ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

RECEIVED
SEP 30 2013
PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

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

Response to the Office of the Attorney General's Second Request for Information dated September 16, 2013

Volume 1 of 2

FILED: September 30, 2013

ORIGINAL

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 1) *Referencing Big Rivers' response to AG 1-9 please provide the following information:*

a. What are the costs associated with Big Rivers Lines of Credit with MISO?

b. Are MISO's lines of credit requirements due to market participation or transmission service? State which one, if any.

c. What amount of the lines of credit required by MISO is related to service and market purchases by the Century Hawesville smelter?

  i. What are the costs related to this amount?

d. Are these costs being recovered from Century under the Century Agreements approved in Docket 2013-00221?

e. What amount of the lines of credit required by MISO is related to service and market purchases by the Century Sebree smelter?

  i. What are the costs related to this amount?

Response)

a. The annual cost of the letter of credit issued by Big Rivers in favor of MISO is $37,500.

b. MISO's letter of credit requirements for Big Rivers are due to market participation and transmission service.

c. The credit requirements of MISO for service and market purchases made by Big Rivers for the Century Hawesville smelter are separate from the credit requirements of MISO referenced in the response to AG 1-9. Century is responsible for providing all necessary credit requirements for its activity in MISO and pays all the costs related to those credit requirements.

    i. Fees and other charges paid by Century for its letters of credit are unknown to Big Rivers.

d. See response to subpart (c).

e. Century Sebree currently purchases its power from Big Rivers, therefore none of the amounts for the letters of credit required by MISO stated in Big Rivers' response to AG 1-9 are related to market purchases by the Century Sebree smelter.

    i. See response to subpart (e).

Witness) Billie J. Richert

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES
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Item 2) *Regarding Big Rivers' response to AG 1-48, please provide quantified details regarding the import and export transfer capabilities of Big Rivers' system before and after the Vectren 345 interconnection and other transmission expansion plans. Please provide all studies performed to quantify these capabilities.*

Response) As shown in the attached, CONFIDENTIAL June 28, 2007 study report titled, "Big Rivers Electric Corporation Bulk Transmission System Assessment," the Big Rivers export transfer capability was expected to increase from 574 MW to 1212 MW with the addition of the Vectren 345 kV interconnection and other transmission expansion plans. The import transfer capability was expected to increase from 621 MW to approximately 1200 MW with the same facility additions.

The attached July 6, 2011 MISO report titled "First Contingency Incremental Transfer Capability Study for Big Rivers Electric Corporation [BREC]" indicated facility overloads are not expected until export transfers from Big Rivers to Southern Indiana reach 1210 MW. The study report also indicated facility overloads are not expected until import transfers from Southern Indiana to Big Rivers reach 1568 MW. A redacted public version of the described study is attached.

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Witness) Christopher S. Bradley

Confidential
Attachment(s)
Produced
Separately

Contains Critical Energy Infrastructure Information - Do Not Release

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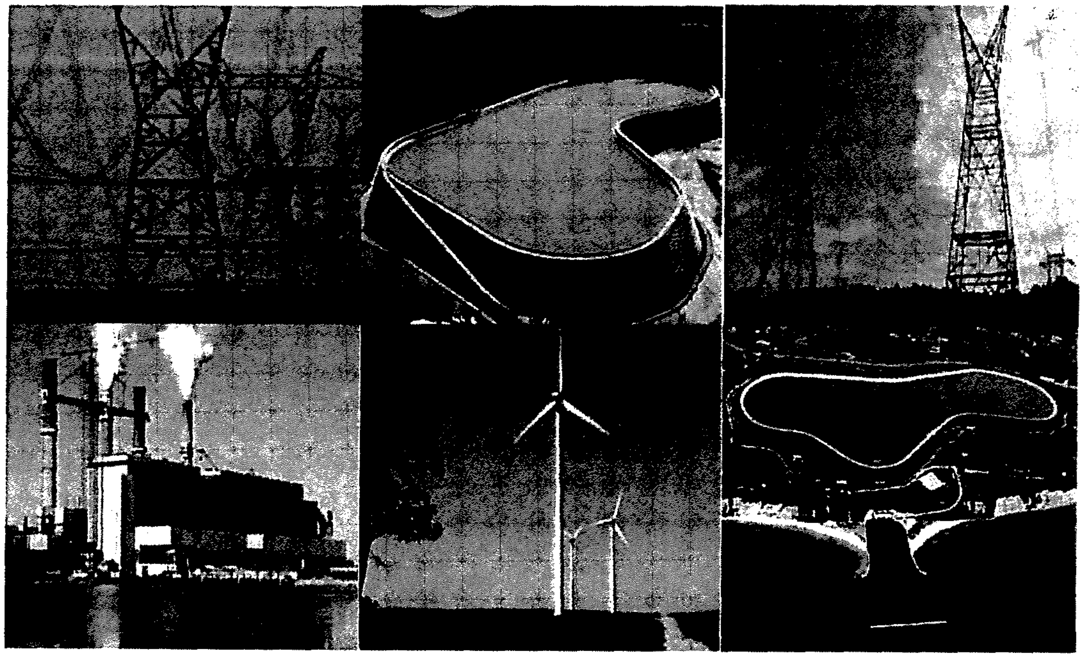
First Contingency Incremental Transfer Capability Study for Big Rivers Electric Corporation [BREC]

July 6, 2011

By
David A. Mendonsa, P.E.



First Contingency Incremental Transfer Capability Study for Big Rivers Electric Corporation [BREC]

A First Contingency Incremental Transfer Capability (FCITC) Study was conducted for Big Rivers Electric Corporation to access transfer capability five years from now, in year 2016. FCITC measures the maximum increase in power transfer that can take place between a **source system** and a **sink system** without violating thermal ratings of transmission lines or transformers. The MISO MTEP11, 2016 Summer Peak model with a security constraint economic dispatch, served as the case for these studies. Four FCITC transfers were studied, including:

1) Southern Indiana to BREC
2) BREC to Southern Indiana
3) TVA to BREC
4) BREC to TVA

The FCITC results for the four transfers are provided. The first contingency causing thermal violations, the associated overloaded transmission system element and the definition of the transfers are also provided.

1) Southern Indiana to BREC Transfer

A high transfer from Southern Indiana to BREC was analyzed. The observed transfer capability of 1568 MWs is limited by [redacted] The results of this transfer study are summarized below in Table 1. Loss of [redacted] will initiate implementation of operating guide [redacted]. The provisions of this operating guide to mitigate [redacted] This operating guide may also restrict the Southern Indiana to BREC transfer capability to 1568 MWs.

Transfer	**Southern Indiana to BREC**
FCITC	1568 MWs
Limiting Element	[redacted]
TDF (%) on the Limiting Element	8.25%
FCITC Flow on the Limiting Element	129.4 MWs
Base Flow on the Limiting Element	46.7 MWs
Limiting Flow on the Limiting Element	176 MWs
Rating of the Limiting Element	176 MWs
Contingency Description	[redacted]

Table 1. – Southern Indiana to BREC Transfer

The definition of the Southern Indiana to BREC transfer is provided below:

> Source of Transfer: SIndiana_Export; Scaling up of generation, including offline generation, in Area 207 – HE, Area 208 – Duke Energy Indiana, Area 212 – Duke Energy Ohio and Kentucky and Area 216 – IP&L
>
> Sink of Transfer: BREC_Import; Scaling down of BREC generation

2) BREC to Southern Indiana Transfer

A high transfer from BREC to Southern Indiana was analyzed. The observed transfer capability of 1210 MWs is limited by [redacted] due to Category A "Base Case" thermal overload at this transfer level. The results of this transfer study are summarized below in Table 2. The second FCITC limitation is 1768 MWs. The [redacted] is the limiting element due to Category A "Base Case" thermal overload at the 1768 MW transfer level.

Transfer	BREC to Southern Indiana
FCITC	1210 MW
Limiting Element	[redacted]
TDF (%) on the Limiting Element	20.37%
FCITC Flow on the Limiting Element	246.4 MW
Base Flow on the Limiting Element	88.6 MW
Limiting Flow on the Limiting Element	335 MW
Rating of the Limiting Element	335 MW
Contingency Description	Base Case

Table 2. – BREC to Southern Indiana Transfer

The definition of the BREC to Southern Indiana transfer is provided below:

Source of Transfer: BREC_Export; Scaling up of generation in Area 314 – BREC

Sink of Transfer: Indiana_Import; Scaling down of generation, including offline generation, in Area 207 – HE, Area 208 – Duke energy Indiana, Area 210 SIGE, Area 212 – Duke Energy Ohio & Kentucky, Area 216 – IP&L and Area 217 - NIPS

3) TVA to BREC Transfer

A high transfer from TVA to BREC was analyzed. The observed transfer capability of 1870 MWs is limited by [redacted] with the Category B contingency loss of [redacted]. The results of this transfer study are summarized below in Table 3. As the transfer from TVA is increasing and the BREC generation is diminishing, the majority of the increasing transfer will flow from TVA. However, as transfer flow from TVA is increasing, load on the [redacted]. At the above transfer level of 1870 MWs, a Category B contingency loss of [redacted] will result in the thermal overloading of [redacted].

Loss of [redacted] will initiate implementation of operating guide [redacted]. The provisions of this operating guide to mitigate potential low voltage and thermal overloads [redacted]. This operating guide may also restrict the TVA to BREC transfer capability to 1870 MWs.

Transfer	**TVA to BREC**
FCITC	1870 MW
Limiting Element	[redacted]
TDF (%) on the Limiting Element	6.92%
FCITC Flow on the Limiting Element	129.3 MW
Base Flow on the Limiting Element	46.7 MW
Limiting Flow on the Limiting Element	176 MW
Rating of the Limiting Element	176 MW
Contingency Description	[redacted]

Table 3. – TVA to BREC Transfer

The definition of the TVA to BREC transfer is provided below:

Source of Transfer: TVA_Export; Scaling up of specific generating units in Area 347 – TVA

Sink of Transfer: BREC_Import; Scaling down of BREC generation

4) BREC to TVA Transfer

A high transfer from BREC to TVA was analyzed. The observed transfer capability of 1263 MWs is limited by [redacted] due to Category A "Base Case" thermal overload at this transfer level. The results of this transfer study are summarized below in Table 4. The second FCITC limitation is 1752 MW. The [redacted]

[redacted] is the limiting element due to Category A "Base Case" thermal overload at the 1752 MW transfer level

Transfer	BREC to TVA
FCITC	1263 MW
Limiting Element	[redacted]
TDF (%) on the Limiting Element	19.52%
FCITC Flow on the Limiting Element	246.4 MW
Base Flow on the Limiting Element	88.6 MW
Limiting Flow on the Limiting Element	335 MW
Rating of the Limiting Element	335 MW
Contingency Description	Base Case

Table 4. – BREC to TVA Transfer

The definition of the BREC to TVA transfer is provided below:

Source of Transfer: BREC_Export; Scaling up of generation in Area 314 – BREC

Sink of Transfer: TVA_Import; Scaling down of generation in Area 347 – TVA

CONCLUSIONS:

BREC import of power from either Southern Indiana generation or TVA is limited by [redacted] with the Category B contingency loss o[redacted]. Loss of service of [redacted] will require operating guide [redacted] to be implemented to mitigate potential low voltage and thermal overloads in [redacted]. The operating guide may limit BREC import of power.

Export of power from BREC to either Southern Indiana or TVA is limited by the [redacted]. The re-dispatch of area generation, particularly at [redacted], may reduce potential emergency loading on this line and allow additional power to be exported.

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Item 3) *Referencing Big Rivers' response to AG 1-69, please provide the following information:*

a. Any knowledge Big Rivers has regarding possible MISO requirements for operation of HMPL, Reid CT, Reid Steam, Green 1 and/or Green 2.

Response) MISO is currently performing an Attachment Y-2 study for Green 1 and Green 2. The final study report is not yet available.

a. Big Rivers has no knowledge regarding possible MISO requirements for operation of HMPL, Reid CT, and Reid Steam.

Witness) Robert W. Berry

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES
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September 30, 2013

Item 4) *Referencing Big Rivers' response to AG 1-69, please include on a current and updated basis all costs associated with possible MISO requirements due to any Sebree smelter contract similar to the Century agreement for operation of the following:*

a. Reid CT;
b. Reid Steam;
c. Green 1; and
d. Green 2

Response) To the extent this request seeks continuous or ongoing updates, Big Rivers objects on the grounds that it is overbroad and unduly burdensome. Big Rivers states that it will update its response as required by law, as ordered by the Commission, or as it otherwise deems appropriate. Notwithstanding this objection, and without waiving it, Big Rivers states as follows.

a-d. It is Big Rivers' intention to idle the Wilson plant due to the Sebree smelter contract termination. Please also refer to the response to AG 2-3.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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Item 5) *Referencing Big Rivers' response to AG 1-124(b) please provide a list of all Wilson and Coleman eventual "re-start" or "start-up" activities and cost of each activity and anticipated times when each activity will start and costs will be incurred.*

Response) Please see the response to AG 2-9.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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Second Request for Information
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Item 6) *Referencing Big Rivers' response to SC 1-14 please provide an explanation of the following:*

a. *Do the values provided for ACES Henry Hub prices include a $0.65/MMBTU delivery charge?*

b. *Is this cost added to the Henry Hub prices to develop the natural gas fuel prices for Big Rivers' generators?*

c. *How is this delivery charge incorporated in the PCM model if it is not incorporated into the ACES Henry Hub price forecast?*

d. *Does ACES add this delivery charge to its models to forecast locational electric prices (Indiana Hub, DI_SOCO, etc) or for dispatch of non Big Rivers' gas units in the region?*

e. *If not, please describe how Henry Hub gas prices are incorporated into the ACES Modeling.*

f. *Are natural gas delivery costs incorporated into the fuel costs, or anywhere else on the variable costs on the "Annual Resource Report" or the "Monthly Resource Report" tab?*

g. *How are these natural gas delivery costs used in the PCM?*

h. *Regarding natural gas delivery to Big Rivers' generating plants, please provide the following:*

  - *i.* *Maps and drawings depicting natural gas pipelines and any Big Rivers owned pipelines used to deliver gas to Big Rivers generating plants.*
  - *ii.* *Describe Big Rivers' natural gas purchasing practices for its generation facilities.*
  - *iii.* *Provide Big Rivers' pipeline transportation contracts.*
  - *iv.* *Provide Big Rivers' fixed and variable costs for natural gas transportation for the past 3 years.*
  - *v.* *Provide Big Rivers' forecasted fixed and variable costs for natural gas transportation for 2013 through 2017.*

i. *Provide a detailed explanation and calculations used to derive the $0.65/MMBTU delivery charge.*

Response)

a. No. The Henry Hub natural gas prices do not include the estimated Big Rivers' $0.65/MMBTU delivery charge.

b. Yes.

c. The PCM model utilizes the Henry Hub natural gas forecast and adds the $0.65/MMBTU delivery charge to it.

d. No. ACES does not use that specific delivery charge in the model that develops locational electric prices.

e. ACES model can use any of several gas hubs based on locations being modeled (for example, Henry Hub, Chicago City Gate, TranscoZ6/NNY, Waha) and plant-specific delivery charges in developing locational electric prices.

f. Only the Reid CT and the Coleman units (unit start-up and pulverizer start-up fuel stabilization) utilize natural gas as a fuel. On the "Annual Resource Report" and "Monthly Resource Report" tabs, the natural gas delivery adder should be incorporated in the start costs for the Coleman units and the fuel cost and start cost for the Reid CT. In reviewing the PCM model runs, the delivery adder charge was not added to the Henry Hub natural gas price as it should have been for the PCM runs provided in Case No. 2013-00199.

g. Please see Big Rivers' response to subpart (c), above.

h.

- i. Big Rivers does not own any natural gas pipelines. Please see the attached electronic file "Texas Gas Map.pdf", which is the Texas Gas Transmission system through which natural gas is delivered to the Reid CT.
- ii. Natural gas is purchased for Coleman Station under a commercial/industrial regulated tariff from Atmos Energy. Natural gas for the Reid CT is purchased as needed from the market by ACES as Big Rivers' agent in accordance with Big Rivers' Energy Related Transaction Authority Policy.
- iii. Please see the attached documents.
- iv. From September 2010 thru August 2013 for natural gas transportation, fixed cost was $759.02, variable cost was $411,673.64.
- v. As noted above, the fixed charge for natural gas transportation is immaterial, thus, the $0.65/MMBTU, as provided in response to SC 1-14, represents the forecasted cost for natural gas transportation.

i. The $0.65/MMBTU delivery charge represents a general "rule of thumb" amount used by Big Rivers in its daily operations. This number was estimated using actual data for the last half of 2011 (7/1/11-12/31/11). During this time period, the average difference between Henry Hub and the delivered price to BREC for natural gas was calculated to be $0.648/MMBTU. Big Rivers has found that this estimate continues to approximate actual costs.

Witness) Robert W. Berry

Electronic
Attachment(s)
Produced
Separately

Request No.: 3690

Rate Schedule IT
Agreement No.: 30596
Dated: June 22, 2010

This Agreement is entered into by and between Texas Gas Transmission, LLC, ("Texas Gas") and Big Rivers Electric Corporation ("Customer").

Services under this Agreement are provided pursuant to Subpart B or Subpart G, Title 18, of the Code of Federal Regulations. Service is subject to and governed by the applicable Rate Schedule and the General Terms and Conditions of the Texas Gas FERC Gas Tariff ("Tariff") as they exist or may be modified from time to time and such are incorporated by reference. In the event the language of this Agreement conflicts with Texas Gas' then-current Tariff, the language of the Tariff will control.

Receipt and Delivery Point(s): Customer may utilize receipt and delivery points located in Service Zone(s) SL, 1, Fayetteville Lateral, Greenville Lateral, 2, 3, and 4.

Contract Demand(s): 20,000 MMBtu per day

Term: This Agreement shall be effective beginning June 28, 2010 and shall remain in effect for a term of five years or until terminated by Texas Gas or Customer upon at least thirty (30) days prior written notice.

Rate: The rate for service shall be the maximum applicable rate (including all other applicable charges Texas Gas is authorized to charge pursuant to its Tariff) unless the parties have entered into an associated discounted or negotiated rate letter agreement.

Exhibit(s): The following Exhibit(s) are attached and made a part of this Agreement:
Exhibit A, Contract Notice Address

IF YOU ARE IN AGREEMENT WITH THE FOREGOING, PLEASE INDICATE IN THE SPACE PROVIDED BELOW.

JD 6/24/10

Texas Gas Transmission, LLC Signature: Thomas A Mischel Date: 6-24-10
Name: THOMAS A. MISCHEL Title: VP-Customer Service

Big Rivers Electric Corporation Signature: Mark A. Bailey Date: 6/24/10
Name: Mark A. Bailey Title: President & CEO

EXHIBIT A

AGREEMENT NO.: 30596

EFFECTIVE DATE: June 28, 2010

Contract Notices:

Customer Correspondence:

Big Rivers Electric Corporation
201 Third St
Henderson, KY 42420

Texas Gas Correspondence:

Texas Gas Transmission, LLC
3800 Frederica Street
Owensboro, KY 42301

Attention: Marketing Services (Contractual matters)
Commercial Accounting (Invoice matters)
Customer Services (Scheduling and Allocation matters)

70)926-8686

TEXAS GAS
TRANSMISSION, LLC

3800 Frederica Street
P.O. Box 20008
Owensboro, KY 42304-0008
270/926-8686

March 22, 2013

Mr. Mike Mattox
Big Rivers Electric Corporation
201 3rd St
Henderson, KY 42420-2979

Re: Discounted Rates Letter Agreement to
HOT Service Agreement No. 30597 between
TEXAS GAS TRANSMISSION, LLC and
BIG RIVERS ELECTRIC CORPORATION dated June 22, 2010

Dear Mike:

This Discounted Rates Letter Agreement ("Agreement") specifies additional terms and conditions applicable to the referenced service agreement ("Contract") between Texas Gas Transmission, LLC ("Texas Gas") and Big Rivers Electric Corporation ("Customer"). This Agreement is subject to all applicable Federal Energy Regulatory Commission ("FERC") regulations. In the event the language of this Agreement conflicts with the Contract, the language of this Agreement will control. In the event the language of this Agreement conflicts with Texas Gas' FERC Gas Tariff currently in effect or any superseding tariff ("Tariff"), the language of the Tariff will control.

1. Texas Gas shall provide service under the Agreement to the Delivery Point listed in the attached Exhibit A. The rates charged for this service also shall be set forth in Exhibit A. In addition to the rate(s) set forth in Exhibit A, Texas Gas shall charge and Customer shall pay all other applicable charges Texas Gas is authorized to charge pursuant to its Tariff.

2. The rates in Exhibit A are applicable only for transportation service utilizing the Delivery Point specifically listed on Exhibit A.

3. This Agreement shall be effective beginning April 1, 2013 and shall continue in full force and effect through October 31, 2013.

4. All rates and services described in this Agreement are subject to the terms and conditions of Texas Gas' Tariff. Texas Gas shall have no obligation to make refunds to Customer unless the maximum rate ultimately established by the FERC for any service described herein is less than the rate paid by Customer under this Agreement. Texas Gas shall have the unilateral right to file with the appropriate regulatory authority and make changes effective in the filed rates, charges, and services in Texas Gas' Tariff, including both the level and design of such rates, charges and services and the general terms and conditions therein.

5. Except as otherwise provided in the FERC's regulations, this Agreement may not be assigned without the express written consent of the other party. Any assignment shall be in accordance with the Tariff and FERC regulations. Such consent shall not be unreasonably withheld. Any assignment made in contravention of this paragraph shall be void at the option of the other party. If such consent is given, this Agreement shall be binding upon and inure to the benefit of the parties and their successors and assigns.

6. In the event any provision of this Agreement is held to be invalid, illegal or unenforceable by any court, regulatory agency, or tribunal of competent jurisdiction, the validity, legality, and enforceability of the remaining provisions, terms or conditions shall not in any way be affected or impaired thereby, and the term, condition, or

provision which is held illegal or invalid shall be deemed modified to conform to such rule of law, but only for the period of time such order, rule, regulation, or law is in effect.

7. THIS AGREEMENT SHALL BE GOVERNED BY AND CONSTRUED UNDER THE LAWS OF THE COMMONWEALTH OF KENTUCKY, EXCLUDING ANY PROVISION WHICH WOULD DIRECT THE APPLICATION OF THE LAWS OF ANOTHER JURISDICTION.

If Customer agrees with the terms and conditions, please so indicate by signing the duplicate originals in the appropriate spaces provided below and returning the originals to Texas Gas.

Very Truly Yours,

TEXAS GAS TRANSMISSION, LLC

JB
4/1/13

By: ____________________
Name: Jeffrey L Bethel
Title: VP Power Generation
Date: 3/28/13

ACCEPTED AND AGREED TO this 28th day of March, 2013.

BIG RIVERS ELECTRIC CORPORATION
By: Robert W Berry 3-28-13
Name: Robert W. Berry
Title: Chief Operating Officer

Signature page to Discounted Rates Letter Agreement dated March 22, 2013, Agreement No. 30597.

Rate Schedule HOT
Agreement No. 30597
Discounted Rates Letter Agreement dated March 22, 2013

EXHIBIT A

DELIVERY POINT

Delivery Point Name	Meter No.	Zone
Big Rivers-Sebree	9465	3

Rate:	$0.10 per MMBtu on any day IT agreement 30596 is utilized for 100% of deliveries to Meter No. 9465. Maximum tariff rate per MMBtu on any day IT agreement 30596 is not utilized for 100% of deliveries to Meter No. 9465.

Request No. 5925

Rate Schedule PAL
Contract No.: 33008
Dated: March 22, 2013
Deal Type: Loan

This Agreement is entered into by and between Texas Gas Transmission, LLC ("Texas Gas") and Big Rivers Electric Corporation ("Customer").

Services under this Agreement are provided pursuant to Subpart B or Subpart G, Title 18, of the Code of Federal Regulations. Service is subject to and governed by the applicable Rate Schedule and the General Terms and Conditions of the Texas Gas FERC Gas Tariff ("Tariff") as they exist or may be modified from time to time and such are incorporated by reference. In the event the language of this Agreement conflicts with Texas Gas' then-current Tariff, the language of the Tariff will control.

Point(s): Point information shall be listed on Exhibit A.

Term: This Agreement shall be effective beginning April 1, 2013 and shall remain in effect through October 31, 2013.

Rate: The rate for service shall be specified on Exhibit A.

Exhibit(s): The following Exhibit(s) are attached and made a part of this Agreement:
Exhibit A, Quantity/Point/Rate Information
Exhibit B, Contract Notice Address

IF YOU ARE IN AGREEMENT WITH THE FOREGOING, PLEASE INDICATE IN THE SPACE PROVIDED BELOW.

JB
4/1/13

Texas Gas Transmission, LLC Signature: Jeffrey L Bittel Date: 3/28/13
Name: Jeffrey L Bittel Title: VP Power Generation

Big Rivers Electric Corporation Signature: Robert W Berry Date: March 28, 2013
Name: Robert W. Berry Title: Chief Operating Officer

Rate Schedule PAL
Contract No.: 33008
to PAL Service Agreement dated March 22, 2013

EXHIBIT A

Maximum Total Loan Quantity:	60,000 MMBtu
Maximum Daily Loan Quantity:	20,000 MMBtu
Loan Quantity Schedule:	April 1, 2013 through October 31, 2013
Maximum Daily Loan Payback Quantity:	20,000 MMBtu
Loan Payback Schedule(s):	April 1, 2013 through October 31, 2013
Daily Charge per MMBtu:	$0.075 per MMBtu per day for Daily Billed Loan Balance $0.03 per MMBtu per day for Intraday Loaned Quantity
Point of Service:	9465

EXHIBIT B

AGREEMENT NO : 33008

EFFECTIVE DATE. April 1, 2013

Contract Notices:

Customer Correspondence:

Big Rivers Electric Corporation
201 3rd St
Henderson, KY 42420

Texas Gas Correspondence:

Texas Gas Transmission, LLC
3800 Frederica Street
Owensboro, KY 42301

Attention: Contract Administration (Contractual matters)
Commercial Accounting (Invoice matters)
Customer Services (Scheduling and Allocation matters)

'270)926-8686

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
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Item 7) *Referencing Big Rivers' response to AG 1-206 please provide the following related to anticipated Wilson Layup costs for each year from 2013 through 2018.*

a. A detailed listing of all anticipated layup costs including a description of each type of costs and the amounts anticipated on an annual basis. Response should include detail similar to that provided in response to KIUC 2-25, PSC 2-20, AG 2-25, PSC 3-16 and any other cross referenced responses provided in Docket 2012-00535 for the years requested.

b. Indicate where each anticipated layup cost item is included in the financial model used in this rate application.

Response

a. A portion of 2013 Wilson Station Layup costs is included in the base period for Case No. 2013-00199, as shown in the table below:

	Description	Type	Base Period 2013
1	FGD, Ductwork, Stack and Module Lay-Up	FDE	$ [redacted]
2	Ductwork, Dead Air, Boiler/Boiler Aux Equipment	FDE	[redacted]
3	Fans, ductwork, steam coils, trap systems	FDE	[redacted]
4	Buners, fuel oil system, pulverizer, ductwork	FDE	[redacted]
5	Turbine Generator	FDE	[redacted]
6	Cooling Tower fill, Basin, acid skid	FDE	[redacted]
7	Total Base Period		[redacted]

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

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

Witness) Robert W. Berry

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

Response to the Office of the Attorney General's Second Request for Information dated September 16, 2013

September 30, 2013

Item 8) *Referencing Big Rivers' response to AG 1-207 please provide the following related to anticipated Coleman Layup costs for each year from 2013 through 2018.*

- ***a.*** *A detailed listing of all anticipated layup costs including a description of each type of costs and the amounts anticipated on an annual basis. Response should include detail similar to that provided in response to KIUC 2-25, PSC 2-20, AG 2-25, PSC 3-16 and any other cross referenced responses provided in Docket 2012-00535 for the years requested.*
- ***b.*** *Indicate where each anticipated layup cost item is included in the financial model used in this rate application.*

Response:

a. There are no layup costs for Coleman Station during the base period for Case No. 2013-00199. The layup costs for Coleman Station for the Forecasted Test Period include:

		Type	Forecasted Test Period
1	C1LAYUP	FDE	$ [redacted]
2	C2LAYUP	FDE	[redacted]
3	C3LAYUP	FDE	[redacted]
4	FGDLAYUP	FDE	[redacted]
5	LAYUP EQUIPMENT	CAPITAL	[redacted]
6	**Total Forecasted Test Period**		$ [redacted]

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

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

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES
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September 30, 2013

Item 9) *Referencing Big Rivers' response to AG 1-124 please provide the following regarding Wilson and Coleman restart costs after idling:*

a. Provide a description of each type of restart or startup costs expected to be incurred by Big Rivers and the year these costs will be incurred.

b. Provide a detailed breakdown of each type of restart or startup costs expected to be incurred by Big Rivers and the year these costs will be incurred.

c. Indicate whether these costs will be capital costs or expenses.

d. Provide a description of all anticipated environmental upgrades that will be required prior to restarting these units.

e. Provide a detailed breakdown of all costs related to any environmental upgrades that will be required prior to restarting these units and the year these costs will be incurred.

f. Provide a description of each type of major maintenance activity that has been deferred that will be completed prior to restarting these units.

g. Provided a detailed breakdown of all costs related to these major maintenance activities and the year these costs will be incurred.

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

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

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

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

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

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

d. Big Rivers currently plans on deferring [redacted] for Coleman and Wilson stations, [redacted]. Big Rivers has not included any other environmental upgrades at this time.

e. The estimated costs to [redacted] currently is $[redacted]. The estimated cost to [redacted] currently is $[redacted]. These costs will be incurred approximately [redacted] [redacted].

[redacted]

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

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

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

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

Witness) Robert W. Berry

Confidential
Attachment(s)
Produced
Separately

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES
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Item 10) ***Referencing Big Rivers' response to AG 1-220, AG 1-221, AG 1-224 and AG 1-227 please explain how Big Rivers can anticipate zero coal inventory at Coleman beginning in June of 2014 and still assume that under the Century Agreement the Century Hawesville smelter will pay a net amount of $0 per month to Big Rivers due to SSR costs related to Coleman operation during the forecasted test period.***

Response) The anticipated idling date of the Coleman Station is May 31, 2014. Thus, inventory at that point in time should be de minimus. Coleman will no longer be in operation and there will be no commensurate charges pursuant to the SSR Agreement.

Witness) Robert W. Berry

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES
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Item 11) ***Please refer to BREC's response to AG 1-9: Beyond the requirement to increase its letter of credit in favor of MISO by $3 million, and to post $2.5 million in cash collateral with MISO, what further actions might need to be taken by BREC to meet MISO's required levels of financial assurances should BREC's financial condition deteriorate further from the present state. What next levels of financial assurance with MISO exist beyond what BREC has satisfied to this point?***

Response) Please refer to the response to AG 2-39. The main goal of MISO's credit evaluation of a market participant is to ensure that the FTR (Financial Transmission Rights) and non-FTR credit limits that are established cover the market participant's expected obligations and exposures. The MISO credit scoring process utilizes both a qualitative and quantitative analysis and, consequently, it is not possible to quantify the additional credit support required for a "what if" scenario if Big Rivers' financial condition should deteriorate further from the present state.

Witness) Billie J. Richert

BIG RIVERS ELECTRIC CORPORATION

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Item 12) *Please refer to BREC's response to AG 1-28: What specifically prompted MISO to notify Big Rivers, when it did on June 26, 2013, that it had "lost its unsecured credit line?"*

a. *It is noted that the events listed at lines 13-18 of the response occurred well before the MISO June 26, 2013 notification date. Is this accurate?*

Response)

a. See the correspondence attached to AG 2-39. On June 10th, Big Rivers requested that MISO reduce the $5 million letter of credit, which is what prompted MISO's review and re-evaluation of the credit support.

Witness) Billie J. Richert

BIG RIVERS ELECTRIC CORPORATION

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Item 13) ***Please refer to BREC's Response to AG 1-53, page 7 (Confidential): Provide all documents, power point presentations, etc. associated with the presentation and analysis of [BEGIN CONFIDENTIAL]*** [redacted] ***[END CONFIDENTIAL], both before the Board of Directors, and in any board work session.***

Response) See attached CFC G&T Trend 2011 Benchmark Data on Key Utility Statistics presentation made to the Board of Directors on February 27, 2013. This CONFIDENTIAL presentation is being filed pursuant to a petition for confidential treatment and motion for deviation.

Witness) Billie J. Richert

Electronic
Attachment(s)
Produced
Separately

BIG RIVERS ELECTRIC CORPORATION

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Item 14) *Please refer to BREC's Response to AG 1-53, page 15(Confidential): Provide all documents, power point presentations, etc. associated with the extensive presentation and analysis of [BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL], both before the Board of Directors, and in any board work session.*

Response) Please see the response to AG 1-158.

Witness) Christopher A. Warren

BIG RIVERS ELECTRIC CORPORATION

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Item 15) *Please refer to BREC's Response to AG 1-53, page 16 (Confidential): Provide all documents, power point presentations, etc. associated with the presentation and analysis of [BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL], both before the Board of Directors, and in any board work session.*

Response) See the attached RUS Loan Application – Financing for the Environmental Compliance Plan presentation made to the Board of Directors on May 17, 2013. This CONFIDENTIAL attachment is being provided pursuant to a petition for confidential treatment.

Witness) Billie J. Richert

Confidential Attachment(s) Produced Separately

BIG RIVERS ELECTRIC CORPORATION

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Item 16) *Please refer to BREC's Response to AG 1-53, page 20, (Confidential): Provide all documents, power point presentations, etc. associated with the extensive presentation and analysis of [BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL], both before the Board of Directors, and in any board work session.*

Response) Please find attached the CONFIDENTIAL PowerPoint labeled "Term Sheet" that was the basis for Mr. Berry's presentation to the Big Rivers Board of Directors on May 17, 2013.

Witness) Robert W. Berry

Confidential
Attachment(s)
Produced
Separately

BIG RIVERS ELECTRIC CORPORATION

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Item 17) ***Please refer to BREC's Response to AG 1-53, page 21, (Confidential): Provide all documents, power point presentations, etc. associated with the presentation and analysis of [BEGIN CONFIDENTIAL]*** [redacted] ***[END CONFIDENTIAL], both before the Board of Directors, and in any board work session.***

Response) Please find the attached, CONFIDENTIAL PowerPoint labeled "Coleman Plant Idle Recommendation" that was the basis for Mr. Berry's presentation to the Big Rivers Board of Directors on May 17, 2013.

Witness) Robert W. Berry

Confidential Attachment(s) Produced Separately

BIG RIVERS ELECTRIC CORPORATION

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Item 18) *Please refer to BREC's response to AG 1-53, page 28, (Confidential): Provide all documents, power point presentations, etc. associated with the presentation and analysis of [BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL], both before the Board of Directors, and in any board work session.*

Response) To the best of Big Rivers' knowledge, there are no responsive documents.

Witness) Thomas W. Davis

BIG RIVERS ELECTRIC CORPORATION

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Item 19) *Please refer to BREC's Response to AG 1-53, page 26, (Confidential): Provide all documents, power point presentations, etc. associated with the presentation and analysis of [BEGIN CONFIDENTIAL* [redacted] *[END CONFIDENTIAL], both before the Board of Directors, and in any board work session.*

a. *Explain what are [BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL], and,*

b. *Explain what is [BEGIN CONFIDENTIAL* [redacted] *[END CONFIDENTIAL].*

c. *State why it is appropriate to not obtain [BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL]*

d. *Describe in detail how the management recommendation and Board action is consistent with BREC's response to KIUC-26.*

Response)

a. The expected changes in Big Rivers' operations over the next 6-12 months are the possible idling of one or more power plants.

b. The impact of the idling of one or more power plants on the underwriting of Big Rivers' property and casualty insurance is that idling a power plant for a period of time, and subsequent start-up, creates a greater risk than if the equipment were being used as intended.

c. This question appears to inaccurately conflate competing bids to obtain insurance policies with competing bids to hire a property and casualty agent. Big Rivers typically obtains bids from competing property and casualty agents every three years. As a result of the unusual circumstances it has faced and continues to face with the two smelter agreement terminations, Big Rivers determined it would be more beneficial to postpone the agent bidding process until 2014, when there would be more certainty surrounding its operations. Even though the competitive bid process to hire a property and casualty agent will be postponed until 2014, Big Rivers will continue to require its current agent to go to the market and obtaincompeting bids for insurance coverage, just as it does every year in an effort to obtain the best and lowest cost coverage.

d. Big Rivers' response to KIUC 1-26 describes steps taken to reduce insurance expense related to the possible idling of power plants. The management recommendation and subsequent Board action described on page 26 of the CONFIDENTIAL attachment to Big Rivers' response to AG 1-53 likewise relates to the possible idling of power plants and the procurement of property and casualty insurance agents.

Witness) Thomas W. Davis

BIG RIVERS ELECTRIC CORPORATION

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Item 20) *Please refer to BREC's Response to AG 1-53 (Confidential): Provide minutes and/or notes from all executive sessions or any other non-Regular meeting of the Big Rivers' Board of Directors, from 1/1/13 to the present, specifically to include the session referenced at page 14, during the [BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL] board meeting, as well as any others during that time period.*

Response) Please see the attached CONFIDENTIAL document. There are no other minutes of executive sessions or other non-regular meetings.

Witness) Mark A. Bailey

Confidential Attachment(s) Produced Separately

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Item 21) *Please refer to BREC's Response to AG 1-52: Please state the current job title, job responsibilities, and tenure/dates of employment at BREC for the following BREC employees:*

- *a.* *Dean Lawrence;*
- *b.* *John Talbert;*
- *c.* *Jennifer Bennett;*
- *d.* *Sharla Austin-Darnell; and*
- *e.* *If any of the above have left employment at BREC, please describe the reasons for such departure.*

Response) Current job titles and dates of employment at BREC for the requested employees are as follows:

- a. Dean Lawrence: Former Employee, 1-14-2013 to 3-22-2013;
- b. John Talbert: Director Governmental Relations, 2-21-2005 to present;
- c. Jennifer Bennett: Director Information Systems, 1-2-2006 to present;
- d. Sharla Austin-Darnell: Director Risk Management and Strategic Planning, 5-31-2013 to present.

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Please see attachments detailing job responsibilities for each position referenced in parts a-d, above.

e. Dean Lawrence, former Director of Risk Management and Strategic Planning, resigned effective March 22, 2013.

Witness) Thomas W. Davis

BIG RIVERS ELECTRIC CORPORATION
JOB DESCRIPTION
JOB TITLE: DIRECTOR GOVERNMENTAL RELATIONS

Position Summary:

This position is responsible for overall relations with entities at the local, state, and federal levels of government, as well as with various electric cooperative organizations.

Essential Functions:

Establishing and maintaining positive relations with all levels of local, state and federal government within the service territory of Big Rivers and its member systems.

Developing and/or reviewing draft state legislation affecting the operations of Big Rivers and its three member systems.

Representing Big Rivers and its three member systems during meetings of the state legislature, legislative committee meetings and legislative conferences.

Interacting with state legislators to present Big Rivers positions on draft legislation.

Representing Big Rivers and its three member systems with the Kentucky Public Service Commission, the Kentucky Energy Cabinet and other state agencies.

Coordinating legislative strategy with the Kentucky Association of Electric Cooperatives and East Kentucky Power Cooperative.

Establishing and maintaining relations with Kentucky's Investor Owned Utilities.

Perform other work duties as assigned.

BIG RIVERS ELECTRIC CORPORATION
JOB DESCRIPTION
JOB TITLE: DIRECTOR INFORMATION SYSTEMS

Position Summary:

Responsible for the daily plans, direction and management of the IS Department in order to ensure the development and implementation of cost-effective systems and efficient computer operations. Provides company-wide direction in areas of policy and planning for IT infrastructure including networks, storage, backups, data management and related functions.

Essential Functions:

Participates in the formulation of the Corporation's short and long term goals and objectives as they relate to information systems / technology.

Formulates and recommends changes and additions to the Corporation's policies and procedures relating to assigned functional activities.

Directs the design, development, and maintenance of systems and software programs.

Establishes IS/IT policies, standards, practices and security measures to ensure effective and consistent information processing and to safeguard information resources.

Plans and controls departmental staffing, development, organization, hardware acquisitions, and software systems to ensure that they are consistent with the business plan of the company.

Supervises and oversees training of information systems/technology staff and evaluates employee performance.

Administers the department's capital and expense budget, within corporate budgetary guidelines.

Develops programs and hardware systems along with staff to ensure cost-effective and current information systems.

Assists all other business units in their projects, providing guidance, technology recommendations and general integration solutions to the established infrastructure.

Directs the design and maintenance of network security.

Implements disaster recovery and emergency action plans for the information systems and technology area of the company.

Ensures the company maintains a compliant CIP program.

Maintains help desk for 24/7 system troubleshooting.

BIG RIVERS ELECTRIC CORPORATION
JOB DESCRIPTION
JOB TITLE: DIRECTOR RISK MANAGEMENT & STRATEGIC PLANNING

Position Summary:

Directs and oversees the strategic planning function in support of Big Rivers' short and long term mission and business objectives. Responsible for assisting in the development, maintenance, and management of an organizational risk management program.

Essential Functions:

Facilitate the identification, planning and execution of Big Rivers' strategic planning activities. Provide leadership in the development and implementation of systems for Big Rivers' strategic planning.

Develop and improve management reporting, including the development, monitoring and reporting of Key Performance Indicators (KPI) and dashboard performance measures.

Assist Big Rivers in developing and maintaining its risk management plan.

Assist in developing programs to protect Big Rivers from various forms of risk and fraud by reviewing transactions and accounts. Identify exposures to potential losses, measure those exposures, and decide how to protect the company from harm.

Facilitate the review of Board policies to ensure risk mitigation for the organization.

Assist the executive and senior management team in their awareness of risks and strategic issues and their implications.

Coordinate the monthly IRMC meeting agenda. Maintain minutes of the monthly meeting.

Prepare written reports for use by Executive management and the Board of Directors; prepare and make oral presentations related to the department's activities.

Perform other work-related duties as needed.

BIG RIVERS ELECTRIC CORPORATION

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Response to the Office of the Attorney General's
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September 30, 2013

Item 22) ***Please refer to BREC's Response to AG 1-52b: Produce all documents related to "2013 Forecast Accuracy Review".***

Response) Please find the requested documents attached to this response.

Witness) Billie J. Richert

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-22
Forecast Accuracy Calculation

	1+11 Forecast February	Actual February	Accuracy
Net Sales Margin (Revenues less Variable Expenses)	22,407,082	22,437,305	
Plus:			
Other revenues (not net sales margin related)	333,867	350,148	
Other operating expenses (not net sales margin related)	18,806,704	19,149,841	
Interest Income/Patronage	171,650	165,145	
TOTAL	41,719,303	42,102,439	99.1%
	4,105,895	3,802,757	

Big Rivers Electric Corporation
IRMC Meeting - May 9, 2013
March 2013 - Forecast Accuracy Calculation

	2+10 Forecast March	Actual March	Accuracy
Gross Margin (Revenues less Variable Expenses)	20,766,182	21,670,482	95.6%
Plus:			
Other revenues (not gross margin related)	295,360	320,517	91.5%
Other operating expenses (not gross margin related)	20,233,471	19,525,301	96.5%
Interest Income/Patronage	955,372	951,687	99.6%
Totals (Absolute amounts forecasted for the period)	42,250,385	42,467,987	95.8%
Margins	1,783,444	3,417,386	8.4%

Reconciliation

March Forecast	**1.8**
Changes from Forecast:	**Fav/(UnFav)**
Gross Margin (Higher off-system volumes & lower variable)	0.9
Labor	0.5
Other Operating Expenses	0.2
Total Changes	1.6
Actual Margins	**3.4**

Big Rivers Electric Corporation
IRMC Meeting - June 13, 2013
April 2013 - Forecast Accuracy Calculation

	3+9 Forecast April	Actual April	Accuracy
Gross Margin (Revenues less Variable Expenses)	19,556,168	20,874,529	93.3%
Plus:			
Other revenues (not gross margin related)	290,800	305,552	94.9%
Interest Income/Patronage	171,680	162,106	94.4%
Less:			
Other operating expenses (not gross margin related)	20,941,767	19,958,854	95.3%
Margins	(923,119)	1,383,333	0.0%

Reconciliation

April Forecast	**-0.9**
Changes from Forecast:	**Fav/(UnFav)**
Gross Margin	1.3
Labor	0.4
Production O&M	0.6
Other Operating Expenses	0
Total Changes	2.3
Actual Margins	**1.4**

	4+8 Forecast April	Actual April	Accuracy
Revenues	46,948,432	47,913,943	97.9%
Variable Expenses	27,392,264	27,039,414	98.7%
Gross Margin	19,556,168	20,874,529	93.3%
Operating expenses (not gross margin related)	20,941,767	19,958,854	95.3%
Other revenues (not gross margin related)	290,800	305,552	94.9%
Interest Income/Patronage	171,680	162,106	94.4%
Net Margins	(923,119)	1,383,333	0.0%

Big Rivers Electric Corporation
IRMC Meeting - July 11, 2013
May 2013 - Forecast Accuracy Calculation

	4+8 Forecast May	Actual May	Accuracy
Gross Margin (Revenues less Variable Expenses)	20,342,425	21,142,055	96.1%
Plus:			
Other revenues (not gross margin related)	233,860	290,824	75.6%
Interest Income/Patronage	156,147	165,318	94.1%
Less:			
Other operating expenses (not gross margin related)	21,883,697	21,336,528	97.5%
Margins	(1,151,265)	261,669	0.0%

Reconciliation (in millions)

May Forecast	$ **(1.20)**
Changes from Forecast:	**Fav/(UnFav)**
Gross Margin	0.8
Labor	0.5
Production O&M	-0.4
G&A Non-Labor	0.6
Other Operating Expenses	0
Total Changes	1.5
Actual Margins	$ **0.30**

	4+8 Forecast May	Actual May	Accuracy
Revenues	48,866,803	50,292,425	97.1%
Variable Expenses	28,524,378	29,150,370	97.8%
Gross Margin	20,342,425	21,142,055	96.1%
Operating expenses (not gross margin related)	21,883,697	21,336,528	97.5%
Other revenues (not gross margin related)	233,860	290,824	75.6%
Interest Income/Patronage	156,147	165,318	94.1%
Net Margins	(1,151,265)	261,669	0.0%

Big Rivers Electric Corporation
IRMC Meeting - August 8, 2013
June 2013 - Forecast Accuracy Calculation

	5+7 Forecast June	Actual June	Accuracy
Gross Margin (Revenues less Variable Expenses)	21,684,775	21,105,212	97.3%
Plus:			
Other revenues (not gross margin related)	273,400	329,310	79.6%
Interest Income/Patronage	155,178	157,781	98.3%
Less:			
Other operating expenses (not gross margin related)	19,263,015	19,067,432	99.0%
Margins	2,850,338	2,524,871	88.6%

Reconciliation (in millions)

June Forecast	$	**2.85**
Changes from Forecast:		**Fav/(UnFav)**
Gross Margin		(0.58)
Labor		0.11
Production O&M		(0.23)
G&A Non-Labor		0.36
Other Operating Expenses		0.01
Total Changes		(0.33)
Actual Margins	$	**2.52**

	5+7 Forecast June	Actual June	Accuracy
Revenues	48,834,544	48,965,976	99.7%
Variable Expenses	27,149,769	27,860,765	97.4%
Gross Margin	21,684,775	21,105,211	97.3%
Operating expenses (not gross margin related)	19,263,015	19,067,432	99.0%
Other revenues (not gross margin related)	273,400	329,310	79.6%
Interest Income/Patronage	155,178	157,781	98.3%
Net Margins	2,850,338	2,524,870	88.6%

Big Rivers Electric Corporation
IRMC Meeting - September 5, 2013
July 2013 - Forecast Accuracy Calculation

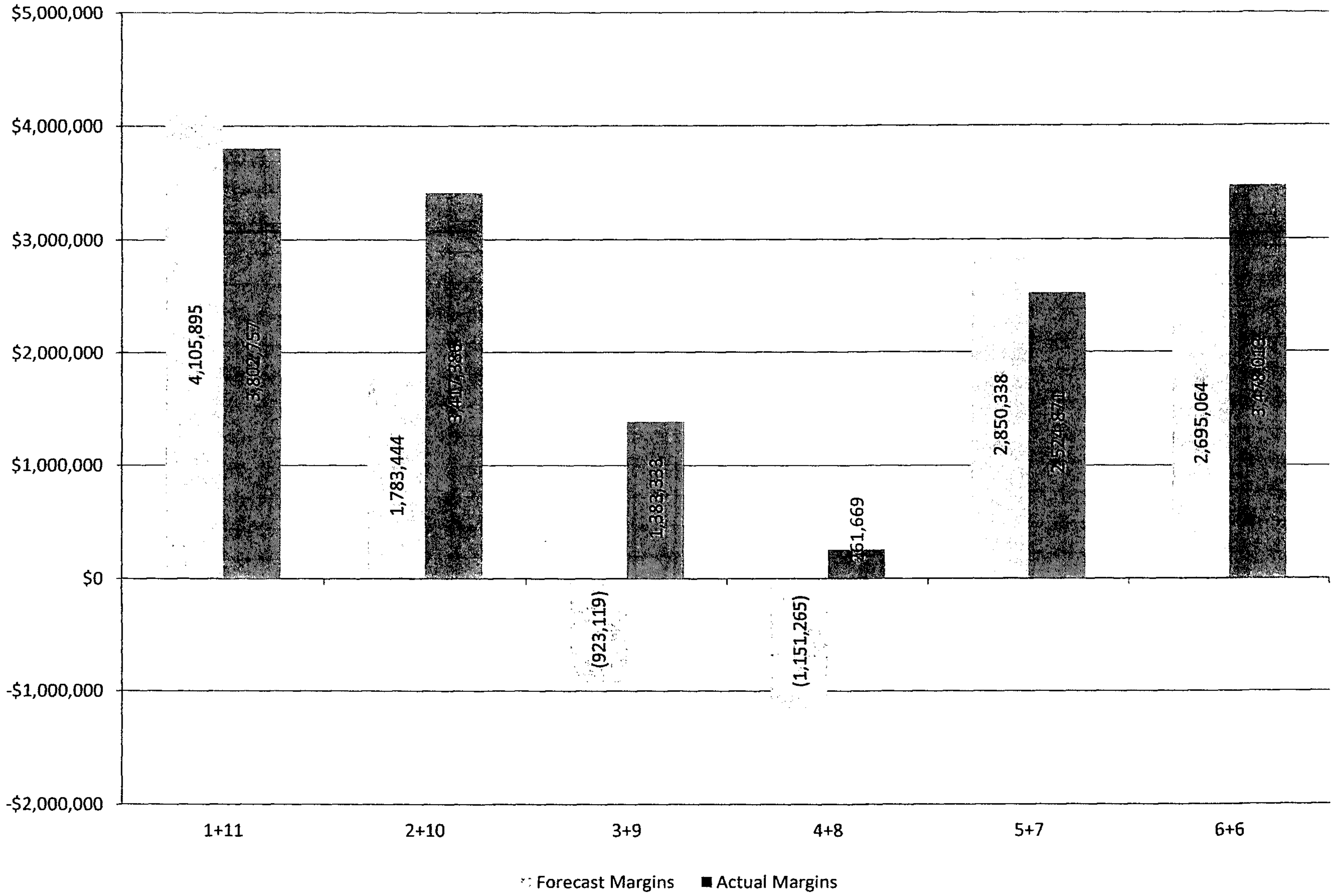
	6+6 Forecast July	Actual July	Accuracy
Gross Margin (Revenues less Variable Expenses)	21,755,689	22,130,434	98.3%
Plus:			
Other revenues (not gross margin related)	310,600	494,525	40.8%
Interest Income/Patronage	157,781	154,467	97.9%
Less:			
Other operating expenses (not gross margin related)	19,529,006	19,301,413	98.8%
Margins	2,695,064	3,478,013	70.9%

Reconciliation (in millions)

July Forecast	$	**2.70**
Changes from Forecast:		**Fav/(UnFav)**
Gross Margin		0.37
Labor		0.09
G&A Non-Labor		0.27
Other Operating Expenses		0.05
Total Changes		0.78
Actual Margins	$	**3.48**

	6+6 Forecast July	Actual July	Accuracy
Revenues	51,918,230	53,546,409	96.9%
Variable Expenses	30,162,541	31,415,975	95.8%
Gross Margin	21,755,689	22,130,434	98.3%
Operating expenses (not gross margin related)	19,529,006	19,301,413	98.8%
Other revenues (not gross margin related)	310,600	494,525	40.8%
Interest Income/Patronage	157,781	154,467	97.9%
Net Margins	2,695,064	3,478,013	70.9%

FORECAST ACCURACY



BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's Second Request for Information dated September 16, 2013

September 30, 2013

Item 23) *Please refer to BREC's Response to AG 1-98, where various Production Cost Model runs are listed: What is the cost of each PCM run, including all BREC management time to provide/develop inputs, and review runs?*

a. *What is the cost in total on the same basis for the PCM runs in aggregate?*

Response) The production cost models provided by ACES are included in the cost of the service agreement with ACES. There is no individual cost attributable to each PCM run. PCM runs require significant BREC management time, however they are not considered an incremental costas planned, and scheduled runs are a normal and necessary business activity.

a. Please see response above.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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Item 24) ***Please refer to BREC's Response to AG 1-145: Describe if and how loss of employment stemming directly and/or indirectly from potential closure of Century's Hawesville and Sebree smelting facilities is taken into consideration in performing the load forecast, especially as it pertains to forecasted residential and small business demand.***

Response) As stated in response to AG 1-145, the base case load forecast is based on the assumption that Century's Hawesville and Sebree smelting facilities will continue to operate. Loss of employment stemming directly and/or indirectly from potential closure of Century's Hawesville and Sebree smelting facilities was not taken into consideration in development of any of the load forecast scenarios.

Witness) Lindsay N. Barron

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES
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Response to the Office of the Attorney General's Second Request for Information dated September 16, 2013

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Item 25) *Please refer to BREC's Response to AG- 1-189, which is in regards to Mr. Walker's tenure as CFO for Old Dominion Electric:*

a. *Identify and describe any occasions known to Mr. Walker, during and since that tenure as CFO, where a Generation and Transmission cooperative in the U.S. such as Big Rivers and Old Dominion lost a customer representing 25% or more of that G&T cooperative's native load;*

b. *For each occasion identified in a, above, describe the actions taken by that G&T cooperative to address such departure, from an operational perspective, to the extent known by Mr. Walker:*

c. *For each occasion identified in a above, describe the action taken by that G&T cooperative to address such departure from a financial perspective to the extent known by Mr. Walker.*

Response)

a. Since Mr. Walker's tenure as CFO for Old Dominion, he has knowledge of two G&Ts, other than Big Rivers, that have either lost significant load or are expected to lose major native load. Old Dominion negotiated a contract exit of its largest member distribution cooperative. The second G&T that is expected to lose significant load is Chugach Electric. Chugach is expected to lose the load of two of its distribution members when their contracts expire in the near future.

b. Because Old Dominion's significant load change occurred after Mr. Walker's tenure at Old Dominion, he does not have detailed knowledge of specific steps taken to address the change of load or if any action was needed. It is general knowledge that subsequent to the exit of Old Dominion's member, two other Old Dominion distribution members purchased significant service territories in Virginia, which could have helped mitigate financial and/or operational issues. Chugach addressed its loss of load by writing off certain generation assets with a corresponding increase in rates and refinancing maturing bullet debt.

c. See Big Rivers' response to part b, above.

Witness) Daniel M. Walker

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September 30, 2013

Item 26) ***Please refer to BREC's response to AG 1-209 f., where it states "MISO has clearly stated to Big Rivers that Big Rivers will not be allowed to make money on the Coleman units in an SSR": Provide copies of the entire document which contains this statement, or if previously provided, provide a reference to such document.***

Response) This was verbally communicated by MISO staff during a meeting with representatives of MISO, Big Rivers and Century Aluminum at MISO's offices in Carmel, Indiana on May 31, 2013. This general philosophy can also be found in the MISO tariff, Section 38.2.7, under "SSR unit compensation", which is publically available at www.misoenergy.org.

Witness) Robert W. Berry

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Item 27) ***Please refer to BREC's response to PSC 1-29 c. provided estimated annual dollar values associated with the indicated efficiencies, for the Base Period, and Future Test Period for:***

- ***a.*** ***Restricted Travel and limited conference attendance;***
- ***b.*** ***Elimination of 8 additional headcount;***
- ***c.*** ***Elimination of backfilling open positions;***
- ***d.*** ***Renegotiation of fuel and reagent contracts; and,***
- ***e.*** ***Maintenance deferral.***

Response)

a. PSC 1-29 (c) refers to programs undertaken since the 2011 rate case. With regard to the current rate case proceeding, these cost savings have been incorporated into the forecast provided. Therefore, the forecasted test period fully reflects these savings resulting from restricting travel and conference attendance.

b. Please refer to Big Rivers' response to subpart (a). Per the forecast submitted in this case, headcount has been dropped dramatically due to the closing of the Wilson and Coleman plants, assumed in 2013 and early 2014, respectively.

Therefore, the test period fully reflects these savings associated with reduced headcount.

c. Please refer to Big Rivers' responses to subparts (a) and (b) above.

d. Big Rivers has been successful in modifying the pricing structure of lime reagent from its supplier for the years 2012 and 2013. The resultant savings, per year, has been approximately $225,000.00. Negotiations are underway for the limestone reagent supplier to Wilson Station to provide additional reagent over extended term, through January 2014, to the existing limestone reagent agreement with no escalation from 2013 to 2014. Negotiations are in process for the limestone reagent supplier to Coleman Station to amend its current agreement for extension of term through May 31, 2014. Big Rivers continues to work with its fuel suppliers in regard to contract modifications that would be beneficial to both parties.

e. During the base period from October 1, 2012 through September 30, 2013, Big Rivers realized an estimated FDE savings of $7,146,704 and estimated capital savings of $11,908,476 for maintenance deferrals at Coleman and Wilson. There are no maintenance deferrals in the future test period beginning February 1, 2014 through January 31, 2015.

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Witnesses) Thomas W. Davis (a-c)

Robert W. Berry (d-e)

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Item 28) *As a follow-up to BREC's response to AG 1-86 and related Attachment AG 1-86(a), the following addresses issues related to costs in the seven-month overlapping test period months of February 2013 through August 2013 in the prior rate case (Case No. 2012-00535) and the current rate case (Case No. 2013-00199).*

a. *Please provide a working Excel version of Attachment AG 1-86(a) as originally requested and provide the costs for each of overlapping months*

b. *Provide a working Excel version schedule for the information requested in this data request.*

c. *Per Attachment AG 1-86(a), for each of the columns showing revenues for the overlapping months in Case No. 00535 and Case No. 00199, provide the amount of Alcan and Century revenues (show Alcan and Century revenues separately) by revenue line item for each of the seven months in each rate case, and cite to related Financial Model worksheet and row reference. For each month, show the Alcan and Century "actual" and "forecasted" revenues.*

d. *Per Attachment AG 1-86(a), for each of the overlapping seven months in Case No. 00535 and Case No. 00199, provide the amount of operating costs that were both included or excluded (as appropriate for each rate case), for*

Wilson and Coleman (provide Wilson and Coleman amounts separately). Show these amounts for Variable Costs, Non-Labor Expenses, and Labor Reduction costs (as provided by BREC in response to AG 1-76 for Wilson) -- and separately identify these amounts included in each of the existing line item descriptions at Attachment AG 1-86(a) with a reference to the Financial Model worksheet and row reference.

e. *For all of these overlapping seven-month Wilson and Coleman costs in subpart (d) above, also provide the related 12-month total forecasted test period amounts, and reconcile the Wilson amounts to the response to AG 1-76 for the entire 12-month forecasted test period with a reference to the Financial Model worksheet and row reference.*

f. *Regarding subpart question (d) and (e) above, separately provide all other Wilson and Coleman operating and other costs for the overlapping seven-month periods and the entire 12-month forecasted test periods, including amounts for all other non-variable costs, administration and general expenses, common costs, lay-up costs, and all other costs not included in the response to AG 1-76. Separately identify these amounts included in each of the existing line item descriptions at Attachment AG 1-86(a) with a* *reference to the Financial Model worksheet and row reference.*

g. *Regarding the revenues and costs shown in the two columns for the seven-month overlapping periods in Case No. 00535 and Case No. 00199, please set forth all costs in the same comparison-basis format for both cases (by either adding in or removing the Wilson and Coleman costs in each column for Case Nos. 00535 and 00199), and show the net change in seven-month overlapping costs between Case No. 00535 and Case No. 00199.*

h. *BREC's response to AG 1-86(a) states that it was necessary to change certain assumptions for this filing, even though there are seven months in common with the prior rate case. Regarding subpart (g) above, after the costs for Case No. 00535 and 00199 have been adjusted to a consistent comparison basis, explain the reason for changes in each of the line item costs at Attachment AG 1-76(a) costs between Case No. 00535 and 00199 for the same seven month overlapping periods. For the changes in assumptions, inputs, and methods in each similar or same cost between the two rate cases, explain and show the amount of the change, and explain in detail why BREC believes the change was necessary. Provide the related supporting documentation, calculations, and citations to the worksheet and*

row references at the Financial Model.

i. ***Per Attachment AG 1-76(a), "Total Cost of Electric Service" showing a difference of BEGIN CONFIDENTIAL*** [redacted] ***END CONFIDENTIAL between costs in Case No. 00535 and Case No. 00199, explain if this is intended to be the same BEGIN CONFIDENTIAL*** [redacted] ******END CONFIDENTIAL shown as the revenue requirement impact of the Century departure in Case No. 00535 (per Exhibit Berry-4), or explain if this amount is merely a coincidence. Provide all related explanations.***

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

a. AG 1-86(a) did not request a working Excel version of the attachment. Nevertheless, please see the electronic attachment labeled 'AG 2-28 Elec. Att. CONFIDENTIAL.xlsx', worksheet 'AG 2-28(a)'.

b. Please see Big Rivers' response to subpart (a).

c. Please see the electronic attachment labeled 'AG 2-28 Elec. Att. CONFIDENTIAL.xlsx', worksheet 'AG 2-28(c)'.

d. Please see the electronic attachment labeled 'AG 2-28(d)(f) and AG 2-29(c) Elec. Att. CONFIDENTIAL.xlsx', worksheet AG 2-28(d).

e. The 12-month information is provided in Big Rivers' response to AG 2-29(c). It is not possible to reconcile this information to AG 1-76, as the data is not comparable. AG 1-76 is a small schedule that shows the Alcan revenue loss ($155 million) and then shows items related to idling Wilson (Variable Costs associated with Alcan, Non-labor and Labor savings from idling Wilson). So, AG 1-76 shows savings from idling Wilson, whereas the information provided in AG 2-28 and AG 2-29 shows the costs included in the respective forecasted test periods.

f. All relevant costs are provided in Big Rivers' responses to AG 2-28(d) and AG 2-29(c). For property tax, property insurance, interest, depreciation, please see the schedule produced in response to KIUC 1-15.

g. Please see Big Rivers' response to AG 2-30.

h. The assumptions that have changed relate to the load forecast (i.e. the Sebree smelter load is changed to zero), the idling of an additional generating station (which includes reductions to variable costs, FDE costs, and labor costs). These changes relate directly to the smelter contract termination notice.

i. AG 1-76(a) does not include the amount referenced in the data request; Big Rivers assumes the question refers to AG 1-86(a). The two amounts are not intended to be identical; the similarity is merely a coincidence.

Witnesses) Jeffrey R. Williams, Christopher A. Warren

Electronic
Attachment(s)
Produced
Separately

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Item 29) *As a follow-up to BREC's response to AG 1-86 and related Attachment AG 1-86(a), the following addresses issues related to a comparison of costs between the forecasted test periods in prior rate case (Case No. 00535) and the current rate case (Case No. 00199). Please provide your responses on a working Excel spreadsheet and show information for each of the twelve months in each rate case.*

a. *Use the same format at information provided at Attachment AG 1-86(a), except provide this information for the entire 12-month forecasted test periods of Case No. 00535 and Case No. 00199, using the same line items (along with any other necessary line items), and cite to the related worksheet and row reference in the Financial Model.*

b. *Using the same format Attachment AG 1-86(a), for each of the columns showing revenues for the overlapping months in Case No. 00535 and Case No. 00199, provide the amount of Alcan and Century revenues (show Alcan and Century revenues separately) by revenue line item for <u>each of the twelve months in each rate case</u>, and cite to related Financial Model worksheet and row reference. For each month, show the Alcan and Century "actual" and "forecasted" revenues. Per Attachment AG 1-86(a), for each of the columns showing revenues for the overlapping months in Case No. 00535 and Case*

No. 00199, provide the amount of Alcan and Century revenues (show Alcan and Century revenues separately) by revenue line item for each of the seven months in each rate case, and cite to related Financial Model worksheet and row reference. For each month, show the Alcan and Century "actual" and "forecasted" revenues.

c. ***Per Attachment AG 1-86(a), for each of the overlapping seven months in Case No. 00535 and Case No. 00199, provide the amount of operating costs that were both included or excluded (as appropriate for each rate case), for Wilson and Coleman (provide Wilson and Coleman amounts separately). Show these amounts for Variable Costs, Non-Labor Expenses, and Labor Reduction costs (as provided by BREC in response to AG 1-76 for Wilson) -- and separately identify these amounts included in each of the existing line item descriptions at Attachment AG 1-86(a) with a reference to the Financial Model worksheet and row reference.***

d. ***BREC's response to AG 1-86(a) states that it was <u>necessary to change certain assumptions for this filing, even though there are seven months in common with the prior rate case</u>. Regarding subpart (b) above, after the costs for Case No. 00535 and 00199 have been adjusted to a consistent***

comparison basis, explain the reason for changes in each of the line item costs. For the change in each similar or same cost between the two rate cases, explain and show the amount of the change related to each change in assumptions, inputs, and methods - - and explain in detail why BREC believes the change was necessary. Provide the related supporting documentation, calculations, and citations to the worksheet and row references at the Financial Model.

e. *Regarding subpart (a) and (b) above, explain and identify all costs (by line item and citation to the Financial Model) that were uniquely included in either Case No. 00535 or Case No. 00199, but were not included in both rate cases, and explain why it was reasonable to include these incremental or different costs in each rate case.*

Response) Big Rivers objects that this request is unduly burdensome. Notwithstanding this objection, and without waiving it, Big Rivers responds as follows.

a. Please see the attachment labeled 'AG 2-29 Elec. Att. CONFIDENTIAL.xlsx', worksheet 'AG 2-29(a)'.

b. Please see the attachment labeled 'AG 2-29 Elec. Att. CONFIDENTIAL.xlsx', worksheet 'AG 2-29(b)'.

c. Please see the attachment labeled 'AG 2-28(d)(f) and AG 2-29(c) Elec. Att. CONFIDENTIAL.xlsx', worksheet 'AG 2-29(c)'. For items excluded from the revenue requirement, please refer to the Direct Testimony of Mr. John Wolfram, Exhibit-2 Wolfram.

d. Please see Big Rivers' response to AG 2-28(h).

e. The items that are uniquely included in one case over the other were lost revenues due to the Alcan contract termination, and related variable costs, the idling of a second plant in the current rate case, and related reductions in labor and fixed departmental expenses. These adjustments were necessary to properly reflect lost revenues, variable costs and planned cost savings from idling a plant. Please see all pro forma adjustments for expenses removed from the revenue requirement in the Direct Testimony of Mr. John Wolfram, Exhibit-2 Wolfram.

Witnesses) Jeffrey R. Williams, Christopher A. Warren

Electronic
Attachment(s)
Produced
Separately

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Item 30) *BREC's response to AG 1-86(a) states that it was necessary to change certain assumptions for this filing even though there are seven months in common with the prior rate case. One business day prior to the start of the evidentiary hearing in Case No. 00535, BREC filed the application for its new rate case in Case No. 00199. Although both cases existed simultaneously and included the same seven-month overlapping period of February 2014 to August 2014, BREC was supporting different costs included in each of the seven-month overlapping periods for each rate case at this same point in time on July 3rd. Address the following:*

- *a.* *At the same point in time on July 3, 2013, explain how BREC can reasonably claim that two different amounts of costs for the same seven month period are accurate and reasonable. Explain how assumptions can be different on the very same day for the very same overlapping seven months in two rate cases.*
- *b.* *Explain if the assumptions used for the seven month overlapping costs in Case No. 00535 are more accurate than those used in Case No. 00199, or vice versa, and explain why, along with supporting documentation and calculations.*
- *c.* *Regarding (a), provide all precedent from prior Kentucky rate cases for this position and explain if BREC has taken this same position in any other rate cases and provide a citation to those rate cases and the Commission's decision.*

d. If it is reasonable to support at least two different sets of costs for the same seven-month overlapping period in two different rate cases at the same point in time, then explain how many sets of different costs can be reasonably supported at the same point in time.

e. Explain why BREC did not, or should not have, updated its assumptions and related costs for overlapping seven months in the prior Case No. 00535 to reflect the revised or updated assumptions and related costs used in current Case No. 00199.

f. Identify and cite to prior rate cases where the same utility has filed two separate rate cases with <u>overlapping forecasted test periods</u> (for a fully forecasted test period rate case) or with <u>overlapping historical test periods</u> (for a historical test period rate case) and cite to the Commission's order in these rate cases and all precedent regarding these types of rate cases, and explain if the Commission allowed or did not allow costs to be recovered for overlapping test periods.

Response)

a. It is reasonable for Big Rivers to rely upon two fully forecasted test periods in two rate cases for which the revenue and expense data differ for the same "overlapping" months. On this point, the use of the fully forecasted test period differs from the use of an historic test period (before applying any pro forma adjustments). It is reasonable for several reasons. First, the forecasts for those months were developed at different points in time. Second, the applicable regulations govern the ability of the applicant to revise its forecasts. For both rate case filings, Big Rivers' use of the fully forecasted test period is consistent with the applicable regulations. When Big Rivers developed the forecast for Case No. 2012-00535 (the "Century rate case"), the forecast included all information that was known and available to Big Rivers at that time. Other information became available after Big Rivers filed that case, but the regulation limits the circumstances under which the applicant can revise the forecasted test period. Specifically, 807 KAR 5:001(16)(11)(d) states in part as follows:

> After an application based on a forecasted test period is filed, there shall be no revisions to the forecast, except for the correction of mathematical errors, unless the revisions reflect statutory or regulatory enactments that could not, with reasonable diligence, have been included in the forecast on the date it was filed.

When Big Rivers developed the forecast for this case (the "Alcan rate case"), the forecast included all information that was known at that time, including any more recent data than was used in the last case. This is consistent with the requirements set forth in 807 KAR 5:001(16)(12)(e) which requires Big Rivers to attest that the forecast is reasonable, reliable, made in good faith, that all basic assumptions used in the forecast have been identified and justified, and that the forecast contains the same assumptions and methodologies as used in the forecast prepared for use by management. The forecast must reflect the most recent available information in order for Big Rivers to meet this requirement.

Finally, and perhaps most importantly, the revenue and expense amounts in the "overlapping" months of the two rate cases need not be identical when one considers the circumstances that will exist at the time the proposed rates in each case become effective. In the Century rate case, it was appropriate to include the effects of the Sebree smelter in the overlapping months, because at the time the proposed rates would take effect in late August 2013, the Alcan contract termination had not yet taken effect. In the Alcan rate case, it is appropriate to exclude the effects of the Sebree smelter in the overlapping months, because at the time those proposed rates will take effect in February 2013, the Alcan contract termination will be effective. Thus, for ratemaking purposes, the amounts in the overlapping seven months should be different for the two cases, because the circumstances that will exist when the rates in each case become effective are different.

b. The premise of the question is flawed. The assumptions used in Case No. 2012-00535 are appropriate for establishing rates to take effect in late August 2013, and the assumptions used in this case are appropriate for establishing rates to take effect in February 2014.

c. The request seeks legal research that Big Rivers did not perform.

d. Big Rivers objects to the question in this subpart because it is argumentative. Big Rivers has not identified how many sets of different costs can be reasonably supported. Please see the responses to subparts (a) and (b).

e. Please see the response to subpart (a).

f. The request seeks legal research that Big Rivers did not perform.

Witness) John Wolfram

Item 31) *BREC's response to AG 1-76 showed the costs savings from idling (laying up) the Wilson plant, calculated as the Alcan revenue loss netted with cost savings from the operating costs identified as Variable Costs, Non-Labor Expenses, and Labor Reduction. Also, Mr. Berry's testimony (p. 16), explains that the Wilson plant will be idled beginning February 1, 2014 (the first month of the forecasted test period) and the Coleman plant will be idled no later than June 1, 2014 (the fifth month of the forecasted test period). Address the following:*

- *a. The response to AG 1-76 states that due to the anticipated lay-up of Wilson, the Wilson operating costs were excluded from the "O&M" worksheet (for incorporation of labor & non-labor reductions), the "PCM" worksheet (for variable costs), and the "Fuel" worksheet (for fuel costs).*
  - *i. Please explain or clarify if this means that all of the Wilson <u>operating</u> plant costs (identified in AG 1-76 as Variable Costs, Non-Labor Expenses, and Labor Reduction) have been removed from the forecasted test period in this rate case.*
  - *ii. Explain and identify all Wilson operating costs that <u>have been removed</u>, and which <u>have not been removed</u>, from this rate case, and show these costs (for each month) for both the base period (separately show actual and forecasted*

costs) and the forecasted test period and reconcile these amounts to the Variable Costs, Non-Labor Expenses, and Labor Reductions shown at the response to AG 1-76.

iii. *Also, for the Wilson operating costs that have been removed and have not been removed from the forecasted test period, show these costs (by month) using the same cost/expense categories shown in BREC's response to AG 1-86 and provide a citation of all costs to worksheet and row references in the Financial Model.*

iv. *Because Wilson is expected to be idled February 1, 2014, explain all Wilson operating costs that were not removed from the test period by this date. Provide all supporting documentation and calculations for this response.*

b. Because Coleman is also anticipated to be laid up no later than June 1, 2014, explain or clarify if all of the Coleman operating plant costs have also been removed from the forecasted test period in this rate case in the same or similar format as the Wilson operating costs identified at the response to AG 1-76.

i. Provide all of the same information for the Coleman operating plant costs savings for Variable Costs, Non-Labor Expenses, and Labor Reduction, as was requested in the prior sub-part (a) question related to Wilson.

ii. Explain and identify all Coleman operating costs that <u>have been removed</u>, and which <u>have not been removed</u>, from this rate case, and show these costs (for each month) for both the base period (separately show actual and forecasted costs) and the forecasted test period and reconcile these amounts to the Variable Costs, Non-Labor Expenses, and Labor Reductions shown at the response to AG 1-76.

iii. Also, for the Coleman operating costs that have been removed and have not been removed from the forecasted test period, show these costs (by month) using the same cost/expense categories shown in BREC's response to AG 1-86 and provide a citation of all costs to worksheet and row references in the Financial Model.

iv. Because Coleman is expected to be idled no later than June 1, 2014, explain all Coleman operating costs that were not removed from the test period by this date. Provide all supporting documentation and calculations for this response.

c. Regarding amounts in prior sub-part questions (a) and (b) for Wilson and Coleman for the current rate case, identify the amount of these Variable Costs, Non-Labor Expenses and Labor Reduction amounts for the prior rate case, and show amounts for the base period and forecasted test period (for each month) in the prior rate case (and identify those amounts included and removed in the prior rate case).

d. If Coleman operating plant costs have not been removed from the forecasted test period in this rate case, explain why Coleman is treated differently than Wilson (assuming Wilson operating costs have been removed) when both plants are expected to be idled before the end of the forecasted test period in this rate case.

e. Explain if the combination of operating costs saved from idling both Wilson and Coleman (identified as those same types of operating costs of Variable Costs, Non-Labor Expenses and Labor Reduction Costs at AG 1-76) are greater than or less than the Alcan revenue loss of $155 million (this is not confidential) provided in response to AG 1-76, and provide all supporting documentation and calculations.

f. *Compare the combined operating cost savings of idling both Wilson and Coleman in this rate case to the combined revenue loss of Alcan (non-confidential - $155 million revenue loss in response to AG 1-76) and Century, and show the net impact along with all supporting documentation and calculations. Regarding the amount of the requested Century revenue loss, provide this amount on a consistent comparison basis to the Alcan revenue loss of $155 million shown at the response to AG 1-76. Thus, the non-confidential $92.4 million "Century Gross Sales Margin of Revenues Less Variable Cost" (provided at Exhibit Berry-4 in the prior rate case) will need to be grossed up to show the total Century revenue loss before variable costs are deducted (which was the format provided in the prior rate case at Exhibit Berry-4).*

g. *Refer to Exhibit Berry-4 in the prior rate case which shows Century revenues less variable costs of $92.4 million less lay-up savings costs and MISO expenses to arrive at net deficiency after savings of $63 million (these amounts are not confidential). Provide supporting documentation and line item Century costs savings (Variable Cost, FDE Non-Labor, FDE Labor, Less Lay-Up Costs, Less Retained BREC Labor, and MISO Expenses) from Exhibit Berry-4 in the prior rate case and reconcile these same types of costs and costs savings to the line* *items shown at the response to Wilson cost savings at AG 1-76 (Variable Costs, Wilson Non-Labor Expenses, Labor Reduction).*

- *i. Identify and explain all types of costs and cost savings that were included and excluded at Exhibit Berry-4 in the prior rate case, compared to the same type of costs and cost savings that have been included and excluded at the response to AG 1-76. Also, explain the reason for the different treatment of these costs and cost savings between the prior rate case and the current rate case.*

h. Regarding the cost savings in Variable Costs, Non-Labor Expenses, and Labor Reduction costs in the response to AG 1-76, explain if these costs have been netted or reduced by "lay-up costs." Provide the lay-up costs and all supporting documentation and calculations. If "lay-up" costs are included in AG 1-76 for Wilson, provide these same lay-up costs for the Coleman plant in this rate case and provide all supporting documentation and calculations.

i. The response to AG 1-76 shows "Labor Reduction" costs of $11 million (non-confidential) related to the Wilson lay-up. However, Mr. Wolfram's testimony and exhibits (pp. 15-16 and Schedule 1.10) in this rate case only shows an adjustment to remove idled Coleman plant non-recurring labor. Explain and *show where the $11 million of Wilson "Labor Reduction" and "Non-Recurring Labor" have been removed in this rate case and provide supporting documentation and calculations. Show amounts for all months and for the base period and forecasted test period, and reconcile these amounts to the same format used for removing Coleman non-recurring labor at Schedule 1.10. Explain the reasons for differences in assumptions and methods used in calculating Labor Reduction and Non-Recurring Labor costs for Wilson and Coleman. Also, provide a citation to where all amounts are reflected in the Financial Model, showing worksheet and row numbers.*

j. The response to AG 1-76 shows confidential "Non-Labor Expenses" related to the Wilson lay-up of BEGIN CONFIDENTIAL [redacted] *END CONFIDENTIAL. Also, Mr. Wolfram's testimony and exhibits (p. 18 and Schedule 1.13) in this rate case only show an adjustment to remove idled Coleman plant non-labor expenses. Explain and show where the Wilson "Non-Labor Expenses" have been removed in this rate case and provide supporting documentation and calculations (show amounts for all months and for the base period and forecasted test period), and reconcile these amounts to the same format used for removing Coleman non-labor expenses at Schedule 1.13.*

Explain the reasons for differences in assumptions and methods used in calculating non-labor expenses for Wilson and Coleman. Also, provide a citation to where all amounts are reflected in the Financial Model, showing worksheet and row numbers.

k. *Explain why depreciation expense was not removed at the Wilson cost savings in response to AG 1-76, and provide total Wilson plant and Coleman plant depreciation expense that is included in the forecasted test period in this rate case by account number and provide supporting documentation and calculations (provide a citation to worksheet and row references in the Financial Model).*

l. *Regarding the cost savings for idling the Wilson plant at AG 1-76, for both Wilson and Coleman, separately identify all other <u>non-variable expenses, administrative and general expenses, other common expenses, other overhead expenses, and all other</u> expenses which have not been removed from this rate case for Wilson and Coleman. Provide supporting documentation and calculations for these amounts for the base period and forecasted test period (along with a citation to where such amounts are included in the Financial Model). Explain why these costs have not been removed from this rate case.*

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

a. No response required.

   i. The costs for operating and maintaining the plant in a normal state are excluded, but the costs for maintaining the plant in an idled state are included. Please see the response to KIUC 2-61.

   ii. The non-recurring costs to idle the Wilson plant occur in 2013, and are therefore not included in the forecast or revenue requirement for this case. Please reference the attachment to this response for variable, non-labor and labor expenses included in the base period.For the costs included in the forecasted test period, please refer to Big Rivers' response to subpart (a)(iii). Reconciling these costs to AG 1-76 is not applicable, as the costs in AG 1-76 are savings as a result of idling the Wilson plant, and those costs are not included in the forecast, as the plant is assumed to be idled in 2013.

iii. Please refer to subpart (a)(ii) for costs that are not included in this case. Please refer to the CONFIDENTIAL attachment to this response for costs included in the forecasted test period for the Wilson plant.

iv. Please refer to subpart (a)(ii). As indicated in the forecast submitted in this case, Wilsonis scheduled to be idled in 2013; consequently, there are no operating costs in the forecasted test period.

b. Confirmed.

i. Please refer to Big Rivers' response for AG 1-282 and AG 1-283 regarding pro forma adjustments for the Coleman plant. The costs for operating and maintaining the plant in a normal state are excluded, but the costs for maintaining the plant in an idled state are included.

ii. Please refer to the response to subpart (b)(i) for non-recurring costs.Please reference the attachment to this response for variable, non-labor and labor expenses included in the base period. For the costs included in the forecasted test period, please refer to Big Rivers' response to subpart (b)(iii). Reconciling these costs to AG 1-76 is not applicable, as the costs in AG 1-76 are savings, rather than the costs included in the base and forecasted test period.

iii. Please refer to subpart (b)(i) for costs that are not included in this case. Please see the CONFIDENTIAL attachment for this response, which shows costs for the Coleman plant in the forecasted test period, net of the pro forma adjustments.

iv. The forecast in this case assumes that the Coleman plant is idled February 1, 2014. Please refer to AG 1-282 and AG 1-283 for non-recurring costs associated with the Coleman plant and related pro forma adjustments.

c. Cost savings from the idling of Wilson Station for the base period in the prior rate case (Case No. 2012-00535) are not applicable because, in that case, the budget assumption was that Wilson Station would be idled beginning on September 1, 2013. Cost savings from the idling of Coleman Station for the base period in the prior rate case (Case No. 2012-00535) are not applicable because, in that case, the budget assumption was that Coleman Station would not be idled.

d. Not applicable.

e. A comparison of the operating costs saved by idling both Wilson and Coleman to the revenue loss of Alcan is not meaningful, because Big Rivers would not idle two plants in response to the termination of one smelter.

f. Please see the attached CONFIDENTIAL document. Note that values in the table are rounded.

g. Please see the attached CONFIDENTIAL document.

i. Please see the attached CONFIDENTIAL document.

h. In regards to the cost savings in Variable Costs, Non-Labor Expenses, and Labor Reduction costs in the response to AG 1-76, the costs have been netted. Please refer to AG 2-28 (f) for the lay-up costs.

i. Please refer to AG 2-63(c).

j. The Wilson plant was assumed to be idled in 2013; consequently, there are no such non-recurring costs included in the revenue requirement.

k. Depreciation expense is a fixed cost and is still included in the revenue requirement. Please see the attachment to this response for Depreciation during the forecasted test period for the Coleman and Wilson plants.

l. Please refer to KIUC 2-15. Additionally, please refer to AG 2-63 for citations to the financial model. Please also refer to AG 1-197 regarding administrative and general expenses.

Witnesses) Jeffrey R. Williams; John Wolfram

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(a)(ii)
Wilson Station Operating Costs for the Base Period

	FY12	FY12	FY12	FY13	FY13	FY13
	Oct	Nov	Dec	Jan	Feb	Mar
OPERATION	704,370	728,977	693,510	693,890	714,351	732,335
MAINTENANCE	1,492,437	973,136	1,048,299	996,732	825,537	815,682
VARIABLES	6,209,050	6,736,158	6,231,386	7,077,806	6,374,508	6,553,894
	8,405,857	8,438,271	7,973,195	8,768,427	7,914,396	8,101,911

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(a)(ii)
Wilson Station Operating Costs for the Base Period

	FY13 Apr	FY13 May	FY13 Jun	FY13 Jul	FY13 Aug	FY13 Sep	Total
OPERATION	756,044	845,954	828,180	892,012	818,773	612,937	9,021,332
MAINTENANCE	905,886	1,038,509	952,885	1,189,683	812,697	871,260	11,922,743
VARIABLES	6,608,474	6,942,537	6,553,403	6,924,850	6,950,525	33,333	73,195,924
	8,270,404	8,827,000	8,334,468	9,006,545	8,581,995	1,517,529	94,139,999

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(a)(iii)
Wilson Station Operating Costs for the Test Period

Line No.		Feb 14 CN 2013-00199	Mar 14 CN 2013-00199	Apr 14 CN 2013-00199	May 14 CN 2013-00199	Jun 14 CN 2013-00199	Jul 14 CN 2013-00199
	WILSON						
1	Non Labor Expenses	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	Labor Expenses	132,509	143,227	136,406	145,176	124,714	136,406
3	Variable Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(a)(iii)
Wilson Station Operating Costs for the Test Period

Line No.		Aug 14 CN 2013-00199	Sep 14 CN 2013-00199	Oct 14 CN 2013-00199	Nov 14 CN 2013-00199	Dec 14 CN 2013-00199	Jan 15 CN 2013-00199
	WILSON						
1	Non Labor Expenses	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	Labor Expenses	145,176	126,968	151,742	124,986	128,950	140,360
3	Variable Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(a)(iii)
Wilson Station Operating Costs for the Test Period

Line No.		Test Period Feb 14-Jan 15 CN 2013-00199	Worksheet and Row Reference In Financial Model	Reference to AG 1-86
	WILSON			
1	Non Labor Expenses	[redacted]	O&M, Rows 127-129, 131-132,135-139,142	Production Expense Non-Labor
2	Labor Expenses	1,636,619	O&M, Rows 149-179	Labor
3	Variable Costs	[redacted]	PCM, Rows 121-135, 140	Fuel, Reagent and Allowances

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(b)(ii)
Coleman Station Operating Costs for the Base Period

	Oct 12	Nov 12	Dec 12	Jan 13	Feb 13	Mar 13	Apr 13
OPERATION	764,201	841,620	549,923	863,219	811,351	837,031	845,251
MAINTENANCE	774,574	695,887	851,052	1,216,282	791,031	1,223,193	1,237,054
VARIABLES	7,150,034	7,904,069	7,824,051	6,949,897	7,118,460	6,951,770	7,615,531
	8,688,808	**9,441,576**	**9,225,026**	**9,029,398**	**8,720,842**	**9,011,994**	**9,697,835**

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(b)(ii)
Coleman Station Operating Costs for the Base Period

	May 13	Jun 13	Jul 13	Aug 13	Sep 13	Total
OPERATION	907,262	820,256	870,956	881,493	827,343	9,819,905
MAINTENANCE	1,110,682	828,560	851,623	813,216	1,083,931	11,477,084
VARIABLES	6,927,782	6,562,148	6,939,752	6,884,365	6,252,787	85,080,646
	8,945,726	**8,210,963**	**8,662,331**	**8,579,074**	**8,164,061**	**106,377,635**

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(b)(iii)
Coleman Station Operating Costs for the Test Period

Line No.		Feb 14 CN 2013-00199	Mar 14 CN 2013-00199	Apr 14 CN 2013-00199	May 14 CN 2013-00199	Jun 14 CN 2013-00199
	COLEMAN					
5	Non Labor Expenses	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Labor Expenses	140,347	151,154	158,789	148,174	104,141
7	Variable Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(b)(iii)
Coleman Station Operating Costs for the Test Period

Line No.		Jul 14 CN 2013-00199	Aug 14 CN 2013-00199	Sep 14 CN 2013-00199	Oct 14 CN 2013-00199	Nov 14 CN 2013-00199
	COLEMAN					
5	Non Labor Expenses	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Labor Expenses	114,019	121,427	106,368	127,355	104,689
7	Variable Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(b)(iii)
Coleman Station Operating Costs for the Test Period

Line No.		Dec 14 CN 2013-00199	Jan 15 CN 2013-00199	Test Period Feb 14-Jan 15 CN 2013-00199
	COLEMAN			
5	Non Labor Expenses	[redacted]	[redacted]	[redacted]
6	Labor Expenses	108,047	116,321	1,500,832
7	Variable Costs	[redacted]	[redacted]	[redacted]

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(b)(iii)
Coleman Station Operating Costs for the Test Period

Line No.		Worksheet and Row Reference In Financial Model	Reference to AG 1-86
	COLEMAN		
5	Non Labor Expenses	O&M Rows 127-129, 131-132,135-139,142	Production Expense Non-labor
6	Labor Expenses	O&M, Rows 149-179	Labor
7	Variable Costs	PCM, Rows 121-135, 140	Fuel, Reagent and Allowances

Big Rivers Electric Corporation
Case No. 2013-00199

Attachment for Response to AG 2-31(f)
Attachment 1
($ millions)

	Century & Alcan
Revenue Loss	$ 360
Variable Cost	[redacted]
Gross Sales Margin	[redacted]
Non Labor Expense	[redacted]
Labor Reduction	$ 22
Addl. OSS Net Sales Margin	[redacted]
Reduction in MISO Administrative Fees	$ 2
Net Revenue Deficiency	[redacted]

Big Rivers Electric Corporation
Case No. 2013-00199

Attachment for Response to AG 2-31(g)
Attachment 1
($ millions)

	Century & Alcan	Century	Alcan
Gross Sales Margin (Revenue less Variable cost)	$ 164	$ 92	$ 72
Non-Labor Expenses	[redacted]	[redacted]	[redacted]
Labor Reduction	$ 22	$ 11	$ 11
Addl. OSS* Gross Sales Margin	[redacted]	[redacted]	[redacted]
Reduction in MISO* Administrative Fees	$ 2	$ 2	$ -
Net Revenue Deficiency	[redacted]	[redacted]	[redacted]

[redacted]

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(k)

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

Line No.	DESCRIPTION	Feb-14	Mar-14	Apr-14	May-14	Jun-14
1	Wilson Depreciation	1,671,036	1,671,036	1,671,106	1,671,238	1,671,395
2	Coleman Depreciation	513,002	513,033	513,075	513,215	513,866
		2,184,039	2,184,069	2,184,181	2,184,452	2,185,261

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-31(k)

Type of Filing: Original - ___X___; Updated

Line No.	DESCRIPTION	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15
1	Wilson Depreciation	1,671,517	1,671,517	1,695,464	1,695,738	1,695,762	1,695,762	1,695,793
2	Coleman Depreciation	513,866	513,866	574,442	574,442	574,442	574,472	574,472
		2,185,383	2,185,383	2,269,905	2,270,180	2,270,204	2,270,234	2,270,265

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 32) *Regarding BREC's Confidential response to PSC 2-15 in regards to the PSC's request if BREC has offered to sell the Wilson and Coleman plants, address the following:*

*BEGIN CONFIDENTIAL****

a. [redacted]

b. [redacted]

c. [redacted]

*END CONFIDENTIAL****

Response) Please see Big Rivers' responses to SC 2-29 and SC 2-30.

BIG RIVERS ELECTRIC CORPORATION

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

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dated September 16, 2013

September 30, 2013

Witness) Robert W. Berry

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 33) *Regarding BREC's Confidential response to PSC 2-15, address the following regarding the PSC's question of whether BREC has offered to sell the Wilson and Coleman plants:*

a. *If BREC would sell the Wilson and/or Coleman plants, explain how any gain or a loss would be recorded on BREC's books.*

b. *Explain if BREC would propose to record the gain or the loss on sale, either above-the-line and included in regulated earnings or below-the-line and excluded from regulated earnings, and explain the potential impact in a rate case filing.*

c. *Explain if BREC would propose to amortize such a gain or loss on its books and explain this treatment and amortization period.*

d. *Explain if BREC would treat a gain on sale different than a loss on sale in regards to how it is recorded on the books and treated in a rate case. For example, explain if BREC would record all "gain" amounts below-the-line and exclude from regulatory earnings, and explain if BREC would record all loss amounts above-the-line to increase its costs sought for recovery from customers in a rate case. Also, explain if any gain or loss would be shared between customers and shareholders.*

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

a. Please see Big Rivers' response to AG 2-35.

b. Please see Big Rivers' response to AG 2-35.

c. Please see Big Rivers' response to AG 2-35.

d. Please see Big Rivers' response to AG 2-35.

Witness) Billie J. Richert

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 34) *Regarding BREC's Confidential response to PSC 2-15, address the following:*

*BEGIN CONFIDENTIAL****

[redacted]

[redacted]

[redacted]

****END CONFIDENTIAL.*

Response) Big Rivers objects that this request is not reasonably calculated to lead to the discovery of admissible evidence. Big Rivers further objects to the extent that this request seeks a legal interpretation of documents that speak for themselves. Notwithstanding these objections, and without waiving them, Big Rivers responds as follows.

a. The Net Book Value ("NBV") calculated for each plant in response to PSC 2-15 excluded Construction Work-In-Progress ("CWIP") as the question requested "net" amounts. Accordingly, Big Rivers provided only net amounts for plant in service as no depreciation is taken on CWIP. In order to avoid potential confusion regarding what amounts were included in the response, Big Rivers explicitly stated that the amounts did not include CWIP within the response. If either the Wilson and/or Coleman plants were sold, the handling of actual CWIP would be based on the terms of the actual sales agreement.

b. Please see the electronic attachment to this response for the NBV of Wilson and Coleman, including CWIP, as of July 31, 2013 with supporting detail.

c. Please see the electronic attachment to this response for supporting detail of the NBV amounts provided in response to PSC 2-15 for Wilson and Coleman as of July 31, 2013.

d. Please see the electronic attachment to this response for detail of the $858.9 million Long-Term Debt balance as of July 31, 2013.

e. Big Rivers has not determined the ultimate use of any sales proceeds from the Wilson and/or the Coleman Units, although the initial disposition of the proceeds is governed by the terms of the Indenture. Both the Wilson and the Coleman Units are subject to the lien of the Indenture. They must be released from the lien of the Indenture in order for Big Rivers to transfer ownership of them. Section 5.2 of the Indenture sets forth the requirements to be met before property subject to the lien of the Indenture can be sold. Section 5.2 D provides that property can be released from the lien of the Indenture if cash equal to the fair value of the property (as determined by an Independent Appraiser or an Engineer) being released is deposited with the Trustee. Once the cash is deposited with the Trustee, it becomes "Deposited Cash" and is part of the Trust Estate. Section 4.8 of the Indenture provides that the Deposited Cash can be released from the lien of the Indenture and used by Big

Rivers upon the basis of Bondable Additions and/or retirement or defeasance of, or principal payments on, Obligations issued under the Indenture. Therefore, Big Rivers must have sufficient Bondable Additions and/or retired debt to justify the release of the proceeds of the sale of its units under the Indenture. At this point in time, Big Rivers has made no decisions as to the use of any such proceeds (assuming there is a sale) once such proceeds are able to be released from the Indenture and transferred to Big Rivers.

f. As discussed in "e" above, the proceeds of the sale of assets subject to the lien of the Indenture would typically be deposited with the Trustee in order for the asset to be released from the lien of the Indenture. Please refer to Big Rivers' response to AG 1-15 for the loan covenants applicable to Big Rivers' debt. Those loan covenants speak for themselves.

Witness) Billie J. Richert

Electronic
Attachment(s)
Produced
Separately

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 35) *Regarding BREC's Confidential response to PSC 2-15 address the following:*

*BEGIN CONFIDENTIAL****

[redacted]

b. [redacted]

[redacted]

*****END CONFIDENTIAL**

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

a. The timing and price for any sale of the plant(s) will affect the total revenue requirement impact, the balance sheet impact, and the operating income statement impact. Because the plants have not been sold, the timing and sale price(s) are not known. Consequently, the requested information is not available.

b. See Big Rivers' response to subpart (a), above.

Witness) Billie J. Richert

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 36) *Provide all supporting documentation Regarding BREC's Confidential response to PSC 2-15, and address the following: BEGIN CONFIDENTIAL****

[redacted]

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's Second Request for Information dated September 16, 2013

September 30, 2013

[redacted]

****END CONFIDENTIAL*

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

a.–d. Please see Big Rivers' response to AG 2-35.

Witness) Billie J. Richert

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 37) *Is there an error in the calculations or methodology of Integrated Resource Plan (IRP) costs included in this rate case and the prior rate case, which should also be addressed in the context of a follow-up to BREC's response to AG 1-285? Specifically, in the prior rate case Mr. Wolfram (p. 19, lines 14 to 19) stated that total IRP budgeted costs were $445,000, these amounts were incurred over three years, and IRP costs of $151,000 were included in the prior rate case (per Exhibit Wolfram-2, Schedule 1.11 of prior rate case). However, in the current rate case Mr. Wolfram (p. 16, lines 18-23) proposes recovery of $60,000 of these same IRP costs, and these IRP costs are for the same overlapping months of the prior rate case February 2014 through April 2014 (per Exhibit Wolfram-2, Sch. 1.11 of current rate case). It is not clear why these IRP costs are not "amortized ratably" over three years as appears to be the intent of Mr. Wolfram's testimony, and this would result in monthly amortized IRP costs of $12,361 (total IRP cost of $445,000 amortized over 36 months = $12,361/month). But instead, Mr. Wolfram's Exhibit and Schedules randomly include different IRP costs in various months, with $35,250 in the months of September and October 2013, $20,600 for January 2014, and $20,000 for the months of February through April 2014. Address the following:*

a. Explain why different amounts of IRP costs are randomly included in various months in 2013 and 2014 (and presumably randomly for the three *year period proposed by BREC), and explain the support for this method and the different monthly amounts (and provide all related calculations).*

b. *Explain why IRP costs should not be ratably amortized (equal amortization per month) over three years, equal to $12,361 per month, which would provide for somewhat different costs included in the prior and current rate case.*

c. *In BREC's response to AG 1-285, explain why the IRP costs of $271,500 shown at 1-285a Attachment do not reconcile to the total IRP costs of $445,000 in Mr. Wolfram's testimony. Provide all reconciliations and supporting documents.*

d. *In BREC's response to AG 1-285(a), explain why only IRP costs of 271,500 are shown for the base period and fully forecasted test period, and show all other remaining IRP costs budgeted or actually incurred for each prior month to reconcile to the total IRP costs of $445,000 (given that Mr. Wolfram claims that $445,000 of IRP costs are spread over 3 years).*

e. *Explain why a 3 year estimate of costs was provided when the bid document (Confidential bid document provided at AG 1-285, page 16 of 80) appears to* *indicate the IRP would be completed over about* [redacted] [redacted].

f. *Explain when actual costs will start being incurred for the IRP, Load Forecast, and Transient Study, and provide supporting documentation for this such as citations to bid documents and RFPs.*

g. *AG 1-285(b) requested copies of actual invoices for work performed to date on the IRP, Load Forecast, and Transient costs included in the test period, but it appears that invoices for only the months of February, March, April, and May 2013 have been provided (and these reflect a relatively small amount of costs). Explain why few costs have been billed and the IRP is not substantially complete, when the prior cited bid document indicated the IRP would be completed by* [redacted].

h. *In BREC's response to AG 1-285, explain why the Load Forecast costs shown at 1-285a Attachment, along with 1-285d Attachment, do not reconcile to the total Load Forecast costs of $65,000 in Mr. Wolfram's testimony. Provide all reconciliations and supporting documents.*

i. *Explain why the Load Forecast and Transient Stability costs are not spread over 3 years, or are not amortized over 3 years.*

j. *In BREC's response to AG 1-285(d), explain why the IRP budgeted costs of $445,000 are* [redacted].

k. *In BREC's response to AG 1-285(d), explain why IRP budgeted costs of $445,000 are significantly greater than the actual IRP costs of $269,780 incurred in 2010 and 2011 as shown at 1-285d Attachment.*

l. *Explain why most of the actual costs of the prior IRP (shown at 1-285d Attachment) were incurred in one year, while the budgeted IRP costs included in this rate case have been spread randomly over three years.*

m. *Explain why IRP, Load, and Transient budgeted costs should be included in the test period when BREC does not provide actual updated cost for these services similar to updates provided for rate case expense.*

Response) Big Rivers objects that this question is overly broad and unduly burdensome. Big Rivers further objects that the question is argumentative to the extent that it mischaracterizes Big Rivers as acting "randomly." Notwithstanding these objections, and without waiving them, Big Rivers responds as follows.

Big Rivers is not aware of any error in the IRP costs identified in this case. The question states that in the current case, Big Rivers "proposes recovery of $60,000 of these same IRP costs" for the "overlapping" months. That is not correct. The $60,000 listed in Exhibit Wolfram-2, Reference Schedule 1.11 is the total amount of IRP cost that is included in the forecasted test period ($20,000 each in February, March and April of 2014). The Exhibits and Schedules do not "randomly include different IRP costs in various months" but instead reflect the amounts of IRP expenses that are included in the forecast for each of the months listed. Big Rivers is proposing to amortize the IRP costs "ratably" over three years. However, Big Rivers must account for the amounts of IRP costs that are already included in the test period to ensure that over-collection of the amortized amount does not takes place.

a. The amounts of IRP costs listed in Exhibit Wolfram-2, Reference Schedule 1.11 reflect the amounts that Big Rivers forecasts for each month listed in the exhibit. They are not random. Due to the timing of the IRP process, including its due date and the work planning required to meet the due date, Big Rivers projected a cost of $20,000 for each of the months of February, March and April of 2014. This means that $60,000 of IRP costs are already included in the fully forecasted test period. The total projected IRP cost every three years is $445,000, and the amortized amount per year is $148,333. Since the test year already includes $60,000, the pro forma adjustment for IRP costs is the difference between $148,333 and $60,000, or $88,333. This is shown in Exhibit Wolfram-2, Reference Schedule 1.11, Column (3).

b. IRP costs are ratably amortized over three years, but the question does not account for the amounts of IRP costs already included in the test period. Please see the response to subpart a.

c. The $271,500 shown in the response to AG 1-285(a) attachment does not reconcile to the $445,000 total IRP costs because the $271,500 includes only those amounts included in the base period and forecast test period. The total amount of $445,000 includes costs for months that are not included in either the base period or the test period. See attached. (Note that in Case No. 2013-00034 Big Rivers was granted an extension, until May 15, 2014 to file its next IRP. This extension of time is not reflected in the forecast of IRP expenses. This has no effect on the revenue requirement because the entire forecasted IRP cost is ratably amortized over three years, not over the test period.)

d. Please see the response to subpart c, above.

e. The estimate of costs over three years is provided because the IRP filing is due every three years. The vendor producing the IRP may do so over [redacted], but the proceeding before the Commission will take additional time, and the entire process will be repeated every three years.

f. Big Rivers has already incurred costs for the Load Forecast, as it was prepared earlier this year. See the Direct Testimony of Lindsay N. Barron. As noted earlier, the Commission granted Big Rivers an extension, until May 15, 2014 to file its next IRP. As a result of this extension of time, costs for the IRP are not expected to be incurred until later this year and in 2014.

g. Please see the response to subpart f, above.

h. The forecasted cost of the Load Forecast is $65,000 every two years. In AG 1-185, the 2013 Actual YTD amount was 54,014, which represented a year-to-date amount rather than a final amount. A small amount of additional expenditures are anticipated before the load forecasting process is formally completed.

i. The Load Forecast is updated every two years, so the costs are amortized over that period and not over three years. The Transient Stability study costs are not amortized over three years because they are removed from the test period revenue requirement. See the Direct Testimony of John Wolfram, page 17.

j. The Big Rivers budget for IRP includes projected costs related to the IRP filing with the Commission, e.g. vendor development of responses to data requests, which are not included in the bid amounts.

k. The 2010 IRP did not include costs for a new Load Forecast or a Reserve Margin Study (as stated in response to AG 1-285d). Additionally, Big Rivers' expects its next IRP to be more complex due to the need to address the potential for new loads, changes to environmental regulations, increased emphasis on Demand Side Management / Energy Efficiency and recommendations in the Commission Staff's Report on the 2010 IRP that Big Rivers agreed to incorporate in its next IRP. All of these items are likely to require substantially more study – and thus more cost – than was undertaken in the 2010 IRP.

l. The costs are not spread randomly over three years. Please see the response to subpart a.

m. Transient Stability Study costs are not included in the revenue requirement. The IRP and Load Forecast costs are not rate case costs, and the Commission practice regarding the amortization of rate case expense does not apply.

Witnesses) Lindsay N. Barron, John Wolfram

Big Rivers E[illegible]ic Corporation
Case No. 2013-00199

Attachment for Response to AG 2-37

Forecasts for IRP and Load Forecast

Line	Description	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	2013
1	Integrated Resource Planning													
2	IRP	-	-	26,250	26,250	26,250	26,250	26,250	26,250	26,250	26,250	-	-	210,000
3	DSM	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	-	-	90,000
4	Planning Margin Study	21,667	21,667	21,667	-	-	-	-	-	-	-	-	-	65,000
5	Case Discovery	-	-	-	-	-	-	-	-	-	-	-	-	-
6	IRP Total	30,667	30,667	56,917	35,250	35,250	35,250	35,250	35,250	35,250	35,250	-	-	365,000
7														
8														
9	Load Forecast	16,250	16,250	16,250	16,250	-	-	-	-	-	-	-	-	65,000

Big Rivers El[illegible]c Corporation
Case No. 2013-00199

Attachment for Response to AG 2-37

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Forecasts for IRP and Load Forecast

Line	Description	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	2014	TOTAL
1	Integrated Resource Planning														
2	IRP	-	-	-	-	-	-	-	-	-	-	-	-	-	210,000
3	DSM	-	-	-	-	-	-	-	-	-	-	-	-	-	90,000
4	Planning Margin Study	-	-	-	-	-	-	-	-	-	-	-	-	-	65,000
5	Data Requests	20,000	20,000	20,000	20,000	-	-	-	-	-	-	-	-	80,000	80,000
6	IRP Total	20,000	20,000	20,000	20,000	-	-	-	-	-	-	-	-	80,000	445,000
7															
8															
9	Load Forecast	-	-	-	-	-	-	-	-	-	-	-	-	-	65,000

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 38) *Regarding BREC's response to AG 1-27, explain and identify all adjustments and amounts reflected in the forecasted test period (by account number and description) that reflect the impact of BREC's May 24, 2013, termination of its $50 million Senior Unsecured Revolving Credit Agreement with CoBank and the subsequent negotiation and amendment of BREC's $50 million Revolving Line of Credit Agreement with CFC on August 20, 2013. Provide supporting documentation and calculations showing the original amount, revised amount, and final change (or impact) regarding the following:*

- *a. Re-financing costs and all other similar or related costs related to this matter.*
- *b. Legal and other professional expenses related to this matter.*
- *c. Other recurring and nonrecurring charges paid to Co-Bank/CFC regarding this matter.*
- *d. Long and short-term debt balances.*
- *e. Interest expense and interest rates.*
- *f. All other revenues, expenses, and balance sheet accounts that were impacted.*
- *g. If the previously mentioned changes or impact are not reflected in the forecasted test period, then explain why that is the case.*

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

a. In conjunction with the 2013 CFC Amended and Restated Revolving Line of Credit Agreement ("2013 CFC A&R LOC"), Big Rivers was required to pay CFC an upfront fee equal to 15 basis points of the aggregate amount of the CFC Commitment, due and payable in advance of the closing of the agreement. On August 19, 2013 Big Rivers paid the upfront fee of $75,000 ($50,000,000 x 0.0015) associated with the 2013 CFC A&R LOC. The payment was deferred to account 18615000 (Deferred Debit-NRUCFC Line of Credit) and is being amortized to account 93020000 over the life of the agreement which matures July 16, 2017. The upfront fee associated with the 2013 CFC A&R LOC increases Big Rivers' actual annual amortization expense by $18,750. However, no adjustment was made to increase the related deferred debit account or amortization expense included in the forecasted test period for this amount based on the timing difference between when the closing of the agreement occurred and the time the forecasted test period for this proceeding was developed.

b. Legal and other professional service expenses associated with the 2013 CFC A&R LOC and the termination of the $50 million Senior Unsecured Revolving Credit

Agreement with CoBank ("2012 CoBank LOC") were not specifically budgeted or forecasted; instead, they are included within the general category of professional services expenses. Expenses associated with professional services should be recovered in this rate case because they are reasonable and prudent expenses.

c. The test year revenue requirement reflects $175,000 in savings from the termination of the 2012 CoBank LOC. The annual line of credit facility fees associated with the 2012 CoBank LOC were $300,000 at the time the agreement was terminated. However, the forecasted test period only includes $125,000 for line of credit fees ($175,000 less than the line of credit fees on the 2012 CoBank LOC) based on securing a new or amended $50M LOC to replace the 2012 CoBank LOC.

d. The 2013 CFC A&R LOC and termination of the 2012 CoBank LOC had no impact on long- or short-term debt balances. Accordingly, no adjustments to the forecasted test period were made for these items.

e. The 2013 CFC A&R LOC and termination of the 2012 CoBank LOC had no impact on interest expense or rates during the forecasted test period. Accordingly, no adjustments to the forecasted test period were made for these items.

f. The unamortized balance associated with the CoBank revolver (Account No. 18140000 – Unamortized Debt Expense-CoBank Revolver) was written off (i.e.

expensed) in May 2013 when the agreement was terminated. The remaining unamortized balance, before the write-off in May 2013, was approximately $417 thousand. The $417 thousand write-off/expense was not included in the forecasted test period, and no adjustment was made to unamortized debt expense or amortization of deferred debt expense in the financial forecast for this item based on plans to secure a new or amended $50 million LOC to replace the 2012 CoBank LOC.

g. See Big Rivers' responses to subparts a through f.

Witness) Billie J. Richert

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 39) *BREC's response to AG 1-28 states that on June 26, 2013, MISO notified BREC it had lost its unsecured credit line of $2.3 million, and that MISO and BREC discussed this matter on June 27.th MISO performed an analysis and both parties agreed BREC would provide additional cash credit support of $2.5 million, which was wired to MISO on June 28, 2013. BREC had a 4.08 financial score and MISO indicated the normal range is around 4.0 on a scale of 1 to 7, but MISO noted the loss of unsecured credit was related to the downgrade by 3 major rating agencies, high industrial composition of customers, loss of CoBank's $50 million revolver and potential loss of CFC's $50 million revolver, and potential loss of 850 MW load and revenue. Address the following:*

a. *Provide a copy of all documentation and agreements with MISO regarding this matter and provide a summary explanation of the purpose of these documents.*

b. *Explain how the 4.08 financial score was determined and provide all related supporting documents and calculations for this calculation, and provide copies of all documents given to MISO that support the 4.08 financial score. Explain if this is a MISO-specific financial assessment, an industry* *assessment, and otherwise explain in more detail this type of financial analysis of BREC.*

c. *Explain the cost versus the benefit of BREC providing additional cash to MISO of $2.5 million to retain a lesser amount of $2.3 million of unsecured credit. Why does the cash provided to MISO exceed the total credit line available?*

d. *Explain the accounting entry made on BREC's books regarding the $2.5 million wired to MISO on June 28, 2013 and explain how this is reflected on BREC's books and explain and show how this is reflected in BREC's forecasted test period.*

e. *Explain the date when MISO first extended the $2.3 million unsecured line of credit to BREC, and provide a copy of this agreement.*

f. *Explain why the reasons cited by MISO were used to justify withdrawing its $2.3 million line of unsecured credit to BREC, and why wasn't MISO already informed of many of these issues (especially if some or most of these reasons were already known, or should have been known, at the time of the original agreement for the $2.3 million of credit). For example, BREC has*

always had a high composition of industrial/smelter customers, and why wasn't this simple fact previously known by MISO.

g. ***Provide a list of all reasons included in agreements between MISO and BREC which can cause default of the $2.3 million unsecured credit.***

Response)

a. See the attached correspondence pertaining to this matter which explains the changes in credit support required by MISO.

b. The 4.08 financial score is based upon MISO's Tariff Attachment L (the Credit Policy) scoring model for Unsecured Credit Limit (UCL). MISO's Tariff Attachment L (the Credit Policy) can be accessed via MISO's website at https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx.

c. Big Rivers no longer has an unsecured credit support (line) of $2.3 million.

d. Debit – Other Special Funds – MISO CCA (an ASSET) and Credit – Temporary Cash Investments for $2.5 million. Both of these are balance sheet accounts and as such the $2.5 million is shown as an asset on Big Rivers' books. This transaction and asset have no impact on Big Rivers' forecasted test period in determining the revenue requirement in this instant case.

e. February 8, 2013. See attached letter from MISO notifying Big Rivers of this action.

f. See Big Rivers' responses to subparts (a) and (b) above.

g. Big Rivers no longer has an unsecured credit support (line) of $2.3 million.

Witness) Billie J. Richert

From: Nathan Falkmann [nfalkmann@misoenergy.org]
Sent: Wednesday, June 26, 2013 1:16 PM
To: Ralph Ashworth
Cc: Billie Richert
Subject: RE: Big Rivers Letter of Credit
Attachments: BIG RIVERS ELECTRIC CORPORATION 6-19-13 Credit Assessment.pdf

Ralph

As discussed, please see the attached letter formalizing Big River's UCL reduction to zero today. Reasons for the reduction included

- The Tariff Attachment L (the Credit Policy) scoring model UCL suggestion of zero, driven by a
  - 4.08 financial score,
  - Below investment grade downgrade by all 3 major rating agencies
  - Negative rating outlook, and
  - High industrial composition of customers.
- Having lost a $50M revolver and potentially losing another $50M revolver on August 20, 2013, which would result in no revolving lines of credit,
- Potentially losing the 850 MW load and Revenue generated by two smelters as soon August 20, 2013, and
- Big River's President and CEO Mark Bailey saying, "Simply put, BRPS has no way to offset this revenue shortfall with cost-cutting initiatives . . . The only way BRPS can make up the $74.5M revenue shortfall in the immediate term is to increase base rates as proposed in this case."

Regarding the collateral return, as discussed, we will not be able to revisit the $3M requested return until after the outage exposures normalize.

As a result of reducing UCL to zero, Big River's would be in a margin call today, based on

- $5M financial security not being sufficient to cover a
- $1.6M FTR Auction Allocation and a
- $4,009,361.25 Non-FTR Exposure.

Submitting a FTR Auction Allocation reduction to $326,348 through the Market Portal today will decrease the likelihood of a margin call tomorrow.

As discussed, the UCL will be reevaluated upon Big River's request if new, positive information comes to light e.g. satisfactory rate case approval, renegotiated access to revolver.

Feel free to give me a call if you have any questions.

Regards
Nathan Falkmann
Credit & Risk Management
MISO | P.O. Box 4202 | Carmel, IN 46082-4202
317.249.5103 (d) 317.249.5899 (f)
www.misoenergy.org

For UPS or FedEx, please send to:
720 City Center Drive Carmel, IN 46032

From: Nathan Falkmann
Sent: Wednesday, June 26, 2013 8:47 AM
To: 'Ralph Ashworth'
Cc: Billie Richert
Subject: RE: Big Rivers Letter of Credit

Ralph

Good to speak with you last night. I have yet to meet with my supervisor but wanted to let you know the Cash Collateral Agreement cannot currently be approved, as it is an old version with MISO's old legal name.

Please fill out this CCA and return the original.

Sorry for any inconvenience
Nathan Falkmann
Credit & Risk Management
MISO | P.O. Box 4202 | Carmel, IN 46082-4202
317.249.5103 (d) 317.249.5899 (f)
www.misoenergy.org

For UPS or FedEx, please send to:
720 City Center Drive Carmel, IN 46032

From: Ralph Ashworth [mailto:Ralph.Ashworth@bigrivers.com]
Sent: Wednesday, June 12, 2013 5:26 PM
To: Nathan Falkmann
Cc: Billie Richert
Subject: RE: Big Rivers Letter of Credit

Nathan,

Attached are the most current interim Big Rivers' 2013 financials available. Big Rivers has not yet generated its financials for May 2013 so I have provided the first quarter 2013 financials (which includes a Cash Flow Statement) and April 2013 RUS Form 12 Balance Sheet and Income Statement. Big Rivers normally only prepares its Cash Flow Statement on a quarterly basis but one can be provided if needed through April 2013. May 2013 financials will be available within the next few days, I will provide those when they become available.

I will be available tomorrow up until 2:00 pm EDT, and anytime on Friday except the hours 9:30 am – 11:30 am. EDT. Let me know what time works best for you.

Ralph

From: Nathan Falkmann [mailto:nfalkmann@misoenergy.org]
Sent: Wednesday, June 12, 2013 7:28 AM
To: Ralph Ashworth
Cc: Billie Richert
Subject: RE: Big Rivers Letter of Credit

Thanks Ralph, with the collateral return request, we are currently reevaluating the credit limit and would like to go over a few questions at your next availability.

I am free this week with the exception of 9:30-11 EDT today, 2-3:30 tomorrow, and 1:30-2:30 Friday.

Additionally, please send interim 2013 financials, preferably through 5/31/13 or the most current available.

Regards
Nathan Falkmann
Credit & Risk Management
MISO | P.O. Box 4202 | Carmel, IN 46082-4202
317.249.5103 (d) 317.249.5899 (f)
www.misoenergy.org

For UPS or FedEx, please send to:

720 City Center Drive Carmel, IN 46032

From: Ralph Ashworth [mailto:Ralph.Ashworth@bigrivers.com]
Sent: Tuesday, June 11, 2013 12:31 PM
To: Nathan Falkmann
Cc: Billie Richert
Subject: RE: Big Rivers Letter of Credit

Nathan,

Big Rivers wants to maintain a letter of credit (LC) with MISO but reduce it from $5 million down to $2 million. The LC of $2 million would be used primarily by our energy services department to provide the credit support needed to participate in FTR auctions. Big Rivers request for approval of a Cash Collateral Agreement was to supplement the $2 million LC if situations arise that additional credit support is required. Big Rivers feels that with a Cash Collateral Agreement in place, and the ability to provide cash deposits, it will expedite the process of providing additional credit support if the need arises. It was my understanding from Mr. Pickering that Big Rivers could provide a combination of an LC and cash deposits (as additional credit support is needed) to meet its credit support requirements with MISO. If you feel further clarification is needed it may be best if we could arrange a call and discuss by phone.

Thanks for your assistance in this matter.

Ralph Ashworth
Director Finance
Big Rivers Electric Corporation
Office: (270) 844-6131

From: Nathan Falkmann [mailto:nfalkmann@misoenergy.org]
Sent: Tuesday, June 11, 2013 9:07 AM
To: Ralph Ashworth
Cc: Billie Richert
Subject: RE: Big Rivers Letter of Credit

Ralph

I apologize I have been out of the office since Wednesday and failed to activate my external OOO message. Going forward emailing misocredit@misoenergy.org will ensure your message is received by someone in my department that is in the office. However, I am here through the end of the month, so we can correspond directly regarding this matter.

We are discussing the collateral return internally and hope to respond well before the end of the week.

Quick point of clarification: I understand you spoke with my colleague, Griffin Pickering. He seemed to think Big River's just wanted to replace the LC with cash collateral, but your voicemail, email, and letter indicate otherwise. Could you reconfirm?

Thanks
Nathan Falkmann
Credit & Risk Management
MISO | P.O. Box 4202 | Carmel, IN 46082-4202
317.249.5103 (d) 317.249.5899 (f)
www.misoenergy.org

For UPS or FedEx, please send to:
720 City Center Drive Carmel, IN 46032

From: Ralph Ashworth [mailto:Ralph.Ashworth@bigrivers.com]
Sent: Monday, June 10, 2013 6:22 PM

To: Nathan Falkmann
Cc: Billie Richert
Subject: Big Rivers Letter of Credit

Nathan,

Billie Richert (VP Accounting, Rates and CFO) here at Big Rivers requested I contact you relating to reducing Big Rivers' $5 million letter of credit (LC)currently issued to the benefit of MISO. Based on previous discussions between you and Billie, it is my understanding that MISO would be willing to approve a reduction in the letter of credit from $5 million down to $2 million. Big Rivers is in the process of putting in place a Cash Collateral Agreement with MISO that will allow us to deposit cash in quick response to a margin call — in the event one does occur. The $5 million LC was issued to MISO and send to the attention of the Manager, Credit Risk & Customer Registration. Could you provide the name and contact information of the person in that position so I can provide a notification of Big Rivers desire to reduce the current LC? I appreciate your assistance in this matter and if you have any questions or comments please contact me by reply to this email or by phone at (270) 844-6131.

Best Regards,

Ralph Ashworth
Director Finance
Office: (270) 844-6131
Email: Ralph.Ashworth@bigrivers.com

MISO

Nathan Falkmann
Analyst Credit & Risk Management
[illegible]-5162
nfalkmann@misoenergy.org

June 26, 2013

Ralph Ashworth
BIG RIVERS ELECTRIC CORPORATION
201 Third Street
Henderson, KY 42419

Re: Creditworthiness Assessment

Dear Ralph:

MISO recent completed an assessment of the creditworthiness of BIG RIVERS ELECTRIC CORPORATION in accordance with the provisions of the MISO Credit Policy (Attachment L of the Transmission, Energy and Operating Reserve Markets Tariff).

Based on this assessment, MISO has reduced the Unsecured Credit Limit from $2,300,000 to $0 for BIG RIVERS ELECTRIC CORPORATION.

Please do not hesitate to contact me if I may provide you with any additional information.

Sincerely,

Nathan Falkmann

Nathan Falkmann
Analyst, Credit & Risk Management

Midcontinent Independent System Operator, Inc.
701 City Center Drive Carmel, IN 46032   1125 Energy Park Drive St. Paul, MN 55108
www.midwestiso.org

MISO

Nathan Falkmann
Analyst, Credit & Risk Management
317-2[illegible]
nfalkmann@misoenergy.org

February 8, 2013

Billie Richert
BIG RIVERS ELECTRIC CORPORATION
201 Third Street
Henderson, KY 42419

Re: Creditworthiness Assessment

Dear Billie:

MISO recently completed an assessment of the creditworthiness of BIG RIVERS ELECTRIC CORPORATION in accordance with the provisions of the MISO Credit Policy (Attachment L of the Transmission, Energy and Operating Reserve Markets Tariff).

Based on this assessment, MISO has reduced the Unsecured Credit Limit from $4,500,000 to $2,300,000 for BIG RIVERS ELECTRIC CORPORATION.

Please do not hesitate to contact me if I may provide you with any additional information.

Sincerely,

Nathan Falkmann

Nathan Falkmann
Analyst, Credit & Risk Management

Midwest Independent Transmission System Operator, Inc
701 City Center Drive Carmel, IN 46032 1125 Energy Park Drive St. Paul, MN 55108
www.midwestiso.org

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 40) ***BREC's response to AG 1-34 indicates it disagrees with the characterization of the costs related to the loss of Century/Alcan smelters as "stranded costs." Please provide BREC's definition of "stranded costs" and explain how this is not applicable to the loss of the Smelters. Also, provide a citation to prior Commission orders and cases which have a definition of stranded costs that is consistent with BREC's definition of that term, or explain why prior Commission precedent regarding such definitions is not appropriate in this proceeding.***

Response) Stranded costs typically refer to prudently-incurred utility costs that may not be recoverable by the utility when a deregulated or competitive market environment is implemented. The costs here are not "stranded" by virtue of any state-wide restructuring of the energy market that will have a permanent impact on the market structure in which Big Rivers operates; instead, they represent a net revenue shortfall caused by the contract termination of two sizable customers.

Even if the definition of stranded costs was not tied to electric restructuring, the costs in this case should not be considered stranded. These costs were not directly assigned to the smelters before the contract termination, and should therefore not be considered stranded by virtue of the smelter contract termination. For these reasons, Big Rivers disagrees with the characterization of these costs as "stranded costs."

Big Rivers is not aware of any Commission orders or cases in which a definition of "stranded costs" is provided. Similarly, Big Rivers is not aware of any rate proceeding before the Commission in which the departure of a major customer (rather than competitive restructuring) was determined to have resulted in "stranded costs."

Witness) John Wolfram

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 41) *BREC's response to AG 1-36 states that it is in the process of providing a "cost reimbursement" agreement to Century to recover all costs associated with the potential transaction. Address the following and* *<u>provide updates to this data request:</u>*

- *a.* *Describe specifically the timelines and deadlines that BREC is working under to provide a cost reimbursement agreement to Century and provide copies of documents that set forth these timelines.*
- *b.* *Provide copies of all previous and new agreements and documents which explain and identify the types of costs (and the amounts of costs, if applicable) which are required to be reimbursed to BREC. Identify all types of costs which are required to be reimbursed under all agreements, and identify all other types of costs that BREC and Century are separately negotiating for reimbursement.*
- *c.* *Explain why BREC cannot identify or provide to the AG, at this time, the amount of costs (or a reasonable estimate of these costs) to be potentially reimbursed by Century. Explain the reasons for delays or why these amounts are not known or cannot be reasonably estimated at this time.*

d. ***Provide a reasonable range or estimate of the minimum and maximum amount of costs that BREC believes is reasonable for reimbursement from Century, identify costs by account and description.***

e. ***Explain if BREC is delaying the quantification or resolution of these reimbursement amounts to avoid reflecting such amounts in this rate case.***

Response) To the extent this request seeks continuous or ongoing updates, Big Rivers objects on the grounds that it is overbroad and unduly burdensome. Big Rivers states that it will update its response as required by law, as ordered by the Commission, or as it otherwise deems appropriate. Notwithstanding this objection, and without waiving it, Big Rivers states as follows.

a. Attached to this response is a copy of the Reimbursement Agreement dated as of September 10, 2013, by and among Big Rivers Electric Corporation, Kenergy Corp., Century Aluminum Company and Century Aluminum Sebree, LLC (the "Reimbursement Agreement").

b. Please see the Reimbursement Agreement provided in response to subpart a of this information request.

c. Big Rivers cannot identify the amount of the costs or a reasonable estimate of the costs that will potentially be reimbursed by Century because those costs are not known and cannot be reasonably estimated. Big Rivers can state that all the costs and expenses described in the Reimbursement Agreement and incurred by Big Rivers will be reimbursed under the terms of that agreement.

d. Big Rivers believes that all costs described in the Reimbursement Agreement that are incurred by Big Rivers should be reimbursed by Century. Please also refer to part c, above.

e. No. In any event, the costs incurred by Big Rivers and the equal and offsetting cost reimbursement from Century will have no net effect on this rate case.

Witness) Robert W. Berry

Execution Version

REIMBURSEMENT AGREEMENT

This **REIMBURSEMENT AGREEMENT**, dated as of September 10, 2013 (this "Agreement"), is made by and among **BIG RIVERS ELECTRIC CORPORATION**, a Kentucky electric generation and transmission cooperative (together with its successors and assigns, "Big Rivers"), **KENERGY CORP.**, a Kentucky electric cooperative corporation (together with its successors and assigns, "Kenergy"), **CENTURY ALUMINUM COMPANY**, a Delaware corporation, (together with its successors and assigns, "Century"), and **CENTURY ALUMINUM SEBREE LLC**, a Delaware limited liability company (together with its successors and assigns, "CAS").

PRELIMINARY STATEMENTS:

A. The parties hereto are considering negotiation of a letter of intent pursuant to which each of them will agree to investigate, evaluate and negotiate electric service arrangements for CAS, whereby Kenergy would provide electric services to CAS with energy supplied from third parties and transmission and ancillary services provided by Big Rivers pursuant to the tariff of Midwest Independent Transmission System Operator, Inc. ("MISO"), all as further described in the letter of intent (the "Transaction").

B. The provisions of this Agreement will govern the rights of Big Rivers and Kenergy and the obligations of Century with respect to the circumstances upon which, and the times at which, Century shall be required to reimburse Big Rivers and Kenergy for certain costs that are incurred by or otherwise chargeable to Big Rivers or Kenergy.

C. Contemporaneously with the execution and delivery of this Agreement, (i) the parties hereto will enter into an Escrow Agreement, dated as of the date hereof, with Old National Bank of Evansville, Indiana (the "Escrow Agreement"), to facilitate the provisions of this Agreement from which amounts deposited in the account established thereunder by Century will be applied in accordance with the terms hereof; and (ii) Century has deposited the Initial Escrow Amount into the Deposit Account (each as defined in the Escrow Agreement).

NOW, THEREFORE, the parties hereto hereby agree as follows:

1. Costs of Century. Century or Century's affiliates will pay all of its own and its affiliates' costs and expenses associated with the proposed Transaction.

2. Costs of Big Rivers or Kenergy; Reimbursement by Century.

(a) Century will reimburse Big Rivers and Kenergy for all out-of-pocket fees, costs and expenses (but excluding internal staffing costs and allocated overhead costs) actually incurred by or otherwise chargeable to Big Rivers or Kenergy, respectively, in connection with the investigation, evaluation and negotiation of, and the preparation of agreements, obtaining of necessary consents and approvals and satisfaction of other conditions precedent for, the Transaction, whether or not the Transaction shall be closed or consummated (collectively, "Transaction Costs"), including, without limitation, all of:

(i) the fees, at standard rates (less any discounts provided to Big Rivers or Kenergy), and expenses of counsel and any advisors to Big Rivers or Kenergy, including fees related to compliance with the requirements of this Agreement; *provided*, that with respect to expenses of current counsel or advisors to Big Rivers or Kenergy, such expenses are of a type reimbursable under the current engagement arrangements;

(ii) the out-of-pocket costs and expenses for travel, food and lodging of employees of Big Rivers or Kenergy, in connection with their consideration and approval of the proposed Transaction;

(iii) the fees and expenses of counsel and any advisors to any creditor of Big Rivers or Kenergy, the consent or approval of which is required to effect the Transaction;

(iv) the fees and expenses of counsel and any advisors to MISO or any wholesale supplier of electric energy, capacity or other electric services to Kenergy for resale to CAS in connection with the investigation, negotiation and evaluation of the Transaction by MISO or any such supplier; and

(v) the fees and expenses of counsel and any advisors to any other third-party not participating in the Transaction, the consent or approval of which is required to effect the Transaction, that are chargeable to or reimbursable by Big Rivers or Kenergy.

(b) The Transaction Costs shall not include:

(i) any taxes or assessments by any governmental or regulatory authority arising out of the consummation of the proposed Transaction or any other transaction entered into in connection therewith or to facilitate the same;

(ii) the costs or expenses associated with Big Rivers' or Kenergy's performance of any debt, obligation or liability undertaken by Big Rivers or Kenergy (as applicable) pursuant to any definitive agreement entered into by it in order to consummate the Transaction or any other transaction entered into in connection with or to facilitate the Transaction; or

(iii) any costs or expenses incurred by or otherwise chargeable to Big Rivers, Kenergy or any other person or entity in connection with any dispute or litigation proceeding between Century or any of its affiliate(s), on the one hand, and Big Rivers, Kenergy or such other person or entity, on the other hand, or between Big Rivers, Kenergy and such other person or entity, directly relating to the interpretation or enforcement of this Agreement or any letter of intent or definitive documentation that may be entered into by Century or its affiliate(s), Big Rivers, Kenergy or such other person or entity. Notwithstanding any other provision hereof, the costs and expenses arising out of proceedings or litigation before any governmental authority relating to obtaining any governmental approvals for the Transaction (but not the costs and expenses arising out of any rate case proceeding before the Kentucky Public Service Commission or any associated litigation in which Big Rivers or Kenergy seek to recover the revenue lost by the termination of the current power sale agreements with CAS) shall constitute Transaction Costs.

(c) Century shall have deposited the Initial Escrow Amount into the Deposit Account in connection with the entry into this Agreement and the Escrow Agreement.

3. Reports; Additional Deposits Into Deposit Account.

(a) Big Rivers, for work it performs as well as that performed by Kenergy, shall provide Century with periodic reports of the Transaction Costs incurred by or otherwise chargeable to Big Rivers or Kenergy (each a "Transaction Costs Report"). Big River and Kenergy shall provide the first Transaction Costs Report to Century on the 11th business day following the effectiveness of this Agreement; *provided*, the parties acknowledge and agree that Big Rivers and Kenergy may not know specific amounts of Transaction Costs incurred or otherwise chargeable to such date. Subsequent Transaction Costs Reports will be provided to Century on the 15th day of each month (or the immediately following business day if the 15th is not a business day) and the reporting period shall be the prior calendar month (each a "Reporting Period"). In addition, on the 1st and 15th day of each month (or the immediately following business day if such 1st or 15th is not a business day), Big Rivers and Kenergy shall provide Century with a telephonic briefing for the Reporting Period that includes a summary of all of the items contained in a Transaction Costs Report to the extent not previously summarized or discussed in a prior Transaction Costs Report; *provided* that briefings on the 1st day of each month may exclude specific information required in clause 3(b)(iv) below and do not require counsel or advisors to Big Rivers or Kenergy to issue additional invoices for such briefing. Big Rivers and Kenergy shall require a representative of each counsel or advisor directly engaged by Big Rivers or Kenergy and incurring Transaction Costs to participate and be prepared to summarize, subject to the preceding sentence, the items listed in clause (b) below for the Reporting Period.

(b) Each Transaction Costs Report will contain:

(i) an updated list of known tasks for the Transaction to be completed and estimated completion dates;

(ii) subject to paragraph 3(e) below and to the extent necessary in view of the invoices provided in clause (iv) below, a description, redacted if applicable, of the work performed on each task during the Reporting Period and the status of those tasks toward completion;

(iii) identify any additional tasks expected to be undertaken and/or completed during the next 30 days;

(iv) the aggregate amount of the Transaction Costs for such Reporting Period, including, subject to paragraph 3(e) below, all related invoices, redacted if applicable, identifying costs or expenses incurred, the hours billed with the associated description, billing rates, and names of the individuals performing the tasks generating the Transaction Costs; and

(v) a budget of the Transaction Costs estimated by Big Rivers and Kenergy to be incurred by or otherwise chargeable to Big Rivers or Kenergy during the 30 days following the date of such report (each a "Budget").

(c) Big Rivers and Kenergy shall (i) require each counsel and advisor to Big Rivers or Kenergy incurring Transaction Costs which customarily bills monthly to provide an invoice for such costs on or before the 10th day of the month for Transaction Costs incurred in the prior month and, subject to paragraph 3(e) below, the invoice, redacted if applicable, shall include hours billed with the associated identification, billing rates, and names of the individuals performing the tasks generating the Transaction Costs in such invoice, and (ii) request other third parties incurring Transaction Costs to provide an invoice with the same information on the same schedule for costs incurred in the prior month. The parties intend that any invoice for Transaction Costs received by Big Rivers or Kenergy shall be included in the next following Transaction Costs Report but redacted if applicable; however failure to do so shall not limit the ability of Big Rivers or Kenergy to include any such Transactions Costs in a later Transaction Costs Report unless such costs were withheld in bad faith.

(d) For purposes of this Agreement, a "task" shall be such work that must be obtained for the Transaction to proceed, such as obtainment of consents, regulatory filings, regulatory approvals, legal review of authority to enter into the Transaction, or MISO application. Included within a task may be transaction structuring, documentation preparation, or similar work.

(e) In describing the tasks performed or to be performed in a Transaction Costs Report, Big Rivers may exclude an identification of any work to the extent such description would, as determined by Big Rivers or Kenergy in good faith, disclose confidential business information, attorney-client privileged or attorney-client work product or to be information the disclosure of which would compromise Big Rivers' or Kenergy's negotiating strategy with Century, its affiliates or other Transaction participants in connection with the Transaction. Notwithstanding this subsection, Big Rivers and Kenergy shall be required to provide some identification of each task including the hours billed, billing rates, and names of the individuals performing the task.

(f) Transaction Cost Report shall be provided in accordance with the form attached hereto as Exhibit A.

(g) The parties hereto agree to work diligently and in good faith to meet the schedule in the Transaction Costs Report but the failure to meet the schedule will not provide a basis to delay or reject reimbursement of Transaction Costs; provided that nothing in this Agreement shall obligate Big Rivers or Kenergy to enter into a letter of intent or definitive documentation with respect to a Transaction or otherwise continue evaluating a potential Transaction if either determines not to continue discussions.

4. Additional Deposits Into Deposit Account. Century shall make additional deposits into the Deposit Account not more than two business days following receipt from Big Rivers or, in the absence thereof, from Kenergy, of each new Budget in an amount equal to the positive difference (if any) of (i) the amount set forth in the Budget to be expended by or on behalf of Big Rivers or Kenergy during the following 30 days, over (ii) the then-current balance in the Deposit Account, after adjustment for any Reimbursement Payment (as defined in the Escrow Agreement) that is not yet reflected in such balance. Big Rivers or Kenergy shall have the right to terminate this Agreement on or after the fifth day following Century's failure to make any additional deposits into the Deposit Account following the receipt of each new Budget from Big Rivers or Kenergy. In the event of a termination of this Agreement as contemplated in this paragraph, Century shall continue to be obligated for the reimbursement of Transaction Costs in accordance with this Agreement that have been incurred by or otherwise chargeable to Big Rivers or Kenergy as of the effectiveness of such termination, or for which Big Rivers or Kenergy is then obligated to reimburse a third party described in paragraph 2(a) due to that third party's incurrence of corresponding fees and disbursements on or prior to such termination.

5. Definitive Documentation. If Century, any of its affiliates, Kenergy or Big Rivers successfully negotiate and enter into definitive documentation with respect to a Transaction, and such Transaction is consummated in accordance with that documentation, without limiting the obligation of Century to make additional deposits into the Deposit Account and the right of Big Rivers and Kenergy to be reimbursed periodically as otherwise provided herein, Century will reimburse Big Rivers and Kenergy for all Transaction Costs that have been incurred by or otherwise chargeable to Big Rivers or Kenergy, but which have not previously been reimbursed by Century pursuant to this Agreement and the Escrow Agreement.

6. Right to Terminate.

(a) Century shall be entitled, in its sole discretion, upon written notice delivered to Big Rivers and Kenergy, to terminate this Agreement and Century's reimbursement obligations hereunder at any time prior to the execution and delivery by Century or any affiliate of Century, Kenergy and Big Rivers of a letter of intent requiring Century to continue to negotiate or attempt to pursue a Transaction with Big Rivers and Kenergy, subject to the other terms and conditions of this Agreement. Upon receipt of such notice, Big Rivers and Kenergy shall immediately cease, or cause to be ceased, all work that would be reimbursable under this Agreement and Century shall not be liable for any such work performed after the date of receipt of the notice.

(b) If Century or any of its affiliates, Kenergy and Big Rivers shall fully execute such a letter of intent at any time prior to Century's termination of this Agreement pursuant to this paragraph, such a unilateral termination of this Agreement by Century may not thereafter be undertaken except upon two business days' prior written notice delivered to Big Rivers and Kenergy which notice may not be given until the earlier to occur of: (i) expiration of the term or duration of that letter of intent or the earlier termination of the same in accordance with its terms (other than any expiration or termination of the letter of intent upon the execution of definitive documentation for the Transaction unless that definitive documentation shall expressly terminate or supersede this Agreement); or (ii) the expiration or termination of such definitive documentation for the Transaction (if any shall be entered into) in accordance with its terms other than in connection with the consummation of the Transaction.

(c) In the event of a termination of this Agreement as contemplated in this paragraph, Century shall continue to be obligated for the reimbursement of reimbursable (in accordance with this Agreement) Transaction Costs that have been incurred by or otherwise chargeable to Big Rivers or Kenergy as of the effectiveness of such termination, or for which Big Rivers or Kenergy is then obligated to reimburse a third party described in paragraph 2(a) due to that third party's incurrence of corresponding fees and disbursements on or prior to such termination; *provided* that Century shall not be obligated to reimburse invoices for Transaction Costs that were received by Big Rivers or Kenergy before the Notice of Termination and could have been included in a prior Transaction Costs Report and Reimbursement Notice which were withheld from prior Transaction Cost Reports in bad faith by Big Rivers or Kenergy; and *provided further* that Big Rivers will provide a final Transaction Costs Report and Reimbursement Notice within 60 days after receipt of notice of termination with respect to each counsel and advisor directly engaged by Big Rivers or Kenergy incurring Transaction Costs and that Century shall have no obligation to pay for any costs of such counsel or advisor directly engaged by Big Rivers or Kenergy not included in such final Reimbursement Notice.

(d) Big Rivers agrees that pursuant to Section 12 of the Escrow Agreement, it will exercise its right to terminate the Escrow Agreement, upon a termination of this Agreement in accordance with this paragraph and reimbursement of all reimbursable Transaction Costs pursuant to this Agreement and the Escrow Agreement.

7. Closing. If Century, its relevant affiliates, Kenergy and Big Rivers successfully negotiate and enter into definitive documentation with respect to a Transaction, and such Transaction is consummated in accordance with that documentation following a termination of this Agreement by Century pursuant to paragraph 6 above, Century agrees to reimburse Big Rivers or Kenergy, as applicable, at the closing of that Transaction for any Transaction Costs that were not previously reimbursed by Century unless otherwise provided in the definitive documentation.

8. Reimbursement Notices.

(a) On the 15th day of each month Big Rivers will deliver a copy of the Reimbursement Notice (as defined in the Escrow Agreement) to Century with respect to all Transaction Costs incurred or otherwise chargeable in the period covered by the Transaction Costs Report that have become reimbursable by Century hereunder for the benefit of either Big Rivers or Kenergy; provided, subject to the limitations in section 6, that the failure to deliver such Reimbursement Notice within such time or the failure to seek reimbursement of any amounts contained in a Transaction Costs Report shall not limit the ability to seek reimbursement for such amounts in a later Reimbursement Notice, including following termination of this Agreement as provided in paragraph 6 hereof. Reimbursement shall be made pursuant to the Escrow Agreement.

(b) Big Rivers and Kenergy will submit a Reimbursement Notice only for costs which have been incurred directly by or are otherwise chargeable to Big Rivers or Kenergy, including by obligation to reimbursement to a third party. Without limiting its rights to verification set forth in this paragraph 8, Century shall have no right to approve any Reimbursement Notice, Transaction Costs Report or the invoices underlying any Transactions Cost Report.

(c) Century may, at its expense (whether before or after the relevant payment), have a third party selected by mutual agreement of Century, Big Rivers and Kenergy confirm whether invoices included in a Reimbursement Notice actually were incurred or were otherwise chargeable and were Transaction Costs (provided that the method of such confirmation may not result in the waiver or implied waiver of any attorney-client or other privilege). Big Rivers and Kenergy will reasonably cooperate with such third party and provide it with all information and supporting documentation as shall be reasonably necessary in order to verify that the items included on invoices included in a Reimbursement Notice are properly chargeable under this Agreement. To facilitate such third party confirmation, Big Rivers and Kenergy agree to keep copies of all billing records for items of Transaction Cost for which reimbursement is sought for a period of one year following the later of the expiration or termination of this Agreement or Century's receipt of the final Reimbursement Notice relating to reimbursement hereunder. Big Rivers and Kenergy will afford the third party reasonable access to such billing records throughout that one-year period. If the third party finds that any fees, costs or expenses are not Transaction Costs or are not reimbursable under the limitations of section 6, then Big Rivers or Kenergy, as applicable, will refund such amounts to Century within five working days. The provisions of the preceding two sentences, together with Century's right to challenge as inappropriate for reimbursement hereunder any invoices (or portions thereof) included in a Reimbursement Notice or Transaction Costs Report and reimbursed or paid hereunder, shall survive the expiration or termination of this Agreement for that one-year period (and thereafter to the extent Century has asserted a claim of wrongful invoicing and reimbursement or payment hereunder during that one-year period, until that claim is finally resolved). During the term of the Escrow Agreement, Century will have no obligation to reimburse Big Rivers or Kenergy for any Transaction Costs if they are not included in a Reimbursement Notice to the extent sufficient funds exist therein to pay such Transaction Costs.

9. No Waiver of Privilege. Notwithstanding payment by Century of fees, costs and expenses of Big Rivers and Kenergy, such payment shall not constitute a waiver of the attorney-client or other privilege of Big Rivers or Kenergy, all of which privilege are expressly preserved.

10. Indemnification. Century hereby agrees to indemnify and hold harmless Big Rivers and Kenergy and any officers, agents or employees of either of them from any and all liability, including costs, fees, and settlements arising out of the failure to pay in full any Transaction Costs of third parties that are reimbursable under this Agreement, *provided*, that as conditions precedent to any liability of Century under this indemnification provision, (a) Big Rivers or Kenergy (as applicable) must notify Century of any claim for indemnification hereunder with reasonable promptness after receiving written notification of the asserted liability, (b) Century, at its election, made promptly after receipt of notice of a claim hereunder, and at its expense, shall have the right to compromise or defend any such matter through counsel of its own choosing, and (c) Century shall have the right to participate in and approve the terms of any settlement of a claim against which indemnification is sought.

11. Miscellaneous. This Agreement shall be governed by and construed and enforced in accordance with the laws of the Commonwealth of Kentucky, shall be for the sole benefit of the parties signatory hereto, and shall not vest in or grant to any other party any third-party beneficiary or other similar rights. Nothing contained in this Agreement shall create any obligation on the part of Century, any of its affiliates, Kenergy or Big Rivers to continue any discussions or negotiations, or to enter into any binding agreement(s), with respect to a Transaction or any other transaction. This Agreement shall become effective upon the later of (a) the execution and delivery of this Agreement and the Escrow Agreement by all parties thereto and (b) the deposit of the Initial Escrow Amount into the Deposit Account.

IN WITNESS WHEREOF, the parties have executed and delivered this Agreement as of the date first set forth above.

BIG RIVERS ELECTRIC CORPORATION

By: Mark A. Bailey
Mark A. Bailey
President and CEO

KENERGY CORP.

By: ______________________
Gregory J. Starheim
President and CEO

CENTURY ALUMINUM COMPANY

By: ______________________
Name:
Title:

CENTURY ALUMINUM SEBREE LLC

By: ______________________
Name:
Title:

IN WITNESS WHEREOF, the parties have executed and delivered this Agreement as of the date first set forth above.

BIG RIVERS ELECTRIC CORPORATION

By: ______________________________
Mark A. Bailey
President and CEO

KENERGY CORP.

By: ______________________________
Gregory J. Starheim
President and CEO

CENTURY ALUMINUM COMPANY

By: ______________________________
Name: Jesse Gary
Title: Exec Vice President

CENTURY ALUMINUM SEBREE LLC

By: ______________________________
Name: Jesse Gary
Title: President

EXHIBIT A

FORM OF TRANSACTION COSTS REPORT

Attachment for Response to AG 2-41

First Report

Schedule Status Update

For the Month Ending September 30, 2013

Task	Percent Complete	Expected Completion Date
Finalize and Sign Reimbursement Agreement & Escrow Agreement	100	9/15/2013
MISO Analysis	0	10/30/2013
Obtain Big Rivers Board Approval	0	10/18/2013
Obtain Members Approval		10/21/2013
Obtain RUS Approval		12/22/2013
File Attachment Y-2 with MISO	50	6/15/2013
Obtain consent of creditors; if needed	0	11/1/2013
Sign agreement with Big Rivers, if needed, on Wilson	0	5/17/2013
File All Agreements with the PSC	0	10/30/2013
PSC approval of contracts	0	1/10/2014

First Report

TRANSACTION COST DETAIL REPORT FOR THE MONTH ENDING September 30, 2013

Entity Providing Service	Current Month's Actual Expenses	YTD Actual Expenses	Expected Expenses (Next 30 Days)
Sullivan, MountJoy, Stainback & Miller		0.00	0.00
Orrick	0.00	0.00	0.00
MISO	0.00	0.00	0.00
Dorsey, King, Gray, Norment (Chris Hopgood)	0.00	0.00	0.00
Dinsmore Shohl	0.00	0.00	0.00
MISO Consultant (Kenergy)	0.00	0.00	0.00
Other	0.00	0.00	0.00
	0.00	0.00	0.00

Prior Month - Escrow Account Balance	**0.00**
Plus: Last Month's Deposit (Expected Expenses)	0.00
Less: Current Month's Actual Disbursements	0.00
⇨ Plus: Payment Required from Century to Escrow	0.00
Current Month - Escrow Balance Required	0.00

Initial Deposit Required $200,000

Attachment for Response to AG 2-41

Invoices received in the Reporting Period

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 42) *Reference BREC's response to AG 1-55, which states it anticipates severance related expenses in 2013-2014 with the idling of one or more power plants, but it has not yet finalized a severance plan or program to be effective in that event, and no severance amounts were paid from 2010 through 2013. In prior Case No. 2012-00535, BREC's response to AG 1-59 (and cites to AG 1-75) states that severance costs of $4.6 million are deferred and amortized in the budget over 60 months beginning September 2013 and the forecasted test period included 12 months of severance amortized costs of $920,000 at "Regulatory Charge", row 47. Finally, Mr. Wolfram's testimony in this rate case removes non-recurring labor expenses related to staffing affected by the anticipated idling of the Coleman plant (p. 15, lines 14-23 and Schedule 1.11 of Exhibit Wolfram-2) and he also notes that revenue requirement adjustments reflect the idling of both the Wilson and Coleman stations (p. 16, lines 11-13). In light of the above, address the following:*

a. *Explain why severance costs were included in the forecasted test period in prior Case No. 2012-00535, but have not been included in this rate case (if this understanding is incorrect, then explain and identify all severance costs included in the forecasted test period in this rate case).*

b. Explain if BREC did not include amortization of severance expenses in this rate case because the amounts are not known or measurable, because BREC has not yet finalized a severance plan.

c. Explain if this change in reasoning means that BREC no longer supports the severance costs included in the prior rate case, or explain why projected severance costs would be appropriate and reasonable for the prior rate case but are not appropriate or reasonable for this rate case. Provide and cite to all Commission precedent that would support this inconsistency in positions.

d. Explain or confirm that Wolfram Schedule 1.11 related to non-recurring labor expenses does not include any severance costs. Otherwise, provide all supporting calculations and documentation for any severance costs included in the forecasted test period of this rate case.

Response)

a. The understanding is not correct. Severance costs for the Coleman Station are included in this case. The total cost is $3.7 million, amortized over a 60-month period. The costs are identified and described in the Direct Testimony of Jeffrey R. Williams on pages 14, 17 and 18; in the Direct Testimony of James V. Haner beginning on page 8; and in Exhibit Haner-2. The amortization of severance costs for the Wilson Station that was proposed in Case No. 2012-00535, a total of $4.6 million amortized over 60 months, is also included in this case. See the response to PSC 1-57, Big Rivers Financial Forecast, tab "Regulatory Charge," row 47. This is appropriate because at the time the rates proposed in this case take effect in February 2014, only five months of the 60 month amortization will have been recovered. Thus, the test period revenue requirement includes $740,000 for Coleman Station ($3.7 million / 5 years) and $920,000 for Wilson Station ($4.6 million / 5 years), for a total annual amount of $1.66 million.

b. Not applicable.

c. Not applicable.

d. Confirmed.

Witness) John Wolfram

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 42) *Reference BREC's response to AG 1-55, which states it anticipates severance related expenses in 2013-2014 with the idling of one or more power plants, but it has not yet finalized a severance plan or program to be effective in that event, and no severance amounts were paid from 2010 through 2013. In prior Case No. 2012-00535, BREC's response to AG 1-59 (and cites to AG 1-75) states that severance costs of $4.6 million are deferred and amortized in the budget over 60 months beginning September 2013 and the forecasted test period included 12 months of severance amortized costs of $920,000 at "Regulatory Charge", row 47. Finally, Mr. Wolfram's testimony in this rate case removes non-recurring labor expenses related to staffing affected by the anticipated idling of the Coleman plant (p. 15, lines 14-23 and Schedule 1.11 of Exhibit Wolfram-2) and he also notes that revenue requirement adjustments reflect the idling of both the Wilson and Coleman stations (p. 16, lines 11-13). In light of the above, address the following:*

a. Explain why severance costs were included in the forecasted test period in prior Case No. 2012-00535, but have not been included in this rate case (if this understanding is incorrect, then explain and identify all severance costs included in the forecasted test period in this rate case).

b. *Explain if BREC did not include amortization of severance expenses in this rate case because the amounts are not known or measurable, because BREC has not yet finalized a severance plan.*

c. *Explain if this change in reasoning means that BREC no longer supports the severance costs included in the prior rate case, or explain why projected severance costs would be appropriate and reasonable for the prior rate case but are not appropriate or reasonable for this rate case. Provide and cite to all Commission precedent that would support this inconsistency in positions.*

d. *Explain or confirm that Wolfram Schedule 1.11 related to non-recurring labor expenses does not include any severance costs. Otherwise, provide all supporting calculations and documentation for any severance costs included in the forecasted test period of this rate case.*

Response)

a. The understanding is not correct. Severance costs for the Coleman Station are included in this case. The total cost is $3.7 million, amortized over a 60-month period. The costs are identified and described in the Direct Testimony of Jeffrey R. Williams on pages 14, 17 and 18; in the Direct Testimony of James V. Haner beginning on page 8; and in Exhibit Haner-2. The amortization of severance costs for the Wilson Station that was proposed in Case No. 2012-00535, a total of $4.6 million amortized over 60 months, is also included in this case. See the response to PSC 1-57, Big Rivers Financial Model, tab "Regulatory Charge," row 47. This is appropriate because at the time the rates proposed in this case take effect in February 2014, only five months of the 60 month amortization will have been recovered. Thus, the test period revenue requirement includes $740,000 for Coleman Station ($3.7 million / 5 years) and $920,000 for Wilson Station ($4.6 million / 5 years), for a total annual amount of $1.66 million.

b. Not applicable.

c. Not applicable.

d. Confirmed.

Witness) John Wolfram

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 43) *Regarding BREC's response to AG 1-53 and the related Confidential Board of Director Minutes (BODM), address the following: BEGIN CONFIDENTIAL****

[redacted]

[redacted]

***END CONFIDENTIAL

Response)

a. Oxford Mining Company - Kentucky, LLC ("Oxford") filed a civil action against Big Rivers on April 26, 2012, styled *Oxford Mining - Kentucky, LLC v. Big Rivers Electric Corporation,* Ohio Circuit Court Civil Action No. 12-

CI-00160. In that suit, Oxford alleges that Big Rivers breached a coal supply agreement with Oxford by terminating that agreement on March 2, 2012. Oxford alleges that it has suffered damage, including lost profits, as a result of the alleged wrongful termination of the coal supply agreement. Big Rivers has asserted a counterclaim against Oxford based on damages Big Rivers suffered as the result of delivery to Big Rivers' generating stations by Oxford of coal that failed to meet contract specifications. This litigation is in the discovery stage. Expenses associated with the Oxford litigation are not specifically budgeted or forecasted; instead, they are included within the general category of professional services expenses. Expenses associated with professional services should be recovered in this rate case because they are reasonable and prudent expenses.

b. Please see the attached CONFIDENTIAL electronic file(s).

c. Big Rivers objects that this request is overly broad and unduly burdensome. Notwithstanding this objection, and without waiving it, Big Rivers responds as follows. A presentation regarding the Alcan termination was provided in response to AG 1-158; a presentation regarding the Century contract term sheet was provided in response to AG 2-16; and a presentation regarding the recently-approved Century contract was provided in response to AG 1-2(a) in Case No. 2013-00221.

d. Big Rivers renewed its membership with the NRECA in July 2013. Please refer to Big Rivers' response to TAB 49 of the Application for the amount of NRECA dues included in the forecasted test period. These dues are coded to major account 930. At the time of the application, any reduction in dues was not known. There was a $74,959 reduction in dues, as described in the attachment. Additionally, members' payment of their own CRN dues saved $14,976.

[redacted]

Witnesses) Robert W. Berry, Mark A. Bailey, Billie J. Richert, Christopher A. Warren, John Wolfram, Thomas W. Davis

Electronic
Attachment(s)
Produced
Separately

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 44) *Regarding BREC's response to AG 1-5, please confirm that the latest presentation/meeting with an investment firm was the JP Morgan presentation on December 18, 2012, per the information provided. Otherwise, provide updated information.*

Response) Confirmed.

Witness) Billie J. Richert

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 45) *Regarding BREC's response to AG 1-5, please confirm that the latest presentation/meeting made to the RUS was the presentation on March 19, 2013, per the information provided. Otherwise, provide updated information.*

Response) Confirmed.

Witness) Billie J. Richert

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 46) ***Regarding BREC's response to AG 1-5, provide an updated copy of the document showing revised contract and conventional TIER projected through year 2023 after the loss Alcan and Century smelters, documents cited as Confidential "Contract and Conventional TIER", page 20 of Financial Projections, Witness: Billie J. Richert, page 24 of 31. Show a scenario with BREC receiving all of its rate increases in prior and current rate case, and show a scenario with BREC receiving none of its rate increase in prior and current rate cases.***

Response) Big Rivers objects to this request on the grounds that it is unduly burdensome insofar as it does not seek data but instead requires Big Rivers to perform additional, original work that is not in its possession. Big Rivers further objects that the request is speculative and, therefore, not reasonably calculated to lead to the discovery of admissible evidence.

Witness) Billie J. Richert

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 47) *BREC's response to AG 1-57 states, BEGIN CONFIDENTIAL**** [redacted] ****END CONFIDENTIAL. Address the following:*

- ***a.*** *Identify the name of the "company" performing the services mentioned above and provide a copy of the related contract, RFP, and engagement letter.*
- ***b.*** *Provide the amount paid to the "company" by account number, and provide copies of all invoices.*
- ***c.*** *Explain if the costs of this "company" have been included in the forecasted test period of this rate case and identify all costs for the base period and forecasted test period, separately show actual and forecasted amounts, and show amounts by account number. Explain why it is reasonable to recover these costs from BREC's customers.*

Response)

a. The name of that company is identified in the confidential portion of the Attorney General's information request number AG 2-53. Please understand that Big Rivers has not engaged that company to perform the services that are the subject of this information request.

b. Big Rivers has paid nothing to that company to perform the services that are the subject of this information request.

c. Please see Big Rivers' response to part b of this information request. No such costs are in the base or test periods, and Big Rivers is not seeking to recover any such costs.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 48) *BREC's response to AG 1-58 provided the amount of payments to Officers/Management that have left BREC employment, including payments for unused vacation, sick leave, and unused personal days. Address the following:*

a. *Provide the amount of accrued expenses (and the number of days represented by each type of expense) included in the base period (show actual and forecasted amounts separately) and forecasted test period by account number for each existing BREC Officer for unused vacation (amount and related days), sick leave (amount and related days), and unused personal days (amount and related days).*

b. *Provide the total actual accumulated liability for each existing BREC Officer for unused vacation, unused sick leave, and unused personal days, at December 31, 2011, December 31, 2012, and through most recent year-to-date in 2013.*

c. *Provide the amount per day that accrues for each Officer for unused vacation, unused sick leave, and unused personal days and explain how this is determined.*

d. *Provide the information in (a) for "Management" employees on a combined basis.*

e. *Provide the information in (b) for "Management" employees on a combined basis.*

f. *Provide the information in (c) for "Management" employees on a combined basis.*

g. *Provide a copy of BREC's policy for unused vacation, unused sick leave, and unused personal days and explain the maximum accrual per year and for total employment time with BREC before amounts begin to expire or are not paid by BREC.*

h. *Explain why $105,074 of mostly unused vacation and unused sick leave was paid to the VP Administrative Services and explain how this significant amount accumulated (explain the period of time of accumulation of these amounts). Explain the same for the $63,249 paid to the Director Finance (and explain the period of time of accumulation of these amounts).*

i. *Regarding the amounts paid as shown at AG 1-58, provide a copy of the journal entry to debit and credit accounts showing these payments.*

Response) Big Rivers objects that the term "Management" is unduly vague as used in this request. Notwithstanding this objection, and without waiving it, Big Rivers responds as follows.

a. The requested information is provided in the attachment to this response. Please see Tab 50 of the Application for officer compensation for the base period and forecasted test period. Please note that paid time off is not budgeted by employee. Base compensation in the forecast represents 2080 hours per employee. Two personal days are awarded every year. If these days are not used, they are automatically paid out in January of the following year; therefore, personal days do not carry forward. All active, full-time employees accumulate sick leave pay at a rate of eight hours at regular straight time rate for each calendar month of continued employment. Upon death, retirement, or voluntary termination at age 55 or older, accumulated sick leave in excess of 480 hours will be paid out at 20% of the employee's pay rate currently in effect. Employees discharged for cause or voluntary termination of employment prior to age 55 forfeit their right to this benefit. Vacation benefits are earned during a given calendar year to be taken the following calendar year. The amount of vacation is determined by the length of full-time service with Big Rivers. Vacation time can accumulate from year to year. A maximum of 200 hours may be carried over from one calendar year to the next. If proper notice is given prior to resigning or upon retirement, employees will be paid for all unused vacation. This includes vacation days earned during the current calendar year.

b. Please see Big Rivers' response to subpart a, above.

c. Please see Big Rivers' response to subpart a, above.

d. Big Rivers objects that this request is unduly burdensome because it seeks information in a manner that it is not maintained (i.e., by title or position) in the ordinary course of business. Big Rivers further objects that the data sought is not reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding these objections, and without waiving them, please see Big Rivers' response to subpart a, above.

e. Please see Big Rivers' response to subpart d, above.

f. Please see Big Rivers' response to subpart d, above.

g. Please see the attachments to Big Rivers' response to AG 1-248.

h. Unused vacation and sick leave were accumulated and carried forward by the VP Administrative Services and Director Finance pursuant to company policy.

Please see the attached document detailing payments made to these employees for unused vacation, sick leave and personal days.

i. Big Rivers cannot provide the requested data because time and labor payroll is part of a project-centric accounting system. Accounting entries are determined by projects and tasks. Employees charge their time/labor to specific projects and tasks based on job function or work order in Big Rivers' time and labor module. After processing payroll, these labor dollars are transferred to the project accounting module. Then, paid time-off and employer-paid benefits are processed through a burdening method to allocate dollars by various projects and tasks. A general journal entry is generated within the project accounting module and transferred to the general ledger. This journal entry reflects total labor and burden dollars by account number.

Witness) Thomas W. Davis

Big Rivers Electric Corporation
Case No. 2013-00199

Attachment for Response to AG 2-48(a)
Statement of Entitlement Accruals[1]

Sick Leave Accrual

	Accrued Hours		Payout Equivalent[2]
Mark Bailey, President and CEO*			
Accumulated Sick Leave 2011	432	$	-
Accumulated Sick Leave 2012	528	$	2,410.37
Accumulated Sick Leave as of 8/30/13	592	$	5,624.20
Bob Berry, VP Production and COO*			
Accumulated Sick Leave 2011	256	$	-
Accumulated Sick Leave 2012	352	$	-
Accumulated Sick Leave as of 8/30/13	400	$	-

Vacation Accrual

	Hours Available		Payout Equivalent
Mark Bailey, President and CEO*			
Vacation Carryover 2011	35.5	$	8,913.34
Vacation Carryover 2012	0	$	-
Vacation balance as of 8/30/13	96	$	24,103.68
Bob Berry, VP Production and COO*			
Vacation Carryover 2011	100	$	13,240.00
Vacation Carryover 2012	154	$	20,920.90
Vacation balance as of 8/30/13	222	$	34,687.50

Note 1: All time is coded to account number 920100.

Note 2: Because Mark Bailey and Bob Berry are over age 55, their payout equivalent is calculated as ([accrued hours]-480)*20%*[per hour value].

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September 30, 2013

Item 49) *Referencing Big Rivers' response to PSC 2-14 please provide the following information regarding natural gas price forecasts shown on the "Big Rivers PCM Run 4-22-13 (2013-2027)" excel spreadsheet "Prices" and "Annual Prices" tab:*

- ***a.** Have these prices been updated to develop the confidential attached table? If so, please provide these updated price forecasts.*
- ***b.** Does ACES use natural gas price forecasts as inputs to develop its Hub power price forecasts?*
- ***c.** The source documentation for these price forecasts.*
- ***d.** Any assumed natural gas transportation costs and the basis for the assumption.*

Response)

a. No.

b. No. Please see response to PSC 2-14 explaining how ACES utilizes broker values and the Wood Mackenzie pricing for developing the market power price forecast.

c. Please see Big Rivers' responses to KIUC 2-5 and KIUC 2-9.

d. Please see Big Rivers' response to AG 2-6(i).

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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Item 50) *Referencing Big Rivers' response to PSC 2-14 please provide the following information regarding coal price forecasts shown on the "Big Rivers PCM Run 4-22-13 (2013-2027)" excel spreadsheet "Prices" and "Annual Prices" tab:*

a. Have these prices been updated to develop the confidential attached table? If so, please provide these updated price forecasts.

b. Does ACES use coal price forecasts as inputs to develop its Hub power price forecasts?

c. The source documentation for these price forecasts.

d. Any assumed coal transportation costs, where these costs are incorporated in the referenced PCM and the developed financial models, or any other PCM and financial model used to develop Big Rivers' revenue requirements in this case, and the basis for the assumption.

Response)

a. No. Big Rivers provides ACES with the delivered fuel pricing and this PCM does not utilize the coal price forecasts displayed on the "Prices" and "Annual Prices" tabs.

b. No. Please see the response to AG 2-49(b).

c. Please see the response to AG 2-49(c).

d. The coal prices provided to ACES from Big Rivers for the PCM runs include the delivery charges. For all PCM runs used for this case, ACES was instructed to utilize the coal pricing provided by Big Rivers as 100% hedged which means the PCM model does not utilize any fuel prices for spot purchases and only uses the coal pricing provided by Big Rivers.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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Item 51) ***Referencing Big Rivers' response to PSC 2-14, please provide an updated PCM and an updated financial model based on this new information.***

Response) Big Rivers objects that this request is unduly burdensome and not reasonably calculated to lead to the discovery of admissible evidence. Big Rivers provided production cost model runs and financial model runs with its response to PSC 2-14 that incorporated the information discussed in that response. Because ACES updates its power market price forecasts on a daily basis and because of the significant time and work required to perform additional "snapshot" updates, it would be infeasible to perform the requested update.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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Item 52) ***Referencing Big Rivers' response to PSC 2-37 and PSC 2-14 please provide the annual average plant account balances and depreciation expense for Coleman and Wilson Stations for each year from 2013 through 2020.***

Response) Please see the attachment to this response for the annual average plant balances and depreciation expense for Coleman and Wilson for each year from 2013 through 2016 based on Big Rivers' 2013-2016 budget. Big Rivers' financial model provides forecasted balances for Total Utility Plant in Service through 2027 but does not track asset balances by major functional plant property group. Accordingly, the information requested for years 2017 through 2020 is not available.

Witness) Billie J. Richert

Big Rivers E[illegible]ic Corporation
Case No. 2013-00199

Attachment for Response to AG 2-52

Average Annual Plant Balances and Depreciation Expense (Coleman and Wilson)
2013-2016 Budget

Coleman:

Average Annual Account Balances:

	2013	2014	2015	2016
3102	$ 1,124,665	$ 1,124,665	$ 1,124,665	$ 1,124,665
3112	19,460,682	19,460,682	19,460,682	19,460,682
3122	86,097,338	88,838,556	88,905,241	88,905,241
312C	123,685,469	136,621,801	154,106,865	154,120,468
312M	-	-	-	-
312W	520,243	608,511	608,511	608,511
3142	33,844,152	34,083,213	34,083,213	34,083,213
3152	9,550,665	10,016,655	10,105,819	10,105,819
3162	1,299,340	1,302,968	1,302,968	1,302,968
Total	$ 275,582,554	$ 292,057,051	$ 309,697,964	$ 309,711,567

Annual Depreciation Expense (Total):

2013	2014	2015	2016
$ 5,791,631	$ 6,404,721	$ 6,894,507	$ 6,895,486

Wilson:

Average Annual Account Balances:

	2013	2014	2015	2016
3104	$ 2,218,858	$ 2,218,858	$ 2,218,858	$ 2,218,858
3114	73,709,296	73,733,479	73,772,776	73,813,585
3124	406,510,013	410,818,634	411,176,239	412,035,037
312E	263,020,917	267,981,156	274,942,419	275,090,540
312P	6,615,946	6,615,946	6,912,187	7,631,631
312Y	-	-	-	-
3144	129,163,985	129,196,632	129,196,632	129,196,632
3154	35,325,073	35,325,073	35,542,720	35,542,720
3164	1,372,912	1,401,932	1,414,023	1,427,324
Total	$ 917,937,000	$ 927,291,710	$ 935,175,854	$ 936,956,327

Annual Depreciation Expense (Total):

2013	2014	2015	2016
$ 19,464,664	$ 20,152,609	$ 20,391,841	$ 20,542,841

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Item 53) *Referencing Big Rivers' response to PSC 2-15 that [BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL]*

Response) [redacted]

Witness) Robert W. Berry

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Item 54) *Referencing Big Rivers' response to KIUC 1-52 and the installation of MATS equipment at Wilson and Coleman, please provide the following:*

- *a.* *Costs of installing this equipment for each unit.*
- *b.* *Dates these costs will be incurred.*
- *c.* *Net Plant for both all Coleman and Wilson accounts for the years of 2014 through 2020.*

Response)

- a. The estimated costs to install MATS equipment at Wilson currently is $[redacted]. The estimated cost to install MATS equipment at Coleman currently is $[redacted].
- b. These costs will be not be incurred on a specific single date; they will be incurredover time, but Big Rivers expects that the vast majority of expenses will be incurred [redacted].
- c. Please see the attachment to this response for budgeted net plant values for Coleman and Wilson for the years 2014 through 2016 based on Big Rivers'

2013-2016 budget. The requested information is not available for years 2017 through 2020.

Witnesses) Robert W. Berry (a-b), Billie J. Richert (c)

Big Rivers Electric Corporation
Case No. 2013-00199

Attachment for Response to 2-54(c)

Budgeted Wilson and Coleman Net Plant Values 2014-2016

Coleman (Net):	**2014**	**2015**	**2016**
3102	$ 1,124,665	$ 1,124,665	$ 1,124,665
3112	2,354,607	2,077,301	1,808,273
3122	51,955,295	50,133,133	48,339,733
312C	134,618,873	130,863,181	127,123,597
312M	-	-	-
312W	452,808	272,562	118,098
3142	14,655,252	13,960,259	13,293,179
3152	4,162,481	3,960,815	3,755,867
3162	1,121,795	1,064,552	1,011,872
Total	**$ 210,445,776**	**$ 203,456,468**	**$ 196,575,284**

Wilson (Net):	**2014**	**2015**	**2016**
3104	$ 2,218,858	$ 2,218,858	$ 2,218,858
3114	30,097,438	29,116,676	28,150,752
3124	186,262,589	178,537,683	171,014,593
312E	143,585,226	137,072,841	130,470,744
312P	3,966,772	3,893,437	2,676,157
312Y	-	-	-
3144	55,557,303	53,026,639	50,497,999
3154	14,704,306	14,201,733	13,480,929
3164	1,391,680	1,352,452	1,309,308
Total	**$ 437,784,172**	**$ 419,420,319**	**$ 399,819,340**

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Item 55) *Referencing Big Rivers' response to KIUC 1-53 please provide the MISO Schedule 9 Network Transmission Calculation for transmission revenue that Century Sebree smelter would pay if a similar agreement to the "Century Agreement" is reached.*

Response) Big Rivers notes that KIUC 1-53 asks about historical cost differences between Coleman, Wilson and Green and does not understand how that question is relevant to a question regarding MISO transmission revenue. However, please see AG 2-80, where the transmission revenue calculation is provided.

Witness) Robert W. Berry

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Item 56) *Referencing Big Rivers' response to KIUC 1-57 regarding ACES fees, please provide the following:*

a. Verify that the ACES fees being paid under the Century Agreement have been credited in the Revenue Requirements for this rate application and describe where this is shown in the filing or in other information provided.

b. What amount of annual costs for ACES fees is included in the forecasted test period and where are those costs shown?

c. Assuming that the Century Sebree smelter enters into an agreement similar to the "Century Agreement," how much of the ACES fee in the forecasted test period would be paid by Century Sebree?

Response)

a. Please see the response to PSC 3-10.

b. Big Rivers included $2,271,665 for the ACES fees in the forecasted test period in this case. Please refer to the Direct Testimony of Mr. Robert W. Berry, page 19, line 16.

c. Please see the response to PSC 3-10.

Witness) John Wolfram

BIG RIVERS ELECTRIC CORPORATION

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Item 57) ***Referencing Big Rivers response to KIUC 1-59(c), please provide the fuel forecasts from J.D. Energy, Argus Coal Daily, Platts Coal Trader and Outlook, and ACES/Wood Mackenzie as well as the market information for coal from independent coal companies bid solicitations used in developing the market price forecasts used in the PCM.***

Response) The ACES Power Marketing coal forecast is comprised of short-term information from ICAP Energy, along with longer term forecast information from Wood / Mackenzie, consolidated in-house at ACES. It is accessible to Big Rivers via their web portal. Big Rivers is able to download the forecast in ACES format, and a CONFIDENTIAL copy is attached to this response. Big Rivers has also provided copies of forecasts from Argus Coal Daily, Platts Coal Trader/Outlook, and J.D. Energy.

In this forward market evaluation, Big Rivers did not have current market bids to utilize for forward pricing forecasts. The bids were aged five to six months and considered not current enough to provide forward pricing for spot or open position tonnage for forecast, due to the decreasing market price for coal.

Please also refer to Big Rivers' response to KIUC 2-10.

Witness) Robert W. Berry

Confidential
Attachment(s)
Produced
Separately

BIG RIVERS ELECTRIC CORPORATION

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Item 58) *Referencing Big Rivers' response to PSC 2-14 and the Reid Steam unit, please provide the following information:*

a. *Explain why VOM, Heat Rate, Fuel Costs, generation, etc. are shown as [BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL] on the Annual and Monthly Resource Report tabs of the Big Rivers PCM Run 4-22-13 (2013-2017) spreadsheet.*

b. *Explain all work completed, or remaining to be completed, as well as completion or expected completion dates for conversion of the unit entirely to natural gas.*

c. *Provide a detailed breakdown of all costs incurred, when they have been incurred or are expected to be incurred to convert the unit to natural gas.*

Response)

a. The Reid Steam unit was not being dispatched to run by the PCM (0 MW of generation) which caused many of results to display "0" or "#/DIV/0!". Please recall in the PCM generation inputs, the Reid Steam unit fuel was switched from coal to natural gas in 2014.

b. To date Big Rivers has submitted a revision of its Title V Permit to KDAQ for approval. In addition, Big Rivers has solicited budgetary pricing for new burner management and turbine control systems. Remaining work includes actual purchase of the burner management and turbine control systems as well as purchase of replacement gas burners. This equipment must then be installed in the unit. The gas supply pipeline to this unit will also be replaced as part of this project. The expected completion date of this project will be the end of 2014 assuming timely issuance of the revised Title V Permit.

c. To date Big Rivers has incurred approximately [redacted] in preparation of the revised Title V permit application. Remaining costs, all of which are to be incurred in the second half of 2014, include:

Burner Management and Turbine Control Systems	[redacted]
Replacement Burners	[redacted]
Gas pipeline replacement	[redacted]
Installation of above components	[redacted]

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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Item 59) ***BREC's response to AG 1-82 states: "In designing its rates and planning for its operations after Century's and/or Alcan's termination, Big Rivers planned for long-term success and developed an operational strategy likely to produce long-term benefits to its members and their member-owners. To address the long-term interests of its members, Big Rivers researched and developed its mitigation plan over the past several years to help mitigate the adverse financial consequences of potential smelter closure."***

- ***a.*** ***Provide all net present value and/or discounted cash flow analyses performed by or for Big Rivers to inform its choices in "developing an operational strategy."***
- ***b.*** ***Provide all net present value and/or discounted cash flow analyses performed by or for Big Rivers that estimates or quantifies the expected "long-term benefits to its member and their member-owners."***
- ***c.*** ***Provide all net present value and/or discounted cash flow analyses performed by or for Big Rivers associated with its choice to "lay up:"***
  - ***i.*** ***The Wilson Plant***
  - ***ii.*** ***The Coleman Plant***

d. *Provide documents which show and explain the basis for any "discount rate" used in the above net present value and/or discounted cash flow analyses.*

e. *Provide annual cash outlays associated with the Wilson Plant beginning with the layup of the plant in 2013 through the entire layup period for:*

  i. *All layup costs (capital and expense), including severance;*

  ii. *Ongoing capital items and expenses while in layup, including FDE and maintenance, property taxes, insurance, etc.;*

  iii. *Capital and expense costs of restarting the plant to bring it out of "layup";*

  iv. *Budgeted or expected maintenance and capital investment to meet pollution control and other environmental mandates;*

  v. *Allocated interest costs; and,*

  vi. *Any other cash expenditures Big Rivers believes to be relevant to the operation of the Wilson Plant.*

  vii. *Identify which of the above costs have been included in this rate case, and provide worksheet and cell reference to those amounts in the Financial Model.*

viii. *Identify which of the above costs have not been included in this rate case.*

f. *Provide annual cash net margins associated with the operation of the Wilson Plant from the time it is brought out of "layup" into operating status, through 2027 (or beyond if available), and any other net cash inflows Big Rivers believes to be relevant to the operation of the Wilson Plant.*

g. *Provide annual cash outlays associated with the Coleman Plant beginning with the layup of the plant in 2014 through the entire layup period for:*

i. *All layup costs (capital and expense), including severance;*

ii. *Ongoing capital items and expenses while in layup, including FDE and maintenance, property taxes, insurance, etc.;*

iii. *Capital and expense costs of restarting the plant to bring it out of "layup";*

iv. *Budgeted or expected maintenance and capital investment to meet pollution control and other environmental mandates;*

v. *Allocated interest costs; and,*

vi. *Any other cash expenditures Big Rivers believes to be relevant to the operation of the Wilson Plant.*

vii. Identify which of the above costs have been included in this rate case, and provide worksheet and cell reference to those amounts in the Financial Model.

viii. Identify which of the above costs have not been included in this rate case.

h. Provide annual cash net margins associated with the operation of the Coleman Plant from the time it is brought out of "layup" into operating status, through 2027 (or beyond if available), and any other net cash inflows Big Rivers believes to be relevant to the operation of the Coleman Plant.

Response)

a. Big Rivers did not perform net present value or discounted cash flow analyses to inform its choices in "developing an operational strategy."

b. Big Rivers did not perform net present value or discounted cash flow analyses to estimate or quantify the expected "long-term benefits to its member and their member-owners."

c. Big Rivers did not perform net present value or discounted cash flow analyses in its choice to "lay up" the Wilson Plant or the Coleman Plant.

d. Not applicable; please see the responses to parts a-c, above.

e. Please see the CONFIDENTIAL Attachment 1 to this response for the cash outlays associated with the Wilson Plant beginning with the layup of the plant in 2013 through startup in 2018.

   i. All layup costs (capital and expense) – Line Nos. 1-2; Severance is not broken out by plant and is excluded.

   ii. Ongoing capital items and expenses while in layup, including FDE and maintenance, property taxes, insurance, etc. – Line Nos. 3-9.

   iii. Capital and expense costs of restarting the plant to bring it out of "layup" – Please reference the response to AG 2-9 in the current case for capital and expense costs of restarting the Wilson Plant.

   iv. Budgeted or expected maintenance and capital investment to meet pollution control and other environmental mandates – Please reference AG 2-9 (e-f)

   v. Allocated interest costs – Line Nos. 10-11.

   vi. There are no other cash expenditures Big Rivers believes to be relevant to the operation of the Wilson Plant.

vii. All of the above costs for years 2014 through 2018 have been included in the Financial Model. The exact values of Wilson Plant Costs cannot be found directly in the financial model. The source files for expenses are the Hyperion budget files, which were provided in the responses to PSC 1-57 and AG 1-227. Please see files '2014 ALCAN' and '2015 ALCAN' that were included in Big Rivers' response to PSC 1-57, and '2016 ALCAN' that was provided in response to AG 1-227, and view the worksheets 'LABOR', 'PROP INS', 'PROP TAX', 'INTEREST', 'OTHER' and 'PROD NL'.

viii. All of the above costs have been included in the Financial Model.

f. Big Rivers does not account for cash net margins by plant.

g. Please see the CONFIDENTIAL Attachment 2 to this response for the cash outlays associated with the Coleman Plant beginning with the layup of the plant in 2014 through startup in 2019.

  i. All layup costs (capital and expense) – Line Nos. 1-2; Severance is not broken out by plant and is excluded.

  ii. Ongoing capital items and expenses while in layup, including FDE and maintenance, property taxes, insurance, etc. – Line Nos. 3-9.

iii. Capital and expense costs of restarting the plant to bring it out of "layup" – Please reference the response to AG 2-9 in the current case for capital and expense costs of restarting the Coleman Plant.

iv. Budgeted or expected maintenance and capital investment to meet pollution control and other environmental mandates – Please reference the response to AG 2-9(e-f).

v. Allocated interest costs – Line Nos. 10-11.

vi. There are no other cash expenditures Big Rivers believes to be relevant to the operation of the Coleman Plant.

vii. All of the above costs for years 2014 through 2019 have been included in the Financial Model. The exact values of Coleman Plant Costs cannot be found directly in the financial model. The source files for expenses are the Hyperion budget files, and were provided in response to PSC 1-57 and AG 1-227. Please see files '2014 ALCAN' and '2015 ALCAN' that were included in Big Rivers' response to PSC 1-57, and '2016 ALCAN' that was provided in response to AG 1-227, and view the worksheets 'LABOR', 'PROP INS', 'PROP TAX', 'INTEREST', 'OTHER' and 'PROD NL'.

viii. All of the above costs have been included in the Financial Model.

h. Big Rivers does not account for cash net margins by plant.

Witness) Jeffrey R. Williams; Christopher A. Warren

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Attachment 1 for Response to AG 2-59
Wilson Plant Costs

Line No.	DESCRIPTION	2013	2014	2015	2016	2017	2018
1	Layup Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	Layup Fixed Departmental Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	Labor Expense	10,914,913	1,633,639	1,669,094	1,710,020	1,752,770	11,907,178
4	Ongoing Fixed Departmental Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	Ongoing Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Property Tax Expense Base	1,048,464	1,081,241	1,093,163	1,107,493	1,136,043	1,165,526
7	Property Tax Expense ECR	14,169	14,417	22,956	21,773	21,454	20,909
8	Property Insurance Expense Base	1,127,161	1,240,971	1,289,128	1,354,001	1,387,745	1,422,328
9	Property Insurance Expense ECR	5,945	6,511	20,724	21,345	21,986	22,645
10	Interest Expense Base	21,932,153	20,658,667	20,621,730	20,509,890	21,037,823	21,578,989
11	Interest Expense ECR	294,576	273,794	329,984	329,984	323,048	315,904
12		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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

Big Rivers Electric Corporation
Case No. 2013-00199

Attachment 2 for Response to AG 2-59
Coleman Plant Costs

Line No.	DESCRIPTION	2013	2014	2015	2016	2017	2018	2019
1	Layup Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	Layup Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	*Labor Expense	12,059,190	5,063,365	1,384,331	1,419,971	1,455,470	3,292,354	13,580,606
4	*Ongoing Fixed Departmental Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	Ongoing Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Property Tax Expense Base	438,274	468,898	479,268	482,978	495,429	508,288	521,461
7	Property Tax Expense ECR	5,936	6,266	10,020	9,509	9,370	9,132	8,893
8	Property Insurance Expense Base	658,951	725,628	753,789	791,722	811,453	831,675	852,400
9	Property Insurance Expense ECR	3,475	3,807	12,115	12,479	12,853	13,239	13,636
10	Interest Expense Base	6,410,007	6,285,309	6,192,024	6,155,852	6,336,641	6,522,013	6,712,081
11	Interest Expense ECR	535,846	484,888	584,400	584,400	572,116	559,464	546,432
12		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 60) ***Identify each approval or other condition arising out of its Indenture and/or other agreements related to debt funding that must be satisfied by Big Rivers associated with sale of a generating unit.***

Response) Big Rivers objects that this request is unduly burdensome and not reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding those objections, and without waiving them, please refer to the attachments to Big Rivers' response to AG 1-15 for copies of all Big Rivers' existing debt agreements, provided in electronic format with the files accompanying those responses.

Witness) Billie J. Richert

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's Second Request for Information dated September 16, 2013

September 30, 2013

Item 61) *Assume net proceeds from sale of a generating unit. What is the required disposition of net proceeds from such sale under Big Rivers' Indenture and/or other agreements related to its debt funding?*

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

Please see Big Rivers' response to AG 2-35. Please also see the attachments to Big Rivers' response to AG 1-15 for copies of Big Rivers' existing debt agreements.

Witness) Billie J. Richert

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 62) *Confirm that BREC's response to AG 1-170 states BREC uses Hyperion to generate budget files for use as source documents for the Financial Model.*

a. *Identify each Oracle Hyperion product that BREC uses, e.g., Oracle Hyperion Planning.*

b. *Provide in electronic spreadsheet readable file format the financial, operating and other inputs to the "Hyperion Budget Model" (Financial Model Overview, Response to AG 1-155, page 5) which were used to generate the "Budget Model Outputs" reflected in the files provided in response to PSC 1-57: '2014 ALCAN.xlsx', '2015 ALCAN.xlsx', and '2016 ALCAN.xlsx'.*

Response) It is confirmed that Big Rivers uses Hyperion to generate budget output files for use as source documents for the Financial Model.

a. Big Rivers uses Hyperion Planning for its forecasting and budgeting.

b. Please refer to the files provided in response to PSC 1-57 and AG 1-154.

Witness) Jeffrey R. Williams

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

CASE NO. 2013-00199

**Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013**

September 30, 2013

Item 63) *BREC's response to AG 1-105(f) and AG 1-106(f) shows the Wilson and Coleman costs will continue to be incurred and included in the cost of service (and not treated as cost savings and not removed from the revenue requirement), including depreciation expense, property tax, property insurance, interest expense, fixed department expense, and labor/labor overhead. Address the following:*

a. Explain if the expenses provided at AG 1-105(f) and 106(f) are per the forecasted test period in this rate case, and if not, then provide such amounts for the forecasted test period in this rate case and the forecasted test period in the prior rate case (Case No. 00535), and explain the reasons for changes between these costs between the two forecasted test periods.

b. Regarding the costs in subpart (a), provide a citation to the Financial Model worksheet and row reference in the current and prior rate case and provide all documentation and supporting calculations for these amounts.

c. Explain why Fixed Department Expenses for the idling of Wilson (and due to Century exit) were treated as a cost savings and removed from the revenue requirement in the prior rate case (Case No. 00535) at Exhibit Berry-4, but these same expenses are included in the revenue requirement in this rate case and are not removed from the revenue requirement.

Response)

a. The amounts provided in Big Rivers' responses to AG 1-105(f) and AG 1-106(f) are per the forecasted test period.

b. Please note that the costs are included in worksheets 'O&M', 'Capex & Depr' and 'Debt' in the 'Financial Forecast (2014-2027) 5-16-2013.xlsx' file distributed by account number as shown in the Hyperion budget files referenced in KIUC 2-29, which were provided in PSC 1-57 and AG 1-227. For property insurance, view the 'O&M' worksheet, lines 70-79. For property tax, view the 'O&M' worksheet, lines 84-96. For production non-labor (or fixed departmental expense), view the 'O&M' worksheet, lines 127-145. For labor, view the 'O&M' worksheet, lines 149-181. For depreciation, view the 'Capex & Depr' worksheet, lines 37-38. For interest expense, view the 'Debt' worksheet, lines 105-109.

c. Exhibit Berry-4 in the previous case (Case No. 2012-000535) removed the non-recurring costs associated with the Wilson plant idling from the revenue requirement. In the current case, the same non-recurring costs occur in 2013, and therefore before the forecasted test period. Thus, there is no pro forma adjustment needed to remove these costs in the current case.

Witnesses) Jeffrey R. Williams and Christopher A. Warren

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 64) *BREC's response to PSC 2-25 (line 17) appears to give the impression that severance costs are included in the test period; however the response to AG 1-55 gives the impression that severance costs were not included in the test period, and AG 1-246 states that $76,667 of severance expense is included in the forecasted test period. Please confirm which is accurate and provide all supporting documentation and calculations.*

a. *Explain if the Board of Directors has approved severance pay for the forecasted test period and provide copies of related minutes and all calculations.*

b. *Explain if BREC has discussed or negotiated severance costs with the labor union and explain if severance costs in this rate case are based on those negotiations. Provide copies of all correspondence and documentation related to severance calculations.*

c. *Explain how BREC determined the amount of severance costs and provide all supporting documentation and calculations.*

Response) Please see Big Rivers' response to AG 2-42.

a. Big Rivers has not submitted a severance plan to the Board of Directors for approval.

b. Big Rivers has not opened negotiations with the labor union regarding a severance plan.

c. Please see the Direct Testimony of James V. Haner, in the application for Case No. 2013-00199, for a description of how Big Rivers determined the amount of severance costs and for supporting documentation and calculations.

Witnesses) Jeffrey R. Williams; Thomas W. Davis (a-c)

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 65) *Regarding BREC's response to AG 1-126 regarding ACES costs included in the forecasted test period, address the following:*

a. Provide copies of the hourly billing rates included in charges to BREC for FY's 2011, 2012 and 2013 (most recent billing rate) and provide copies of sample invoices that show the billing rates.

b. If hourly billing rates cannot be determined, provide the average billing rates for the periods in subpart (a), and provide related supporting documentation and calculations.

c. Explain if the 3% increase in ACES costs for the forecasted test period is intended to reflect increased billing hours, increased billing rates, or other increases in ACES costs, and provide related supporting documentation and calculations.

Response)

a. Please see the attached ACES invoices for 2011, 2012, and 2013 (through September). ACES bills a flat fee so billing rates are not present on the invoices. Pursuant to 807 KAR 5:001 Section 4(10)(a), account numbers have been redacted.

b. The requested calculation is not possible because actual hours worked by all ACES employees for Big Rivers is not tracked.

c. The 3% increase was based on professional judgment. ACES fees increased by 4.5% from 2011 to 2012, and by 4.2% from 2012 to 2013. This was largely affected by MWh sales increases to the smelters, following the Unwind. Note that, as a result of the smelter closure(s), there is potential for ACES' fees to be reduced over a delayed period, in reverse of the previously explained increases following the Unwind. Consequently, Big Rivers took a conservative approach and assumed a 3% increase from 2013 to 2014. Because Big Rivers is an owner of ACES, Big Rivers pays a pro-rata share of ACES total expenses, thus billing hours and rates are not applicable.

Witness) Robert W. Berry

Wire#: 50327
Ck dated 3/3/11

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	11/4836-IN
Invoice Date.	12/17/2010
Due Date:	1/3/2011
For the month of:	January 2011

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2011 Monthly Service Fee	$166,927.67

Purpower
0376 55711000

TOTAL AMOUNT DUE: $166,927.67

MOM - 2/28/11
2-28-11

Direct questions to:
Reed Reimer at ACES Power 317-344-7038

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire #: 50281
CK Date: 2/11/11

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #: 11/4890-IN
Invoice Date: 1/20/2011
Due Date: 2/1/2011
For the month of: **February 2011**

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2011 Monthly Service Fee	$166,927.67

TOTAL AMOUNT DUE: $166,927.67

RECEIVED
FEB 14

Direct questions to:
Reed Reimer at ACES Power 317-344-7038

cwb 1/26/11

BR A0025
1-3[illegible]-11
1-31-11
EAC 0314
923/00-0000

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire#: 50325
Ck. Date: 3/1/11

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	11/4940-IN
Invoice Date:	2/18/2011
Due Date:	3/1/2011
For the month of:	**March 2011**

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2011 Monthly Service Fee	$166,927.67

TOTAL AMOUNT DUE: $166,927.67

MOM - 2-22-11

2-22-11

~~BRA 0025~~ PURPOWER
~~EAC 0314~~ 0376
~~923101-0000~~ 557110-0000

Direct questions to:
Reed Reimer at ACES Power 317-344-7038

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire #: 50400
ck Date: 4/1/11

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	11/4990-IN
Invoice Date:	3/18/2011
Due Date:	4/1/2011
For the month of:	**April 2011**

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2011 Monthly Service Fee	$166,927.67

TOTAL AMOUNT DUE: $166,927.67

MOM- 3/21/11
3-22-11

Direct questions to:
Reed Reimer at ACES Power 317-344-7038

Remit Payment via:

ACH Transfer.
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

~~BRA0025~~
~~EAC 0314~~
~~923101 0600~~
PUR POWER
5571100
0376
0449

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

7

Wire#: 50473
Ck made: 5/3/11

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	11/5046-IN
Invoice Date:	4/20/2011
Due Date:	5/2/2011
For the month of:	May 2011

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2011 Monthly Service Fee	$166,927.67

PURPOWER
BRA0025
557100
~~0314-923T01-0000~~ 0376
0999

TOTAL AMOUNT DUE: $166,927.67

YLDM 4-26-11
Boy 4-26-11

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire#: 50547
Ck-date: 6/1/11

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	11/5098-IN
Invoice Date:	5/20/2011
Due Date:	6/1/2011
For the month of:	June 2011

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2011 Monthly Service Fee	$166,927.67

TOTAL AMOUNT DUE: $166,927.67

5-23-11

5/24/11

BRA0025
EAC 0314
923101-0000

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

PURPOWER
55711000
0376
0099

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire # 50619
Ck date: 7/6/11

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #: 11/5148-IN
Invoice Date: 6/20/2011
Due Date: 7/1/2011
For the month of: **July 2011**

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2011 Monthly Service Fee	$166,927.67

PURPOWER
55711000
0316
0999

~~BRA0025~~
~~0314 923101-0000~~

TOTAL AMOUNT DUE: $166,927.67

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

MDM - 6-27-11
6-27-11

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

w.re#: 50782
ck date: 9/14/11

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	11/5203-IN
Invoice Date:	7/20/2011
Due Date:	8/1/2011
For the month of:	August 2011

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2011 Monthly Service Fee	$166,927.67

PURPOWER
5571100D
0376
0999

TOTAL AMOUNT DUE: $166,927.67

GXDM- 9/14/11
9-14-11

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire#: 50256
Ck Date: 9/1/11

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #: 11/5252-IN
Invoice Date: 8/18/2011
Due Date: 9/1/2011
For the month of: September 2011

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2011 Monthly Service Fee	$166,927.67

PURPOWER
55711000
0376
0999

BRA0025
~~EAC 0319~~
923101-0000

8-30-11

TOTAL AMOUNT DUE: $166,927.67

MDM- 8/30/11

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire#: 50830
Ck date: 10/3/11

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	11/5308-IN
Invoice Date:	9/20/2011
Due Date:	10/3/2011
For the month of:	**October 2011**

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2011 Monthly Service Fee	$166,927.67

PURPOWER
55711000
0370
0999

TOTAL AMOUNT DUE: $166,927.67

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

~~BRA0025~~
~~EAC 9314~~
~~92301-0000~~
~~0025~~

MOM - 9-21-01
9-21-11

Remit Payment via:

<u>ACH Transfer:</u>
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

<u>Wire Transfer (Please use ACH if possible):</u>
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire#: 50912
Ck Date: 11/1/11

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0824

Invoice #: 11/5366-IN
Invoice Date: 10/20/2011
Due Date: 11/1/2011
For the month of: **November 2011**

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2011 Monthly Service Fee	$166,927.67

PURPOWER
55711000
0376
0999

TOTAL AMOUNT DUE: **$166,927.67**

10-21-11

10-21-11

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire#: 50984
Ck date: 12/1/11

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	11/5422-IN
Invoice Date:	11/15/2011
Due Date:	12/1/2011
For the month of:	**December 2011**

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2011 Monthly Service Fee	$166,927.67

Purpower
55711000
0376
0999

TOTAL AMOUNT DUE: $166,927.67

11-16-11
By 11-16-11

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire#: 51073
Ck date: 01/03/12

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #: 12/5484-IN
Invoice Date: 12/20/2011
Due Date: 1/3/2012
For the month of: **January 2012**

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2012 Monthly Service Fee	$174,557.58

Purpower
55711000
0376
0999

TOTAL AMOUNT DUE: **$174,557.58**

KDM - 12-21-11
12-21-11

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

Remit Payment via:

<u>ACH Transfer:</u>
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

<u>Wire Transfer (Please use ACH if possible):</u>
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire#: 511.49
ck date: 2/1/12

ACES POWER
MARKETING

4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #: 12/5546-IN
Invoice Date: 1/20/2012
Due Date: 2/1/2012
For the month of: February 2012

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2012 Monthly Service Fee	$174,557.58

Pur Power
55711000
0376
0999

TOTAL AMOUNT DUE: $174,557.58

EMS
01-23-12

1-23-12

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire #: 51230
Ck Date: 3/1/12

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	12/5601-IN
Invoice Date:	2/20/2012
Due Date:	3/1/2012
For the month of:	**March 2012**

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2012 Monthly Service Fee	$174,557.58

Purpower
55711000
0376
0999

EMS
02/21/12

TOTAL AMOUNT DUE: $174,557.58

By 2-21-12

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

WTRE: 51306
Ck date: 4/2/12

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #: 12/5653-IN
Invoice Date: 3/20/2012
Due Date: 4/2/2012
For the month of: **April 2012**

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2012 Monthly Service Fee	$174,557.58
142000	Non-Resident Withholding Tx-IN	$3,052.00
142000	Non-Resident Withholding Tx-GA	$56.88
142000	Non-Resident Withholding Tx-MD	$67.00

PurPower
55711000
0376
0999
#174,557.58

IncomeTax
STATE
0662
0999
$3,175.88

TOTAL AMOUNT DUE: $177,733.46

Direct questions to:
Kim Fohrmann at ACES Power 317-344-7046

3-21-12

Ems
03-21-12

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Rcvd-A/P

Wire#: 51384
ck date: 5/1/12

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	12/5708-IN
Invoice Date:	4/16/2012
Due Date:	5/1/2012
For the month of:	May 2012

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2012 Monthly Service Fee	$174,557.58

Purpower
55711000
0376
0999

TOTAL AMOUNT DUE: $174,557.58

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

EMS
04-16-12

4/18/12

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

2

Wire #: 51459
ck Date: 6/1/12

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	12/5758-IN
Invoice Date:	5/18/2012
Due Date:	6/1/2012
For the month of:	**June 2012**

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2012 Monthly Service Fee	$174,557.58

PURPOWER
55711000
0374
0994

EMS
05-21-12

5/21/12

TOTAL AMOUNT DUE: $174,557.58

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire#: 51533
Ck date: 7/2/12

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #: 12/5819-IN
Invoice Date: 6/20/2012
Due Date: 7/2/2012
For the month of: July 2012

Attention: Bill Blackburn

Fax #: 270-827-2558

400001	2012 Monthly Service Fee	$174,557.58

Purpower
55711000
0376
0999

TOTAL AMOUNT DUE: $174,557.58

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

EMB
06-21-12

6/21/12

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire#: 51620
ck date: 8/1/12

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	12/5873-IN
Invoice Date:	7/20/2012
Due Date:	8/1/2012
For the month of:	**August 2012**

Attention: Mark Hite

Fax #: 270-827-2558

400001	2012 Monthly Service Fee	$174,557.58

PurPower
55711000
0376
0999

TOTAL AMOUNT DUE: $174,557.58

Emb
07-23-12

7/24/12

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire #: 51213

Ck Date: 9/4/12

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	12/5928-IN
Invoice Date:	8/20/2012
Due Date:	9/4/2012
For the month of:	September 2012

Attention: Mark Hite

Fax #: 270-827-2558

400001	2012 Monthly Service Fee	$174,557.58

Purpower
55711000
0376
0999

TOTAL AMOUNT DUE: $174,557.58

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

EMS
08-20-12

GB
8/21/12

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Vch#: 51793
CK Date: 10/1/12

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #: 12/5978-IN
Invoice Date: 9/20/2012
Due Date: 10/1/2012
For the month of: **October 2012**

Attention: Mark Hite

Fax #: 270-827-2558

400001	2012 Monthly Service Fee	$174,557.58

Purpower
55711000
0376
0999

EMB
09-21-12

9/21/12

TOTAL AMOUNT DUE: $174,557.58

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire#! 51882
ck date! 11/1/12

ACES POWER
MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	12/6031-IN
Invoice Date:	10/19/2012
Due Date:	11/1/2012
For the month of:	**November 2012**

Attention: Mark Hite

Fax #: 270-827-2558

400001	2012 Monthly Service Fee	$174,557.58

PURPOWER
55711000
0376
0999

TOTAL AMOUNT DUE: $174,557.58

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

EMS 10/22/12 VB 10/22/12

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire#: 51965
Ck date: 12/3/12

ACES POWER MARKETING
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #: 12/6081-IN
Invoice Date: 11/20/2012
Due Date: 12/3/2012
For the month of: **December 2012**

Attention: Mark Hite

Fax #: 270-827-2558

400001	2012 Monthly Service Fee	$174,557.58
400001	2012 Member Fee Adjustment	$68,816.00-

TOTAL AMOUNT DUE: $105,741.58

Ems
11-21-12

Purpower
55711000
0376
0999

Direct questions to:
Kim Fuhrmann at ACES Power 317-344-7046

YB
11/26/12

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York
Swift: BOFAUS3N

Wire#: 52041
CK Date: 1/2/13

ACES
excellence in energy
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #: 13/6136-IN
Invoice Date: 12/20/2012
Due Date: 1/2/2013
For the month of: **January 2013**

Attention: Billie Richert

Fax #: 270-827-2558

400001	2013 Monthly Service Fee	$181,803.42

TOTAL AMOUNT DUE: $181,803.42

Purpower
55711000
0376
0999

Direct questions to:
Kim Fuhrmann at ACES 317.344.7046

EMB
12-21-12

12/21/12

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York

Rcvd 12/31/12 - A/P
DW

Wire#: 52126
Ck Date: 2/1/13

ACES
excellence in energy
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #: 13/6196-IN
Invoice Date: 1/18/2013
Due Date: 2/1/2013
For the month of: **February 2013**

Attention: Billie Richert

Fax #: 270-827-2558

400001	2013 Monthly Service Fee	$181,803.42

TOTAL AMOUNT DUE: $181,803.42

Purpower
55711000
0376
0999

Direct questions to:
Kim Fuhrmann at ACES 317.344.7046

emb 1-21-13
JB 1/22/13

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York

Wire #: 52190
ck date: 3/1/13

ACES
excellence in energy
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	13/6249-IN
Invoice Date:	2/20/2013
Due Date:	3/1/2013
For the month of:	**March 2013**

Attention: Billie Richert

Fax #: 270-827-2558

400001	2013 Monthly Service Fee	$181,803.42

TOTAL AMOUNT DUE: $181,803.42

Purpower
55711000
0376
0999

Direct questions to;
Kim Fuhrmann at ACES 317.344.7046

EMB
02/21/13

2/21/13

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York

Wire#: 52279
CK date: 4/1/13

ACES
excellence in energy
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #: 13/6307-IN
Invoice Date: 3/20/2013
Due Date: 4/1/2013
For the month of: **April 2013**

Attention: Billie Richert

Fax #: 270-827-2558

400001	2013 Monthly Service Fee	$181,803.42
142000	Non-Resident Withholding Tx-IN	$1,500.00
142000	Non-Resident Withholding Tx-GA	$35.92
142000	Non-Resident Withholding Tx-MD	$31.00

Purpower	Income TAX
55711060	STATE
0376	0642
0999	0999
# 181,803.42	# 1,566.92

TOTAL AMOUNT DUE: $183,370.34

Direct questions to:
Kim Fuhrmann at ACES 317.344.7046

EMB
03\21\13

3/21/13

Remit Payment via:

<u>ACH Transfer:</u>
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

<u>Wire Transfer (Please use ACH if possible):</u>
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York

Rcvd A/P 3/25/13

Wire#: 52355
CK date: 5/1/13

ACES
excellence in energy
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	13/6359-IN
Invoice Date:	4/17/2013
Due Date:	5/1/2013
For the month of:	May 2013

Attention: Billie Richert

Fax #: 270-827-2558

400001	2013 Monthly Service Fee	$181,803.42

TOTAL AMOUNT DUE: $181,803.42

PurPower
55711000
0376
0999

Direct questions to:
Kim Fuhrmann at ACES 317.344.7046

emb
04/17/13

4/17/13

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York

RECEIVED 4/18/13

Wire#: 52434
ck date: 6/3/13

ACES
excellence in energy
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #: 13/6418-IN
Invoice Date: 5/20/2013
Due Date: 6/3/2013
For the month of: June 2013

Attention: Billie Richert

Fax #: 270-827-2558

400001	2013 Monthly Service Fee	$181,803.42

TOTAL AMOUNT DUE: $181,803.42

Direct questions to:
Kim Fuhrmann at ACES 317.344.7046

EMA
05'20'13

GB
5/20/13

RECEIVED
5/20/13
DW

Purpower
55711000
0376
0999

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York

Wire #: 52520
CL date: 7/1/13

ACES
excellence in energy
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	13/6480-IN
Invoice Date:	6/20/2013
Due Date:	7/1/2013
For the month of:	July 2013

Attention: Billie Richert

Fax #: 270-827-2558

400001	2013 Monthly Service Fee	$181,803.42

TOTAL AMOUNT DUE: $181,803.42

Purpower
55711000
0376
0999

Direct questions to:
Kim Fuhrmann at ACES 317.344.7046

EmS
06/21/13

YB
6/21/13

RECEIVED
6/21/13

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York

Wire#: 52602
Ck Date: 8/1/13

ACES
excellence in energy
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #:	13/6541-IN
Invoice Date:	7/19/2013
Due Date:	8/1/2013
For the month of:	**August 2013**

Attention: Billie Richert

Fax #: 270-827-2558

400001	2013 Monthly Service Fee	$181,803.42

TOTAL AMOUNT DUE: $181,803.42

Purpower
55711000
0376
0999

Direct questions to:
Kim Fuhrmann at ACES 317.344.7046

EMA
07/21/13

BB
7/24/13

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York

Wire#: 52690
ck date: 9/3/13

ACES
excellence in energy
4140 West 99th Street, Carmel, IN 46032

Invoice

Big Rivers Electric Corp.
PO Box 24
Henderson, KY 42419-0024

Invoice #: 13/6605-IN
Invoice Date: 8/20/2013
Due Date: 9/3/2013
For the month of: **September 2013**

Attention: Billie Richert

Fax #: 270-827-2558

400001	2013 Monthly Service Fee	$181,803.42

TOTAL AMOUNT DUE: $181,803.42

RECEIVED 8/22/13
DW

Purpower
55711000
0376
0999

Direct questions to:
Kim Fuhrmann at ACES 317.344.7046

ems
08/22/13

VB
8/22/13

Remit Payment via:

ACH Transfer:
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 071000039
Bank Name: Bank of America
Bank Address: Chicago, Illinois

Wire Transfer (Please use ACH if possible):
Account Name: ACES Power Marketing
Account #: [redacted]
ABA Routing #: 026009593
Bank Name: Bank of America
Bank Address: New York, New York

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's Second Request for Information dated September 16, 2013

September 30, 2013

Item 66) *As a follow-up to BREC's response to AG 1-135, explain how forecasted property tax (ad valorem expense), property insurance, and accumulated deferred income tax reserve are calculated in this rate case if not based in part on forecasted capital expenditures for the related periods. Provide all supporting documentation and calculations.*

Response) Property tax is calculated using the forecasted capital expenditures. Property insurance is calculated by talking to our vendor and updating the value of net plant assets. There is no calculation currently necessary for accumulated deferred income tax reserve.

Witness) Jeffrey R. Williams

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

CASE NO. 2013-00199

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 67) *BREC's response to AG 1-173(a) states that for a substantial portion of O&M costs, outside professional costs, and other A&G expenses - - the Company uses vendor proposals, price quotes, and existing contracts to establish forecasted costs. Address the following:*

a. *For each of the 10 largest individual line item costs included in the forecasted test period for O&M, outside professional costs, and A&G expenses - - provide copies of vendor proposals, price quotes, and existing contracts to support these forecasted costs.*

b. *For outside professional costs related to legal/attorney fees included in the forecasted test period - - provide vendor proposals, price quotes, and existing contracts for the 10 largest individual legal/attorney fees.*

c. *Provide vendor proposals, price quotes, and existing contracts for all legal/attorney fees included in the forecasted test period for rate case expense amortized from the prior rate case (Case No. 00535) and for additional/new legal costs related to this rate case (Case No. 00199).*

Response)

a. A CONFIDENTIAL attachment summarizing the ten largest individual line item costs included in the forecasted test period for O&M, outside professional costs, and A&G expenses is attached hereto.

- Outage (line items 1, 2, 5): Please refer to CONFIDENTIAL electronic file(s) attached to Big Rivers' response to KIUC 1-40(e) for a sample of the reports, analyses, and documentation on which the outage plan is based.
- Demand Side Management (DSM) (line item 6): Refer to page 17 of the Wolfram Testimony and Reference Schedule 1.12, Exhibit Wolfram-2, Demand Side Management Expenses ("DSM").
- Right of Way Maintenance (line item 7): Attached is the proposal for 2014 right of way maintenance. Right of way maintenance is budgeted per mile of planned maintenance with an average of $8,600 per mile bid price.
- All other line items: Attached are copies of invoices and/or award recommendation to support the attached costs. Pursuant to 807 KAR 5:001 Section (4)(a), Big Rivers has redacted its state taxpayer ID number and account number.

b. As indicated in Big Rivers' response to AG 1-256(d), please see PSC 1-54 and all subsequent monthly updates for copies of contracts, engagement letters, and/or invoices. Additionally, please see AG 1-259(a).

c. As indicated in Big Rivers' response to AG 1-256(d), please see PSC 1-54 and all subsequent monthly updates in both cases (Case Nos. 2012-00535 and 2013-00199) for copies of contracts, engagement letters, and/or invoices related to the cases. Additionally, please see the response to AG 1-259(a).

Witnesses) Billie J. Richert, DeAnna M. Speed

Big Rivers Electric Corporation
Case No. 2013-00199
Attachment for Response to AG 2-67(a)

O&M, Outside Professional Costs, and A&G Expenses

		FTP	Supporting Documentation
1	[redacted]	[redacted]	Refer to KIUC 1-40e
2	[redacted]	[redacted]	Refer to KIUC 1-40e
3	Managed Information Systems Services	2,500	Invoice
4	[redacted]	[redacted]	Refer to KIUC 1-40e
5	Demand Side Management (DSM)	1,096	Refer to Wolfram Testimony (page 17) and Schedule 1.12 (Exhibit Wolfram-2)
6	Right of Way Mtce	1,061	Proposal
7	Customer Billing Services	700	Award Recommendation
8	PSC Assessment	820	Invoice
9	NRECA Dues	355	Invoice
10	NERC	300	Invoice
	Total of Ten Largest Individual Line Items	[redacted]	

Nancy Utley
1-26-11

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy® Cooperative

AWARD RECOMMENDATION

TO: File

FROM: Dana Clevidence, Procurement Agent II

DATE: January 13, 2011

RE: Contract Services for Member Coops Utility Billing

This award recommendation is to establish an Oracle based Blanket Purchase Order for the existing contract previously issued to Pinnacle Data Systems. Pinnacle Data Systems provides utility bill printing, mailing and scanning services for our member cooperatives.

Contractor: Pinnacle Data Systems

Scope of Award: To provide utility bill printing, mailing and scanning services

Contract Value: $2,412,000 for three years, fully budgeted

Contract Term: From August 20, 2010 until August 20, 2013 (3 years with an option from contractor for an additional two years, based on one year intervals)

Reason: The committee solicited ten bidders and Pinnacle Data was the third lowest amongst the ten. Pinnacle was selected due to past outstanding performance and turnaround time

In accordance with the Corporate Policies and Procedures, please indicate your agreement with the award recommendation by signing below.

Dana Clevidence
Dana Clevidence, Procurement Agent

Dave Titzer, Mgr of Information Systems

Rob Toerne, Director of Purchasing

Mark Bailey, President and CEO

Invoice Number
6513012

Attachment for Response to AG 2-67

Invoice Date August 30, 2013

BIG RIVERS ELECTRIC COMPANY
CUSTOMER NUMBER: 2063712
201 Third Street
Henderson, Kentucky 42419-0024
ATTENTION TO: Billing Department

Due Date: September 14, 2013
TERMS: NET 15 DAYS

DESCRIPTION			CHARGES	TAXES
August 2013				
SEE ATTACHED FOR FURTHER BREAKOUT OF CHARGES				
Billing for: August 2013 SERVICES				
Service Agreement Number	**Description**	**Date**		
MFA AL 2008-002: ITSA	**ITSA: Baseline and Variable Charges**			
	MidRange DBA Charge	August 2013	$16,560.00	$ -
	Midrange Services	August 2013	$5,710.32	$ -
	Managed Storage	August 2013	$ 5,601.40	$ -
	Workplace Services	August 2013	$44,448.18	$ -
	Service Desk	August 2013	$7,000.00	$ -
	Network Management	August 2013	$10,097.84	$ -
	Application Services	August 2013	$74,467.00	$ -
	Account Team	August 2013	$22,408.00	$ -
	CO34 Hyperion Upgrade (Capital Inves	August 2013	$0.00	$ -
	Travel Expense	August 2013	$6,779.84	$ -
A AL 2008-002: ITSA Change Orders				
ITSA CO-009	Application Services (Hyperion Plannin(	August 2013	$3,878.08	$ -
		Services Total	$196,950.66	$ -
	Kentucky Taxable (6.0%):			

REMITTANCE COPY

THANK YOU FOR YOUR BUSINESS

Amount Due **$196,950.66**

14554

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION
3353 Peachtree Road NE, Suite 600
Atlanta, GA 30326
404-446-2560 (T)

INVOICE

DATE	NUMBER
8/15/2012	14554

2012
4th QUARTER ASSESSMENT

Billing Address

Big Rivers Electric Corporation
Travis D. Housley
P.O. Box 24
Henderson, KY 42419

Be advised that 0.903% of the 2012 NERC Assessment billed on the enclosed invoice is allocable to non-deductible lobbying expenditures. Any questions regarding this notice should be directed to susan.turpen@nerc.net.

Please return the bottom portion with your payment. Please reference the invoice number on your check.

Charge Code	Description	Amount
1274NERC	Big Rivers Electric Corporation NERC Assmnt	$29,454.29
1274REGION	Big Rivers Electric Corporation SERC REGION Assmnt	$35,345.58

Release 3

PO 210267
ORG 0014
Exp Type 0626
Task 930200-0000
org 0014

D Crockett 8/24/12

Ok for payment

BIG RIVERS ELECTRIC CORP.
Received
SEP 17 2012
ACCOUNTS PAYABLE

Payment Terms: Net 45 Days — Total: $64,799.87

Customer ID 1274
Customer Name Big Rivers Electric Corporation
Invoice ID 14554
Invoice Date 8/15/2012

Charge Code	Description	Amount
1274NERC	Big Rivers Electric Corporation NERC Assmnt	$29,454.29
1274REGION	Big Rivers Electric Corporation SERC REGION Assmnt	$35,345.58

2

Payment Terms: Net 45 Days — Total: $64,799.87

National Rural Electric Cooperative Association
A Touchstone Energy® Cooperative

Invoice

Mr. Mark A. Bailey		**Date:**	5/8/2012
Big Rivers Electric Corporation		**Invoice #:**	851082
PO Box 24		**Vendor Account #:**	388
Henderson, KY 42419-0024			

NRECA MEMBERSHIP DUES
For Member Year Beginning: 6/2/2012

Year 2010

NRECA G&T Member

NRECA Dues	MWH Sales	11,969,420			
	Less Sales to G&T's	93,184			
	Net MWH Sales	11,876,236	X	0.02490	$295,718.00
CRN Dues	MWH Sales	11,969,420			
	Less Sales to G&T's	93,184			
	Net MWH Sales	11,876,236	X	0.00394	$46,792.00
Plus Payments to CRN Fund for Related Systems (see attached)					$14,933.00
				Total Membership Dues Payable	$357,443.00

NRECA has estimated that 13% of the 2012 budget is allocated to lobbying expenses to which IRC Section 162(2)(3) and 6033(e)(1) as amended apply. Consequently, this portion of your 2012 system dues is not deductible for federal income tax purposes.

Thank you for your continued support.

PLEASE RETURN A COPY OF INVOICE WITH REMITTANCE **Direct payments to: NRECA** **PO Box 758777, Baltimore, MD 21275-8777**	**Payment is due June 7, 2012. Please make check payable to NRECA.**	**$357,443.00**

Contributions or gifts to NRECA are NOT deductible as charitable contributions for federal invoice tax purposes. However, payments ARE deductible by members as an ordinary and necessary business expense. NRECA Taxpayer Identification Number: 53-0116145.

BRA0001
930200-0000
0626- 297,983.70
0627- 44,526.30
0001

BRA0001
930212-0000
0626-14,933.00
0001

3

COMMONWEALTH OF KENTUCKY
DEPARTMENT OF REVENUE
FRANKFORT, KY 40619

NOTICE DATE 06/19/2012	PERIOD 07/01/2012-06/30/2013	**CASE** 000000900033	TAX PUBLIC SERVICE COMMISSION ASSESSMENT
NOTICE # 106344610	RETURN DUE 07/31/2012	**TAXPAYER-ID** [redacted]	TAXPAYER NAME BIG RIVERS ELECTRIC CORP

EXPLANATION OF NOTICE

ANNUAL PUBLIC SERVICE COMMISSION ASSESSMENT FOR THE ABOVE PERIOD.

MESSAGES: PENALTIES PROVIDED PER KRS 278.990(3) INCLUDE $1,000, PLUS $25 PER DAY FOR EACH DAY THE ASSESSMENT REMAINS UNPAID. KRS 131.440(1)(A) IMPOSES A COST OF COLLECTION FEE FOR TWENTY-FIVE PERCENT (25%) ON ALL ASSESSMENTS WHICH ARE OR BECOME DUE AND OWING TO THE DEPARTMENT. IF THE AMOUNT DUE IS NOT PAID BY JULY 31, 2004, THESE PENALTIES AND FEES MAY BE ADDED TO THIS ASSESSMENT AND REFERRED FOR ENFORCED COLLECTION ACTION.

QUESTIONS CONCERNING THIS ASSESSMENT MAY BE DIRECTED TO THE PUBLIC SERVICE COMMISSION, 211 SOWER BOULEVARD, PO BOX 615, FRANKFORT, KENTUCKY 40602, TELEPHONE NUMBER (502) 564-3940. KRS 278.130 PROVIDES FOR THE ANNUAL ASSESSMENT OF PUBLIC SERVICE COMPANIES.

Albert Yockey 6/22/2012

per Billy 6/22/12

GROSS INTRASTATE RECEIPTS	461,586,621.00
TAX LIABILITY	TAX LIABILITY 809,622.93
TOTAL LIABILITY	TOTAL LIABILITY 809,622.93

BRA0019
928100-0000
0626 0019
~~[illegible]~~

<<<< EXPLANATION OF NOTICE CONTINUED ON NEXT PAGE >>>>

2

DETACH VOUCHER AND RETURN WITH PAYMENT. *MAKE CHECK PAYABLE TO KENTUCKY STATE TREASURER.*

18

COMMONWEALTH OF KENTUCKY
DEPARTMENT OF REVENUE
FRANKFORT, KY 40619

NOTICE DATE	PERIOD	**CASE**	TAX
06/19/2012	07/01/2012-06/30/2013	000000900033	PUBLIC SERVICE COMMISSION ASSESSMENT
NOTICE #	RETURN DUE	**TAXPAYER-ID**	TAXPAYER NAME
10634461C	07/31/2012	[redacted]	BIG RIVERS ELECTRIC CORP

EXPLANATION OF NOTICE

ANNUAL PUBLIC SERVICE COMMISSION ASSESSMENT FOR THE ABOVE PERIOD.

MESSAGES: PENALTIES PROVIDED PER KRS 278.990(3) INCLUDE $1,000, PLUS $25 PER DAY FOR EACH DAY THE ASSESSMENT REMAINS UNPAID. KRS 131.440(1)(A) IMPOSES A COST OF COLLECTION FEE FOR TWENTY-FIVE PERCENT (25%) ON ALL ASSESSMENTS WHICH ARE OR BECOME DUE AND OWING TO THE DEPARTMENT. IF THE AMOUNT DUE IS NOT PAID BY JULY 31, 2004, THESE PENALTIES AND FEES MAY BE ADDED TO THIS ASSESSMENT AND REFERRED FOR ENFORCED COLLECTION ACTION.

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Albert Yockey 6/22/201

6/22/12

GROSS INTRASTATE RECEIPTS		461,586,621.00
TAX LIABILITY		TAX LIABILITY 809,622.93
TOTAL LIABILITY		TOTAL LIABILITY 809,622.93

BRA0019
928100-0000
0626 0019
~~92[illegible]~~

<<<< **EXPLANATION OF NOTICE CONTINUED ON NEXT PAGE** >>>>

DETACH VOUCHER AND RETURN WITH PAYMENT. MAKE CHECK PAYABLE TO KENTUCKY STATE TREASURER.

NOTICE OF TAX DUE

CASE NUMBER

00080962293

000000900033

#BWNCSLW
#126IJ 4612 992229 1#

BIG RIVERS ELECTRIC CORP
* ATTN: C WILLIAM BLACKBURN
VP & CFO
201 THIRD STREET
HENDERSON KY 42420

****
* TOTAL DUE AS OF: *
* 07/03/2012 *
****

$809,622.93

ENTER AMOUNT PAID:

3

10A5009911

KENTUCKY DEPARTMENT OF REVENUE
FRANKFORT, KY 40619

[redacted]

EXPLANATION OF NOTICE, CONTINUED *PAGE 2*
TAXPAYER ID: [redacted]
NOTICE NUMBER: 106344610

TOTAL DUE AS OF: 07/03/2012	TOTAL AMOUNT OF TAX 809,622.93 TOT	BALANCE DUE 809,622.93

PLEASE RETURN THE NOTICE OF TAX DUE STUB WITH PAYMENT TO:
DEPARTMENT OF REVENUE, FRANKFORT, KENTUCKY 40619.

TO PAY BY VISA OR MASTERCARD, PLEASE CALL (502) 564-4921, EXT. 5357. A CONVENIENCE FEE OF 2.5% WILL APPLY TO EACH PAYMENT.

IMPORTANT REMINDER: INCLUDE YOUR **TAXPAYER IDENTIFICATION NUMBER, TYPE OF TAX, AND TAX PERIOD** ON ANY PAYMENT OR LETTER SENT TO THE DEPARTMENT OF REVENUE. THIS ENABLES THE DEPARTMENT OF REVENUE TO CORRECTLY CREDIT YOUR ACCOUNT FOR THE TAX PERIOD AND TYPE TAX FOR WHICH YOU INTENDED.

REPLY TO: JUDY STEPHENSON
DEPARTMENT OF REVENUE
STATION NUMBER 62
501 HIGH STREET
P O BOX 181
FRANKFORT KY 40602

TEL: (502) 564-9280
FAX: (502) 564-3393
OFFICE HOURS: 8:00 A.M. TO 5:00 P.M. EASTERN TIME

NOTICE REQUIREMENT FOR INTERNET POSTING

IF YOUR TAX LIABILITY REMAINS UNPAID FOR MORE THAN 90 DAYS AFTER THE DATE OF THIS ORIGINAL NOTICE, THE DEPARTMENT OF REVENUE MAY POST YOUR NAME AND THIS LIABILITY FOR PUBLIC INSPECTION, INCLUDING POSTINGS IN YOUR LOCAL NEWSPAPER AND/OR ON THE INTERNET. HOWEVER, IF YOU NOTIFY THE DEPARTMENT IN WRITING DURING THIS PERIOD OF ANY OF THE FOLLOWING, THE DEPARTMENT MUST EXCLUDE YOUR NAME FROM ANY PUBLIC POSTING:

1. YOU HAVE AN APPEAL PENDING OR INTEND TO FILE AN APPEAL PURSUANT TO KRS 131.110 ET SEQ. WITH RESPECT TO THIS LIABILITY;
2. YOU ARE CURRENTLY PAYING THIS TAX LIABILITY THROUGH A VALID PAY AGREEMENT;
3. THE DEPARTMENT IS REVIEWING OR ADJUSTING THIS TAX LIABILITY;
4. YOU ARE IN BANKRUPTCY AND THE AUTOMATIC STAY IS STILL IN EFFECT.

ADDITIONALLY, A TAXPAYER'S NAME WILL BE EXCLUDED OR REMOVED FROM ANY PUBLIC POSTING IN THE EVENT THE DEPARTMENT IS NOTIFIED IN WRITING THAT THE TAXPAYER IS DECEASED.

PLEASE PROVIDE WRITTEN BASIS FOR EXCLUSION TO THE **DIVISION OF COLLECTIONS, P.O. BOX 491, FRANKFORT, KY 40602**, OR E-MAIL IT TO *KRC.WEBRESPONSENOTICEOFTAXDUE@KY.GOV*.

NOTICE OF INTENT TO OFFSET

IF ANY PORTION OF YOUR LIABILITY REMAINS UNPAID AFTER 60 DAYS FROM THE DATE OF THIS NOTICE, THE DEPARTMENT MAY SUBMIT YOUR DEBT TO THE TREASURY OFFSET PROGRAM (TOP). ONCE YOUR DEBT IS SUBMITTED TO TOP FOR OFFSET, THE UNITED STATES DEPARTMENT OF TREASURY MAY REDUCE OR WITHHOLD ANY OF YOUR ELIGIBLE FEDERAL TAX REFUNDS OR VENDOR PAYMENTS BY THE AMOUNT OF YOUR DEBT. THESE OFFSET PROCESSES ARE AUTHORIZED BY 31 U.S.C. 3716, 26

Proposed Right-of-Way Maintenace

2014

	Scope	Cost
Phase 1 Herbicide program, brush control	1,200 acres	$ 240,000
Phase 2 T&M work; yard trees, danger trees, etc	36 weeks	$ 178,000
Phase 2 Reclaim original right-of-way (cut to full width) & remove off right-of-way hazard trees	87 lines miles **	$ 751,000
Total 2014 Work		**$ 1,169,000**
** Note: Cost based on average bid price of $8600 per line mile for similar projects from 2013		

Awarded to Custom Air
Awarded to Asplundh Tree Expert
To be bid

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 68) ***As a follow-up to AG 1-179, provide documentation (and copies of correspondence that BREC has had with bondholders/rating agencies) to show that bondholders/rating agencies have used the 25 G&Ts as a peer group for making comparisons for financial performance, or that they would rely on these G&Ts for their TIERs and MFIRs.***

Response) Based on Mr. Walker's more than twenty years of experience, he has found that the rating agencies collect and analyze a variety of financial data points of the cooperatives they rate. The ratios and coverages they seem to routinely use in their reports, publications, and discussions are DSC, equity ratio, and TIER/ MFI. While bondholders don't publish their analysis, Mr. Walker has found from discussions with bondholders during the bond marketing process that they tend to do similar analysis as rating agencies. Please see the attached publications from S&P, Moodys, and Fitch rating agencies on G&Ts.

Witness) Daniel M. Walker

STANDARD
& POOR'S
RATINGS SERVICES

RatingsDirect®

Industry Report Card:

Expect U.S. Electric Cooperative Utilities To Maintain A Stable Course In 2013

Primary Credit Analyst:
David N Bodek, New York (1) 212-438-7969; david_bodek@standardandpoors.com

Secondary Contacts:
Geoffrey E Buswick, Boston (1) 617-530-8311; geoffrey_buswick@standardandpoors.com
Theodore A Chapman, Dallas (1) 214-871-1401; theodore_chapman@standardandpoors.com
Paul J Dyson, San Francisco (1) 415-371-5079; paul_dyson@standardandpoors.com
Peter V Murphy, New York (1) 212-438-2065; peter_murphy@standardandpoors.com
Jeffrey M Panger, New York (1) 212-438-2076; jeff_panger@standardandpoors.com
Judith G Waite, New York (1) 212-438-7677; judith_waite@standardandpoors.com

Table Of Contents

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Industry Report Card:

Expect U.S. Electric Cooperative Utilities To Maintain A Stable Course In 2013

U.S. cooperative utilities, much like their public power and investor-owned counterparts, face similar primary credit risks. Within each of these ownership sectors, credit issues utilities need to address include:

- The Environmental Protection Agency's (EPA) increasing use of regulatory initiatives to limit power plant emissions through rules that could have costly implications for utilities and their operations;
- The price and operational concerns that natural gas-fired generation's increasing role in electric production presents; and
- A weak, but moderately improving, economy that has limited some utilities' ratemaking and financial flexibility.

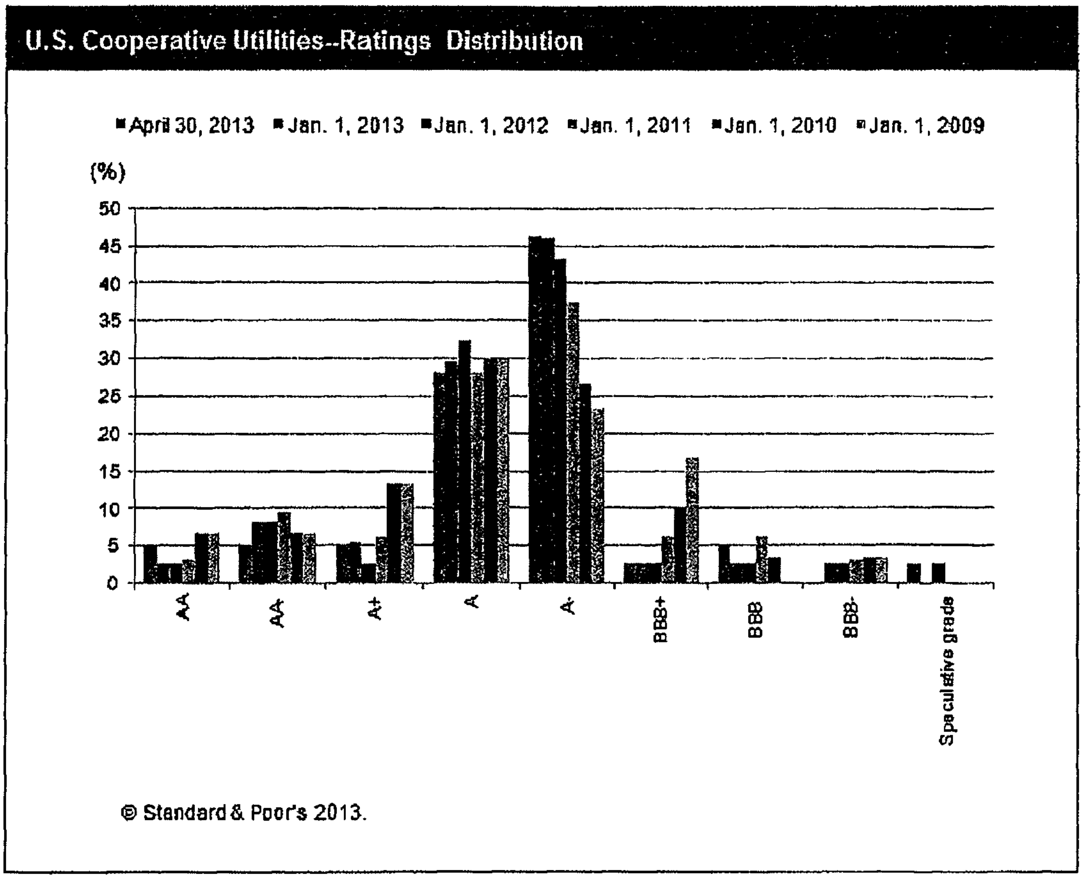
Nevertheless, Standard & Poor's Ratings Services' outlook for U.S. electric cooperative utilities' business conditions and credit quality remains largely favorable for 2013. We expect cooperative utilities will continue exhibiting resilience to the credit exposures they face. Consequently, Standard & Poor's doesn't expect much in the way of rating changes in the sector.

We believe the following factors stabilize cooperative utilities' credit quality:

- Electric utilities sell an essential commodity, which tempers, but does not eliminate, demand elasticity during economic downturns.
- Cooperative utilities' generally residential retail customer bases contribute to prospects for stable financial performance because residential customers have historically shown less volatility to economic cycles than commercial and industrial customers.
- Contracts between generation and transmission (G&T) cooperatives and their wholesale customers limit the utilities' exposure to competitive merchant power markets, where electricity prices and opportunities to make sales fluctuate with changes in demand and fuel prices.
- With few exceptions, distribution cooperatives' retail customers cannot select alternative providers or bypass the utilities delivering their power.
- Many cooperative utility boards have autonomous rate-making authority that boosts financial flexibility.
- The absence of a profit motive reduces incentives for management to place capital at risk.

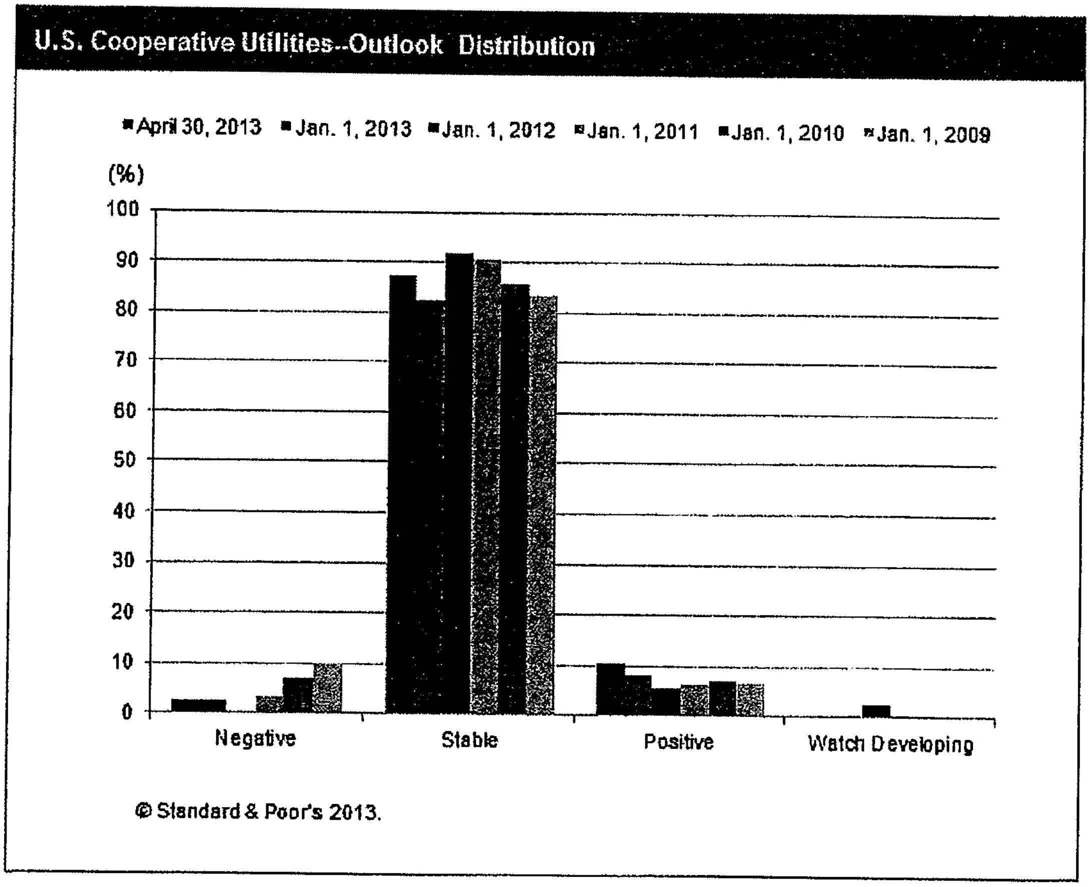
These attributes provide many cooperative utilities with the ability to withstand changing conditions or create credit protective responses. The sector's historically strong ratings distribution (see charts 1 and 2) and limited rating volatility bear this out. Not all of the sector's utilities have been immune to recent years' challenges because, in some cases, credit exposures either were too much for management to address effectively or management acted in ways that did not stem pressures on financial performance. However, by and large, we expect continued stability.

Chart 1



© Standard & Poor's 2013.

Chart 2



Emissions Regulation Is A Key Challenge For Electric Utilities

Reducing power plant emissions is one of President Barack Obama's top priorities. He has emphasized this goal in his inaugural address, State of the Union message, and many other speeches and comments. His second term's environmental remediation objectives build on the foundation of the significant regulations shepherded by his first term's EPA administrator.

During his second term, we expect that the president will look to his energy secretary nominee, Ernest Moniz, and EPA administrator nominee, Gina McCarthy, to implement his environmental vision. The EPA nominee played a seminal role in developing the agency's rules for curbing carbon dioxide and mercury emissions during the administration's first term. Her historical accomplishments suggest a predisposition toward more stringent emissions controls, which might add to utilities' capital and operating costs. Yet we cannot predict the extent to which utilities will face additional regulatory controls even after new leadership is in place.

The regulations the EPA proposed and adopted during the president's first term covered a broad range of pollutants, including carbon, mercury, sulfur dioxide, nitrogen oxide, and particulates. Some of the agency's recent rules have taken effect, and others, like the Cross-State Air Pollution Rule, have been vacated following a legal challenge. Some of the proposals were groundbreaking, including those that would limit carbon emissions for new power plants. The carbon initiative is widely viewed as effectively barring new coal plant construction in the U.S.

The array of recent EPA emissions control initiatives will add significant capital spending requirements to certain coal-fired power plants--if they can achieve compliance. For a meaningful number of plants, the economics don't justify emissions retrofits, particularly against the backdrop of low natural gas prices that are eroding the competitiveness of coal plants. Consequently, utilities across the ownership spectrum have retired numerous coal plants and slated more for retirement.

The Department of Energy's Energy Information Administration (EIA) reports that 36 coal units representing 4,000 megawatts (MW) closed in 2010-2011 and about 50 units representing 8,000 MW closed in 2012. In July 2012, the EIA forecast that by 2015 utilities will retire another 110 units representing about 16,700 MW. Generally, the affected plants are small, legacy plants that have uncompetitive heat rates and have not generated much power in recent years. While these characteristics present significant hurdles for further investments in emissions retrofits, they should also limit the financial and operational impacts of the units' closing.

Among cooperative utilities, we have observed that many anticipated stricter regulations and have already invested in controls such as scrubbers, selective catalytic reduction, and flue gas desulfurization. These investments have positioned utilities to meet many of the new control requirements and temper their exposure to additional costs. For example, utilities such as East Kentucky Power Cooperative (EKPG), Great River Energy, and Southern Illinois Power Cooperative (SIPC) have already made significant strides by adding emissions controls. They expect additional compliance investments to be moderate relative to the size of their balance sheets. Few cooperative utilities have plans to idle capacity.

Irrespective of whether a cooperative's board or regulatory body sets rates, we expect that those who do so for cooperative utilities will provide for recovery of the costs they will incur to comply with regulations. We believe rate adjustments could help support stable credit quality as emissions constraints increase. However, in our view, financial metrics could dwindle and credit quality might suffer if rate adjustments merely aim to recover regulatory costs and do not provide for excess margins consistent with historical levels. We believe the presence of a sound financial cushion that protects lenders and creditors is integral to strong credit quality.

We are monitoring whether the confluence of rising compliance costs and the economic environment might have implications for the size of rate adjustments and the prospects for achieving credit-protective financial cushions.

Low Natural Gas Prices Benefit Many Utilities, But Are Harming Some

Natural gas prices remain moderate. After Henry Hub prices reached highs of nearly $13 per million Btu (mmBtu) in mid-2008, natural gas prices fell precipitously, to only 30% of the high a year later. Prices fells as demand for the commodity withered with the economy. Natural gas inventories subsequently mushroomed with the advent of hydraulic fracturing, which also held prices down. Although prices are above their approximately $2 low-point, they generally remain in the $3.50-$4.50 per mmBtu range.

Low natural gas prices have helped lower production costs, which benefited many utilities' bottom lines. Lower electricity production and procurement costs have reduced upward pressures on customers' bills during the recession.

The shift in the relative economics of gas-fired resources relative to coal-based electricity enabled gas-fired generation to increasingly displace more costly and dirtier coal resources. The change in the fuels' comparative costs provided a path to economical environmental compliance. Coal's declining contribution to U.S. electricity production bears out this change. It declined to 37% in 2012 from about 50% in 2002 and 2007, and natural gas's contribution rose to 30% from 18% (see table 1).

Table 1

U.S. Electricity Production By Energy Source

(%)	2012	2007	2002
Coal	37	49	50
Natural gas	30	22	18
Nuclear	19	20	20
Renewables	12	9	9
Other (including petroleum)	1	2	2

Source: Energy Information Administration.

Even where opportunities to displace coal-fired electricity production through the dispatch of gas-fired resources or purchases abound, utilities with significant firm coal purchase commitments have missed out on some of the benefits. Coal supply contracts with take-or-pay requirements have ongoing financial and physical obligations. They have led to increasing coal piles at some utilities as they have switched to natural gas resources. Some have sold the surplus, with varying results. Others, to address storage constraints, have had to burn coal, regardless of the fuel's economics compared with those of natural gas.

For some utilities with generation surpluses, low natural gas prices have been a liability. Lower natural gas prices have adversely affected utilities that frequently rely on surplus sales' margins to support sound financial performance. Natural gas prices set electricity prices in many markets. Lower gas prices, together with the recession's erosion of demand, whittled down wholesale electricity prices and reduced opportunities to profit from wholesale sales of electricity.

Some utilities have historically relied on surplus sales margins to reduce their retail customers' rates. As margins from surplus sales declined, these utilities faced having to choose between increasing the financial burden on retail customers or allowing financial metrics to degrade. Utilities with long positions generally responded by raising rates. Even so, the varying magnitudes of rate adjustments have not uniformly supported financial metrics. Cooperative utilities with significant long positions include Associated Electric Cooperative, Basin Electric Power Cooperative, Buckeye Power, and Seminole Electric Cooperative. Although Basin Electric's margins from sales of surplus electricity and synthetic natural gas are vulnerable to the impacts of low natural gas prices, eclipsing the effects are rising electricity demand associated with oil and gas exploration and production in the Williston Basin and robust agriculture prices that increased the demand for the anhydrous ammonia that Basin produces as a byproduct of its synthetic natural gas production.

Rate Autonomy And Regulation Shape Credit Quality

While our rating methodology ascribes a lot of value to the flexibility that autonomous ratemaking provides to utilities, the credit quality of those that are subject to rate regulation does not necessarily suffer from outside regulation's presence.

The timing of regulators' rate actions tends to lag utility boards' rate adjustments. This distinction can contribute to lower ratings for regulated utilities. We nevertheless view regulators as providing lenders and investors with a threshold sound level of credit protection. Most believe that the regulators have a legal obligation to set rates to provide for utilities' recovery of prudently incurred costs plus a reasonable return. Standard & Poor's ratings distribution for rate-regulated, investor-owned utilities reflects these principles. Standard & Poor's rating for most regulated investor-owned utilities is 'BBB', compared with a 'B' rating for most U.S. nonfinancial corporate issuers.

Sometimes, regulators provide protections that exceed their mandate. EKPC provides an example of a regulator's credit-supportive actions that positively influenced our rating. We cited financial improvements that flowed from regulatory oversight as a key factor underlying the positive outlook on the utility. After finding that management actions and in some cases, inaction, were degrading EKPC's financial and operational performance, the Kentucky Public Service Commission (PSC) made recommendations to address the problems. The utility implemented the commission's directives, revised its processes for strategic decisions, halted its deteriorating trajectory, and strengthened its financial and operational performance.

While we often view autonomous ratemaking authority as more conducive to strong credit quality than outside rate oversight, possessing this flexibility does not automatically strengthen credit quality. To bolster credit quality, a utility board that sets rates needs to demonstrate a commitment to rate adjustments that are consistent with strong credit quality.

Although SIPC, a G&T cooperative, possesses autonomous ratemaking authority, its board chooses to set rates at levels that it projects will produce only slightly better than break-even coverage. Based on the utility's financial forecast, our calculations indicate coverage will be about 1.05x. We view these targets as adequate for recovering costs and debt service, but as constraining the rating. SIPC cites its customer base's demographics as limiting its ratemaking flexibility and the strength of the financial cushion it can create for lenders. Similarly, its management and board chose to forgo rate increases in the years leading up to the beginning of the debt amortization that financed its investment in a new power plant. On the cusp of the debt's amortization and the end of the project's capitalized interest period, the board raised rates 22% to achieve its coverage target.

Several of SIPC's seven member distribution cooperatives concluded that the wholesale rate increase was too steep to recover with the G&T and are deferring their recovery from retail customers of all or part of the G&T's rate increase. We believe that the members' decision could erode the quality of their contributions to the SIPC cash flows that support its debt service. We view the interplay between the G&T's decision to budget for thin margins and the members' decisions to delay as diluting the value of the utility's autonomous ratemaking authority and limiting its contribution to credit quality. Consequently, Standard & Poor's assigned its 'BBB' issuer credit rating, which is below the "A-' modal rating for G&T cooperative utilities..

Irrespective of whether a utility is self-regulated or subject to outside regulation, pass-through rate adjustment mechanisms that allow utilities to dynamically recover changes in operating costs can go a long way to preserving credit quality. The frequency of reconciling adjustments can be crucial during periods when commodity prices, such as those for natural gas and electricity, are volatile. Formulaic or automatic mechanisms provide greater certainty to lenders than discretionary mechanisms, but a track record of timely deployment of discretionary adjustments can overcome these concerns.

Customer Concentration Persists As An Important Credit Factor

Standard & Poor's rating methodology provides that meaningful concentrations among commercial and industrial customers have the potential to erode the benefits of otherwise sound credit metrics. Most cooperative utilities benefit from the stability that diverse, largely residential customer bases provide. We believe that a significant amount of residential load can limit a utility's exposure to the impacts of economic cycles on customer use. By comparison, commercial and industrial customers are more likely to have elastic demand during economic upheaval.

A recent illustration of the distinctions between the credit exposures we associate with different customer classes is the extreme industrial customer concentration Kentucky's Big Rivers Electric Corp. faces, which has heavily influenced its rating. This exposure's credit risks came to the fore during the past year.

Big Rivers exhibited what we view as strong debt service coverage of nearly 1.5x in 2010 and greater than 1.6x in 2011. This coverage outshined that of many other G&T cooperatives. Big Rivers' debt-to-capitalization stands at about 67%, which we also view as very favorable for a cooperative utility. However, the rating emphasizes its exposure to customer concentrations that overshadow the contributions of strong financial metrics.

Two aluminum smelters are Big Rivers' distribution members' largest end-use customers. The smelters have accounted for about two-thirds of the G&T's energy sales and absorbed much of its fixed costs. The smelters' economic viability depends on the strength of aluminum's highly volatile market prices and the smelting process's production costs. Electricity prices heavily influence production costs. During the downturn, aluminum demand and prices eroded as manufacturing and construction withered, which squeezed the smelters' financial margins.

After one of the smelters notified Big Rivers in August 2012 of its plans to close its facility in 2013, the utility applied to the PSC for authority to reallocate among its remaining customers the fixed costs that the smelter had borne. Although the utility's rate application was an important step toward preserving its financial integrity, we revised the outlook to negative to reflect the prospect of a large customer departure and its potential ramifications for financial performance, ratemaking flexibility, and credit quality. The second smelter responded to the specter of reallocated costs by notifying the utility of its plans to close its facility.

Although near-term financial performance is stable while the smelters fulfill obligations remaining under their contracts, the prospects for Big Rivers losing so much load and the tremendous burden that reallocated costs would create for the remaining customers, including questions of whether this substantial reallocation is feasible, led us to lower the rating to 'BB-' with a negative outlook after the second smelter gave notice. The utility is engaging in ongoing discussions with the smelters.

A Moderately Improving Economic Outlook Supports Stable Credit Conditions

Standard & Poor's sees signs of movement toward economic recovery, even if they are moderate. Our economists' baseline forecast projects 2.7% U.S. GDP growth in 2013 and 3.1% in 2014, compared with 2012's 2.2% and 2011's 1.8%. Unemployment stands at levels closely aligned with Standard & Poor's 7.8% forecast for 2013 and indicate some job market strengthening. However, room for improvement remains. We expect interest rates on 10-year Treasury notes to climb modestly during 2013 and 2014 as the economy mends (see table 2). We project natural gas prices to remain within a narrow band, which bodes well for utilities that can take advantage of the low gas prices. Although the economy still exhibits weakness, we believe the chance of another U.S. recession in the next year is 10%-15%, down from 2012 estimates of 20%-25%.

We base our expectations for cooperative utility credit quality on Standard & Poor's baseline economic forecast scenario. However, we recognize that economic performance in specific markets might be better or worse than the national averages, which can lead to different rating consequences among individual utilities.

Due to the nature of forecasting, we recognize that actual economic performance is likely to differ from the baseline. Therefore, Standard & Poor's also prepares upside and downside cases for the national economy to explore the probability and magnitude of alternative scenarios. Yet, we have observed during the recent recessionary era that the credit profiles of electric cooperative utilities generally have the capacity to withstand sizable economic contraction.

Table 2

Standard & Poor's Economic Outlook: Indicators for Electric Cooperative Utilities

		--Forecast/scenarios*--						
		--Downside (10%-15%)--		--Baseline (65%-75%)--		--Upside (15%-20%)--		Actual
Macroeconomic indicator	**Comment**	**2013**	**2014**	**2013**	**2014**	**2013**	**2014**	**2012**
Real GDP (% change)	The recovery has gained traction and should continue, even with federal sequestration, which could contribute to ratemaking flexibility. Moderate growth eases growth-related capital spending needs	0.8	0.7	2.7	3.1	3.4	4.5	2.2
Unemployment rate (%)	Job growth influences utilities' ratemaking flexibility	8.6	9.0	7.8	7.3	7.2	5.9	8.1
10-year Treasury-note yield (%)	Low interest rates benefit the capital-intensive utility industry	1.1	1.7	2.1	2.6	2.9	4.2	1.8
Natural gas (Henry Hub; $/mil. Btu)	Low natural gas prices help lower production costs and can reduce pressures on customers' bills as utilities pursue other spending needs	N.A.	N.A.	3.8	5.0	N.A.	N.A.	2.8

*Standard & Poor's derives its forecast for GDP growth, unemployment rates, treasury note yield and natural gas prices using the Global Insight model of the U.S. economy. N.A.--Not available.

For most utilities, the recession diminished growth-related capital spending needs. In turn, that reduced debt requirements and upward pressures on rates. Nondiscretionary capital spending, including emissions projects, created financing needs, but low interest rates tempered those costs. Low natural gas prices have also reduced operating costs for many utilities. As the economy gains momentum, capital spending and financing needs will likely increase. However, more favorable employment and improving wages could enhance utilities' ability to adjust rates and preserve financial margins as they face added costs.

We Expect Rating Stability To Continue

The sector's nearly universal stable outlooks indicate that, with few exceptions, neither the economy nor increasingly more stringent emissions regulations are likely to lead to widespread downgrades. We expect the rate-setting bodies -- whether the utility itself or an outside body -- will adjust rates to provide for the recovery of mandated environmental costs and facilitate the implementation of new regulations.

However, the full recovery of regulatory costs alone will not ensure ratings stability. Excess margins that protect lenders are critical to maintaining credit quality, and a migration to merely adequate margins could impair ratings, particularly if the economy constrains rate adjustments or regulatory compliance costs prove too high.

Issuer Review

Table 3

Issuer Review/Rating/Comments	Analyst
Arkansas Electric Cooperative Corp. (AECC) (AA/Stable/A-1+) We raised our rating to 'AA' from 'AA-' to reflect our view of management actions that transformed the utility's financial risk profile from break-even coverage to coverage levels of at least 1.5x, which are among the strongest of the cooperatives we rate; favorable leverage as measured by debt-to-capitalization of 65%, which we believe is strong for a cooperative utility; recent legislation that facilitates more frequent and less burdensome rate filings; the resulting expectations of consistently strong DSC; and the completion of the most capital-intensive portions of its capital program, which included new plant acquisitions and construction. In addition, the higher rating reflects our view that management and its member cooperatives are willing to raise rates as needed to maintain strong credit metrics. Although the EPA's call for further studies might delay installation of emission control equipment on the older coal-fired plants in Arkansas, management's five-year forecast includes these costs at the maximum estimated amount.	Judith Waite
Associated Electric Cooperative Inc., MO (AA/Stable) This G&T cooperative benefits from a very large footprint that contributes to the integrity of financial metrics. However, the utility has historically relied on sales of surplus energy and purchases for resale to enhance financial performance and maintain favorable member rates. Nonmember revenues peaked at 43% of operating revenues in 2004, but declined significantly to about 18% in 2009-2012 as native load grew, surplus capacity declined and lower natural gas prices depressed wholesale markets' electricity prices. Management implemented a 25.3% rate increase in 2008 and a 12.5% increase in 2009 to offset these trends, but has held rates at that level since 2009, which is an element that contributed to 2012's 20 basis point DSC decline to about 1.25x from 1.45x in 2010-2011. Fixed charge coverage was 5-10 basis points lower in those years. . We believe Associated is very carbon-intensive, which could have credit implications depending on the costs of complying with emissions regulations.	David Bodek
Baldwin Electric Membership Cooperative (BEMC), AL (A/Stable) This PowerSouth distributor, with about 68,000 metered accounts, has seen growth in customers and sales taper off as the Mobile MSA's economy deals with some high profile question marks related to a steel mill and Department of Defense contracts. While none of those large employers lies within BEMC's service area, many of its residential customers rely on those employers. The growth slowdown, however, has not translated into a measurable financial impact; DSC in 2012 was about 2.0x, with fixed charge coverage holding steady at just over 1.2x. Cash is consistently at or above two months' of operations. Between internally generated cash and	Ted Chapman

RUS borrowings, Baldwin has been able to fund projects that are primarily characterized as maintenance of efforts.

Basin Electric Power Cooperative, ND (A/Stable)

The utility achieved strong accrual-basis DSC of 1.6x in 2012 after more than 1.9x in 2011. Financial performance benefits from growing electric demand associated with the service area's oil and gas exploration and production in the Williston Basin. Also, robust agriculture prices increased demand for the anhydrous ammonia that Basin produces as a byproduct of its synthetic natural gas production. These developments eclipsed the impact of low natural gas prices that erode margins from sales of surplus electricity and synthetic natural gas. This G&T utility's financial performance remains vulnerable to rising debt service obligations. We believe that Basin's substantial reliance on nonmember revenues that are susceptible to cyclicality distinguishes it from many G&T cooperatives and do not provide the revenue security or predictability of member sales under long-term requirements contracts. However, the proportion of member revenues reached 49% in 2012, up from 29% in 2007. Nevertheless, member revenues' contribution remains low compared with those of other G&T cooperatives.

David Bodek

Big Rivers Electric Corp. (BREC), KY (BB-/Negative)

Big Rivers exhibited what we consider to be strong DSC of nearly 1.5x in 2010 and greater than 1.6x in 2011, which exceeded many other G&T cooperatives' ratios. Similarly, its debt-to-capitalization stands at about 67%, which we also view as very favorable for a cooperative utility. However, we view the utility's credit quality as intertwined with its members' two leading customers' performance. The two are aluminum smelters that account for about two-thirds of the G&T's energy sales. As manufacturing and construction withered during the economic downturn, aluminum demand and prices sharply eroded, which squeezed the smelters' financial margins. In August 2012, one of the smelters notified Big Rivers of plans to close its facility. The utility applied to the PSC for authority to reallocate among its remaining customers the fixed costs that were borne by the smelter. Although we viewed the utility's rate application as a critical step towards preserving the utility's financial integrity, the second smelter responded to the rate filing's specter of reallocated costs by notifying Big Rivers of its plans to close its facility. The utility's financial performance remains on stable footing in the near term, but the prospects of losing so much load and the tremendous burden that reallocated costs would create for remaining customers led us to lower the rating to 'BB-' with a negative outlook.

David Bodek

Brazos Electric Power Cooperative, Inc., TX (A-/Positive)

After extensive delays, we expect the Sandy Creek Energy Center--an 800 MW pulverized coal plant--to achieve commercial operational status in time for summer 2013. Despite the delay and cost overrun, Brazos was insulated from any financial or operational repercussions, given that the bulk of its $740 million, five-year capital budget consists of transmission-related projects that carry a regulated rate of return from the state public utilities commission. Management has established a DSC target of at least 1.25x and 15% equity, which it projects to achieve even after accounting for equity contributions to the Sandy Creek project. Accrual-basis fixed charge coverage was more than 1.3x in 2012 and has bested the forecast for several consecutive years. If the trend of exceeding forecast coverage metrics continues, there is the potential for an 'A' rating. Capacity additions have been driven primarily by growth from the distributors that serve some of the most affluent suburbs in the Fort Worth MSA. Management has met its goals of increased fuel and shaft diversity.

Ted Chapman

Brunswick Electric Membership Corp., NC (A/Stable)

In our view, the distribution cooperative's credit strengths include the board's willingness to set rates that target 2.0x DSC; the all-requirements power supply contract with North Carolina Electric Membership Corp. that provides fairly low-cost power; and a growing, primarily residential, customer base that is mainly in Brunswick County, an attractive destination for retirees. The cooperative has invested heavily in its power delivery system to assure reliability, and nearly all of its power lines along the coast are now underground. The utility also installed an automated meter reading system, which allows customers to monitor their usage and it to implement time-of-use rates. The cooperative's 65% debt to capitalization indicates that the balance sheet is more highly leveraged than those of most distribution utilities, which constrains the rating. The debt-funded system expansion accommodated rapid population growth.

Judith Waite

Buckeye Power, Inc., OH (A-/Stable)

In our view, Buckeye's uneven financial results and increased leverage have resulted in weak DSC in the past five years--ranging from 1.03x-1.09x. We believe the 2011 and 2012 coverage levels of 1.08x and 1.03x, respectively, were inflated through a 2011 financial transaction in which the utility used a portion of its line of credit to repay a note, effectively deferring the next three years of note amortization to 2015, when the line expires. Buckeye's rates to its members are slightly above average for G&T cooperatives. Already long on power, it recently added additional capacity, some of which exceeds the utility's contract customers' needs.

Jeff Panger

Moreover, a weak natural gas market has chilled the utility's ability to generate profits on sales from its surplus capacity. Given reliance on volatile wholesale sales revenue, we believe that achieving significantly improved financial metrics in the next five years is uncertain. Since 2005, debt has more than doubled to $1.4 billion.

Central Electric Power Cooperative Inc., SC (AA-/Stable)

David Bodek

Central Electric principally procures and transmits electricity to its 20 distribution cooperative members and their more than 720,000 customers. It collects and remits funds for energy purchases and develops and finances transmission assets. In our view, the narrow scope of its business model translates into low business risk that mitigates narrow DSC margins and limited working capital. Although power supply costs are passed through as incurred, overhead costs are not fully recovered in the year incurred if the utility sells fewer-than-projected MWh.

Central Iowa Power Cooperative (CIPCO) (A/Stable)

Peter Murphy

CIPCO is a G&T utility that benefits from a diverse and low-cost generation portfolio, including coal and nuclear baseload resources, natural gas peaking capacity and a growing renewable energy portfolio of PPAs. CIPCO owns a 20% stake (124 MW) in a nuclear plant whose Nuclear Regulatory Commission license runs through 2034, and which provided 31% of its energy in 2012. This nuclear resource, along with sizeable contracted wind capacity, bring low-carbon attributes to the utility at a time when stricter emissions regulations are looming. However, CIPCO does have exposure to carbon regulation for about half of its energy resources, although this remains below the average for its region. The utility increased slightly in 2012 and the relatively low density of its 12 member cooperatives' service territories, which contributes to above-average retail rates, could limit practical rate-making flexibility. However, economic growth has resulted in an all-time system peak (July 2012). Nevertheless, we believe CIPCO's financial performance was strong the past seven fiscal years, with 2012 DSC at 1.26x and robust liquidity..

Chugach Electric Association, AK (A-/Stable/A-1)

Peter Murphy

Chugach serves about 67,400 retail members, and is among Alaska's leading electricity providers and generators. Its financial performance remains solid, in our view. The utility posted 2012 DSC of 1.9x, which is lower than before but represents the utility's first year with mainly amortizing debt. Chugach refinanced $270 million of bullet maturities in 2011 and early 2012, and now all its long term debt will amortize serially. New money borrowings of about $250 million during the past two years funded the utility's 70% share of a recently operational natural gas-fired generation plant (Anchorage Municipal Light and Power owns the remaining 30%). Management expects the plant's more efficient gas generation capacity will result in substantial fuel savings, which is critical, given the region's long-term natural gas supply concerns. The utility faces several issues that are rare among cooperatives, including the authority of the Regulatory Commission of Alaska (RCA) over both retail and wholesale contract rates. However, the RCA's rate determinations have been generally favorable for Chugach's cost-recovery.

Dairyland Power Cooperative (DPC), WI (A/Stable)

Jeff Panger

DPC has what we consider a diverse membership of 25 distribution cooperatives that serves primarily residential bases in four states. Members have all-requirement contracts through 2055 and account for about 75% of operating revenues. Fiscal 2012 financial results have not been released yet. For fiscal 2012, coverage of scheduled debt service was 1.25x, which we view as sound. The utility had about 49 days' of operating expenses in cash, and inclusive of credit lines, liquidity was 235 days. DPC still relies on coal-fired generation. The environmental retrofit of its baseload coal plants is the primary driver of its capital plan, but will not materially alter its balance sheet. At fiscal year-end 2011, the utility had $871 million of debt outstanding, and management expects total debt will rise modestly over the next several years. DPC has no baseload needs through 2020 and complies with Wisconsin's 10% by 2015 renewable portfolio mandate.

Diverse Power Inc., GA (A/Stable)

Judith Waite

Diverse Power, a distribution cooperative, will own about 18.4 MW of the new Vogtle nuclear units through its membership in Oglethorpe Power Corp (OPC). OPC and the other owners expect the nuclear units will begin operating in 2017 and 2018 and replace contractual power purchases. By the end of 2012, OPC had invested about $1.7 billion in the Vogtle plant construction and expects its share of the total cost to be about $4.2 billion (in 2008 dollars). Diverse's share of the cost is 2.79%, or about $117 million. OPC supplies about 53% of Diverse's electricity, and will supply almost all power supply once the Vogtle units begin operating. Its rates are in line with state averages, despite the lower density of the cooperative's customer base, and will likely continue to be even with the cost of the Vogtle units included, since almost all providers of electricity in Georgia are investors in the project. The utility exhibits fixed charge coverage of about 1.2x and what we view as strong liquidity.

East Kentucky Power Cooperative Inc. (BBB/Positive)

This G&T cooperative produces nearly all of the energy it sells to its 16 member cooperatives. It relies only nominally on off-system sales revenues. The utility and its members are subject to state rate regulation. Although the utility lacks the scope of autonomous ratemaking authority traditionally available to cooperative utilities, we believe that lenders benefit from the commission's oversight. The positive outlook reflects our view of the commission's 2008 mandated management audit that not only stopped the utility's financial risk and operational profile from degrading, but helped turn around financial performance. DSC ratios were only about 0.9x in 2007-2008, but rate adjustments produced coverage of 1.1x in 2009-2012, and nearly 1.3x in 2011-2012. The rating could be raised if the utility sustains its improvements. East Kentucky exhibits very high leverage, in our view, with a debt-to-capitalization ratio of 88% in 2012. Coal resources account for about 85% of the utility's energy sales, which exposes it to the impacts of potentially higher regulation costs.

David Bodek

Georgia Transmission Corp. (GTC) (AA-/Stable/A-1+)

GTC is the transmission system of the OPC cooperative electric system, and is part of Georgia's Integrated Transmission System. GTC expects capital expenditures for 2013-2017 to be about $850 million to fund the transmission system's continuing upgrade and expansion. During the next several years, there will be increased competition for funding from the Federal Financing Bank under the guarantee of the RUS, and funding will depend on annual legislature approval. However, GTC continues to have what we view as good access to RUS-guaranteed debt. The cooperative has $74 million available under RUS loan commitments, and also has a $300 million shelf loan available from the National Rural Utilities Cooperative Finance Corp., of which $244 million remains available. In addition, it sold secured debt in the private placement market in 2009 and 2010, and completed its first solo tax-exempt bond transaction in 2012. Management expects debt to increase to about $2 billion in 2017 from $1.6 billion in 2012. Financial metrics are adequate, in our view, with DSC of 1.1x-1.2x but we believe mitigating this are the low business risk of this transmission utility and the strong level of liquidity GTC maintains.

Judith Waite

Golden Spread Electric Cooperative, Inc., TX (A/Stable)

This G&T cooperative provides power to 16 member cooperatives in the Southwest Power Pool (SPP) at rates regulated by the FERC and in the Electric Reliability Council of Texas (ERCOT), where rates are not regulated. Golden Spread serves SPP members with 1,035 MW of owned generation and the 500 MW it purchases. In 2019, the 500 MW contract will expire, ramping down before then. Golden Spread has invested in wind turbines (78.3 MW) and associated gas-fired quick-start generating units (168 MW), which began operating in mid-2011. In ERCOT, Golden Spread has a power supply contract that terminates in May 2016. From 2013-2019, management expects to invest $1.4 billion for new gas-fired generation primarily in the SPP. Protecting the financial risk profile are the member contracts' terms. The purchased power contracts include a 1.5x DSC margin on generating plant debt. Because the utility can adjust rates monthly with an annual true-up to assure full cost recovery, management expects to show fairly strong, stable coverage even after adding debt to fund construction of new assets. Management projects DSC of about 1.5x by 2016. We estimate fixed charge coverage will be about 1.25x.

Judith Waite

Great River Energy, MN (A-/Stable)

This utility lowered its DSC targets in 2011-2012 based on progress toward strengthening equity. Coverage was 1.1x in 2011-2012, compared with at least 1.2x in 2008-2010. Lower consumer electric demand and the addition of the new Spiritwood plant led the utility to reevaluate resource needs. Spiritwood sits idle. Capacity is sufficient for at least a decade. This G&T cooperative serves 28 member distribution cooperatives. Member revenues account for about 90% of operating revenues, which limits reliance on competitive wholesale markets for revenues. However, low natural gas prices that are compressing spark spreads on off-system sales, as well as softer market demand for power, present financial pressures. The utility benefits from the availability of an automatic monthly power cost adjustment mechanism that allows it to pass through increases in fuel and purchased power costs and, importantly, recover declines in nonmember margins to preserve financial performance. The utility depends heavily on coal-fired resources, which expose it and its customers to potentially higher regulatory costs.

David Bodek

Guadalupe Valley Electric Power Cooperative Inc. (GVEC), TX (A+/Stable)

In December 2012, GVEC reached a settlement with its current power supplier, the Lower Colorado River Authority (LCRA), whereby GVEC will be allowed to make purchases from others under a partial requirements option until the June 2016 expiration of its purchased power agreement. After that it intends to end its LCRA relationship and pursue other supply options. Management has already executed some new medium-term purchased power agreements that will provide the bulk of its baseload requirements, and still has sufficient time to fully address the remainder of its requirements after the LCRA contract has expired. The utility has a history of what we view as very strong financial metrics, including annual DSC of 3x-4x.

Ted Chapman

Hoosier Energy Rural Electric Cooperative Inc., IN (A/Stable)

The rating on Hoosier reflects our view of the utility's ability to adjust rates under all-requirements contracts for its 18 distribution cooperative members; its fixed cost coverage and liquidity that are above levels generally seen for cooperatives; and a power cost adjustment mechanism that we expect will minimize cyclical under- or over-collection of power costs. Hoosier depends on its coal-fired Merom and Ratts station units for the bulk of its energy needs, which exposes the cooperative to potentially significant outage or carbon regulation costs. Increased capital spending and debt levels, placed upward pressure on rates. Nevertheless, we believe strong DSC and fixed cost coverage, in the 1.3x and 1.2x ranges, respectively, and solid liquidity, measuring 226 days of operating expenses, mitigate this exposure.

Jeff Panger

Minnkota Power Cooperative, Inc., ND (A-/Stable)

This G&T and its 11 distribution cooperatives own sufficient generating capacity to supply electricity demand at least through 2030, including the needs of Northern Municipal Power Agency (NMPA), a joint action agency for 12 municipalities in Minnesota and North Dakota that accounts for about 7% of the combined Minnkota-NMPA kilowatt-hour sales. Coal-fired units supply most of the power, but Minnkota has made the necessary investment in pollution control equipment and expects any additional required investment will be small. The utility owns and operates the 256 MW Milton R. Young unit 1 and its members own 455 MW unit 2. In 2012-2013, Minnkota's members are investing about $376 million to build two power lines. Retail rates of about 11 cents are between the higher average in Minnesota and the lower average in North Dakota. In our view, Minnkota's strong business profile and good credit metrics support the rating. In 2011 and 2012, DSC was about 1.50x and fixed charge coverage about 1.25x.

Judith Waite

North Carolina Electric Membership Corp. (A-/Stable)

This G&T utility generates only about one-third of its customers' energy needs and purchases the balance, which yields accrual basis fixed charge coverage that is about 30 basis points lower than direct debt coverage. DSC of at least 1.4x in 2010-2012 was strong, in our view, and fixed charge coverage was about 1.1x. Using the utility's financial projections, we calculated fixed charge coverage that will consistently be about 1.1x through 2017, which we believe represents a baseline for the rating. We believe the utility is highly leveraged, particularly for a utility that relies on others for substantial portions of its customers' electricity needs. Its debt-to-capitalization ratio was 92% in 2012, which was improved compared to 2008's 100%.

David Bodek

Oglethorpe Power Corp. (OPC), GA (A/Stable/A-1)

The generation cooperative's stated commitment to maintaining a moderately strong financial risk profile as management pursues plans to add substantial generating assets is an important credit factor. These plans, in particular OPC's nuclear investment, will likely increase debt to about $9 billion by 2018 from $6 billion now, and annual debt service will peak at about $700 million in 2018 compared to about $380 million now. By the end of 2012, OPC's investment in the Vogtle 3 and 4 nuclear units was about $1.7 billion. In accordance with the indenture, Oglethrope must set wholesale rates high enough to cover costs plus a 1.1x MFI. The board raised the MFI to 1.12x in 2009 and 1.14x in 2010-2013. As a result, and combined with higher load, DSC was 1.53x in 2010 and 1.57x in 2011, but slipped to 1.15x in 2012. Management expects DSC to be about 1.2x during the Vogtle plant construction period. The board also directed management to increase liquidity significantly. We view both steps as evidence of its commitment to maintaining the rating.

Judith Waite

Old Dominion Electric Cooperative (ODEC), VA (A/Stable)

This G&T is subject to FERC regulation and its members face state rate regulation. Pass-through mechanisms mitigate regulatory concerns. Having a high proportion of residential customers benefits the utility. ODEC's distribution members acquired and added about 100,000 Potomac Edison customers. The utility plans to meet growing energy needs by developing resources and adding power purchases. It depends substantially on power purchases, which its limited generating investment and 67% debt-to-capitalization ratio reflect. In 2011, ODEC reduced its bullet debt maturities to 7% of total debt from 40%. DSC in 2012 was what we view as a strong 1.4x. Historically, fixed charge coverage has been at least 1.2x.

David Bodek

Peninsula Generation Cooperative (PGC), MI (A-/Positive)

PGC is a wholly owned subsidiary of Wolverine Power Cooperative. It was formed for the sole purpose of purchasing an ownership interest in Ohio Valley Electric Corp.'s coal-fired Kyger Creek and Clifty Creek plants. The rating on PGC reflects our views of Wolverine's credit quality because the latter has an unconditional obligation to purchase PGC power and pay debt service, even if the plant is not operating. In addition to its five distribution cooperative members that operate under take-and-pay power sales contracts through 2050, Wolverine's alternative energy supply member, Wolverine Power Marketing Cooperative, competes for large commercial and industrial customers in Michigan. We revised our outlook to positive from stable in 2012, reflecting management's projection that rate adjustments at WPC will lead to improved coverage of debt service and fixed costs. We could raise the rating within the next two years if WPC successfully achieves the

Jeff Panger

stronger coverage levels consistent with projections, and if compliance with environmental regulations -- both existing and future -- does not weaken WPC's financial performance. In 2012, fixed charge coverage was 1.3x.

PowerSouth Energy Cooperative, AL (A-/Stable)

The board of this G&T cooperative agreed to raise rates sufficiently to create a reserve for expected capital spending. This indicates a shift toward stronger bondholder protection. The board intends to establish a cash reserve of at least $170 million to partially fund plant acquisition and construction costs, in accordance with the mortgage indenture that requires that the cooperative fund at least 9% of all major capital spending with internally generated cash. We view the plan to build cash as a vehicle for strengthening operating cash flow, bolstering DSC and equity. Historical DSC was about 1.1x and the utility projects coverage of about 1.2x, which it achieved in 2011and 2012. Most of PowerSouth's electricity comes from low-cost, compliant coal-fired plants, supplemented by gas-fired units and purchased power. After 2016, about 10% of electricity will come from nuclear power. The utility has a 20-year contract with the Municipal Power Agency of Georgia for 125 MW of the Vogtle nuclear generating units under construction.

Judith Waite

Rayburn Country Electric Cooperative Inc., TX (A-/Stable)

This Rockwall, Texas-based G&T has five distributors contractually committed through 2041, and about 170,000 ultimate meters. Energy requirements have historically been met via purchased power agreements, save for a 2010 purchase of an undivided ownership interest in a combined cycle plant that represents about one-third of energy requirements. However, management has begun planning for new capacity to address existing PPAs that will begin to expire later in the decade. Its options include building, acquiring new power plants, PPAs, or some combination thereof. The distributors that lie in some of the Dallas area's most affluent suburbs continue to drive growth. The more rural members, however, are contributing to load as well. The cooperative's financial ability to incur commitments is adequate, in our view, given annual fixed charge coverage that conservatively is forecast to be at least 1.1x.

Ted Chapman

San Miguel Electric Cooperative Inc., TX (A-/Stable)

Management in March 2013 completed a new indenture to replace its RUS mortgage. This should allow San Miguel more financing options given that it expects some additional investment for pollution controls, although the full size and timeline of projects have not been fully determined. This single-asset cooperative owns and operates the 411 MW lignite-fired San Miguel plant for the benefit of its two G&T off-takers, South Texas Electric Cooperative and Brazos, both of which we rate 'A-'. We understand that contracts obligate South Texas and Brazos Electric to pay San Miguel's debt obligations through 2020, even if the plant is not operating. This plant is an important resource for these utilities, but is only one of several in their portfolios. South Texas and Brazos share output and costs in equal shares under long-term contracts expiring in June 2020.

Ted Chapman

Seminole Electric Cooperative, FL (A-/Stable)

Nine of Seminole's 10 members have signed extensions of their take and pay all requirement contracts through 2045. The extension includes provisions for conversion to partial-requirement membership, signaling that member interests are not necessarily aligned. The approved withdrawal of the tenth and historically second-largest member (Lee County Electric Cooperative) in 2014 bears this out further. While this relieves Seminole of the need to provide additional power supply, it diminishes the membership base's overall diversity. Fixed cost coverage for 2012 was weak, in our opinion, at just 1.03x. We will be monitoring the cooperative's projections, due out this summer; if they indicate a continuing trend, the rating or outlook could face stress. We believe liquidity is just adequate. At fiscal year-end 2012 (Dec. 31), cash and investments, and available credit lines measured 88 days of operating expenses, while money in the RUS' cushion of credit boosted total liquidity to 101 days of operating expenses. Seminole has what we view as a substantial carbon footprint.

Jeff Panger

South Mississippi Electric Power Association (SMEPA) (A-/Stable)

This G&T cooperative's operations have yielded accrual debt service coverage that was consistently at least 1.3x in 2009-2012. Fixed charge coverage was about 1.1x. SMEPA produces about one-third of its 11 members' customers' energy needs and purchases the balance under contracts. Nearly 100% of energy sales are to native load, which we view as contributing to revenue-stream predictability and stability. The utility raised rates substantially in recent years to maintain its financial strength. Coal resources, including power purchases, account for about 53% of SMEPA's energy sales, which exposes the utility and its lenders to potentially higher regulatory costs. The utility faces significant capital spending needs. Projects include generation capacity additions, emissions remediation at existing power plants, and renewal and rehabilitation. SMEPA projects $894 million of 2013-2016 capital spending and debt rising to $1.7 billion by 2013 from $1.4 billion in 2012, $960 million in 2011 and $836 million in 2010. After 2013, the utility projects that its debt

David Bodek

balances will stabilize.

South Texas Electric Cooperative (STEC) (A-/Stable)

Ted Chapman

STEC's integrated resources plan identified building new capacity as the primary driver to serve the load growth and to replace a PPA that expires in 2021. The predominantly rural residential native load, as well as exploration and production activity in the Eagle Ford Shale are in part driving load growth. Coleto Creek No. 2, a proposed 650 MW coal unit in Goliad County, is on hold for now, although given EPA's March 2012 announcement regarding new source carbon emissions, the project might be scrapped altogether. STEC might still opt to build baseload later in the decade as one possible way to address an anticipated need for capacity by 2020. Management suspended a surcharge it had used to build up funds for an equity contribution to Coleto 2 but still plans to designate the reserves toward some future plan. We expect fixed charge coverage of about 1.2x, like that of 2011 and 2012.

Southern Illinois Power Cooperative Inc. (SIPC) (BBB/Stable)

David Bodek

This G&T cooperative serves seven member distribution cooperatives and their 82,000 retail customers. It also serves another 19,000 customers through a wholesale non-member. SIPC projects that its debt service coverage will decline to about 1.05x as it begins servicing the $467 million of debt it issued to fund its interest in the Prairie State Energy Campus (PSEC). By comparison, coverage was 1.2x in 2010 and 2011. Some member cooperatives are deferring recovering their share of the G&T's recent 22% rate increase in their retail rates. We view this strategy as diluting some of the benefits of their rate-setting autonomy and as having the potential to erode the quality of the revenue streams that support SIPC debt service and operations. The utility expects PSEC to displace power purchases and raise self-production to more than 90% from about 70%.

Square Butte Electric Cooperative, ND (A-/Stable)

Peter Murphy

Square Butte owns a 455 MW lignite-fired mine-mouth generating station (Milton R. Young 2). It sells half of the output under a long-term contract to Minnkota Power Cooperative, the plant's operator. The balance is sold to Minnesota Power Inc. (MP). In a transaction related to the sale of 465 miles of transmission to MP, Minnkota's share of the plant's energy and capacity will increase annually beginning in 2014, eventually reaching 100% by 2026. The Young 2 plant is competitive, providing power in 2012 at an average cost of $41.10 per MWh, achieving 91.6% capacity factor, despite its 35-year age. The plant complies with nitrogen oxide emissions requirements, but potential EPA regulations covering emissions, coal ash, and intake water could drive capital costs. Square Butte has posted debt service coverage of 1.11 to 1.13 in the past four fiscal years. We view liquidity, including committed lines of credit as sound, at more than 430 days as of Dec. 31, 2012.

Sulphur Springs Valley Electric Cooperative (SSVEC), AZ (A-/Stable)

David Bodek

SSVEC is a distribution cooperative that relies on its G&T and other suppliers for all of its customers' electricity needs. It is a member and one of six owners of Arizona Electric Power Cooperative (AEPCO), its principal power supplier. In fiscal years 2010-2012, utility operations produced what view as strong accrual coverage of direct debt of at least 1.5x and sound fixed charge coverage of at least 1.2x. The Arizona Corporation Commission regulates the utility's rates. A power cost adjustment mechanism enables the utility to recover changes in fuel costs and market power purchases from customers without filing a rate case before the ACC. However, management and the board have discretion in timing SSVEC's cost recovery and the board emphasizes maintaining stable retail rates, which we view as having the potential to erode cash flows. The EPA has directed AEPCO, to cut nitrogen oxide, sulfur dioxide, and particulate matter emissions at its Apache generating station, which might double its $197 million of debt. AEPCO and others are appealing the orders.

Tri-State Generation & Transmission Association, CO (A/Stable)

David Bodek

Tri-State is a G&T cooperative serving 44 members across a 250,000-square-mile area in portions of Wyoming, Nebraska, Colorado, and New Mexico. It indirectly serves more than 610,000 retail customers. Tri-State's board established multiyear targets for incrementally strengthening financial margins. Yet, in 2012 it decided to extend by nearly a decade its time horizon for strengthening debt service coverage to 1.2x from 1.15x. Operating revenues provided slightly less than 1.0x debt service coverage in 2011-2012 because the utility used its RUS cushion of credit as a rate stabilization fund in those years. However, by treating the draws on the $268 million the utility deposited with the RUS as revenues available for debt service, coverage would have been at least 1.3x in 2011-2012. Tri-State faces legal challenges from members in Nebraska and New Mexico which could have implications for financial performance if the members prevail. We expect the utility will need additional debt to finance compliance with more stringent emissions regulations, add generation capacity for 2022 and beyond and develop the recently acquired Colowyo mine for use beyond 2017.

Vermont Electric Cooperative, Inc. (VEC) (A-/Stable)

We raised our rating on VEC in 2011 to reflect our assessment of the stronger financial risk profile of this distribution cooperative in northern Vermont. Unlike most cooperatives, VEC's rates are regulated. In recent years, the regulator has approved rate increases that include a 2.18x MFI, compared with 1.50x-1.80x in previous years. This will allow the utility to self-fund about 40% of its $50 million five-year capital investment plant. DSC strengthened to 2.5x in 2012 from about 2.0x in 2009 and 2010. Fixed charge coverage was 1.85x in 2012, up from 1.4x in 2009-2010. Management contracts for about 90% of electricity requirements about two years out, but the tenor of a portion of the supply portfolio is much longer. Committed lines of credit permit direct borrowing up to $10 million and letters of credit up to a cap of $20 million combined. This mitigates somewhat management's decision to maintain very minimal unrestricted cash.

Judith Waite

Wabash Valley Power Association (WVPA), IN (A-/Stable)

WVPA generated margins that increased its equity level to 16%, and toward management's 20% target. Audited figures for fiscal 2012 indicate a margin of $17.5 million. What we view as good budget performance and low market prices for power and natural gas have helped the utility achieve stronger margins, with no cost deferrals since fiscal 2008. DSC in fiscal 2012 was good in our view, at 1.4x, consistent with the previous year's performance. We believe, liquidity was strong as of Dec. 31, 2012, at more than 120 days' expenditures, when considering $100 million of committed lines of credit; and on-balance sheet liquidity is also sufficient, at 64 days. Wholesale rates are competitive, at $73 per MWh for 2012, and $74 for 2013. Management expects rates to increase modestly annually for the next few several years. By capacity, most of WVPA's owned resources are gas-based, although overall, more than 50% of energy comes from coal. The utility has 26 members, although two will terminate membership within the next couple of years, and combined with a nonmember that WVPA will supply through 2017, account for about 15% of annual revenue. We believe the loss does not threaten credit quality, due to a flexible portfolio of purchased power contracts; the addition of a new member, now its largest (12% of sales); and the modest growth in sales to remaining members.

Peter Murphy

Western Farmers Electric Cooperative, OK (BBB+/Positive)

We revised our outlook on this G&T cooperative to positive from stable in 2011 to reflect the benefits of a generation plant's lease restructuring that we believe averted a potentially costly lease-termination; and reduced, but did not remove, the cooperative's exposure to ratings triggers and contingent liabilities. The revised outlook also reflects our view of the utility's projections of stronger DSC because of debt extensions and rate increase plans. However, accrual DSC slipped to 1.1x in 2011 and 2012 from 1.3x in 2010. An ability to achieve strong DSC is important to the direction of credit quality. Recently, two members that have accounted for about 10% of operating revenues and had brought litigation agreed to end their membership in the cooperative and transition to power purchase arrangements with WFEC pending their severing their relationships with the utility. We are monitoring the impact of the settlement on financial performance. In addition, some members' DSC ratios have been weak in recent years and we are assessing the impact on the quality of the cash flows that WFEC derives from its members.

David Bodek

Note: Ratings as of April 30, 2013. DSC--Debt service coverage. EPA--Environmental Protection Agency. FERC--Federal Energy Regulatory Commission. G&T--Generation and transmission. MFI--Margins for interest. MSA--Metropolitan statistical area. MW--Megawatt. MWh--Megawatt-hour. RUS--Rural Utilities Service.

Recent Rating Activity

Table 4

Recent Rating Actions

Issuer	State	To	From	Date
Arkansas Electric Cooperative Corp.	AR	AA/Stable	AA-/Stable	April 26, 2013
Big Rivers Electric Corp.	KY	BB-/Negative	BBB-/Negative	Feb. 4, 2013
East Kentucky Power Cooperative Inc.	KY	BBB/Positive	BBB/Stable	March 4, 2013
Peninsula Generation Cooperative	MI	A-/Positive	A-/Stable	Dec. 19, 2012

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Table 5

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Related Criteria And Research

USPF Criteria: Applying Key Rating Factors To U.S. Cooperative Utilities, Nov. 21, 2007

Comments and data reflect publicly available information as of April 30, 2013.

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FitchRatings

U.S. Public Power
Peer Study

June 2013

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Inside **Page**

Summary

- This report highlights the financial performance of Fitch-rated public power utilities.
- The report utilizes nine financial ratios that are calculated from the most recent annual audits.
- The ratios are presented by utility type, rating category, and region.
- A utility's financial measures, relative to Fitch-designated regional and national peer groups, constitute an important component of Fitch's credit analysis.

2012 Performance Highlights

- Debt service coverage for wholesale systems continued its downward trend, while coverage for 'AA' and 'A' retail systems diverged, broadly reflecting weaker margins for most systems.
- Cash on hand medians generally increased for wholesale and retail systems, affirming strong liquidity throughout the sector.
- The ratio of capital expenditures to depreciation generally continued to decline for most systems. This trend, together with increased cash on hand, likely remains attributable to slower growth and the deferral of certain capital expenditures.
- Leverage metrics remained relatively unchanged for both retail and wholesale systems, with leverage medians for 'A' rated systems remaining higher than 'AA' systems.

Overview

Fitch Ratings presents the 2013 edition of its annual "U.S. Public Power Peer Study." This report compares the recent financial performance of wholesale and retail public power systems, as well as rural electric cooperatives. The ratios highlighted in this report are some of the primary financial calculations used in comparing utility systems in Fitch's committee process, and can be used by market participants to assist in making their own comparisons. It is important to note that financial metrics represent only one key component, among others, in Fitch's utility credit analysis. To review Fitch's full public power criteria, please see the report, "U.S. Public Power Rating Criteria," dated Dec. 18, 2012.

The U.S. Public Power Peer Study is a point-in-time assessment of Fitch-rated public power utilities. The ratios for each issuer are determined using audited information. While more than half of the audits used in this study are dated Dec. 31, 2012, different audit dates may skew the distribution of the ratios.

Also, financial ratios and metrics detailed in the report may occasionally differ from those reported in new issue and full rating reports. This can be a result of adjustments made by Fitch during the rating review process to reflect additional information received from the issuer, as well as circumstances unique to the credit. In each case, Fitch seeks to highlight these adjustments for the benefit of the reader in the reports and press releases it publishes during the rating process.

Excel Addendum

Fitch has released the peer comparison tables in spreadsheet form to improve the peer study's use as a tool for investors and other market participants. In this year's release of the Excel addendum, financial ratios and metrics for prior fiscal years (2009–2011) and the current fiscal year will again be included to move beyond a point-in-time comparison of utilities and allow for an accessible review of historical trends.

In an effort to make the Excel addendum as useful and timely as possible, Fitch began updating the addendum in December, with audited figures from issuers whose fiscal years end between Jan. 31 and June 30. The remaining issuers are updated during the regular production of the peer study and addendum in early June, as usual.

What's New?

This year's edition of the addendum features the new Public Power Dashboard, which provides a system overview, including key rating, operational, and financial information for each of the public power and cooperative issuers included in the peer study, and the ability to compare trends in operational and financial data between two systems, and financial metrics against rating category medians.

The addendum also continues to feature a dynamic charting application that allows the user to generate a quick graphic representation of how a utility's selected financial metrics compare with the respective medians and offers tools for comparing a utility's key financial metrics to median calculations on a notch-specific rating basis for comparable entities rated within the same rating category (i.e. 'AA', 'A', 'BBB'), and against the entire portfolio of Fitch-rated issuers.

Utility Systems Included in Report

The majority of utility systems rated by Fitch's public power group fall into three categories: wholesale systems, retail systems, and generation and transmission (G&T) cooperative systems. The following is a brief description of each of the sectors.

Wholesale Systems

Wholesale systems represent utilities whose revenues are primarily derived from sales to other systems or its members, and are typically organized as joint action agencies (JAAs). The number of members in JAAs can vary from three (Northern Illinois Municipal Power Agency) to more than 100 (American Municipal Power). Additionally, JAAs may be organized to own one generating unit or a diverse portfolio of resources. Wholesale providers that are not organized as JAAs, some of which are quasi-state agencies, are also included in this category.

Retail Systems

Retail utility systems derive the majority of their revenues from sales to end-user customers. Retail systems may be fully integrated utilities or distribution-only systems.

Rural Electric Cooperatives

G&T Cooperatives

G&T cooperatives typically provide wholesale power supply and transmission services to their member distribution cooperatives. G&T revenues are primarily derived from sales and services provided to members, but may also include payments from third-party market participants. G&T cooperatives are generally organized as not-for-profit entities that operate for the benefit of their owner members.

Metrics for G&T cooperatives are included in the calculation of medians for wholesale systems, and are also presented separately in this report.

Distribution Cooperatives

Distribution cooperatives sell power to their owner members (or end-user customers), and are included in the retail category.

Commentary

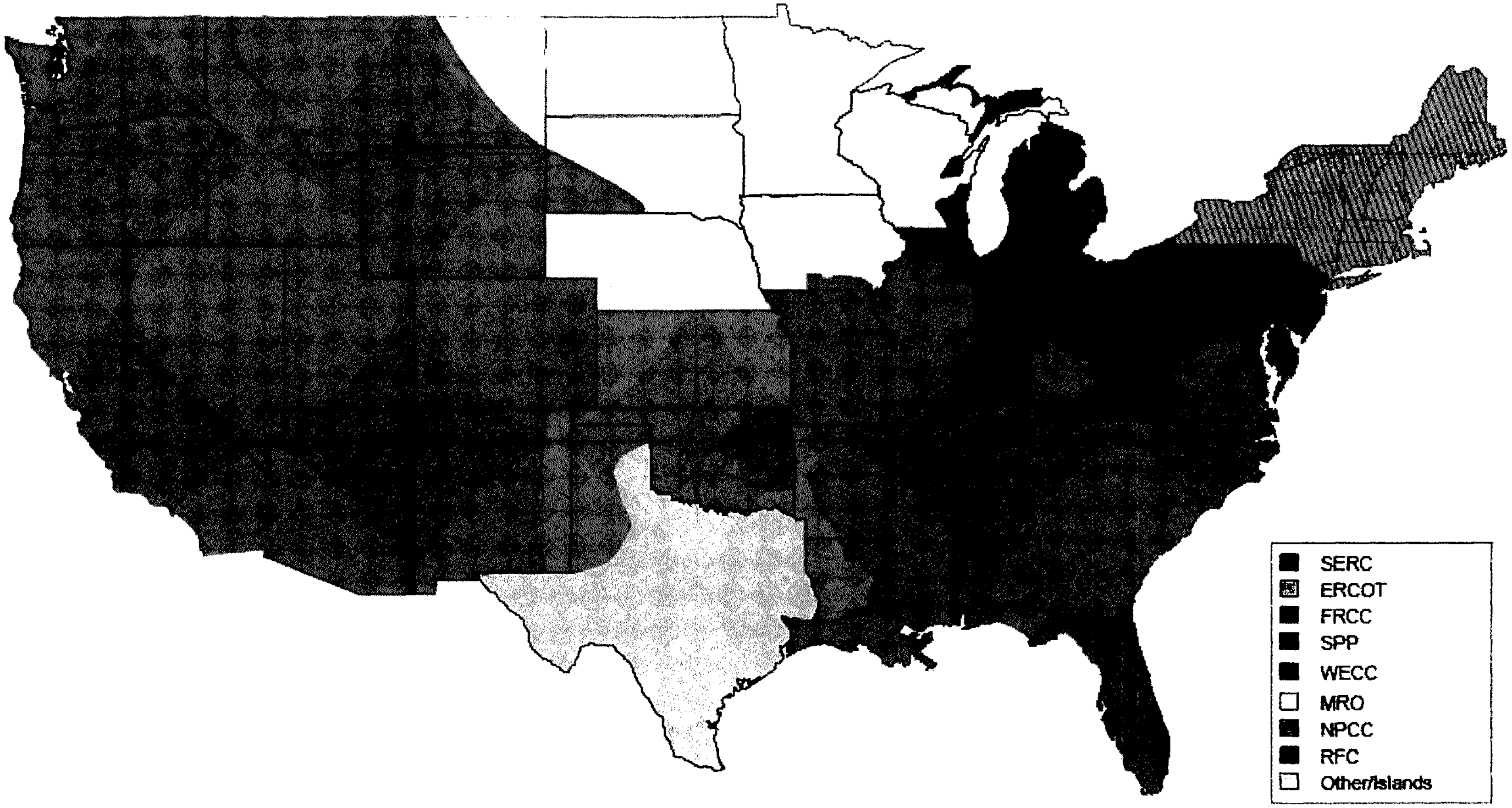
Medians Are Not Targets

While the peer study includes median calculations for financial ratios by rating category, these should not be construed as targets for specific ratios or ratings. The medians reflect a single point in time, may not reflect relevant adjustments, and in many instances are based on a small sampling of public power issuers.

Comments Welcome

As always, Fitch welcomes comments, ideas, and suggestions from users to improve the value of the U.S. Public Power Peer Study.

NERC Regions



NERC – North American Electric Reliability Corporation. SERC – Southeastern Electric Reliability Council. ERCOT – Electric Reliability Council of Texas. FRCC – Florida Reliability Coordinating Council. SPP – Southwest Power Pool. WECC – Western Electricity Coordinating Council. MRO – Midwest Reliability Organization. NPCC – Northeast Power Coordinating Council. RFC – Reliability First Corporation. Other Islands – Alaska, Guam, Puerto Rico, and U.S. Virgin Islands. Note: NERC regions are shown within U.S. geographical boundaries only.
Source: Fitch and NERC.

Public Power Operating Profiles

Issuer	Rating	Outlook/Watch	Type	Self-Regulated	Primary Fuel Exposure	Total Debt 2012 ($000)	Total Members/ Wholesale Customers[a]	Total Retail Customers[b]
Reliability First Corporation (RFC)								
Buckeye Power Inc., OH	A	RO: Negative	G&T Coop	Yes	Coal	1,656,066	25	380,000
Delaware Municipal Electric Corporation	A–	RO: Stable	Wholesale	Yes	Gas	63,914	9	64,000
Dover Electric Revenue Fund, DE	AA–	RO: Stable	Retail	Yes	Gas	30,033	—	22,912
Indiana Municipal Power Agency	A+	RO: Stable	Wholesale	Yes	Coal	1,298,618	59	190,020
Old Dominion Electric Cooperative, VA	A	RO: Stable	G&T Coop	No (FERC)	Coal/Nuclear	766,128	11	550,000
Electric Reliability Council of Texas (ERCOT)								
Austin Electric, TX	AA–	RO: Stable	Retail	Yes	Coal/Nuclear	1,413,102	—	422,370
Boerne Utility System, TX	A	RO: Stable	Retail	Yes	Coal	44,040	—	14,237
Brazos Electric Power Cooperative, TX	A	RO: Stable	G&T Coop	Yes	Gas	2,483,426	16	538,770
Brownsville Public Utilities Board, TX	A+	RO: Negative	Retail	Yes	Gas	345,482	—	46,102
Bryan Utilities City Electric System, TX	A+	RO: Stable	Retail	Yes	Coal/Gas	202,610	—	32,893
Bryan Utilities Rural Electric System, TX	A+	RO: Stable	Retail	Yes	Coal/Gas	8,525	—	16,446
CoServ Electric, TX	AA–	RO: Stable	Retail	Yes	Gas	551,117	—	167,023
Floresville Electric Light & Power System, TX	AA–	RO: Stable	Retail	Yes	Coal/Nuclear	23,744	—	14,321
Garland Electric Fund, TX	AA–	RO: Stable	Retail	Yes	Coal	294,642	—	68,396
Georgetown Utility Funds, TX	AA–	RO: Negative	Retail	Yes	Coal/Gas	59,050	—	24,341
Golden Spread Electric Cooperative, TX	A	RO: Stable	G&T Coop	No (FERC)	Gas	539,314	16	270,000
Granbury Municipal Utilities, TX	A+	RO: Stable	Retail	Yes	Nuclear	18,806	—	3,223
Guadalupe Valley Electric Cooperative Inc., TX	AA–	RO: Stable	Retail	Yes	Coal	173,790	—	71,164
Kerrville Public Utility Board, TX	AA–	RO: Stable	Retail	Yes	Coal	4,462	—	21,696
Lower Colorado River Authority — Consolidated	A	RO: Stable	Wholesale	Yes	Coal	3,327,400	43	1,000,000
New Braunfels Utilities, TX	AA	RO: Stable	Retail	Yes	Coal	32,755	—	31,601
Pedernales Electric Cooperative Inc., TX	AA–	RO: Stable	Retail	Yes	Coal	711,477	—	247,816
Sam Rayburn Municipal Power Agency, TX	BBB+	RO: Stable	Wholesale	Yes	Coal	124,010	3	11,348
San Antonio City Public Service, TX (CPS Energy)	AA+	RO: Stable	Retail	Yes	Coal	4,883,654	—	723,522
San Miguel Electric Cooperative, TX	A–	RO: Stable	G&T Coop	Yes	Coal	214,470	2	NM
Seguin Utility Fund, TX	A+	RO: Stable	Retail	Yes	Coal	21,822	—	8,247
South Texas Electric Cooperative Inc.	A–	RO: Stable	G&T Coop	Yes	Coal	787,114	8	244,408
Texas Municipal Power Agency	A+	RO: Stable	Wholesale	Yes	Coal	852,158	4	162,438
Florida Reliability Coordinating Council (FRCC)								
Florida Municipal Power Agency — All-Requirements Project	A	RO: Stable	Wholesale	Yes	Gas	1,280,668	14	269,486
Fort Pierce Utilities Authority, FL	A+	RO: Stable	Retail	Yes	Gas	98,637	—	27,765
Gainesville Regional Utilities, FL	AA–	RO: Stable	Retail	Yes	Coal	1,006,695	—	92,461
Jacksonville Beach Combined Utility Funds, FL	AA–	RO: Stable	Retail	Yes	Gas	31,330	—	30,446
JEA – Electric System and Bulk Power Supply System, FL	AA	RO: Stable	Retail	Yes	Coal	2,973,285	—	422,314
Kissimmee Utility Authority, FL	AA–	RO: Stable	Retail	Yes	Gas	180,485	—	64,007
Lakeland Electric Utility, FL	AA–	RO: Stable	Retail	Yes	Gas	487,560	—	120,771
Leesburg Electric System, FL	A+	RO: Stable	Retail	Yes	Gas	40,971	—	22,412
Ocala, FL Combined Utility Funds	AA–	RO: Stable	Retail	Yes	Gas	155,190	—	50,498
Orlando Utilities Commission, FL	AA	RO: Stable	Retail	Yes	Coal	1,564,285	—	227,893
Reedy Creek Improvement District — Utility Fund, FL	A	RO: Stable	Retail	Yes	Gas	310,070	—	1,316
Tallahassee Electric Fund, FL	AA–	RO: Stable	Retail	Yes	Gas	608,751	—	108,317
Vero Beach Electric System, FL	A+	RO: Stable	Retail	Yes	Gas	48,659	—	34,068
Winter Park Electric Services Fund, FL	AA–	RO: Stable	Retail	Yes	Purchased	70,378	—	14,261

[a]Total Members/Wholesale Customers – Most recent figures available; some figures may be estimated. [b]Total Retail Customers – Figures for wholesale systems represent retail customers served by the members; most recent data available; some figures may be estimated. N.A. – Not available. G&T – Generation and transmission. FERC – Federal Energy Regulatory Commission. NM – Not meaningful. *Continued on next page.*
Source: Fitch Ratings.

Public Power Operating Profiles (Continued)

Issuer	Rating	Outlook/Watch	Type	Self-Regulated	Primary Fuel Exposure	Total Debt 2012 ($000)	Total Members/ Wholesale Customers[a]	Total Retail Customers[b]
Midwest Reliability Organization (MRO)								
Basin Electric Power Cooperative, ND	A+	RO: Stable	G&T Coop	Yes	Coal	4,215,594	134	2,800,000
Batavia Electric Fund, IL	A–	RO: Stable	Retail	Yes	Coal	25,670	—	10,844
Big Rivers Electric Corp., KY	BB	RO: Negative	G&T Coop	No	Coal	925,243	3	112,500
Central Iowa Power Cooperative	A	RO: Stable	G&T Coop	Yes	Coal	358,509	13	133,710
Corn Belt Power Cooperative, IA	A–	RO: Stable	G&T Coop	Yes	Coal	226,306	10	32,000
East Kentucky Power Cooperative	BBB	RO: Stable	G&T Coop	No	Coal	2,750,523	16	522,523
Great River Energy, MN	A–	RO: Stable	G&T Coop	Yes	Coal	2,854,809	28	650,000
Illinois Municipal Electric Agency	A+	RO: Stable	Wholesale	Yes	Coal	1,264,397	32	162,485
Lincoln Electric System, NE	AA	RO: Stable	Retail	Yes	Coal	701,843	—	130,546
Municipal Energy Agency of Nebraska	A	RO: Stable	Wholesale	Yes	Coal	166,948	68	124,006
Rochester Public Utilities, MN	AA–	RO: Stable	Retail	Yes	Coal	78,800	—	49,990
Southern Illinois Power Cooperative	BBB	RO: Stable	G&T Coop	Yes	Coal	715,343	7	82,391
Western Minnesota Municipal Power Agency	AA–	RO: Stable	Wholesale	Yes	Coal	268,456	61	153,300
WPPI Energy (Wisconsin Public Power Inc.)	A+	RO: Stable	Wholesale	Yes	Coal	385,292	51	199,300
Northeast Power Coordinating Council (NPCC)								
Connecticut Municipal Electric Energy Cooperative	A+	RO: Stable	Wholesale	Yes	Gas	169,399	5	72,588
Hydro-Quebec	AA–	RO: Stable	Retail	Yes	Hydro	43,543,000	—	4,107,426
Long Island Power Authority, NY	A	RO: Negative	Retail	Yes	Gas	9,731,965	—	1,100,000
Massachusetts Municipal Wholesale Electric Company — Consolidated	A+	RO: Stable	Wholesale	Yes	Nuclear	301,230	28	399,487
New York Power Authority	AA	RO: Stable	Wholesale	Yes	Hydro	2,991,000	—	1,057
Vermont Electric Cooperative, VT	BBB+	RO: Stable	Retail	No	Purchased	65,150	—	37,972
Southern Electric Reliability Council (SERC)								
Arkansas Electric Cooperative Corporation	A+	RO: Stable	G&T Coop	Yes	Coal	995,708	17	498,000
Associated Electric Cooperative Inc., MO	AA–	RO: Stable	G&T Coop	Yes	Coal	1,957,679	51	875,000
Bristol Utilities Authority, VA	A–	RO: Stable	Retail	Yes	Coal	41,604	—	17,461
Chattanooga Electric Power Board — Electric System, TN	AA	RO: Stable	Retail	Yes	Coal	287,489	—	172,439
City of Greenville (NC)	A+	RO: Stable	Retail	Yes	Coal/Nuclear	109,844	—	63,789
Concord Utility Funds, NC	AA	RO: Stable	Retail	Yes	Coal	97,343	—	27,675
Greer Commission of Public Works, SC	A+	RO: Stable	Retail	Yes	Nuclear	86,535	—	18,066
Memphis Light, Gas & Water Division — Electric Division, TN	AA+	RO: Stable	Retail	Yes	Coal	788,788	—	422,884
Municipal Electric Authority of Georgia	A+	RO: Stable	Wholesale	Yes	Coal/Nuclear	6,273,902	48	308,000
Municipal Gas Authority of Georgia	A+	RO: Stable	Wholesale	Yes	Gas	286,841	77	225,828
Nashville Electric Service, TN	AA+	RO: Stable	Retail	Yes	Coal	569,812	—	364,130
North Carolina Eastern Municipal Power Agency	A–	RO: Stable	Wholesale	Yes	Nuclear/Coal	2,249,722	32	269,000
North Carolina Electric Membership Corporation	A–	RO: Stable	G&T Coop	Yes	Nuclear	1,211,982	25	958,559
North Carolina Municipal Power Agency No. 1	A	RO: Stable	Wholesale	Yes	Nuclear	1,629,475	19	162,980
Oglethorpe Power Corporation, GA	A	RO: Negative	G&T Coop	Yes	Coal/Gas	6,672,338	38	1,800,000
Paducah Power System, KY	A–	RO: Stable	Retail	Yes	Coal/Gas	165,892	—	22,407
Piedmont Municipal Power Agency, SC	A–	RO: Stable	Wholesale	Yes	Nuclear	1,088,140	10	99,856
PowerSouth Energy Cooperative and Subsidiaries, AL	A–	RO: Stable	G&T Coop	Yes	Coal	1,364,415	20	420,965
Sikeston Board of Municipal Utilities, MO	BBB+	RO: Stable	Retail	Yes	Coal	143,384	—	9,122
South Carolina Public Service Authority (Santee Cooper)	AA–	RO: Stable	Wholesale	Yes	Coal	5,887,076	—	900,842
South Mississippi Electric Power Association	A–	RO: Stable	G&T Coop	Yes	Gas	1,399,106	11	410,870
Tennessee Valley Authority	AAA	RO: Negative	Wholesale	Yes	Coal	25,065,000	155	4,600,000

[a]Total Members/Wholesale Customers – Most recent figures available; some figures may be estimated. [b]Total Retail Customers – Figures for wholesale systems represent retail customers served by the members; most recent data available; some figures may be estimated. N.A. – Not available. G&T – Generation and transmission. FERC – Federal Energy Regulatory Commission. NM – Not meaningful. *Continued on next page.*

Source: Fitch Ratings.

Public Power Operating Profiles (Continued)

Issuer	Rating	Outlook/Watch	Type	Self-Regulated	Primary Fuel Exposure	Total Debt 2012 ($000)	Total Members/ Wholesale Customers[a]	Total Retail Customers[b]
Southwest Power Pool (SPP)								
Grand River Dam Authority, OK	A	RO: Stable	Wholesale	Yes	Coal	911,962	25	NM
Kansas City Board of Public Utilities, KS	A+	RO: Stable	Retail	Yes	Coal	521,290	—	63,281
Lubbock Power & Light Fund, TX	A+	RO: Stable	Retail	Yes	Coal	131,705	—	101,036
Nebraska Public Power District	A+	RO: Stable	Wholesale	Yes	Coal	2,211,566	76	89,335
Oklahoma Municipal Power Agency	A	RO: Stable	Wholesale	Yes	Coal/Gas	635,841	39	113,291
Springfield Public Utility, MO	AA	RO: Stable	Retail	Yes	Coal	755,857	—	110,192
Western Farmers Electric Cooperative, OK	A–	RO: Stable	G&T Coop	Yes	Coal	922,323	23	278,082
Western Electric Coordinating Council (WECC)								
Alameda Municipal Power — Electric Services, CA	A+	RO: Stable	Retail	Yes	Geo/Hydro	32,186	—	34,338
Anaheim Electric Utilities Fund, CA	AA–	RO: Stable	Retail	Yes	Coal	706,655	—	115,113
Benton CO Public Utility District No. 1, WA	A+	RO: Stable	Retail	Yes	Hydro	59,391	—	47,710
Boise Kuna Irr Dist ADA and Canyon Counties (ID)	A–	RO: Stable	Retail	Yes	Hydro	20,177	—	4,040
Bonneville Power Administration, WA	AA	RO: Stable	Wholesale	Yes	Hydro	14,534,245	146	NM
Bountiful Light and Power, UT	AA–	RO: Stable	Retail	Yes	Coal/Hydro	14,655	—	16,573
Chelan CO Public Utility District No. 1 — Consolidated, WA	AA+	RO: Negative	Retail	Yes	Hydro	877,554	—	48,463
Clark County Public Utility District — Electric System, WA	A+	RO: Stable	Retail	Yes	Hydro	228,405	—	185,803
Colorado Springs Utilities, CO	AA	RO: Stable	Retail	Yes	Coal	2,307,972	—	673,261
Cowlitz County Public Utility District No. 1 — Electric, WA	A	RO: Negative	Retail	Yes	Hydro	256,825	—	48,252
Eagle Mountain Electric and Gas Funds (UT)	A	RO: Stable	Retail	Yes	Coal/Gas	29,487	—	11,254
Eugene Electric Board, OR	AA–	RO: Negative	Retail	Yes	Hydro	314,117	—	88,965
Gallup Joint Utilities Fund, NM	AA–	RO: Stable	Retail	Yes	Coal	23,400	—	10,515
Glendale Electric Funds, CA	A+	RO: Negative	Retail	Yes	Coal	117,640	—	85,358
Grant County Public Utility District No. 2 — Electric System	AA	RO: Stable	Retail	Yes	Hydro	162,990	—	46,500
Grays Harbor County Public Utility District No. 1, WA	A	RO: Stable	Retail	Yes	Hydro	127,791	—	41,464
Heber Light & Power Company, UT	AA–	RO: Stable	Retail	Yes	Hydro/Coal/Gas	10,630	—	11,059
Imperial Irrigation District — Energy, CA	A+	RO: Stable	Retail	Yes	Gas	573,985	—	148,562
Klickitat CO Public Utility District No. 1, WA	A–	RO: Negative	Retail	Yes	Hydro	143,834	—	12,202
Lodi Electric Fund, CA	A–	RO: Stable	Retail	Yes	Gas	74,630	—	25,350
Los Alamos County Joint Utility System Fund, NM	A–	RO: Stable	Retail	Yes	Coal/Hydro	61,310	—	8,660
Los Angeles Department of Water & Power — Power System, CA	AA–	RO: Stable	Retail	Yes	Coal	6,601,051	—	1,471,000
Modesto Irrigation District, CA	A	RO: Positive	Retail	Yes	Gas	557,493	—	113,931
Overton Power District No. 5, NV	BBB+	RO: Negative	Retail	Yes	Purchased	55,029	—	13,910
Pasadena Water & Power, CA	AA	RO: Stable	Retail	Yes	Coal	145,059	—	64,836
Pend Oreille County Public Utility District No. 1 — Combined, WA	A–	RO: Stable	Retail	Yes	Hydro	29,525	—	8,782
Platte River Power Authority, CO	AA	RO: Stable	Wholesale	Yes	Coal	279,510	4	149,876
Redding Electric Utility Fund, CA	A	RO: Stable	Retail	Yes	Coal/Gas	164,029	—	43,281
Riverside Electric Utility, CA	AA–	RO: Stable	Retail	Yes	Coal	635,686	—	107,321
Roseville Electric Fund, CA	A+	RO: Stable	Retail	Yes	Gas	249,330	—	54,115
Sacramento Municipal Utility District, CA	A+	RO: Stable	Retail	Yes	Gas	2,941,245	—	604,053
Silicon Valley Power, CA	A+	RO: Stable	Retail	Yes	Gas	210,646	—	52,825
Snohomish CO Public Utility District No. 1, WA	AA–	RO: Stable	Retail	Yes	Hydro	546,169	—	324,581
Sulphur Valley Springs Electric Cooperative, AZ	A–	RO: Stable	Retail	No	Coal	168,572	—	51,752
Tacoma Power, WA	AA–	RO: Stable	Retail	Yes	Hydro	547,037	—	169,012
Tri-State Generation & Transmission Association Inc.	A	RO: Stable	G&T Coop	Yes	Coal	2,785,075	44	610,600
Turlock Irrigation District, CA	A+	RO: Stable	Retail	Yes	Gas/Hydro	1,247,018	—	99,913

[a]Total Members/Wholesale Customers – Most recent figures available; some figures may be estimated. [b]Total Retail Customers – Figures for wholesale systems represent retail customers served by the members; most recent data available; some figures may be estimated. N.A. – Not available. G&T – Generation and transmission. FERC – Federal Energy Regulatory Commission. NM – Not meaningful. *Continued on next page.*
Source: Fitch Ratings.

Public Power Operating Profiles (Continued)

Issuer	Rating	Outlook/Watch	Type	Self-Regulated	Primary Fuel Exposure	Total Debt 2012 ($000)	Total Members/ Wholesale Customers[a]	Total Retail Customers[b]
Other/Islands								
Anchorage Electric Utility Fund, AK	A+	RO: Stable	Retail	No	Gas	240,325	—	30,599
Chugach Electric Association Inc., AK	A–	RO: Positive	Retail	No	Gas	557,590	—	82,004
Guam Power Authority	BBB–	RO: Stable	Retail	No	Oil	646,429	—	49,978
Puerto Rico Electric Power Authority	BBB+	RW: Negative	Retail	Yes	Oil	8,935,502	—	1,469,541
Virgin Islands Electric System	BB	RO: Negative	Retail	No	Oil	304,852	—	54,653

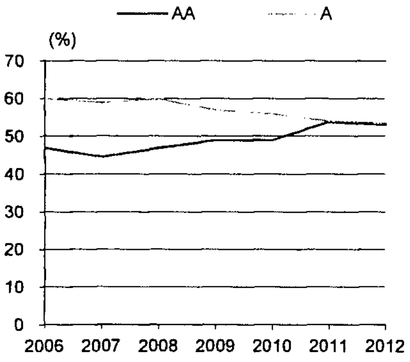
[a]Total Members/Wholesale Customers – Most recent figures available; some figures may be estimated. [b]Total Retail Customers – Figures for wholesale systems represent retail customers served by the members; most recent data available; some figures may be estimated. N.A. – Not available. G&T – Generation and transmission. FERC – Federal Energy Regulatory Commission. NM – Not meaningful.
Source: Fitch Ratings.

Retail Electric Trends

Below, the trends of 'AA' and 'A' medians for retail electric systems are displayed for nine of the financial metrics used in Fitch's analysis.

Equity/Capitalization

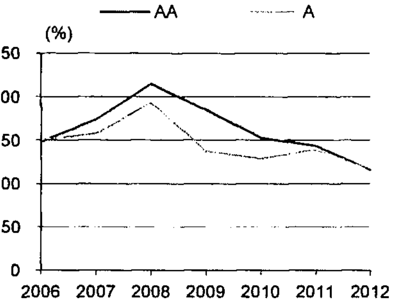
Provides a measure of cost recovery.



Source: Fitch.

Capex/Depreciation and Amortization

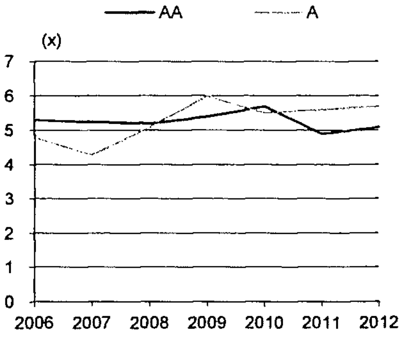
Indicates whether annual capital spending keeps pace with depreciation.



Source: Fitch.

Debt/FADS

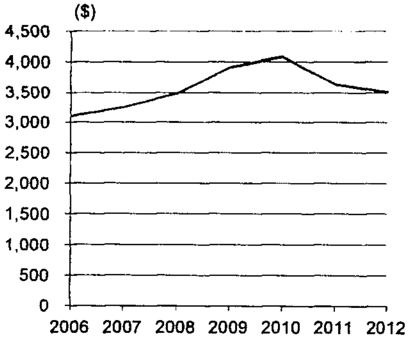
Indicates the size of debt compared to the margin available for debt service.



Source: Fitch.

Debt/Customer (Retail)

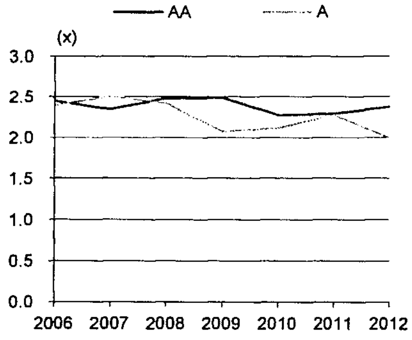
Provides a measure for relative comparison of leverage.



Source: Fitch.

Debt Service Coverage

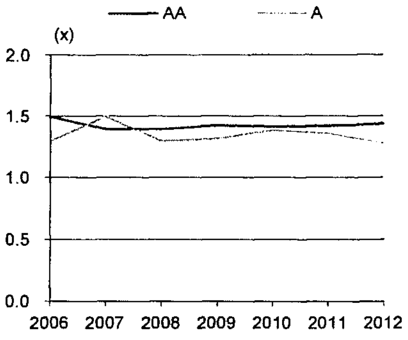
Indicates the margin available to meet current debt service requirements.



Source: Fitch.

Coverage of Full Obligations

Indicates the margin available to meet current debt service and other fixed obligations.

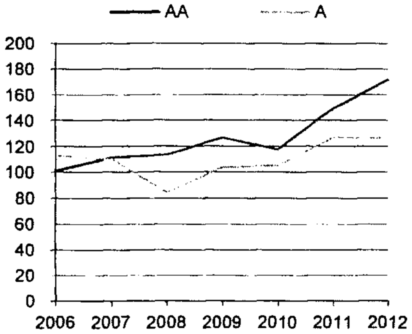


Source: Fitch.

FADS – Funds available for debt service. Note: Please see pages 19 and 20 for "Glossary of Terms" and "Ratio Definitions."

Days Cash on Hand

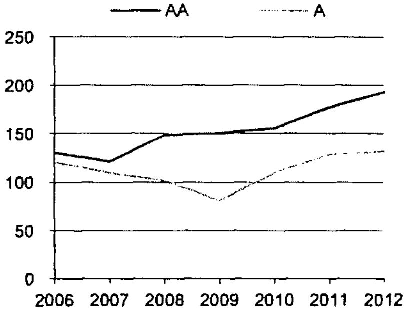
Indicates financial flexibility, specifically cash and cash equivalents, relative to expenses.



Source: Fitch.

Days Liquidity on Hand

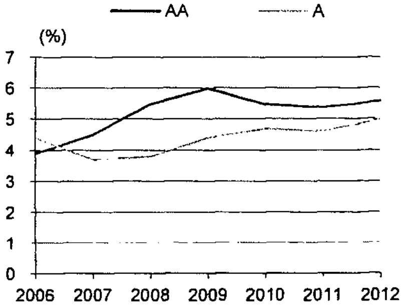
Indicates financial flexibility, including all available sources of cash and liquidity, relative to expenses.



Source: Fitch.

General Fund Transfer/ Operating Revenues

Indicates the degree to which a utility supports city or county general fund operations.



Source: Fitch.

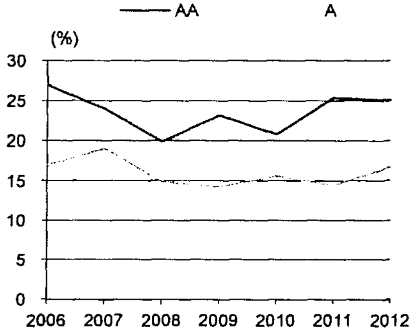
FADS – Funds available for debt service. Note: Please see pages 19 and 20 for "Glossary of Terms" and "Ratio Definitions."

Wholesale Electric Trends

Below, the trends of 'AA' and 'A' medians for wholesale electric systems are displayed for six of the financial metrics used in Fitch's analysis.

Equity/Capitalization

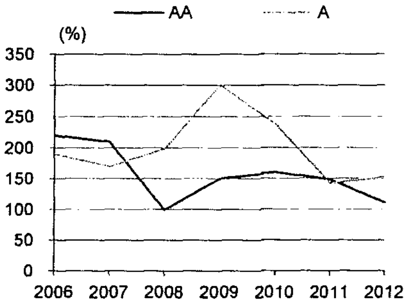
Provides a measure of cost recovery, leverage, and debt capacity.



Source: Fitch.

Capex/Depreciation and Amortization

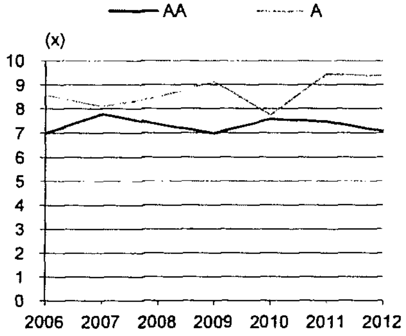
Indicates amount of capital spending relative to asset depreciation.



Source: Fitch.

Debt/FADS

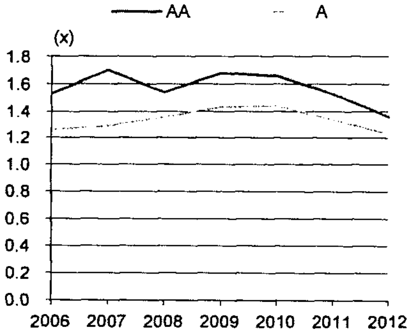
Indicates the size of debt compared to the margin available for debt service.



Source: Fitch.

Debt Service Coverage

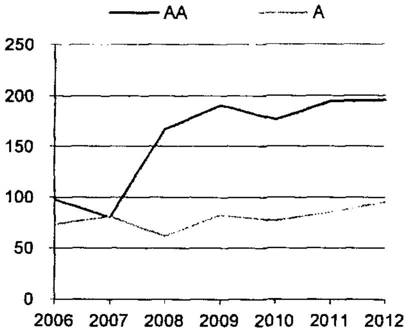
Indicates the margin available to meet current debt service requirements.



Source: Fitch.

Days Cash on Hand

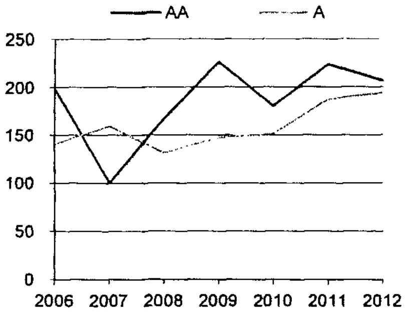
Indicates financial flexibility, specifically cash and cash equivalents, relative to expenses.



Source: Fitch.

Days Liquidity on Hand

Indicates financial flexibility, including all available sources of cash and liquidity, relative to expenses.



Source: Fitch.

FADS – Funds available for debt service. Note: Please see pages 19 and 20 for "Glossary of Terms" and "Ratio Definitions."

Retail Systems

Issuer	Rating	Outlook/ Watch	Region	Total Revenues 2012 ($000)	Debt Service Coverage 2012 (x)	Coverage of Full Obligations 2012 (x)	Debt/ FADS 2012 (x)	Days Cash on Hand 2012	Days Liquidity on Hand 2012	Transfer Payment as % of Operating Revs 2012	Capex/ Depreciation 2012 (%)	Equity/ Capitalization 2012 (%)	Debt Per Customer 2012 ($)
AA+ Rated Senior Debt													
Chelan CO Public Utility District No. 1 — Consolidated, WA	AA+	RO: Negative	WECC	321,733	2.36	2.20	5.1	564	682	2.3	70.5	34.7	18,108
Memphis Light, Gas & Water Division — Electric Division, TN	AA+	RO: Stable	SERC	1,319,000	1.77	1.14	3.4	55	55	3.0	167.3	58.6	1,865
Nashville Electric Service, TN	AA+	RO: Stable	SERC	1,154,512	3.11	1.32	3.9	72	72	2.5	133.2	50.3	1,565
San Antonio City Public Service, TX (CPS Energy)	AA+	RO: Stable	ERCOT	2,284,496	2.18	1.31	5.4	211	211	12.6	102.0	40.5	6,750
Median				**1,236,756**	**2.27**	**1.32**	**4.5**	**142**	**142**	**2.8**	**117.6**	**45.4**	**4,308**
AA Rated Senior Debt													
Chattanooga Electric Power Board — Electric System, TN	AA	RO: Stable	SERC	560,996	3.09	1.24	5.5	57	57	0.0	351.6	48.2	1,667
Colorado Springs Utilities, CO	AA	RO: Stable	WECC	858,297	2.00	1.79	7.6	116	182	3.6	182.6	38.7	3,428
Concord Utility Funds, NC	AA	RO: Stable	SERC	113,577	2.89	1.78	3.0	348	348	0.5	73.4	70.7	3,517
Grant County Public Utility District No. 2 — Electric System	AA	RO: Stable	WECC	218,708	6.14	4.51	2.4	346	346	5.6	512.8	77.7	3,505
JEA – Electric System and Bulk Power Supply System, FL	AA	RO: Stable	FRCC	1,358,090	3.17	2.02	6.0	170	170	9.8	70.5	19.9	7,040
Lincoln Electric System, NE	AA	RO: Stable	MRO	276,110	2.04	1.43	7.6	200	322	6.6	133.9	28.7	5,376
New Braunfels Utilities, TX	AA	RO: Stable	ERCOT	118,019	6.14	1.52	1.4	172	172	5.1	205.4	89.1	1,037
Orlando Utilities Commission, FL	AA	RO: Stable	FRCC	854,383	1.52	1.20	6.4	353	353	12.0	101.7	40.5	6,864
Pasadena Water & Power, CA	AA	RO: Stable	WECC	185,951	3.06	1.33	3.4	480	480	8.5	124.8	78.2	2,237
Springfield Public Utility, MO	AA	RO: Stable	SPP	385,602	1.95	1.60	7.3	122	122	3.2	83.0	55.0	6,859
Median				**330,856**	**2.98**	**1.56**	**5.8**	**186**	**252**	**5.4**	**129.4**	**51.6**	**3,511**
AA– Rated Senior Debt													
Anaheim Electric Utilities Fund, CA	AA–	RO: Stable	WECC	397,931	1.67	1.16	8.0	108	108	3.8	104.6	32.2	6,139
Austin Electric, TX	AA–	RO: Stable	ERCOT	1,179,872	1.71	1.09	4.8	67	138	8.9	113.3	53.2	3,346
Bountiful Light and Power, UT	AA–	RO: Stable	WECC	26,640	7.72	1.83	1.9	327	327	8.8	721.4	57.7	884
CoServ Electric, TX	AA–	RO: Stable	ERCOT	392,331	2.17	1.33	7.9	83	83	0.8	263.7	37.3	3,300
Dover Electric Revenue Fund, DE	AA–	RO: Stable	RFC	101,903	4.79	1.25	1.6	202	202	8.7	70.9	78.4	1,311
Eugene Electric Board, OR	AA–	RO: Negative	WECC	246,227	2.33	1.29	6.2	109	109	5.6	142.9	52.2	3,531
Floresville Electric Light & Power System, TX	AA–	RO: Stable	ERCOT	29,701	2.38	1.20	5.7	95	95	3.0	169.6	59.2	1,658
Gainesville Regional Utilities, FL	AA–	RO: Stable	FRCC	354,624	2.24	1.70	6.7	57	142	10.2	130.2	32.7	10,888
Gallup Joint Utilities Fund, NM	AA–	RO: Stable	WECC	30,950	3.60	2.85	2.5	378	378	6.3	115.8	74.4	2,225
Garland Electric Fund, TX	AA–	RO: Stable	ERCOT	223,701	4.11	2.37	3.2	647	968	9.0	85.7	56.8	4,308
Georgetown Utility Funds, TX	AA–	RO: Negative	ERCOT	85,941	3.11	1.10	3.0	111	111	7.4	133.7	79.7	2,426
Guadalupe Valley Electric Cooperative Inc., TX	AA–	RO: Stable	ERCOT	192,149	2.98	1.44	4.5	47	264	2.1	292.8	53.7	2,442
Heber Light & Power Company, UT	AA–	RO: Stable	WECC	13,137	2.95	1.62	3.8	145	145	2.3	118.6	70.0	961
Hydro-Quebec	AA–	RO: Stable	NPCC	12,228,000	2.11	1.93	5.7	220	388	5.3	151.2	30.4	10,601
Jacksonville Beach Combined Utility Funds, FL	AA–	RO: Stable	FRCC	89,204	3.25	2.47	2.1	298	298	4.0	84.2	84.5	1,029
Kerrville Public Utility Board, TX	AA–	RO: Stable	ERCOT	42,677	2.73	1.27	0.6	90	90	3.1	105.1	90.6	206
Kissimmee Utility Authority, FL	AA–	RO: Stable	FRCC	173,082	1.21	1.07	8.6	223	265	5.3	60.7	50.2	2,820
Lakeland Electric Utility, FL	AA–	RO: Stable	FRCC	290,337	1.96	1.47	5.3	222	222	8.3	96.2	39.0	4,037
Los Angeles Department of Water & Power — Power System, CA	AA–	RO: Stable	WECC	3,116,823	2.62	1.48	7.6	151	151	8.0	250.6	43.4	4,487
Ocala, FL Combined Utility Funds	AA–	RO: Stable	FRCC	165,759	6.66	1.74	3.6	265	265	6.5	79.2	64.7	3,073
Pedernales Electric Cooperative Inc., TX	AA–	RO: Stable	ERCOT	587,821	2.19	1.45	5.4	49	133	0.2	104.5	38.7	2,871
Riverside Electric Utility, CA	AA–	RO: Stable	WECC	333,029	1.97	1.22	5.7	297	297	10.1	146.8	43.0	5,923
Rochester Public Utilities, MN	AA–	RO: Stable	MRO	142,602	3.57	1.34	2.8	137	137	5.8	93.6	60.7	1,576
Snohomish CO Public Utility District No. 1, WA	AA–	RO: Stable	WECC	591,010	2.06	1.28	5.1	193	193	5.3	237.6	76.3	1,683
Tacoma Power, WA	AA–	RO: Stable	WECC	387,833	2.15	1.94	4.5	335	335	10.9	107.8	58.8	3,237
Tallahassee Electric Fund, FL	AA–	RO: Stable	FRCC	312,722	1.74	1.11	7.6	271	271	8.6	73.4	41.4	5,620
Winter Park Electric Services Fund, FL	AA–	RO: Stable	FRCC	46,034	3.16	2.58	5.1	25	115	5.5	107.3	16.3	4,935
Median				**223,701**	**2.38**	**1.44**	**5.1**	**151**	**193**	**5.8**	**113.3**	**53.7**	**3,073**

FADS – Funds available for debt service. Note: Fiscal 2011 audit — Anchorage Electric Utility; Gallup Joint Utilities; Grays Harbor PUD; Klickitat PUD; Memphis Light, Gas & Water. Draft Fiscal 2012 audit — Imperial Irrigation District. *Continued on next page.*
Source: Fitch Ratings.

Retail Systems (Continued)

Issuer	Rating	Outlook/ Watch	Region	Total Revenues 2012 ($000)	Debt Service Coverage 2012 (x)	Coverage of Full Obligations 2012 (x)	Debt/ FADS 2012 (x)	Days Cash on Hand 2012	Days Liquidity on Hand 2012	Transfer Payment as % of Operating Revs 2012	Capex/ Depreciation 2012 (%)	Equity/ Capitalization 2012 (%)	Debt Per Customer 2012 ($)
A+ Rated Senior Debt													
Alameda Municipal Power — Electric Services, CA	A+	RO: Stable	WECC	51,435	2.99	1.21	4.3	248	248	7.9	49.8	62.1	937
Anchorage Electric Utility Fund, AK	A+	RO: Stable	Other	134,418	1.68	1.30	4.3	128	128	8.9	324.6	49.9	7,854
Benton CO Public Utility District No. 1, WA	A+	RO: Stable	WECC	129,146	3.24	1.42	3.3	185	218	9.1	101.7	67.6	1,245
Brownsville Public Utilities Board, TX	A+	RO: Negative	ERCOT	165,571	2.45	1.68	5.6	243	243	4.7	176.3	54.3	7,494
Bryan Utilities City Electric System, TX	A+	RO: Stable	ERCOT	147,972	2.24	1.42	4.8	150	150	6.2	114.0	47.1	6,160
Bryan Utilities Rural Electric System, TX	A+	RO: Stable	ERCOT	31,496	7.15	1.54	1.6	79	79	0.0	383.0	83.9	518
City of Greenville (NC)	A+	RO: Stable	SERC	256,728	2.23	1.16	3.8	113	113	2.2	104.7	74.3	1,722
Clark County Public Utility District — Electric System, WA	A+	RO: Stable	WECC	360,729	1.59	1.20	3.8	74	97	5.7	91.0	46.9	1,229
Fort Pierce Utilities Authority, FL	A+	RO: Stable	FRCC	96,460	2.48	1.45	3.8	167	167	4.9	55.3	64.5	3,553
Glendale Electric Funds, CA	A+	RO: Negative	WECC	199,462	4.13	1.01	4.2	136	136	10.6	119.9	74.1	1,378
Granbury Municipal Utilities, TX	A+	RO: Stable	ERCOT	17,721	1.92	1.35	5.9	53	53	5.7	27.7	57.2	5,835
Greer Commission of Public Works, SC	A+	RO: Stable	SERC	67,499	1.68	1.23	7.9	125	125	1.5	56.4	61.9	4,790
Imperial Irrigation District – Energy, CA	A+	RO: Stable	WECC	405,201	1.50	1.22	9.7	197	250	0.0	186.2	61.1	3,864
Kansas City Board of Public Utilities, KS	A+	RO: Stable	SPP	289,369	2.37	1.47	6.2	34	34	17.8	453.0	44.2	8,238
Leesburg Electric System, FL	A+	RO: Stable	FRCC	58,575	4.38	1.06	3.6	144	144	12.5	471.5	62.9	1,828
Lubbock Power & Light Fund, TX	A+	RO: Stable	SPP	189,209	1.99	1.09	3.8	135	135	6.5	122.4	56.0	1,304
Roseville Electric Fund, CA	A+	RO: Stable	WECC	160,775	2.04	1.32	7.1	125	125	5.8	27.4	50.2	4,607
Sacramento Municipal Utility District, CA	A+	RO: Stable	WECC	1,382,274	2.20	1.88	6.6	192	211	0.0	185.2	20.9	4,869
Seguin Utility Fund, TX	A+	RO: Stable	ERCOT	41,464	3.12	1.48	3.8	260	260	8.3	140.7	74.0	2,646
Silicon Valley Power, CA	A+	RO: Stable	WECC	297,644	3.20	1.54	3.9	292	292	5.3	125.7	75.3	3,988
Turlock Irrigation District, CA	A+	RO: Stable	WECC	318,905	1.54	1.42	11.9	256	400	0.0	140.9	19.9	12,481
Vero Beach Electric System, FL	A+	RO: Stable	FRCC	86,941	2.20	1.03	3.3	97	97	6.6	36.6	69.6	1,428
Median				**154,374**	**2.24**	**1.34**	**4.3**	**140**	**140**	**5.8**	**121.2**	**61.5**	**3,708**
A Rated Senior Debt													
Boerne Utility System, TX	A	RO: Stable	ERCOT	22,167	1.96	1.48	7.8	170	170	7.1	680.2	51.4	3,093
Cowlitz County Public Utility District No. 1 — Electric, WA	A	RO: Negative	WECC	228,882	1.67	1.18	6.7	78	78	5.0	96.4	51.2	5,323
Eagle Mountain Electric and Gas Funds (UT)	A	RO: Stable	WECC	12,091	1.41	1.17	11.4	233	233	0.0	249.9	29.8	2,620
Grays Harbor County Public Utility District No. 1, WA	A	RO: Stable	WECC	110,408	1.62	1.25	7.3	84	84	8.2	138.7	52.8	3,082
Long Island Power Authority, NY	A	RO: Negative	NPCC	3,546,152	0.31	0.46	365.3	33	43	9.1	121.0	3.3	8,847
Modesto Irrigation District, CA	A	RO: Positive	WECC	366,601	1.71	1.38	5.8	239	239	0.0	103.8	14.8	4,893
Redding Electric Utility Fund, CA	A	RO: Stable	WECC	164,353	2.02	1.23	6.1	73	73	3.4	44.3	39.6	3,790
Reedy Creek Improvement District — Utility Fund, FL	A	RO: Stable	FRCC	192,726	1.27	1.19	6.3	37	37	0.0	63.2	16.1	235,616
Median				**178,540**	**1.65**	**1.21**	**7.0**	**81**	**81**	**4.2**	**112.4**	**34.7**	**4,342**
A– Rated Senior Debt													
Batavia Electric Fund, IL	A–	RO: Stable	MRO	43,893	6.11	1.64	3.0	138	138	1.7	87.8	66.5	2,367
Boise Kuna Irr Dist ADA and Canyon Counties (ID)	A–	RO: Stable	WECC	45,852	2.94	1.26	4.4	38	78	1.2	107.0	63.7	4,994
Bristol Utilities Authority, VA	A–	RO: Stable	SERC	81,089	4.78	1.71	3.1	91	91	0.0	342.6	74.5	2,383
Chugach Electric Association Inc., AK	A–	RO: Positive	Other	266,971	2.07	1.85	9.7	24	265	0.2	285.5	23.0	6,800
Klickitat CO Public Utility District No. 1, WA	A–	RO: Negative	WECC	33,636	1.23	1.16	17.9	175	175	4.0	174.0	49.3	11,788
Lodi Electric Fund, CA	A–	RO: Stable	WECC	64,251	1.43	1.01	7.4	92	92	15.3	60.0	2.1	2,944
Los Alamos County Joint Utility System Fund, NM	A–	RO: Stable	WECC	60,256	1.73	1.49	3.3	160	160	1.3	108.4	72.4	7,080
Paducah Power System, KY	A–	RO: Stable	SERC	63,191	1.47	1.26	9.2	70	70	3.4	83.1	16.5	7,404
Pend Oreille County Public Utility District No. 1 — Combined, WA	A–	RO: Stable	WECC	46,170	1.75	1.25	4.0	125	125	5.0	109.4	65.2	3,362
Sulphur Valley Springs Electric Cooperative, AZ	A–	RO: Stable	WECC	107,940	1.96	1.35	7.7	2	76	0.0	168.9	32.5	3,257
Median				**61,724**	**1.86**	**1.30**	**5.9**	**92**	**109**	**1.5**	**108.9**	**56.5**	**4,178**

FADS – Funds available for debt service. Note: Fiscal 2011 audit — Anchorage Electric Utility; Gallup Joint Utilities; Grays Harbor PUD; Klickitat PUD; Memphis Light, Gas & Water. Draft Fiscal 2012 audit — Imperial Irrigation District. *Continued on next page.*
Source: Fitch Ratings.

Retail Systems (Continued)

Issuer	Rating	Outlook/ Watch	Region	Total Revenues 2012 ($000)	Debt Service Coverage 2012 (x)	Coverage of Full Obligations 2012 (x)	Debt/ FADS 2012 (x)	Days Cash on Hand 2012	Days Liquidity on Hand 2012	Transfer Payment as % of Operating Revs 2012	Capex/ Depreciation 2012 (%)	Equity/ Capitalization 2012 (%)	Debt Per Customer 2012 ($)
BBB+ Rated Senior Debt													
Overton Power District No. 5, NV	BBB+	RO: Negative	WECC	35,431	1.04	1.02	10.4	55	115	0.0	223.4	37.0	3,956
Puerto Rico Electric Power Authority	BBB+	RW: Negative	Other	5,046,494	0.97	0.67	12.8	26	44	5.6	89.5	(6.1)	6,080
Sikeston Board of Municipal Utilities, MO	BBB+	RO: Stable	SERC	70,169	1.05	1.05	7.8	297	297	0.0	91.1	30.5	15,718
Vermont Electric Cooperative, VT	BBB+	RO: Stable	NPCC	72,754	2.42	1.47	5.2	7	110	4.3	219.9	46.5	1,716
Median				**71,462**	**1.05**	**1.04**	**9.1**	**41**	**113**	**2.2**	**155.5**	**33.8**	**5,018**
BBB– Rated Senior Debt													
Guam Power Authority	BBB–	RO: Stable	Other	438,672	0.90	0.90	10.7	17	17	0.0	160.0	17.5	12,934
BB Rated Senior Debt													
Virgin Islands Electric System	BB	RO: Negative	Other	331,414	0.89	0.89	11.9	11	11	0.2	81.9	17.9	5,578

FADS – Funds available for debt service. Note: Fiscal 2011 audit — Anchorage Electric Utility; Gallup Joint Utilities; Grays Harbor PUD; Klickitat PUD; Memphis Light, Gas & Water. Draft Fiscal 2012 audit — Imperial Irrigation District.
Source: Fitch Ratings.

All Wholesale Systems (Includes G&T Cooperatives)

Issuer	Rating	Outlook/ Watch	Region	Total Revenues 2012 ($000)	Debt Service Coverage 2012 (x)	Coverage of Full Obligations 2012 (x)	Debt/ FADS 2012 (x)	Days Cash on Hand 2012	Days Liquidity on Hand 2012	Capex/ Depreciation 2012 (%)	Equity/ Capitalization 2012 (%)
AAA Rated Senior Debt											
Tennessee Valley Authority	AAA	RO: Negative	SERC	11,220,000	1.18	1.16	7.1	41	41	112.2	17.5
AA Rated Senior Debt											
Bonneville Power Administration, WA	AA	RO: Stable	WECC	3,317,850	2.15	0.94	10.2	224	365	221.0	15.2
New York Power Authority	AA	RO: Stable	NPCC	2,673,000	4.27	2.13	4.4	232	252	64.2	53.7
Platte River Power Authority, CO	AA	RO: Stable	WECC	182,635	1.60	1.50	5.0	196	196	44.6	62.7
Median				**2,673,000**	**2.15**	**1.50**	**5.0**	**224**	**252**	**64.2**	**53.7**
AA– Rated Senior Debt											
Associated Electric Cooperative Inc., MO	AA–	RO: Stable	SERC	1,081,899	1.17	1.16	8.0	38	207	105.5	20.3
South Carolina Public Service Authority (Santee Cooper)	AA–	RO: Stable	SERC	1,887,797	1.24	1.17	11.1	99	198	233.3	25.1
Western Minnesota Municipal Power Agency	AA–	RO: Stable	MRO	169,917	1.36	1.23	7.0	331	331	643.8	30.0
Median				**1,081,899**	**1.24**	**1.17**	**8.0**	**99**	**207**	**233.3**	**25.1**
A+ Rated Senior Debt											
Arkansas Electric Cooperative Corporation	A+	RO: Stable	SERC	653,251	1.81	1.50	7.9	62	120	624.6	34.0
Basin Electric Power Cooperative, ND	A+	RO: Stable	MRO	1,919,345	1.48	1.48	9.5	131	313	168.5	20.7
Connecticut Municipal Electric Energy Cooperative	A+	RO: Stable	NPCC	176,016	1.42	1.12	7.7	111	217	4.9	14.8
Illinois Municipal Electric Agency	A+	RO: Stable	MRO	280,660	1.49	1.19	23.3	58	80	1,119.1	7.0
Indiana Municipal Power Agency	A+	RO: Stable	RFC	406,980	1.03	1.02	13.6	96	96	154.1	13.2
Massachusetts Municipal Wholesale Electric Company — Consolidated	A+	RO: Stable	NPCC	287,403	1.24	1.16	3.1	150	195	82.7	0.0
Municipal Electric Authority of Georgia	A+	RO: Stable	SERC	876,029	1.00	1.00	11.7	126	305	311.5	0.0
Municipal Gas Authority of Georgia	A+	RO: Stable	SERC	374,277	1.16	1.16	1.8	86	188	2.4	13.6
Nebraska Public Power District	A+	RO: Stable	SPP	1,080,998	1.20	1.11	7.1	153	247	149.1	32.8
Texas Municipal Power Agency	A+	RO: Stable	ERCOT	162,491	1.55	1.10	12.9	54	211	16.4	5.7
WPPI Energy (Wisconsin Public Power Inc.)	A+	RO: Stable	MRO	474,646	1.11	1.02	10.5	70	99	66.8	33.9
Median				**406,980**	**1.24**	**1.12**	**9.5**	**96**	**195**	**149.1**	**13.6**
A Rated Senior Debt											
Brazos Electric Power Cooperative, TX	A	RO: Stable	ERCOT	841,553	1.20	1.12	12.2	118	436	155.4	16.8
Buckeye Power Inc., OH	A	RO: Negative	RFC	626,876	0.99	0.99	13.2	11	98	428.5	17.9
Central Iowa Power Cooperative	A	RO: Stable	MRO	187,408	1.56	1.46	5.6	193	478	120.2	31.9
Florida Municipal Power Agency — All-Requirements Project	A	RO: Stable	FRCC	472,091	1.15	1.11	10.7	120	150	21.4	14.5
Golden Spread Electric Cooperative, TX	A	RO: Stable	ERCOT	378,784	2.33	1.53	6.3	245	505	232.7	38.8
Grand River Dam Authority, OK	A	RO: Stable	SPP	411,023	1.13	1.12	6.0	138	138	134.3	36.7
Lower Colorado River Authority — Consolidated	A	RO: Stable	ERCOT	1,261,700	1.49	1.44	7.1	127	127	229.0	25.4
Municipal Energy Agency of Nebraska	A	RO: Stable	MRO	162,677	0.89	0.97	16.0	69	92	119.1	25.3
North Carolina Municipal Power Agency No. 1	A	RO: Stable	SERC	471,495	1.13	1.12	8.1	248	248	127.6	4.0
Oglethorpe Power Corporation, GA	A	RO: Negative	SERC	1,324,110	1.32	1.31	12.0	137	641	212.2	9.2
Oklahoma Municipal Power Agency	A	RO: Stable	SPP	171,230	1.08	1.06	12.5	125	125	164.6	4.2
Old Dominion Electric Cooperative, VA	A	RO: Stable	RFC	842,681	1.37	1.12	7.3	18	264	77.1	32.8
Tri-State Generation & Transmission Association Inc.	A	RO: Stable	WECC	1,256,996	0.99	1.00	9.4	31	224	169.9	23.5
Median				**472,091**	**1.15**	**1.12**	**9.4**	**125**	**224**	**155.4**	**23.5**

G&T – Generation and transmission. FADS – Funds available for debt service. Note: Fiscal 2011 audit — Municipal Gas Authority of Georgia. *Continued on next page.*
Source: Fitch Ratings.

All Wholesale Systems (Includes G&T Cooperatives) (Continued)

Issuer	Rating	Outlook/ Watch	Region	Total Revenues 2012 ($000)	Debt Service Coverage 2012 (x)	Coverage of Full Obligations 2012 (x)	Debt/ FADS 2012 (x)	Days Cash on Hand 2012	Days Liquidity on Hand 2012	Capex/ Depreciation 2012 (%)	Equity/ Capitalization 2012 (%)
A– Rated Senior Debt											
Corn Belt Power Cooperative, IA	A–	RO: Stable	MRO	122,104	1.34	1.22	7.4	6	85	244.0	27.7
Delaware Municipal Electric Corporation	A–	RO: Stable	RFC	144,110	6.60	1.57	2.5	57	68	999.1	28.6
Great River Energy, MN	A–	RO: Stable	MRO	921,197	1.20	1.17	9.4	190	379	128.4	13.5
North Carolina Eastern Municipal Power Agency	A–	RO: Stable	SERC	696,526	1.23	1.20	6.8	275	275	109.3	4.4
North Carolina Electric Membership Corporation	A–	RO: Stable	SERC	1,044,460	1.63	1.20	7.8	69	116	123.8	8.5
Piedmont Municipal Power Agency, SC	A–	RO: Stable	SERC	204,520	1.23	1.19	12.0	177	177	153.0	2.2
PowerSouth Energy Cooperative and Subsidiaries, AL	A–	RO: Stable	SERC	591,711	1.14	1.11	9.4	59	205	110.7	15.8
San Miguel Electric Cooperative, TX	A–	RO: Stable	ERCOT	147,123	1.46	1.46	6.2	34	147	116.4	17.1
South Mississippi Electric Power Association	A–	RO: Stable	SERC	760,696	1.26	1.12	10.3	13	84	784.4	16.7
South Texas Electric Cooperative Inc.	A–	RO: Stable	ERCOT	320,929	1.46	1.22	10.2	47	377	697.6	17.3
Western Farmers Electric Cooperative, OK	A–	RO: Stable	SPP	457,165	1.08	1.05	10.5	28	215	210.2	18.4
Median				**457,165**	**1.26**	**1.20**	**9.4**	**57**	**177**	**153.0**	**16.7**
BBB+ Rated Senior Debt											
Sam Rayburn Municipal Power Agency, TX	BBB+	RO: Stable	ERCOT	35,128	0.99	0.99	6.1	14	14	3.6	(3.4)
BBB Rated Senior Debt											
East Kentucky Power Cooperative	BBB	RO: Stable	MRO	843,059	1.25	1.23	10.8	97	205	131.3	11.6
Southern Illinois Power Cooperative	BBB	RO: Stable	MRO	174,768	1.06	1.06	13.9	4	183	155.0	9.3
Median				**508,914**	**1.16**	**1.16**	**12.4**	**51**	**194**	**143.2**	**10.5**
BB Rated Senior Debt											
Big Rivers Electric Corp., KY	BB	RO: Negative	MRO	568,342	0.72	0.79	12.0	54	127	89.1	30.3

G&T – Generation and transmission. FADS – Funds available for debt service. Note: Fiscal 2011 audit — Municipal Gas Authority of Georgia.
Source: Fitch Ratings.

G&T Cooperative Systems

Issuer	Rating	Outlook/Watch	Region	Total Revenues 2012 ($000)	Debt Service Coverage 2012 (x)	Coverage of Full Obligations 2012 (x)	Debt/ FADS 2012 (x)	Days Cash on Hand 2012	Days Liquidity on Hand 2012	Capex/ Depreciation 2012 (%)	Equity/ Capitalization 2012 (%)
AA– Rated Senior Debt											
Associated Electric Cooperative Inc., MO	AA–	RO: Stable	SERC	1,061,899	1.17	1.16	8.0	38	207	105.5	20.3
A+ Rated Senior Debt											
Arkansas Electric Cooperative Corporation	A+	RO: Stable	SERC	653,251	1.81	1.50	7.9	62	120	624.6	34.0
Basin Electric Power Cooperative, ND	A+	RO: Stable	MRO	1,919,345	1.48	1.48	9.5	131	313	168.5	20.7
Median				**1,286,298**	**1.65**	**1.49**	**8.7**	**97**	**217**	**396.6**	**27.4**
A Rated Senior Debt											
Brazos Electric Power Cooperative, TX	A	RO: Stable	ERCOT	841,553	1.20	1.12	12.2	118	436	155.4	16.8
Buckeye Power Inc., OH	A	RO: Negative	RFC	626,876	0.99	0.99	13.2	11	98	428.5	17.9
Central Iowa Power Cooperative	A	RO: Stable	MRO	187,408	1.56	1.46	5.6	193	478	120.2	31.9
Golden Spread Electric Cooperative, TX	A	RO: Stable	ERCOT	378,784	2.33	1.53	6.3	245	505	232.7	38.8
Oglethorpe Power Corporation, GA	A	RO: Negative	SERC	1,324,110	1.32	1.31	12.0	137	641	212.2	9.2
Old Dominion Electric Cooperative, VA	A	RO: Stable	RFC	842,681	1.37	1.12	7.3	18	264	77.1	32.8
Tri-State Generation & Transmission Association Inc.	A	RO: Stable	WECC	1,256,996	0.99	1.00	9.4	31	224	169.9	23.5
Median				**841,553**	**1.32**	**1.12**	**9.4**	**118**	**436**	**169.9**	23.5
A– Rated Senior Debt											
Corn Belt Power Cooperative, IA	A–	RO: Stable	MRO	122,104	1.34	1.22	7.4	6	85	244.0	27.7
Great River Energy, MN	A–	RO: Stable	MRO	921,197	1.20	1.17	9.4	190	379	128.4	13.5
North Carolina Electric Membership Corporation	A–	RO: Stable	SERC	1,044,460	1.63	1.20	7.8	69	116	123.8	8.5
PowerSouth Energy Cooperative and Subsidiaries, AL	A–	RO: Stable	SERC	591,711	1.14	1.11	9.4	59	205	110.7	15.8
San Miguel Electric Cooperative, TX	A–	RO: Stable	ERCOT	147,123	1.46	1.46	6.2	34	147	116.4	17.1
South Mississippi Electric Power Association	A–	RO: Stable	SERC	760,696	1.26	1.12	10.3	13	84	784.4	16.7
South Texas Electric Cooperative Inc.	A–	RO: Stable	ERCOT	320,929	1.46	1.22	10.2	47	377	697.6	17.3
Western Farmers Electric Cooperative, OK	A–	RO: Stable	SPP	457,165	1.08	1.05	10.5	28	215	210.2	18.4
Median				**524,438**	**1.30**	**1.19**	**9.4**	**41**	**176**	**169.3**	**16.9**
BBB Rated Senior Debt											
East Kentucky Power Cooperative	BBB	RO: Stable	MRO	843,059	1.25	1.23	10.8	97	205	131.3	11.6
Southern Illinois Power Cooperative	BBB	RO: Stable	MRO	174,768	1.06	1.06	13.9	4	183	155.0	9.3
Median				**508,914**	**1.16**	**1.16**	**12.4**	**51**	**194**	**143.2**	**10.5**
BB Rated Senior Debt											
Big Rivers Electric Corp., KY	BB	RO: Negative	MRO	568,342	0.72	0.79	12.0	54	127	89.1	30.3

G&T – Generation and transmission. FADS – Funds available for debt service.
Source: Fitch Ratings.

Wholesale Systems (Excludes G&T Cooperatives)

Issuer	Rating	Outlook/ Watch	Region	Total Revenues 2012 ($000)	Debt Service Coverage 2012 (x)	Coverage of Full Obligations 2012 (x)	Debt/ FADS 2012 (x)	Days Cash on Hand 2012	Days Liquidity on Hand 2012	Capex/ Depreciation 2012 (%)	Equity/ Capitalization 2012 (%)
AAA Rated Senior Debt											
Tennessee Valley Authority	AAA	RO: Negative	SERC	11,220,000	1.18	1.16	7.1	41	41	112.2	17.5
AA Rated Senior Debt											
Bonneville Power Administration, WA	AA	RO: Stable	WECC	3,317,850	2.15	0.94	10.2	224	365	221.0	15.2
New York Power Authority	AA	RO: Stable	NPCC	2,673,000	4.27	2.13	4.4	232	252	64.2	53.7
Platte River Power Authority, CO	AA	RO: Stable	WECC	182,635	1.60	1.50	5.0	196	196	44.6	62.7
Median				**2,673,000**	**2.15**	**1.50**	**5.0**	**224**	**252**	**64.2**	**53.7**
AA– Rated Senior Debt											
South Carolina Public Service Authority (Santee Cooper)	AA–	RO: Stable	SERC	1,887,797	1.24	1.17	11.1	99	198	233.3	25.1
Western Minnesota Municipal Power Agency	AA–	RO: Stable	MRO	169,917	1.36	1.23	7.0	331	331	643.8	30.0
Median				**1,028,857**	**1.30**	**1.20**	**9.1**	**215**	**265**	**438.6**	**27.6**
A+ Rated Senior Debt											
Connecticut Municipal Electric Energy Cooperative	A+	RO: Stable	NPCC	176,016	1.42	1.12	7.7	111	217	4.9	14.8
Illinois Municipal Electric Agency	A+	RO: Stable	MRO	280,660	1.49	1.19	23.3	58	80	1,119.1	7.0
Indiana Municipal Power Agency	A+	RO: Stable	RFC	406,960	1.03	1.02	13.6	96	96	154.1	13.2
Massachusetts Municipal Wholesale Electric Company — Consolidated	A+	RO: Stable	NPCC	287,403	1.24	1.16	3.1	150	195	82.7	0.0
Municipal Electric Authority of Georgia	A+	RO: Stable	SERC	876,029	1.00	1.00	11.7	126	305	311.5	0.0
Municipal Gas Authority of Georgia	A+	RO: Stable	SERC	374,277	1.16	1.16	1.8	86	188	2.4	13.6
Nebraska Public Power District	A+	RO: Stable	SPP	1,080,998	1.20	1.11	7.1	153	247	149.1	32.8
Texas Municipal Power Agency	A+	RO: Stable	ERCOT	162,491	1.55	1.10	12.9	54	211	16.4	5.7
WPPI Energy (Wisconsin Public Power Inc.)	A+	RO: Stable	MRO	474,646	1.11	1.02	10.5	70	99	66.8	33.9
Median			.	**374,277**	**1.20**	**1.11**	**10.5**	**96**	**195**	**82.7**	**13.2**
A Rated Senior Debt											
Florida Municipal Power Agency — All-Requirements Project	A	RO: Stable	FRCC	472,091	1.15	1.11	10.7	120	150	21.4	14.5
Grand River Dam Authority, OK	A	RO: Stable	SPP	411,023	1.13	1.12	6.0	138	138	134.3	36.7
Lower Colorado River Authority — Consolidated	A	RO: Stable	ERCOT	1,261,700	1.49	1.44	7.1	127	127	229.0	25.4
Municipal Energy Agency of Nebraska	A	RO: Stable	MRO	162,677	0.89	0.97	16.0	69	92	119.1	25.3
North Carolina Municipal Power Agency No. 1	A	RO: Stable	SERC	471,495	1.13	1.12	8.1	248	248	127.6	4.0
Oklahoma Municipal Power Agency	A	RO: Stable	SPP	171,230	1.08	1.06	12.5	125	125	164.6	4.2
Median				**441,259**	**1.13**	**1.12**	**9.4**	**126**	**133**	**131.0**	**19.9**
A– Rated Senior Debt											
Delaware Municipal Electric Corporation	A–	RO: Stable	RFC	144,110	6.60	1.57	2.5	57	66	999.1	28.6
North Carolina Eastern Municipal Power Agency	A–	RO: Stable	SERC	696,526	1.23	1.20	6.8	275	275	109.3	4.4
Piedmont Municipal Power Agency, SC	A–	RO: Stable	SERC	204,520	1.23	1.19	12.0	177	177	153.0	2.2
Median				**204,520**	**1.23**	**1.20**	**6.8**	**177**	**177**	**153.0**	**4.4**
BBB+ Rated Senior Debt											
Sam Rayburn Municipal Power Agency, TX	BBB+	RO: Stable	ERCOT	35,128	0.99	0.99	6.1	14	14	3.6	(3.4)

G&T – Generation and transmission. FADS – Funds available for debt service. Note: Fiscal 2011 audit — Municipal Gas Authority of Georgia.
Source: Fitch Ratings.

Financial Summary Glossary of Terms

Capitalization

Total debt plus total equity.

Debt to Customer

Total debt divided by total customers. This ratio represents a measure of leverage per end user.

Fund Available for Debt Service (FADS)

Operating income, plus depreciation and amortization (taken from cash flow statement), plus interest income (taken from cash flow statement). FADS does not include any benefit from the use of (or deposit to) the rate-stabilization funds, non-operating connection fees, or capital contributions.

Full Obligations

An obligation proxy that includes annual debt service plus a fixed charge related to purchase power expense. The fixed charge is calculated as 30% of purchase power expense and is an estimate of the portion of purchase power costs that are associated with debt service.

Transfer Payments

Transfer payments include payments to the general fund, payments in lieu of taxes (PILOT), free services provided and other taxes paid.

Operating Income

Operating revenue less operating expenses.

Restricted Funds

Cash and investments that are restricted in use (e.g. debt service reserve funds, debt service funds, and construction funds) and not deemed to be available to meet short-term liquidity needs.

Total Annual Debt Service

Sum of scheduled long-term principal and total annual cash interest payments (includes interest on long-term and short-term debt). Does not generally include principal amounts paid as a part of a refinancing or voluntary prepayments. Additionally, capitalized interest may be excluded for systems undertaking large construction programs.

Unrestricted Funds

Cash and short-term investments that are available for short-term liquidity needs with no limitations on use. Funds restricted solely by board or management policy may also be included.

Total Debt

Sum of long-term debt, capital leases, outstanding commercial paper, notes payable, and current maturities of long-term debt and capital leases. No adjustments are made for unamortized discounts or premiums.

Total Equity

Net assets (retained earnings plus contributed capital plus patronage capital).

Ratio Definitions

Ratio	Calculation	Significance
Cash Flow		
FADS ($)	Operating Revenues – Operating Expenses + Depreciation + Amortization + Interest Income	Provides available, current cash resources.
Debt Service Coverage (x)	FADS/Total Annual Debt Service	Indicates the margin available to meet current debt service requirements.
Coverage of Full Obligations (x)	(FADS + Fixed Charges – General Fund Transfer and/or PILOT Payments Excluded from Operating Expenses)/(Annual Debt Service + Fixed Charges)	Indicates the margin available to meet current debt service requirements and proxy obligations related to purchased power.
Debt to FADS (x)	Total Debt/FADS	Indicates the size of debt compared to the margin available for debt service.
Liquidity		
Days Cash on Hand	Unrestricted Cash and Investments/(Operating Expenses – Depreciation+ Amortization)*365	Indicates financial flexibility, specifically cash and short-term investments, relative to expenses.
Days Liquidity on Hand	(Unrestricted Cash and Investments + Available Lines of Credit and Commercial Paper Capacity)/(Operating Expenses – Depreciation + Amortization)*365	Indicates financial flexibility, including all available sources of cash, short-term investments, and liquidity, relative to expenses.
Capital Structure		
Equity to Capitalization (%)	Total Equity/Capitalization	Provides a measure of cost recovery, leverage, and debt capacity.
Debt to Customer ($)	Total Debt/Total Customers	Provides a measure for relative comparison of leverage.
Other		
Capex to Depreciation and Amortization (%)	Capex/(Depreciation + Amortization)	Indicates the relationship between capital spending and the depreciation of existing assets.
Transfer Payments to Operating Revenues (%)	(General Fund Transfers + PILOT + Other taxes)/Operating Revenues	Indicates the degree to which a utility supports city or county general fund, or other governmental operations.

Source: Fitch Ratings.

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INFRASTRUCTURE

MOODY'S
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RATING METHODOLOGY

U.S. Electric Generation & Transmission Cooperatives

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Summary

This rating methodology explains Moody's approach to assessing credit risk in the U.S. electric generation & transmission cooperative sector (G&T co-ops). This methodology is intended as a reference tool to use when evaluating credit profiles within this sector, helping issuers, investors, and other interested market participants understand how key qualitative and quantitative risk characteristics are likely to affect rating outcomes. This methodology does not include an exhaustive treatment of all factors that are reflected in Moody's ratings, but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector.

This rating methodology supersedes the Rating Methodology for U.S. Electric Generation & Transmission Cooperatives published in December 2009. While this updated framework is based upon the same core principles as the December 2009 methodology, its scope has been broadened to include an additional cooperative and incorporates refinements in our analysis that better reflect key credit fundamentals of this sector. No rating changes will result from publication of this rating methodology.

This report includes discussion of the five rating factors and sub-factors included in the rating grid. The purpose of the rating grid is to provide a reference tool that can be used to approximate credit profiles within the U.S. electric generation & transmission cooperative sector. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to these entities. The grid is a summary, and as such, does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary significantly. In addition, the illustrative mapping in this document uses historical results while our ratings are based on forward-looking expectations. As a result, the grid-indicated rating will not match the actual rating of each entity in every case.

The grid contains five factors that are important in our assessment for ratings in the U.S. electric generation & transmission cooperative sector.

1. Long-Term Wholesale Power Supply Contracts/Regulatory Status
2. Rate Flexibility
3. Member/Owner Profile
4. Financial Metrics
5. Size

Certain factors also encompass a number of sub-factors or metrics that we explain in detail. Since an issuer's scoring on a particular grid factor sometimes will not match its overall rating, in the Appendix we include a discussion of some "outliers" – cooperatives whose grid-indicated rating differs significantly from the actual rating.

We note that our rating analysis in this sector covers factors that are common across all industries as well as factors that can be meaningful on a company or sector-specific basis. Our ratings incorporate qualitative considerations and factors that do not lend themselves to a transparent presentation in a grid format. The grid represents a decision to avoid greater complexity that would result in grid-indicated ratings that map more closely to actual ratings, in favor of simple and more transparent presentation of the factors that are most important for ratings in this sector most of the time.

Highlights of this report include:

- An overview of the rated universe
- A summary of the rating methodology
- A description of the key factors that drive rating quality
- Comments on the grid assumptions and limitations, including a discussion of rating considerations that are not included in the grid.

The Appendices show the full grid (Appendix A); a table that lists the grid output for covered issuers with explanatory comments on some of the more significant differences between the grid-implied rating for each sub-factor and our actual rating (Appendix B); a brief sector overview (Appendix C); and a discussion of key rating issues for the U.S. electric generation & transmission cooperative sector over the intermediate term (Appendix D).

This methodology describes the analytical framework used in determining credit ratings. In some instances our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the use of credit estimates and country ceilings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities. Documents that describe our approach to such cross-sector methodological considerations can be found at http://www.moodys.com under the Research and Ratings directory.

About the Rated Universe Covered by This Methodology

An electric generation & transmission cooperative is a not-for-profit rural electric system whose primary function is to provide electric power on a wholesale basis to its owners. These owners are comprised of a group of distribution co-ops and in some instances may also include other G&T co-ops. Each distribution[1] cooperative sells power on a retail basis to its customers, who are the members that own the distribution co-op.

Moody's currently rates 18 U.S. electric G&T cooperatives, included among which are many of the larger G&T co-ops and a growing number of the medium to smaller-sized ones. The group of 18 has approximately $31.8 billion of debt outstanding. All except one of these issuers are currently rated investment grade with 15 carrying a stable outlook, two having a positive outlook and one being under review for possible downgrade. The 17 investment-grade G&T cooperatives currently occupy the single-A to mid-Baa range and the lone non-investment-grade G&T cooperative is rated Ba1 and under review for possible downgrade.

The credit profile of G&T co-ops on the whole is stable. Since December 2009, we added Seminole Electric Cooperative to our rated universe, bringing the total to 18 in all. In addition to the new rating assigned for Seminole Electric, we assigned an A1 senior secured rating for Arkansas Electric Cooperative, an A3 senior secured rating for PowerSouth Electric Cooperative, and an A3 senior secured rating for South Mississippi Electric Power Association, marking the first time we rated that class of debt for those three entities. Other rating actions in the U.S. electric generation & transmission cooperative sector since December 2009 included five downgrades, three upgrades, one outlook change to negative from stable, three outlook changes to stable from negative, and two outlook changes to positive from stable.

Meanwhile, G&T co-ops, in large part, maintain sound credit quality reflecting the strong contractual bonds with member owners under long-term wholesale power supply contracts, rate setting autonomy, and conservative management of their businesses by:

- using long term supply planning to diversify their supply mix, while managing the current tepid demand growth
- tightly controlling operating costs,
- increasing rates when necessary, and
- carefully attending to liquidity.

G&T co-ops are similar to investor-owned utilities (IOUs) and Municipal and Public Utilities (Municipals) as they all operate in a capital intensive industry and provide an essential service. While all three subsets of the U.S. power sector strive to provide safe and reliable electric service at the lowest possible cost, the G&T co-ops and the Municipals are not for profit entities, so they are not influenced by the profit generating motives that can sometimes influence strategic operating and financial decisions made by the IOUs. Revenue stability and predictability tends to be higher for both G&T co-ops and Municipals because of the rate setting autonomy that exists, whereas IOUs can experience more variability due to rate regulation that governs the rate setting process for them. Financing sources vary across the three sectors. IOUs primarily rely on the capital markets, including through issuance of common stock, whereas the Municipals fund their operations primarily through tax-exempt debt issuance in the public and private capital markets, while the G&T co-ops rely extensively on loans

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[1] Moody's would apply this methodology for the distribution cooperatives with some adjustments.

provided by the Rural Utilities Service (RUS), other cooperative financial institutions, and to a lesser extent, the public and private capital markets. Reference is made to the table in appendix C for additional characteristics that distinguish the risk profiles of these three subsets of the U.S. power sector.

The high average rating assigned to this sector is consistent with historical and expected rating performance and the very low incident of default in the sector, with only one Moody's rated G&T co-op default in the past 23 years. In 2011, Southern Montana Electric Generation and Transmission Cooperative, Inc. (SME; not rated), defaulted.

Southern Montana Electric Generation and Transmission Cooperative, Inc. (SME; not rated), filed for bankruptcy protection on October 21, 2011 owing to severe cash flow problems caused by increased power supply costs, reduced volume sales, disagreement among SME's member-owners to raise their rates, and various litigation proceedings.

While SME was not rated by Moody's, it is possible to use the methodology grid to assess what its likely grid-implied rating might have been in the years ahead of the default. It would likely have merited the weakest possible score on approximately half of the grid factors, both qualitative and quantitative; in particular it would likely have scored very weakly on several of the sub-factors in Factor 2 (rate flexibility), including purchased power as a percentage of total megawatt hour sales, new build exposure, and rate shock exposure; it also would have scored very weakly on factor 5 (size). As a result, the grid-implied rating would likely have been no better than borderline investment grade, which would have firmly positioned it as a negative outlier, weaker than any of the credits in the rated portfolio of U.S. electric G&T cooperatives at the time. Furthermore, the preponderance of "lowest-possible" scores for several factors would have suggested a credit weaker than the broad sector peer group against which the grid was calibrated, arguing for the final rating to be positioned lower. In fact, as any signs of member disagreement became apparent in tandem with other weak factor scores, a Moody's Rating Committee would likely have considered a rating outcome significantly below the grid-implied rating.

SME's bankruptcy filing is a stark reminder highlighting the need for G&T cooperatives to secure adequate sources of liquidity, as most of the strong investment grade rated G&T cooperatives have done in recent years.

The following table illustrates the distribution of ratings in the U.S. G&T cooperative sector.

FIGURE 1

Rated Issuers

Company	Long-Term Rating	Type of Rating	Short-Term Rating	Outlook	Total Debt as of Latest Fiscal Year-End ($ Millions)
Arkansas Electric Cooperative	A1	Senior Secured	P-1	Stable	996 (a)
Associated Electric Cooperative	A1	Senior Secured		Stable	1,918
Basin Electric Power Cooperative	A1	Senior Secured	P-1	Stable	3,938
Big Rivers Electric Corp.	Ba1	Senior Secured		RUR ↓	786
Buckeye Power Inc.	A2	Senior Secured		Stable	1,656 (b)
Chugach Electric Association	-	-	P-2	Stable	604
Dairyland Power Cooperative	A3	Issuer Rating		Stable	1,012
Georgia Transmission	A2	Senior Secured	P-2	Positive	1,732
Golden Spread Electric Cooperative	A3	Issuer Rating		Stable	513
Great River Energy	Baa1	Senior Secured		Stable	2,789
Hoosier Energy	A3	Senior Secured		Stable	1,188
Minnkota Power Cooperative	Baa2	Issuer Rating		Stable	559
Oglethorpe Power Corp.	Baa1	Senior Secured	P-2	Stable	6,672
Old Dominion Electric Cooperative	A3	Senior Secured		Positive	864
PowerSouth Energy	A3	Senior Secured		Stable	1,413
Seminole Electric	A3	Senior Secured		Stable	1,313
South Mississippi Electric Power Association	A3	Senior Secured		Stable	960
Tri-State G&T Association	A3	Senior Secured		Stable	2,913
Total Unadjusted Debt of Rated G&T Co-ops					**31,828**

Notes:

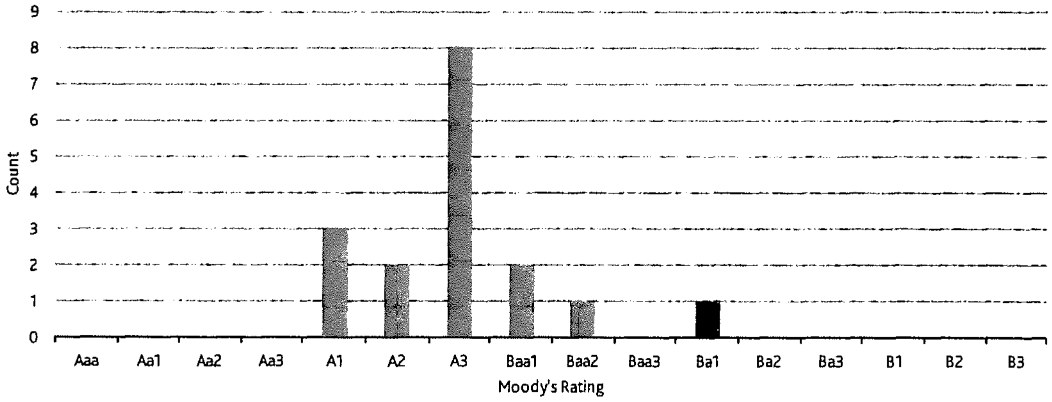
(a) Fiscal year-end October 31

(b) Fiscal year-end June 30

Source: Moody's and cooperative annual audits

FIGURE 2

Electric G&T Cooperatives Rating Distribution



Source: Moody's

About This Rating Methodology

Moody's U.S. electric G&T cooperative rating methodology consists of the six sections listed below.

1) Identification and Discussion of the Key Rating Factors

The grid in this methodology focuses on five broad rating factors, further broken down into 14 rating sub-factors and their weightings.

FIGURE 3

Rating Factor / Sub-Factor Weighting - U.S. Electric G&T Cooperatives

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Wholesale Power Contracts and Regulatory Status	20%	% Member Load Served and Regulatory Status	20%
Rate Flexibility	20%	Board Involvement / Rate Adjustment Mechanism	5%
		Purchased Power / Sales (%)	5%
		New Build Capex (% of Net PP&E)	5%
		Rate Shock Exposure	5%
Member / Owner Profile	10%	Residential Sales / Total Sales	5%
		Members' Consolidated Equity / Capitalization	5%
3-Year Average G&T Financial Metrics	40%	TIER	5%
		DSC	5%
		FFO / Debt	10%
		FFO / Interest	10%
		Equity / Capitalization	10%
G&T Size	10%	MWh Sales	5%
		Net PP&E	5%
Total	**100%**		**100%**

These factors are critical to the analysis of U.S. Electric G&T cooperatives and, in most instances, can be benchmarked across the sector. The discussion begins with a review of each factor and an explanation of its importance to the rating.

2) Measurement or Estimation of the Key Rating Factors

We explain the measurements we use to assess performance on each of the rating factors and sub-factors. We explain the rationale for using specific rating factors and provide insights on the way these are applied in the rating decision process. Many of the sub-factors are found in or derived from the financial statements of the G&T co-ops and those of their members, while others are calculated or derived using data gathered from various sources, and observations and estimates by Moody's analysts.

Moody's ratings are forward looking and incorporate our expectations of future financial and operating performance. We use both historical and projected financial results in the rating process; however, this document makes use only of historic data, and does so solely for illustrative purposes. Historical operating results help us understand the pattern of a company's performance and how it compares to its peers. Historical data also assists us in, among other things, looking through the earnings volatility that can sometimes occur during a given year and evaluating whether projected future results are realistic.

The illustrative mapping examples in this rating methodology uses historical data in most instances based on information as of the latest fiscal year end, which in most cases is 12/31/11; however, the sub-factors for financial metrics use three-year averages for the last three fiscal years.

All of the quantitative credit metric measures comprising the sub-factors in Factor 4 incorporate Moody's standard adjustments to the income statement, statement of cash flows, and balance sheet and include adjustments for certain off-balance sheet financings and certain other reclassifications in the income statement and statement of cash flows.

For definitions of our most common ratio terms please see "Moody's Basic Definitions for Credit Statistics (User's Guide)", June 2011. For a description of our standard adjustments, please see "Rating Implementation Guidance - Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations", December 2010 (128137). These documents can be found at www.moodys.com under the Research and Ratings directory, in the Special Reports subdirectory.

3) Mapping Grid Factors to the Rating Categories

After estimating or calculating each sub-factor, the outcomes for each of the sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, or B).

4) Mapping Issuers to the Grid and Discussion of Grid Outliers

In this section (Appendix B), we provide a table showing how each company maps within the specific rating sub-factors. The weighted average of the sub-factor ratings produces a grid implied rating for each factor. We highlight companies whose grid implied performance on a specific sub-factor is two or more broad rating categories higher or lower than its actual rating and discuss general reasons for such positive and negative outliers for a particular sub-factor.

5) Assumptions and Limitations and Rating Considerations that are not covered in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, additional factors that are not included in the grid that can be important in determining ratings, and limitations and key assumptions that pertain to the overall rating methodology.

6) Determining the Overall Grid-Implied Rating

To determine the overall grid-implied rating, the indicated rating category for each sub-factor is converted into a numeric value based upon the scale below.

FIGURE 4

Aaa	Aa	A	Baa	Ba	B
1	3	6	9	12	15

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-average factor score. The composite weighted factor score is then mapped back to an alpha-numeric rating based on the ranges in the table below. For example, an issuer with a composite weighted factor score of 8.2 would have a Baa1 grid-implied rating. We used a similar procedure to derive the grid-implied ratings shown in the illustrative examples.

FIGURE 5

Factor Numerics

Composite Rating

Indicated Rating	Aggregate Weighted Factor Score
Aaa	x < 1.5
Aa1	1.5 ≤ x < 2.5
Aa2	2.5 ≤ x < 3.5
Aa3	3.5 ≤ x < 4.5
A1	4.5 ≤ x < 5.5
A2	5.5 ≤ x < 6.5
A3	6.5 ≤ x < 7.5
Baa1	7.5 ≤ x < 8.5
Baa2	8.5 ≤ x < 9.5
Baa3	9.5 ≤ x < 10.5
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5

Discussion of the Key Grid Factors

Moody's analysis of U.S. G&T co-ops focuses on five broad rating factors:

» Long-Term Wholesale Power Supply Contracts/Regulatory Status

» Rate Flexibility

» Member/Owner Profile

» Financial Metrics

» Size

Factor 1: Long-Term Wholesale Power Supply Contracts/Regulatory Status

Long-Term Wholesale Power Supply Contracts/Regulatory Status - Why it Matters

Against a myriad of credit challenges, including spending for capital projects, volatile fuel costs and persisting uncertainty surrounding environmental regulations and related costs, the strength of the wholesale power contracts and the predictable revenue stream they provide for G&T co-ops is a primary source of credit support. Because the prevalence of rate autonomy is similarly an integral credit factor linked to costs tied to the wholesale power contract, we include regulatory status of the G&T co-op and its distribution member/owners as part of Factor 1.

Long term wholesale power supply contracts between G&T co-ops and their members provide G&T co-ops with a high degree of assurance that costs and capital investment can be recovered from rates charged to customers. These contracts typically require the member co-ops to purchase all or virtually all of their supply requirements from the G&T co-op and generally stipulate that co-op members must pay their pro-rata portion of all of the G&T co-op's fixed and variable costs related to the generation, procurement and transmission of their respective energy needs.

G&T co-ops have more flexibility to increase rates in response to rising costs as regulatory approval is typically not required. The regulatory status/relationship with regulators is important because G&T co-ops that operate in states that have some form of regulatory authority over their rate setting activities may have more difficulty raising rates compared to peers who are not directly subject to regulatory control. Assessing a member/owner's regulatory status is also important because some are subject to rate regulation, in which case the member may be denied approval for a large rate increase, making it difficult to comply with its contractual obligations to the G&T co-op.

An unsupportive regulatory jurisdiction is a credit negative and leaves co-ops with less flexibility to raise rates if needed. In contrast, absence of regulatory control over the rate setting process is a credit positive. Most co-ops are not subject to rate regulation, and set the rates they charge their members after careful consideration of their underlying cost structure and expected demand for power. They calculate what level of revenues would be required in order to meet operating costs, minimum required interest, and debt service coverage covenants in the RUS mortgage and/or other debt indentures, while also providing some cushion of revenue and equity to protect against adverse events such as sudden increases in costs or operating difficulties with key generating plants.

Long-Term Wholesale Power Supply Contracts/Regulatory Status - How We Assess It for the Grid

Based on data that can be derived from various sources, we calculate the percentage of member power supply needs served under the long-term wholesale power contract(s), with consideration as to whether the contracts are all requirements or substantially all requirements in nature. An assessment of the wholesale power contract allows us to identify whether the member co-ops are required to purchase all or virtually all of their supply requirements from the G&T co-op. For G&T co-ops who are not subject to rate regulation, the indicated rating for Factor 1 can range from Aaa to B and is largely determined by the overall percentage of member sales made under the wholesale power contracts. To receive the highest score of Aaa requires a legislative statute that precludes regulatory intervention in any future rate setting process. There are no such instances that currently apply within the rated universe.

We understand that there are currently 10 states that have full regulatory jurisdiction over the level of rates that co-ops can charge their members. These states are: Arizona, Arkansas, Alaska, Kansas, Kentucky, Louisiana, Maine, Maryland, Vermont, and Wyoming. There are a few other states including Indiana, New Mexico, and Michigan where state commissions have partial jurisdiction over G&T co-ops. Even if 100% of members' needs are met through sales under the wholesale power contracts, G&T co-ops conducting business in any of the aforementioned states would receive an indicated rating for Factor 1 of A at best. Where precisely the few rate-regulated G&Ts score within the range of A to B depends not only on the percentage of members' needs met through sales under the wholesale power contract, but also on our consideration of how supportive of credit quality the regulatory practices are and our understanding of the type of working relationships that prevail between the co-ops and the regulators.

FIGURE 6

Factor 1: Long-Term Wholesale Power Supply Contracts and Regulatory Status (20%)

	Aaa	Aa	A	Baa	Ba	B
Percentage of Member Load Served under Wholesale Power Contracts and Regulatory Status	100% and G&T and its Distribution Member/Owner Cooperatives are Not Rate Regulated by State Commission; Legislative statute to preclude regulatory intervention in the future rate setting process; Very good contractual relationships	100% and G&T is Not Rate Regulated by State Commission; No legislative statute to preclude regulatory intervention in the future G&T rate setting process; Some Distribution Member/Owner Cooperatives May Be Subject to Rate Regulation by State Commission; Very Supportive Commission Practices; Very Good Regulatory/ Contractual Relationships	> 80% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated by State Commission; Very Supportive Commission Practices; Very Good Regulatory/ Contractual Relationships	> 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Moderately Supportive Commission Practices; Reasonably Good Regulatory/ Contractual Relationships	< 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Unsupportive Commission Practices; Generally Difficult Regulatory/ Contractual Relationships	< 60% and/or G&T is Rate Regulated by State Commission; Most Distribution Member/Owner Cooperatives are Rate Regulated By State Commission; Very Unsupportive Commission Practices; Often Contentious Regulatory/ Contractual Relationships

Factor 2: Rate Flexibility

Rate Flexibility - Why it Matters

Prices for fuels used to generate electricity are unregulated in the U.S. and can be subject to dramatic fluctuation. G&T co-ops need the flexibility to raise rates in order to cover sharply higher prices for fuels, in addition to rising operating costs, and costs associated with existing mandated environmental requirements and those inevitably coming related for carbon emissions along with any capital investment associated with construction of new plants, among other factors.

Board Involvement/Rate Adjustment Mechanisms: The extent to which a G&T co-op can ensure timely and full recovery of its costs and investments will have an integral effect on its overall financial performance and thus its creditworthiness. Each G&T co-op's board of directors has a fiduciary responsibility to approve, or, where rate regulation applies, to seek regulatory approval of rates that ensure compliance with the financial covenants associated with debt indentures. To the extent that unexpected events arise, causing concerns about the ability to comply with covenants, the board should be expected to move quickly to adjust rates upward when needed. Also, variable cost adjustment mechanisms provide for more automatic changes in rates when costs change and increase the speed with which rates can be increased when costs increase. The extent to which variable cost adjustment mechanisms are available is especially important where regulatory jurisdiction applies to a G&T co-op. The existence of variable cost adjustment mechanisms is a credit strength, especially when rate adjustments can be implemented at frequent intervals. Such mechanisms mitigate liquidity pressures that might otherwise arise when the cost of fuels exceeds rates in effect at that time.

Degree of Reliance on Purchased Power. Most of the power supply needs of G&T co-op members are met from generating plants owned by the G&T co-ops. Some G&Ts rely on market purchases of power to meet a portion of the member needs because their owned resources are insufficient, uneconomic, or periodically unavailable.

Assessing the degree of reliance on purchased power to meet members' demand and the rationale behind that strategy is important because G&Ts who purchase large amounts of power from the market to meet member demands have less control over this obligation, particularly if forced to purchase power at inopportune times, which may increase price volatility for one of their largest costs. Relying on such a strategy also heightens the importance of liquidity, risk management policies and procedures, and counterparty credit assessment.

New Build Exposure Relative to Existing Asset Base. This factor is important because G&T co-ops largely finance capital investment with debt and rely upon rate increases to service the debt. When construction is delayed or runs above budget, the rate increases needed to cover the increased costs could lead to member resistance or, in the cases where regulation applies, cost recovery delays or disallowances.

Potential for Rate Shock Exposure. In many respects, the potential for rate shock exposure is linked to rate competitiveness, so we consider rate competitiveness as part of this sub-factor. Assessing the potential for rate shock exposure is important because a large rate increase can lead to member resistance even when the new higher level of rates is still competitive with other providers of power in the region. If the G&T co-op's rates are noticeably higher than other providers in its geographic area, regulatory relationships for those G&T co-ops subject to regulation could become strained and/or member unrest more broadly could lead to contract challenges or possible withdrawal from the co-op.

Rate Flexibility - How We Assess It for the Grid

Board Involvement/Rate Adjustment Mechanisms. The timing and extent to which a G&T co-op can increase rates is impacted by the activity of its board of directors and a number of rate adjustment mechanisms.

First we assess how active a board has been from a historical perspective with respect to approving or seeking regulatory approval of rate increases and consider the extent to which past behavior might change. To the extent that unexpected events arise, causing concerns about the ability to comply with covenants, we believe the board should be expected to move quickly to adjust rates upward when needed. Those G&T co-ops whose boards of directors are exceptionally proactive in adjusting rates as necessary and who benefit from legislative statute that would preclude regulatory intervention in the future rate setting process would most likely receive the highest indicated ratings. In contrast, G&T co-ops with less active or even inactive boards of directors and who otherwise face uncertainty surrounding the extent and timing of cost recovery would receive much lower indicated ratings for this sub-factor.

With respect to situations where variable cost adjustment mechanisms apply, rates that can automatically adjust to fuel and/or purchased power cost increases without requiring action by the Board or regulators are viewed more favorably and generally result in a higher indicated rating for this sub-factor. In instances where recovery of variable cost increases is deferred, we consider the time period over which recovery occurs, with shorter recovery periods being better from a liquidity and credit quality standpoint.

Degree of Reliance on Purchased Power: To measure the degree to which a G&T relies on purchased power in conducting its business, we divide the amount of megawatt hours it purchases during the most recent fiscal year by the total megawatt hours of energy it sells. This data can usually be found in the G&T co-op's latest annual report and/or other published data sources. In those instances where a G&T co-op relies on purchased power to meet less than 40% of its energy requirements during a given fiscal year, the indicated rating for this sub-factor would be at least Baa and improve gradually as the percentage declines according to the Factor 2 table descriptions. Conversely, where the dependence on purchased power exceeds the 40% level, then the indicated rating would be Ba or lower according to the Factor 2 table descriptions. In addition to the specific percentage calculation, we also take into account the extent to which purchases are made based solely on economic dispatch decisions (i.e. opportunistically purchasing cheaper power on the market instead of running owned generation plants). Such power purchases are usually made to maximize cost competitiveness in the G&T co-op's supply portfolio. Moody's views purchases made on an economic dispatch basis to be less of a credit risk as compared to situations where the G&T co-op is relying extensively on more expensive spot market power purchases due to an unplanned outage at one of its owned generation plants or above market firm purchase power contracts required to meet customer demands for power.

New Build Exposure Relative to Existing Asset Base: To measure this sub-factor, Moody's divides the estimated future capital expenditures for a particular G&T co-op over the next five years by the net property, plant, and equipment report for the latest fiscal year end. The lower the resulting percentage from this calculation is, the better the indicated rating for the sub-factor will likely be, as the G&T will likely face less need to issue debt and increase rates to cover the higher financing costs.

Potential for Rate Shock Exposure: To measure the potential for rate shock exposure, Moody's continues to look at the extent to which a G&T relies on purchased power to meet its energy demand during the latest fiscal year and its new build exposure. A lower percentage in both instances is generally viewed more favorably under the methodology. Our measurement criteria for this sub-factor also considers the G&T co-op's reliance on coal and other carbon emitting generating resources. Those G&T co-ops with a high reliance on such resources will be scored lower on this sub-factor due to their vulnerability to environmental regulations and accompanying carbon costs.

Cost competitive G&T co-ops have greater flexibility to raise rates to offset cost increases or to build additional equity and would therefore be more likely to receive a higher indicated rating for this sub-factor than those G&T co-ops who are competitively challenged. Favorable characteristics include low or improving cost structure, lower wholesale prices versus peers, and low distribution member rates versus competitors in the region. Moody's also assesses a G&T co-op's prospects to realize future rate increases in order to offset increasing costs, as compared with others in the region, although consistent rate data is often not publicly available. Nonetheless, Moody's seeks whatever public information is available, as well as confidential information on a company by company basis.

FIGURE 7

Factor 2 - Rate Flexibility (20%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Assess Board Involvement in Setting Rates / Variable Cost Adjustment Mechanisms	Exceptionally proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory/ political intervention in the rate setting process; Legislative statute to preclude regulatory intervention in the future rate setting process	Proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory/ political intervention in the rate setting process; No legislative statute to preclude regulatory intervention in the future rate setting process	Active board in support of timely rate filings; possibility for regulatory/political intervention in the rate setting process in certain instances; frequent fuel cost adjustment capability in place under regulatory practice; timely recovery of any deferrals	Reasonably active board in support of timely rate filings; annual fuel cost adjustment capability in place under regulatory practice; reasonably timely recovery of any deferrals	Inactive board; limited, if any ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	Inactive board; no ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	5%
Purchased Power/Total MWh Sales (%)	x < 5%	5% ≤ x < 20%	20% ≤ x < 30%	30% ≤ x < 40%	40% ≤ x < 60%	x ≥ 60%	5%
New Build Exposure (Prospective 5-yr New Build Capex as % Net PP&E)	x < 5%	5% ≤ x < 25%	25% ≤ x < 50%	50% ≤ x < 75%	75% ≤ x ≤ 120%	x > 120%	5%
Potential for Rate Shock Exposure	Better rates than all others in the region on a consistent basis; Extremely low (e.g. Less than 5% reliance on purchased power and less than 5% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 0-20% of generation from carbon fuels	Much better rates than most in the region on a consistent basis; Very low (e.g. less than 20% reliance on purchased power and less than 25% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 20-40% of generation from carbon fuels	Better rates than most in the region on a consistent basis; Low (e.g. less than 30% reliance on purchased power and/or less than 50% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 40-55% of generation from carbon fuels	Better rates than some and worse rates than some in the region on a consistent basis; Moderate (e.g. less than 40% reliance on purchased power and/or less than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 55-70% of generation from carbon fuels	Worse rates than most in the region on a consistent basis; High (e.g. greater than 40% reliance on purchased power or greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 70-85% of generation from carbon fuels	Worse rates than all in the region on a consistent basis; Very high (e.g. greater than 40% reliance on purchased power and greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 85-100% of generation from carbon fuels	5%

Factor 3: Member/Owner Profile

Member/Owner Profile - Why it Matters

Assessing the member/owner profile of a G&T co-op is important because the members who own the G&T co-op are also its primary source of cash flow. Similar to the way we would assess the counterparty credit risk for an IOU that sells sizable amounts of power to another entity, or buys significant amounts of power from a wholesale power producer, we focus on the overall creditworthiness of the members. Although not specifically weighted, we seek information about the members' expected consolidated demand growth and their consolidated assets when evaluating the overall member profile. The following two sub-factors, which are weighted at 5% each, provide good insight into the members' creditworthiness and ability to meet obligations to the G&T co-op under the long-term wholesale power contract.

Residential Sales as a Percentage of Total Sales: The diversity of the members' retail customer mix is important in our analysis of G&T co-ops because substantial reliance upon any single customer or a small number of customers (such as large industrial customers) tends to be associated with greater variability of revenue. Members who own the G&T co-ops tend to serve large residential customer bases, with a majority of energy being sold to such customers, although some sales may be to more volatile industrial and commercial customers. A higher percentage of sales to residential customers is favorable because such sales are generally more stable and predictable.

Members Consolidated Equity to Capitalization: The financial condition of the member/owners, as measured in part by the members' consolidated equity to capitalization, is important because it affects their ability to perform under the wholesale power contracts that members have with their G&T co-op. For the most part, distribution co-ops carry less business and financial risk than G&T co-ops. The difference in the financial strength is largely attributable to the fact that the RUS has historically set tighter financial covenants for the distribution co-ops than for the G&T co-ops. In addition, the distribution co-ops are far less capital intensive than G&T co-ops who own generation assets. Distribution co-ops typically maintain higher levels of equity to total capitalization and stronger interest coverage ratios than G&T co-ops.

Member/Owner Profile - How We Assess It for the Grid

Residential Sales as a Percentage of Total Sales: To measure this sub-factor, we first generally aggregate the individual residential energy sales and total energy sales for each member/owner of a particular G&T co-op in the latest fiscal year. This information is generally available through requests made to the G&T co-op because their members provide this data to them. The aggregate residential energy sales level is then divided by the aggregate total energy sales level to derive the aggregate percentage for the year. Under the Methodology, a higher percentage of more stable and predictable residential sales is viewed more favorably than a concentration of sales to large commercial and/or industrial customers.

Members Consolidated Equity to Capitalization: This sub-factor is measured by simply aggregating each member's total equity and debt as reported for the latest fiscal year end. The aggregate totals are then used to divide total members' equity by the sum of total members' debt plus equity. Members generally file financial statements with the RUS or otherwise make such statements available to the G&T that they have an ownership interest in. The large majority of the G&T co-ops that are covered by the methodology fall into the Baa category with consolidated member equity to capitalization in the range of 25% to 50%.

FIGURE 8

Factor 3 - Member / Owner Profile (10%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Residential Sales/ Total Sales (%)	x ≥ 80%	75% ≤ x < 80%	50% ≤ x < 75%	40% ≤ x < 50%	20% ≤ x < 40%	x < 20%	5%
Members' Consolidated Equity/Capitalization (%)	x ≥ 65%	55% ≤ x < 65%	50% ≤ x < 55%	25% ≤ x < 50%	20% ≤ x < 25%	x < 20%	5%

Factor 4: G&T Financial Metrics

G&T Financial Metrics - Why it Matters

Financial strength is an important indicator of a G&T co-op's ability to meet its obligations, including debt service. Moody's considers historical coverage ratios and also places a significant emphasis on the expected trend for coverage metrics when assessing the credit risk of G&T co-ops. Although we continue to note that some G&T co-ops have large investment portfolios that considerably augment the bottom line, we consider it important that the G&T co-op be profitable on an operating basis. G&T co-ops that rely extensively on profits from investment portfolios and diversified operations to compensate for negative G&T operating margins are viewed negatively.

Scores under Factor 4 may be higher or lower than what might be produced based on historical results, depending on our view of expected future financial performance.

Times Interest Earned Ratio (TIER) and Debt Service Coverage Ratio (DSC): These two ratios are important because they have governed RUS loan documentation for many years. In addition to TIER and DSC, Moody's also looks at margins for interest (MFI) as defined in certain indentures.

Funds from Operations Coverage of Interest (FFO/Interest) and FFO/Debt: The FFO/Interest and FFO/Debt metrics are important because they provide insight regarding the amount and quality of a G&T co-op's cash flow and its ability to service its debt.

Equity/Total Adjusted Capitalization: Moody's evaluates the G&T co-op's equity as a percentage of total adjusted capitalization to see how much flexibility there is in the balance sheet to absorb unexpected events. When measuring the level of equity cushion, G&T co-ops and the RUS have tended to rely on equity expressed as a percentage of total assets. However, Moody's and many investors prefer to measure equity as a percentage of total capitalization, because it facilitates comparison with IOU capital structures.

G&T Financial Metrics - How We Assess It for the Grid

The ratios used as a basis for this methodology are three year averages of calculations using the latest three fiscal year end statements, including our standard adjustments. Three-year averages are used in part to smooth out some of the year to year volatility in financial performance and financial statement ratios. The ranges for each of the five metrics that would correspond to a particular indicated rating category appear in the table at the bottom of this section. The individual metric definitions are as follows:

TIER:

(Net margins, as represented by net profit after tax before unusual items + Interest + Income Tax) / Interest

DSCR:

(Net margins, as represented by net profit after tax before unusual items + Interest + Depreciation & Amortization) / (Interest + Principal Payment)

FFO / Interest:

(Funds from operations + Interest expense)/ Interest expense

FFO / Debt:

Funds from operations / (Short Term Debt + Long Term Debt, gross)

Equity / Total Capitalization:

(Deferred Taxes + Minority or Non-controlling Interest + Book Equity) / (Short Term Debt + Long Term Debt, gross + Deferred Taxes + Minority or Non-controlling Interest + Book Equity)

FIGURE 9

Factor 4 - 3-Year Average G&T Financial Metrics (40%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
TIER	x ≥ 1.6x	1.4x ≤ x < 1.6x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
DSC	x ≥ 1.9x	1.4x ≤ x < 1.9x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
FFO/Debt	x ≥ 15%	10% ≤ x < 15%	6% ≤ x < 10%	3% ≤ x < 6%	2% ≤ x < 3%	x < 2%	10%
FFO/Interest	x ≥ 3.25x	2.5x ≤ x < 3.25x	2.0x ≤ x < 2.5x	1.5x ≤ x < 2.0x	1.2x ≤ x < 1.5x	x < 1.2x	10%
Equity/Total Capitalization	x ≥ 50%	35% ≤ x < 50%	20% ≤ x < 35%	5% ≤ x < 20%	3% ≤ x < 5%	x < 3%	10%

Factor 5: G&T Size

G&T Size - Why it Matters

Size, together with Factor 3, Member/Owner Profile, has the lowest weighting of the five key factors because it tends to be less important for entities, such as G&T co-ops, that are subject to limited competition. That said, we still find that size, as measured by the following two sub-factors, which are weighted at 5% each, does matter.

***Megawatt hour sales*:** This sub-factor is important because it is an indicator for economies of scale (i.e., a G&T co-op is better off if it can spread its fixed costs over a larger number of megawatt hours of electricity, thereby increasing its price competitiveness).

***Net Property, Plant, and Equipment*:** This sub-factor is important because G&T co-ops can benefit from having a larger pool of assets and a more diverse source of fuels to run the generation assets it owns. A G&T co-op that has its assets concentrated in one generating plant could be subject to extreme cost pressures to the extent that it has to buy power on the open market due to an extended outage at its sole generating plant. Similarly, overdependence on one particular fuel source could materially raise costs during a period of prolonged price increases for that commodity.

G&T Size - How We Assess It for the Grid

We identify the amount of megawatt hour sales and net property, plant, and equipment data primarily from the G&T co-op's latest annual report. See the Factor 5 table below for the ranges that would apply for a particular indicated rating for the two sub-factors in Factor 5.

FIGURE 10

Factor 5 - G&T Size (10%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Megawatt hour sales (Millions of MWhs)	x ≥ 50	20 ≤ x < 50	11 ≤ x < 20	5 ≤ x < 11	3 ≤ x < 5	x < 3	5%
Net PP&E ($ in Billions)	x ≥ $5 billion	2 ≤ x < 5	1 ≤ x < 2	0.4 ≤ x < 1	0.3 ≤ x < 0.4	x < $0.3 billion	5%

Assumptions and Limitations, and Rating Considerations that Are Not Covered in the Grid

The rating methodology grid represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that would enable the grid to map more closely to actual ratings. Accordingly, the five rating factors in the grid do not constitute an exhaustive treatment of all the considerations that are important for ratings of entities in the U.S. electric generation & transmission cooperative sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used to illustrate the mapping in the grid is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we cannot publish or otherwise disclose. In other cases, we estimate future results based upon past performance, industry trends or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, sector trends, new technology, regulatory and legal actions, as well as management's appetite for additional debt to finance capital expenditures, or unexpected external transfers to affiliated governments or enterprises.

Key rating assumptions that apply in this sector include our view that sovereign credit risk is strongly correlated with that of other domestic issuers, that legal priority of claim affects average recovery on different classes of debt, sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology grid, we did not explicitly include certain important factors that are common to all G&T co-ops, such as the quality and experience of management, assessments of governance and the quality of financial reporting and information disclosure. The assessment of these factors can be highly subjective and vary over time. Therefore, ranking these factors by rating category in a grid would suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, and possible government interference in some state, provincial or local governments. Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies, and macroeconomic trends also affect ratings. While these are important considerations, it is not possible to precisely express these in the rating methodology grid without making the grid excessively complex and significantly less transparent. Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk but two identical G&T co-ops might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liquidity position.

Other Rating Considerations

Moody's considers other factors in addition to those discussed in this report, but in most cases understanding the considerations discussed herein will enable a good approximation of our view on the credit quality of entities in the U.S. electric generation & transmission cooperative sector. Ratings consider additional factors, including our assessment of future operating performance that may deviate from historical performance, the quality of management, governance, financial controls, liquidity management, seasonality and event risk. The analysis of these factors remains an integral part of our rating process.

Management Quality

The quality of management is an important factor supporting the credit strength of a G&T co-op. Moody's normally meets with senior executives to assess management's business strategies, policies, and philosophies, and evaluates management performance relative to performance of peers and our projections.

An established managerial record provides Moody's with insight into management's likely future performance in stressed situations. This can be an indicator of management's tendency to stray significantly from what may be an effective current business philosophy, or conversely, to adopt changes where they are warranted by new sets of circumstances.

Governance

Among the areas of focus in governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, and ownership structure. We note that the default by Southern Montana Electric Generation and Transmission Cooperative, Inc. (not rated) in late 2011 was partially the result of extensive member disputes and serves as a recent example of the importance of proper governance and cost recovery.

Financial Controls

Moody's relies on the accuracy of audited financial statements to assign and monitor ratings. Such accuracy is only possible when companies have sufficient internal controls, including centralized operations, and consistency in accounting policies and procedures.

Weaknesses in the overall financial reporting processes, financial report restatements or delays in producing audited financial statements can be indications of a potential breakdown in internal controls.

Liquidity Management

Liquidity is a meaningful credit consideration for all companies but is especially critical in lower rated companies as these issuers have less operating and financial flexibility. We form an opinion on a company's likely near-term liquidity requirements from the perspective of both the sources and uses of cash. This may include monitoring bank covenants and compliance cushions to assess whether a company is likely to require covenants relief in the event of even a modest industry downturn or of an issuer-specific decline of performance.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events include a change in ownership and in the credit quality of that owner, a recapitalization, or an unexpected change in rates or terms of a material contract, weather events, litigation, and changes in governing regulation, legislation or law.

Conclusion: Summary of the Grid-Indicated Rating Outcomes

The objective of our methodology is for users to be able to estimate in most cases, within two alpha-numeric rating notches, the likely senior most credit rating for a U.S. electric generation & transmission cooperative. The grid-indicated ratings map to current assigned or implied senior most ratings as follows (See Appendix B for the details). For consistency in drawing our conclusions, we rely upon an implied senior secured rating (i.e. the implied senior most rating) for the three G&T cooperatives who have senior secured debt in their respective capital structures but whose current ratings are senior unsecured Issuer Ratings.

- nine cooperatives have a grid-indicated rating that matches their actual (or implied) senior most rating,
- seven cooperatives have a grid-indicated rating that is one alpha-numeric notch from their actual (or implied) senior most rating,
- one cooperative has a grid-indicated rating that is two alpha-numeric notches from its actual senior most rating, and
- one cooperative has a grid-indicated rating that is more than two alpha-numeric notches from its actual senior most rating.

Appendix A: U. S. Electric G&T Cooperative Methodology Factor Grid

FIGURE 11

Appendix A: U.S. Electric Generation & Transmission Cooperatives Methodology Factor Grid

Factor 1: Long-Term Wholesale Power Supply Contracts and Regulatory Status

Weighting: 20%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Percentage of Member Load Served under Wholesale Power Contracts and Regulatory Status	100% and G&T and its Distribution Member/Owner Cooperatives are Not Rate Regulated by State Commission; Legislative statute to preclude regulatory intervention in the future rate setting process; Very Good Contractual Relationships	100% and G&T is Not Rate Regulated by State Commission; No legislative statute to preclude regulatory intervention in the future G&T rate setting process; Some Distribution Member/Owner Cooperatives May Be Subject to Rate Regulation by State Commission; Very Supportive Commission Practices; Very Good Regulatory/ Contractual Relationships	> 80% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated by State Commission; Very Supportive Commission Practices; Very Good Regulatory/ Contractual Relationships	> 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Moderately Supportive Commission Practices; Reasonably Good Regulatory/ Contractual Relationships	< 70% and/or G&T is Rate Regulated by State Commission; Some Distribution Member/Owner Cooperatives May Be Rate Regulated By State Commission; Unsupportive Commission Practices; Generally Difficult Regulatory/ Contractual Relationships	< 60% and/or G&T is Rate Regulated by State Commission; Most Distribution Member/Owner Cooperatives are Rate Regulated By State Commission; Very Unsupportive Commission Practices; Often Contentious Regulatory/ Contractual Relationships	20%

Factor 2: Rate Flexibility

Weighting: 20%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Assess Board Involvement in Setting Rates / Variable Cost Adjustment Mechanisms	Exceptionally proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory/political intervention in the rate setting process; Legislative statute to preclude regulatory intervention in the future rate setting process	Proactive board that supports management recommendations for timely adjustment of rates to cover all costs of service; no regulatory/political intervention in the rate setting process; No legislative statute to preclude regulatory intervention in the future rate setting process	Active board in support of timely rate filings; possibility for regulatory/political intervention in the rate setting process in certain instances; frequent fuel cost adjustment capability in place under regulatory practice; timely recovery of any deferrals	Reasonably active board in support of timely rate filings; annual fuel cost adjustment capability in place under regulatory practice; reasonably timely recovery of any deferrals	Inactive board; limited, if any ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	Inactive board; no ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	5%
Purchased Power/Total MWh Sales (%)	x < 5%	5% ≤ x < 20%	20% ≤ x < 30%	30% ≤ x < 40%	40% ≤ x < 60%	x ≥ 60%	5%
New Build Exposure (Prospective 5-yr New Build Capex as % Net PP&E)	x < 5%	5% ≤ x < 25%	25% ≤ x < 50%	50% ≤ x < 75%	75% ≤ x ≤ 120%	x > 120%	5%
Potential for Rate Shock Exposure	Better rates than all others in the region on a consistent basis; Extremely low (e.g. Less than 5% reliance on purchased power and less than 5% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 0-20% of generation from carbon fuels	Much better rates than most in the region on a consistent basis; Very low (e.g. less than 20% reliance on purchased power and less than 25% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and 20-40% of generation from carbon fuels	Better rates than most in the region on a consistent basis; Low (e.g. less than 30% reliance on purchased power and/or less than 50% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 40-55% of generation from carbon fuels	Better rates than some and worse rates than some in the region on a consistent basis; Moderate (e.g. less than 40% reliance on purchased power and/or less than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 55-70% of generation from carbon fuels	Worse rates than most in the region on a consistent basis; High (e.g. greater than 40% reliance on purchased power or greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 70-85% of generation from carbon fuels	Worse rates than all in the region on a consistent basis; Very high (e.g. greater than 40% reliance on purchased power and greater than 75% 5-year-newbuild capex as percentage of latest year-end Net PP&E; and/or 85-100% of generation from carbon fuels	5%

FIGURE 11

Appendix A: U.S. Electric Generation & Transmission Cooperatives Methodology Factor Grid

Factor 3: Member / Owner Profile

Weighting: 10%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Residential Sales/Total Sales (%)	x ≥ 80%	75% ≤ x < 80%	50% ≤ x < 75%	40% ≤ x < 50%	20% ≤ x < 40%	x < 20%	5%
Members' Consolidated Equity/Capitalization (%)	x ≥ 65%	55% ≤ x < 65%	50% ≤ x < 55%	25% ≤ x < 50%	20% ≤ x < 25%	x < 20%	5%

Factor 4: 3-Year Average G&T Financial Metrics

Weighting: 40%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
TIER	x ≥ 1.6x	1.4x ≤ x < 1.6x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
DSC	x ≥ 1.9x	1.4x ≤ x < 1.9x	1.2x ≤ x < 1.4x	1.1x ≤ x < 1.2x	1.0x ≤ x < 1.1x	x < 1.0x	5%
FFO/Debt	x ≥ 15%	10% ≤ x < 15%	6% ≤ x < 10%	3% ≤ x < 6%	2% ≤ x < 3%	x < 2%	10%
FFO/Interest	x ≥ 3.25x	2.5x ≤ x < 3.25x	2.0x ≤ x < 2.5x	1.5x ≤ x < 2.0x	1.2x ≤ x < 1.5x	x < 1.2x	10%
Equity/Total Capitalization	x ≥ 50%	35% ≤ x < 50%	20% ≤ x < 35%	5% ≤ x < 20%	3% ≤ x < 5%	x < 3%	10%

Factor 5: G&T Size

Weighting: 10%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Megawatt hour sales (Millions of MWhs)	x ≥ 50	20 ≤ x < 50	11 ≤ x < 20	5 ≤ x < 11	3 ≤ x < 5	x < 3	5%
Net PP&E ($ in Billions)	x ≥ $5 billion	2 ≤ x < 5	1 ≤ x < 2	0.4 ≤ x < 1	0.3 ≤ x < 0.4	x < $0.3 billion	5%

Appendix B: Methodology Grid Indicated Ratings with Observations and Outliers for Grid Mapping

FIGURE 12

Rating Factors					Factor 1: Wholesale Power Contracts / Reg Status	Factor 2: Rate Flexibility				Factor 3: Member/ Owner Profile		Factor 4: 3-Year Average G&T Financial Metrics					Factor 5: G&T Size	
	Long-Term Rating	Type of Rating	Outlook	Indicated Rating	% Memb. Load Served & Reg Stat	Board Involve / Rate Adj. Mech.	Purch. Pwr / Sales (%)	New Build Capex (% Net PP&E)	Rate Shock	Resid. Sales	Member Consol. Eq / Cap	TIER	DSC	FFO / Debt	FFO / Interest	Eq / Cap	MWh sales	Net PP&E
Factor Weighting					20%	5%	5%	5%	5%	5%	5%	5%	5%	10%	10%	10%	5%	5%
Arkansas Electric Cooperative (a)	A1	Senior Secured	Stable	A2	A	A	Aa	Baa	Ba	A	Baa	Aa	A	A	Aa	Aa	A	A
Associated Electric Cooperative	A1	Senior Secured	Stable	A1	Aa	Aa	Aa	Aa	Ba	A	Baa	A	A	A	A	Baa	Aa	Aa
Basin Electric Power Cooperative	A1	Senior Secured	Stable	A3	Aa	Aa	Baa	A	Ba	Ba	Baa	B	A	Baa	A	A	Aa	Aa
Big Rivers Electric Corp.	Ba1	Senior Secured	RUR ↓	A2	A	Baa	A	Aa	B	B	Baa	Ba	Aaa	Aaa	Aaa	A	A	A
Buckeye Power Inc. (b)	A2	Senior Secured	Stable	A3	Aa	A	Ba	A	B	A	A	A	Baa	Baa	A	Baa	Baa	A
Chugach Electric Association	<c>	<c>	Stable	A3	Baa	A	Aa	Ba	B	A	Baa	A	Aaa	A	Aaa	A	B	Baa
Dairyland Power Cooperative	A3	Issuer Rating	Stable	A3	Aa	Aa	Baa	A	B	A	Baa	A	A	Baa	A	Baa	Baa	A
Georgia Transmission	A2	Senior Secured	Positive	A3	Aa	Aa	Aaa	A	A	A	Baa	Baa	Ba	Baa	Baa	Baa	B	A
Golden Spread Electric Cooperative	A3	Issuer Rating	Stable	A2	A	Aa	B	Ba	Ba	B	A	Aaa	Aaa	Aaa	Aaa	Aa	Baa	Baa
Great River Energy	Baa1	Senior Secured	Stable	Baa1	A	A	A	A	Ba	A	Baa	Ba	Baa	Baa	Baa	Baa	A	Aa
Hoosier Energy	A3	Senior Secured	Stable	A2	Aa	A	A	Baa	B	A	Aa	Aa	A	A	Aa	Baa	Baa	A
Minnkota Power Cooperative	Baa2	Issuer Rating	Stable	Baa1	Aa	Aa	Baa	B	B	A	Baa	A	A	Ba	Baa	Baa	Baa	Baa
Oglethorpe Power Corp.	Baa1	Senior Secured	Stable	Baa2	Ba	Baa	Aaa	Ba	Ba	A	Baa	B	A	Baa	Baa	Baa	Aa	Aaa
Old Dominion Electric Cooperative	A3	Senior Secured	Positive	A3	Aa	A	B	Baa	Baa	A	Baa	A	B	A	A	A	A	A
PowerSouth Energy	A3	Senior Secured	Stable	A3	Aa	Aa	A	A	B	A	Baa	A	A	Baa	A	Baa	Baa	A
Seminole Electric	A3	Senior Secured	Stable	A3	A	Aa	Baa	Aa	B	A	Baa	Aa	A	A	A	Baa	A	A
South Mississippi Electric Power Association	A3	Senior Secured	Stable	A2	Aa	Aa	B	B	B	A	Aa	Aa	A	A	Aa	Baa	Baa	A
Tri-State G&T Association	A3	Senior Secured	Stable	A3	A	A	Baa	A	B	Ba	A	Aa	Baa	A	A	A	A	Aa

✓

We identify positive or negative "outliers" for a given sub-factor as an issuer whose grid sub-factor score is at least two broad rating categories higher or lower than a company's actual rating (e.g. a Baa -rated company whose rating on a specific sub-factor is in the Aa-rating category is flagged as a positive outlier for that sub-factor).

▨ Positive outlier: grid-indicated performance for a sub-factor is two or more broad rating categories higher than the actual Moody's Rating for the issuer

■ Negative outlier: grid-indicated performance for a sub-factor is two or more broad rating categories lower than the actual Moody's Rating for the issuer

(a) Fiscal year-end October 31

(b) Fiscal year-end June 30

<c> No LT rating;Senior Secured A3 was withdrawn on Feb. 1, 2012; short-term rating is P-2

Factor 1: Observations and Outlier Discussion

Long-Term Wholesale Power Supply Contracts/Regulatory Status

The nature of the long-term wholesale power contracts taken together with regulatory status is one of the most important drivers of G&T co-op ratings, so it is not surprising that there are no negative outliers. The large majority of rated G&T co-ops score quite well with indicated ratings of Aa or A. The high ratings that so many of the G&T co-ops receive for Factor 1 help offset weaker scores in other areas, especially in Factor 2.

Notwithstanding the solid indicated ratings for Factor 1, we draw attention to the following observations. The protection afforded by wholesale power supply contracts can be eroded by challenges to, or changes in, the contracts over time, or more suddenly, due to a need for exceptionally large rate increases.

Under a strict interpretation of the definitions, Oglethorpe Power Corp. (OPC) would receive a B indicated rating for Factor 1. This strict interpretation results from the fact that OPC's owned resources provided only about 52% of its members' power requirements in fiscal year 2011. The situation results from a conscious decision by OPC's members to enter into power supply arrangements with third-party suppliers for their future incremental growth as permitted under the amended wholesale power supply contracts, extending through 2050. In Oglethorpe's case, we do not consider the low score to be an undue credit risk because its members remain joint and severally liable to pay all of the cooperative's costs and we believe Oglethorpe's stable supply of relatively affordable baseload power will become increasingly valuable to its members as their needs grow and they are continually forced to look for additional sources of supply. We believe an indicated rating of Ba sufficiently captures the degree of credit impact from the current relationships between OPC and its members when considered together with its rate autonomy.

Chugach Electric Association (CEA) is somewhat unique because it operates as a combined G&T co-op and distribution cooperative. As such, the 95% of its sales made to customers includes not only the 39% of energy sales made under wholesale power contracts, but also the 54% of energy sales made directly to retail customers under the tariff and certificated service territory in the state of Alaska. In our view, retail revenues from direct sales to commercial and residential customers are equal to, if not better than, the quality of wholesale revenues derived from sales to member co-ops. There is uncertainty surrounding the wholesale contracts that Chugach has with Homer Electric Association (HEA) and Matanuska Electric Association (MEA), which comprise the large majority of its wholesale revenues. Initially, both customers stated that they were not intending to renew when their contracts expire on January 1, 2014 and December 31, 2014, respectively. Although HEA currently stands by its stated intentions, MEA periodically holds discussions with Chugach about possible alternatives to an all-requirements arrangement in the future. Notwithstanding what appears to be an evolving stance on the part of MEA, we observe that Chugach has been steadily planning for the potential loss of at least some, if not substantially all, of its existing wholesale revenue. For example, Chugach has been adjusting its depreciation schedules, beyond those steps already approved, to coincide with the potential loss of this wholesale load and is seeking approval for additional revenue opportunities through use of its existing transmission assets and/or by providing additional services. Beyond these steps, Chugach could seek recovery of revenue shortfalls through rate cases. The uncertainty surrounding the impending wholesale load loss is incorporated into our credit risk assessment of Chugach.

Although bankruptcy filings have been rare within the U.S. electric generation and transmission cooperative sector, the bankruptcy filings of Cajun Electric Power Cooperative, Wabash Valley Power Association, and Big Rivers Electric Corporation in the late 1980's and 1990's, and the more recent filing by Southern Montana Electric Generation and Transmission Cooperative, Inc. were partially due to insufficient rate relief by its state regulators. These examples are worthy representation of the added uncertainty and credit risk that can be caused by third party regulation.

Factor 2: Observations and Outlier Discussion

Rate Flexibility

Factor 2 contains the most outliers of any of the five key Factors, the substantial majority of which are negative outliers. In particular, almost three-quarters of the rated universe are negative outliers for the Rate Shock Exposure sub-factor, largely reflecting the substantial dependence that the sector has on generation from carbon emitting fuels, especially coal. There are also four negative outliers for the New Build Exposure sub-factor, primarily reflecting the sizable capital investments in new generating capacity and transmission infrastructure on top of normal maintenance of existing property, plant and equipment for those G&Ts. Although Oglethorpe's New Build Exposure had previously been a negative outlier, this is no longer the case since its participation in construction of a new nuclear plant, contributed to the October 2010 downgrade of its senior secured rating to Baa1 from A3.

Golden Spread, Old Dominion, and South Mississippi are all negative outliers for the sub-factor measuring Purchased Power as a Percentage of Sales. In the case of Golden Spread, we classify their contracts with Southwestern Public Service Company and AEP as purchased power, which results in a very weak score on this factor; however, we do not believe that Golden Spread is overly exposed to the market price volatility. For example, Golden Spread can reduce market sales from its Mustang units and other facilities and utilize this owned capacity for the benefit of its members, if needed. Golden Spread's negative outlier status may also improve as it pursues construction of additional generation capacity. Old Dominion and South Mississippi may also seek to increase their respective owned generating capacity; however, in the near term we believe purchased power will remain integral to their resource strategy.

Big Rivers' outlier status for the sub-factors measuring Purchased Power as a Percentage of Sales and New Build Capex both shifted to positive from negative following two negative rating actions since August 2012, following contract termination notices jeopardizing the high concentration of sales that its largest member/owner, Kenergy, makes to two aluminum smelters. We also note that the amount of power that Big Rivers is purchasing significantly declined when it completed unwind transactions to re-establish its direct rights to power produced from its generation assets previously leased to LG&E. Moreover, Big Rivers' capex budget includes some flexibility related to maintenance projects and environmental spending for the next two years is estimated at $60 million; we understand that Big Rivers is arranging funding for environmental related capex.

The low ratings for so many of the G&Ts relating to sub-factors in Factor 2 are largely balanced by higher scores in Factor 1 and Factor 4. The rate autonomy and relatively competitive rates for so many of the G&Ts make it more likely that the members will accept what in many instances will be the ongoing need for rate increases even after a series of rate increases implemented over the past few years.

Factor 3: Observations and Outlier Discussion

Member/Owner Profile

Indicated ratings for Factor 3 map reasonably well to the actual ratings for the large majority of the 18 rated G&T co-ops in this methodology, with just three negative outliers.

Basin Electric Power Cooperative, Golden Spread Electric Cooperative, and Tri-State Electric G&T Association are negative outliers for residential sales as a percentage of total sales to retail customers. We note that Basin's member base serves territories dependent on farming, mining, and oil and gas exploration and production. Thus, Basin is considerably more dependent on potentially more cyclical sales than many of its peers who sell energy to a more sizable and generally more stable residential customer base. Although the absolute level of residential sales made by Basin's members is expected to continue to increase modestly, those will likely be outpaced by large commercial and industrial sales due to the make-up of the customer base for several of Basin's members. That said, many of the regions served by Basin's members have economies that are growing at a faster pace than the national average which bodes well for Basin's utility revenue growth potential. Golden Spread's sixteen members have a substantial footprint extending from the Oklahoma panhandle in the North and South through the mid-plains section of Texas. The substantially lower percentage of sales made by Golden Spread to residential customers compared to its peers results from a significant presence of oil and gas companies, agriculture-related industries and live stock farmers/ranchers in its service territory. Also, there is a significant seasonal irrigation load it serves, which can vary year to year. Importantly, Golden Spread is not exposed to any significant industrial load concentration. Since Tri-State's member base spans a vast territory throughout four states, including service territories dependent on farming, mining, and oil and gas exploration and production, it has among the smallest percentage of residential sales compared to its peers. Also, Tri-State is not over-exposed to commercial or industrial customer concentration, which tempers credit risk related to its members' relatively smaller percentage of residential sales compared to other G&T co-ops' members.

Big Rivers' low score for residential sales as a percentage of total sales to retail customers is no longer a negative outlier because its reliance on industrial load factored heavily in the two negative rating actions since August 2012, following contract termination notices jeopardizing the high concentration of sales that its largest member/owner, Kenergy, makes to two aluminum smelters.

Factor 4: Observations and Outlier Discussion

G&T Financial Metrics

Factor 4 takes into account historical financial statements. Historic results help us to understand the pattern of a G&T's financial and operating performance and how the G&T compares to its peers. While Moody's rating committees and the rating process use both historical and projected financial results, this document makes use only of historic data, and does so solely for illustrative purposes.

Although a significant number of the sub-factors in Factor 4 map reasonably well to a G&T's actual rating, there are several instances where significant positive outlier status is evident. Most notably, Golden Spread and Big Rivers are positive outliers for four of their five key financial metrics. In the case of Golden Spread, this reflects conservative financing strategies through the years. We anticipate that additional debt to fund Golden Spread's current long-term capital expansion plan is likely to cause these metrics to drift on average into the Aa category at a minimum, thus eliminating the outlier status. Big Rivers' mapping is based on its three-year average financial metrics through December 31, 2011, which reflect substantial improvement upon completion of the unwinding of lease transactions in 2009. Recent historical financial performance, which does not include the effect of the 2009 lease unwind, produces financial metrics more aligned with other peer G&T's. Notwithstanding the current A2 Indicated Rating for Big Rivers under the Methodology, its actual senior secured rating of Ba1, which is under review for downgrade, reflects the unique credit risks relating to Big Rivers' load concentration to two aluminum smelters, the smelter contract termination notices and the fact that receipt of the notices will impact cash flow in August 2013 in one instance and in January 2014 for the other.

Georgia Transmission Corporation and Oglethorpe Power Corporation are negative outliers on DSC and TIER, respectively, reflecting greater acceptance by their respective management and boards to manage results close to the minimum required levels contained in their debt indentures.

Factor 5: Observations and Outlier Discussion

G&T Size

Even the largest G&T co-op, Oglethorpe Power Corporation, is considered to be relatively small by investor-owned electric utility standards, so this has a limiting effect on the number of positive outliers.

In the case of Oglethorpe Power and Great River Energy, the significant investments in property, plant, and equipment were financed primarily with debt, which resulted in weaker metrics and lower ratings, thus contributing to the positive outlier status for the size factor. Although Big Rivers has increased its megawatt hours sold and net property, plant and equipment in recent years, it is a positive outlier for the size factors more so because of its low rating level reflecting the unique risks relating to Big Rivers' load concentration to the two aluminum smelters.

The two negative outliers are Chugach Electric and Georgia Transmission Corp., reflecting smaller than average size for the rated universe.

Although Chugach Electric is a negative outlier for megawatt hours sold it is by far the largest power provider in the state of Alaska and is geographically isolated, which tends to temper credit risk related to its small size.

Appendix C: G&T Co-op Industry Overview

G&T co-ops represent one of the three main forms of ownership for enterprises involved in the generation and delivery of electricity. Investor owned utilities (IOUs) constitute a sizeable majority of the U.S. electricity sector, with government owned municipal or public power entities representing the second largest segment of the market, and G&T co-ops being by far the smallest segment. G&T co-ops do not directly compete with each other or with investor owned utilities or government owned entities in a substantial way because cooperatives mainly provide service to their owner members under long term all requirements power contracts.

The A3 average (senior most) rating assigned for G&T co-ops is two alpha-numeric notches below the average rating for municipal or public power entities which is in the high A range; is one alpha-numeric notch below the average rating for US municipal joint action agencies, which is in the mid-A range; and is one alpha-numeric notch higher than the average rating for IOUs, which is in the high Baa range. G&T co-ops tend to be significantly smaller than investor owned utilities but have higher ratings because they are able to raise rates without the regulatory review required for investor owned utilities. G&T co-ops also face less competition given their contractual relationship with their member owners.

The following chart compares some of the characteristics that distinguish the risk profiles of these three subsets of the U.S. power sector.

FIGURE 13

Investor-Owned Utilities	G&T Co-Ops	Municipal And Public Power
Rate regulated	Most are not rate regulated but their owners may be	Not rate regulated
Profit seeking; operated for the benefit of public shareholders with obligations to serve regulated ratepayers	Not-for-profit; operated for the benefit of their owner members	Not-for profit; Operated for public benefit for the region served
Most are larger; may have multiple entities in an issuer family	All are small relative to IOUs	Most are small relative to IOUs
Subject to competition in the wholesale market; sometimes in the retail market	Little competition	Little competition
Some history of defaults, usually as a result of needing rate increases that are too large to be acceptable to ratepayers	Some history of defaults; usually due to need for rate increases that are too large to be acceptable to members	No defaults for load servicing utilities; two for JAA or project related financings
Can file Chapter 11 bankruptcy	Can file Chapter 11 bankruptcy	More impediments to bankruptcy but may be able to file Chapter 9
Tend to have higher rates compared to municipal or public power	Rates tend to be comparable to IOUs	Tend to have lower rates than G&T co-ops and IOUs
Rely extensively on capital markets	Most borrow from the Rural Utilities Service and cooperative financial institutions; larger issuers access the capital markets	Rely on public and private markets for financing needs; may have access to government funding if needed

Comparison with Joint Action Agencies

Moody's rates approximately $42 billion of bonds issued by U.S. Municipal Joint Action Agencies (JAAs), which have an average rating in the mid-A range and exhibit some characteristics in common with electric generation and transmission cooperatives. Both are nonprofit enterprises and are governed by their members. Cooperatives as well as many JAAs tend to serve small rural communities in the U.S. A significant difference between the two is the greater ability of JAAs to issue low cost tax-exempt debt, although cooperatives may borrow at below market rates through the federal RUS.

Since the 1970's, groups of city-owned electric utilities have established JAAs to pool resources to finance the construction of new generation facilities or to jointly purchase electric power supply. Participating members of JAAs are contractually obligated for power supply through take-or-pay and take-and-pay power sales agreements. These agreements are the underlying security for tax-exempt debt issued by JAAs. The power sales agreements are structured to have the same term as the debt issue.

JAAs have unregulated rate-setting authority and their municipal utility participants can recover costs by independently raising retail rates. The most recently completed period of borrowing by the JAA's was largely undertaken to finance ownership in new generation plants in order to assist their participant members in meeting demand growth and also to diversify their generation fuel mix.

The four key rating factors Moody's considers for JAA ratings include:

- Participant Credit Quality and Cost Recovery framework
- Asset Quality (Take-or-Pay)/Resource Risk Management (All Requirement)
- Competitiveness
- Financial Strength and Liquidity
- Willingness to Recover Costs With Sound Financial Metrics (All-Requirement)

Key questions embedded in our analysis of these factors are:

- What is the average weighted credit quality of participants?
- What are the demographic and economic characteristics of the service areas of the participating municipal electricity distributors?
- How economic are power sales contracts relative to competitors?
- How are the power supply contracts structured, and what are the bond security provisions?
- How do JAAs manage their balance sheet and liquidity as they plan for capital spending in order to position the JAA to meet future demand growth and competition?

Appendix D

Key Rating Issues over the Intermediate Term

Environmental Regulations on the Horizon

Many G&T co-ops have been postponing some of the sizable environmental expenditures originally anticipated to meet pollution control measures and emissions limitations to address concerns about carbon while awaiting more clarity on the specifics of the requirements. Nevertheless, these expenditures still loom on the horizon and will undoubtedly influence supply planning decisions, including whether to retrofit or retire coal units, diversify more into gas-fired plants and/or renewable energy sources, and/or promote efficiency and demand-side management programs. As the effective dates for some impending regulations quickly approach and other regulations are developed, G&T co-ops could experience progressively higher capital expenditures over the intermediate term, all of which would be recoverable in rates under their respective wholesale power supply contracts.

Large Capital Expenditures

Given the capital intensive nature of the G&T co-op sector, it is not unusual for capital spending plans to outpace depreciation and amortization in heavy spending years. In addition to the aforementioned environmental related spending there are other more routine maintenance and upgrades to existing generation and transmission infrastructure that are essential to ensure meeting reliability standards so critical when providing an essential service. In order to meet rising electricity demand as the U.S. slowly emerges from a recession, many G&T co-ops will wrestle with supply planning decisions. Finding the delicate balance between the right mix of new owned resources, power purchase arrangements, efficiency and demand-side management programs, while also complying with environmental regulations and/or renewable portfolio standards is no easy task. For those G&Ts that elect to participate in the construction of large, highly capital intensive projects that are largely financed with debt, especially nuclear plants, which have not been built in the U.S. in many years, the challenges could be particularly daunting and significantly pressure their credit quality.

The U.S. Economic and Financial Market Conditions

Having fared reasonably well during the recession period of 2008-2009, G&T co-ops are poised to take advantage of the sluggish economic recovery unfolding in the U.S. Our view is influenced in part by the load forecasts for many G&T co-ops that point to modest increases in customer usage of electricity in the 1% - 2% range over the next few years. We see this projected trend as a credit positive since falling demand for electricity would likely increase the need for rate increases to avoid material decline in overall financial performance and a weakening of the credit profile. With sound credit quality expected to be maintained going forward, we anticipate that investors will continue to be receptive to making investments in debt offerings made by G&T co-ops.

Ability versus Willingness To Raise Rates

Rate autonomy, long-term contractual relationships with member/owners, and virtual monopoly control over providing an essential service are key factors that will continue to support sound credit quality in the U.S. electric G&T cooperative sector. Because electric G&T co-ops provide such an essential service, we believe that the sector has a high degree of flexibility to raise rates charged to customers, which facilitates control over their financial position and increases the likelihood of achieving targeted financial metrics. We refer to this flexibility as the "willingness of a G&T co-op to adequately maintain its financial strength commensurate with its rating level". For some of the G&T co-ops, the prevailing low commodity price environment, especially for natural gas, has helped cushion the overall effect on members' rates owing to rate increases to cover other non-fuel costs. That said, there are occasions when affordability pressures surface and test the willingness of G&T co-ops to move ahead with wholesale power rate increases to their member/owners. For example, this may occur on the heels of situations where debt costs rapidly increase during large capital construction programs or when expansions are undertaken to accommodate projected customer growth that comes up short of original expectations. Also, a G&T co-op's "willingness" can be severely tested when unemployment rates persist at high levels and/or other economic growth indicators are weak. Since electricity is one of the most essential services to the economy, we view the customer's willingness to pay for the service to be very high. We also note that the relatively small proportion of total personal income spent on electricity can help temper credit risks tied to the affordability factor.

G&Ts who choose to defer increasing rates to their members in the face of sharply higher costs or who are unable to gain approval from regulators to do so when rate regulation applies will likely experience a deterioration in their key credit metrics. Inability to obtain regulatory approval for rate increases has contributed to the bankruptcy of G&T co-ops in the past. As an alternative to imposing a large rate increase at one time, we observe that some G&T co-ops have had reasonably good success following a strategy of smaller, more frequent rate increases to be phased in over a period of years.

Rates charged by G&T co-ops need to be regionally competitive with rates charged by other power providers. Rate competitiveness of G&T co-ops relative to other power providers is important because it affects the willingness of co-op members to accept rate increases when costs increase. With most other power providers currently facing similar operating costs and capital spending requirements, as well as sometimes increasingly expensive insurance and pension benefits, we do not expect that the rates that G&T co-ops charge their members will be materially less competitive than those charged by other power providers.

Prevailing Reliance on Low-Cost Loans from U.S. Government Sponsored Agencies, While Increasing Access to Other Capital Sources

G&T co-ops rely heavily on low cost loans from the Rural Utilities Service of the U.S. Department of Agriculture (RUS) and from RUS guaranteed loans provided by the Federal Financing Bank (FFB), a government funding arm. Thus, any federal budgetary constraints could have negative consequences on this vital low-cost funding source. That said, a strong historical lobbying presence in Washington through National Rural Electric Cooperative Association has historically served as a buffer to this risk.

In addition to the RUS, G&T co-ops also rely heavily on loans provided by cooperative financial institutions such as the National Rural Utilities Cooperative Finance Corporation (NRUCFC; A2 senior unsecured; stable outlook) and CoBank. More recently, given the benefits from flight to quality, there is a growing number of the larger commercial banking institutions that have increased lending to the sector through participation in syndicated bank revolving credit agreements. Often the G&T co-ops also maintain relationships with smaller local commercial banking institutions.

Still, the RUS is the single largest provider of debt financing to the sector. Given the history of political support for the RUS loan program, our ratings reflect our assessment that the probability of systemic withdrawal of such low cost funding is low. The ratings do, however, incorporate the RUS decision not to provide loans for the construction of base load coal and nuclear plants.

Some cooperatives have elected to repay all RUS loans or otherwise obtain lien accommodations in order to obtain more financial flexibility, which results in a greater reliance upon the capital markets as a source of funding. Larger G&T co-ops, such as some of those in Moody's rated universe, have long ago increased financial flexibility by accessing the capital markets. In recent years, a growing number of G&T co-ops have done likewise, given their desire to increase financing flexibility and the RUS decision not to lend for the construction of base load coal and nuclear plants. We anticipate that this trend will continue.

Moody's Related Research

Industry Outlooks:

» U.S Regulated Electric Utilities, February 2013 (149379)

» U.S. Power Projects February 2013 (149974)

» U.S. Public Power Industry Outlook, June 2012 (141124)

Rating Methodologies:

» Natural Gas Pipelines, November 2012 (146415)

» Regulated Electric and Gas Utilities, August 2009 (118481)

» U.S. Public Power Electric Utilities with Generation Ownership Exposure, November 2011 (135299)

» U.S. Municipal Joint Action Agencies, October 2012 (145899)

» Power Generation Projects, December 2012 (147991)

» U.S. Public Power Electric Utilities, April 2008 (106322)

Special Comments:

» Infrastructure Companies Well Insulated from Fiscal Cliff Risks, December 2012 (148299)

» Slow Economic Recovery Tests Willingness to Manage Rates and Costs, October 2012 (146421)

» Household Electric Utility Affordability – Impact of Recession, October 2012 (146562)

» Default and Recovery Rates for Project Finance Bank Loans, 1983-2011, February 2013 (149603)

» Infrastructure Default and Recovery Rates, 1983-2012H1, December 2012 (146791)

» Southern Montana Electric Bankruptcy Is Credit Negative for US Generation and Transmission Cooperative Sector, October 2011 (137017)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

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MOODY'S
INVESTORS SERVICE

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

Response to the Office of the Attorney General's Second Request for Information dated September 16, 2013

September 30, 2013

Item 69) ***Explain how often BREC updates its Financial Model to reflect updated/new assumptions, new vendor quotes/contracts, other inputs, and to update assumptions based on the changes in "actual" costs. Explain if this decision to reflect new/updated information is entirely subject to BREC's discretion and decision-making or explain if there is a written policy that requires such periodic updates (and provide a copy of this policy).***

Response) At a minimum, Big Rivers reviews and updates its Financial Model on an annual basis. Big Rivers will periodically update the financial forecast based on known and forecasted changes. The Annual Fiscal Review Policy was provided in response to PSC 1-8, Attachment 1, and the Financial Forecasting section of this policy is located on page 2 of 6, Section 4 (a).

Witness) Christopher A. Warren

BIG RIVERS ELECTRIC CORPORATION

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

Response to the Office of the Attorney General's
Second Request for Information
dated September 16, 2013

September 30, 2013

Item 70) *BREC's response to AG 1-237(e) and (f) only vaguely addresses in a one sentence response the reason for changes in payroll costs from 2011 to 2012, but BREC never addresses the change in payroll costs for other periods as requested and never provides other information that was requested. Address the following:*

a. *Regarding the $13.4 million increase in total payroll costs (from $25.1 m for forecast base period ending September 30, 2013 to $38.5 m for forecast test period ending January 31, 2015, and related payroll expensed and capitalized) for which BREC did not explain or provide supporting documentation or calculations, explain if BREC's "non-response" is an indication that BREC does not have any explanation or supporting documentation or calculations for this significant change in payroll costs. Otherwise provide the supporting documentation and calculations as previously requested for all payroll periods.*

b. *Show the amount of increase in payroll costs from the forecasted base period September 30, 2013 to the forecasted test period ending January 31, 2015, for each specific component or item that caused payroll to increase by at least $250,000 between these two periods, including changes due to increased/new hires, annual payroll cost-of-living increases, merit*

increases, incentive increases, non-recurring costs, severance pay, overtime, and all other changes in cost.

c. ***Address subpart (a) and (b) also for BREC's response to AG 1-238, and separately address this information for "exempt" and "non-exempt" labor.***

d. ***Explain why BREC did not provide the information requested in this data request and related schedules for payroll compensation by each specific component (long-term incentives, bonuses, annual pay increases, etc.) for each of the periods requested in the prior and current rate case.***

Response) Big Rivers objects that this request is argumentative and inaccurate insofar as it suggests that Big Rivers "vaguely" responded to referenced data requests or provided so-called "non-response[s]" to overly broad, unduly burdensome, data requests that are not reasonably calculated to lead to the discovery of admissible evidence.

a. In the attachment to the response for AG 1-237(a) page 1 of 6, the total payroll costs for the base period are separated into Actual Base Period ($24,056,263) and Forecasted Base Period ($25,106,476). The total payroll costs for the Base Period is the sum of the two ($49,162,739). If both portions of the Base Period are accounted for, there is no increase in total payroll costs from the Base Period to the Test Period.

b. There is no increase in payroll costs from the forecasted base period to the forecasted test period. See the response to part a., above.

c. The attachment to Big Rivers' response to AG 1-238(a) provides the requested payroll costs for "exempt" and "non-exempt" labor.

d. Big Rivers objects that this request is argumentative and that the phrase "this data request" is unduly vague and ambiguous because it is not clear whether "this data request" refers to AG 2-70, AG 1-237, or AG 1-238. Notwithstanding these objections, and without waiving them, Big Rivers responds that its responses to AG 1-237 and AG 1-238 explained why it was objecting to those requests. As indicated in the responses to AG 1-237 and AG 1-238, Big Rivers explained that it "objects that [the] request is overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. Big Rivers further objects to the extent that this request seeks information that is not maintained in the ordinary course of business or that is not maintained in the manner requested. Information pertaining to periods prior to the Unwind Transaction is not relevant, and actual calendar year 2010 data is not available as a result of Big Rivers' Oracle transition late that year." The subparts of the responses to those requests also contain narrative explanation regarding what was provided, in addition to the data provided in the attached schedules and electronic files. In short, the request was overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence insofar as it sought information for periods of time not relevant to this rate case (or, for which the requested data is not available) and in a format that would require Big Rivers to reconfigure its systems and business recordkeeping in order to complete the schedule referenced in the request. The remainder of the requested information was provided.

Witness) Billie J. Richert