20.	Total Production Expense (13 + 19)		75,228,426.81	35.57	
21.	Depreciation	403.1	6,001,922.37		
22.	Interest	427	6,030,344.22		
23.	Total Fixed Cost (21 + 22)		12,032,266.59	5.69	
24.	Power Cost (20 + 23)		87,260,693.40	41.25	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION	KY0062
PLANT	WILSON
PERIOD ENDED	Sep-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	8	2,018,026.7	310.500	.0			6,040.3	21.2	335.7	177.8
2.											
3.											
4.											
5.											
6.	Total	8	2,018,026.7	310.500	.0			6,040.3	21.2	335.7	177.8
7.	Average BTU		11,948	138,000	0						
8.	Total BTU(10^6)		24,111,383	42,849	0		24,154,232				
9.	Total Del..Cost ($)		49,126,992.33	967,907.82	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	440,000	2,454,224.090	
2.				
3.				
4.				
5.				
6.	Total	440,000	2,454,224.090	9,842
7.	Station Service (MWh)		165,948.720	
8.	Net Generation (MWh)		2,288,275.370	10,556
9.	Station Service (%)		6.76	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	110
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	80.81
2.	Plant Factor (%)	84.83
3.	Running Plant Capacity Factor (%)	92.34
4.	15 Minute Gross Maximum Demand (kW)	461,911
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	1,486,212.43		
2.	Fuel, Coal	501.1	51,373,596.51		
3.	Fuel, Oil	501.2	967,907.82		2.13
4.	Fuel, Gas	501.3	0.00		22.59
5.	Fuel, Other	501.4			0
6.	**Fuel Sub-Total (2 thru 5)**	501	52,341,504.33	22.87	0
7.	Steam Expenses	502	7,702,817.54		2.17
8.	Electric Expenses	505	976,801.78		
9.	Miscellaneous Steam Power Expenses	506	2,586,167.70		
10.	Allowances	509	36,926.36		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub-Total (1 + 7 thru 11)**		12,788,925.81	5.59	
13.	**Operation Expense (6 + 12)**		65,130,430.14	28.46	
14.	Maintenance, Supervision and Engineering	510	1,086,956.27		
15.	Maintenance of Structures	511	784,538.23		
16.	Maintenance of Boiler Plant	512	8,161,056.72		
17.	Maintenance of Electric Plant	513	645,782.60		
18.	Maintenance of Miscellaneous Plant	514	506,489.58		
19.	**Maintenance Expense (14 thru 18)**		11,184,823.40	4.89	
20.	**Total Production Expense (13 + 19)**		76,315,253.54	33.35	
21.	Depreciation	403.1	14,374,281.37		
22.	Interest	427	16,212,825.92		
23.	**Total Fixed Cost (21 + 22)**		30,587,107.29	13.37	
24.	**Power Cost (20 + 23)**		106,902,360.83	46.72	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART F IC - INTERNAL COMBUSTION PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION: KY0062
PLANT: REID
PERIOD ENDED: Sep-12

SECTION A. INTERNAL COMBUSTION GENERATING UNITS

NO.	UNIT NO. (a)	SIZE (kW) (b)	FUEL CONSUMPTION: OIL (1000 Gals.) (c)	GAS (1000 C.F.) (d)	OTHER (e)	TOTAL (f)	OPERATING HOURS: IN SERVICE (g)	ON STANDBY (h)	OUT OF SERVICE: Sche. (i)	Unsched (j)	GROSS GENERATION (MWh) (k)	BTU PER kWh (1)
1.	1	70,000	.000	106,377			214.8	6,302.3	.0	57.9	6,495.790	
2.												
3.												
4.												
5.												
6.	Total	70,000	.000	106,377			214.8	6,302.3	.0	57.9	6,495.790	16,376
7.	Average BTU		0	1,000			Station Service (MWh)				793.590	
8.	Total BTU(10^6)		0	106,377		106,377	Net Generation (MWh)				5,702.200	18,655
9.	Total Del..Cost ($)		0.00	318,433.44			Station Service % of Gross				12.22	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	0	5.	Maint. Plant Payroll ($)	
2.	No. Employees Part-Time				
3.	Total Empl. - Hrs. Worked		6.	Other Accounts. Plant Payroll ($)	
4.	Oper. Plant Payroll ($)		7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	1.55
2.	Plant Factor (%)	1.41
3.	Running Plant Capacity Factor (%)	43.20
4.	15 Minute Gross Maximum Demand (kW)	63,895
5.	Indicated Gross Maximum Demand kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	546	0.00		
2.	Fuel, Oil	547.1	0.00		
3.	Fuel, Gas	547.2	318,757.44		3.00
4.	Fuel, Other	547.3			
5.	Energy for Compressed Air	547.4			
6.	**Fuel Sub-Total *(2 thru 5)***	547	318,757.44	55.90	3.00
7.	Generation Expenses	548	28,251.21		
8.	Miscellaneous Other Power Generation Expenses	549	0.00		
9.	Rents	550	0.00		
10.	**Non-Fuel Sub-Total *(1 + 7 thru 9)***		28,251.21	4.95	
11.	**Operation Expense *(6+ 10)***		347,008.65	60.86	
12.	Maintenance, Supervision and Engineering	551	0.00		
13.	Maintenance of Structures	552	0.00		
14.	Maintenance of Generating and Electric Plant	553	165,094.25		
15.	Maintenance of Miscellaneous Other Power Generating Plant	554	0.00		
16.	**Maintenance Expense *(12 thru 15)***		165,094.25	28.95	
17.	**Total Production Expense *(11 + 16)***		512,102.90	89.81	
18.	Depreciation	403.1,411.10	223,167.44		
19.	Interest	427	156,886.63		
20.	**Total Fixed Cost *(18+ 19)***		380,054.07	66.65	
21.	**Power Cost *(17 + 20)***		892,156.97	156.46	

REMARKS *(including Unscheduled Outages)*

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART I - LINES AND STATIONS

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Sep-12

SECTION A. EXPENSE AND COSTS

ITEM	ACCOUNT NUMBER	LINES (a)	STATIONS (b)
Transmission Operation			
1. Supervision and Engineering	560	201,878.54	279,130.98
2. Load Dispatching	561	2,922,092.91	
3. Station Expenses	562		586,169.54
4. Overhead Line Expenses	563	788,988.90	
5. Underground Line Expenses	564	0.00	
6. Miscellaneous Expenses	566	176,334.66	297,083.86
7. **Subtotal *(1 thru 6)***		4,088,295.01	1,162,384.40
8. Transmission of Electricity by Others	565	2,093,962.25	
9. Rents	567	0.00	18,525.87
10. **Total Transmission Operation *(7 thru 9)***		6,182,257.26	1,180,910.27
Transmission Maintenance			
11. Supervision and Engineering	568	179,752.55	188,878.51
12. Structures	569		6,864.80
13. Station Equipment	570		1,268,925.86
14. Overhead Lines	571	1,524,821.70	
15. Underground Lines	572	0.00	
16. Miscellaneous Transmission Plant	573	211,352.32	354,984.96
17. **Total Transmission Maintenance *(11 thru 16)***		1,915,926.57	1,819,634.13
18. **Total Transmission Expense *(10 + 17)***		8,098,183.83	3,000,544.40
19. RTO/ISO Expense - Operation	575	1,662,990.30	
20. RTO/ISO Expense - Maintenance	576	0.00	
21. **Total RTO/ISO Expense *(19 + 20)***		1,662,990.30	
22. Distribution Expense - Operation	580-589	0.00	0.00
23. Distribution Expense - Maintenance	590-598	0.00	0.00
24. **Total Distribution Expense *(22 + 23)***		0.00	0.00
25. **Total Operation And Maintenance *(18 + 21 + 24)***		9,761,174.13	3,000,544.40
Fixed Costs			
26. Depreciation - Transmission	403.5	1,399,251.61	2,091,818.45
27. Depreciation - Distribution	403.6	0.00	0.00
28. Interest - Transmission	427	2,014,137.84	2,433,805.47
29. Interest - Distribution	427	0.00	0.00
30. **Total Transmission *(18 + 26 + 28)***		11,511,573.28	7,526,168.32
31. **Total Distribution *(24 + 27 + 29)***		0.00	0.00
32. **Total Lines And Stations *(21 + 30 + 31)***		13,174,563.58	7,526,168.32

SECTION B. FACILITIES IN SERVICE

TRANSMISSION LINES		SUBSTATIONS	
VOLTAGE (kV)	MILES	TYPE	CAPACITY (kVA)
1.69 kV	833.20	13. Distr. Lines	0
2.345 kV	68.40		
3 138 kV	14.40	14. Total *(12 + 13)*	1,265.60
4.161 kV	349.60		
5.		15. Step up at Generating Plants	1,879,800
6.			
7.		16. Transmission	3,540,000
8.			
9.		17. Distribution	0
10.			
11.			
12. Total *(1 thru 11)*	1,265.60	18. Total *(15 thru 17)*	5,419,800

SECTION C. LABOR AND MATERIAL SUMMARY

ITEM	LINES	STATIONS
1. Number of Employees		53
2. Oper. Labor	1,164,186.52	727,475.22
3. Maint. Labor	1,044,805.60	1,182,871.53
4. Oper Material	6,681,061.04	453,435.05
5. Maint. Material	871,120.97	836,762.60

SECTION D. OUTAGES

1. Total	34,105.70
2. Avg. No. Dist Cons. Served	112,887.00
3. Avg. No. Hours Out Per Cons.	0.30

RUS Form 12 – August 2012

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT** **ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD ENDED August -2012
INSTRUCTIONS - See help in the online application *This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C. 552).*	BORROWER NAME **Big Rivers Electric Corporation**

CERTIFICATION

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7 CFR CHAPTER XVII

(check one of the following)

X All of the obligations under the RUS loan documents have been fulfilled in all material respects.

__ There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part A Section C of this report.

Mark A. Bailey 9/24/12

SIGNATURE OF PRESIDENT AND CEO DATE

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART A - FINANCIAL**	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED Aug-12

SECTION A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	YEAR-TO-DATE BUDGET (c)	THIS MONTH (d)
1. Electric Energy Revenues	373,264,263.06	372,919,098.14	407,418,123.00	48,521,047.54
2. Income From Leased Property (Net)	0.00	0.00	0.00	0.00
3. Other Operating Revenue and Income	1,892,855.84	3,507,731.46	2,675,836.00	532,311.77
4. **Total Operation Revenues & Patronage Capital** *(1 thru 3)*	**375,157,118.90**	**376,426,829.60**	**410,093,959.00**	**49,053,359.31**
5. Operating Expense - Production - Excluding Fuel	32,715,959.58	32,354,404.29	36,969,770.00	4,332,271.95
6. Operating Expense - Production - Fuel	154,981,335.57	147,663,332.22	161,742,748.00	19,182,585.00
7. Operating Expense - Other Power Supply	73,990,115.79	75,307,390.69	81,776,230.00	8,464,719.70
8. Operating Expense - Transmission	6,173,952.24	6,737,619.60	7,244,273.00	805,197.37
9. Operating Expense - RTO/ISO	1,639,985.78	1,492,808.88	1,683,941.00	129,231.53
10. Operating Expense - Distribution	0.00	0.00	0.00	0.00
11. Operating Expense - Customer Accounts	0.00	0.00	0.00	0.00
12. Operating Expense - Customer Service & Information	305,891.34	330,418.69	495,461.00	41,074.15
13. Operating Expense - Sales	91,863.04	97,108.69	696,668.00	71,609.71
14. Operating Expense - Administrative & General	17,541,926.58	18,270,377.59	17,963,239.00	2,473,766.46
15. **Total Operation Expense** *(5 thru 14)*	**287,441,029.92**	**282,253,460.65**	**308,572,330.00**	**35,500,455.87**
16. Maintenance Expense - Production	25,354,797.11	27,872,440.01	41,541,131.00	4,096,943.23
17. Maintenance Expense - Transmission	2,853,768.11	3,397,565.24	2,697,073.00	613,514.13
18. Maintenance Expense - RTO/ISO	0.00	0.00	0.00	0.00
19. Maintenance Expense - Distribution	0.00	0.00	0.00	0.00
20. Maintenance Expense - General Plant	85,026.68	110,923.80	70,290.00	16,668.30
21. **Total Maintenance Expense** *(16 thru 20)*	**28,293,591.90**	**31,380,929.05**	**44,308,494.00**	**4,727,125.66**
22. Depreciation and Amortization Expense	23,070,278.89	27,288,427.96	27,777,043.00	3,521,139.27
23. Taxes	128,389.00	4,060.88	885.00	0.00
24. Interest on Long-Term Debt	30,706,304.75	30,014,852.72	29,796,966.00	3,850,707.93
25. Interest Charged to Construction - Credit	<419,278.00>	<508,558.00>	<354,467.00>	<64,644.00>
26. Other Interest Expense	58,931.25	54,956.69	0.00	43,835.62
27. Asset Retirement Obligations	0.00	0.00	0.00	0.00
28. Other Deductions	144,748.13	163,359.75	246,331.00	25,405.38
29. **Total Cost Of Electric Service** *(15 + 21 thru 28)*	**369,423,995.84**	**370,651,489.70**	**410,347,582.00**	**47,604,025.73**
30. **Operating Margins** *(4 less 29)*	**5,733,123.06**	**5,775,339.90**	**<253,623.00>**	**1,449,333.58**
31. Interest Income	124,226.32	55,976.00	44,365.00	18,477.45
32. Allowance For Funds Used During Construction	0.00	0.00	0.00	0.00
33. Income (Loss) from Equity Investments	0.00	0.00	0.00	0.00
34. Other Non-operating Income (Net)	9,288.48	0.00	0.00	0.00
35. Generation & Transmission Capital Credits	0.00	0.00	0.00	0.00
36. Other Capital Credits and Patronage Dividends	96,795.44	58,674.04	33,000.00	13,799.40
37. Extraordinary Items	0.00	0.00	0.00	0.00
38. **Net Patronage Capital Or Margins** *(30 thru 37)*	**5,963,433.30**	**5,889,989.94**	**<176,258.00>**	**1,481,610.43**

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART A - FINANCIAL

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Aug-12

INSTRUCTIONS - See help in the online application.

SECTION B. BALANCE SHEET

ASSETS AND OTHER DEBITS	
1. Total Utility Plant in Service	1,985,784,265.59
2. Construction Work in Progress	56,509,725.15
3. Total Utility Plant *(1 + 2)*	**2,042,293,990.74**
4. Accum. Provision for Depreciation and Amort.	954,111,029.09
5. Net Utility Plant *(3 - 4)*	**1,088,182,961.65**
6. Non-Utility Property (Net)	0.00
7. Investments in Subsidiary Companies	0.00
8. Invest. in Assoc. Org. - Patronage Capital	3,680,691.11
9. Invest. in Assoc. Org. - Other - General Funds	43,840,793.00
10. Invest. in Assoc. Org. - Other - Nongeneral Funds	0.00
11. Investments in Economic Development Projects	10,000.00
12. Other Investments	5,333.85
13. Special Funds	186,796,621.07
14. Total Other Property And Investments *(6 thru 13)*	**234,333,439.03**
15. Cash - General Funds	5,770.55
16. Cash - Construction Funds - Trustee	0.00
17. Special Deposits	598,308.29
18. Temporary Investments	107,521,746.13
19. Notes Receivable (Net)	0.00
20. Accounts Receivable - Sales of Energy (Net)	43,961,766.22
21. Accounts Receivable - Other (Net)	1,264,040.87
22. Fuel Stock	31,513,504.21
23. Renewable Energy Credits	0.00
24. Materials and Supplies - Other	26,465,194.02
25. Prepayments	1,847,646.36
26. Other Current and Accrued Assets	210,911.84
27. Total Current And Accrued Assets *(15 thru 26)*	**213,388,888.49**
28. Unamortized Debt Discount & Extraor. Prop. Losses	3,996,007.60
29. Regulatory Assets	0.00
30. Other Deferred Debits	2,939,363.06
31. Accumulated Deferred Income Taxes	0.00
32. Total Assets And Other Debits *(5+14+27 thru 31)*	**1,542,840,659.83**

LIABILITIES AND OTHER CREDITS	
33. Memberships	75.00
34. Patronage Capital a. Assigned and Assignable b. Retired This year c. Retired Prior years **d. Net Patronage Capital (a-b-c)**	0.00
35. Operating Margins - Prior Years	<241,898,352.19>
36. Operating Margin - Current Year	5,834,013.94
37. Non-Operating Margins	639,053,513.20
38. Other Margins and Equities	<7,278,744.80>
39. Total Margins & Equities *(33 + 34d thru 38)*	**395,710,505.15**
40. Long-Term Debt - RUS (Net)	206,633,152.41
41. Long-Term Debt - FFB - RUS Guaranteed	0.00
42. Long-Term Debt - Other - RUS Guaranteed	0.00
43. Long-Term Debt - Other (Net)	641,077,494.03
44. Long-Term Debt - RUS - Econ. Devel. (Net)	0.00
45. Payments - Unapplied	0.00
46. Total Long-Term Debit *(40 thru 44-45)*	**847,710,646.44**
47. Obligations Under Capital Leases - Noncurrent	0.00
48. Accumulated Operating Provisions and Asset Retirement Obligations	24,938,562.55
49. Total Other NonCurrent Liabilities *(47 +48)*	**24,938,562.55**
50. Notes Payable	0.00
51. Accounts Payable	26,797,358.38
52. Current Maturities Long-Term Debt	81,178,305.97
53. Current Maturities Long-Term Debt - Rural Development	0.00
54. Current Maturities Capital Leases	0.00
55. Taxes Accrued	796,215.69
56. Interest Accrued	3,864,638.64
57. Other Current and Accrued Liabilities	7,695,234.60
58. Total Current & Accrued Liabilities *(50 thru 57)*	**120,331,753.28**
59. Deferred Credits	154,149,192.41
60. Accumulated Deferred Income Taxes	0.00
61. Total Liabilities and Other Credits *(39 + 46 + 49 + 58 thru 60)*	**1,542,840,659.83**

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD ENDED Aug-12
INSTRUCTIONS - See help in the online application.	

Part B SE - Sales of Electricity

Sale No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Fuel Type (e)	Average Monthly Billing Demand (MW) (f)	Actual Average Monthly NCP Demand (g)	Actual Average Monthly CP Demand (h)
	Ultimate Consumer(s)							
	Distribution Borrowers							
1	Jackson Purchase Energy Corp	KY0020	RQ			130	142	128
2	Kenergy Corporation	KY0065	IF					
3	Kenergy Corporation	KY0065	LF					
4	Kenergy Corporation	KY0065	RQ			368	383	359
5	Meade County Rural ECC	KY0018	RQ			89	99	88
	G&T Borrowers							
6	PowerSouth Energy Coop	AL0042	OS					
	Others							
7	ADM Investor Services		OS					
8	Henderson Muncipal Power & Light		OS					
9	Louisville Gas & Electric		OS					
10	Midwest Independent Trans. Sys. Op.		OS					
11	PJM Interconnection		OS					
12								
Total for Ultimate Consumer(s)						0	0	0
Total for Distribution Borrowers						587	624	575
Total for G&T Borrowers						0	0	0
Total for Others						0	0	0
Grand Total						587	624	575

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD ENDED Aug-12
INSTRUCTIONS - See help in the online application.	

Part B SE - Sales of Electricity

Sale No.	Electricity Sold (MWh) (i)	Revenue Demand Charges (j)	Revenue Energy Charges (k)	Revenue Other Charges (l)	Revenue Total (j + k + l) (m)
1	464,618.229	9,871,269.50	13,655,255.86		23,526,525.36
2	128,185.298		3,850,971.73		3,850,971.73
3	4,950,179.274		240,390,986.54		240,390,986.54
4	1,469,922.225	29,384,359.16	39,860,126.69		69,244,485.85
5	317,593.070	6,744,164.00	9,326,230.62		16,070,394.62
6	460.000		17,325.40		17,325.40
7			<24,460.00>		<24,460.00>
8	16,240.176		457,677.04		457,677.04
9	180.000		6,960.60		6,960.60
10	692,821.100		19,382,153.20		19,382,153.20
11			<3,922.20>		<3,922.20>
12			0.00		
	0	0	0	0	0
	7,330,498.096	45,999,792.66	307,083,571.44	0.00	353,083,364.10
	460.000	0.00	17,325.40	0.00	17,325.40
	709,241.276	0.00	19,818,408.64	0.00	19,818,408.64
	8,040,199.372	45,999,792.66	326,919,305.48	0.00	372,919,098.14

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD NAME Aug-12
INSTRUCTIONS - See help in the online application.	

PART B PP - Purchased Power

Purchase No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Energy Type (e)	Average Monthly Billing Demand (MW) (f)	Average Monthly NCP Demand (g)	Average Monthly CP Demand (h)
	Distribution Borrowers							
	G&T Borrowers							
	Others							
1	Cargill Power Markets		OS					
2	Henderson Municipal Power & Light		RQ					
3	Louisville Gas & Electric		OS					
4	Midwest Independent Trans. Sys. Op.		OS					
5	Southeastern Power Admin.		LF					
6								
Total for Distribution Borrowers						0	0	0
Total for G&T Borrowers						0	0	0
Total for Others						0	0	0
Grand Total						0	0	0

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD NAME Aug-12
INSTRUCTIONS - See help in the online application.	

PART B PP - Purchased Power

Purchase No.	Electricity Purchased (MWh) (i)	Electricity Received (MWh) (j)	Electricity Delivered (MWh) (k)	Demand Charges (l)	Energy Charges (m)	Other Charges (n)	Total (l + m + n) (o)
1	36,000.000				993,600.00		993,600.00
2	875,776.970				41,274,871.69		41,274,871.69
3	4,410.000				165,608.38		165,608.38
4	1,018,456.200				25,066,220.47		25,066,220.47
5	205,593.000				5,724,436.73		5,724,436.73
6					0.00		
	0.000				0.00		0.00
	0.000				0.00		0.00
	2,140,236.170				73,224,737.27		73,224,737.27
	2,140,236.170				**73,224,737.27**		**73,224,737.27**

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART C - SOURCES AND DISTRIBUTION OF ENERGY	BORROWER DESIGNATION KY0062 PERIOD ENDED Aug-12
INSTRUCTIONS - See help in the online application.	

SOURCES OF ENERGY (a)	NO. OF PLANTS (b)	CAPACITY (kW) (c)	NET ENERGY RECEIVED BY SYSTEM (MWh) (d)	COST ($) (e)
Generated in Own Plant *(Details on Parts D and F IC)*				
1. Fossil Steam	4	1,489.000	5,934,895.458	254,481,240.48
2. Nuclear				
3. Hydro				
4. Combined Cycle				
5. Internal Combustion	1	70.000	5,260 130	788,567.82
6. Other				
7. Total in Own Plant *(1 thru 6)*	5	1,559.000	5,940,155.588	255,269,808.30
Purchased Power				
8. Total Purchased Power			2,140,236.170	73,224,737.27
Interchanged Power				
9. Received Into System (Gross)			1,494,482.000	
10 Delivered Out of System (Gross)			1,384,650.000	
11. Net Interchange *(9 minus 10)*			109,832.000	
Transmission For or By Others - (Wheeling)				
12. Received Into System			0.000	
13. Delivered Out of System			0.000	
14. Net Energy Wheeled *(12 minus 13)*			0.000	
15. Total Energy Available for Sale (7 + 8 + 11 + 14)			8,190,223.758	
Distribution of Energy				
16. Total Sales			8,040,199.372	
17. Energy Furnished to Others Without Charge				
18. Energy Used by Borrower *(Excluding Station Use)*				
19. Total Energy Accounted For *(16 thru 18)*			8,040,199.372	
Losses				
20. Energy Losses - MWh *(15 minus 19)*			150,024.386	
21. Energy Losses - Percentage ((20 divided by 15) * 100)			1.83 %	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART D - STEAM PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062
PLANT
COLEMAN
PERIOD ENDED
Aug-12

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	7	601,349.9	0.000	17,704.5			5,343.8	103.1	0.0	408.1
2.	2	3	653,090.7	0.000	13,088.2			5,643.2	54.2	0.0	157.6
3.	3	4	693,213.8	0.000	24,243.6			5,712.5	0.0	0.0	142.5
4.											
5.											
6.	Total	14	1,947,654.4	0.000	55,036.3			16,699.5	157.3	0.0	708.2
7.	Average BTU		11,337	0	1,000						
8.	Total BTU(10^6)		22,080,558	0	55,036		22,135,594				
9.	Total Del.Cost ($)		50,977,610.14	2,265.59	156,040.50						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	160,000	687,804.000	
2.	2	160,000	746,140.000	
3.	3	165,000	798,228.000	
4.				
5.				
6.	Total	485,000	2,232,172.000	9,917
7.	Station Service (MWh)		205,300.180	
8.	Net Generation (MWh)		2,026,871.820	10,921
9.	Station Service (%)		9.20	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (inc. Superintendent)	111
2.	No. Employees Part-Time	
3.	**Total Empl. - Hrs. Worked**	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	**Total Plant Payroll ($)**	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	77.82
2.	Plant Factor (%)	78.61
3	Running Plant Capacity Factor (%)	82.66
4.	15 Minute Gross Maximum Demand (kW)	489,901
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	1,111,159.01		
2.	Fuel, Coal	501.1	53,286,522.14		2.41
3.	Fuel, Oil	501.2	2,265.59		
4.	Fuel, Gas	501.3	156,040.50		2.84
5.	Fuel, Other	501.4			
6.	**Fuel Sub Total (2 thru 5)**	501	53,444,828.23	26.37	2.41
7.	Steam Expenses	502	3,793,482.92		
8.	Electric Expenses	505	1,358,460.30		
9.	Miscellaneous Steam Power Expenses	506	1,392,151.84		
10.	Allowances	509	26,602.04		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub Total (1 + 7 thru 11)**		7,681,856.11	3.79	
13.	**Operation Expense (6 + 12)**		61,126,684.34	30.16	
14.	Maintenance, Supervision and Engineering	510	1,001,461.94		
15.	Maintenance of Structures	511	778,805.69		
16.	Maintenance of Boiler Plant	512	4,777,705.04		
17.	Maintenance of Electric Plant	513	797,590.97		
18.	Maintenance of Miscellaneous Plant	514	1,019,282.97		
19.	**Maintenance Expense (14 thru 18)**		8,374,846.61	4.13	
20.	**Total Production Expense (13 + 19)**		69,501,530.95	34.29	
21.	Depreciation	403.1	3,687,323.90		
22.	Interest	427	4,652,506.79		
23.	**Total Fixed Cost (21 + 22)**		8,339,830.69	4.11	
24.	**Power Cost (20 + 23)**		77,841,361.64	38.40	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION
KY0062
PLANT
REID
PERIOD ENDED
Aug-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	6	28,599.6	32.926	.0			571.2	4,777.6	.0	506.2
2.											
3.											
4.											
5.											
6.	Total	6	28,599.6	32.926	.0			571.2	4,777.6	.0	506.2
7.	Average BTU		12,206	138,000	0						
8.	Total BTU(10^6)		349,087	4,544	0		353,631				
9.	Total Del..Cost ($)		872,499.36	104,850.38	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	72,000	29,068.000	
2.				
3.				
4.				
5.				
6.	Total	72,000	29,068.000	12,166
7.	Station Service (MWh)		13,742.000	
8.	Net Generation (MWh)		15,326.000	23,074
9.	Station Service (%)		47.28	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	17
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	8.59
2.	Plant Factor (%)	6.90
3.	Running Plant Capacity Factor (%)	70.68
4.	15 Minute Gross Maximum Demand (kW)	57,776
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10⁶ BTU (c)
1.	Operation, Supervision and Engineering	500	179,394.39		
2.	Fuel, Coal	501.1	1,054,512.03		3.02
3.	Fuel, Oil	501.2	104,850.38		23.07
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	**Fuel Sub Total (2 thru 5)**	501	1,159,362.41	75.65	3.28
7.	Steam Expenses	502	368,885.12		
8.	Electric Expenses	505	183,113.83		
9.	Miscellaneous Steam Power Expenses	506	145,137.76		
10.	Allowances	509	5,460.50		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub Total (1 + 7 thru 11)**		881,991.60	57.55	
13.	**Operation Expense (6 + 12)**		2,041,354.01	133.20	
14.	Maintenance, Supervision and Engineering	510	162,609.79		
15.	Maintenance of Structures	511	72,245.09		
16.	Maintenance of Boiler Plant	512	599,745.26		
17.	Maintenance of Electric Plant	513	187,094.29		
18.	Maintenance of Miscellaneous Plant	514	110,613.42		
19.	**Maintenance Expense (14 thru 18)**		1,132,307.85	73.88	
20.	**Total Production Expense (13 + 19)**		3,173,661.86	207.08	
21.	Depreciation	403.1	304,213.58		
22.	Interest	427	480,027.10		
23.	**Total Fixed Cost (21 + 22)**		784,240.68	51.17	
24.	**Power Cost (20 + 23)**		3,957,902.54	258.25	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION: KY0062
PLANT: GREEN
PERIOD ENDED: Aug-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	5	929,423.6	157.382	.0			5,206.3	598.2	.0	50.5
2.	2	7	823,709.5	180.247	.0			4,642.3	1,151.4	.0	61.3
3.											
4.											
5.											
6.	Total	12	1,753,133.1	337.629	.0			9,848.6	1,749.6	.0	111.8
7.	Average BTU		11,800	138,000	0						
8.	Total BTU(10^6)		20,686,971	46,593	0		20,733,563				
9.	Total Del..Cost ($)		44,167,507.83	1,077,601.91	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	250,000	1,115,374.970	
2.	2	242,000	965,533.050	
3.				
4.				
5.				
6.	Total	492,000	2,080,908.020	9,964
7.	Station Service (MWh)		204,770.074	
8.	Net Generation (MWh)		1,876,137.946	11,051
9.	Station Service (%)		9.84	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	113
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	71.20
2.	Plant Factor (%)	72.24
3.	Running Plant Capacity Factor (%)	85.81
4.	15 Minute Gross Maximum Demand (kW)	499,181
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	1,039,931.53		
2.	Fuel, Coal	501.1	45,782,538.12		2.21
3.	Fuel, Oil	501.2	1,077,601.91		23.13
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			
6.	Fuel Sub Total (2 thru 5)	501	46,860,140.03	24.98	2.26
7.	Steam Expenses	502	8,208,831.48		
8.	Electric Expenses	505	2,155,862.34		
9.	Miscellaneous Steam Power Expenses	506	961,762.26		
10.	Allowances	509	13,782.16		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		12,380,169.77	6.60	
13.	Operation Expense (6 + 12)		59,240,309.80	31.58	
14.	Maintenance, Supervision and Engineering	510	989,476.10		
15.	Maintenance of Structures	511	786,064.12		
16.	Maintenance of Boiler Plant	512	5,004,998.14		
17.	Maintenance of Electric Plant	513	640,598.59		
18.	Maintenance of Miscellaneous Plant	514	564,795.06		
19.	Maintenance Expense (14 thru 18)		7,985,932.01	4.26	
20.	Total Production Expense (13 + 19)		67,226,241.81	35.83	
21.	Depreciation	403.1	5,342,275.56		
22.	Interest	427	5,368,874.87		
23.	Total Fixed Cost (21 + 22)		10,711,150.43	5.71	
24.	Power Cost (20 + 23)		77,937,392.24	41.54	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION
KY0062
PLANT
WILSON
PERIOD ENDED
Aug-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	7	1,779,498.1	270.400	.0			5,325.2	21.2	335.7	172.9
2.											
3.											
4.											
5.											
6.	Total	7	1,779,498.1	270.400	.0			5,325.2	21.2	335.7	172.9
7.	Average BTU		11,936	138,000	0						
8.	Total BTU(10^6)		21,240,089	37,315	0		21,277,404				
9.	Total Del..Cost ($)		43,079,036.84	841,891.62	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	440,000	2,163,304.180	
2.				
3.				
4.				
5.				
6.	Total	440,000	2,163,304.180	9,836
7.	Station Service (MWh)		146,744.488	
8.	Net Generation (MWh)		2,016,559.692	10,551
9.	Station Service (%)		6.78	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	107
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	79.99
2.	Plant Factor (%)	83.97
3.	Running Plant Capacity Factor (%)	92.33
4.	15 Minute Gross Maximum Demand (kW)	461,911
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	1,323,302.43		
2.	Fuel, Coal	501.1	45,065,856.41		2.12
3.	Fuel, Oil	501.2	841,891.62		22.56
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	**Fuel Sub-Total (2 thru 5)**	501	45,907,748.03	22.77	2.16
7.	Steam Expenses	502	6,818,253.61		
8.	Electric Expenses	505	878,406.68		
9.	Miscellaneous Steam Power Expenses	506	2,332,617.40		
10.	Allowances	509	32,611.09		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub-Total (1 + 7 thru 11)**		11,385,191.21	5.65	
13.	**Operation Expense (6 + 12)**		57,292,939.24	28.41	
14.	Maintenance, Supervision and Engineering	510	970,655.06		
15.	Maintenance of Structures	511	645,875.61		
16.	Maintenance of Boiler Plant	512	7,602,541.93		
17.	Maintenance of Electric Plant	513	555,301.30		
18.	Maintenance of Miscellaneous Plant	514	471,145.11		
19.	**Maintenance Expense (14 thru 18)**		10,245,519.01	5.08	
20.	**Total Production Expense (13 + 19)**		67,538,458.25	33.49	
21.	Depreciation	403.1	12,766,871.18		
22.	Interest	427	14,439,254.63		
23.	**Total Fixed Cost (21 + 22)**		27,206,125.81	13.49	
24.	**Power Cost (20 + 23)**		94,744,584.06	46.98	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART F IC - INTERNAL COMBUSTION PLANT

BORROWER DESIGNATION
KY0062

PLANT
REID

PERIOD ENDED
Aug-12

INSTRUCTIONS - See help in the online application.

SECTION A. INTERNAL COMBUSTION GENERATING UNITS

NO.	UNIT NO. (a)	SIZE (kW) (b)	FUEL CONSUMPTION OIL (1000 Gals.) (c)	GAS (1000 C.F.) (d)	OTHER (e)	TOTAL (f)	OPERATING HOURS IN SERVICE (g)	ON STANDBY (h)	OUT OF SERVICE Sche. (i)	Unsched (j)	GROSS GENERATION (MWh) (k)	BTU PER kWh (1)
1.	1	70,000	.000	98,240			201.9	5,598.2	.0	54.9	5,935.210	
2.												
3.												
4.												
5.												
6.	Total	70,000	.000	98,240			201.9	5,598.2	.0	54.9	5,935.210	16,552
7.	Average BTU		0	1,000			Station Service (MWh)				675.080	
8.	Total BTU(10^6)		0	98,240		98,240	Net Generation (MWh)				5,260.130	18,676
9.	Total Del..Cost ($)		0.00	290,989.52			Station Service % of Gross				11.37	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	0	5.	Maint. Plant Payroll ($)	
2.	No. Employees Part-Time		6.	Other Accounts. Plant Payroll ($)	
3.	Total Empl. - Hrs. Worked				
4.	Oper. Plant Payroll ($)		7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	1.59
2.	Plant Factor (%)	1.45
3.	Running Plant Capacity Factor (%)	42.00
4.	15 Minute Gross Maximum Demand (kW)	63,895
5.	Indicated Gross Maximum Demand kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	546	0.00		
2.	Fuel, Oil	547.1	0.00		
3.	Fuel, Gas	547.2	291,253.52		2.96
4.	Fuel, Other	547.3			
5.	Energy for Compressed Air	547,4			
6.	**Fuel Sub-Total *(2 thru 5)***	547	291,253.52	55.37	2.96
7.	Generation Expenses	548	25,195.60		
8.	Miscellaneous Other Power Generation Expenses	549	0.00		
9.	Rents	550	0.00		
10.	**Non-Fuel Sub-Total *(1 + 7 thru 9)***		25,195.60	4.79	
11.	**Operation Expense *(6+ 10)***		316,449.12	60.16	
12.	Maintenance, Supervision and Engineering	551	0.00		
13.	Maintenance of Structures	552	0.00		
14.	Maintenance of Generating and Electric Plant	553	133,834.53		
15.	Maintenance of Miscellaneous Other Power Generating Plant	554	0.00		
16.	**Maintenance Expense *(12 thru 15)***		133,834.53	25.44	
17.	**Total Production Expense *(11 + 16)***		450,283.65	85.60	
18.	Depreciation	403.1,411.10	198,564.26		
19.	Interest	427	139,719.91		
20.	**Total Fixed Cost *(18+ 19)***		338,284.17	64.31	
21.	**Power Cost *(17 + 20)***		788,567.82	149.91	

REMARKS *(including Unscheduled Outages)*

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART I - LINES AND STATIONS	BORROWER DESIGNATION KY0062 PERIOD ENDED Aug-12
INSTRUCTIONS - See help in the online application.	

SECTION A. EXPENSE AND COSTS

ITEM	ACCOUNT NUMBER	LINES (a)	STATIONS (b)
Transmission Operation			
1. Supervision and Engineering	560	181,740.72	253,697.74
2. Load Dispatching	561	2,583,191.71	
3. Station Expenses	562		516,970.15
4. Overhead Line Expenses	563	723,712.03	
5. Underground Line Expenses	564	0.00	
6 Miscellaneous Expenses	566	155,353.63	270,847.76
7. **Subtotal *(1 thru 6)***		3,643,998.09	1,041,415.65
8. Transmission of Electricity by Others	565	2,035,738.42	
9. Rents	567	0.00	16,467.44
10. **Total Transmission Operation *(7 thru 9)***		5,679,736.51	1,057,883.09
Transmission Maintenance			
11. Supervision and Engineering	568	161,153.75	170,966.17
12. Structures	569		6,155.29
13. Station Equipment	570		1,150,533.37
14. Overhead Lines	571	1,430,710.82	
15. Underground Lines	572	0.00	
16. Miscellaneous Transmission Plant	573	165,997.77	312,048.07
17. **Total Transmission Maintenance *(11 thru 16)***		1,757,862.34	1,639,702.90
18. **Total Transmission Expense *(10 + 17)***		7,437,598.85	2,697,585.99
19. RTO/ISO Expense - Operation	575	1,492,808.88	
20. RTO/ISO Expense - Maintenance	576	0.00	
21. **Total RTO/ISO Expense *(19 + 20)***		1,492,808.88	
22. Distribution Expense - Operation	580-589	0.00	0.00
23. Distribution Expense - Maintenance	590-598	0.00	0.00
24. **Total Distribution Expense *(22 + 23)***		0.00	0.00
25. **Total Operation And Maintenance *(18 + 21 +24)***		8,930,407.73	2,697,585.99
Fixed Costs			
26. Depreciation - Transmission	403.5	1,150,345.44	1,830,681.12
27. Depreciation - Distribution	403.6	0.00	0.00
28. Interest - Transmission	427	1,788,317.54	2,187,431.45
29. Interest - Distribution	427	0.00	0.00
30. **Total Transmission *(18 + 26 + 28)***		10,376,261.83	6,715,698.56
31. **Total Distribution *(24 +27 +29)***		0.00	0.00
32. **Total Lines And Stations *(21 + 30 + 31)***		11,869,070.71	6,715,698.56

SECTION B. FACILITIES IN SERVICE

TRANSMISSION LINES		SUBSTATIONS	
VOLTAGE (kV)	MILES	TYPE	CAPACITY (kVA)
1. 69 kV	833.20		
2. 345 kV	68.40	13. Distr. Lines	0
3. 138 kV	14.40		
4. 161 kV	349.60	14. Total *(12 + 13)*	1,265.60
5.			
6.		15. Step up at Generating Plants	1,879,800
7.			
8.		16. Transmission	3,540,000
9.			
10		17. Distribution	0
11.			
12. Total *(1 thru 11)*	1,265.60	18. Total *(15 thru 17)*	5,419,800

SECTION C. LABOR AND MATERIAL SUMMARY

1. Number of Employees		56
ITEM	LINES	STATIONS
2. Oper. Labor	988,716.86	696,341.10
3. Maint. Labor	944,677.56	1,066,235.10
4. Oper. Material	6,138,581.34	406,789.18
5 Maint. Material	813,184.78	573,467.80

SECTION D. OUTAGES

1. Total	24,407.50
2. Avg. No. Dist. Cons. Served	112,867.00
3. Avg. No. Hours Out Per Cons.	0.22

RUS Form 12 – July 2012

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0572-0032. The time required to complete this information collection is estimated to average 21 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT** **ELECTRIC POWER SUPPLY**	**BORROWER DESIGNATION** KY0062 **PERIOD ENDED** July -2012
INSTRUCTIONS* - *See help in the online application *This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C. 552).*	**BORROWER NAME** **Big Rivers Electric Corporation**

CERTIFICATION

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7 CFR CHAPTER XVII

(check one of the following)

X All of the obligations under the RUS loan documents have been fulfilled in all material respects.

__ There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part A Section C of this report.

Mark A Bailey 8/20/12

SIGNATURE OF PRESIDENT AND CEO DATE

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART A - FINANCIAL

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Jul-12

SECTION A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	YEAR-TO-DATE BUDGET (c)	THIS MONTH (d)
1. Electric Energy Revenues	324,292,363.18	324,398,050.60	354,633,938.00	50,686,384.96
2. Income From Leased Property (Net)	0.00	0.00	0.00	0.00
3. Other Operating Revenue and Income	1,708,000.69	2,975,419.69	2,341,919.00	566,567.76
4. **Total Operation Revenues & Patronage Capital** *(1 thru 3)*	**326,000,363.87**	**327,373,470.29**	**356,975,857.00**	**51,252,952.72**
5. Operating Expense - Production - Excluding Fuel	28,445,296.87	28,022,132.34	32,079,968.00	4,185,349.76
6. Operating Expense - Production - Fuel	134,903,380.47	128,480,747.22	138,051,936.00	21,590,497.91
7. Operating Expense - Other Power Supply	64,095,863.09	66,842,670.99	74,895,219.00	8,667,192.96
8. Operating Expense - Transmission	5,167,812.57	5,932,422.23	6,291,420.00	953,658.50
9. Operating Expense - RTO/ISO	1,447,577.74	1,363,577.35	1,457,246.00	138,461.34
10. Operating Expense - Distribution	0.00	0.00	0.00	0.00
11. Operating Expense - Customer Accounts	0.00	0.00	0.00	0.00
12. Operating Expense - Customer Service & Information	235,165.37	289,344.54	435,887.00	90,126.26
13. Operating Expense - Sales	6,328.32	25,498.98	623,979.00	4,906.25
14. Operating Expense - Administrative & General	16,191,082.53	15,796,611.13	15,829,940.00	2,003,714.47
15. **Total Operation Expense** *(5 thru 14)*	**250,492,506.96**	**246,753,004.78**	**269,665,595.00**	**37,633,907.45**
16. Maintenance Expense - Production	22,273,262.74	23,775,496.78	38,072,523.00	3,349,706.75
17. Maintenance Expense - Transmission	2,481,882.51	2,784,051.11	2,308,617.00	450,038.41
18. Maintenance Expense - RTO/ISO	0.00	0.00	0.00	0.00
19. Maintenance Expense - Distribution	0.00	0.00	0.00	0.00
20. Maintenance Expense - General Plant	75,301.44	94,255.50	61,760.00	1,056.65
21. **Total Maintenance Expense** *(16 thru 20)*	**24,830,446.69**	**26,653,803.39**	**40,442,900.00**	**3,800,801.81**
22. Depreciation and Amortization Expense	20,192,002.45	23,767,288.69	24,260,517.00	3,403,659.95
23. Taxes	128,389.00	4,060.88	885.00	0.00
24. Interest on Long-Term Debt	26,851,232.28	26,164,144.79	26,019,738.00	3,679,669.13
25. Interest Charged to Construction - Credit	<393,756.00>	<443,914.00>	<322,073.00>	<58,502.00>
26. Other Interest Expense	58,923.08	11,121.07	0.00	10,958.90
27. Asset Retirement Obligations	0.00	0.00	0.00	0.00
28. Other Deductions	128,372.49	137,954.37	203,773.00	15,309.25
29. **Total Cost Of Electric Service** *(15 + 21 thru 28)*	**322,288,116.95**	**323,047,463.97**	**360,271,335.00**	**48,485,804.49**
30. **Operating Margins** *(4 less 29)*	**3,712,246.92**	**4,326,006.32**	**<3,295,478.00>**	**2,767,148.23**
31. Interest Income	116,447.27	37,498.55	39,025.00	5,861.00
32. Allowance For Funds Used During Construction	0.00	0.00	0.00	0.00
33. Income (Loss) from Equity Investments	0.00	0.00	0.00	0.00
34. Other Non-operating Income (Net)	9,288.48	0.00	0.00	0.00
35. Generation & Transmission Capital Credits	0.00	0.00	0.00	0.00
36. Other Capital Credits and Patronage Dividends	96,795.44	44,874.64	25,000.00	0.00
37. Extraordinary Items	0.00	0.00	0.00	0.00
38. **Net Patronage Capital Or Margins** *(30 thru 37)*	**3,934,778.11**	**4,408,379.51**	**<3,231,453.00>**	**2,773,009.23**

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART A - FINANCIAL

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Jul-12

INSTRUCTIONS - See help in the online application.

SECTION B. BALANCE SHEET

ASSETS AND OTHER DEBITS		LIABILITIES AND OTHER CREDITS	
1. Total Utility Plant in Service	1,981,269,297.42	33. Memberships	75.00
2. Construction Work in Progress	65,352,550.78	34. Patronage Capital a. Assigned and Assignable b. Retired This year c. Retired Prior years **d. Net Patronage Capital (a-b-c)**	0.00
3. Total Utility Plant *(1 + 2)*	**2,046,621,848.20**		
4. Accum. Provision for Depreciation and Amort.	957,483,737.55		
5. Net Utility Plant *(3 - 4)*	**1,089,138,110.65**		
6. Non-Utility Property (Net)	0.00	35. Operating Margins - Prior Years	<241,898,352.19>
7. Investments in Subsidiary Companies	0.00	36. Operating Margin - Current Year	4,370,880.96
8. Invest. in Assoc. Org. - Patronage Capital	3,676,551.28	37. Non-Operating Margins	639,035,035.75
9. Invest, in Assoc. Org. - Other - General Funds	43,840,793.00	38. Other Margins and Equities	<7,278,744.80>
10. Invest. in Assoc. Org. - Other - Nongeneral Funds	0.00	**39. Total Margins & Equities *(33 + 34d thru 38)***	**394,228,894.72**
11. Investments in Economic Development Projects	10,000.00	40. Long-Term Debt - RUS (Net)	206,633,152.41
		41. Long-Term Debt - FFB - RUS Guaranteed	0.00
12. Other Investments	5,333.85	42. Long-Term Debt - Other - RUS Guaranteed	0.00
13. Special Funds	187,736,321.03	43. Long-Term Debt - Other (Net)	644,177,302.90
14. Total Other Property And Investments *(6 thru 13)*	**235,268,999.16**	44. Long-Term Debt - RUS - Econ. Devel. (Net)	0.00
		45. Payments - Unapplied	0.00
15. Cash - General Funds	5,769.90	**46. Total Long-Term Debit *(40 thru 44-45)***	**850,810,455.31**
16. Cash - Construction Funds - Trustee	0.00	47. Obligations Under Capital Leases - Noncurrent	0.00
17. Special Deposits	598,263.43		
18. Temporary Investments	105,756,525.84		
19. Notes Receivable (Net)	0.00	48. Accumulated Operating Provisions and Asset Retirement Obligations	24,830,506.38
20. Accounts Receivable - Sales of Energy (Net)	45,604,251.92	**49. Total Other NonCurrent Liabilities *(47 +48)***	**24,830,506.38**
21. Accounts Receivable - Other (Net)	362,983.33	50. Notes Payable	0.00
22. Fuel Stock	31,409,997.83	51. Accounts Payable	29,457,417.82
23. Renewable Energy Credits	0.00		
24. Materials and Supplies - Other	26,138,253.01	52. Current Maturities Long-Term Debt	78,078,497.10
25. Prepayments	2,167,302.20		
26. Other Current and Accrued Assets	883,405.96	53. Current Maturities Long-Term Debt - Rural Development	0.00
27. Total Current And Accrued Assets *(15 thru 26)*	**212,926,753.42**	54. Current Maturities Capital Leases	0.00
		55. Taxes Accrued	648,289.17
28. Unamortized Debt Discount & Extraor. Prop. Losses	3,925,124.83	56. Interest Accrued	1,519,834.37
		57. Other Current and Accrued Liabilities	8,587,474.59
29. Regulatory Assets	0.00		
30. Other Deferred Debits	2,936,332.24	**58. Total Current & Accrued Liabilities *(50 thru 57)***	**118,291,513.05**
31. Accumulated Deferred Income Taxes	0.00	59. Deferred Credits	156,033,950.84
		60. Accumulated Deferred Income Taxes	0.00
32. Total Assets And Other Debits *(5+14+27 thru 31)*	**1,544,195,320.30**	**61. Total Liabilities and Other Credits *(39 + 46 + 49 + 58 thru 60)***	**1,544,195,320.30**

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Jul-12

Part B SE - Sales of Electricity

Sale No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Fuel Type (e)	Average Monthly Billing Demand (MW) (f)	Actual Average Monthly NCP Demand (g)	Actual Average Monthly CP Demand (h)
	Ultimate Consumer(s)							
	Distribution Borrowers							
1	Jackson Purchase Energy Corp	KY0020	RQ			126	139	125
2	Kenergy Corporation	KY0065	IF					
3	Kenergy Corporation	KY0065	LF					
4	Kenergy Corporation	KY0065	RQ			365	381	364
5	Meade County Rural ECC	KY0018	RQ			88	99	87
	G&T Borrowers							
6	PowerSouth Energy Coop	AL0042	OS					
	Others							
7	ADM Investor Services		OS					
8	Henderson Muncipal Power & Light		OS					
9	Midwest Independent Trans. Sys. Op.		OS					
10	PJM Interconnection		OS					
11								
	Total for Ultimate Consumer(s)					0	0	0
	Total for Distribution Borrowers					579	619	566
	Total for G&T Borrowers					0	0	0
	Total for Others					0	0	0
	Grand Total					579	619	566

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Jul-12

Part B SE - Sales of Electricity

Sale No.	Electricity Sold (MWh) (i)	Revenue Demand Charges (j)	Revenue Energy Charges (k)	Revenue Other Charges (l)	Revenue Total (j + k + l) (m)
1	398,258.439	8,417,400.50	11,642,981.14		20,060,381.64
2	108,679.533		3,233,381.68		3,233,381.68
3	4,328,305.338		209,527,393.35		209,527,393.35
4	1,272,803.179	25,403,608.63	34,302,522.25		59,706,130.88
5	276,176.650	5,853,282.50	8,068,952.34		13,922,234.84
6	460.000		17,325.40		17,325.40
7			<24,464.00>		<24,464.00>
8	16,239.166		457,640.39		457,640.39
9	625,203.700		17,498,086.64		17,498,086.64
10			<60.22>		<60.22>
11			0.00		
	0	0	0	0	0
	6,384,223.139	39,674,291.63	266,775,230.76	0.00	306,449,522.39
	460.000	0.00	17,325.40	0.00	17,325.40
	641,442.866	0.00	17,931,202.81	0.00	17,931,202.81
	7,026,126.005	39,674,291.63	284,723,758.97	0.00	324,398,050.60

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

BORROWER DESIGNATION
KY0062

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY

PERIOD NAME
Jul-12

INSTRUCTIONS - See help in the online application.

PART B PP - Purchased Power

Purchase No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Energy Type (e)	Average Monthly Billing Demand (MW) (f)	Average Monthly NCP Demand (g)	Average Monthly CP Demand (h)
	Distribution Borrowers							
	G&T Borrowers							
	Others							
1	Cargill Power Markets		OS					
2	Henderson Municipal Power & Light		RQ					
3	Midwest Independent Trans. Sys. Op.		OS					
4	Southeastern Power Admin.		LF					
5								
Total for Distribution Borrowers						0	0	0
Total for G&T Borrowers						0	0	0
Total for Others						0	0	0
Grand Total						0	0	0

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD NAME Jul-12
INSTRUCTIONS - See help in the online application.	

PART B PP - Purchased Power

Purchase No.	Electricity Purchased (MWh) (i)	Electricity Received (MWh) (j)	Electricity Delivered (MWh) (k)	Demand Charges (l)	Energy Charges (m)	Other Charges (n)	Total (l + m + n) (o)
1	36,000.000				993,600.00		993,600.00
2	761,037.960				36,108,674.18		36,108,674.18
3	903,839.700				22,605,246.39		22,605,246.39
4	196,362.000				5,300,203.27		5,300,203.27
5					0.00		
	0.000				0.00		0.00
	0.000				0.00		0.00
	1,897,239.660				65,007,723.84		65,007,723.84
	1,897,239.660				**65,007,723.84**		**65,007,723.84**

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART C - SOURCES AND DISTRIBUTION OF ENERGY

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Jul-12

INSTRUCTIONS - See help in the online application.

SOURCES OF ENERGY (a)	NO. OF PLANTS (b)	CAPACITY (kW) (c)	NET ENERGY RECEIVED BY SYSTEM (MWh) (d)	COST ($) (e)
Generated in Own Plant *(Details on Parts D and F IC)*				
1. Fossil Steam	4	1,489,000	5,154,433.258	220,895,159.97
2. Nuclear				
3. Hydro				
4. Combined Cycle				
5. Internal Combustion	1	70,000	4,898.050	738,478.24
6. Other				
7. Total in Own Plant *(1 thru 6)*	5	1,559,000	5,159,331.308	221,633,638.21
Purchased Power				
8. Total Purchased Power			1,897,239.660	65,007,723.84
Interchanged Power				
9. Received Into System (Gross)			1,301,564.000	
10. Delivered Out of System (Gross)			1,201,223.000	
11. Net Interchange *(9 minus 10)*			100,341.000	
Transmission For or By Others - (Wheeling)				
12. Received Into System			0.000	
13. Delivered Out of System			0.000	
14. Net Energy Wheeled *(12 minus 13)*			0.000	
15. Total Energy Available for Sale (7 + 8 + 11 + 14)			7,156,911.968	
Distribution of Energy				
16. Total Sales			7,026,126.005	
17. Energy Furnished to Others Without Charge				
18. Energy Used by Borrower *(Excluding Station Use)*				
19. Total Energy Accounted For *(16 thru 18)*			7,026,126.005	
Losses				
20. Energy Losses - MWh *(15 minus 19)*			130,785.963	
21. Energy Losses - Percentage ((20 divided by 15) * 100)			1.83 %	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART D - STEAM PLANT

BORROWER DESIGNATION: KY0062
PLANT: COLEMAN
PERIOD ENDED: Jul-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	6	534,534.6	0.000	15,389.3			4,738.2	97.1	0.0	275.7
2.	2	2	575,683.2	0.000	11,273.0			4,961.8	54.2	0.0	95.0
3.	3	3	619,849.1	0.000	19,669.8			5,093.4	0.0	0.0	17.6
4.											
5.											
6.	Total	11	1,730,066.9	0.000	46,332.1			14,793.4	151.3	0.0	388.3
7.	Average BTU		11,334	0	1,000						
8.	Total BTU(10^6)		19,608,578	0	46,332		19,654,910				
9.	Total Del.Cost ($)		45,252,447.84	2,265.59	123,244.09						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	160,000	612,042.000	
2.	2	160,000	658,470.000	
3.	3	165,000	714,414.000	
4.				
5.				
6.	Total	485,000	1,984,926.000	9,902
7.	Station Service (MWh)		180,408.180	
8.	Net Generation (MWh)		1,804,517.820	10,892
9.	Station Service (%)		9.09	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	111
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	79.27
2.	Plant Factor (%)	80.07
3.	Running Plant Capacity Factor (%)	82.97
4.	15 Minute Gross Maximum Demand (kW)	489,901
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	963,005.09		
2.	Fuel, Coal	501.1	47,296,976.92		2.41
3.	Fuel, Oil	501.2	2,265.59		
4.	Fuel, Gas	501.3	123,244.09		2.66
5.	Fuel, Other	501.4			
6.	Fuel Sub Total (2 thru 5)	501	47,422,486.60	26.28	2.41
7.	Steam Expenses	502	3,219,379.17		
8.	Electric Expenses	505	1,184,568.31		
9.	Miscellaneous Steam Power Expenses	506	1,218,556.88		
10.	Allowances	509	24,947.32		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		6,610,456.77	3.66	
13.	Operation Expense (6 + 12)		54,032,943.37	29.94	
14.	Maintenance, Supervision and Engineering	510	861,138.04		
15.	Maintenance of Structures	511	700,999.45		
16.	Maintenance of Boiler Plant	512	3,694,205.17		
17.	Maintenance of Electric Plant	513	626,732.56		
18.	Maintenance of Miscellaneous Plant	514	910,984.55		
19.	Maintenance Expense (14 thru 18)		6,794,059.77	3.77	
20.	Total Production Expense (13 + 19)		60,827,003.14	33.71	
21.	Depreciation	403.1	3,226,435.05		
22.	Interest	427	4,053,223.07		
23.	Total Fixed Cost (21 + 22)		7,279,658.12	4.03	
24.	Power Cost (20 + 23)		68,106,661.26	37.74	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION
KY0062
PLANT
REID
PERIOD ENDED
Jul-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

			FUEL CONSUMPTION					OPERATING HOURS			
NO.	UNIT NO. (a)	TIMES STARTED (b)	COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE Scheduled (j)	OUT OF SERVICE Unsched (k)
1.	1	6	24,312.4	32.789	.0			485.7	4,165.6	.0	459.7
2.											
3.											
4.											
5.											
6.	Total	6	24,312.4	32.789	.0			485.7	4,165.6	.0	459.7
7.	Average BTU		12,187	138,000	0						
8.	Total BTU(10^6)		296,295	4,525	0		300,820				
9.	Total Del..Cost ($)		743,095.67	104,419.78	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	72,000	24,399.000	
2.				
3.				
4.				
5.				
6.	Total	72,000	24,399.000	12,329
7.	Station Service (MWh)		11,938.000	
8.	Net Generation (MWh)		12,461.000	24,141
9.	Station Service (%)		48.93	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	17
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	8.26
2.	Plant Factor (%)	6.63
3.	Running Plant Capacity Factor (%)	69.77
4.	15 Minute Gross Maximum Demand (kW)	57,776
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	156,210.22		
2.	Fuel, Coal	501.1	903,189.49		3.05
3.	Fuel, Oil	501.2	104,419.78		23.08
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	Fuel Sub Total (2 thru 5)	501	1,007,609.27	80.86	3.35
7.	Steam Expenses	502	303,401.00		
8.	Electric Expenses	505	162,217.03		
9.	Miscellaneous Steam Power Expenses	506	122,401.82		
10.	Allowances	509	4,619.77		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		748,849.84	60.10	
13.	Operation Expense (6 + 12)		1,756,459.11	140.96	
14.	Maintenance, Supervision and Engineering	510	142,372.71		
15.	Maintenance of Structures	511	59,304.41		
16.	Maintenance of Boiler Plant	512	467,718.31		
17.	Maintenance of Electric Plant	513	157,237.16		
18.	Maintenance of Miscellaneous Plant	514	92,106.60		
19.	Maintenance Expense (14 thru 18)		918,739.19	73.73	
20.	Total Production Expense (13 + 19)		2,675,198.30	214.69	
21.	Depreciation	403.1	266,781.50		
22.	Interest	427	418,497.85		
23.	Total Fixed Cost (21 + 22)		685,279.35	54.99	
24.	Power Cost (20 + 23)		3,360,477.65	269.68	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION
KY0062
PLANT
GREEN
PERIOD ENDED
Jul-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	3	805,154.7	128.047	.0			4,512.8	598.2	.0	.0
2.	2	6	699,417.0	165.660	.0			3,953.7	1,151.3	.0	6.0
3.											
4.											
5.											
6.	**Total**	9	1,504,571.7	293.707	.0			8,466.5	1,749.5	.0	6.0
7.	Average BTU		11,774	138,000	0						
8.	Total BTU(10^6)		17,714,827	40,532	0		17,755,359				
9.	Total Del. Cost ($)		38,067,940.73	923,569.47	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	250,000	963,375.690	
2.	2	242,000	818,057.640	
3.				
4.				
5.				
6.	**Total**	492,000	1,781,433.330	9,967
7.	Station Service (MWh)		176,281.818	
8.	Net Generation (MWh)		1,605,151.512	11,061
9.	Station Service (%)		9.90	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	114
2.	No. Employees Part-Time	
3.	**Total Empl. - Hrs. Worked**	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	**Total Plant Payroll ($)**	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	70.30
2.	Plant Factor (%)	70.84
3.	Running Plant Capacity Factor (%)	85.44
4.	15 Minute Gross Maximum Demand (kW)	495,771
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	903,435.47		
2.	Fuel, Coal	501.1	39,456,028.65		2.23
3.	Fuel, Oil	501.2	923,569.47		22.79
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			
6.	**Fuel Sub Total (2 thru 5)**	501	40,379,598.12	25.16	2.27
7.	Steam Expenses	502	7,016,722.67		
8.	Electric Expenses	505	1,879,719.60		
9.	Miscellaneous Steam Power Expenses	506	829,951.49		
10.	Allowances	509	12,144.95		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub Total (1 + 7 thru 11)**		10,641,974.18	6.63	
13.	**Operation Expense (6 + 12)**		51,021,572.30	31.79	
14.	Maintenance, Supervision and Engineering	510	855,180.65		
15.	Maintenance of Structures	511	682,261.06		
16.	Maintenance of Boiler Plant	512	4,230,734.02		
17.	Maintenance of Electric Plant	513	593,357.24		
18.	Maintenance of Miscellaneous Plant	514	490,556.11		
19.	**Maintenance Expense (14 thru 18)**		6,852,089.08	4.27	
20.	**Total Production Expense (13 + 19)**		57,873,661.38	36.05	
21.	Depreciation	403.1	4,562,103.04		
22.	Interest	427	4,685,932.03		
23.	**Total Fixed Cost (21 + 22)**		9,248,035.07	5.76	
24.	**Power Cost (20 + 23)**		67,121,696.45	41.82	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062
PLANT
WILSON
PERIOD ENDED
Jul-12

SECTION A. BOILERS/TURBINES

			FUEL CONSUMPTION					OPERATING HOURS			
										OUT OF SERVICE	
NO.	UNIT NO. (a)	TIMES STARTED (b)	COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	IN SERVICE (h)	ON STANDBY (i)	Scheduled (j)	Unsched (k)
1.	1	7	1,532,215.1	265.400	.0			4,581.2	21.2	335.7	172.9
2.											
3.											
4.											
5.											
6.	Total	7	1,532,215.1	265.400	.0			4,581.2	21.2	335.7	172.9
7.	Average BTU		11,917	138,000	0						
8.	Total BTU(10^6)		18,259,407	36,625	0		18,296,032				
9.	Total Del..Cost ($)		36,801,822.43	825,888.34	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	440,000	1,858,575.250	
2.				
3.				
4.				
5.				
6.	Total	440,000	1,858,575.250	9,844
7.	Station Service (MWh)		126,272.324	
8.	Net Generation (MWh)		1,732,302.926	10,562
9.	Station Service (%)		6.79	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	111
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	78.73
2.	Plant Factor (%)	82.65
3.	Running Plant Capacity Factor (%)	92.20
4.	15 Minute Gross Maximum Demand (kW)	461,911
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	1,158,142.16		
2.	Fuel, Coal	501.1	38,541,081.98		2.11
3.	Fuel, Oil	501.2	825,888.34		22.55
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	**Fuel Sub-Total (2 thru 5)**	501	39,366,970.32	22.73	2.15
7.	Steam Expenses	502	6,006,732.66		
8.	Electric Expenses	505	779,868.75		
9.	Miscellaneous Steam Power Expenses	506	2,025,901.43		
10.	Allowances	509	27,959.32		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub-Total (1 + 7 thru 11)**		9,998,604.32	5.77	
13.	**Operation Expense (6 + 12)**		49,365,574.64	28.50	
14.	Maintenance, Supervision and Engineering	510	846,020.41		
15.	Maintenance of Structures	511	545,261.59		
16.	Maintenance of Boiler Plant	512	6,809,836.13		
17.	Maintenance of Electric Plant	513	467,779.44		
18.	Maintenance of Miscellaneous Plant	514	425,364.28		
19.	**Maintenance Expense (14 thru 18)**		9,094,261.85	5.25	
20.	**Total Production Expense (13 + 19)**		58,459,836.49	33.75	
21.	Depreciation	403.1	11,259,256.33		
22.	Interest	427	12,587,231.79		
23.	**Total Fixed Cost (21 + 22)**		23,846,488.12	13.77	
24.	**Power Cost (20 + 23)**		82,306,324.61	47.51	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART F IC - INTERNAL COMBUSTION PLANT

BORROWER DESIGNATION: KY0062
PLANT: REID
PERIOD ENDED: Jul-12

INSTRUCTIONS - See help in the online application.

SECTION A. INTERNAL COMBUSTION GENERATING UNITS

NO.	UNIT NO. (a)	SIZE (kW) (b)	FUEL CONSUMPTION OIL (1000 Gals.) (c)	GAS (1000 C.F.) (d)	OTHER (e)	TOTAL (f)	OPERATING HOURS IN SERVICE (g)	ON STANDBY (h)	OUT OF SERVICE Sche. (i)	Unsched (j)	GROSS GENERATION (MWh) (k)	BTU PER kWh (1)
1.	1	70,000	.000	89,702			183.6	4,873.7	.0	53.7	5,444.310	
2.												
3.												
4.												
5.												
6.	Total	70,000	.000	89,702			183.6	4,873.7	.0	53.7	5,444.310	16,476
7.	Average BTU		0	1,000			Station Service (MWh)				546.260	
8.	Total BTU(10^6)		0	89,702		89,702	Net Generation (MWh)				4,898.050	18,314
9.	Total Del..Cost ($)		0.00	303,878.91			Station Service % of Gross				10.03	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	0	5.	Maint. Plant Payroll ($)	
2.	No. Employees Part-Time		6.	Other Accounts. Plant Payroll ($)	
3.	**Total Empl. - Hrs. Worked**				
4.	Oper. Plant Payroll ($)		7.	**Total Plant Payroll ($)**	

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	1.67
2.	Plant Factor (%)	1.52
3.	Running Plant Capacity Factor (%)	42.36
4.	15 Minute Gross Maximum Demand (kW)	63,895
5.	Indicated Gross Maximum Demand kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10⁶ BTU (c)
1.	Operation, Supervision and Engineering	546	0.00		
2.	Fuel, Oil	547.1	0.00		
3.	Fuel, Gas	547.2	304,082.91		3.39
4.	Fuel, Other	547.3			
5.	Energy for Compressed Air	547.4			
6.	**Fuel Sub-Total *(2 thru 5)***	547	304,082.91	62.08	3.39
7.	Generation Expenses	548	22,247.23		
8.	Miscellaneous Other Power Generation Expenses	549	0.00		
9.	Rents	550	0.00		
10.	**Non-Fuel Sub-Total *(1 + 7 thru 9)***		22,247.23	4.54	
11.	**Operation Expense *(6+ 10)***		326,330.14	66.62	
12.	Maintenance, Supervision and Engineering	551	0.00		
13.	Maintenance of Structures	552	0.00		
14.	Maintenance of Generating and Electric Plant	553	116,346.89		
15.	Maintenance of Miscellaneous Other Power Generating Plant	554	0.00		
16.	**Maintenance Expense *(12 thru 15)***		116,346.89	23.75	
17.	**Total Production Expense *(11 + 16)***		442,677.03	90.38	
18.	Depreciation	403.1,411.10	173,961.08		
19.	Interest	427	121,840.13		
20.	**Total Fixed Cost *(18+ 19)***		295,801.21	60.39	
21.	**Power Cost *(17 + 20)***		738,478.24	150.77	

REMARKS *(including Unscheduled Outages)*

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART I - LINES AND STATIONS	BORROWER DESIGNATION KY0062
	PERIOD ENDED Jul-12
INSTRUCTIONS - See help in the online application.	

SECTION A. EXPENSE AND COSTS

ITEM	ACCOUNT NUMBER	LINES (a)	STATIONS (b)
Transmission Operation			
1. Supervision and Engineering	560	160,716.03	219,780.42
2. Load Dispatching	561	2,279,791.07	
3. Station Expenses	562		450,519.53
4. Overhead Line Expenses	563	650,475.30	
5. Underground Line Expenses	564	0.00	
6. Miscellaneous Expenses	566	139,004.65	239,356.13
7. **Subtotal *(1 thru 6)***		3,229,987.05	909,656.08
8. Transmission of Electricity by Others	565	1,778,370.09	
9. Rents	567	0.00	14,409.01
10. **Total Transmission Operation *(7 thru 9)***		5,008,357.14	924,065.09
Transmission Maintenance			
11. Supervision and Engineering	568	141,526.26	146,719.05
12. Structures	569		4,647.19
13. Station Equipment	570		912,683.36
14. Overhead Lines	571	1,202,705.46	
15. Underground Lines	572	0.00	
16. Miscellaneous Transmission Plant	573	134,999.34	238,770.45
17. **Total Transmission Maintenance *(11 thru 16)***		1,479,231.06	1,304,820.05
18. **Total Transmission Expense *(10 + 17)***		6,487,588.20	2,228,885.14
19. RTO/ISO Expense - Operation	575	1,363,577.35	
20. RTO/ISO Expense - Maintenance	576	0.00	
21. **Total RTO/ISO Expense *(19 + 20)***		1,363,577.35	
22. Distribution Expense - Operation	580-589	0.00	0.00
23. Distribution Expense - Maintenance	590-598	0.00	0.00
24. **Total Distribution Expense *(22 + 23)***		0.00	0.00
25. **Total Operation And Maintenance *(18 + 21 +24)***		7,851,165.55	2,228,885.14
Fixed Costs			
26. Depreciation - Transmission	403.5	1,006,552.26	1,588,997.27
27. Depreciation - Distribution	403.6	0.00	0.00
28. Interest - Transmission	427	1,552,323.72	1,926,702.11
29. Interest - Distribution	427	0.00	0.00
30. **Total Transmission *(18 + 26 + 28)***		9,046,464.18	5,744,584.52
31. **Total Distribution *(24 +27 +29)***		0.00	0.00
32. **Total Lines And Stations *(21 + 30 + 31)***		10,410,041.53	5,744,584.52

SECTION B. FACILITIES IN SERVICE

TRANSMISSION LINES		SUBSTATIONS	
VOLTAGE (kV)	MILES	TYPE	CAPACITY (kVA)
1.69 kV	833.20	13. Distr. Lines	0
2.345 kV	68.40	14. Total *(12 + 13)*	1,265.60
3.138 kV	14.40	15. Step up at Generating Plants	1,879,800
4.161 kV	349.60	16. Transmission	3,540,000
5.		17. Distribution	0
6.		18. Total *(15 thru 17)*	5,419,800
7.			
8.			
9.			
10.			
11.			
12. Total *(1 thru 11)*	1,265.60		

SECTION C. LABOR AND MATERIAL SUMMARY

1. Number of Employees		56
ITEM	LINES	STATIONS
2. Oper. Labor	909,343.93	571,720.98
3. Maint. Labor	846,426.94	938,228.27
4. Oper. Material	5,462,590.56	352,344.11
5. Maint. Material	632,804.12	366,591.76

SECTION D. OUTAGES

1. Total	18,107.60
2. Avg. No. Dist. Cons. Served	112,887.00
3. Avg. No. Hours Out Per Cons.	0.16

RUS Form 12 – June 2012

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0572-0032. The time required to complete this information collection is estimated to average 21 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD ENDED June -2012
INSTRUCTIONS - See help in the online application *This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C. 552).*	BORROWER NAME **Big Rivers Electric Corporation**

CERTIFICATION

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7 CFR CHAPTER XVII

(check one of the following)

X All of the obligations under the RUS loan documents have been fulfilled in all material respects.

__ There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part A Section C of this report.

Mark A. Bailey 7/24/12

SIGNATURE OF PRESIDENT AND CEO DATE

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART A - FINANCIAL**	BORROWER DESIGNATION KY0062 PERIOD ENDED Jun-12
INSTRUCTIONS - See help in the online application.	

SECTION A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	YEAR-TO-DATE BUDGET (c)	THIS MONTH (d)
1. Electric Energy Revenues	273,551,013.06	273,711,665.64	301,745,614.00	46,967,405.68
2. Income From Leased Property (Net)	0.00	0.00	0.00	0.00
3. Other Operating Revenue and Income	1,520,063.26	2,408,851.93	2,008,002.00	502,405.45
4. Total Operation Revenues & Patronage Capital *(1 thru 3)*	**275,071,076.32**	**276,120,517.57**	**303,753,616.00**	**47,469,811.13**
5. Operating Expense - Production - Excluding Fuel	24,222,206.04	23,836,782.58	27,057,459.00	3,967,036.08
6. Operating Expense - Production - Fuel	114,182,313.92	106,890,249.31	114,716,008.00	19,401,189.69
7. Operating Expense - Other Power Supply	55,019,146.67	58,175,478.03	67,585,079.00	7,966,350.62
8. Operating Expense - Transmission	4,647,033.54	4,978,763.73	5,397,379.00	632,615.66
9. Operating Expense - RTO/ISO	1,266,777.77	1,225,116.01	1,230,160.00	180,642.32
10. Operating Expense - Distribution	0.00	0.00	0.00	0.00
11. Operating Expense - Customer Accounts	0.00	0.00	0.00	0.00
12. Operating Expense - Customer Service & Information	189,671.33	199,218.28	384,487.00	46,695.99
13. Operating Expense - Sales	22,499.55	20,592.73	550,697.00	9,812.50
14. Operating Expense - Administrative & General	13,677,210.01	13,792,896.66	13,821,188.00	3,269,510.77
15. Total Operation Expense *(5 thru 14)*	**213,226,858.83**	**209,119,097.33**	**230,742,457.00**	**35,473,853.63**
16. Maintenance Expense - Production	18,929,472.76	20,425,790.03	33,556,033.00	2,678,601.00
17. Maintenance Expense - Transmission	2,140,135.14	2,334,012.70	1,959,605.00	539,476.46
18. Maintenance Expense - RTO/ISO	0.00	0.00	0.00	0.00
19. Maintenance Expense - Distribution	0.00	0.00	0.00	0.00
20. Maintenance Expense - General Plant	58,066.81	93,198.85	53,276.00	25,103.31
21. Total Maintenance Expense *(16 thru 20)*	**21,127,674.71**	**22,853,001.58**	**35,568,914.00**	**3,243,180.77**
22. Depreciation and Amortization Expense	17,313,896.45	20,363,628.74	20,752,510.00	3,391,766.37
23. Taxes	128,389.00	4,060.88	885.00	0.00
24. Interest on Long-Term Debt	22,995,627.28	22,484,475.66	22,242,510.00	3,705,656.39
25. Interest Charged to Construction - Credit	<375,434.00>	<385,412.00>	<254,205.00>	<57,445.00>
26. Other Interest Expense	58,909.69	162.17	0.00	0.00
27. Asset Retirement Obligations	0.00	0.00	0.00	0.00
28. Other Deductions	116,389.31	122,645.12	161,215.00	12,675.30
29. Total Cost Of Electric Service *(15 + 21 thru 28)*	**274,592,311.27**	**274,561,659.48**	**309,214,286.00**	**45,769,687.46**
30. Operating Margins *(4 less 29)*	**478,765.05**	**1,558,858.09**	**<5,460,670.00>**	**1,700,123.67**
31. Interest Income	110,282.00	31,637.55	33,972.00	4,356.28
32. Allowance For Funds Used During Construction	0.00	0.00	0.00	0.00
33. Income (Loss) from Equity Investments	0.00	0.00	0.00	0.00
34. Other Non-operating Income (Net)	9,288.48	0.00	0.00	0.00
35. Generation & Transmission Capital Credits	0.00	0.00	0.00	0.00
36. Other Capital Credits and Patronage Dividends	96,795.44	44,874.64	25,000.00	0.00
37. Extraordinary Items	0.00	0.00	0.00	0.00
38. Net Patronage Capital Or Margins *(30 thru 37)*	**695,130.97**	**1,635,370.28**	**<5,401,698.00>**	**1,704,479.95**

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE	BORROWER DESIGNATION KY0062
FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART A - FINANCIAL	PERIOD ENDED Jun-12
INSTRUCTIONS - See help in the online application.	

SECTION B. BALANCE SHEET

ASSETS AND OTHER DEBITS

1. Total Utility Plant in Service	1,980,197,560.10
2. Construction Work in Progress	64,799,330.12
3. Total Utility Plant *(1 + 2)*	**2,044,996,890.22**
4. Accum. Provision for Depreciation and Amort.	953,691,035.45
5. Net Utility Plant *(3 - 4)*	**1,091,305,854.77**
6. Non-Utility Property (Net)	0.00
7. Investments in Subsidiary Companies	0.00
8. Invest. in Assoc. Org. - Patronage Capital	3,676,551.28
9. Invest, in Assoc. Org. - Other - General Funds	684,993.00
10. Invest. in Assoc. Org. - Other - Nongeneral Funds	0.00
11. Investments in Economic Development Projects	10,000.00
12. Other Investments	5,333.85
13. Special Funds	154,599,638.82
14. Total Other Property And Investments *(6 thru 13)*	**158,976,516.95**
15. Cash - General Funds	5,877.85
16. Cash - Construction Funds - Trustee	0.00
17. Special Deposits	622,686.57
18. Temporary Investments	47,652,971.03
19. Notes Receivable (Net)	0.00
20. Accounts Receivable - Sales of Energy (Net)	42,426,508.21
21. Accounts Receivable - Other (Net)	451,755.22
22. Fuel Stock	35,425,338.10
23. Renewable Energy Credits	0.00
24. Materials and Supplies - Other	26,295,716.22
25. Prepayments	2,498,949.25
26. Other Current and Accrued Assets	851,493.73
27. Total Current And Accrued Assets *(15 thru 26)*	**156,231,296.18**
28. Unamortized Debt Discount & Extraor. Prop. Losses	2,573,860.21
29. Regulatory Assets	0.00
30. Other Deferred Debits	1,724,616.64
31. Accumulated Deferred Income Taxes	0.00
32. Total Assets And Other Debits *(5+14+27 thru 31)*	1,410,812,144.75

LIABILITIES AND OTHER CREDITS

33. Memberships	75.00
34. Patronage Capital a. Assigned and Assignable b. Retired This year c. Retired Prior years **d. Net Patronage Capital (a-b-c)**	0.00
35. Operating Margins - Prior Years	<241,898,352.19>
36. Operating Margin - Current Year	1,603,732.73
37. Non-Operating Margins	639,029,174.75
38. Other Margins and Equities	<7,278,744.80>
39. Total Margins & Equities *(33 + 34d thru 38)*	**391,455,885.49**
40. Long-Term Debt - RUS (Net)	573,195,974.62
41. Long-Term Debt - FFB - RUS Guaranteed	0.00
42. Long-Term Debt - Other - RUS Guaranteed	0.00
43. Long-Term Debt - Other (Net)	142,100,000.00
44. Long-Term Debt - RUS - Econ. Devel. (Net)	0.00
45. Payments - Unapplied	0.00
46. Total Long-Term Debt *(40 thru 44-45)*	**715,295,974.62**
47. Obligations Under Capital Leases - Noncurrent	0.00
48. Accumulated Operating Provisions and Asset Retirement Obligations	24,447,120.70
49. Total Other NonCurrent Liabilities *(47 +48)*	**24,447,120.70**
50. Notes Payable	0.00
51. Accounts Payable	23,008,684.18
52. Current Maturities Long-Term Debt	78,281,995.94
53. Current Maturities Long-Term Debt - Rural Development	0.00
54. Current Maturities Capital Leases	0.00
55. Taxes Accrued	2,269,210.48
56. Interest Accrued	9,924,397.84
57. Other Current and Accrued Liabilities	8,272,367.04
58. Total Current & Accrued Liabilities *(50 thru 57)*	**121,756,655.48**
59. Deferred Credits	157,856,508.46
60. Accumulated Deferred Income Taxes	0.00
61. Total Liabilities and Other Credits *(39 + 46 + 49 + 58 thru 60)*	1,410,812,144.75

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Jun-12

Part B SE - Sales of Electricity

Sale No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Fuel Type (e)	Average Monthly Billing Demand (MW) (f)	Actual Average Monthly NCP Demand (g)	Actual Average Monthly CP Demand (h)
	Ultimate Consumer(s)							
	Distribution Borrowers							
1	Jackson Purchase Energy Corp	KY0020	RQ			122	133	120
2	Kenergy Corporation	KY0065	IF					
3	Kenergy Corporation	KY0065	LF					
4	Kenergy Corporation	KY0065	RQ			357	372	341
5	Meade County Rural ECC	KY0018	RQ			86	97	85
	G&T Borrowers							
6	PowerSouth Energy Coop	AL0042	OS					
	Others							
7	ADM Investor Services		OS					
8	Henderson Muncipal Power & Light		OS					
9	Midwest Independent Trans. Sys. Op.		OS					
10	PJM Interconnection		OS					
11								
	Total for Ultimate Consumer(s)					0	0	0
	Total for Distribution Borrowers					565	602	546
	Total for G&T Borrowers					0	0	0
	Total for Others					0	0	0
	Grand Total					565	602	546

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY

BORROWER DESIGNATION
KY0062

PERIOD ENDED
Jun-12

INSTRUCTIONS - See help in the online application.

Part B SE - Sales of Electricity

Sale No.	Electricity Sold (MWh) (i)	Revenue Demand Charges (j)	Revenue Energy Charges (k)	Revenue Other Charges (l)	Revenue Total (j + k + l) (m)
1	320,310.272	6,934,031.50	9,342,019.73		16,276,051.23
2	103,003.222		2,969,949.81		2,969,949.81
3	3,699,068.365		179,020,982.69		179,020,982.69
4	1,052,326.083	21,241,046.05	28,232,790.76		49,473,836.81
5	226,930.610	4,891,113.00	6,614,618.29		11,505,731.29
6	460.000		17,325.40		17,325.40
7			12,338.50		12,338.50
8	16,239.166		457,640.39		457,640.39
9	523,423.300		13,977,862.43		13,977,862.43
10			<52.91>		<52.91>
11			0.00		
	0	0	0	0	0
	5,401,638.552	33,066,190.55	226,180,361.28	0.00	259,246,551.83
	460.000	0.00	17,325.40	0.00	17,325.40
	539,662.466	0.00	14,447,788.41	0.00	14,447,788.41
	5,941,761.018	33,066,190.55	240,645,475.09	0.00	273,711,665.64

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE	BORROWER DESIGNATION KY0062
FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	PERIOD NAME Jun-12
INSTRUCTIONS - See help in the online application.	

PART B PP - Purchased Power

Purchase No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Energy Type (e)	Average Monthly Billing Demand (MW) (f)	Average Monthly NCP Demand (g)	Average Monthly CP Demand (h)
	Distribution Borrowers							
	G&T Borrowers							
	Others							
1	Cargill Power Markets		OS					
2	Henderson Municipal Power & Light		RQ					
3	Midwest Independent Trans. Sys. Op.		OS					
4	Southeastern Power Admin.		LF					
5								
Total for Distribution Borrowers						0	0	0
Total for G&T Borrowers						0	0	0
Total for Others						0	0	0
Grand Total						0	0	0

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD NAME Jun-12
INSTRUCTIONS - See help in the online application.	

PART B PP - Purchased Power

Purchase No.	Electricity Purchased (MWh) (i)	Electricity Received (MWh) (j)	Electricity Delivered (MWh) (k)	Demand Charges (l)	Energy Charges (m)	Other Charges (n)	Total (l + m + n) (o)
1	36,000.000				993,600.00		993,600.00
2	625,987.400				30,665,106.96		30,665,106.96
3	812,497.000				20,044,215.66		20,044,215.66
4	189,196.000				4,912,499.66		4,912,499.66
5					0.00		
	0.000				0.00		0.00
	0.000				0.00		0.00
	1,663,680.400				56,615,422.28		56,615,422.28
	1,663,680.400				56,615,422.28		56,615,422.28

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART C - SOURCES AND DISTRIBUTION OF ENERGY	BORROWER DESIGNATION KY0062 PERIOD ENDED Jun-12
INSTRUCTIONS - See help in the online application.	

SOURCES OF ENERGY (a)	NO. OF PLANTS (b)	CAPACITY (kW) (c)	NET ENERGY RECEIVED BY SYSTEM (MWh) (d)	COST ($) (e)
Generated in Own Plant *(Details on Parts D and F IC)*				
1. Fossil Steam	4	1,489,000	4,301,766.414	186,176,004.23
2. Nuclear				
3. Hydro				
4. Combined Cycle				
5. Internal Combustion	1	70,000	1,932.250	469,269.40
6. Other				
7. Total in Own Plant *(1 thru 6)*	5	1,559,000	4,303,698.664	186,645,273.63
Purchased Power				
8. Total Purchased Power			1,663,680.400	56,615,422.28
Interchanged Power				
9. Received Into System (Gross)			1,060,640.000	
10. Delivered Out of System (Gross)			976,260.000	
11. Net Interchange *(9 minus 10)*			84,380.000	
Transmission For or By Others - (Wheeling)				
12. Received Into System			0.000	
13. Delivered Out of System			0.000	
14. Net Energy Wheeled *(12 minus 13)*			0.000	
15. Total Energy Available for Sale (7 + 8 + 11 + 14)			6,051,759.064	
Distribution of Energy				
16. Total Sales			5,941,761.018	
17. Energy Furnished to Others Without Charge				
18. Energy Used by Borrower *(Excluding Station Use)*				
19. Total Energy Accounted For *(16 thru 18)*			5,941,761.018	
Losses				
20. Energy Losses - MWh *(15 minus 19)*			109,998.046	
21. Energy Losses - Percentage ((20 divided by 15) * 100)			1.82 %	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART D - STEAM PLANT

BORROWER DESIGNATION: KY0062
PLANT: COLEMAN
PERIOD ENDED: Jun-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	6	445,772.4	0.000	14,679.9			3,994.2	97.1	0.0	275.7
2.	2	1	496,124.9	0.000	9,247.5			4,312.8	54.2	0.0	0.0
3.	3	3	524,339.4	0.000	16,545.4			4,349.4	0.0	0.0	17.6
4.											
5.											
6.	Total	10	1,466,236.7	0.000	40,472.8			12,656.4	151.3	0.0	293.3
7.	Average BTU		11,356	0	1,000						
8.	Total BTU(10^6)		16,650,584	0	40,473		16,691,057				
9.	Total Del.Cost ($)		38,307,948.89	0.00	142,870.53						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	160,000	511,424.000	
2.	2	160,000	569,740.000	
3.	3	165,000	606,910.000	
4.				
5.				
6.	Total	485,000	1,688,074.000	9,888
7.	Station Service (MWh)		152,692.180	
8.	Net Generation (MWh)		1,535,381.820	10,871
9.	Station Service (%)		9.05	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	113
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	79.04
2.	Plant Factor (%)	79.70
3.	Running Plant Capacity Factor (%)	82.47
4.	15 Minute Gross Maximum Demand (kW)	489,075
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	832,043.33		
2.	Fuel, Coal	501.1	40,068,566.62		2.41
3.	Fuel, Oil	501.2	0.00		
4.	Fuel, Gas	501.3	142,870.53		3.53
5.	Fuel, Other	501.4			
6.	Fuel Sub Total (2 thru 5)	501	40,211,437.15	26.19	2.41
7.	Steam Expenses	502	2,708,288.48		
8.	Electric Expenses	505	1,006,991.87		
9.	Miscellaneous Steam Power Expenses	506	1,047,986.57		
10.	Allowances	509	19,771.83		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		5,615,082.08	3.66	
13.	Operation Expense (6 + 12)		45,826,519.23	29.85	
14.	Maintenance, Supervision and Engineering	510	734,030.28		
15.	Maintenance of Structures	511	585,340.60		
16.	Maintenance of Boiler Plant	512	2,897,514.42		
17.	Maintenance of Electric Plant	513	539,419.18		
18.	Maintenance of Miscellaneous Plant	514	770,601.43		
19.	Maintenance Expense (14 thru 18)		5,526,905.91	3.60	
20.	Total Production Expense (13 + 19)		51,353,425.14	33.45	
21.	Depreciation	403.1	2,755,354.84		
22.	Interest	427	3,480,430.27		
23.	Total Fixed Cost (21 + 22)		6,235,785.11	4.06	
24.	Power Cost (20 + 23)		57,589,210.25	37.51	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION	KY0062
PLANT	REID
PERIOD ENDED	Jun-12

SECTION A. BOILERS/TURBINES

			FUEL CONSUMPTION					OPERATING HOURS			
NO.	UNIT NO. (a)	TIMES STARTED (b)	COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE Scheduled (j)	OUT OF SERVICE Unsched (k)
1.	1	1	41.2	5.977	.0			2.5	3,987.3	.0	377.2
2.											
3.											
4.											
5.											
6.	Total	1	41.2	5.977	.0			2.5	3,987.3	.0	377.2
7.	Average BTU		12,457	138,000	0						
8.	Total BTU(10^6)		513	825	0		1,338				
9.	Total Del..Cost ($)		1,278.00	19,765.40	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (1)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	72,000	44.000	
2.				
3.				
4.				
5.				
6.	Total	72,000	44.000	30,409
7.	Station Service (MWh)		8,812.000	
8.	Net Generation (MWh)		<8,768.000>	<153>
9.	Station Service (%)		20,027.27	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	17
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	.09
2.	Plant Factor (%)	.01
3.	Running Plant Capacity Factor (%)	24.44
4.	15 Minute Gross Maximum Demand (kW)	11,188
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	134,802.15		
2.	Fuel, Coal	501.1	145,474.04		283.58
3.	Fuel, Oil	501.2	19,765.40		23.96
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	**Fuel Sub Total (2 thru 5)**	501	165,239.44		123.60
7.	Steam Expenses	502	258,590.00		
8.	Electric Expenses	505	139,231.61		
9.	Miscellaneous Steam Power Expenses	506	106,931.54		
10.	Allowances	509	17.57		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub Total (1 + 7 thru 11)**		639,572.87		
13.	**Operation Expense (6 + 12)**		804,812.31		
14.	Maintenance, Supervision and Engineering	510	124,803.04		
15.	Maintenance of Structures	511	53,499.10		
16.	Maintenance of Boiler Plant	512	347,587.35		
17.	Maintenance of Electric Plant	513	85,421.66		
18.	Maintenance of Miscellaneous Plant	514	81,342.84		
19.	**Maintenance Expense (14 thru 18)**		692,653.99		
20.	**Total Production Expense (13 + 19)**		1,497,466.30		
21.	Depreciation	403.1	229,349.42		
22.	Interest	427	359,475.62		
23.	**Total Fixed Cost (21 + 22)**		588,825.04		
24.	**Power Cost (20 + 23)**		2,086,291.34	0	

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PLANT D - STEAM PLANT**	BORROWER DESIGNATION KY0062 PLANT GREEN PERIOD ENDED Jun-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	3	667,188.0	106.316	.0			3,768.8	598.2	.0	.0
2.	2	5	562,443.4	145.921	.0			3,215.7	1,151.3	.0	.0
3.											
4.											
5.											
6.	Total	8	1,229,631.4	252.237	.0			6,984.5	1,749.5	.0	.0
7.	Average BTU		11,742	138,000	0						
8.	Total BTU(10^6)		14,438,332	34,809	0		14,473,141				
9.	Total Del..Cost ($)		31,198,485.29	791,716.81	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	250,000	795,387.110	
2.	2	242,000	655,103.250	
3.				
4.				
5.				
6.	Total	492,000	1,450,490.360	9,978
7.	Station Service (MWh)		146,063.721	
8.	Net Generation (MWh)		1,304,426.639	11,095
9.	Station Service (%)		10.07	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	114
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	67.00
2.	Plant Factor (%)	67.51
3.	Running Plant Capacity Factor (%)	84.31
4.	15 Minute Gross Maximum Demand (kW)	495,771
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	781,313.41		
2.	Fuel, Coal	501.1	32,382,495.98		2.24
3.	Fuel, Oil	501.2	791,716.81		22.74
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			
6.	**Fuel Sub Total (2 thru 5)**	501	33,174,212.79	25.43	2.29
7.	Steam Expenses	502	5,840,747.28		
8.	Electric Expenses	505	1,609,789.23		
9.	Miscellaneous Steam Power Expenses	506	723,487.59		
10.	Allowances	509	9,946.57		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub Total (1 + 7 thru 11)**		8,965,284.08	6.87	
13.	**Operation Expense (6 + 12)**		42,139,496.87	32.30	
14.	Maintenance, Supervision and Engineering	510	737,021.54		
15.	Maintenance of Structures	511	617,879.42		
16.	Maintenance of Boiler Plant	512	3,707,394.32		
17.	Maintenance of Electric Plant	513	539,993.78		
18.	Maintenance of Miscellaneous Plant	514	420,552.92		
19.	**Maintenance Expense (14 thru 18)**		6,022,841.98	4.62	
20.	**Total Production Expense (13 + 19)**		48,162,338.85	36.92	
21.	Depreciation	403.1	3,910,947.23		
22.	Interest	427	4,034,742.70		
23.	**Total Fixed Cost (21 + 22)**		7,945,689.93	6.09	
24.	**Power Cost (20 + 23)**		56,108,028.78	43.01	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PLANT D - STEAM PLANT

BORROWER DESIGNATION
KY0062
PLANT
WILSON
PERIOD ENDED
Jun-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

			FUEL CONSUMPTION					OPERATING HOURS			
NO.	UNIT NO. (a)	TIMES STARTED (b)	COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE Scheduled (j)	OUT OF SERVICE Unsched (k)
1.	1	6	1,305,810.1	231.700	.0			3,913.4	21.2	335.7	96.7
2.											
3.											
4.											
5.											
6.	Total	6	1,305,810.1	231.700	.0			3,913.4	21.2	335.7	96.7
7.	Average BTU		11,888	138,000	0						
8.	Total BTU(10^6)		15,523,470	31,975	0		15,555,445				
9.	Total Del..Cost ($)		31,002,674.45	719,987.08	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	440,000	1,577,661.680	
2.				
3.				
4.				
5.				
6.	Total	440,000	1,577,661.680	9,860
7.	Station Service (MWh)		106,935.725	
8.	Net Generation (MWh)		1,470,725.955	10,577
9.	Station Service (%)		6.78	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	112
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	78.21
2.	Plant Factor (%)	82.11
3.	Running Plant Capacity Factor (%)	91.62
4.	15 Minute Gross Maximum Demand (kW)	461,911
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10⁶ BTU (c)
1.	Operation, Supervision and Engineering	500	1,000,359.72		
2.	Fuel, Coal	501.1	32,510,905.22		2.09
3.	Fuel, Oil	501.2	719,987.08		22.52
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	Fuel Sub-Total (2 thru 5)	501	33,230,892.30	22.59	2.14
7.	Steam Expenses	502	5,135,954.74		
8.	Electric Expenses	505	669,180.70		
9.	Miscellaneous Steam Power Expenses	506	1,768,121.37		
10.	Allowances	509	23,887.10		
11.	Rents	507	0.00		
12.	Non-Fuel Sub-Total (1 + 7 thru 11)		8,597,503.63	5.85	
13.	Operation Expense (6 + 12)		41,828,395.93	28.44	
14.	Maintenance, Supervision and Engineering	510	728,294.11		
15.	Maintenance of Structures	511	460,541.93		
16.	Maintenance of Boiler Plant	512	6,117,283.68		
17.	Maintenance of Electric Plant	513	411,817.26		
18.	Maintenance of Miscellaneous Plant	514	377,997.38		
19.	Maintenance Expense (14 thru 18)		8,095,934.36	5.50	
20.	Total Production Expense (13 + 19)		49,924,330.29	33.95	
21.	Depreciation	403.1	9,650,810.14		
22.	Interest	427	10,817,333.43		
23.	Total Fixed Cost (21 + 22)		20,468,143.57	13.92	
24.	Power Cost (20 + 23)		70,392,473.86	47.86	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART F IC - INTERNAL COMBUSTION PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION
KY0062

PLANT
REID

PERIOD ENDED
Jun-12

SECTION A. INTERNAL COMBUSTION GENERATING UNITS

NO.	UNIT NO. (a)	SIZE (kW) (b)	FUEL CONSUMPTION: OIL (1000 Gals.) (c)	GAS (1000 C.F.) (d)	OTHER (e)	TOTAL (f)	OPERATING HOURS: IN SERVICE (g)	ON STANDBY (h)	OUT OF SERVICE: Sche. (i)	Unsched (j)	GROSS GENERATION (MWh) (k)	BTU PER kWh (1)
1.	1	70,000	.000	38,703			82.9	4,263.1	.0	21.0	2,329.240	
2.												
3.												
4.												
5.												
6.	Total	70,000	.000	38,703			82.9	4,263.1	.0	21.0	2,329.240	16,616
7.	Average BTU		0	1,000			Station Service (MWh)				396.990	
8.	Total BTU(10^6)		0	38,703		38,703	Net Generation (MWh)				1,932.250	20,030
9.	Total Del..Cost ($)		0.00	108,323.63			Station Service % of Gross				17.04	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	0	5.	Maint. Plant Payroll ($)	
2.	No. Employees Part-Time		6.	Other Accounts. Plant Payroll ($)	
3.	**Total Empl. - Hrs. Worked**				
4.	Oper. Plant Payroll ($)		7.	**Total Plant Payroll ($)**	

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	.83
2.	Plant Factor (%)	.76
3.	Running Plant Capacity Factor (%)	40.14
4.	15 Minute Gross Maximum Demand (kW)	63,895
5.	Indicated Gross Maximum Demand kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering				
2.	Fuel, Oil	546	0.00		
3.	Fuel, Gas	547.1	0.00		
4.	Fuel, Other	547.2	108,467.63		2.80
5.	Energy for Compressed Air	547.3			
6.	**Fuel Sub-Total *(2 thru 5)***	547.4			
7.	Generation Expenses	547	108,467.63	56.14	2.80
8.	Miscellaneous Other Power Generation Expenses	548	19,339.92		
9.	Rents	549	0.00		
10.	**Non-Fuel Sub-Total *(1 + 7 thru 9)***	550	0.00		
11.	**Operation Expense *(6+ 10)***		19,339.92	10.01	
12.	Maintenance, Supervision and Engineering		127,807.55	66.14	
13.	Maintenance of Structures	551	0.00		
14.	Maintenance of Generating and Electric Plant	552	0.00		
15.	Maintenance of Miscellaneous Other Power Generating Plant	553	87,453.79		
16.	**Maintenance Expense *(12 thru 15)***	554	0.00		
17.	**Total Production Expense *(11 + 16)***		87,453.79	45.26	
18.	Depreciation		215,261.34	111.40	
19.	Interest	403.1,411.10	149,357.90		
20.	**Total Fixed Cost *(18+ 19)***	427	104,650.16		
21.	**Power Cost *(17 + 20)***		254,008.06	131.46	
			469,269.40	242.86	

REMARKS *(including Unscheduled Outages)*

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART I - LINES AND STATIONS	BORROWER DESIGNATION KY0062 PERIOD ENDED Jun-12
INSTRUCTIONS - See help in the online application	

SECTION A. EXPENSE AND COSTS

ITEM	ACCOUNT NUMBER	LINES (a)	STATIONS (b)
Transmission Operation			
1. Supervision and Engineering	560	138,861.53	191,010.78
2. Load Dispatching	561	2,006,322.59	
3. Station Expenses	562		391,965.42
4. Overhead Line Expenses	563	592,598.39	
5. Underground Line Expenses	564	0.00	
6. Miscellaneous Expenses	566	120,757.07	201,662.98
7. **Subtotal** *(1 thru 6)*		2,858,539.58	784,639.18
8. Transmission of Electricity by Others	565	1,324,993.65	
9. Rents	567	0.00	10,591.32
10 **Total Transmission Operation** *(7 thru 9)*		4,183,533.23	795,230.50
Transmission Maintenance			
11. Supervision and Engineering	568	122,152.37	127,675.90
12. Structures	569		3,633.94
13. Station Equipment	570		797,139.07
14. Overhead Lines	571	998,536.01	
15. Underground Lines	572	0.00	
16. Miscellaneous Transmission Plant	573	109,262.18	175,613.23
17. **Total Transmission Maintenance** *(11 thru 16)*		1,229,950.56	1,104,062.14
18. **Total Transmission Expense** *(10 + 17)*		5,413,483.79	1,899,292.64
19. RTO/ISO Expense - Operation	575	1,225,116.01	
20. RTO/ISO Expense - Maintenance	576	0.00	
21. **Total RTO/ISO Expense** *(19 + 20)*		1,225,116.01	
22. Distribution Expense - Operation	580-589	0.00	0.00
23. Distribution Expense - Maintenance	590-598	0.00	0.00
24. **Total Distribution Expense** *(22 + 23)*		0.00	0.00
25. **Total Operation And Maintenance** *(18 + 21 +24)*		6,638,599.80	1,899,292.64
Fixed Costs			
26. Depreciation - Transmission	403.5	862,759.08	1,361,997.66
27. Depreciation - Distribution	403.6	0.00	0.00
28. Interest - Transmission	427	1,326,336.66	1,678,542.52
29. Interest - Distribution	427	0.00	0.00
30. **Total Transmission** *(18 + 26 + 28)*		7,602,579.53	4,939,832.82
31. **Total Distribution** *(24 +27 +29)*		0.00	0.00
32. **Total Lines And Stations** *(21 + 30 + 31)*		8,827,695.54	4,939,832.82

SECTION B. FACILITIES IN SERVICE

TRANSMISSION LINES		SUBSTATIONS	
VOLTAGE (kV)	MILES	TYPE	CAPACITY (kVA)
1.69 kV	833.20		
2.345 kV	68.40	13. Distr. Lines	0
3 138 kV	14.40		
4.161 kV	349.60	14. Total *(12 + 13)*	1,265.60
5.			
6.		15. Step up at Generating Plants	1,879,800
7.			
8.		16. Transmission	3,540,000
9.			
10.		17. Distribution	0
11.			
12. Total *(1 thru 11)*	1,265.60	18. Total *(15 thru 17)*	5,419,800

SECTION C. LABOR AND MATERIAL SUMMARY

1. Number of Employees		56
ITEM	LINES	STATIONS
2. Oper. Labor	783,548.73	497,181.42
3. Maint. Labor	733,460.25	811,284.03
4. Oper. Material	4,625,100.51	298,049.08
5. Maint. Material	496,470.31	292,776.11

SECTION D. OUTAGES

1. Total	10,366.30
2. Avg. No. Dist. Cons. Served	112,887.00
3. Avg. No. Hours Out Per Cons.	0.09

RUS Form 12 – May 2012

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0572-0032. The time required to complete this information collection is estimated to average 21 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD ENDED May -2012
INSTRUCTIONS - See help in the online application *This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C. 552).*	BORROWER NAME **Big Rivers Electric Corporation**

CERTIFICATION

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7 CFR CHAPTER XVII

(check one of the following)

X All of the obligations under the RUS loan documents have been fulfilled in all material respects.

__ There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part A Section C of this report.

Mark A. Bailey 6/21/12

SIGNATURE OF PRESIDENT AND CEO DATE

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART A - FINANCIAL

BORROWER DESIGNATION
KY0062

PERIOD ENDED
May-12

INSTRUCTIONS - See help in the online application.

SECTION A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	YEAR-TO-DATE BUDGET (c)	THIS MONTH (d)
1. Electric Energy Revenues	228,062,974.30	226,744,259.96	253,935,918.00	48,310,479.83
2. Income From Leased Property (Net)	0.00	0.00	0.00	0.00
3. Other Operating Revenue and Income	1,313,664.97	1,906,446.48	1,674,085.00	379,621.36
4. **Total Operation Revenues & Patronage Capital** *(1 thru 3)*	**229,376,639.27**	**228,650,706.44**	**255,610,003.00**	**48,690,101.19**
5. Operating Expense - Production - Excluding Fuel	20,242,215.34	19,869,746.50	22,035,963.00	4,063,007.51
6. Operating Expense - Production - Fuel	95,812,527.24	87,489,059.62	94,300,830.00	20,411,564.91
7. Operating Expense - Other Power Supply	45,058,183.57	50,209,127.41	60,034,303.00	8,773,219.54
8. Operating Expense - Transmission	3,634,430.50	4,346,148.07	4,486,498.00	1,080,099.58
9. Operating Expense - RTO/ISO	1,003,395.07	1,044,473.69	1,013,512.00	195,899.43
10. Operating Expense - Distribution	0.00	0.00	0.00	0.00
11. Operating Expense - Customer Accounts	0.00	0.00	0.00	0.00
12. Operating Expense - Customer Service & Information	160,870.23	152,522.29	328,755.00	21,773.37
13. Operating Expense - Sales	1,422.07	10,780.23	465,579.00	4,906.25
14. Operating Expense - Administrative & General	10,951,626.05	10,523,385.89	11,166,761.00	1,922,589.10
15. **Total Operation Expense** *(5 thru 14)*	**176,864,670.07**	**173,645,243.70**	**193,832,201.00**	**36,473,059.69**
16. Maintenance Expense - Production	14,774,469.29	17,747,189.03	26,524,272.00	2,626,366.45
17. Maintenance Expense - Transmission	1,707,057.36	1,794,536.24	1,605,188.00	391,114.00
18. Maintenance Expense - RTO/ISO	0.00	0.00	0.00	0.00
19. Maintenance Expense - Distribution	0.00	0.00	0.00	0.00
20. Maintenance Expense - General Plant	41,080.29	68,095.54	45,694.00	21,472.98
21. **Total Maintenance Expense** *(16 thru 20)*	**16,522,606.94**	**19,609,820.81**	**28,175,154.00**	**3,038,953.43**
22. Depreciation and Amortization Expense	14,435,952.60	16,971,862.37	17,260,435.00	3,391,700.13
23. Taxes	63,389.00	4,060.88	885.00	0.00
24. Interest on Long-Term Debt	19,243,619.06	18,778,819.27	18,558,462.00	3,815,294.95
25. Interest Charged to Construction - Credit	<354,209.00>	<327,967.00>	<203,411.00>	<64,767.00>
26. Other Interest Expense	58,902.14	162.17	0.00	0.00
27. Asset Retirement Obligations	0.00	0.00	0.00	0.00
28. Other Deductions	104,824.88	109,969.82	119,034.00	27,074.18
29. **Total Cost Of Electric Service** *(15 + 21 thru 28)*	**226,939,755.69**	**228,791,972.02**	**257,742,760.00**	**46,681,315.38**
30. **Operating Margins** *(4 less 29)*	**2,436,883.58**	**<141,265.58>**	**<2,132,757.00>**	**2,008,785.81**
31. Interest Income	103,079.99	27,281.27	28,100.00	4,106.38
32. Allowance For Funds Used During Construction	0.00	0.00	0.00	0.00
33. Income (Loss) from Equity Investments	0.00	0.00	0.00	0.00
34. Other Non-operating Income (Net)	6,966.36	0.00	0.00	0.00
35. Generation & Transmission Capital Credits	0.00	0.00	0.00	0.00
36. Other Capital Credits and Patronage Dividends	96,795.44	44,874.64	25,000.00	0.00
37. Extraordinary Items	0.00	0.00	0.00	0.00
38. **Net Patronage Capital Or Margins** *(30 thru 37)*	**2,643,725.37**	**<69,109.67>**	**<2,079,657.00>**	**2,012,892.19**

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART A - FINANCIAL

BORROWER DESIGNATION
KY0062

PERIOD ENDED
May-12

INSTRUCTIONS - See help in the online application.

SECTION B. BALANCE SHEET

ASSETS AND OTHER DEBITS	
1. Total Utility Plant in Service	1,980,206,599.86
2. Construction Work in Progress	61,264,299.68
3. Total Utility Plant *(1 + 2)*	**2,041,470,899.54**
4. Accum. Provision for Depreciation and Amort.	951,109,753.63
5. Net Utility Plant *(3 - 4)*	**1,090,361,145.91**
6. Non-Utility Property (Net)	0.00
7. Investments in Subsidiary Companies	0.00
8. Invest. in Assoc. Org. - Patronage Capital	3,676,551.28
9. Invest. in Assoc. Org. - Other - General Funds	684,993.00
10. Invest. in Assoc. Org. - Other - Nongeneral Funds	0.00
11. Investments in Economic Development Projects	10,000.00
12. Other Investments	5,333.85
13. Special Funds	156,550,569.57
14. Total Other Property And Investments *(6 thru 13)*	**160,927,447.70**
15. Cash - General Funds	5,974.52
16. Cash - Construction Funds - Trustee	0.00
17. Special Deposits	572,684.22
18. Temporary Investments	39,621,359.09
19. Notes Receivable (Net)	0.00
20. Accounts Receivable - Sales of Energy (Net)	43,268,089.84
21. Accounts Receivable - Other (Net)	2,995,426.26
22. Fuel Stock	38,868,141.63
23. Renewable Energy Credits	0.00
24. Materials and Supplies - Other	26,039,389.26
25. Prepayments	2,819,291.72
26. Other Current and Accrued Assets	709,308.31
27. Total Current And Accrued Assets *(15 thru 26)*	**154,899,664.85**
28. Unamortized Debt Discount & Extraor. Prop. Losses	2,352,257.14
29. Regulatory Assets	0.00
30. Other Deferred Debits	1,742,064.80
31. Accumulated Deferred Income Taxes	0.00
32. Total Assets And Other Debits *(5+14+27 thru 31)*	1,410,282,580.40

LIABILITIES AND OTHER CREDITS	
33. Memberships	75.00
34. Patronage Capital	
a. Assigned and Assignable	
b. Retired This year	
c. Retired Prior years	
d. Net Patronage Capital (a-b-c)	0.00
35. Operating Margins - Prior Years	<241,898,352.19>
36. Operating Margin - Current Year	<96,390.94>
37. Non-Operating Margins	639,024,818.47
38. Other Margins and Equities	<7,278,744.80>
39. Total Margins & Equities *(33 + 34d thru 38)*	**389,751,405.54**
40. Long-Term Debt - RUS (Net)	571,396,359.25
41. Long-Term Debt - FFB - RUS Guaranteed	0.00
42. Long-Term Debt - Other - RUS Guaranteed	0.00
43. Long-Term Debt - Other (Net)	142,100,000.00
44. Long-Term Debt - RUS - Econ. Devel. (Net)	0.00
45. Payments - Unapplied	0.00
46. Total Long-Term Debt *(40 thru 44-45)*	**713,496,359.25**
47. Obligations Under Capital Leases - Noncurrent	0.00
48. Accumulated Operating Provisions and Asset Retirement Obligations	24,301,060.49
49. Total Other NonCurrent Liabilities *(47 +48)*	**24,301,060.49**
50. Notes Payable	0.00
51. Accounts Payable	25,693,241.63
52. Current Maturities Long-Term Debt	78,281,995.94
53. Current Maturities Long-Term Debt - Rural Development	0.00
54. Current Maturities Capital Leases	0.00
55. Taxes Accrued	2,010,981.66
56. Interest Accrued	9,021,480.49
57. Other Current and Accrued Liabilities	7,852,315.33
58. Total Current & Accrued Liabilities *(50 thru 57)*	**122,860,015.05**
59. Deferred Credits	159,873,740.07
60. Accumulated Deferred Income Taxes	0.00
61. Total Liabilities and Other Credits *(39 + 46 + 49 + 58 thru 60)*	1,410,282,580.40

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD ENDED May-12
INSTRUCTIONS - See help in the online application.	

Part B SE - Sales of Electricity

Sale No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Fuel Type (e)	Average Monthly Billing Demand (MW) (f)	Actual Average Monthly NCP Demand (g)	Actual Average Monthly CP Demand (h)
	Ultimate Consumer(s)							
	Distribution Borrowers							
1	Jackson Purchase Energy Corp	KY0020	RQ			114	126	113
2	Kenergy Corporation	KY0065	IF					
3	Kenergy Corporation	KY0065	LF					
4	Kenergy Corporation	KY0065	RQ			344	360	335
5	Meade County Rural ECC	KY0018	RQ			83	94	82
	G&T Borrowers							
	Others							
6	Henderson Muncipal Power & Light		OS					
7	Midwest Independent Trans. Sys. Op.		OS					
8	PJM Interconnection		OS					
9	PowerSouth Energy Coop		OS					
10								
Total for Ultimate Consumer(s)						0	0	0
Total for Distribution Borrowers						541	580	530
Total for G&T Borrowers						0	0	0
Total for Others						0	0	0
Grand Total						541	580	530

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD ENDED May-12
INSTRUCTIONS - See help in the online application.	

Part B SE - Sales of Electricity

Sale No.	Electricity Sold (MWh) (i)	Revenue Demand Charges (j)	Revenue Energy Charges (k)	Revenue Other Charges (l)	Revenue Total (j + k + l) (m)
1	258,176.145	5,411,739.50	7,518,340.43		12,930,079.93
2	95,253.722		2,721,624.27		2,721,624.27
3	3,088,661.350		149,502,183.94		149,502,183.94
4	866,849.362	17,153,541.63	23,191,421 13		40,344,962.76
5	188,521 160	3,927,585.00	5,486,263.87		9,413,848.87
6	16,239.166		457,640.39		457,640.39
7	427,962.800		11,356,635.58		11,356,635.58
8			<41 18>		<41.18>
9	460.000		17,325.40		17,325.40
10			0.00		
	0	0	0	0	0
	4,497,461.739	26,492,866.13	188,419,833.64	0.00	214,912,699.77
	0.000	0.00	0.00	0.00	0.00
	444,661.966	0.00	11,831,560.19	0.00	11,831,560.19
	4,942,123.705	26,492,866.13	200,251,393.83	0.00	226,744,259.96

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD NAME May-12
INSTRUCTIONS - See help in the online application.	

PART B PP - Purchased Power

Purchase No.	Name of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Energy Type (e)	Average Monthly Billing Demand (MW) (f)	Average Monthly NCP Demand (g)	Average Monthly CP Demand (h)
	Distribution Borrowers							
	G&T Borrowers							
	Others							
1	Cargill Power Markets		OS					
2	Henderson Municipal Power & Light		RQ					
3	Midwest Independent Trans. Sys. Op.		OS					
4	Southeastern Power Admin.		LF					
5								
Total for Distribution Borrowers						0	0	0
Total for G&T Borrowers						0	0	0
Total for Others						0	0	0
Grand Total						0	0	0

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062 PERIOD NAME May-12
INSTRUCTIONS - See help in the online application.	

PART B PP - Purchased Power

Purchase No.	Electricity Purchased (MWh) (i)	Electricity Received (MWh) (j)	Electricity Delivered (MWh) (k)	Demand Charges (l)	Energy Charges (m)	Other Charges (n)	Total (l + m + n) (o)
1	36,000.000				993,600.00		993,600.00
2	496,464.390				25,446,374.77		25,446,374.77
3	720,279.100				17,956,345.42		17,956,345.42
4	183,002.000				4,541,990.73		4,541,990.73
5					0.00		
	0.000				0.00		0.00
	0.000				0.00		0.00
	1,435,745.490				48,938,310.92		48,938,310.92
	1,435,745.490				48,938,310.92		48,938,310.92

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART C - SOURCES AND DISTRIBUTION OF ENERGY**	BORROWER DESIGNATION KY0062 PERIOD ENDED May-12
INSTRUCTIONS - See help in the online application.	

SOURCES OF ENERGY (a)	NO. OF PLANTS (b)	CAPACITY (kW) (c)	NET ENERGY RECEIVED BY SYSTEM (MWh) (d)	COST ($) (e)
Generated in Own Plant *(Details on Parts D and F IC)*				
1. Fossil Steam	4	1,489,000	3,524,998.657	154,314,154.17
2. Nuclear				
3. Hydro				
4. Combined Cycle				
5. Internal Combustion	1	70,000	1,379.970	401,692.00
6. Other				
7. Total in Own Plant *(1 thru 6)*	5	1,559,000	3,526,378.627	154,715,846.17
Purchased Power				
8. Total Purchased Power			1,435,745.490	48,938,310.92
Interchanged Power				
9. Received Into System (Gross)			821,344.000	
10. Delivered Out of System (Gross)			751,686.000	
11. Net Interchange *(9 minus 10)*			69,658.000	
Transmission For or By Others - (Wheeling)				
12. Received Into System			0.000	
13. Delivered Out of System			0.000	
14. Net Energy Wheeled *(12 minus 13)*			0.000	
15. Total Energy Available for Sale (7 + 8 + 11 + 14)			5,031,782.117	
Distribution of Energy				
16. Total Sales			4,942,123.705	
17. Energy Furnished to Others Without Charge				
18. Energy Used by Borrower *(Excluding Station Use)*				
19. Total Energy Accounted For *(16 thru 18)*			4,942,123.705	
Losses				
20. Energy Losses - MWh *(15 minus 19)*			89,658.412	
21. Energy Losses - Percentage ((20 divided by 15) * 100)			1.78 %	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART D - STEAM PLANT

BORROWER DESIGNATION
KY0062
PLANT
COLEMAN
PERIOD ENDED
May-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	6	368,049.4	0.000	13,256.1			3,274.2	97.1	0.0	275.7
2.	2	1	415,766.4	0.000	7,360.2			3,592.8	54.2	0.0	0.0
3.	3	1	446,220.9	0.000	10,779.5			3,634.4	0.0	0.0	12.6
4.											
5.											
6.	Total	8	1,230,036.7	0.000	31,395.8			10,501.4	151.3	0.0	288.3
7.	Average BTU		11,368	0	1,000						
8.	Total BTU(10^6)		13,983,057	0	31,396		14,014,453				
9.	Total Del.Cost ($)		32,092,712.00	0.00	105,667.58						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	160,000	421,585.000	
2.	2	160,000	479,068.000	
3.	3	165,000	517,170.000	
4.				
5.				
6.	Total	485,000	1,417,823.000	9,884
7.	Station Service (MWh)		126,536.180	
8.	Net Generation (MWh)		1,291,286.820	10,853
9.	Station Service (%)		8.92	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	111
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	79.58
2.	Plant Factor (%)	80.16
3.	Running Plant Capacity Factor (%)	83.48
4.	15 Minute Gross Maximum Demand (kW)	488.530
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/$10^6$ BTU (c)
1.	Operation, Supervision and Engineering	500	690,408.13		
2.	Fuel, Coal	501.1	33,572,424.30		2.40
3.	Fuel, Oil	501.2	0.00		
4.	Fuel, Gas	501.3	105,667.58		3.37
5.	Fuel, Other	501.4			
6.	Fuel Sub Total (2 thru 5)	501	33,678,091.88	26.08	2.40
7.	Steam Expenses	502	2,247,884.96		
8.	Electric Expenses	505	832,316.88		
9.	Miscellaneous Steam Power Expenses	506	872,390.51		
10.	Allowances	509	17,612.43		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		4,660,612.91	3.61	
13.	Operation Expense (6 + 12)		38,338,704.79	29.69	
14.	Maintenance, Supervision and Engineering	510	609,402.26		
15.	Maintenance of Structures	511	440,641.81		
16.	Maintenance of Boiler Plant	512	2,466,430.61		
17.	Maintenance of Electric Plant	513	394,351.17		
18.	Maintenance of Miscellaneous Plant	514	645,579.45		
19.	Maintenance Expense (14 thru 18)		4,556,405.30	3.53	
20.	Total Production Expense (13 + 19)		42,895,110.09	33.22	
21.	Depreciation	403.1	2,296,181.78		
22.	Interest	427	2,905,521.97		
23.	Total Fixed Cost (21 + 22)		5,201,703.75	4.03	
24.	Power Cost (20 + 23)		48,096,813.84	37.25	

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PLANT D - STEAM PLANT**	BORROWER DESIGNATION KY0062 PLANT REID PERIOD ENDED May-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: Scheduled (j)	Unsched (k)
1.	1	0	.0	.000	.0			.0	3,269.8	.0	377.2
2.											
3.											
4.											
5.											
6.	Total	0	.0	.000	.0			.0	3,269.8	.0	377.2
7.	Average BTU		0	0	0						
8.	Total BTU(10^6)		0	0	0						
9.	Total Del..Cost ($)		0.00	278.39	0.00		0				

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	72,000	.000	
2.				
3.				
4.				
5.				
6.	Total	72,000	.000	0
7.	Station Service (MWh)		7,421.000	
8.	Net Generation (MWh)		<7,421.000>	0
9.	Station Service (%)		0	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	17
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	.00
2.	Plant Factor (%)	.00
3.	Running Plant Capacity Factor (%)	.00
4.	15 Minute Gross Maximum Demand (kW)	0
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	113,409.37		
2.	Fuel, Coal	501.1	128,672.37		0
3.	Fuel, Oil	501.2	278.39		0
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	Fuel Sub Total (2 thru 5)	501	128,950.76		0
7.	Steam Expenses	502	216,709.81		
8.	Electric Expenses	505	116,663.33		
9.	Miscellaneous Steam Power Expenses	506	88,742.21		
10.	Allowances	509	5.00		
11.	Rents	507	0.00		
12.	Non-Fuel Sub Total (1 + 7 thru 11)		535,529.72		
13.	Operation Expense (6 + 12)		664,480.48		
14.	Maintenance, Supervision and Engineering	510	105,899.90		
15.	Maintenance of Structures	511	45,401.72		
16.	Maintenance of Boiler Plant	512	294,012.84		
17.	Maintenance of Electric Plant	513	80,147.58		
18.	Maintenance of Miscellaneous Plant	514	69,160.67		
19.	Maintenance Expense (14 thru 18)		594,622.71		
20.	Total Production Expense (13 + 19)		1,259,103.19		
21.	Depreciation	403.1	191,916.79		
22.	Interest	427	300,236.71		
23.	Total Fixed Cost (21 + 22)		492,153.50	0	
24.	Power Cost (20 + 23)		1,751,256.69		

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT** **ELECTRIC POWER SUPPLY** **PLANT D - STEAM PLANT**	BORROWER DESIGNATION KY0062 PLANT GREEN PERIOD ENDED May-12
INSTRUCTIONS - See help in the online application.	

SECTION A. BOILERS/TURBINES

			FUEL CONSUMPTION					OPERATING HOURS			
										OUT OF SERVICE	
NO.	UNIT NO. (a)	TIMES STARTED (b)	COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	IN SERVICE (h)	ON STANDBY (i)	Scheduled (j)	Unsched (k)
1.	1	3	539,673.4	97.197	.0			3,048.8	598.2	.0	.0
2.	2	5	439,208.6	141.755	.0			2,495.7	1,151.3	.0	.0
3.											
4.											
5.											
6.	Total	8	978,882.0	238.952	.0			5,544.5	1,749.5	.0	.0
7.	Average BTU		11,717	138,000	0						
8.	Total BTU(10^6)		11,469,560	32,975	0		11,502,536				
9.	Total Del..Cost ($)		24,814,657.71	747,281.06	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	250,000	642,748.170	
2.	2	242,000	509,775.720	
3.				
4.				
5.				
6.	Total	492,000	1,152,523.890	9,980
7.	Station Service (MWh)		117,504.583	
8.	Net Generation (MWh)		1,035,019.307	11,113
9.	Station Service (%)		10.20	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	114
2.	No. Employees Part-Time	
3.	Total Empl. - Hrs. Worked	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	63.74
2.	Plant Factor (%)	64.23
3.	Running Plant Capacity Factor (%)	84.36
4.	15 Minute Gross Maximum Demand (kW)	495,771
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	658,771.50		
2.	Fuel, Coal	501.1	25,786,471.52		2.25
3.	Fuel, Oil	501.2	747,281.06		22.66
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			
6.	**Fuel Sub Total (2 thru 5)**	501	26,533,752.58	25.64	2.31
7.	Steam Expenses	502	4,796,580.82		
8.	Electric Expenses	505	1,346,819.07		
9.	Miscellaneous Steam Power Expenses	506	607,020.97		
10.	Allowances	509	8,481.49		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub Total (1 + 7 thru 11)**		7,417,673.85	7.17	
13.	**Operation Expense (6 + 12)**		33,951,426.43	32.80	
14.	Maintenance, Supervision and Engineering	510	611,749.99		
15.	Maintenance of Structures	511	550,761.54		
16.	Maintenance of Boiler Plant	512	3,119,573.70		
17.	Maintenance of Electric Plant	513	507,329.27		
18.	Maintenance of Miscellaneous Plant	514	364,405.78		
19.	**Maintenance Expense (14 thru 18)**		5,153,820.28	4.98	
20.	**Total Production Expense (13 + 19)**		39,105,246.71	37.78	
21.	Depreciation	403.1	3,259,791.42		
22.	Interest	427	3,367,611.72		
23.	**Total Fixed Cost (21 + 22)**		6,627,403.14	6.40	
24.	**Power Cost (20 + 23)**		45,732,649.85	44.19	

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PLANT D - STEAM PLANT**	BORROWER DESIGNATION KY0062 PLANT WILSON PERIOD ENDED May-12

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE Scheduled (j)	Unsched (k)
1.	1	5	1,077,283.1	203,700	.0			3,204.8	21.2	335.7	85.3
2											
3.											
4.											
5.											
6.	Total	5	1,077,283.1	203,700	.0			3,204.8	21.2	335.7	85.3
7.	Average BTU		11,831	138,000	0						
8.	Total BTU(10^6)		12,745,336	28,111	0		12,773,447				
9.	Total Del..Cost ($)		25,168,860.15	630,776.95	0.00						

SECTION A. BOILERS/TURBINES (CONT.)

NO.	UNIT NO. (1)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	440,000	1,294,340.780	
2.				
3.				
4.				
5.				
6.	Total	440,000	1,294,340.780	9,869
7.	Station Service (MWh)		88,227.250	
8.	Net Generation (MWh)		1,206,113.530	10,591
9.	Station Service (%)		6.82	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	117
2.	No. Employees Part-Time	
3.	**Total Empl. - Hrs. Worked**	
4.	Oper. Plant Payroll ($)	
5.	Maint. Plant Payroll ($)	
6.	Other Accts. Plant Payroll ($)	
7.	**Total Plant Payroll ($)**	

SECTION C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	77.28
2.	Plant Factor (%)	80.66
3.	Running Plant Capacity Factor (%)	91.79
4.	15 Minute Gross Maximum Demand (kW)	459,250
5.	Indicated Gross Maximum Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	854,257.05		
2.	Fuel, Coal	501.1	26,431,131.62		2.07
3.	Fuel, Oil	501.2	630,776.95		22.44
4.	Fuel, Gas	501.3	0.00		0
5.	Fuel, Other	501.4			0
6.	**Fuel Sub-Total (2 thru 5)**	501	27,061,908.57	22.44	2.12
7.	Steam Expenses	502	4,297,013.97		
8.	Electric Expenses	505	580,322.80		
9.	Miscellaneous Steam Power Expenses	506	1,488,319.08		
10.	Allowances	509	19,935.40		
11.	Rents	507	0.00		
12.	**Non-Fuel Sub-Total (1 + 7 thru 11)**		7,239,848.30	6.00	
13.	**Operation Expense (6 + 12)**		34,301,756.87	28.44	
14.	Maintenance, Supervision and Engineering	510	620,831.58		
15.	Maintenance of Structures	511	409,129.27		
16.	Maintenance of Boiler Plant	512	5,633,782.92		
17.	Maintenance of Electric Plant	513	353,895.49		
18.	Maintenance of Miscellaneous Plant	514	337,597.47		
19.	**Maintenance Expense (14 thru 18)**		7,355,236.73	6.10	
20.	**Total Production Expense (13 + 19)**		41,656,993.60	34.54	
21.	Depreciation	403.1	8,042,360.67		
22.	Interest	427	9,034,079.52		
23.	**Total Fixed Cost (21 + 22)**		17,076,440.19	14.16	
24.	**Power Cost (20 + 23)**		58,733,433.79	48.70	

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART F IC - INTERNAL COMBUSTION PLANT

BORROWER DESIGNATION
KY0062
PLANT
REID
PERIOD ENDED
May-12

INSTRUCTIONS - See help in the online application.

SECTION A. INTERNAL COMBUSTION GENERATING UNITS

NO.	UNIT NO. (a)	SIZE (kW) (b)	FUEL CONSUMPTION OIL (1000 Gals.) (c)	GAS (1000 C.F.) (d)	OTHER (e)	TOTAL (f)	OPERATING HOURS IN SERVICE (g)	ON STANDBY (h)	OUT OF SERVICE Sche. (i)	Unsched (j)	GROSS GENERATION (MWh) (k)	BTU PER kWh (1)
1.	1	70,000	.000	28,072			61.1	3,565.9	.0	20.0	1,703.650	
2.												
3.												
4.												
5.												
6.	Total	70,000	.000	28,072			61.1	3,565.9	.0	20.0	1,703.650	16,478
7.	Average BTU		0	1,000			Station Service (MWh)				323.680	
8.	Total BTU(10^6)		0	28,072		28,072	Net Generation (MWh)				1,379.970	20,342
9.	Total Del..Cost ($)		0.00	86,235.83			Station Service % of Gross				19.00	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1	No. Employees Full-Time (Inc. Superintendent)	0	5.	Maint. Plant Payroll ($)	
2.	No. Employees Part-Time				
3.	Total Empl. - Hrs. Worked		6.	Other Accounts. Plant Payroll ($)	
4.	Oper. Plant Payroll ($)		7.	Total Plant Payroll ($)	

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	.73
2.	Plant Factor (%)	.67
3.	Running Plant Capacity Factor (%)	39.83
4.	15 Minute Gross Maximum Demand (kW)	63,895
5.	Indicated Gross Maximum Demand kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10⁶ BTU (c)
1.	Operation, Supervision and Engineering	546	0.00		
2.	Fuel, Oil	547.1	0.00		
3.	Fuel, Gas	547.2	86,355.83		3.08
4.	Fuel, Other	547.3			
5.	Energy for Compressed Air	547.4			
6.	**Fuel Sub-Total *(2 thru 5)***	547	86,355.83	62.58	3.08
7.	Generation Expenses	548	16,081.72		
8.	Miscellaneous Other Power Generation Expenses	549	0.00		
9.	Rents	550	0.00		
10.	**Non-Fuel Sub-Total *(1 + 7 thru 9)***		16,081.72	11.65	
11.	**Operation Expense *(6+ 10)***		102,437.55	74.23	
12.	Maintenance, Supervision and Engineering	551	0.00		
13.	Maintenance of Structures	552	0.00		
14.	Maintenance of Generating and Electric Plant	553	87,104.01		
15.	Maintenance of Miscellaneous Other Power Generating Plant	554	0.00		
16.	**Maintenance Expense *(12 thru 15)***		87,104.01	63.12	
17.	**Total Production Expense *(11 + 16)***		189,541.56	137.35	
18.	Depreciation	403.1,411.10	124,754.72		
19.	Interest	427	87,395.72		
20.	**Total Fixed Cost *(18+ 19)***		212,150.44	153.74	
21.	**Power Cost *(17 + 20)***		401,692.00	291.09	

REMARKS *(including Unscheduled Outages)*

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART I - LINES AND STATIONS	BORROWER DESIGNATION KY0062 PERIOD ENDED May-12
INSTRUCTIONS - See help in the online application.	

SECTION A. EXPENSE AND COSTS

ITEM	ACCOUNT NUMBER	LINES (a)	STATIONS (b)
Transmission Operation			
1. Supervision and Engineering	560	116,773.21	160,578.64
2. Load Dispatching	561	1,692,347.51	
3. Station Expenses	562		328,537.61
4. Overhead Line Expenses	563	500,588.89	
5. Underground Line Expenses	564	0.00	
6. Miscellaneous Expenses	566	101,811.35	166,268.51
7. **Subtotal *(1 thru 6)***		2,411,520.96	655,384.76
8. Transmission of Electricity by Others	565	1,268,950.20	
9. Rents	567	0.00	10,292.15
10. **Total Transmission Operation *(7 thru 9)***		3,680,471.16	665,676.91
Transmission Maintenance			
11. Supervision and Engineering	568	101,613.04	106,237.52
12. Structures	569		2,481.99
13. Station Equipment	570		683,290.44
14. Overhead Lines	571	657,106.35	
15. Underground Lines	572	0.00	
16. Miscellaneous Transmission Plant	573	81,068.19	162,738.71
17. **Total Transmission Maintenance *(11 thru 16)***		839,787.58	954,748.66
18. **Total Transmission Expense *(10 + 17)***		4,520,258.74	1,620,425.57
19. RTO/ISO Expense - Operation	575	1,044,473.69	
20. RTO/ISO Expense - Maintenance	576	0.00	
21. **Total RTO/ISO Expense *(19 + 20)***		1,044,473.69	
22. Distribution Expense - Operation	580-589	0.00	0.00
23. Distribution Expense - Maintenance	590-598	0.00	0.00
24. **Total Distribution Expense *(22 + 23)***		0.00	0.00
25. **Total Operation And Maintenance *(18 + 21 +24)***		5,564,732.43	1,620,425.57
Fixed Costs			
26. Depreciation - Transmission	403.5	718,965.90	1,134,998.05
27. Depreciation - Distribution	403.6	0.00	0.00
28. Interest - Transmission	427	1,099,226.69	1,403,066.69
29. Interest - Distribution	427	0.00	0.00
30. **Total Transmission *(18 + 26 + 28)***		6,338,451.33	4,158,490.31
31. **Total Distribution *(24 +27 +29)***		0.00	0.00
32. **Total Lines And Stations *(21 + 30 + 31)***		7,382,925.02	4,158,490.31

SECTION B. FACILITIES IN SERVICE

TRANSMISSION LINES		SUBSTATIONS	
VOLTAGE (kV)	MILES	TYPE	CAPACITY (kVA)
1.69 kV	833.20	13. Distr. Lines	0
2.345 kV	68.40		
3.138 kV	14.40		
4.161 kV	349.60	14. Total *(12 + 13)*	1,265.60
5.		15. Step up at Generating Plants	1,879,800
6.			
7.			
8.		16. Transmission	3,540,000
9.			
10.		17. Distribution	0
11.			
12. Total *(1 thru 11)*	1,265.60	18. Total *(15 thru 17)*	5,419,800

SECTION C. LABOR AND MATERIAL SUMMARY

1. Number of Employees		56
ITEM	LINES	STATIONS
2. Oper. Labor	657,669.74	414,480.93
3. Maint. Labor	610,195.71	683,649.54
4. Oper Material	4,067,275.11	251,195.98
5. Maint. Material	229,591.87	271,099.12

SECTION D. OUTAGES

1. Total	43.90
2. Avg. No. Dist. Cons. Served	112,887.00
3. Avg. No. Hours Out Per Cons.	0.00