ORIGINAL

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

APPLICATION OF BIG RIVERS	)	
ELECTRIC CORPORATION FOR A	)	Case No. 2012-00535
GENERAL ADJUSTMENT IN RATES	)	

Response to the Office of the Attorney General's Supplemental Request for Information dated March 14, 2013

FILED: March 28, 2013

ORIGINAL

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

Response to the Office of the Attorney General's
Supplemental Set of Data Requests
Dated March 14, 2013

March 28, 2013

Item 1) ***Referencing Big Rivers' response to AG 1-47: Has Big Rivers included all additional costs related to redirecting Wilson fuel related contracts to alternative generating stations in its forecasted revenue requirements? If not, please provide these estimated costs.***

a. If these costs are not part of the current forecast, would Big Rivers be allowed to recover such costs in its Fuel Adjustment Clause? How much would the FAC have to be on average just to recover these costs? How would costs be reflected in market offers for energy from Big Rivers "alternative generating stations?" Explain all answers in detail.

Response) Big Rivers has included all known additional costs related to redirecting Wilson fuel to an alternative generating station in its forecasted revenue requirements.

a. Not applicable.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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CASE NO. 2012-00535

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Item 2) *Referencing Big Rivers' response to PSC 2-21(a): Provide all correspondence and results provided by MISO as a response to Big Rivers December 2012 Attachment Y-2 requests for analysis of idling Coleman and Wilson.*

Response) Please see Big Rivers' response to PSC 3-6.

Witness) Robert W. Berry

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CASE NO. 2012-00535

**Response to the Office of the Attorney General's
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Dated March 14, 2013**

March 28, 2013

Item 3) ***Referencing Big Rivers' response to PSC 2-22, regarding OATT operating and maintenance costs previously paid by Century, it is not clear how the following statement: "If Century enters into a bilateral contract with a third party and the bilateral contract does not have a designated generator, then only one-half of the cost paid by Century will be paid to Big Rivers," corresponds to the statement made later in that same response that "Century will be responsible for paying all normal transmission service costs under the MISO Tariff."***

a. Please specifically identify the cost to which the first statement is referring. Are these transmission costs?

b. Please provide a detailed cost breakdown of the costs currently recovered from Century (transmission expenses, transmission depreciation, etc.) and costs that would be recovered from Century if Century should enter into a bilateral contract with and without designated generation.

Response)

a. The statement, "If Century enters into a bilateral contract with a third party and the bilateral contract does not have a designated generator, then only one-half of the cost paid by Century will be paid to Big Rivers," refers to transmission cost paid by Century to MISO. It is Big Rivers' understanding that if Century is required to purchase transmission under MISO Schedule 7 – Long-Term and Short-Term Firm Point-to-Point Service instead of Schedule 9

- Network Integration Transmission Service, Big Rivers will receive roughly one-half of the cost paid by Century. It is Big Rivers' understanding that if Century purchases transmission under Schedule 9 - Network Integration Transmission Service, Big Rivers will receive the full amount paid by Century.

b. Big Rivers currently provides a bundled service to all customers. That service includes transmission. Big Rivers does not track the transmission costs recovered from individual customer classes.

Based on conversations with MISO, Big Rivers approximates it would receive either 100% of Network Integration Transmission Service paid by Century or roughly 50% of the Point-to-Point Service paid by Century. MISO's current tariff for Network Integration Transmission Service is $17,082.07/MW-Year. MISO's current tariff for Firm Point-to-Point Service is $32,702.07/MW-Year. Big Rivers has not yet come to definitive terms with Century for obtaining market power, thus Big Rivers is unsure of any revenues it would receive.

Witness) Robert W. Berry

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Item 4) ***Referencing Big Rivers' response to AG 1-8, where it states "Big Rivers also continues to negotiate with Century Aluminum to allow it to obtain its power from the wholesale market,":***

- ***a. Please state whether this is the only scenario still viable in these negotiations.***
- ***b. Describe any other scenarios being discussed or pursued under which Big Rivers and/or Kenergy would continue to provide power to Century.***
- ***c. Describe any other scenarios being pursued or discussed wherein Century would obtain power other than directly through Big Rivers / Kenergy.***

Response) Big Rivers objects to the extent that this request seeks information that is protected by the attorney-client privilege and the work product doctrine. Notwithstanding this objection, but without waiving it, Big Rivers states as follows.

a. As we have stated from the very beginning, Big Rivers is willing to allow Kenergy to obtain power from the wholesale power market to serve the aluminum smelters, providing the smelters pay any incremental cost associated with them obtaining power from the market, and they agree that Big Rivers is no longer obligated to provide power to Kenergy to serve the aluminum smelters. Big Rivers is also willing to serve the smelters from its system at cost of service rates.

b. Other than the two scenarios identified in the response to subpart (a) above, Big Rivers is not pursuing any other scenarios to continue to provide power to Century.

c. As stated in the response to subpart (b) above, Big Rivers is not pursuing any other scenarios to continue to provide power to Century. During the 2013 legislative session, House Bill 211 and Senate Bill 71 were filed to allow both Century and Alcan the ability to obtain their power supply from the wholesale market. There have been multiple amendments to House Bill 211 that would require Big Rivers to provide power to the smelters from its own portfolio at wholesale prices. Big Rivers does not support this bill or any bill that requires our Member customers to subsidize the for-profit aluminum smelters.

Witness) Robert W. Berry

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2012-00535

Response to the Office of the Attorney General's Supplemental Set of Data Requests Dated March 14, 2013

March 28, 2013

Item 5) ***Referencing Big Rivers' response to AG 1-16(b):***

a. Acknowledge that the loss of the Alcan load will occur during the fully forecasted future test year the company chose for the instant case.

b. Acknowledge that because no data regarding the loss of the Alcan load was provided either in the application, or in data responses, that seven (7) months of the test year is affected.

c. Acknowledge that the seven (7) month period referenced above contains inaccurate and/or insufficient data.

d. Acknowledge that the lack of this information prevents the Commission from making an informed determination as to the reasonableness of the application.

e. Provide copies of any and all analyses, modeling, or studies the company performed prior to the filing of this case regarding the then-potential loss of the Alcan load, regardless of whether such loss would have occurred prior to or after the loss of the Century load.

Response)

a. Big Rivers acknowledges that the Alcan contract termination will become effective during the fully forecasted test period proposed in the instant case.

b. No. Big Rivers does acknowledge that seven (7) months of the forecast test period (i.e. February through August of 2014) will be affected by the Alcan contract termination. However, Big Rivers did not provide "no data" regarding the potential impacts of the Alcan contract termination in its data responses; please see the response to part (e) below.

c. No. The test period data represents all of the information that Big Rivers could reasonably have included in its forecast at the time this case was filed. The test period data was prepared and filed in a manner consistent with the applicable regulations and is neither insufficient nor inaccurate. 807 KAR 5:001 requires that 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. The impacts of the Alcan contract termination do not meet these criteria. Please see the response to AG 2-15.

d. No. Nothing related to the Alcan contract termination prevents the Commission from making an informed determination of the reasonableness of Big Rivers' request in this case. As noted in response to PSC 2-1, Big Rivers is in the process of evaluating the implications of the Alcan termination notice on Big Rivers, but it should have no impact on this rate proceeding. Big Rivers needs the rate relief sought in this proceeding beginning August 20, 2013. The termination of Alcan's retail power contract is effective January 31, 2014. Big Rivers will file a separate proceeding in June of 2013 to address the Alcan contract termination to the extent Big Rivers needs additional rate relief beginning January 31, 2014. In the meantime, the fact that Big Rivers expects to seek additional rate increases in the near future does not prevent the Commission from determining that the request for rate relief as filed in this proceeding is reasonable.

e. Please see the Big Rivers Load Concentration Analysis and Mitigation Plan provided in response to AG 1-89. Big Rivers filed analyses supporting the Load Concentration Analysis & Mitigation Plan in Case No. 2012-00063.

Witness) John Wolfram

BIG RIVERS ELECTRIC CORPORATION

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CASE NO. 2012-00535

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March 28, 2013

Item 6) ***Referencing Big Rivers' response to AG 1-23 where it states "Smelter parent guarantees survive": Please summarize Big Rivers' understanding of the financial impact of these guarantees and the circumstances under which Big Rivers would benefit financially from any such guarantees.***

Response) A smelter parent guarantee does not provide increased financial benefits from a smelter; it only provides additional assurance of performance or payment of obligations already due from a smelter. For example, under the terms of the Century parent guarantee, Century Aluminum Company unconditionally and irrevocably guarantees the prompt performance and payment when due of the "Guaranteed Obligations." The Guaranteed Obligations include, but are not limited to, the obligations of Century Aluminum of Kentucky General Partnership to Kenergy under the Retail Agreement and the obligations of Century to Big Rivers under the Coordination Agreement. Big Rivers would preserve the financial benefits due it under the Guaranteed Obligations directly or through Kenergy if Century Aluminum of Kentucky General Partnership for any reason did not perform or pay a Guaranteed Obligation, and Big Rivers or Kenergy obtained performance or payment of that Guaranteed Obligation from Century Aluminum Company.

Witness) Robert W. Berry

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Item 7) ***Referencing Big Rivers' response to AG 1-25: Describe the resources and materials used by Big Rivers to ensure that its Enterprise Risk Management policies are programs reference and include "best practices" in enterprise risk management, including external review of and participation in enterprise risk management.***

Response) Big Rivers' Enterprise Risk Management Policy (attached to the response to AG 1-25(b)) was part of a comprehensive program developed under the guidance of former Big Rivers' Vice President of Accounting, Mark Hite.

In June of 2003, multiple members of Big Rivers' Board of Directors attended a course on the "Fundamentals of Energy Risk Management for Directors" presented by the National Rural Electric Cooperative Association. Please see the course materials at Attachment 1 on the PUBLIC CD accompanying these responses. The following year, Mr. Hite reviewed certain enterprise risk management materials from MCR Performance Solutions ("MCR"). Please see Attachment 2 accompanying these responses.

In developing Big Rivers' Enterprise Risk Management Policy, Mr. Hite was assisted by APMCR, a professional utilities management consulting firm that was an alliance company of Aces Power Marketing and MCR. APMCR met with Big Rivers personnel multiple times in 2006 and 2007 to discuss enterprise risk management and Big Rivers' implementation of an enterprise risk management program. APMCR also presented certain enterprise risk management materials to Big Rivers' Board of Directors. In connection with these discussions, APMCR developed numerous materials relied on by Big Rivers during its development and implementation of the Enterprise Risk Management Policy. Please see

Attachments 3 through 10 (Attachments 7, 9, and 10 are provided on the CONFIDENTIAL CD accompanying these responses).

After Big Rivers implemented its Enterprise Risk Management Policy, it ensured the policy met the Public Service Commission's standards in part by analyzing the Commission's management audit of East Kentucky Power Company, which included an audit of EKPC's risk management practices. Please see Attachment 11 accompanying these responses.

Please also see the confidential attachments to AG 2-13(d) for minutes of Big Rivers' Internal Risk Management Committee meetings.

Witness) Mark A. Bailey

Attachment 1 to AG 2-7 is provided on the PUBLIC CD accompanying these responses.

File: 1.00.27

Barbara Harwood

From: David Spainhoward [dspainhoward@bigrivers.com]
Sent: Wednesday, March 17, 2004 8:19 AM
To: bharwood@bigrivers.com
Subject: FW: Enterprise Risk Diagnostic Info & MCR Info

APM MCR ERM Diagnostic Q A.pd.. | Risk Four Ltr Word POV.pdf | MCR Paper - Risky Business.pdf... | MCR Paper - Quantifying GT Ris.. | MCR Experience Statements.pdf | mcr-group.pdf

Barbara:

Please print this e-mail and all of the attachments for me.

Thanks

David

-----Original Message-----
From: Mark Hite [mailto:mhite@bigrivers.com]
Sent: Tuesday, March 16, 2004 3:02 PM
To: Richard Beck; David Spainhoward; Bill Blackburn; Travis D. Housley; Mike Core
Subject: FW: Enterprise Risk Diagnostic Info & MCR Info

Fellas:
Please print the attached and bring it to our meeting this Friday afternoon from 2 till 4:30 in the board room. (The NCAA will have to wait.)
Mark

-----Original Message-----
From: John Sturm [mailto:JohnSt@acespower.com]
Sent: Tuesday, March 16, 2004 2:44 PM
To: mhite@bigrivers.com
Subject: Enterprise Risk Diagnostic Info & MCR Info

Mark,

> Attached below is some information regarding the Enterprise Risk Management Diagnostic (Q&A document), as well as other MCR info. MCR's has published several G&T risk management white papers that I highly recommend. Jeff Walker, Jeff Hume and Jim Pardikes of MCR will be at your offices on Friday at 2pm. Please forward these to anyone else that may like additional information about enterprise risk management and our alliance partner.
>
> Regards,
John Sturm
>
>
> Diagnostic Q&A:
> > <<APM MCR ERM Diagnostic Q A.pdf>>
> MCR G&T White Papers:
> > <<Risk Four Ltr Word POV.pdf>> > > <<MCR Paper - Risky Business.pdf>>
> > <<MCR Paper - Quantifying GT Risks.pdf>>
>
> MCR Bios/Info:
> > <<MCR Experience Statements.pdf>> > > <<mcr-group.pdf>>
> MCR Website:
> www.mcr-group.com
>

Pages 2-4 of this attachment have been omitted from the public filing. They have been provided under a petition for confidential treatment.

MCR

Point of View

Reflecting the opinions of
MCR PERFORMANCE SOLUTIONS

Risk is not a Four-Letter Word
Reflecting Risk in Planning & Forecasting

Jim Pardikes, Dave Thompson, and Dan Rupp
June 2003

The issues confronting generation and transmission (G&T) cooperatives are often the same issues facing investor owned utilities (IOUs) ... volatile fuel prices, unpredictable returns from off-system power sales, the need to improve credit measures, and uncertain load growth. Many IOUs have taken steps to better understand and manage their business risks. G&T coops also need to manage risk. It's no easy task, but management can start by focusing the planning process on understanding how key risk factors impact key performance variables such as member rates, the TIER ratio, and cash flow.

What's Wrong with the Current Forecast?

Financial forecasting has always been important to G&T coops. This kind of modeling ultimately produces a simple point forecast of earnings or cash flow. A base case point forecast, however, is no longer enough. The new generation of forecasting embeds risk analysis into the financial model and does not stop at simply developing the point forecast of the one-year budget or the three-year plan. That is, G&T coops now require a forecasting tool that automatically integrates key risk factors such as market prices, fuel prices and plant availability into the forecast and shows the range of potential outcomes in member rates, cash flow, and the TIER ratio.

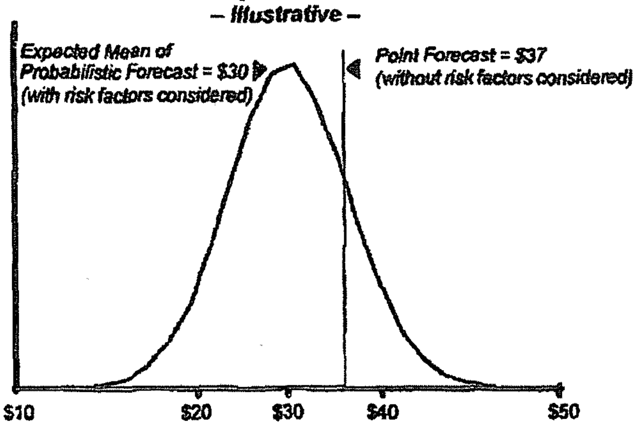
The new generation of forecasting embeds risk analysis into the financial model.

What are the Benefits of Incorporating Risk into the Forecast?

Incorporating risk into the forecast allows the senior team to understand the *probability* of meeting their financial goals. For example, is there a 50-50 chance of hitting the targeted member rates or only a 10% chance? Monte Carlo simulation runs hundreds of trials in one run of the model, thus allowing management to understand how different risk factors can combine and impact the likelihood of achieving their financial targets. Identifying and understanding the specific business risk factors has the following benefits:

- Better management of overall cash flow volatility through highlighting exposures — for example, can we narrow the variability of the forecast through "insurance plays" and how do these strategies impact the probability of hitting our financial target?
- Enhanced communications to constituents (e.g., the Board or Coop Managers) regarding why a short-term budget or long-term plan can vary from the point estimate — budget targets are not a "slam dunk" and can often be overoptimistic after considering key risks (See Figure 1)
- Improved decisions through the integration of risk factors into economic evaluations of investments — will this investment do well or, conversely, what combination of factors could make this investment go "South"?

Figure 1
The Overoptimistic Forecast
– Illustrative –



How Can Risk Be Integrated Into the Forecasting Process?

Most G&T coops have not yet integrated Monte Carlo capabilities into their core forecasting tool. They either have no risk tool or the risk tool they do have is run separately from the forecasting tool, leading to potentially inconsistent results. Embedding risk analysis into the planning and forecasting process allows senior management to become more engaged and talk in terms of a range or probability of achieving certain financial targets (rather than just a budgeted point estimate). Once the modeling capabilities are in place, the following steps are required:

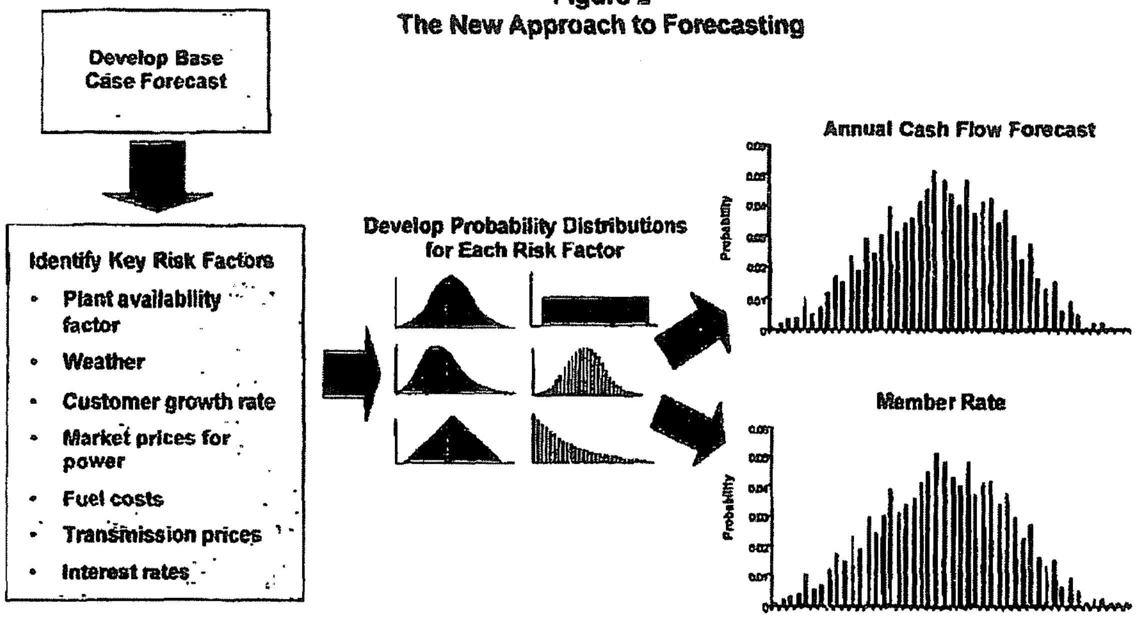
Embedding risk analysis into the planning and forecasting process allows senior management to become more engaged.

- Identify the risk factors that will be important to achieving your financial targets (e.g., plant availability, market prices, fuel costs, weather, etc.)
- Quantify the risk factors by determining the probability distributions and interrelationships/correlations among the factors
- Analyze the impacts of risk factors and determine the probability of achieving financial targets such as cash flow, member rates, TIER ratio, net income, etc.
- Package the analysis so senior management can be in a discussion of business risks and potential strategies for managing these risks

The process of integrating risk into the forecasting process results in a range of cash flow or member rate impacts. (See Figure 2) These results allow management to understand the probability of hitting a particular target. Management can answer key questions such as:

- What is the probability that member rates will rise more than 10% over the next three years? What factors are most important and how can they be managed?
- How likely is it that our non-member sales will produce over $2 million in margin? Should we increase or decrease our percentage of spot sales vs. contracted sales?
- Will admitting a new member increase or decrease the probability of a rate increase? What new risks will be introduced?

Figure 2
The New Approach to Forecasting



What's Required to Be Successful?

Some G&T coops are more likely than others to benefit from integrating risk into their planning and forecasting process. Companies facing specific business issues will have a sense of urgency and commitment to make risk analysis work. These issues include whether to admit a prospective new member, building a power plant vs. purchasing capacity, determining the proper time for a planned outage, etc. Risk analysis can be used to communicate to the Board the combination of risk factors that could result in negative or positive financial results and the resulting impacts on member rates.

The senior management team of a G&T should manage risk rather than avoid it.

The senior management team must be willing to invest their time to get comfortable with risk analysis, interpreting the results, and running alternatives with different assumptions. "Hands-on" management teams get the most benefit — gaining strategic insights from risk analysis cannot be delegated to staff.

In today's volatile business environment, if a G&T's planning and forecasting process is still relying on point forecasts and is not taking uncertainty into account, then it is missing a major part of the business landscape. The senior team of a G&T should embrace a new way of thinking about the planning process — managing risk rather than avoiding it.

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MCR

Risky Business
Communicating the G&T Budget and Rate Forecast to Members

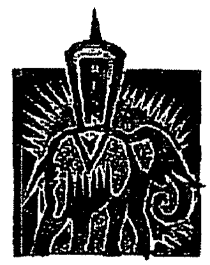
September 2003

Jim Pardikes
Greg Ridderbusch
Dave Thompson

Risky Business
Communicating the G&T Budget and Rate Forecast to Members

Jim Pardikes, Greg Ridderbusch, Dave Thompson

All G&Ts and their member distribution cooperatives do their best to forecast rates into the future. From this process, executives make promises to their boards and members about the prices to be paid for power. But the power markets today bear more risks than in recent history. Specifically incorporating those risks into the planning and forecasting process is an emerging best practice that some G&Ts are adopting. By augmenting the traditional forecast with risk analysis, G&T leadership teams are better positioned to keep the promises made.



There is a big elephant lurking unseen in the board room name "Risk," that everyone knows is there but wish would quietly go away.

It's Budgeting Time ... What Promises Are Being Made?

Every year starting in summer and continuing into the fall, G&T leadership teams go through the process of preparing next year's budget for board approval, including a multi-year forecast of member rates. Member distribution cooperatives count on these forecasts because power costs are the largest expense item impacting their rates to consumer members. The G&T CEO and CFO typically present a precise-looking trend-line, and an implicit promise is made about the future: *these are the prices that members will be charged for power.* However, there is a big elephant lurking unseen in the board room named "Risk," that everyone knows is there, but wish would quietly go away.

In today's energy markets, there is more potential volatility in the budget and forecast than in the past. Despite this volatility, the financial conversation between G&Ts and their members typically does not include a quantitative discussion of potential impacts of risks on member rates. It is time for G&Ts to augment the forecast process to account for risk volatility. While the approach is straightforward, it does represent a new set of capabilities. However, the results will provide insights into rate forecast uncertainties associated with the underlying power generation and transmission business.

The G&T board and the leadership team have always lived with risks that impact the ability to deliver on promised rates. Historically, these risks have been addressed with conservative financial policies, prudence, and good management. But here's the problem – external, less controllable risks have become so significant that the financial dialogue between the G&T and its members must change.

Just consider a few of these externalities:

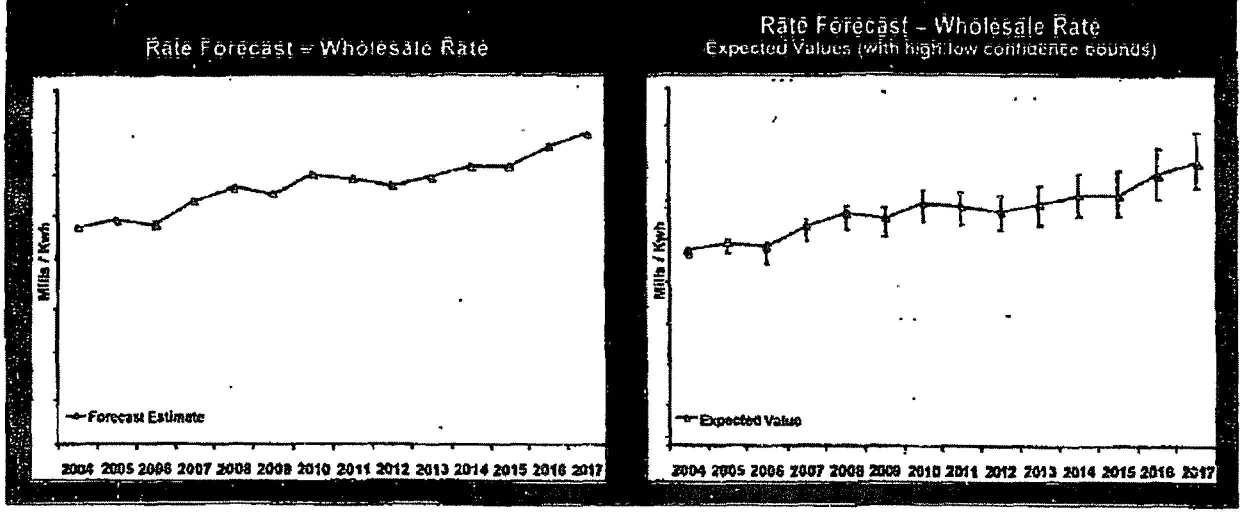
- Natural gas price volatility and deliverability – Especially where a greater proportion of the newer capacity portfolio are gas-fired combined cycle and peaking units
- Forward price curves – Many factors impact future power prices, including regional capacity, demand, status of planned regional power projects, fuel costs, etc.
- Transmission – Impact of transmission constraints, RTO costs and regional construction
- Environmental compliance – New Source Review, timing and capital requirements for emission control, political climate for new coal-fired generation
- Interest rates and availability of low cost capital – Not even Mr. Greenspan knows what will happen here. The RUS and other traditional sources of cooperative financing have greater demand than supply.

Finally, consider that some, none, or all of these risks will play out on different time lines. Trying to forecast in this environment with conventional "what if" sensitivity analysis is not going to provide robust answers—it ignores how multiple risk factors can interact together. Past common practices present a forecast of annual *point estimates* (see the graphic on the left in Figure 1). It looks precise, but provides members with no information about the potential to come in higher or lower than the yearly point estimate.

Progressing to a forecast augmented by strategic risk analysis yields an *expected value* within the bounds of a probability distribution (see the graphic on the right in Figure 1). Now members see information about how low or high the rate might be for the year. Also note, that the high:low bounds widen with each additional year, because uncertainty increases with time. Incorporating risk into the forecast allows the senior team to understand the *probability* of meeting their financial promises to members.

Incorporating risk into the forecast allows the senior team to understand the *probability* of meeting their financial promises to members.

Figure 1
Rate Forecasts Before and After Risk Analysis



What Are the Benefits of Incorporating Risk Into the Forecast?

Risk analysis can be used to communicate to the Board the combination of risk factors that could result in negative or positive outcomes. Virtually all G&Ts are addressing business issues like the following:

- **Achieving Budget** – What is the probability that costs and revenues will change so that member rates will need to increase more than 10% over the next three years? Is there a 50% chance that the budgeted member rates will achieve the desired financial results (net margin, TIER, DSC), or only a 25% chance?
- **Buy vs. Build** – How is the variability of the projected power cost impacted by either building a new gas-fired power plant, or purchasing a series of long term contracts? Should we increase or decrease our percentage of spot sales vs. contracted sales? How will going "long" narrow our variability in financial results?
- **Resource Planning** – What is the impact of load growth, capacity growth, and weather on our power supply portfolio? What is the probability distribution over time that a shortfall occurs in peaking or intermediate resources?

Most G&Ts have not integrated risk simulation capabilities into their forecasting processes and tools.

To answer these questions, forecasting tools must be capable of running risk simulations (literally automating thousands of simultaneous what-if simulations (or model runs)), thus allowing management to understand how different risk factors can combine and impact the likelihood of achieving their financial targets.

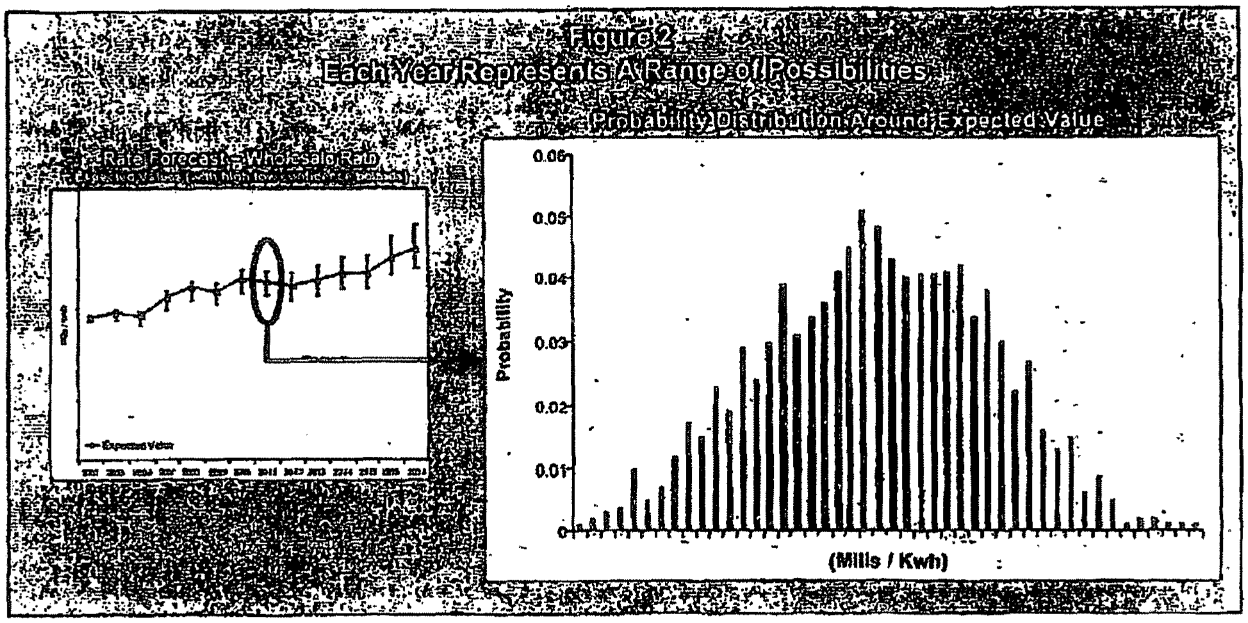
By identifying and understanding the specific business risk factors, and quantitatively factoring them into the forecast, G&Ts gain a number of benefits:

- **Quantified Risk Exposures** – With risk simulation models, the analyst can tell the senior team about combinations of risks that yield bad outcomes for the G&T. Importantly, the risk analytics quantify those risk exposures, enabling their prioritization. If the worst potential events and impacts are known, then the senior team can know the net margin at risk. Hence, they can evaluate risk mitigation strategies (hedging, insurance, etc.) based on the cost versus risk, and the management team's appetite for assuming risk.
- **More Informed Decisions** – A classic decision for any G&T is build vs. buy for a future capacity shortfall relative to member supply requirements. This decision has historically been analyzed with conventional what-if analysis, but risk analytics provide whole new insights to inform your decisions.
- **Insightful Communications** – Many G&Ts talk about business risks, but moving beyond "gloom and doom" discussions, risk analytics can be used to put some quantification around risk impacts in discussions with members. They also implicitly move your organization from a point estimate promise, to an informed forecast about the probabilities of achieving the desired financial results.

How Can Risk Be Integrated Into the Forecasting Process?

Most G&T cooperatives have not yet integrated risk simulation capabilities into their forecasting processes and tools. The integration requires a nominal investment in tools and a commitment to build internal skills. MCR clients have built the competency, and once established, risk analysis is executed with the following steps:

- Identify the risk factors that will be important to achieving your financial targets (e.g., plant availability, market prices, fuel costs, weather, environmental compliance, etc.)



- Quantify the risk factors by determining the probability distributions and interrelationships/correlations among the factors
- Run a corporate financial model with integrated risk analysis tools. Analyze the impacts of risk factors and determine the probability of achieving financial targets such as net margin, cash flow, member rates, TIER, and DSC
- Package the analysis so senior management can use the results to discuss business risks and potential strategies for managing these risks

G&T senior teams must add risk management to their "tool set" to actively and quantitatively manage risk.

The process of integrating risk into the forecasting process results in a range of projected member rates tied to a corresponding range of net margin or TIER (see Figure 2). These results allow management to understand the probability of hitting a particular target. For each year, the probability distribution illustrates the high and low bounds around the expected value, assuming a chosen level of confidence (e.g., 75% confident). Each point within the distribution is the result of a specific plausible combination of risk factors.

What's Required to See the "Elephant"?

With this information, the senior team can quantitatively consider strategies to mitigate the risks, and also communicate with greater certainty about the likelihood of hitting the promised rates. However, the senior team must be willing to invest their time to get comfortable with risk analysis and results interpretation. Gaining strategic insights from risk analysis cannot be delegated to staff.

The initial step towards reflecting risk in the business plan forecast is to assess your current practices. First, is the data sufficient for risk analysis? Second, are the available tools adequate? Next, to what degree has the strategic risk management process been established? And finally, how does the leadership team and board use risk analytics to guide the company? (See Figure 3 for a simple guide to average, good, and best practices in these four areas.)

Figure 3
Rate Your G&T's Current Risk Management Practices

	Average	Good	Best Practice
Data	• VaR calculations in place • List(s) of risk drivers prioritized subjectively	• Risk drivers defined as probability distributions • Some level of analysis behind risk parameters • Risk data in central location	• 2nd iteration in refining drivers and parameters • Special studies to quantify correlations, etc. • Risk database created and maintained
Tools	• Ad hoc issue analysis models	• Corporate financial model in place with integrated risk analytics	• 2nd stage corporate financial model which also can integrate member inputs
Process	• Risk Committee identified • Risk policy books in place for power marketing • Issue based projects (e.g., credit)	• Risk analysis in base case plan • Risk Committee owns the risk management process • Risk analytics used on ad hoc basis for key operating and investment decisions	• Risk analysis and measures part of ongoing planning discussions with members • Risk analytics in all major capital allocation decisions and strategies
Management	• CFO viewed as being in the lead • Leadership team has only limited training in risk concepts	• Management trained in risk basics • Acceptance of role of risk in strategies • Board introduced to risk analysis; distinction made between point and probabilistic estimates	• Comfortable communicating strategic risk concepts and risk analysis with Board • Risk part of the ongoing language of interactive management discussions

In today's volatile business environment, most G&Ts' planning and forecasting process are still relying on point forecasts and not taking uncertainty into account. It is time for the senior team to add risk management to its "tool set" — actively and quantitatively managing risk, thereby taming that elephant rather than avoiding it. When your budget and forecast are completed each year, your leadership team, Board, and members will have a more insightful understanding of what the numbers and promises mean.

Jim Pardikes

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Jim Pardikes has 20 years experience in consulting to the utility industry including electric and gas IOUs and G&Ts. His expertise includes financial forecasting and using analytical tools to develop strategies in the corporate, energy marketing, and transmission areas.

Greg Ridderbusch

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Greg Ridderbusch has 16 years of utility industry experience. He consults to G&T cooperatives, municipals, and IOUs. His expertise includes strategy and business planning, process improvement, performance management, and decision analysis.

Dave Thompson

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Dave Thompson has 12 years consulting experience in the energy industry. His experience has been in the performance management, strategic planning, and portfolio risk management areas working with generation, trading, and energy services business units.

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You Can't Manage What You Don't Measure

Quantifying Risks and Addressing Challenges for G&T Cooperatives

January 2004

Jim Pardikes
Dave Thompson
Greg Ridderbusch

You Can't Manage What You Don't Measure

Quantifying Risks and Addressing Challenges for G&T Cooperatives

Jim Pardikes, Dave Thompson, Greg Ridderbusch

Most Generation and Transmission (G&T) cooperatives have gone through a process of identifying risks facing the business. These risks are often prioritized and, in some cases, risk mitigation strategies have been developed for the top risks. Identifying and prioritizing risks is necessary, *but not sufficient*, for evaluating cost-risk tradeoffs and developing effective risk mitigation strategies. G&T senior teams must also *quantify* the risks in terms of their potential impact on net margin, member rates, and TIER. In so doing, management will need to address key challenges in ensuring the proper tools and processes are in place to quantify risk.

Developing Strategies Before Quantifying—Jumping the Gun

Volatile fuel prices, diminishing capacity reserve margins, looming environmental capital expenditures, and a push towards voluntary adherence to Sarbanes-Oxley principles have prompted virtually every major G&T to develop some sort of risk management initiative. In almost every case, senior management has participated in a "list and prioritize" exercise. In some cases, the Board has been involved, typically in education sessions. Despite this progress, most G&Ts have skipped a key step in the strategic risk management process—the quantification of risks.

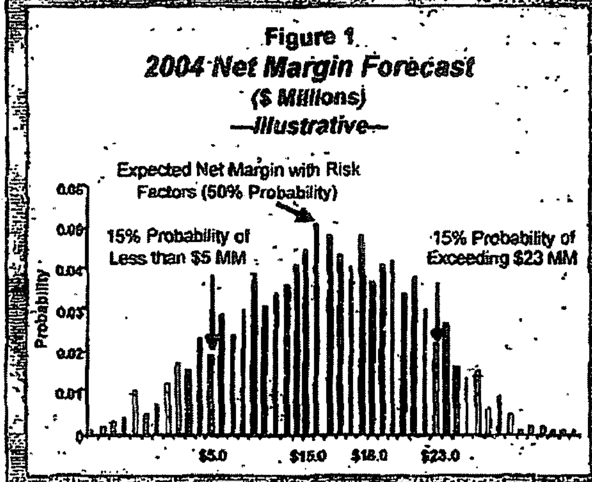
Most G&Ts have skipped a step in the strategic risk management process—the quantification of risk.

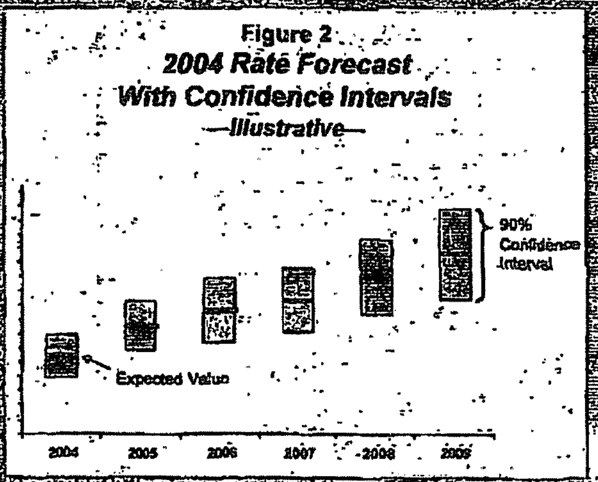
The familiar adage of "you can't manage what you don't measure" applies to managing risk. By quantifying risk in terms of its impact on rates and key financial measures such as net margin[1], senior management teams will develop more effective strategies for managing risk. Answering questions, such as those listed below, will help senior management quantify existing risks and provide a strategic context for developing the "best" strategies:

- How much variability is there around the base case forecasts of net margin, cash flow, TIER and member rates? (See Figure 1)
- What is the probability that we will achieve our target for net margin and TIER using our budgeted rates?
- Linked to our resource plans, what is the high and low trajectory (i.e., confidence band) for member rates over the next five years? (See Figure 2)

Quantifying the answers to these questions encourages the right discussions at the senior level and leads to a more confident and informed management team with regard to managing risks.

[1] For more information, see MCR White Paper, "Risky Business: Communicating the G&T Budget and Rate Forecast to Members," September 2003.





An Integrated View For Quantifying Risks

In order to effectively quantify risk and answer these questions, G&Ts need an integrated view of risk. While traditional what-if studies, or sensitivity analyses, can provide management with useful information on standalone risks (such as fuel prices, load forecasts, or unit outages), they provide only point estimates and, therefore, an incomplete picture related to risk.[2] As a result, what-if analysis provides limited insights in connection with the development of risk management strategies.

It is necessary to develop an integrated picture of all the relevant enterprise-wide risks, which can then be translated into probabilistic impacts on rates and net margin.

Instead, it is necessary to develop an integrated picture of all the relevant enterprise-wide risks, including the volatility of the risks, how they interact, and how they correlate (or move together). This integrated view of risks can then be translated into probabilistic impacts on key measures such as rates and net margin ... answering questions such as, "What is the *probability* that rates will have to be increased by 5% to achieve the desired TIER?" Quantifying risks using a probability approach requires completion of the following steps:

- For each key risk, develop a probability distribution that describes the mean, standard deviation, and type of curve, e.g., "We expect natural gas prices to have a mean of $5.00, grow by 5% per year, have a standard deviation of $1.00, and a lognormal distribution with reversion to the mean."
- Develop correlations among key risks, e.g., "Gas-fired generation units are the primary driver of market prices in our region. Based on recent data, there is a 70% correlation between natural gas prices and peak power prices."
- Run the financial and risk model to see the integrated impacts on rates and other measures such as net margin, cash flow, TIER and DSC—iterate and refine the probability distributions as appropriate.

This probabilistic approach gives the senior team a common denominator, such as rates, to assess the cost tradeoffs of investing in risk-reducing strategies. Moreover, probabilistic analysis allows the senior team to directly see how risk-reducing strategies can reduce the probability of a "bad outcome," such as increased rates, decreased net margin, or insufficient cash flow. In contrast, traditional what-if analysis only provides point estimates and does not provide insights into the likelihood of a bad outcome. Therefore, a point estimate does not directly lend itself to evaluating cost-risk tradeoffs.

[2] See MCR Point of View, "Risk is Not a Four-Letter Word: Reflecting Risk in Planning and Forecasting," June 2003.

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Attachment 2 for Response to AG 2-7
Witness: Mark A. Bailey

Having the Pieces in Place for Quantifying Risk

In order to successfully move beyond the simple identification of risks and effectively quantify risk, G&Ts must address two areas: tools and process.

Tools. Most G&T cooperatives have not yet integrated enterprise-wide Monte Carlo risk capabilities into their core financial forecasting tools. They may do isolated risk analysis using production costing or trading tools, but most G&Ts do not yet capture enterprise-wide risks. The new generation of financial forecasting tools should do the following to effectively quantify risk:

- Include Monte Carlo risk analysis and a graphics engine to enable probabilistic risk analysis
- Specify risk distribution and correlations for each risk factor (e.g., purchased power prices, demand, fuel prices, forced outage rate, interest rates, etc.)
- Produce full financial statements (income statement, balance sheet and cash flow) and reside within the official budget and financial forecast to ensure credibility with the senior team and the Board
- Provide automated iteration and risk driver logic to capture integrated impacts (e.g., a unit outage leads to the dispatch of higher cost units and higher fuel expense along with increased purchased power at market prices)
- Provide quick turnaround to facilitate interactive senior management discussion

> **The risk process must be integrated with the budget, resource planning, and strategy development activities ... leading to executive-level strategies that assess cost-risk tradeoffs.**

Process. Tools to quantify risk are necessary, but they are not enough. In order to effectively manage risk, a process must be in place (see Exhibit 3). Staff experts need to be trained, and the risk management initiative needs to be a clearly articulated priority of the management team. Education must be ongoing for senior management and member leaders since risk concepts and techniques can be challenging, and take more time than a single training workshop. Risk-based concepts and forecast results need to become part of the "language" when discussing financials with the members.

This risk process must be integrated with the budget, resource planning, and strategy development activities ... leading to executive-level strategies that assess cost-risk tradeoffs and produce concrete operational actions to manage risk. The investments related to these risk mitigation strategies may reduce the expected mean of net margin but also narrow its variability, and thus, reduce the possibility of a "perfect storm" (see Exhibit 4). For example, a hedging contract that caps natural gas prices for summer peakers will increase the budgeted revenue requirement by the contract cost, but will reduce a "left tail event" should natural gas costs skyrocket.

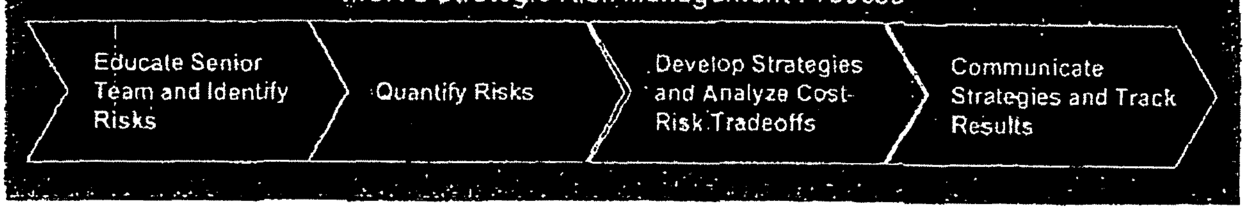
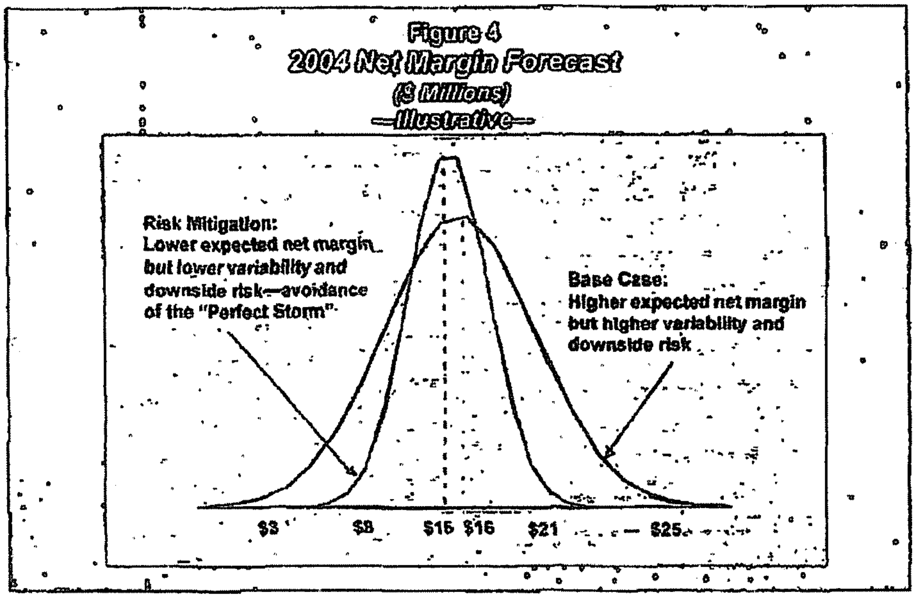


Figure 3
MCR's Strategic Risk Management Process



Conversely, failing to establish a process that integrates risk analysis with budgeting and planning can lead to a default strategy that increases risk. A default strategy implies assuming more risk (and wider variability) with the hope of achieving a higher net margin without an increase in member rates. Some additional strategy-related issues which should be evaluated include:

Failing to establish a process that integrates risk analysis with budgeting and planning can lead to a strategy that increases risk.

- How much should we be willing to pay for outage insurance?
- What percentage of our fuel needs should be hedged?
- Should we go "long" by buying a multi-year purchased power contract (with its inherent premium) or obtain incremental power needs from the short-term market?
- How much extra capacity beyond the minimum reserve margin makes sense? Should we build or buy?
- What type of generation should we build—gas or coal?

Addressing these types of questions helps shape the risk tolerance of the senior team and results in a more informed team when it comes to discussing these risks with the Board, lenders, and ratings agencies. These actions must be monitored and regularly reported to evaluate whether the desired results of the strategies are actually occurring. A key to success is having an "owner" at the senior level drive the overall strategic risk management process.

Typical Challenges When Moving Forward

As G&Ts decide to put in place the tools and process to do integrated strategic risk management, there are three challenges that they will need to address:

- **How do we get probability distributions for the risk factors?**
Developing appropriate probability distributions requires considerable thought because they are critical to developing credible risk analysis. For certain types of risks, such as unit outages, G&Ts usually have historical data that can be used to develop probability distributions. Data for other risks, such as

purchased power prices, can be obtained through power marketing affiliates or external databases. Judgment surfaces with regard to the type of curve to be used, e.g., lognormal. Lastly, a third type of risk, such as environmental capital expenditures or O&M, can be developed based on discussions among experts within the company. In all cases, these discussions are most effectively done in a workshop setting where there is live dialogue, "give and take," and finally, quantification of the probability distribution.

- **How will the existing detailed production costing tool fit in?** Detailed production costing tools typically use Monte Carlo risk capabilities for modeling unit outages, but do not cover all enterprise-wide risks. Many production models rely on other models to do risk analysis on load forecasting and fuel costs. In addition, since production costing models are not financial forecasting tools, they do not capture those items necessary for calculating net margin and rates. These items include fixed O&M, interest expense, debt financing, revenue requirements, existing rates, and depreciation. In most cases, these tools do not produce a balance sheet, so debt, equity, cash, and working capital are not captured. Additionally, since these tools are typically built in proprietary languages, they do not integrate with Excel-based risk packages and thus provide limited risk analytics. Despite these limitations, production costing tools are still very necessary for risk analysis, because they are needed to inform and validate the results of the integrated financial and risk model runs.

Net margin and rates provide better measures for quantifying risk and variability of financial performance, because they capture both the cost and the benefit of strategies.

- **What is the right financial measure to use?** Net margin and rates provide better measures for quantifying the risk and variability of financial performance as compared to other measures, such as gross margin, because they capture both the cost and the benefit of strategies. For example, the interest and depreciation costs of building a new plant are captured with net margin, but not gross margin. Using gross margin in this example would consider the benefit of the reduced exposure to purchased power from new capacity, but would ignore the cost. Also related to its more comprehensive view, net margin and rates capture the impact of non-operating activities, such as interest income and investments in power marketing and energy services companies. In addition, net margin and rates are measures that members can relate to ... and link to the budget. Lastly, since some G&Ts have fuel adjustment clauses to maintain the targeted net margin, it is not enough to look only at net margin—one must also consider the impact on rates.

By addressing these challenges, G&Ts develop a robust and credible risk analysis that is integrated into the budgeting and planning processes ... leading to thoughtful discussions at the senior level and the development of appropriate risk mitigation strategies.

Aiming First ... Then Pulling the Trigger

The events of the past couple years have made G&T senior teams much more aware of the benefits of managing risk—more stable and predictable rates for member cooperatives. The temptation, however, is to pull the trigger too early on developing and implementing risk mitigation strategies without quantifying the risks. Only by addressing the challenges and by having the tools and processes in place to first quantify risk, can G&Ts develop the proper strategies that explicitly manage the tradeoff between cost and risk.

Jim Pardikes

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Jim Pardikes has 20 years experience in consulting to the utility industry including electric and gas IOUs and G&Ts. His expertise includes strategic risk management, financial forecasting, and using analytical tools to develop strategies in the corporate, transmission, and energy marketing areas.

Dave Thompson

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Dave Thompson has 12 years consulting experience in the energy industry. His experience has been in the performance management, strategic planning, and portfolio risk management areas working with generation, trading, and energy services business units.

Greg Ridderbusch

gridderbusch@mcr-group.com
Greg Ridderbusch has 16 years of utility industry experience. He consults to G&T cooperatives, municipals, and IOUs. His expertise includes strategy and business planning, process improvement, performance management, and decision analysis.

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James Pardikes

Jim is a Senior Manager at MCR. He has 20 years experience consulting to the utility industry with particular expertise in developing business growth strategies. In recent years, Jim has integrated the use of strategic risk management concepts and analytical tools into client engagements for G&Ts and IOUs to support the business planning and forecasting process.

Prior to joining MCR, Jim was a Senior Manager in Accenture's energy practice. Jim was also a Vice President with CSC Planmetrics (now CSC Consulting) where he specialized in wholesale energy marketing and retail business strategy for utilities.

Sampling of Recent Engagements

Conducted a diagnostic of the current state of a G&T's strategic risk management process, including recommendations for improving its ability to quantify and manage enterprise-wide risk. The project included conducting interviews and meetings at the senior and mid-management levels to educate them on strategic risk management, and assessing the ability of the client's current modeling tools to do probabilistic risk analysis on key performance measures such as net margin, cash flow and rates. In subsequent phases, MCR and the client will be implementing MCR's Financial and Risk Strategy Tool (FRST™) to do strategic risk analysis on the two-year budget and the 20-year forecast.

Worked with an executive team of a G&T utility to analyze its earnings and cash flow at risk under the base case forecast and under various business growth strategies. Risk drivers and probability distributions for each asset group were identified and modeled using MCR's FRST™ in conjunction with a leading risk analysis tool. The results were presented to the Board as part of an overall directive to the executive team to establish an improved strategic risk management process.

Worked with the management team of a Transmission Business Unit of a midwestern electric utility to analyze the merits of forming an Independent Transmission Company (ITC) vs. directly joining an existing Regional Transmission Organization (RTO). The project used MCR's FRST™ to develop a reference case and analyze the benefits and risks of forming an ITC. Risk factors and probability distributions were modeled to analyze the range of start-up and operating costs. Based on the project's evaluation of economic and non-economic factors, the client chose to spearhead the formation of a new RTO.

Worked for a top 10 energy marketer to develop a marketing and sales plan linked to North American leadership aspirations. The analysis included a competitive and marketplace assessment including segmentation of the national wholesale and unbundled large retail gas and electric markets. To support energy trading and tolling initiatives, the plan concentrated on opportunities for customer partnerships that would provide "asset control" of pipeline capacity, storage and generation.

Worked with a top five gas trader and marketer to identify a value-creation strategy based on a new Customer Relationship Management (CRM) system. The reference case financial forecast was modeled in order to analyze the incremental impact of the new marketing approach. The new system and related account management processes are projected to increase origination and energy outsourcing deals by 25%, resulting in annual margin increases of $5 million.

Selected Clients

- Ameren
- American Transmission Company
- British Petroleum Gas and Power
- BC Hydro
- Deseret Power G&T
- Dairyland Power Cooperative
- KCP&L/Great Plains Energy
- Honeywell Energy Solutions
- NiSource
- OGE Energy
- PacifiCorp/Scottish Power
- Wisconsin Energy

Education

Jim received a Master of Business Administration in Finance and Marketing from Michigan State University and a Bachelor of Business Administration with an emphasis in Accounting from the University of Michigan.

White Papers, Articles

"You Can't Manage What You Don't Measure—Quantifying Risks for G&T Cooperatives," MCR White Paper, with Dave Thompson and Greg Ridderbusch, January 2004

"Risky Business—Communicating the G&T Budget and Rate Forecast to Members," MCR White Paper, with Greg Ridderbusch and Dave Thompson, September 2003

"Risk is Not a Four-Letter Word—Reflecting Risk in Planning and Forecasting for Cooperatives," MCR White Paper, with Dave Thompson and Dan Rupp, June 2003

"Where Else Can You Earn 14.5%—Time to Rethink Your Transmission Strategy," MCR White Paper, with Dean C. Maschoff, January 2003

"Down, But Not Out—Growing the Transmission Business Under the SMD," MCR White Paper with Nisha Shanbag, September 2002

"The 21st Century Transmission Company ... Moving Ahead in Uncertain Times," MCR WhitePaper, with Nisha Shanbag, April 2002

"Don't Slice (and Dice) to the Bone," GridWeek, March 22, 2002

"Regulatory Uncertainty? One Sure Bet—Manage Transmission as a Business," MCR White Paper, with Dean C. Maschoff and Nisha Shanbag, January 2002

"Get Ready or Get Serious—Strategic Response to FERC's Code of Conduct Proposal," MCR White Paper, with Dean C. Maschoff, December 2001

David E. Thompson

Dave is a Senior Manager at MCR, with over ten years of management consulting experience. In his career, he has developed significant expertise in crafting innovative business solutions and sophisticated analytics in connection with strategic planning and performance management initiatives, focusing on assessment of market opportunities and competitive dynamics.

Prior to joining MCR, Dave's previous work experience includes CSC Planmetrics (now CSC Consulting), Dresser Industries and Johnson Controls.

Recent Engagements

Worked with a major diversified utility to develop a portfolio optimization plan. The project utilized MCR's strategic financial model to support the client's strategic planning and long-term goal setting process. MCR reviewed the five-year business plans for all business units to identify key business drivers and linkages across the company. The analysis included scenario development and Monte Carlo risk analysis for the portfolio of business units. The results were used to set long-term earnings targets and support decisions around the optimal combination of business units to minimize risk for various levels of expected return.

Worked with a large G&T cooperative to incorporate risk analysis in the development of long-term strategies to address future resource needs. Project included identification of risks, quanitification of risks and development of assessment tools to identify potential outcome distributions of potential resource options. The results of the project were incorporated in management's decision on near-term investment of a set of new resources.

Worked with a G&T cooperative to develop a risk-based analysis of key financial metrics. The project included development and quantification of risks through client workshops and research. An overall financial model was developed to incorporate risk distributions as key inputs in order to run simulations on the overall financials. Key output variables included net margin, member rates, TIER and DSC targets. The analysis was incorporated into the development of the overall strategic plan and helped drive the development of new risk mitigation strategies.

Worked with a large diversified utility with both U.S. and international investments to develop processes and tools to forecast and manage enterprise-wide cash flow. The company was experiencing a liquidity crisis and suffered from inaccurate income, balance sheet and cash flow forecasts. In conjunction with the client team, we developed processes and tools to better mirror actual financial transactions in the forecast. The project resulted in more accurate forecasts and tools that help management optimize their decisions related to debt, asset sales and other liquidity events.

Worked with a large electric utility to develop and implement a performance management system that "monetized" key operating measures for plant operations, fuel supply and dispatch/trading business units. Also developed related performance measurement processes, metrics, and targets for the business units linked to corporate income targets.

Selected Clients

Ameren	NiSource
Alliant Energy	Pacificorp
Cinergy	PG&E
DTE Energy	ProLiance Energy
Enbridge	Vectren
FirstEnergy	VerticalNet
Great River Energy	Xcel Energy

Education

Dave has a Master of Business Administration from the University of Chicago, graduating with honors. He received his Bachelor of Science degree in Mechanical Engineering from the University of Notre Dame.

White Papers, Articles

"You Can't Manage What You Don't Measure—Quantifying Risks for G&T Cooperatives," MCR White Paper, with Dave Thompson and Greg Ridderbusch, January 2004

"Risky Business—Communicating the G&T Budget and Rate Forecast to Members," MCR White Paper, with Greg Ridderbusch and Jim Pardikes, September 2003

"Earnings at Risk and Wall Street Communication," MCR White Paper, with Dean C. Maschoff, September 2003

"Do You Know What's In Your Financial Forecast," MCR White Paper, with Deb Whitaker, July 2003

"Risk is Not a Four-Letter Word—Reflecting Risk in Planning and Forecasting for Cooperatives," MCR White Paper, with Jim Pardikes and Dan Rupp, June 2003

"Is Nothing Sacred? Perspectives on Duke's Perfect Storm and Earnings at Risk," MCR White Paper, with Dean C. Maschoff, October 2002

"This Year Will Different—A New Perspective on Strategic Planning," MCR White Paper, with Dean C. Maschoff, July 2002

"Something Old, Something New—How to Develop Strategies That Manage Risk, Create Value, and Grow Earnings," MCR White Paper, with Dean C. Maschoff and Deb Whitaker, July 2002

"Growth, *Still* A Management Imperative," MCR White Paper, with Nilsa Shepsle, April 2002

"Review of 2001: Maintaining Shareholder Value," MCR White Paper, with Nilsa Shepsle, January 2002

"Generating Plant Sales and Acquisitions: Who's Doing What, and Why", Public Utilities Fortnightly, with Dean Maschoff and Jim Pardikes, et al., February 15, 1999

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Corporate and Financial

Strategic Risk Analysis

Volatile fuel prices...*Uncertain load growth*...Unknown regulatory landscape...Unpredictable returns from off-system power sales

You don't have to be a trading organization to face these risks. Diverse energy businesses also must tackle unknowns and risks from a variety of sources...all of which lead to financial uncertainty. It's scary to think that one major event could threaten your earnings projection or rate forecast, forcing you to tell investors or cooperative members that you were wrong.

Strategic Risk Analysis provides information on the probability of achieving key measures—what-if analysis and single-point estimates are no longer enough. The marketplace demands something more robust. Strategic Risk Analysis allows you to identify key business drivers and the risks associated with these drivers. You will understand the impacts of risk. This knowledge will help you define appropriate strategies to manage risk. At the end of the day, you will have:

- Better management of downside risk because you highlighted exposures
- Enhanced communications to stakeholders such as the Board, Members, Stock holders, Wall Street, Credit Agencies, Lenders on the inherent volatility in the business
- Improved decision-making through integration of risk factors into economic evaluations of investments, e.g., resource additions
- Better integration of risk into the planning process

MCR is the leading Strategic Risk Management consultancy to the energy industry. Our knowledge of risks, tools, probability data, and the company-wide risk management process provides complete risk management solutions. This allows our clients to better evaluate cost-risk tradeoffs and develop appropriate risk mitigation strategies.

Whitepapers & Articles

"You Can't Manage What You Don't Measure. Quantifying Risks and Addressing Challenges for G&T Cooperatives" author--Jim Pardikes, Dave Thompson, Greg Ridderbusch.

"Risky Business. Communicating the Budget and Rate Forecast to Members" author--Jim Pardikes, Greg Ridderbusch, and Dave Thompson

"Risk Is Not A Four-Letter Word: Reflecting Risk in Planning and Forecasting" author--Jim Pardikes, Dave Thompson, Dan Rupp

"Sarbanes-OxleyShould Motivate Utilities to Improve. Don You Know What's In Your Financial Forecast?" author--Dave Thompson

"Earnings At Risk and Wall Street Communications" author--Dean Maschoff, Dave Thompson

"Understanding Earnings Volatility. A Portfolio Risk Analysis Approach" author--Len Rubin

Case No. 2012-00535
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MCR—About Us

Leonard R. Rubin

Len Rubin is a highly recognized thought leader in energy industry performance management. More than two dozen investor-owned and cooperative clients have improved their financial performance using the budgeting and financial management reporting systems Len has instituted. Len offers a strong combination of finance and accounting acumen, knowledge of information technology solutions, and a broad understanding of his clients' issues and needs.

A founding partner of MCR, Len has 20 years of energy, IOU, and cooperative consulting experience. Prior to MCR, Len was an officer with CSC Planmetrics, a consulting and technology firm serving the utility industry. Len received his Masters of Business Administration degree in finance from the University of Chicago. He graduated from the University of Pennsylvania with a Masters of Arts and Bachelor of Arts degree in regional science.

Len's client focus includes:

- Transformations of CFO organizations to better meet the challenges of tomorrow
- Corporate performance management
- Development of financial management information systems
- Creation of new visions and operating policies for shared services organizations
- Strategic growth strategy development that refocuses a company's competitive position in the marketplace and generates additional revenue for the company
- New business launches involving market and internal core competency assessments and business plan and financial forecast development

Len is a frequent speaker at A.G.A./EEI conferences and meetings. He is a staff member of the annual Public Utility Topics in Budgeting Course. Len also authored numerous papers on performance-based management and how to profitably grow new business.

FRANK CRAIG

Leonard R. Rubin

Recent White Papers

"Sarbanes-Oxley: the Morning After At Last... A Real Chance to Transform the Organization" author–Len Rubin

"Understanding Earnings Volatility, A Portfolio Risk Analysis Approach" author–Len Rubin

"Managing Performance to Today's Utility: Why Balance Isn't Enough" author–Len Rubin

"Realizing Value From Your ERP System, Is There Any Hope?" author–Len Rubin, Frank Craig

Case No. 2012-00535
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Pages 29-73 of this attachment have been omitted from the public filing. They have been provided under a petition for confidential treatment.

January 12, 2006
Enterprise Risk Management
Kickoff Meeting and Interviews
Proposed Schedule

TIME FRAME	ACTIVITY	PARTICIPATENTS
8:00-9:00	Presentation by John Sturm & MCR team	Mike Core and all VP's
9:00-10:00	Interview with John and MCR team	Mike Core & Travis Housley
10:00-11:00	Interview with John and MCR team	Bill Blackburn
11:00-12:00	Interview with John and MCR team	David Spainhoward
13:00-14:00	Staff Meeting	Mike Core, Paula Mitchell & all VP's
14:00-15:00	Interview with John and MCR team	David Crockett & Travis Housley
15:00-16:00	Interview with John and MCR team	Richard Beck
16:00-17:00	Interview with John and MCR team	James Haner

Enterprise Risk Management Questionnaire
Big Rivers Project
January 2006

Overview:

1. What are the biggest changes affecting you as a result of the prospective change in business?

2. What economic or other factors could influence the attractiveness of this deal?

3. What areas of risk are you directly responsible for during the transition and under the prospective on-going operation?

4. Are there areas of risk that you feel are not adequately addressed with existing staff?

Policies and Procedures:

5. Are you familiar with any written policies and procedures that govern your current risk management activities?

6. What additional policies and procedures would you expect to need under the prospective new business structure?

Tools:

7. Do you use tools or other software in performing risk management related duties, and if so what are they?

8. How satisfactory is each tool that you use and do you feel the same tools will be adequate under your prospective business structure?

9. Do you have suggestions for improvements to the tools themselves?

10. Do you feel that there are tools that are needed but not available at this time, and if so what?

Process:

11. Under the prospective business structure, do you feel that you will be dependent on any others (staff, departments, or APM) for data or information that support your risk management tasks, and if so, what?

12. Are there any process/procedural related issues that you feel will need improvement?

Education/Skills:

13. What type of staff support will you expect to need under the prospective business structure?

14. Have you received sufficient training on performing your risk management duties as it relates to the prospective business structure?

15. What additional training would be useful in performing your tasks?

Attachment 5 to AG 2-7 has been omitted from the public filing. It has been provided under a petition for confidential treatment.

James Pardikes

Jim is a Senior Manager at MCR. He has 20 years experience consulting to the utility industry with particular expertise in developing business growth strategies. In recent years, Jim has integrated the use of strategic risk management concepts and analytical tools into client engagements for G&Ts and IOUs to support the business planning and forecasting process.

Prior to joining MCR, Jim was a Senior Manager in Accenture's energy practice. Jim was also a Vice President with CSC Planmetrics (now CSC Consulting) where he specialized in wholesale energy marketing and retail business strategy for utilities.

Sampling of Recent Engagements

Conducted a diagnostic of the current state of a G&T's strategic risk management process, including recommendations for improving its ability to quantify and manage enterprise-wide risk. The project included conducting interviews and meetings at the senior and mid-management levels to educate them on strategic risk management, and assessing the ability of the client's current modeling tools to do probabilistic risk analysis on key performance measures such as net margin, cash flow and rates. In subsequent phases, MCR and the client will be implementing MCR's Financial and Risk Strategy Tool (FRST™) to do strategic risk analysis on the two-year budget and the 20-year forecast.

Worked with an executive team of a G&T utility to analyze its earnings and cash flow at risk under the base case forecast and under various business growth strategies. Risk drivers and probability distributions for each asset group were identified and modeled using MCR's FRST™ in conjunction with a leading risk analysis tool. The results were presented to the Board as part of an overall directive to the executive team to establish an improved strategic risk management process.

Worked with the management team of a Transmission Business Unit of a midwestern electric utility to analyze the merits of forming an Independent Transmission Company (ITC) vs. directly joining an existing Regional Transmission Organization (RTO). The project used MCR's FRST™ to develop a reference case and analyze the benefits and risks of forming an ITC. Risk factors and probability distributions were modeled to analyze the range of start-up and operating costs. Based on the project's evaluation of economic and non-economic factors, the client chose to spearhead the formation of a new RTO.

Worked for a top 10 energy marketer to develop a marketing and sales plan linked to North American leadership aspirations. The analysis included a competitive and marketplace assessment including segmentation of the national wholesale and unbundled large retail gas and electric markets. To support energy trading and tolling initiatives, the plan concentrated on opportunities for customer partnerships that would provide "asset control" of pipeline capacity, storage and generation.

Worked with a top five gas trader and marketer to identify a value-creation strategy based on a new Customer Relationship Management (CRM) system. The reference case financial forecast was modeled in order to analyze the incremental impact of the new marketing approach. The new system and related account management processes are projected to increase origination and energy outsourcing deals by 25%, resulting in annual margin increases of $5 million.

Selected Clients

Ameren	KCP&L/Great Plains Energy
American Transmission Company	Honeywell Energy Solutions
British Petroleum Gas and Power	NiSource
BC Hydro	OGE Energy
Deseret Power G&T	PacifiCorp/Scottish Power
Dairyland Power Cooperative	Wisconsin Energy

Education

Jim received a Master of Business Administration in Finance and Marketing from Michigan State University and a Bachelor of Business Administration with an emphasis in Accounting from the University of Michigan.

White Papers, Articles

"You Can't Manage What You Don't Measure—Quantifying Risks for G&T Cooperatives," MCR White Paper, with Dave Thompson and Greg Ridderbusch, January 2004

"Risky Business—Communicating the G&T Budget and Rate Forecast to Members," MCR White Paper, with Greg Ridderbusch and Dave Thompson, September 2003

"Risk is Not a Four-Letter Word—Reflecting Risk in Planning and Forecasting for Cooperatives," MCR White Paper, with Dave Thompson and Dan Rupp, June 2003

"Where Else Can You Earn 14.5%—Time to Rethink Your Transmission Strategy," MCR White Paper, with Dean C. Maschoff, January 2003

"Down, But Not Out—Growing the Transmission Business Under the SMD," MCR White Paper with Nisha Shanbag, September 2002

"The 21st Century Transmission Company ... Moving Ahead in Uncertain Times," MCR WhitePaper, with Nisha Shanbag, April 2002

"Don't Slice (and Dice) to the Bone," GridWeek, March 22, 2002

"Regulatory Uncertainty? One Sure Bet—Manage Transmission as a Business," MCR White Paper, with Dean C. Maschoff and Nisha Shanbag, January 2002

"Get Ready or Get Serious—Strategic Response to FERC's Code of Conduct Proposal," MCR White Paper, with Dean C. Maschoff, December 2001

David E. Thompson

Dave is a Senior Manager at MCR, with over ten years of management consulting experience. In his career, he has developed significant expertise in crafting innovative business solutions and sophisticated analytics in connection with strategic planning and performance management initiatives, focusing on assessment of market opportunities and competitive dynamics.

Prior to joining MCR, Dave's previous work experience includes CSC Planmetrics (now CSC Consulting), Dresser Industries and Johnson Controls.

Recent Engagements

Worked with a major diversified utility to develop a portfolio optimization plan. The project utilized MCR's strategic financial model to support the client's strategic planning and long-term goal setting process. MCR reviewed the five-year business plans for all business units to identify key business drivers and linkages across the company. The analysis included scenario development and Monte Carlo risk analysis for the portfolio of business units. The results were used to set long-term earnings targets and support decisions around the optimal combination of business units to minimize risk for various levels of expected return.

Worked with a large G&T cooperative to incorporate risk analysis in the development of long-term strategies to address future resource needs. Project included identification of risks, quanitification of risks and development of assessment tools to identify potential outcome distributions of potential resource options. The results of the project were incorporated in management's decision on near-term investment of a set of new resources.

Worked with a G&T cooperative to develop a risk-based analysis of key financial metrics. The project included development and quantification of risks through client workshops and research. An overall financial model was developed to incorporate risk distributions as key inputs in order to run simulations on the overall financials. Key output variables included net margin, member rates, TIER and DSC targets. The analysis was incorporated into the development of the overall strategic plan and helped drive the development of new risk mitigation strategies.

Worked with a large diversified utility with both U.S. and international investments to develop processes and tools to forecast and manage enterprise-wide cash flow. The company was experiencing a liquidity crisis and suffered from inaccurate income, balance sheet and cash flow forecasts. In conjunction with the client team, we developed processes and tools to better mirror actual financial transactions in the forecast. The project resulted in more accurate forecasts and tools that help management optimize their decisions related to debt, asset sales and other liquidity events.

Worked with a large electric utility to develop and implement a performance management system that "monetized" key operating measures for plant operations, fuel supply and dispatch/trading business units. Also developed related performance measurement processes, metrics, and targets for the business units linked to corporate income targets.

Selected Clients

Ameren	NiSource
Alliant Energy	Pacificorp
Cinergy	PG&E
DTE Energy	ProLiance Energy
Enbridge	Vectren
FirstEnergy	VerticalNet
Great River Energy	Xcel Energy

Education

Dave has a Master of Business Administration from the University of Chicago, graduating with honors. He received his Bachelor of Science degree in Mechanical Engineering from the University of Notre Dame.

White Papers, Articles

"You Can't Manage What You Don't Measure—Quantifying Risks for G&T Cooperatives," MCR White Paper, with Dave Thompson and Greg Ridderbusch, January 2004

"Risky Business—Communicating the G&T Budget and Rate Forecast to Members," MCR White Paper, with Greg Ridderbusch and Jim Pardikes, September 2003

"Earnings at Risk and Wall Street Communication," MCR White Paper, with Dean C. Maschoff, September 2003

"Do You Know What's In Your Financial Forecast," MCR White Paper, with Deb Whitaker, July 2003

"Risk is Not a Four-Letter Word—Reflecting Risk in Planning and Forecasting for Cooperatives," MCR White Paper, with Jim Pardikes and Dan Rupp, June 2003

"Is Nothing Sacred? Perspectives on Duke's Perfect Storm and Earnings at Risk," MCR White Paper, with Dean C. Maschoff, October 2002

"This Year Will Different—A New Perspective on Strategic Planning," MCR White Paper, with Dean C. Maschoff, July 2002

"Something Old, Something New—How to Develop Strategies That Manage Risk, Create Value, and Grow Earnings," MCR White Paper, with Dean C. Maschoff and Deb Whitaker, July 2002

"Growth, *Still* A Management Imperative," MCR White Paper, with Nilsa Shepsle, April 2002

"Review of 2001: Maintaining Shareholder Value," MCR White Paper, with Nilsa Shepsle, January 2002

"Generating Plant Sales and Acquisitions: Who's Doing What, and Why", Public Utilities Fortnightly, with Dean Maschoff and Jim Pardikes, et al., February 15, 1999

Attachment 7 to AG 2-7 is provided on the CONFIDENTIAL CD accompanying these responses.

Notes from 3/6/06 Member CEO conference call 1pm to 3pm
Participants: Mark Bailey, Burns Mercer, Kelly Nuckols, Jack Gaines, John Sturm, Jim Pardikes
Agenda:

1. Board presentation clarifications
2. Review/discuss slide 5 (Illustrative member rate comparison)
3. Review/discuss slide 7 (risk prioritization slide)
4. Key discussion items
    a) Risk tolerance
    b) Organizational
    c) Economic development
    d) Fuel procurement
    e) Potential smelter differences in risk tolerance
5. Other
6. Board retreat draft presentation outline/objectives

CEO comments and discussion:

1. Board presentation clarifications – No clarifications requested
2. Slide 5 – member rate comparison
    a. Need to be able to better see difference between upside and downside potential in rates. It seems they should not be symmetrical. (Discussed tools that need to be put in place to produce better analytics)
    b. Surprised that forecasted rates and LG&E contract rates are not closer together. (Discussed where the "value" chart came from and that on-going forecasting capabilities may be available to further quantify rates, rate variability, and changes in assumptions that can impact the overall rate)
    c. We discussed how risks can impact year to year rate uncertainty (e.g. coal price risk) and how risks can impact rate levels (e.g. load growth)
3. Slide 5 – top tier risk priorities and risk dictionary discussions
    a. Comment that pension liability and health care could be viewed as higher priority than tier 3. Discussion ensued about the incremental impact of changes to these items are not as great as other risks. Also discussed that they are a function of the hiring/staff retention risk that is a tier 1 risk, and that together these are all part of the "organizational" strategic issue. This led to discussion about correlations between risks and care that needed to be taken in prioritizing some risks so as to not double count.
    b. Comment that access to capital/credit should be a top risk. We explained that we assume that this initial issue is resolved as a condition of the unwind and that this project addresses the post unwind, so therefore it is not a tier 1 risk.
    c. Comment that transmission availability should be a tier 2 risk due to that lack of ability to manage. BREC is able to manage direct connects more than it can manage the broader region. Understood that real risk is beyond the interconnects. APMCR agreed to discuss with staff to determine if it should be moved horizontally to Tier 2.

d. Comment on why "member contracts" is not a risk. We explained that extending the member contracts is a condition of closing, therefore it is not a top tier risk We agreed to add the issue under risk "W" –KPSC approval of unwind to ensure this risk is still captured. There was a comment that their co-op had some concern about signing a 35-year contract. We explained the tie between financing, credit ratings, and length of member contracts. This may be something to isolate and discuss further with the member – unfortunately it was clear who brought up the issue.
e. They indicated that "co-op status" should be removed as a risk since the legislation recently passed. We agreed to remove if no staff objects or outstanding issues exist.
f. Risk dictionary discussions included:
g. Comment made on why a "preference for a single bargaining unit contract" on risk item Z. They felt diversity of multiple contracts with varied timing had some advantages. We agreed to further address with staff and clarify.
h. Risk "AW" strategy on getting members to post credit on behalf of the smelters was discussed. It was felt that the smelter contract required LC's for 3 months and did not understand why additional security may be needed.
i. It was the belief that a risk response strategy for Risk "AL" of establishing a cash sinking fund would probably not be acceptable to the KPSC. It is not acceptable to the KPSC at the distribution co-op level in their rate making.

4. Key discussion items
    a. Risk tolerance
        i. Members generally want rate stability even if a slight premium is paid.
        ii. If the forecast has a significant rate increase in it (e.g., expiring contracts) , then as long as it is predictable and understood it may be acceptable. They indicated a desire to be able to proactively communicate and prepare for predicted rate increases.
    b. Organizational
        i. It was overviewed as a big issue involving many risks. There was hardly any comments or discussion from the CEO's on this topic.
    c. Economic development (Increasing impact on rates)
        i. The issue was discussed and lead to the following outstanding questions:
            1. How much do the smelter contracts reduce the impact of rate increases on the remaining native load? If so, is there a difference in short term and long term impacts?
            2. Would the KPSC allow the BREC current rate structure for new loads to be continued? Or would they allow some policy to control/mitigate certain load growth?

ii. A comment was made that the Board is used to excess sales margins and their strategy is to maintain top 10% in lowest retail rates. Does this mean control growth to maintain rate goal?
iii. Discussion ensued that load growth is best influenced through rates.
iv. Agreement that economic development is an issue that requires further discussion among the member CEOs and the Board.

d. Fuel procurement was discussed broadly
    i. There was some discussion about breaking down the risks and impacts on rate to a component level (show the fuel rate and the base rate). More discussion ensued about the tools to quantify risk on the whole and the component level.
    ii. Many of the risk tolerance issues used fuel procurement (and economic development) as the example. Therefore we discussed hedging levels and timeframes, policies to support and that these items result in the fuel procurement strategy. We took time to review how fuel procurement would be used as the example for an ERM process at the retreat.

e. Smelter differences in risk tolerance and key decision drivers.
    i. A comment that it would not be a surprise if the smelters had a difference in risk tolerance was made. We also explained that key decision drivers could impact differences in hedging.
    ii. Discussion ensued about differences in strategy using the fuel procurement example. For example, forward fuel prices could rise 10% while forward aluminum prices simultaneously rise 20%. This may lead to the smelters desiring to lock in 100% of their coal price risk (while locking in aluminum sales prices and margins simultaneously). At the same time, coal price increases could lead BREC to hedge at the low end of their policy creating a difference in desired hedging execution.
    iii. Impacts of differences in risk tolerance and strategy could create an administrative and contractual challenge. It could also lead to a policy at the board level of what type of customers could have input into hedging components of their power supply. May need to further address.

5. Board retreat presentation
    a. We reviewed the outline of the presentation/objectives. They were comfortable with the approach.
    b. A comment was made that ERM is a new approach with the Board. We explained that additional sessions will be necessary to educate the board and walk through the policy development process.
    c. They requested a copy of the presentation in advance of the retreat.
    d. We agreed to discuss with Mike Core, and if acceptable, send them the presentation with a target date of Tuesday afternoon, March 14.

Attachment 9 to AG 2-7 is provided on the CONFIDENTIAL CD accompanying these responses.

Attachment 10 to AG 2-7 is provided on the CONFIDENTIAL CD accompanying these responses.

Paula Mitchell

From: Mark Bailey
Sent: Friday, April 30, 2010 9:06 AM
To: Albert Yockey; Bob Berry; David Crockett; James Haner; Jennifer Keach; Mark Hite
Cc: Bill Blackburn; Paula Mitchell
Subject: FW: Updated East Kentucky table
Attachments: East Kentucky Management Audit Table.doc

Attached you will find a summary Paula and I have put together of the important points as I see them from the PSC management audit of EKPC. The right hand column labeled "Big Rivers Activity" summarizes where I believe Big Rivers is (e.g. our current "status") regarding each of these items. The basic approach in completing this column summary consists of one of 4 situations. They are:

Big Rivers is already "doing"
Big Rivers is in the "process of doing"
Big Rivers "needs to consider doing"
Issue is "not applicable" to Big Rivers

In addition to listing these basic status items, in a few cases I have some extra verbage to explain the status rating. I'd like for those of you who have not already done so to look this over. If you have a different view of the status evaluation I have made, I'd like for you to let me know along with a brief explanation to support your opinion. Your "brief explanation" needs to be of a nature that Paula can put your explanation in the appropriate block of the chart to explain our rating without widening the section of the chart for that particular item.

Bill Denton intends to devote the upcoming Board meeting Thursday night Work Session to a discussion of the EKPC audit. I thought I would provide this summary to the Board prior to that night to possibly assist and track efforts the Board may decide are needed as a result of those discussions.

I'd like your feedback by the end of the day on Tuesday, May 4th so Paula can make any changes so the material can then sent to the Board to allow sufficient time for their review ahead of the Thursday meeting.

Thanks, Mark

From: Paula Mitchell
Sent: Friday, April 30, 2010 8:47 AM
To: Mark Bailey
Subject: Updated East Kentucky table

Paula Mitchell

From: Mark Bailey
Sent: Monday, April 26, 2010 10:37 AM
To: Albert Yockey; Bill Blackburn; Bob Berry; David Crockett; James Haner; Jennifer Keach; Mark Hite; Paula Mitchell
Subject: EKPC Management Audit

I have read the PSC's management audit report of EKPC and was gratified to see a number of the issues raised involved things we are already doing or in the process of undertaking. There were some items included that we should focus on. The following list caught my eye.

- Whistleblower Policy – Al, I'm not sure we have a separate policy, but we have elements that such a policy might encompass in place as part of another policy or through other means, e.g. how to report concerns though the Code of Conduct policy. We also have a separate independent ethics line employees can call to report concerns. Jennifer, we may need to once again internally publicize this line's existence and how to use it.
- Strategic Planning and KPI reporting received some emphasis in the audit report. We have a plan that has been discussed with the board and employees and a copy is posted on the intranet. Al, We need to consider updating it and getting a more formal KPI reporting mechanism in place. Bill, Does the Board have access to our intranet?
- Supply Planning received some mention. Bill, we should have both Mike Mattox and Russ Pogue review and take to heart the items included in the report on Supply Planning and DSM.
- Outage Insurance - Bill/ Mark/James, we need to look at this. Please get together and decide who will take the lead in looking into this. ACES may be able to help in this regard.
- Capital Budgeting & Spending – The report addressed EKPC's practice of budgeting way more for capital than what they historically spent. The report suggested that variances consistently greater than 5% were unacceptable. We need to make note of this issue.
- Board Policy – We are currently focused on updating Board policies and looking at what others are doing in that regard. Al. That effort needs to continue.
- Board Recommendations- EKPC management was criticized for not offering the Board options in dealing with various issues with risks, pro's & con's of the options discussed with the Board. All, We need to be mindful of this concern.

Each of you need to read this report and make sure members of your staff who have responsibility for functions mentioned in the report read the appropriate sections as well. David, specifically, the matters involving transmission expansion and interconnection should be reviewed by the appropriate personnel. Bill, those individuals involved with buying and selling power should review the sections of the report that deal with buying vs. generating power when it makes economic sense to do so.

Thanks, Mark

EAST KENTUCKY MANAGEMENT AUDIT
May 5, 2010
Mark Bailey – highlights and comments

ITEM NO.	SECTION	PAGE NO.	EXCERPT FROM REPORT	BIG RIVERS ACTIVITY
1.	II. Strategic Planning A. Background	9	EKPC does not engage in a regular, structured, and consistent strategic planning process. Management also does not regularly prepare a "strategic plan" document for board input and review, nor is such a document made available to employees for use in guiding their activities.	Doing – update frequency an open question Al
2.	II. Strategic Planning A. Background	9	A corporate scorecard identified several key performance measures; however, Liberty could find no follow-up documents indicating that this general plan became a source of guidance, reference, and measurement in substantial ways.	Process of doing get methodology going
3.	II. Strategic Planning B. Findings 2. NRECA Report	10	…(Supply planning) efforts were very limited in the scope of alternatives considered.	Process of doing Bill - met w/ members twice
4.	II. Strategic Planning B. Findings 2. NRECA Report	10	Transmission as an alternative to new supply received little if any consideration.	Doing David C. - Request from Power Supply Mattox
5.	II. Strategic Planning B. Findings 2. NRECA Report	11	NCG was also critical of the EKPC power supply functions: • EKPC's transmission system was not robust enough for effective energy transfers, and current plans do not eliminate these concerns, • EKPC lacked a robust integrated resource planning process	Process of doing Mattox - supply side Crockett -
6.	II. Strategic Planning B. Findings 2. NRECA Report	12	Risk management was not well organized or coordinated, and EKPC did not follow a hedging strategy proposed by the Alliance for Cooperative Energy Services (ACES or ACES Power Marketing)	Doing - Al

EAST KENTUCKY MANAGEMENT AUDIT

May 5, 2010

Mark Bailey – highlights and comments

ITEM NO.	SECTION	PAGE NO.	EXCERPT FROM REPORT	BIG RIVERS ACTIVITY
7.	II. Strategic Planning B. Findings 2. NRECA Report	12	EKPC had no operating contingency plan for the loss of a baseload unit.	Need to consider doing – doing to some extent as part of reserve sharing effort.
8.	II. Strategic Planning C. Conclusions, 1.	14	The NorthStar initiative has inappropriately focused EKPC on cost cutting as the primary and most important strategic program. Cost control is important, but NorthStar has diverted management's focus and limited resources from more critical strategic issues, such as EKPC's financial health and performance, its lack of access to power markets, and its unbalanced power supply portfolio.	Not applicable – different NorthStar Focus different: meet financial obligations
9.	II. Strategic Planning C. Conclusions, 2.	15	Management has not put a sufficient priority on "making the plan happen." Liberty's interviews with EKPC management personnel did not reveal the necessary sense of urgency to complete action plans called for by the planning effort.	Process of doing
10.	II. Strategic Planning C. Conclusions, 2.	15	Nevertheless, a focus on making and executing action plans remains critical. It is important that attention return to the need to assure that plans and strategies that are now already getting stale get updated, that action plans become established to address revised strategies, that accountability for executing plans be clear and enforced, that progress be tracked, and that there be a process for continually re-evaluating strategies and plans in light of what one can expect to be continued change and development in the power supply world in which EKPC must operate and compete successfully.	Process of doing Analyst to prepare template

Talked w/ om & EK

may nee to adju NorthSt

EAST KENTUCKY MANAGEMENT AUDIT

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Mark Bailey – highlights and comments

ITEM NO.	SECTION	PAGE NO.	EXCERPT FROM REPORT	BIG RIVERS ACTIVITY
11.	II. Strategic Planning C. Conclusions, 3.	16	However, EKPC has not yet evaluated crucial issues regarding major transmission investments and ISO membership and whether the benefits from market power transactions override the costs involved.	Process of doing Smelters agreement Sectron tie miso
12.	III. Finance and Performance Management B. Findings, 4.	21	The timing of expenditures on projects tends to slip from year to year, routinely causing large under-spends from the approved capital budget. The financial managers also noted that the board generally does not consider under-spending the budget to be a problem.	Process of doing Projects
13.	III. Finance and Performance Management B. Findings, 5.	21	EKPC tracks its performance compared to benchmarks or market information where available.	Doing in generation and in process of doing in other areas.
14.	III. Finance and Performance Management B. Findings, 6	24	Liberty's request for EKPC's analysis of these alternatives generated the response that the cooperative does not perform its own analysis on financing proposals such as sale/leasebacks.	Process of doing
15.	III. Finance and Performance Management B. Findings, 7.	24	The NCG report found significant weaknesses in EKPC's planning for addressing the consequences of generating unit outages (unit outage insurance). James - provide description	Need to consider doing - are in the process of obtaining outage insurance quotes for long-term loss and we are tracking the value of lost opportunities when generation units are out of service

looking for coverages in 2011

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ITEM NO.	SECTION	PAGE NO.	EXCERPT FROM REPORT	BIG RIVERS ACTIVITY
16.	III. Finance and Performance Management C. Conclusions, 1.	25	EKPC management has failed to establish an optimal equity level target or credit rating goals, anticipating rejection by the board of directors of the need for a more conservative approach to financial security.	Equity target - Need to consider doing Credit rating – doing Mark Hite
17.	III. Finance and Performance Management C. Conclusions, 4.	27	EKPC did not in the past exhibit significant concern about its ability to obtain financing for a huge capital program that would be difficult in corporate financial markets, especially with EKPC's poor financial performance.	Doing Very focused
18.	III. Finance and Performance Management C. Conclusions, 5.	27	EKPC has under-spent its approved capital budget by 34 to 50 percent in each of the last four years. This poor performance indicates deficiencies in both capital planning and in management accountability for budget variances.	Process of doing
19.	IV. Asset Mix and Power Supply A. Background	29	Apart from the question of fuel source, EKPC and its members have concentrated on a build/own/operate strategy, and, again, a strategy that has served members well in the past. This build/own/operate strategy, however, is now viewed as significantly more risky in recent years, as portfolio diversification has become an increasingly important value to power suppliers.	Not applicable – not building generation – plan is to avoid need to build/buy for as long as possible

EAST KENTUCKY MANAGEMENT AUDIT

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ITEM NO.	SECTION	PAGE NO.	EXCERPT FROM REPORT	BIG RIVERS ACTIVITY
20.	IV. Asset Mix and Power Supply B. Findings, 1.	30	Such arrangements can take the form of joint plant ownership or a commitment to purchase a portion of the plant output, for example. Partnering with other enterprises (e.g., investor-owned utilities or other G&Ts) may allow larger and more efficient generating units that lower capacity and energy costs for all participants. Partnerships can also spread the ownership risks among the participants, mitigate some portions of risk through purchase power agreements, and permit optimal choices from among those who can best serve design, construction, and operations roles. A key component to partnering is spreading the ownership of risk among financially stable partners.	Doing
Remember 22.	IV. Asset Mix and Power Supply B. Findings, 3.	31	The 2009 IRP included demand-side management (DSM) as a resource, growing its contribution to 300 MW over 15 years.	Process of doing
23.	IV. Asset Mix and Power Supply B. Findings, 3.	31	EKPC engaged an industry consultant, who reviewed and recommended small changes in the assumptions used in the IRP analysis.	~~Process of~~ doing GDS
24.	IV. Asset Mix and Power Supply B. Findings, 4.	31	It has not focused on the promotion of economical exchanges of power with its neighboring system.	Doing Bill
25.	IV. Asset Mix and Power Supply B. Findings, 5.	32	The "economic dispatch" of the EKPC system did not regularly include power supply from outside sources.	Doing
26.	IV. Asset Mix and Power Supply B. Findings, 5.	33	EKPC could also pursue agreements with regional power suppliers to provide back-up capacity to each other to mitigate the risk of unplanned unit outages.	Process of doing Talked w/ OMU EKPC

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ITEM NO.	SECTION	PAGE NO.	EXCERPT FROM REPORT	BIG RIVERS ACTIVITY
27.	IV. Asset Mix and Power Supply C. Conclusions, 3.	34	Good business practice requires executives of all companies, especially capital-intensive power suppliers, to know the approximate value of each of their major facilities or asset classes.	Need to consider doing
28.	IV. Asset Mix and Power Supply C. Conclusions, 5.	35	When asked about investing in and strengthening the transmission system to allow for additional purchased power or exchanges, EKPC noted that there had not been in the last five years any requests of the transmission planning staff to analyze transmission system capability "for specific power imports into the EKPC System."	Doing Touched in Strategic planning AI – find goal that address this
29.	IV. Asset Mix and Power Supply C. Conclusions, 5.	35	EKPC has made 345 kV additions based on improving reliability. Liberty concluded that, through the present, EKPC efforts to strengthen its transmission system have focused on reliability, without appropriately considering economy. Investing significant amounts in the transmission system to facilitate beneficial power purchases, sales and exchanges, through either bilateral agreements or an ISO, has not yet been pursued with sufficient vigor, candor, or analytical rigor.	Process of doing Bill-
30.	V. Governance A. Background	38	Such a conclusion would not be possible if several directors had proved knowledgeable about the strategic plan.	Process of doing

Get Bd strategic Plan

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ITEM NO.	SECTION	PAGE NO.	EXCERPT FROM REPORT	BIG RIVERS ACTIVITY
31.	V. Governance B. Findings, 1.	40-41	Liberty crafted a set of standards for EKPC that was intended to establish (board member) minimum requirements. Liberty's standards require that the board: set strategic direction, assure financial health, assure adequate controls and the overall integrity of the cooperative, provide oversight and direction of management, assure that problems and issues brought to its attention are satisfactorily resolved, assure the board has the attributes to accomplish the above.	Need to consider doing Bd has to do this.
32.	V. Governance B. Findings, 3.	42	The board maintains a series of formal policy statements, which currently numbers 13. Some of the statements are more than five years old.	Process of doing Focus on those out of date
33.	V. Governance B. Findings, 3.	42	One notable omission, which has previously been called to the board's attention by the NRECA team, is a "whistleblower policy."	Doing – looking whether needs strengthening
34.	V. Governance B. Findings, 7.	44	Strategic thinking opportunities should be included on every agenda.	Need to consider doing Mark B.
35.	V. Governance C. Conclusions, 4.	48	A critical question asked in designing this audit was the degree of conflict that may exist between directors' obligations to their cooperatives and to EKPC.	Doing
36.	V. Governance C. Conclusions, 4.	49	MCR's suggestions included managing growth and delaying the need for new generation, increasing generation and transmission access to markets for surplus sales, and lowering new construction costs per kW through partnerships.	Doing
37.	V. Governance C. Conclusions, 5.	50	It is the board that must decide if it can define and enforce upon itself a discipline that places the interests of EKPC above others.	Doing

EAST KENTUCKY MANAGEMENT AUDIT
May 5, 2010
Mark Bailey – highlights and comments

ITEM NO.	SECTION	PAGE NO.	EXCERPT FROM REPORT	BIG RIVERS ACTIVITY
38.	V. Governance C. Conclusions, 5.	50	In all such cases, however, the director's role is to assure an understanding of the represented group – it is not to advocate for that group against the interests of the enterprise the directors serve.	Doing
39.	V. Governance C. Conclusions, 6.	50	The board does not adequately consider the risks facing EKPC on a structured basis and does not require a management program of risk assessment and mitigation. The board does not adequately consider risk in its decision-making processes.	Doing
40.	V. Governance C. Conclusions, 6.	50	Risks must be factored into the decision-making process. It is simply inadequate to make a decision solely on the basis of economics without also considering risk.	Doing
41.	V. Governance C. Conclusions, 8.	52	The board, in making decisions, is rarely given options by management.	Doing – need to consider if this needs additional focus
42.	V. Governance C. Conclusions, 8.	52	Liberty found no indicators that management is routinely and analytically held accountable for its performance in tangible and meaningful ways.	Doing
43.	V. Governance C. Conclusions, 9.	53	A deficiency in fraud risk management was specifically identified for the board's attention.	Process of doing – focused audits
44.	V. Governance C. Conclusions, 10.	53	The notion of a board that has neither the license nor desire to police itself is not logical; the board should take very seriously this responsibility.	Doing

EAST KENTUCKY MANAGEMENT AUDIT

May 5, 2010

Mark Bailey – highlights and comments

ITEM NO.	SECTION	PAGE NO.	EXCERPT FROM REPORT	BIG RIVERS ACTIVITY
45.	VI. Recommendations C. Liberty's Initial Recommendations 1. November-Vintage Recommendations – Management, 7.	60	EKPC should make operating budget performance an important measure affecting the compensation of the CEO, CFO, and all managers with budget responsibility.	Doing, but could consider doing it differently. Incentive Plan – North Star; [illegible] factor
46.	VI. Recommendations C. Liberty's Initial Recommendations 2. November-Vintage Recommendations – Governance, 6.	63	The board must articulate a new, EKPC-centric way of thinking and acknowledge that, while the consumer's voice must be heard, a role of consumer advocate is not acceptable for directors.	Doing
47.	VI. Recommendations C. Liberty's Initial Recommendations 2. November-Vintage Recommendations – Governance, 10.	64	It is the role of the board to provide guidance, direction and oversight and not, as suggested by some, merely to ratify the CEO's desires.	Doing
48.	VI. Recommendations C. Liberty's Initial Recommendations 2. November-Vintage Recommendations – Governance, 10.	64	A second improvement would be a requirement that management provide analysis in addition to "numbers."	Doing

EAST KENTUCKY MANAGEMENT AUDIT
May 5, 2010
Mark Bailey – highlights and comments

ITEM NO.	SECTION	PAGE NO.	EXCERPT FROM REPORT	BIG RIVERS ACTIVITY
49.	VI. Recommendations C. Liberty's Initial Recommendations 2. November-Vintage Recommendations – Governance, 10.	64	Directors should insist on substantive input to agendas, including the topics and the amount of discussion expected.	Doing to some extent now, need to consider further
50.	VI. Recommendations C. Liberty's Initial Recommendations 2. November-Vintage Recommendations – Governance, 10.	65	As a final note, we previously discussed the tone of Policy No. 104 (board/CEO responsibilities) as seeming to be designed to keep the board in its place. This policy should be reviewed and revised as appropriate to define a tone more consistent with an active, involved board.	Process of doing How frequently check
51.	VI. Recommendations E. Specific Comments on EKPC's January and February Submissions, 2.	72	Liberty concluded, as have others, that the committee approach at EKPC has not been effective.	Doing – do not utilize committees

~~David S.~~
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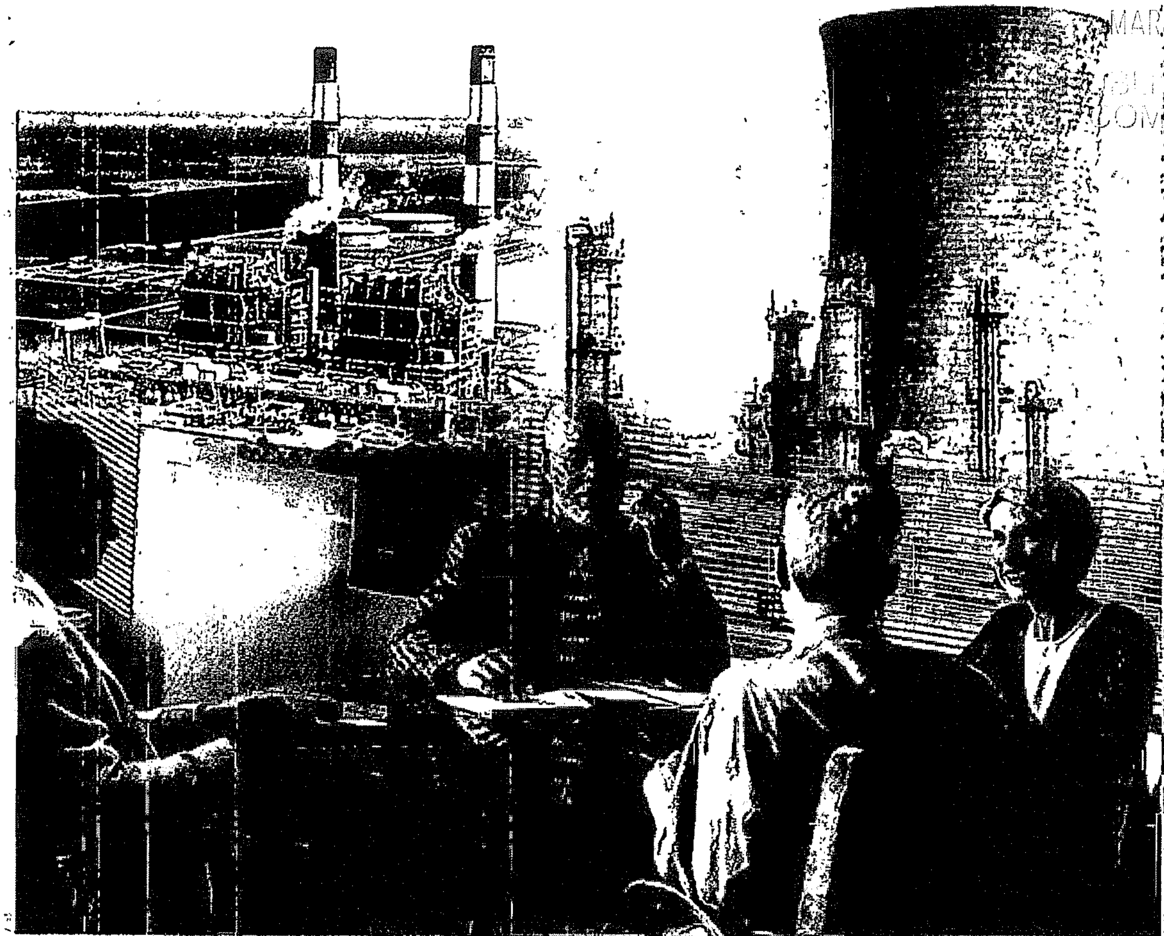
Course 967.1

Fundamentals of Energy Risk Management for Directors



National Rural Electric Cooperative Association
A Touchstone Energy Cooperative

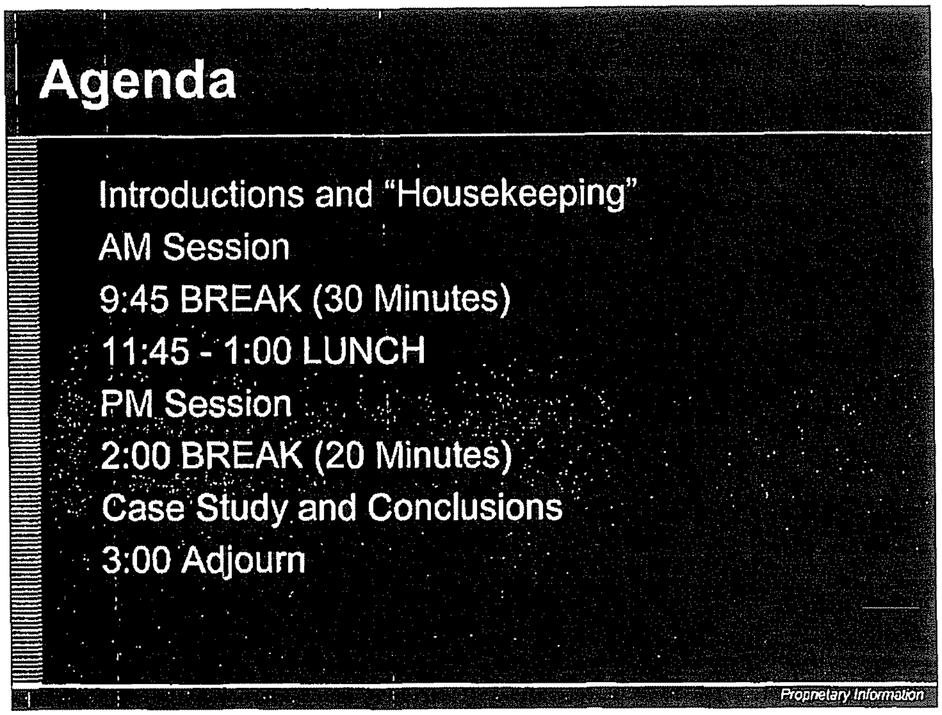
ACES POWER MARKETING
Co-ops of America

Participant Guide

Version Date: November 2002

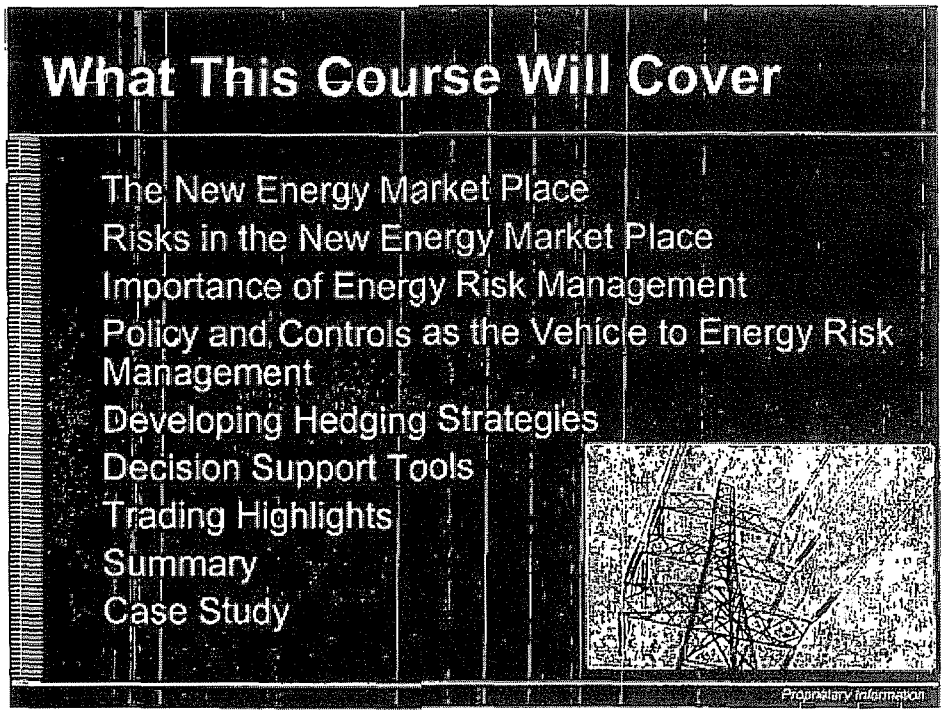
1 of 158

Case No. 2012-00535
Attachment 1 for Response to AG 2-7
Witness: Mark A. Bailey

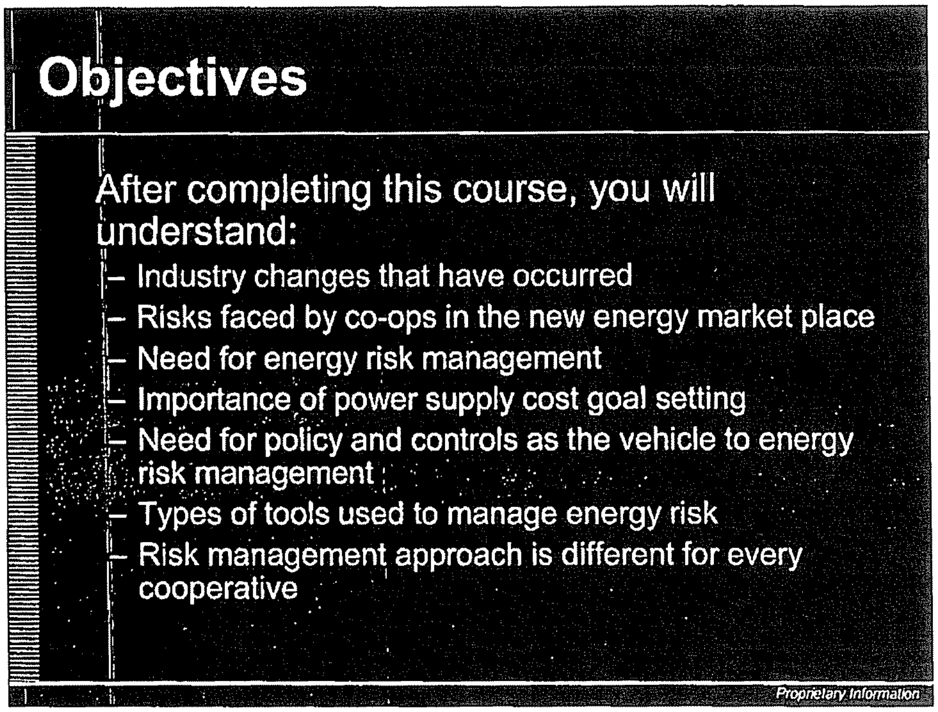


• Notes:

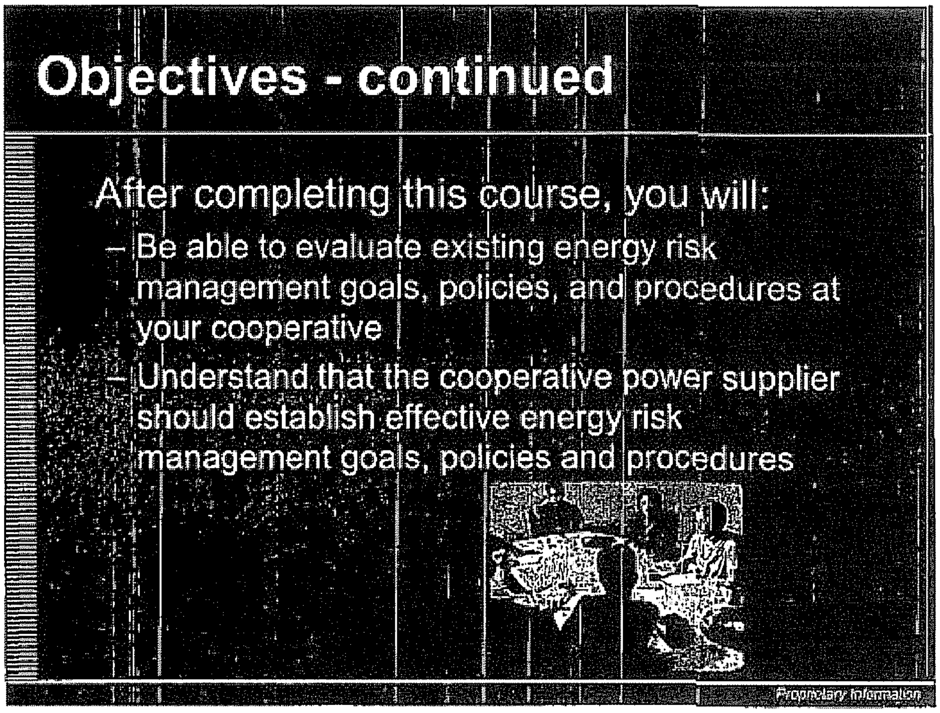
Turn to page C-1 of Appendix C (Exhibit 1) for an exercise.



- This course will be covering:
  - Industry background and the new energy market place
  - Risks in the new energy market place
  - Importance of energy risk management
  - Policy and controls as a vehicle to energy risk management
  - Developing a hedging strategy for your power supply portfolio
  - Power supply portfolio decision support tools
  - Trading highlights
  - Summary: The keys to success
  - Case study



- By the time you leave today, you will understand the:
    - Industry changes that have occurred
    - Risks faced by cooperatives in the new energy market place
    - Need for energy risk management
    - Importance of energy risk management goal setting
    - Need for policy and controls as a vehicle to energy risk management
    - Types of tools used to manage energy risk
- You will also understand that every cooperative will have a different risk management approach.



- In addition, after completing this course, you will:
  - be able to evaluate existing energy risk management goals, policies, and procedures at your cooperative.
  - understand that your G&T should establish effective risk management goals, policies and procedures.

Case No. 2012-00535
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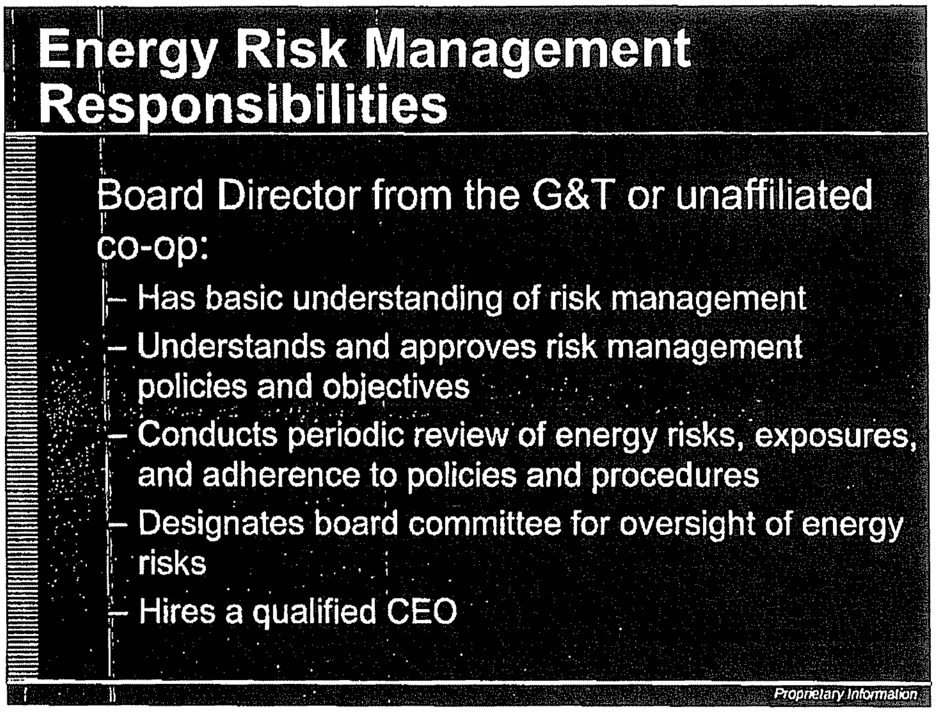
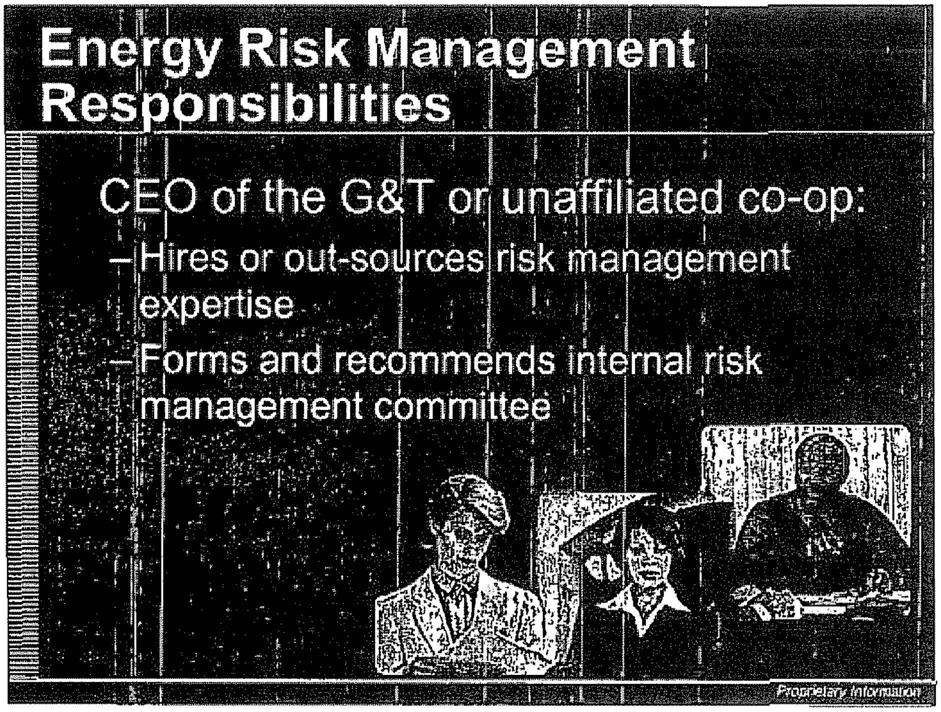


- The energy risk management responsibilities of the Board Director from the G&T or unaffiliated cooperative:
    - Has a basic understanding of risk management.
    - Understands and approves risk management objectives and policies.
    - Conducts periodic review of energy risks, exposures, and adherence to policies and procedures.
    - Designates Board committee for oversight of energy risks (e.g., audit committee, risk oversight committee).
    - Hires a qualified CEO.
- Note this does not say the Board Director should be involved in deal specifics or negotiate deals. The Board Director should guide, not do.



- The energy risk management responsibilities of the CEO of the G&T or unaffiliated cooperative:
  - Hires or outsources risk management expertise.
  - Forms and recommends an internal risk management committee that:
    - Possesses broad expertise in risk management.
    - Assures risk management policies and procedures are implemented and executed.
    - Regularly reviews energy risks and exposures.
    - Recommends policy changes to board oversight committee.

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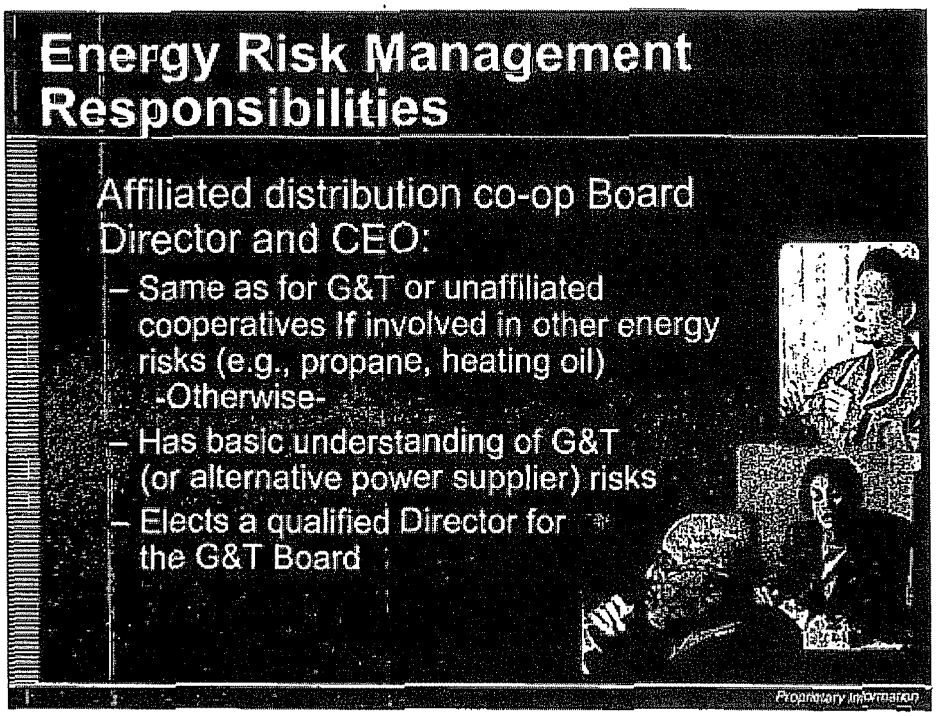
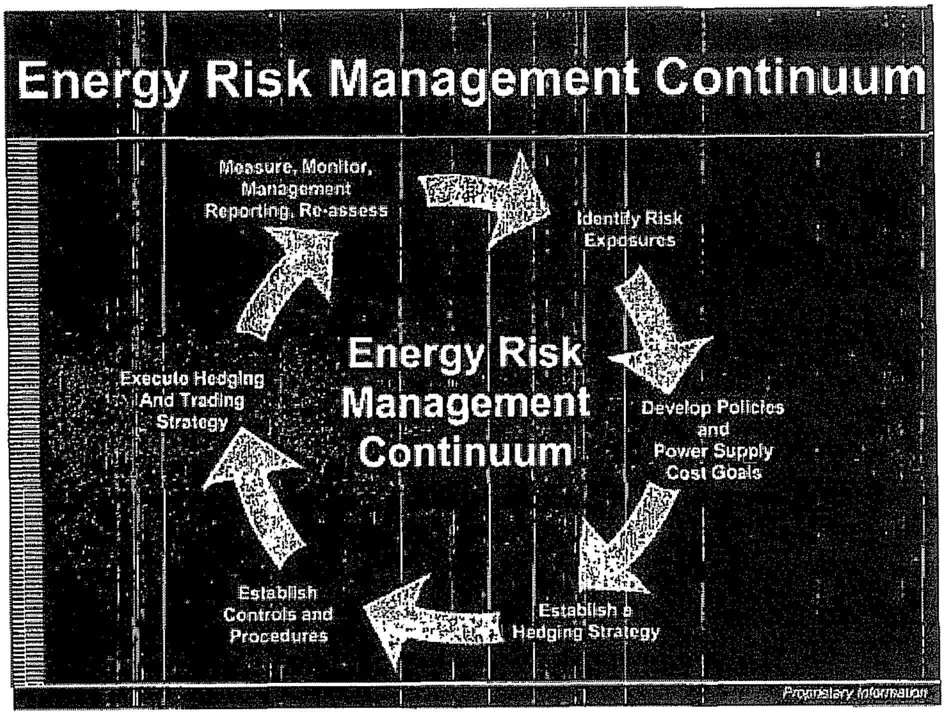


- The energy risk management responsibilities of the Board Director and CEO of the affiliated distribution cooperative:
    - Same as that for G&T or unaffiliated cooperatives if involved in other energy risks (e.g., propane, heating oil).
    - Has a basic understanding of G&T (or alternative power supplier) risks.
    - Elects a qualified Director for the G&T Board.



- The Risk Management Continuum:
  - Identify risk exposures
  - Develop policies and power supply cost goals
  - Establish a hedging strategy
  - Establish controls and procedures
  - Execute the hedging and trading strategy
  - Measure, monitor, management reporting, and reassessment
- This is an on-going process.

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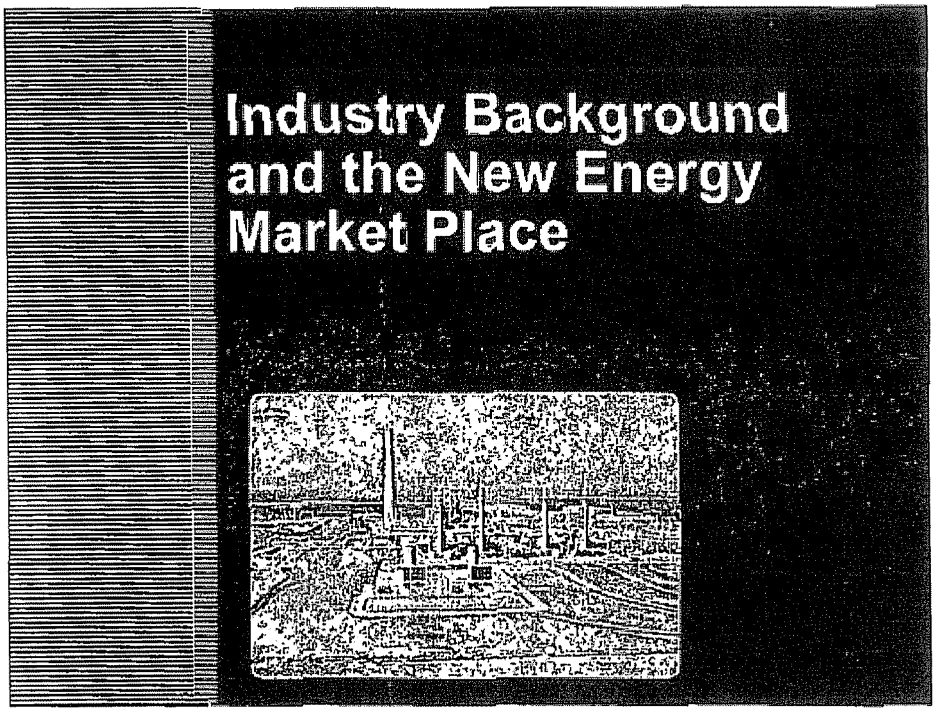
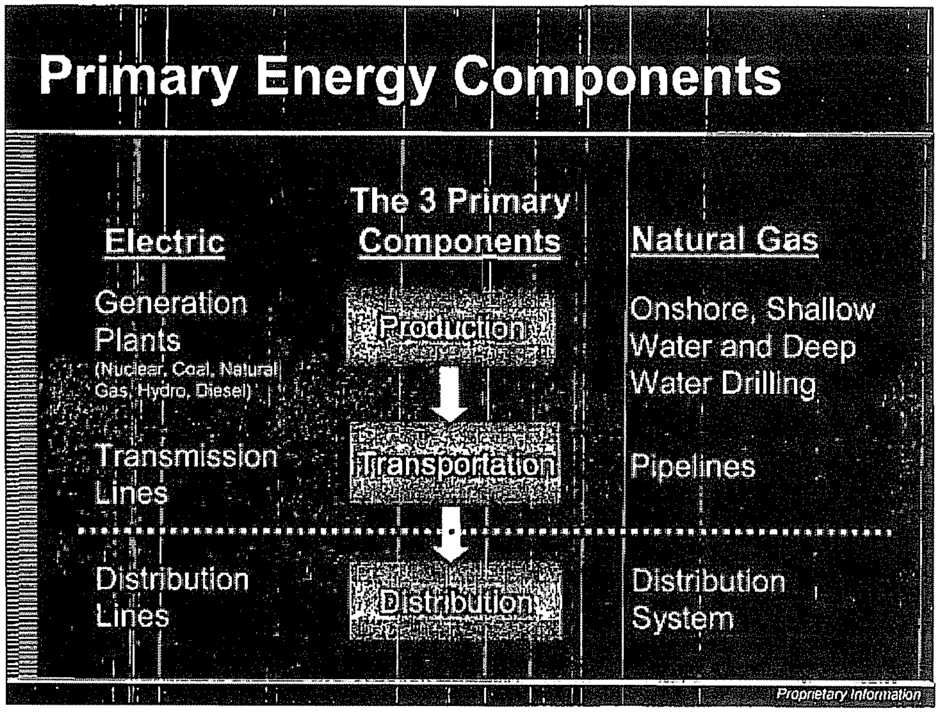
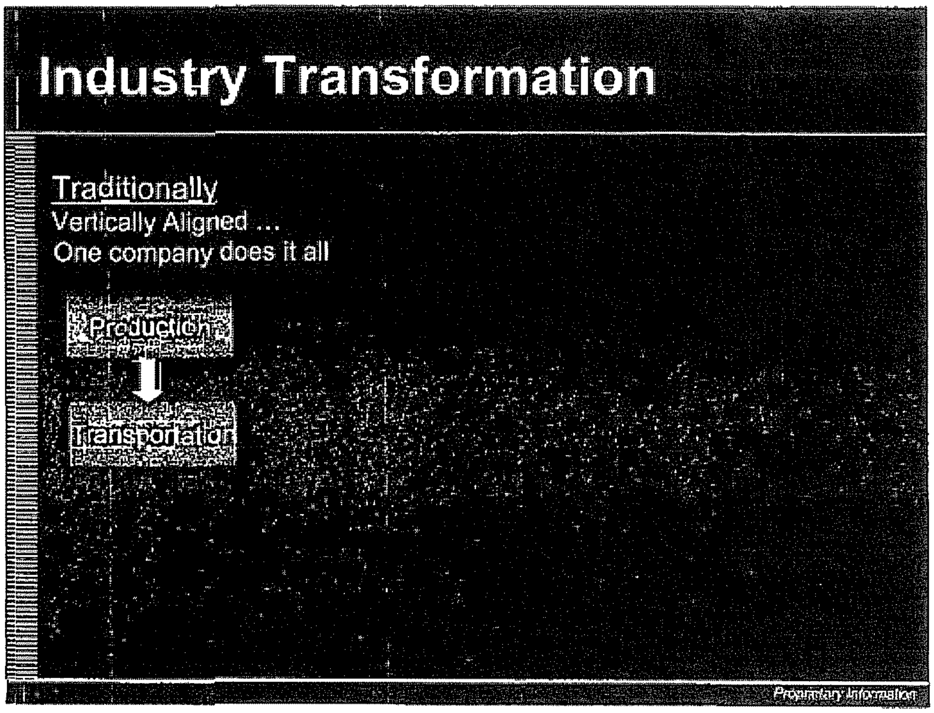


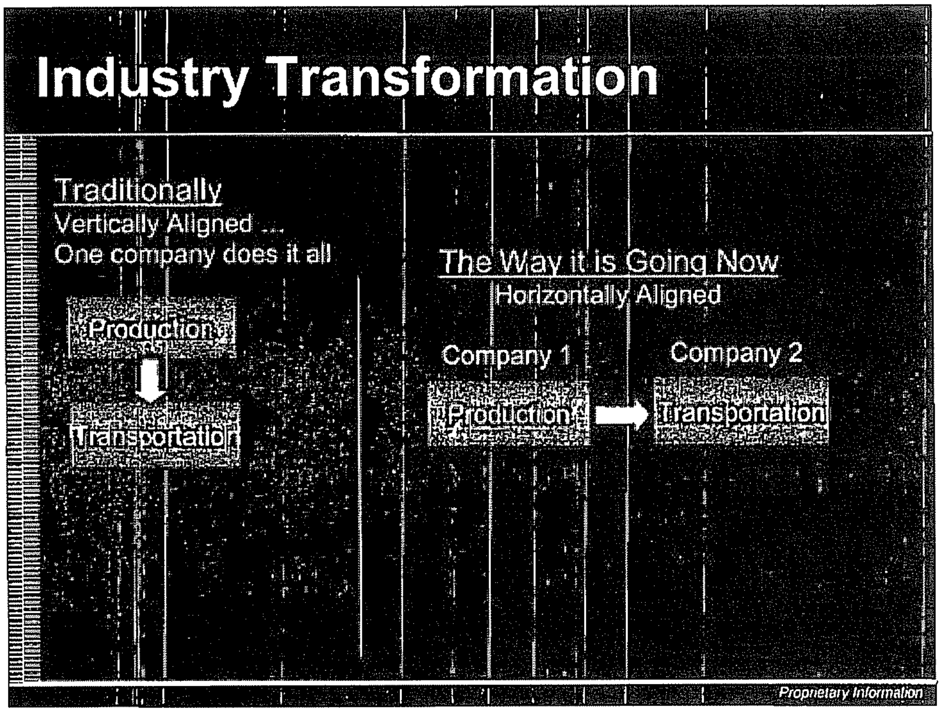
- Industry Background and the New Energy Market Place.
    - This topic covers the changes that have occurred in our industry and provides a brief background on where we've been and where we're going.
    - It examines two primary industries:
        - Electricity, and
        - Natural gas.
- The wholesale side was deregulated to introduce competition into the market, to bring efficiency in generation, and to ultimately result in price reduction.



- Most industries have three primary energy components as they pertain to the electric and natural gas industries:
    - Production
    - Transportation
    - Distribution
- This course is only going to focus on production and transportation.



- Traditionally, the electric industry was vertically aligned - one company did it all - production, transportation, and distribution.
- The utility produced the power, owned the plants, built the lines, owned the distribution lines, etc.



- The industry is now transforming from one that is vertically aligned to one that is horizontally aligned, in some states, where the production, transportation, and distribution functions may be performed by three separate companies.
  - Deregulation is tending to force each of the three primary components into three separate businesses. The purpose of deregulation is to encourage competition in the production component.
- Why do you think we're going to a horizontally integrated industry?
  - The separation of production and transportation is also to create more competition in the movement of the commodity, reduce "pancaking" of transportation charges, and eliminate market abuse and manipulation of market prices by those who control both of these pieces of the energy chain.
    - If one company controls both the production and transportation of the commodity, this may open the way for price manipulation and market abuse.
    - There is a distinction in wholesale and retail markets. The retail side of the business is in flux, while the wholesale side has been deregulated.
- This course is focused on wholesale energy.

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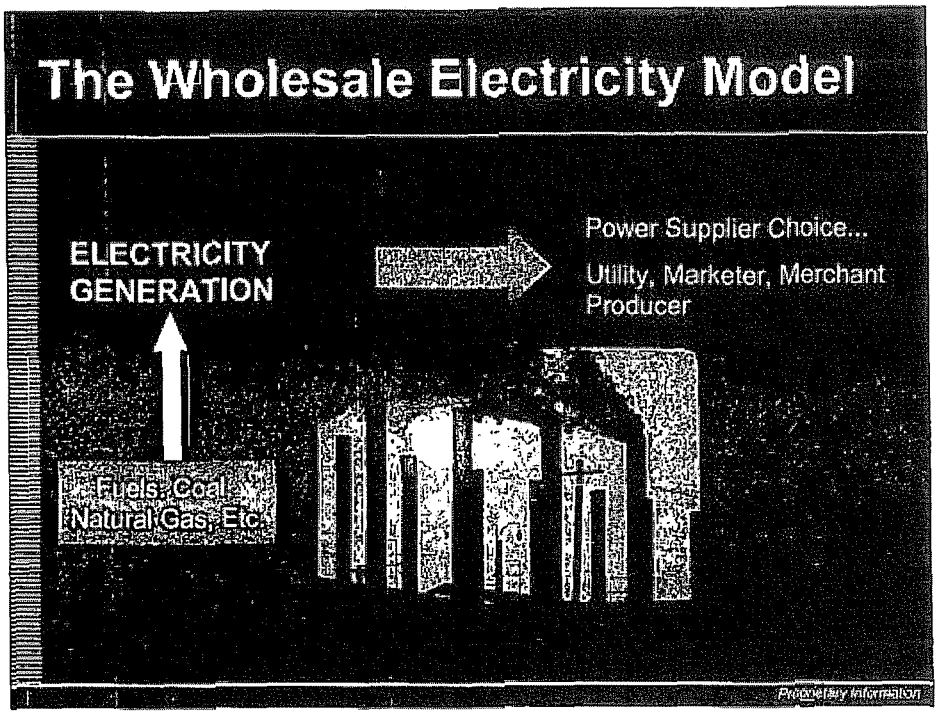
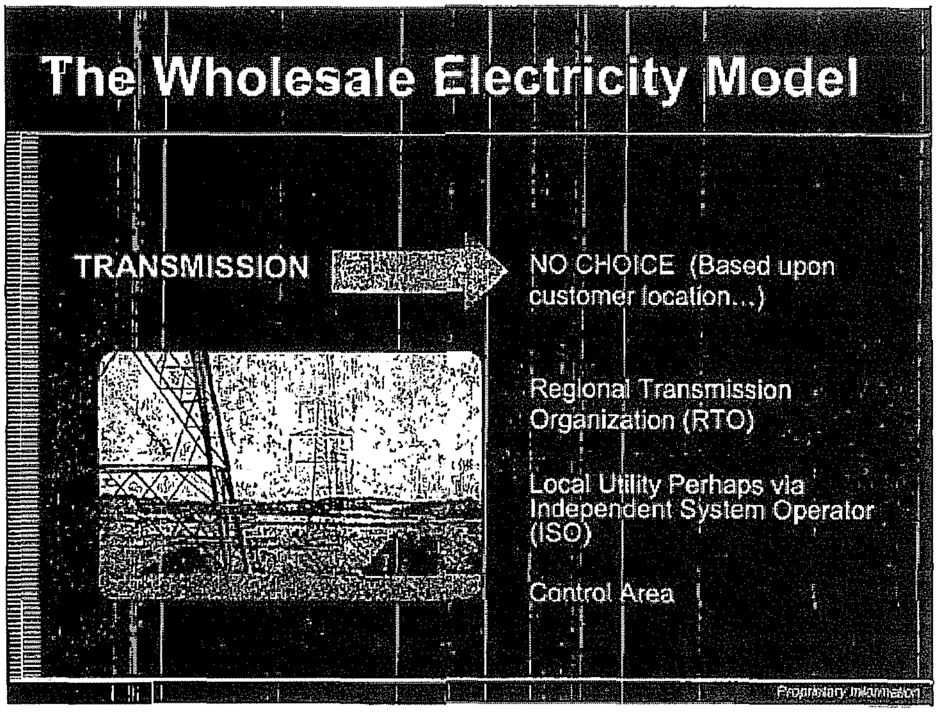
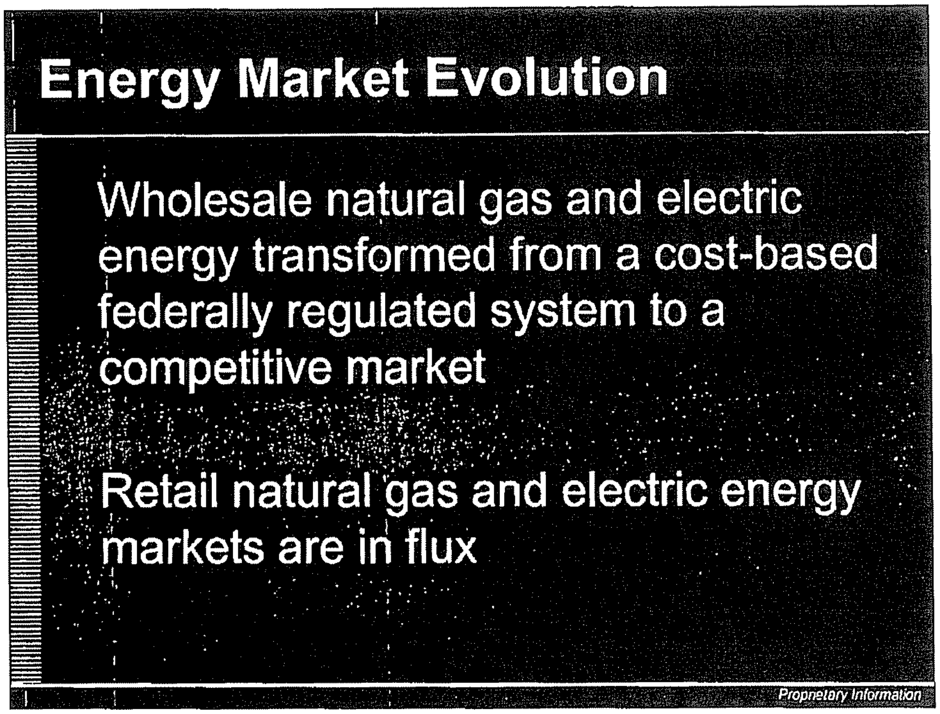


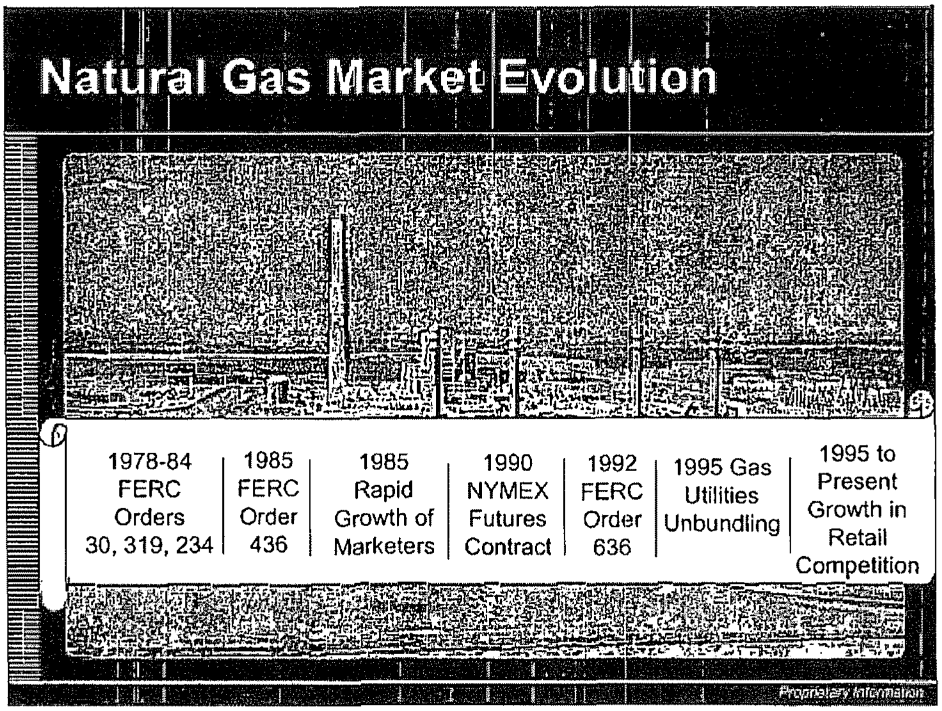
- The wholesale side of the business is made up of the generation and transportation (transmission) portions of the entire chain.
- The generation component of the wholesale electricity model:
  - In the wholesale electric industry, the production component is the generation plant (nuclear, coal, natural gas, hydroelectric, diesel).
  - What we're starting to see in the industry is competition in the wholesale electricity market.
  - Power suppliers now have more choices. They can purchase electricity from a utility, a power marketer, or a merchant producer.
- Note that merchant producers are now building power plants to sell to power suppliers in the hope of financial gain (profit).



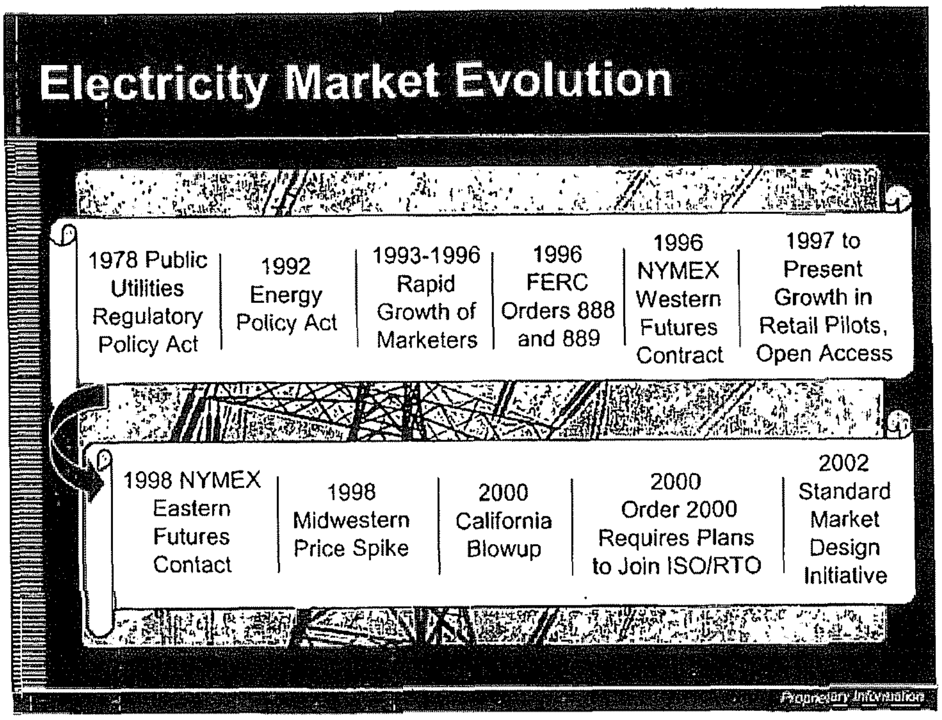
- Transmission: the transportation component of the wholesale electricity model:
  - Transmission is accomplished though transmission lines - high voltage lines that move bulk quantities from point A to point B.
  - In the wholesale electricity model, there is no choice for transmission (it is based on customer location).
  - To get your electricity to the load, you must use the transmission system in your location.
  - You purchase transmission from a Control Area. Or, perhaps the Control Area has turned over transmission to a Regional Transmission Organization (RTO) or a local utility through an Independent System Operator.
- Transmission remains regulated by the FERC. If people have limited choice in how they move the electricity from the generator to the load, there is an opportunity for price gouging.



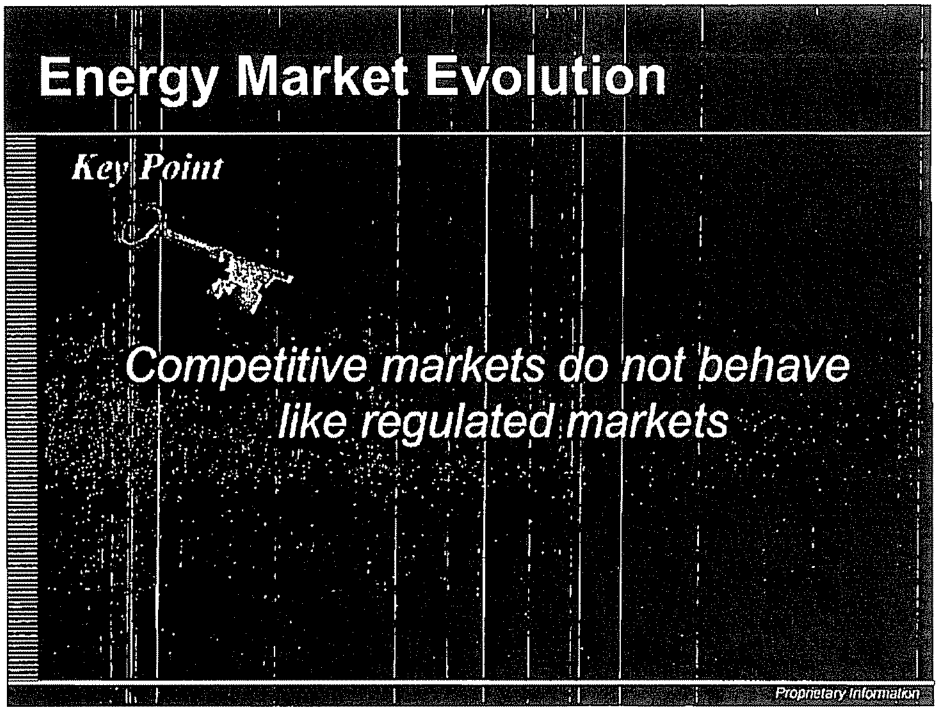
- The energy market evolution over the last two decades:
    - The wholesale natural gas and electric energy industries have transformed from a cost-based federally regulated system to a competitive market (i.e., a free, open market). Again, we're talking about just the production of the actual commodity (i.e., natural gas and electricity):
        - Natural gas (1982-present)
        - Electricity (1992-present)
    - The retail natural gas and electric energy industry is in flux. In some areas, the retail natural gas and electric energy industry was somewhat shifting from a monopolistic, state-regulated system to a competitive market. But, there has been a slowing of this over the last 3 - 5 years. In some cases, they've reversed course entirely. We don't know where retail competition is going, especially in electricity.
    - The wholesale energy markets are at a point of no return. They are very much a market-driven, competitive business.



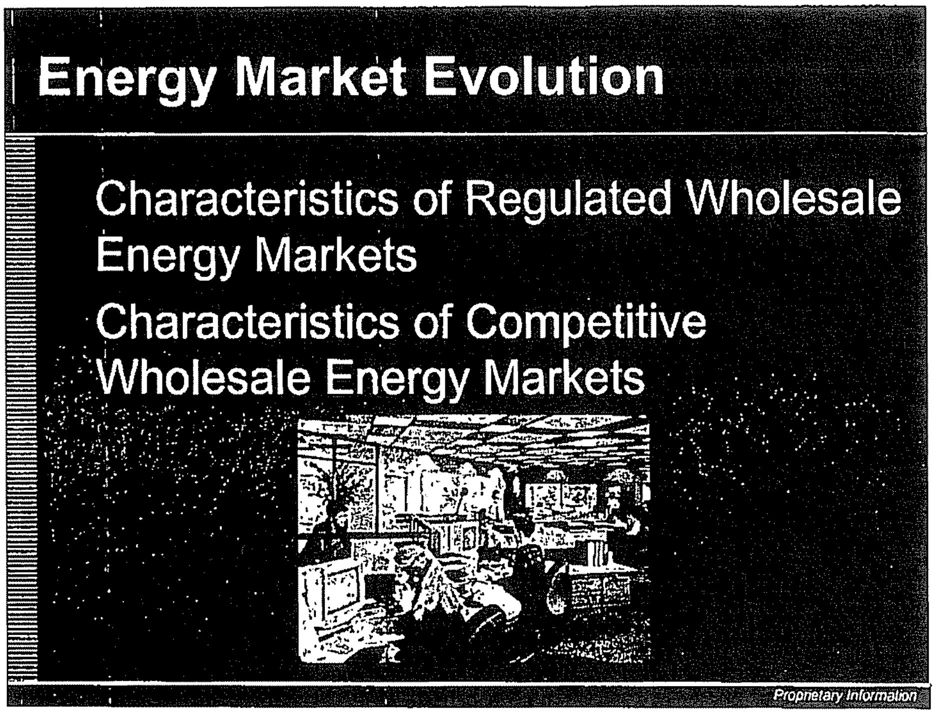
- Deregulation of natural gas began back in 1978.
- The wholesale natural gas industry deregulated a bit more quickly than electricity.
- This industry was already somewhat more horizontally aligned as gas production (e.g, deep or shallow water drilling) was already separate from the gas utilities.
- All of the FERC Orders (30, 319, 234, 436 and 636) provided methodical steps toward open access to wholesale gas transportation.
- Evolution of the natural gas market:
    - 1978 - 84 Federal Energy Regulatory Commission (FERC) Orders 30, 319, and 234 enabled certain industrials to transport natural gas for end-use
    - 1985 FERC Order 436 allowed voluntary unbundled interstate transportation
    - 1985 saw the rapid growth of natural gas marketers
    - 1990 NYMEX established a natural gas futures contract
    - 1992 FERC Order 636 required pipelines to exit merchant function and offer solely deregulated transport
    - 1995 gas utilities began unbundling transport
    - 1995 - present... growth in retail competition



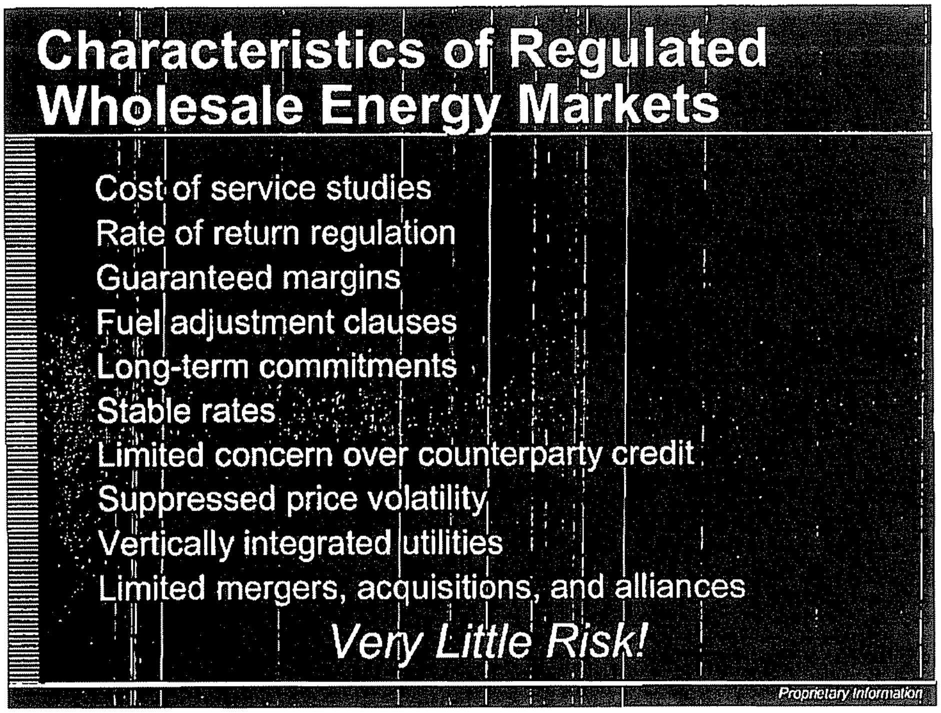
- The whole idea behind deregulation was to bring efficiencies to the market and to lower prices.
- Electricity is like no other business in the world. We've deregulated the wholesale side successfully but the retail side is still in flux.
- When you go to an open wholesale marketplace from a regulated marketplace, we introduce a whole new element of risk.
- Evolution of the electricity market:
  - 1978 Public Utilities Regulatory Policy Act (PURPA) encouraged independent power producers
  - 1992 Energy Policy Act (EPACT) - FERC empowered to order wholesale open access
  - 1993 - 1996 saw rapid growth in power marketers
  - 1996 FERC Order 888 required wholesale transmission open access and Order 889 required standards of conduct between utility generation and transmission functions
  - 1996 NYMEX established western futures contracts
  - 1997 to the Present - growth in retail pilots and open access programs
  - 1998 NYMEX introduced eastern futures contracts
  - 1998 Midwestern Price Spike
  - 2000 was the California "blowup" that stymied retail deregulation
  - 2000 - Order 2000 requires plans to join ISO/RTO
  - 2002 - Standard Market Design Initiative



- Competitive markets do not behave like regulated markets!



- This topic is going to examine the characteristics of a regulated wholesale energy market and compare them to the characteristic of a competitive wholesale energy market.



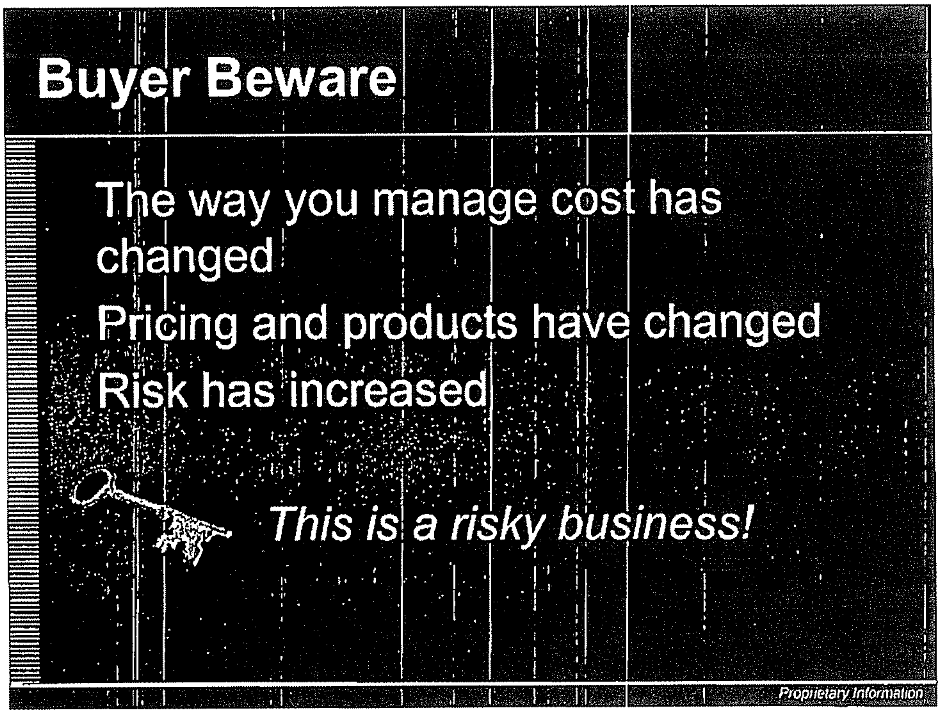
- Basically, under a regulated market, you were in a cost-plus business. You ran your business, added up the costs and then added the guaranteed rate of return you were allowed.
  - The power supplier set the price based on cost of service studies.
  - The rate of return was regulated.
  - There were guaranteed margins.
  - Everyone had fuel cost adjustment clauses.
  - People were not afraid to make long-term commitments, such as 20-, 30- and even 40-year contracts.
  - Rates to the end user were stable.
  - Limited concern about the credit worthiness of the utilities - counterparty credit.
  - There was suppressed price volatility.
  - As we discussed earlier, utilities were vertically integrated.
  - There were limited mergers, acquisitions, and alliances.
- What is critical to this list is that in a regulated "protected" market, there is very little volatility and very little risk. Therefore, there is little need for risk management.

Characteristics of Competitive Wholesale Energy Markets

- Market pricing
- Thin margins
- Severe price volatility
- Horizontally integrated industry
- Short term commitments
- Credit risk requires significant consideration
- Abrupt business exits and bankruptcies
- Numerous mergers, acquisitions, and alliances
- Specialized risk management and trading skills

Proprietary Information

- Characteristics of a competitive wholesale energy market.
  - In contrast today, the utilities don't set prices, the market now sets the price.
  - There are thin margins.
  - There is severe price volatility.
  - As we discussed, it is a horizontally integrated industry.
  - Commitments are now much more short term.
  - Credit risk requires significant consideration.
  - There are abrupt business exits and bankruptcies.
  - There are numerous mergers, acquisitions, alliances and new players.
  - Need specialized risk management and trading skills.
- What is required in a competitive environment is risk management. The competitive wholesale energy market requires specialized risk management and trading skills.



- Buyer beware is the watchword in this new environment:
  - The way you manage cost has changed.
  - Pricing and products have changed; and
  - Risk has increased.
- This is a risky business!

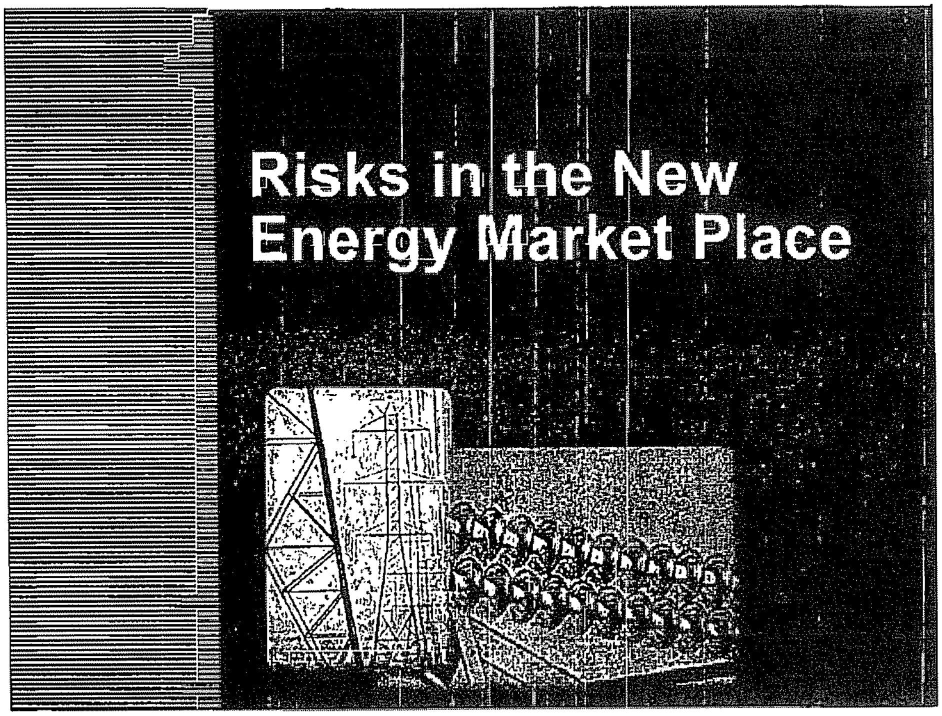
Committee of Chief Risk Officers

- Committee's charter is to standardize risk management practices
- Establish best practices to objectively manage risk
- Establish disclosure standards
- Improve energy industry business ethics
- Bring credibility back to the industry through self-regulation
- Restore energy trading industry confidence with regulators, investors, and stakeholders

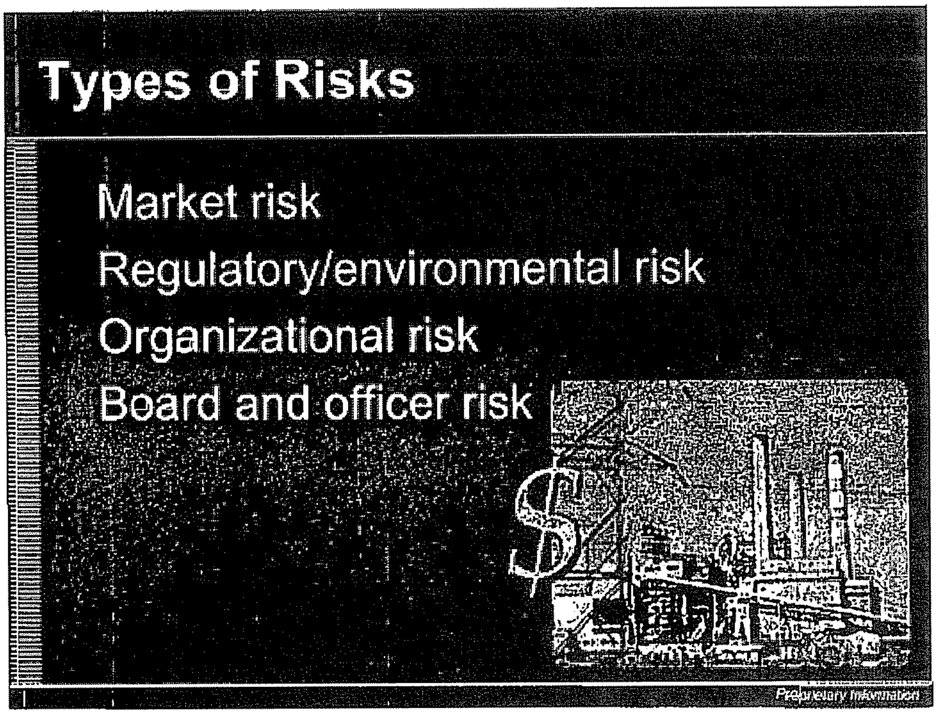
Proprietary Information

- Committee of Chief Risk Officers (CCRO):
    - Committee's charter is to standardize risk management practices
    - Establish best practices to objectively manage risk
    - Establish disclosure standards
    - Improve energy industry business ethics
    - Bring credibility back to the industry through self-regulation
- Industry participants have banded together to self-police the industry, to eliminate poor business practices, create accountability standards among all participants, and eliminate the market abuses that have occurred over the past several years.
- A partial list of some of the CCRO members is shown below.
    - American Electric Power
    - Cinergy
    - Conectiv
    - Constellation Energy Group
    - Dominion
    - Duke Energy
    - Exelon
    - Florida Power & Light
    - Mirant
    - Nisource
    - Ontario Power Generation
    - Pepco Energy Services
    - PG&E National Energy Group
    - PNM
    - Portland General Electric
    - Progress Energy
    - Reliant Resources, Inc.
    - RWE Trading Americas, Inc.
    - Tractebel North America
    - TVA

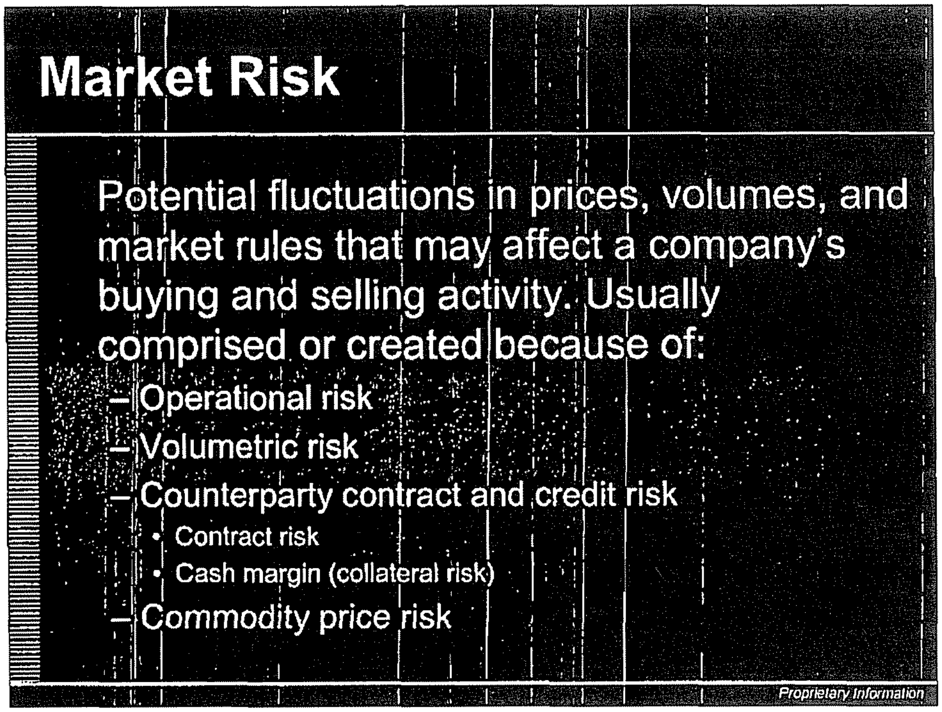
ACES is member



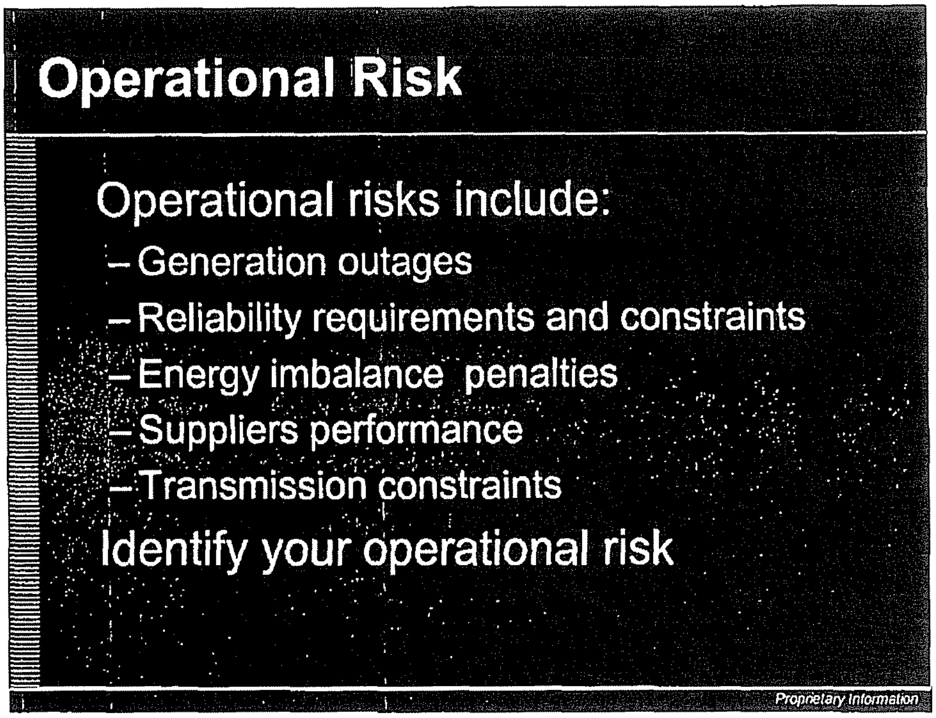
- This topic covers a number of different types of risks to which you may be exposed in the new energy market place.



- Types of risks in the new energy market place:
  - Market Risk
  - Regulatory/Environmental Risk
  - Organizational Risk
  - Board and Officer Risk



- Market risk definition:
    - Market risk consists of the potential fluctuations in prices, volumes, and market rules that may affect a company's buying and selling activity.
- There are numerous factors and situations that can expose a company to prices that adversely impact the company and they fall into four categories. Market risk is usually comprised or created because of:
    - Operational risk
    - Volumetric risk
    - Counterpart contract and credit risk
        - Contract risk
        - Cash margin (collateral risk)
    - Commodity price risk

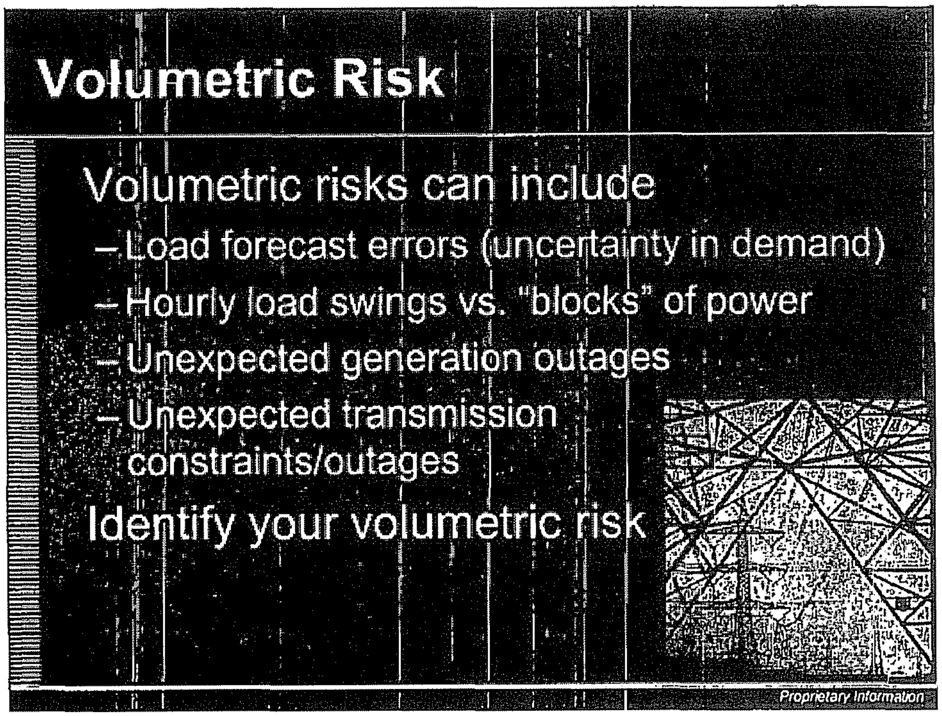


- Operational risk definition:
  - Operational risk is the risk of loss that directly or indirectly is the result of failed systems, processes, contracts, or people.
- Operational risk includes:
  - Generation outages and performance
  - Reliability requirements and constraints for control areas
  - Energy imbalance penalties for non-control areas
  - Suppliers performance - contracts and credit
  - Transmission constraints for reasons outside of your control
- These are the types of questions you should ask and think about as you identify your operational risk.
  - What is the cost impact of extreme weather and loads?

  - What is the cost impact of unit outages or de-rates?

  - Do you have specific geographic transmission delivery constraints?

  - What is the cost when your real-time supplies do not match your demand?



- Volumetric risk definition:
  - The risk that commodity volumes will vary from the expected volume and result in a loss due to changing commodity prices.
- Types of volumetric risk:
  - Load and weather forecasting
  - Power supply comes in 'blocks' and full-requirements hourly demand will swing
  - There will be unexpected generation outages
  - There will be unexpected transmission constraints/outages
- Types of questions the G&Ts and non-aligned co-ops ask when identifying volumetric risk:
  - What are prices when you have excess or not enough supply?

    ____

  - What flexibility or options are involved in purchases/sales?

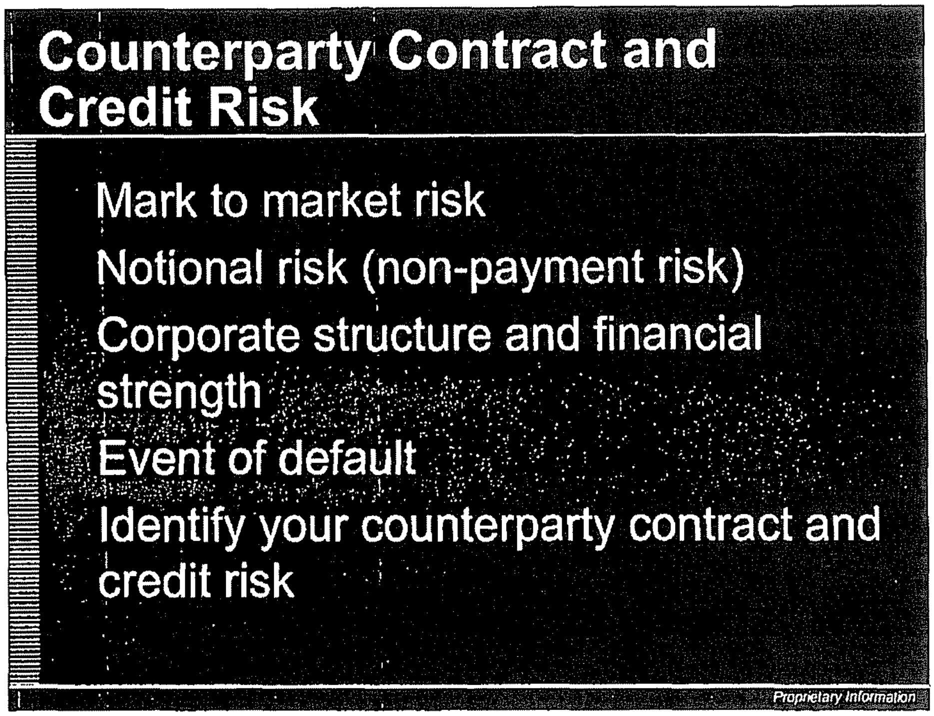
    ____

  - What is the impact of unexpected generation outages?

    ____

  - What is the impact of unexpected transmission outages?

    ____



- Counterparty definition:
    - A counterparty is someone you do business with. For example, if you buy a car, the person you buy the car from is the counterparty.
- Counterparty contract and credit risk definitions:
    - The risk of loss associated with the non-performance or non-payment by a counterparty to an agreement. Contract risk is specific to the risks involving contractual performance. Credit risk is the potential for adverse occurrence if a counterparty in unable to pay its obligation.
- Counterparty contract and credit risk: Mark to market risk; Notional risk (non-payment risk); Corporate structure and financial strength; What happens in the event of default?
- Types of questions the G&Ts and non-aligned co-ops ask when identifying counterparty contract and credit risk:
    - What are the obligations in the event of default?

    ____

    - Do you have a netting or set-off agreement?

    ____

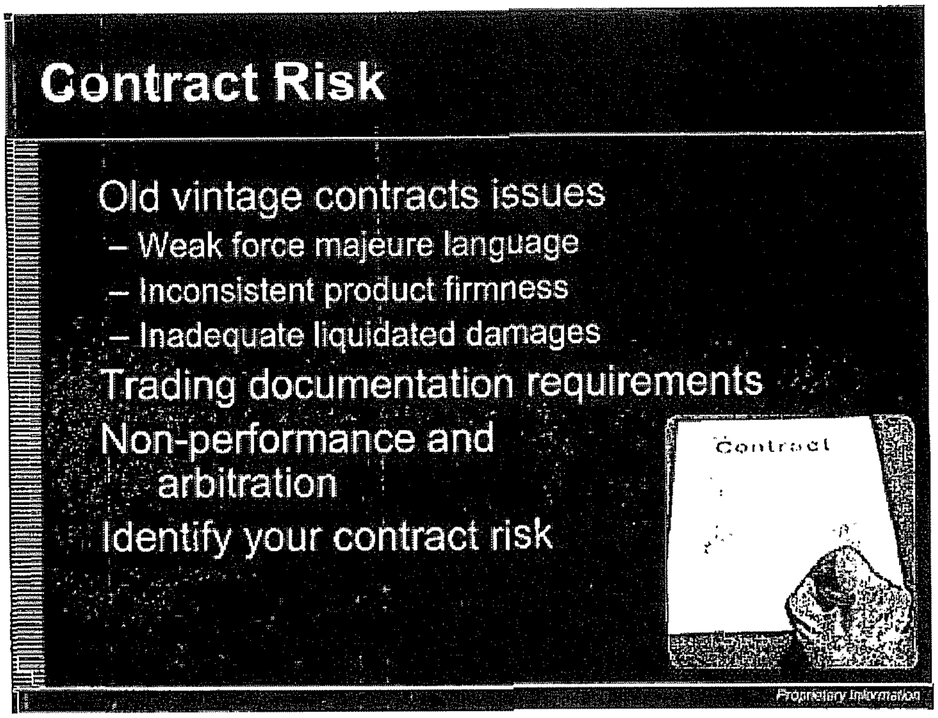
    - What is the legal name of your counterparty?

    ____

    - Are they who you think they are, or are they an inadequately capitalized subsidiary?

    ____

- A power shortage in June 1998 in the Midwest caused hourly prices to reach $10,000 per MWh.
- Example
    - Imagine you are going to work in the morning and you need to fill up your 20-gallon gas tank. Prices are $1.00 per gallon. However, you're in a rush and decide to fill up at lunch.
    - At lunch, you notice that prices have risen to $10.00 per gallon. You can't believe this is real, so you decide to wait until after work to fill up your tank.
    - After work, prices have risen to $100.00 per gallon. To fill up your tank it will cost you $2,000.00!
- This is equivalent to the $10,000 per MWh volatility faced in the Midwest in 1998. This type of volatility exposed the weaknesses of contractual agreements that were being used at the time. There were many contractual defaults and non-performance issues.
    - New contract provisions emerge
    - Standardized contracts
    - Force Majeure
    - Liquidated damages
    - Cash margining

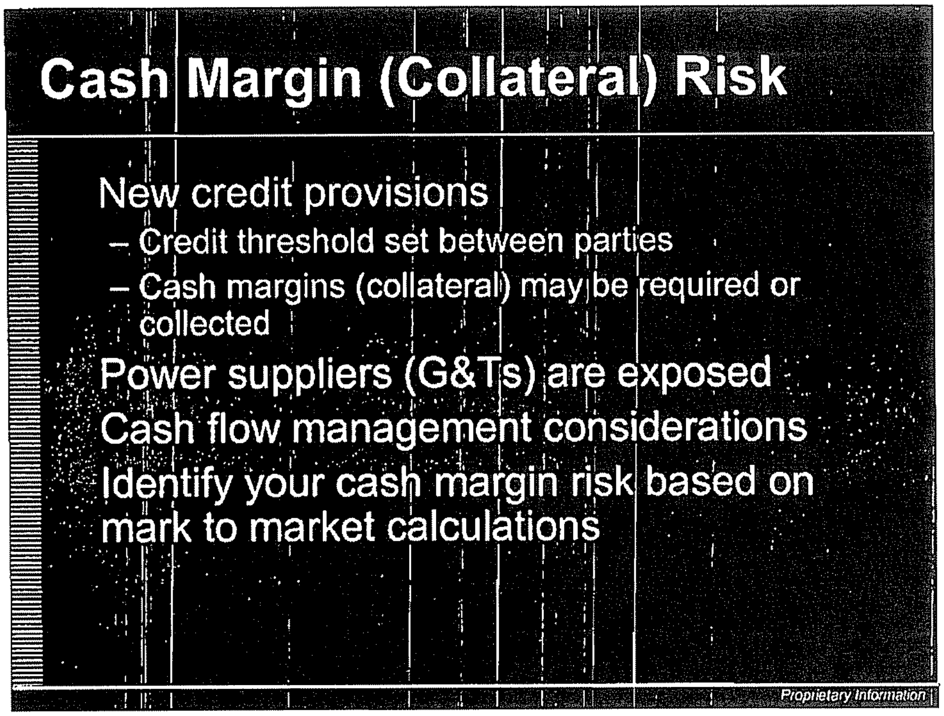


- When you deal in contracts and buy power supplies, the language used in the contract and its interpretation is very important.
    - Old vintage contracts may be unreasonable, have dated operating requirements, and optionality risks. Old contracts may have language that means something entirely different today. Old contracts are typically more lenient and don't allow cash margins.
    - Force majeure (acts of God) and firmness of delivery (a firm delivery means delivery should occur no matter what).
    - Trading documentation requirements (confirms, authorized traders, oral dealings, and recordings).
    - Non-performance and arbitration.
- Types of questions the G&Ts and non-aligned co-ops ask when identifying contract risk:
    - What are the exact performance obligations?

      ____
    - What is the process with each counterparty to execute binding transactions?

      ____
    - What are the contractual rights for non-performance?

      ____
- Contracts are very important in the wholesale energy business. It is the only thing that will protect you if things go wrong. Contracts written prior to 2000 really need to be examined!
- Refer to Appendix C Exhibit 2 (page C-2) for an exercise and example of how liquidated damages are calculated.



- Cash margin risk definition:
  - The risk associated with inadequate cash flow resulting from cash margin requirements of a contractual agreement.
- With all of the new participants and new players in the market, you have a cash margin risk. What does this mean?
- Types of cash margin risk:
  - New credit provisions
    - Credit threshold set between parties
    - Cash margins (collateral) may be required or collected
  - Power suppliers (G&Ts) are exposed
  - Cash flow managément considerations
  - Identify your cash margin risk based on mark to market calculations
- Types of questions the G&Ts and non-aligned co-ops ask when identifying cash margin risk:
  - What do your contracts allow for?

    ____

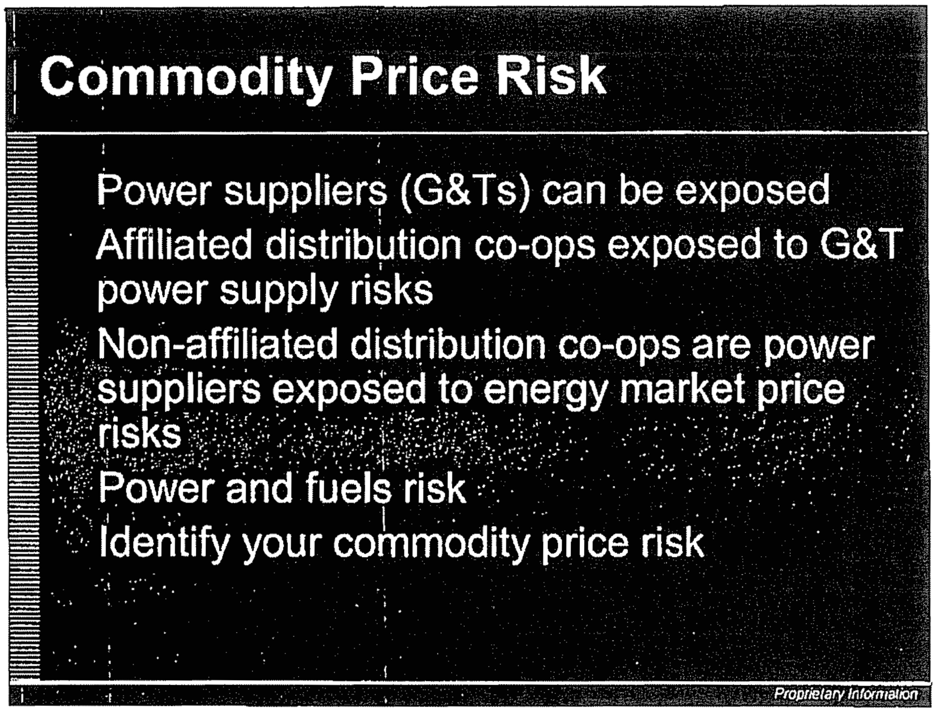
  - Do all your contracts allow for cash margining?

    ____

  - Will incoming margins offset outgoing margins?

    ____

- Refer to Appendix C Exhibit 3 (page C-3) for an exercise and example of how mark to market works and cash margin is calculated.



- Commodity price risk definition:
    - The risk of loss associated with changes in commodity prices.
- Types of commodity price risk:
    - Power suppliers (G&Ts) are exposed to this risk through their "all requirements" contracts and energy market prices.
    - Affiliated distribution co-ops are exposed to G&T power supply risks.
    - Non-affiliated distribution co-ops are power suppliers to their end users. They are exposed energy market price risks.
    - Power and fuels risk (natural gas, coal, etc.).
- Types of questions the G&Ts and non-aligned co-ops ask when identifying commodity price risk:
    - What are the prices or rate formulas you are using to buy or sell?

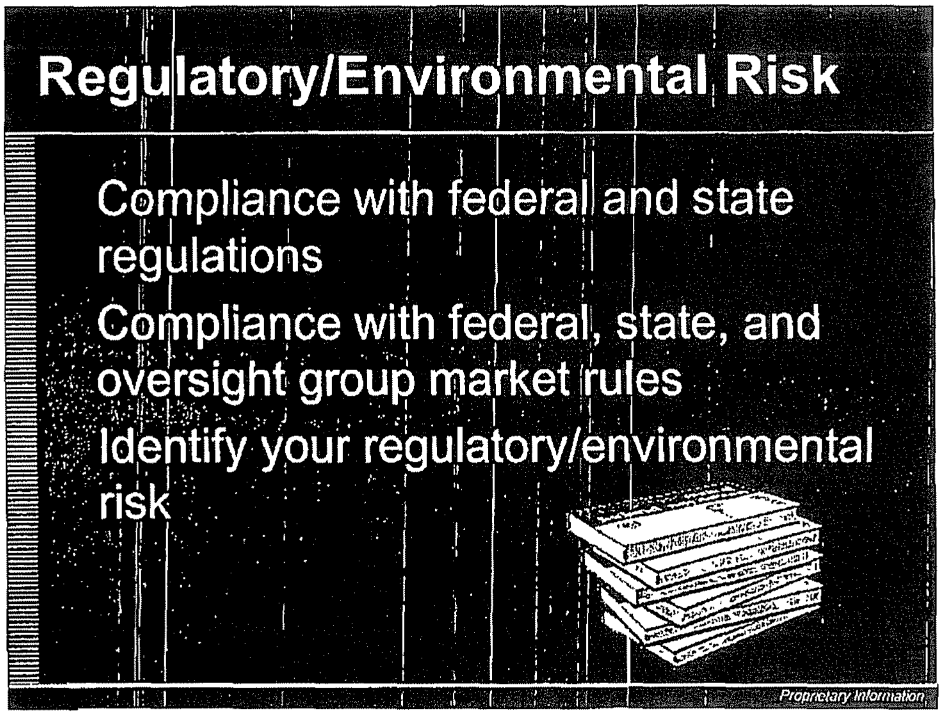
      ____

    - What flexibility or options are involved?

      ____

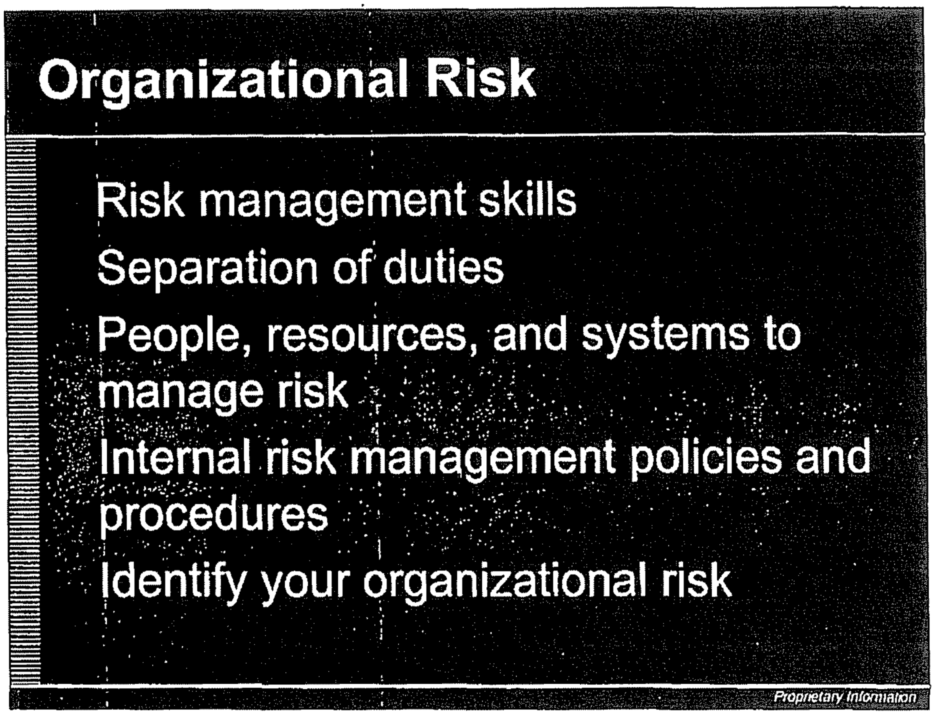
    - What periods or how long are you covered?

      ____



- Regulatory/environmental risk definition:
    - The current and prospective risks associated with regulatory and environmental market regulations and potential changes in these regulatory rules.
- Regulatory/environmental risk:
    - There must be compliance with federal and state regulations.
    - There must be compliance with federal, state, and oversight group market rules.
- Types of questions the G&Ts and non-aligned co-ops ask when identifying regulatory/environmental risks:
    - What are the federal, state, and oversight group regulatory requirements and market rules?

      ____
    - What is the potential for changes in regulation?______________________
        - Retail market?______________________
        - Wholesale market?______________________
        - Transmission rules? ______________________
        - Environmental issues?______________________
        - New taxes? (this is also a contract issue)______________________
- There is an effort to have greater oversight on commodity trading in light of the outright abuses and fraud that have recently occurred in the energy trading business. This oversight begins with the governance of the organization and its Board of Directors.
- Your company should be actively involved in State and Federal regulatory changes.



- Organizational risk definition:
  - The risks associated with the lack of risk management and trading expertise, systems, or internal policies and procedures that are designed to manage energy risks.
- Organizational risk:
  - Do people in your company have risk management skills?
  - Do you have separation of duties? That is, the people that monitor the activities are not the traders.
    - Are controls in place to mitigate rogue trading activities? We'll learn more about controls later in this course.
  - Do you have the people, resources, and systems to manage risk?
  - Do you have internal risk management policies and procedures?
- Types of questions the G&Ts and non-aligned co-ops ask when identifying organizational risk:
  - Have you hired or outsourced risk management skills?

  ____

  - Do you have the appropriate organizational structure?

  ____

  - Do you provide adequate education and training for your staff?

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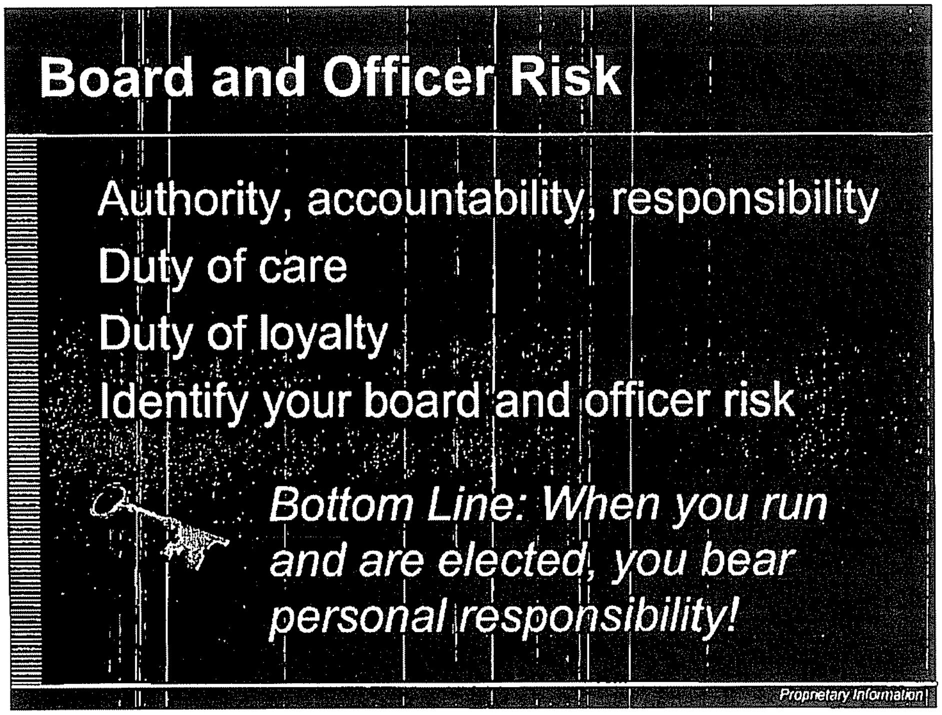
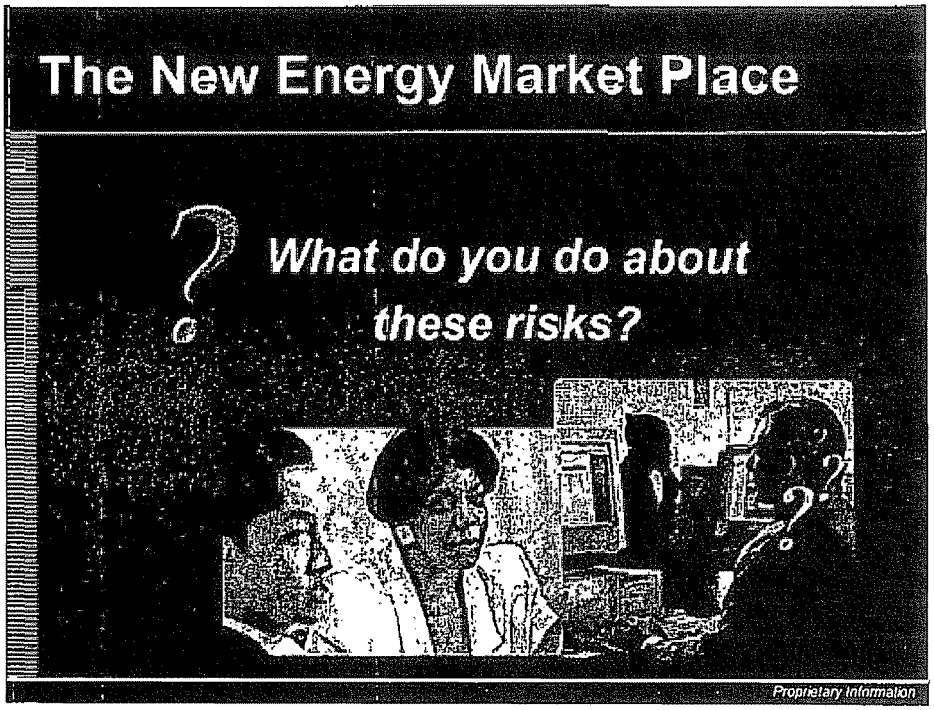
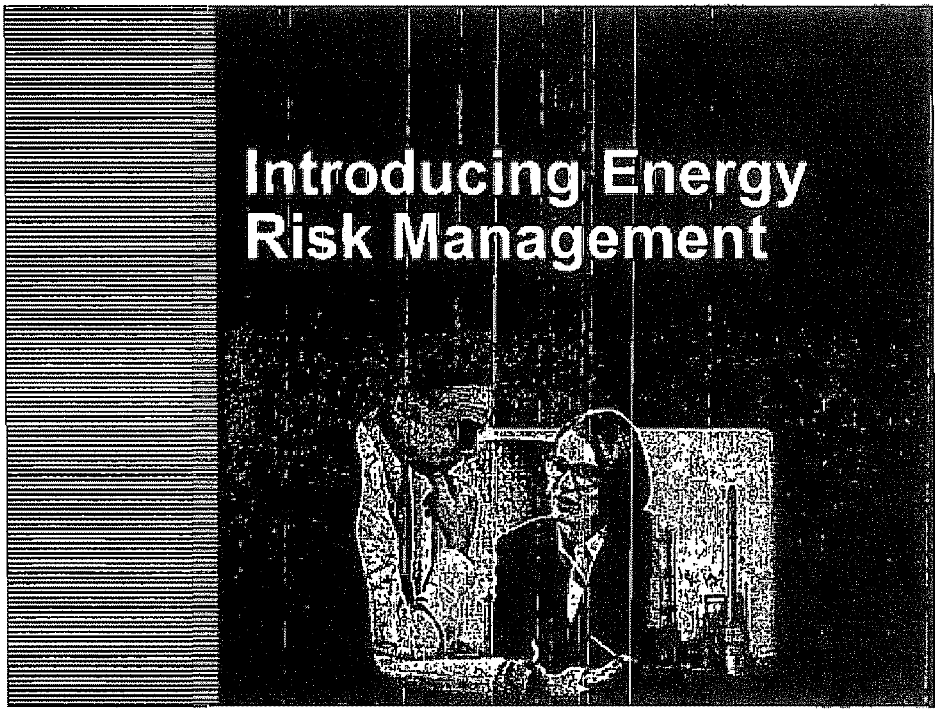


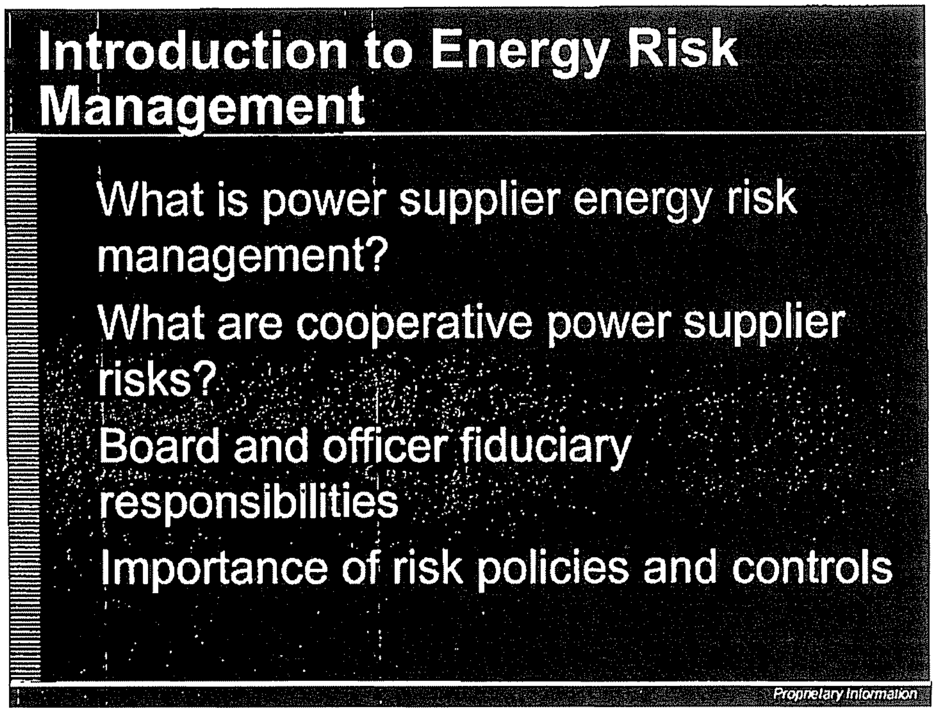
- Board and officer risk: authority, accountability, and responsibility.
- Duty of Care:
  - Knowledge of basic fundamentals of hedging.
  - Reasonable systematic oversight of experienced management.
- Duty of Loyalty:
  - As directors you have a duty to establish policies by which management runs the company.
- Types of questions to ask when identifying board and officer risk:
  - Do you have specific risk management policies?
  - Do corporate goals incorporate an articulated "risk tolerance"?
  - Have you developed board level policies and procedures to guide the G&T in managing risk management procedures?
  - Have you earned your CCD (Certified Cooperative Director)?



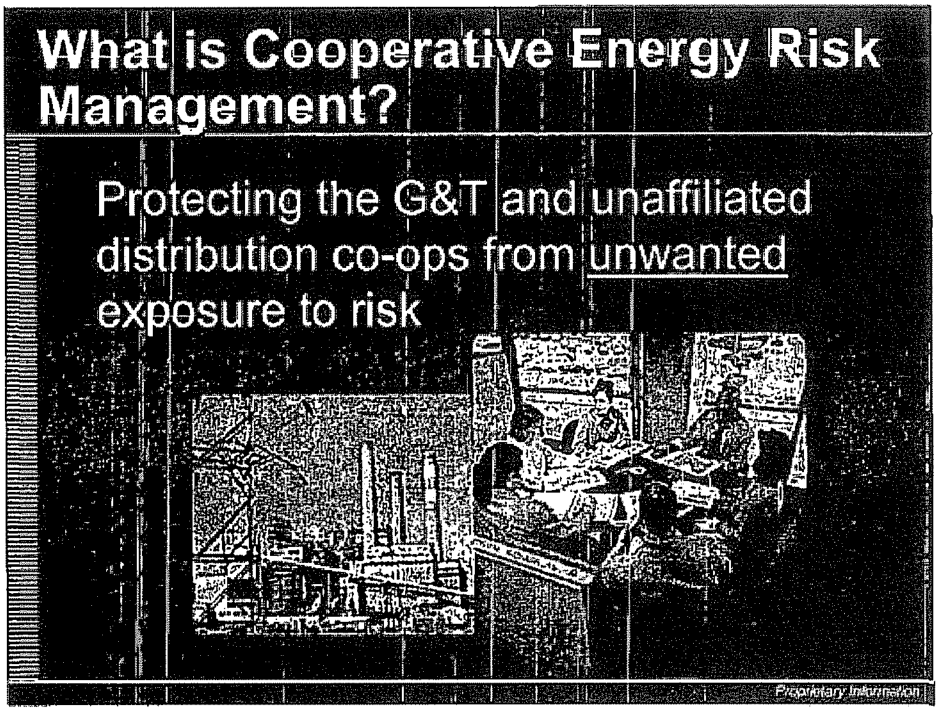
- What do you do about these risks?



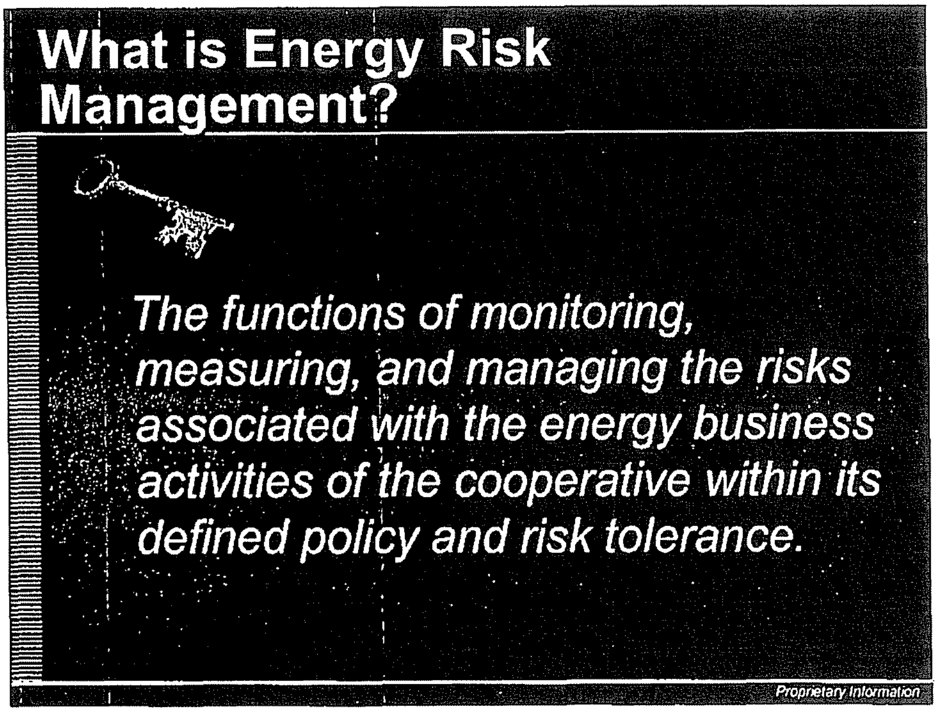
- Energy Risk Management: The topic of energy risk management is very broad and covers all the risks that we have just discussed.



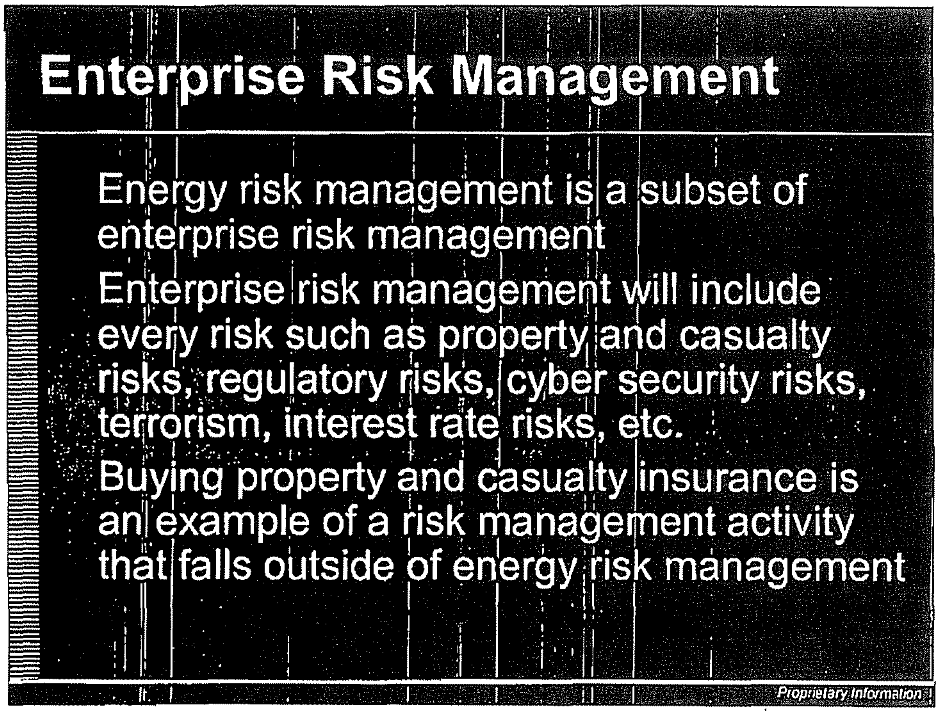
- This topic will help answer the following questions:
  - What is power supplier energy risk management?
  - What are cooperative power supplier risks?
  - What are the board and officer fiduciary responsibilities?
  - What is the importance of risk policies and controls?



- What is Cooperative Energy Risk Management?
  - Protecting the G&T and unaffiliated distribution co-ops from unwanted exposure to risk, resulting from:
    - Participation in the wholesale energy market
    - Other areas of risk within its business
- Risk is not all together a bad thing, because it can provide a reward or a return. Knowing what risks you are taking, and why, is what energy risk management is about.



- Energy risk management definition:
  - Energy risk management encompasses the functions of monitoring, measuring, and managing the risks associated with the energy business activities of the cooperative within its defined policy and risk tolerance.
- The board of directors needs to define the risk tolerance for the cooperative.
  - Are you willing to take a lot of risk or very little?
  - What is your risk tolerance? (What amount of risk causes sleeplessness?)
- Once you have answered these questions, you should develop a plan to manage the risk you are willing to take.
  - Bottom Line: It is up to the board of directors to establish the level of risk tolerance they are willing to accept on behalf of their consumers.
- Risk management is different for every cooperative.
- Refer to Appendix C Exhibit 4 (page C-4) for an exercise in assessing your risk tolerance.



- Energy risk management as subset of enterprise risk management.
- Enterprise risk management will include every risk such as property and casualty risks, regulatory risks, cyber security risks, terrorism, interest rate risks, etc.
    - Buying property and casualty insurance is an example of a risk management activity that falls outside of energy risk management.
- Energy risk management typically represents 70-80% of total enterprise risk management.

Board of Directors Energy Risk Management Responsibility

Directors' duties well established

Duties fit into three categories

– Duty of loyalty

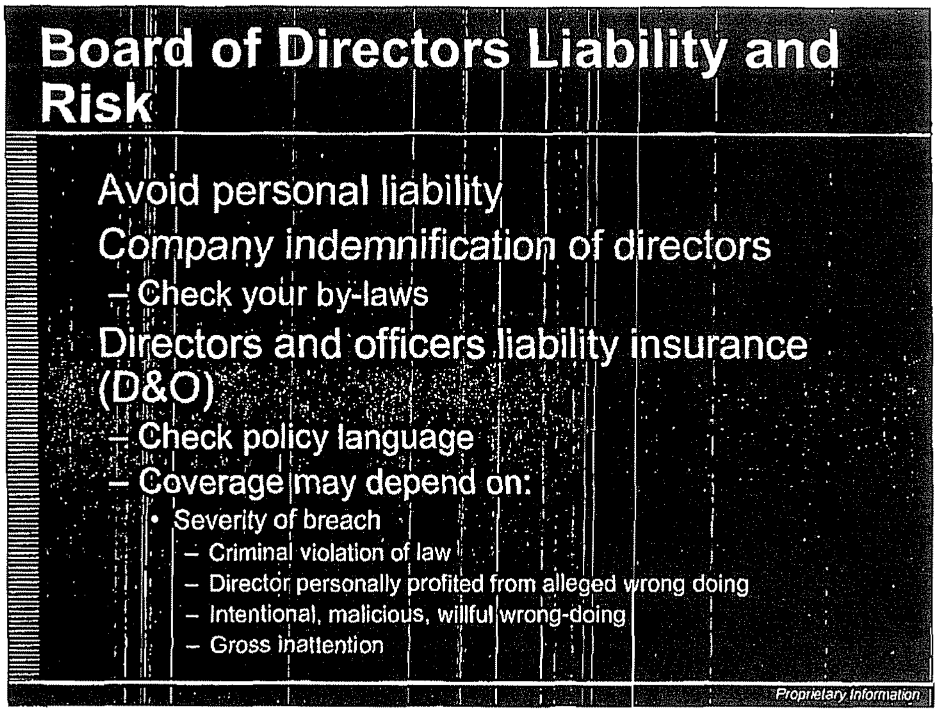
– Duty of care

– Authority, accountability, and responsibility (a.k.a. loyalty, care and obedience)

Duty to manage company with care and according to applicable statutory standard

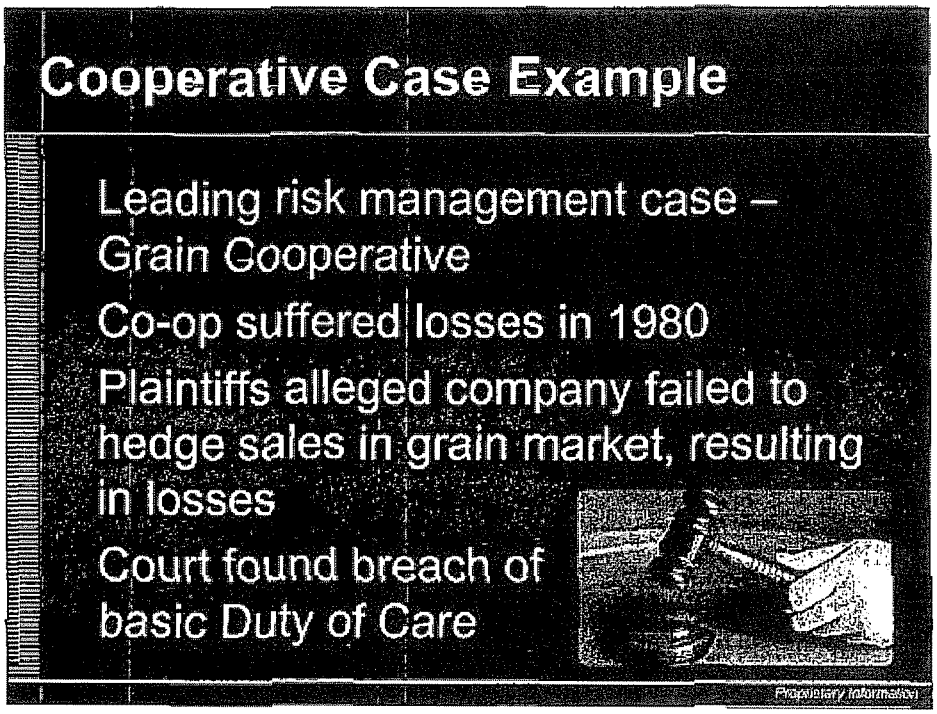
Proprietary Information

- What are your responsibilities in energy risk management?
- Board of Directors' energy risk management responsibility:
    - Directors' duties are well established through:
        - State statutes
        - Case law
    - Duties fit into three primary categories that we've already discussed:
        - Duty of loyalty
        - Duty of care
        - Authority, accountability, and responsibility (also known as loyalty, care, and obedience)
- The Board of Directors has the duty to insure the Company is managed ~~the company~~ with care and according to applicable statutory standard.

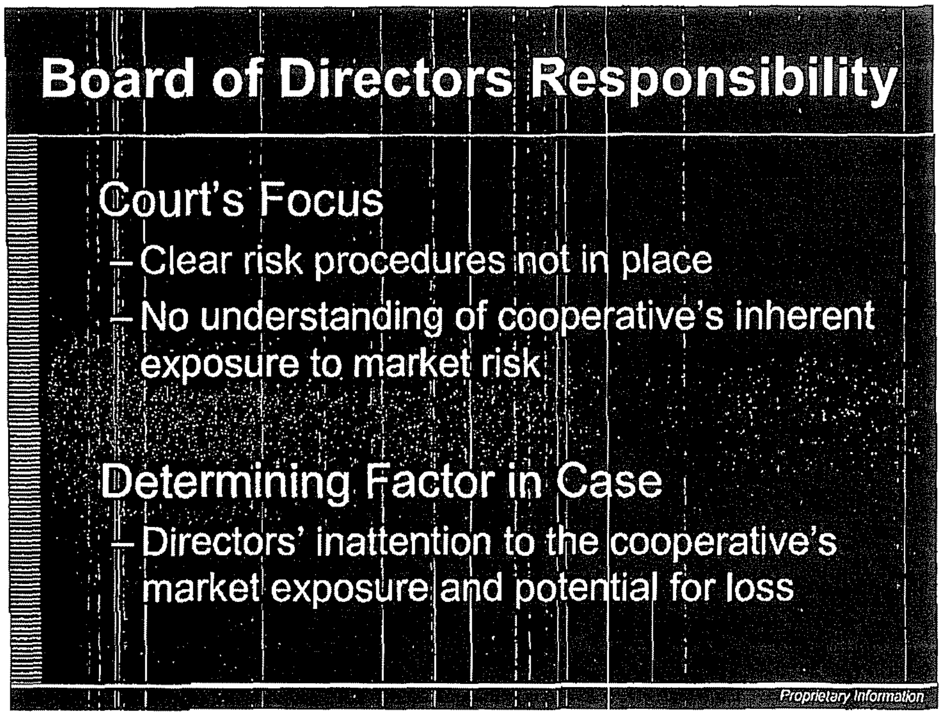


- Board of Directors liability and risk.
  - Avoid personal liability
  - Company indemnification of directors
    - Check your by-laws
  - Directors and officers liability insurance (D&O)
    - Check policy language
    - Coverage may depend on:
      - Severity of breach
        - Criminal violation of law
        - Director personally profited from alleged wrong doing
        - Intentional, malicious, willful wrong-doing
        - Gross inattention

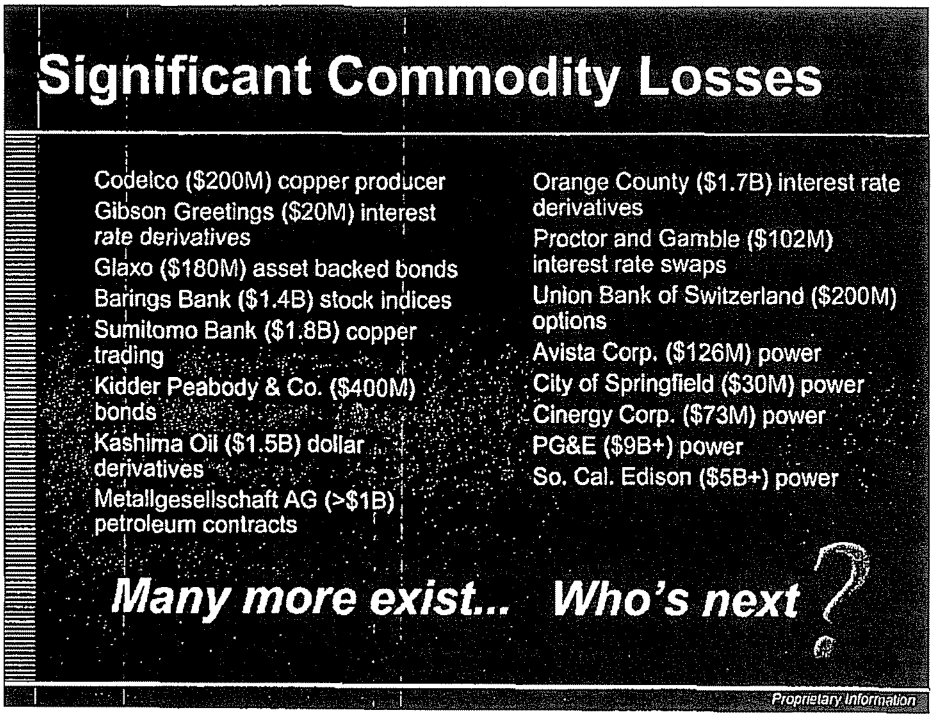
Case No. 2012-00535
Attachment 1 for Response to AG 2-7
Witness: Mark A. Bailey



- Grain Cooperative Risk Management Case:
    - Co-op suffered fairly significant losses in 1980.
    - Plaintiffs alleged company failed to hedge sales in grain market, resulting in losses.
    - Court found breach of basic Duty of Care:
        - Management inexperienced in hedging (Directors' responsibility).
        - Directors lacked basic knowledge of hedging fundamentals.
        - Gross inattention to market exposure and potential for loss.
        - Lack of risk-evaluation procedures/management.
        - *In summary, they were unaware of the risks they faced and had no policies and procedures in place.*
- The Directors' were personally liable for $424,000 in losses.

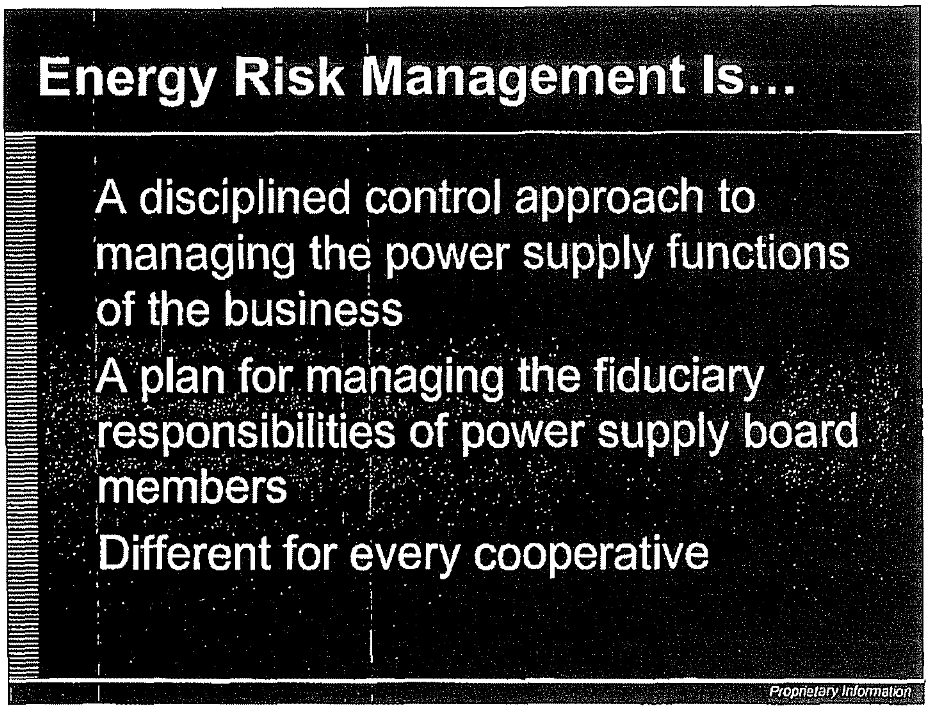


- The Court's focus in this case:
    - Clear risk procedures were not in place:
        - Directors failed to insist on formal policy and systematic oversight.
        - No authority matrix.
    - No understanding of cooperative's inherent exposure to market risk.
- The determining factor in this case:
    - The determining factor was not the failure to hedge, but…
    - Directors' inattention to the cooperative's market exposure and potential for loss.
    - Inattention was demonstrated by lack of procedures and controls.

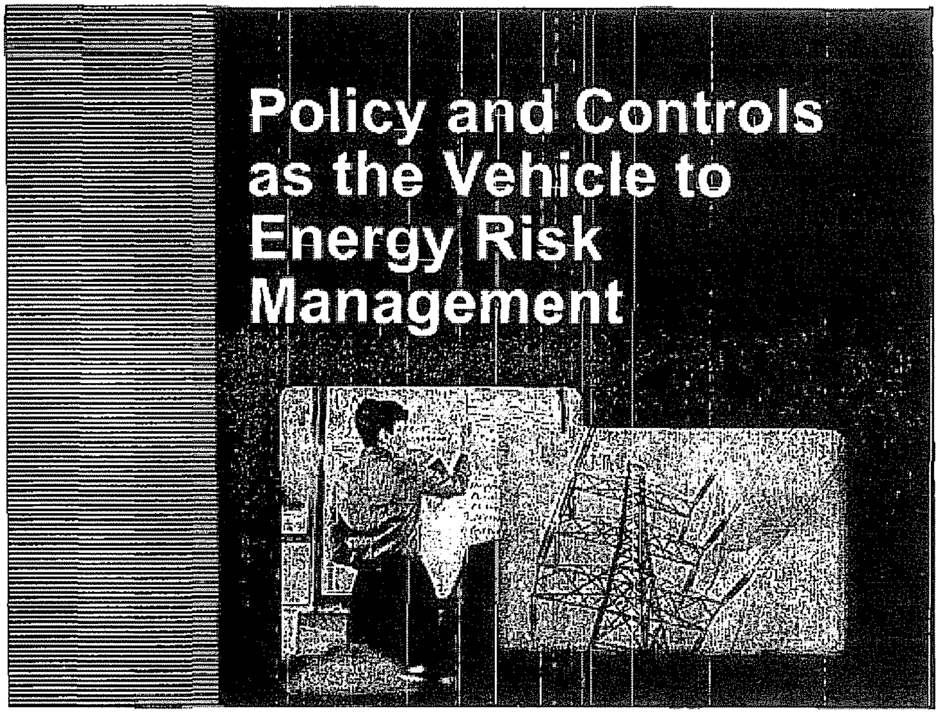


- In addition to the examples of losses on this list, many more exist.

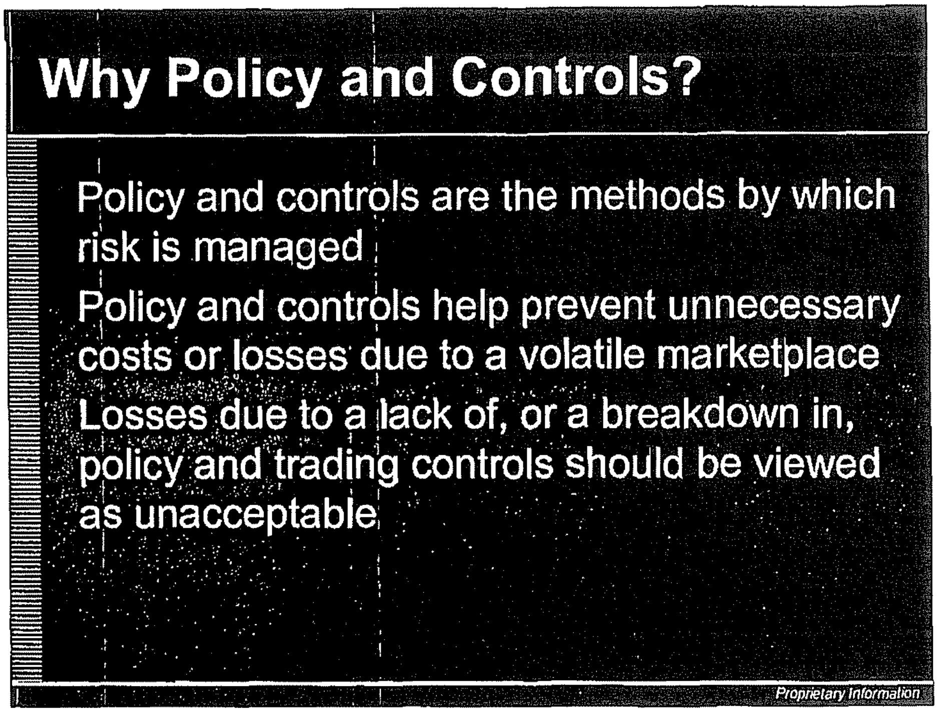
- Common themes to these types of losses:
  - Board and management misunderstanding of trading activities.
  - Lack of corporate controls or lax enforcement.
  - Early warning signs ignored.
  - Lack of separation of authority.
  - Lack of risk management expertise and risk management systems to monitor and measure the risks of the company.



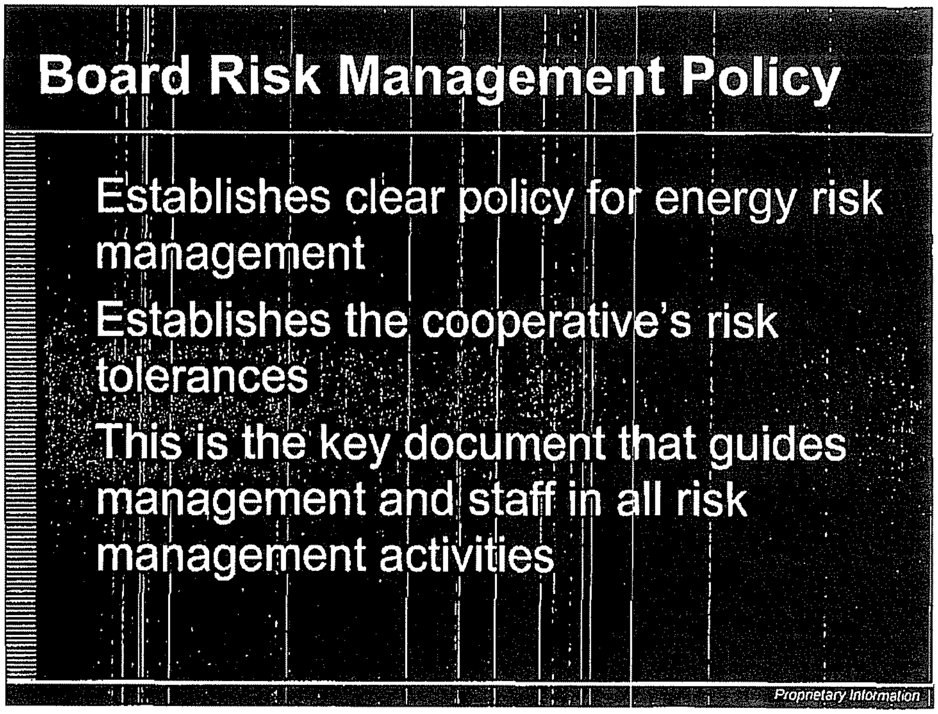
- Energy risk management is:
  - A disciplined control approach to managing the power supply functions of the business.
  - A plan for managing the fiduciary responsibilities of power supply board members.
- Energy risk management will be different for every cooperative. There is not one cookie cutter approach.



- So how do you manage risks?
    - You use controls.

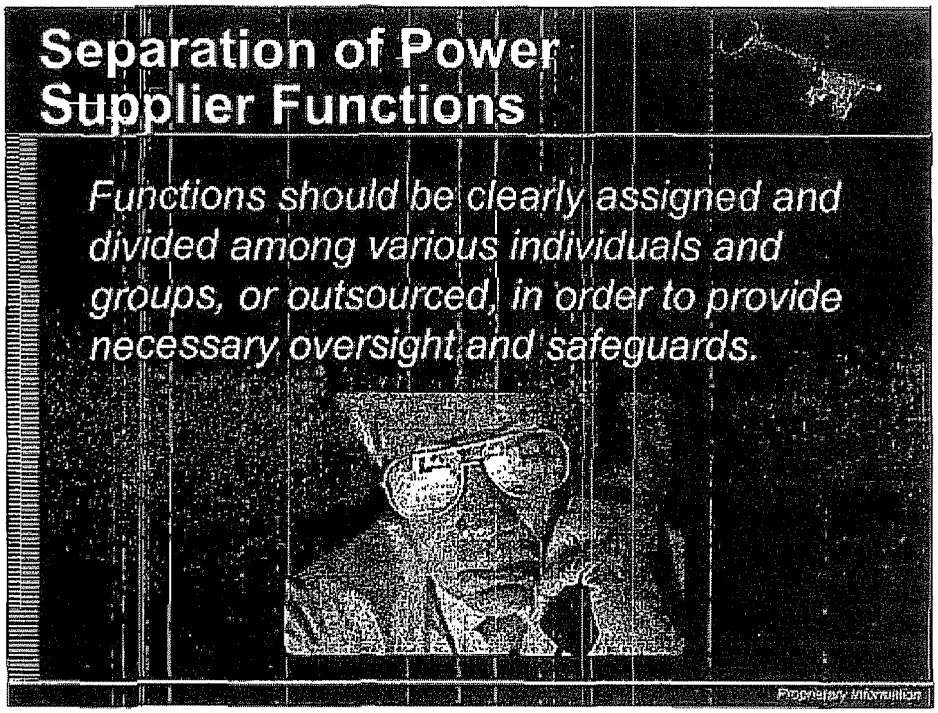


- So why are policy and controls necessary?
- Policy and controls are the method by which we manage our risk.
    - Policy and controls help prevent unnecessary costs or losses due to a volatile marketplace.
    - Unnecessary costs or losses due to a breakdown in policy and trading controls should be viewed as unacceptable.
- The Rural Utility Service (RUS) now requires G&Ts applying for loans to address most of the issues in an energy risk management policy.

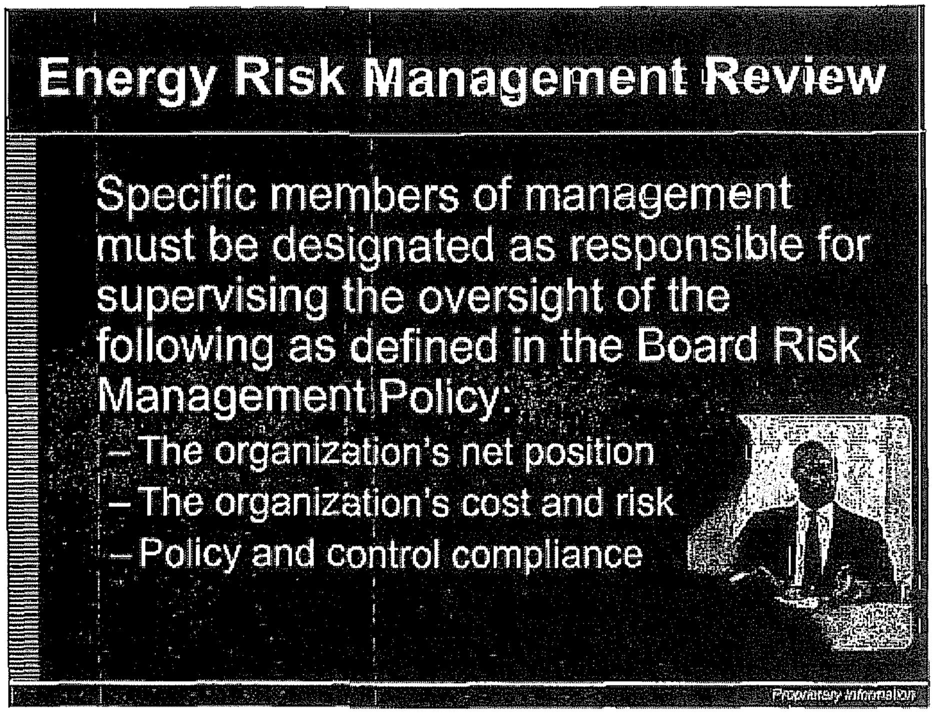


- The Board of Directors, by setting a risk management policy, creates a key component of the controls to be established. The board's risk management policy should:
    - Establish clear policy for energy risk management.
    - Establish the cooperative's risk tolerances.
- This policy is the key document that guides management and staff in all risk management activities.
- Refer to Appendix C Exhibit 5 (page C-5) to see an example of a generic Board Risk Management Policy outline.
- It is important to note that each policy may differ based on many factors, but a policy consistent with the Board of Directors risk tolerance should be adopted to guide risk management activities.

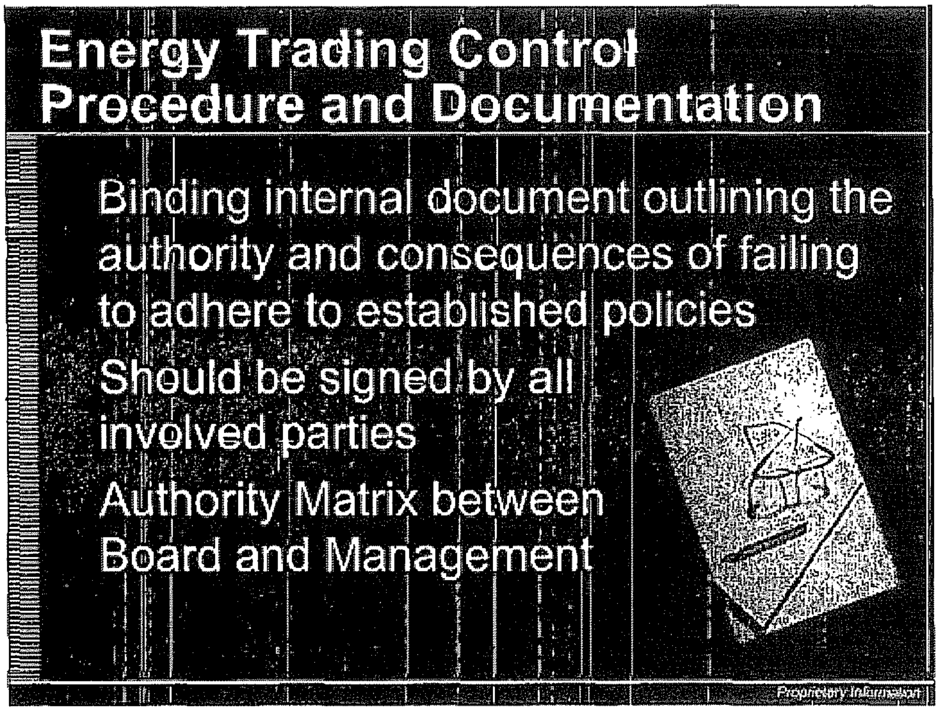
- Part of implementing and executing controls is the separation of power supplier functions. You should establish:
  - The accountability, authority, and responsibility of the organization at the board and management levels.
    - Board = Basic knowledge of hedging and proper oversight of risk management policies and procedures.
    - Management = Expertise in power supply and day-to-day operations and adherence to risk management policies and procedures.
  - Risk management committees, including:
    - Board committee
    - Internal risk management committee



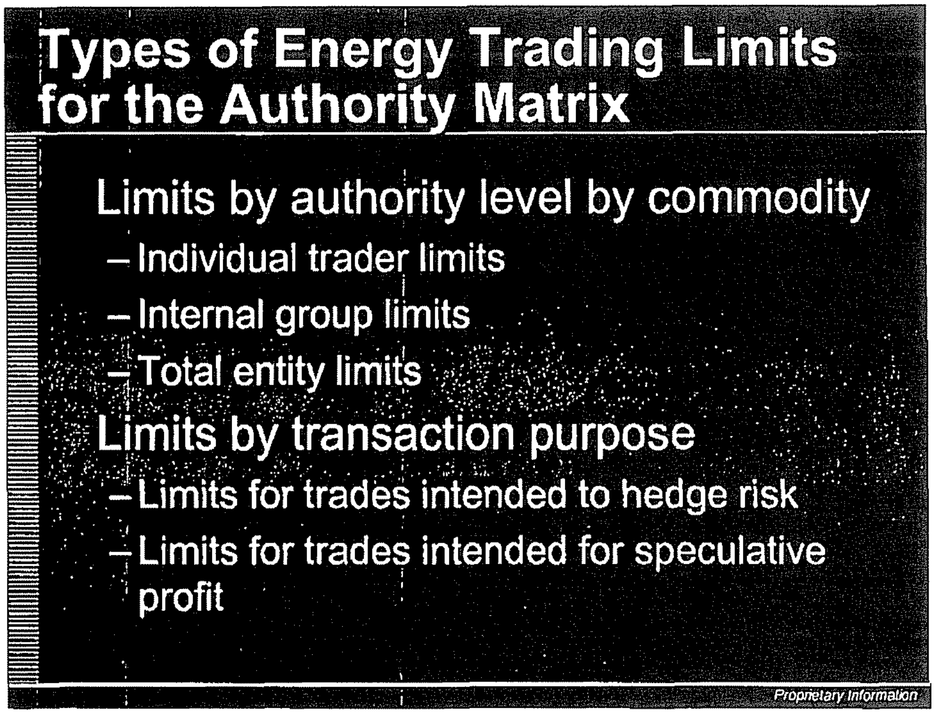
- The following functions should be clearly assigned and divided among various individuals and groups, or outsourced, in order to provide necessary oversight and safeguards:
    - Trading
    - Confirmation of trades
    - Legal approvals
    - Auditing
    - Payment approvals
    - Credit review and approval
    - Contract review and approval
    - Transaction pricing



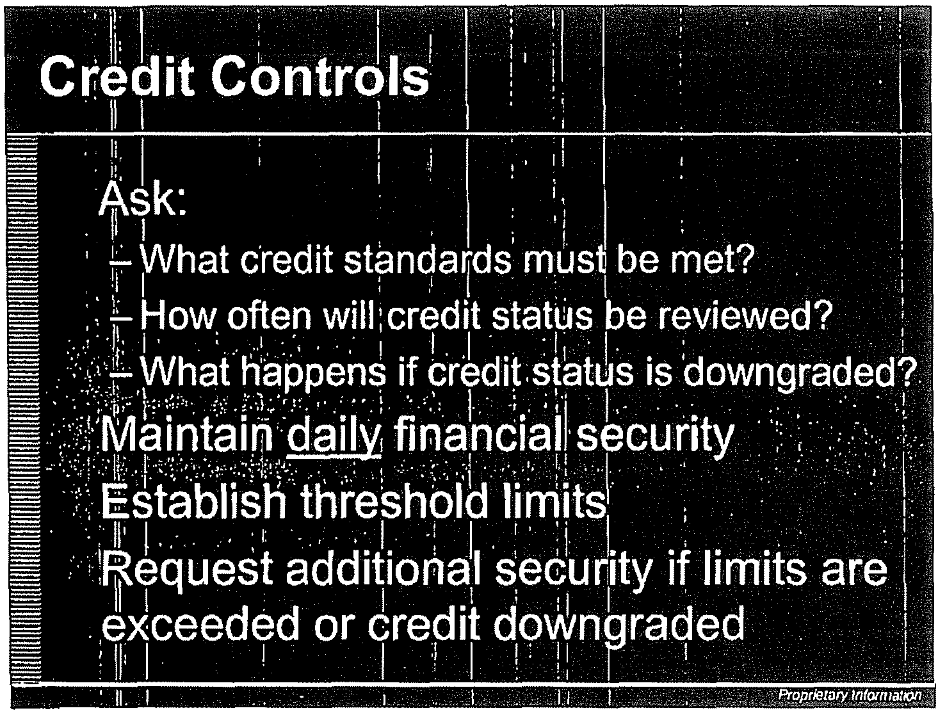
- Specific members of management must be designated as responsible for supervising the oversight of the following within the board's risk tolerance policy:
  - The organization's net position
  - The organization's cost and risk
  - Policy and control compliance
- Outside auditors should perform periodic checks on all risk management tasks.



- Energy trading control procedures and documentation are very important.
  - You should have in place a *binding document outlining* the *authority* and consequences of failing to adhere to that authority.
  - The document should be signed by all involved parties.
  - An *Authority Matrix between the Board and management* should be developed. An Authority Matrix defines agreed upon trading limits by authority by commodity.
- Example: Sue has the authority to buy X amount of natural gas. To exceed X amount, she must get the next higher level of authority to approve the purchase. Joe, is an hourly trader, and can do no more than 50MW with out approval from a higher authority.



- Types of energy trading limits for the Authority Matrix.
  - Limits by authority level by commodity (power, fuels):
    - Individual trader limits
    - Internal group limits
    - Total entity limits, for example:
      - CEO authority limit
      - Transactions requiring board approval
  - Limits by transaction purpose:
    - Limits for trades intended to hedge risk
    - Limits for trades intended for speculative profit
- Refer to Appendix C Exhibit 6 (page C-9) for an example of a generic power trading authority matrix.



- Credit controls.
  - Questions to ask about controlling credit:
    - What credit standards must be met?

      ____

    - How often will credit status be reviewed?

      ____

    - What happens if credit status is downgraded?

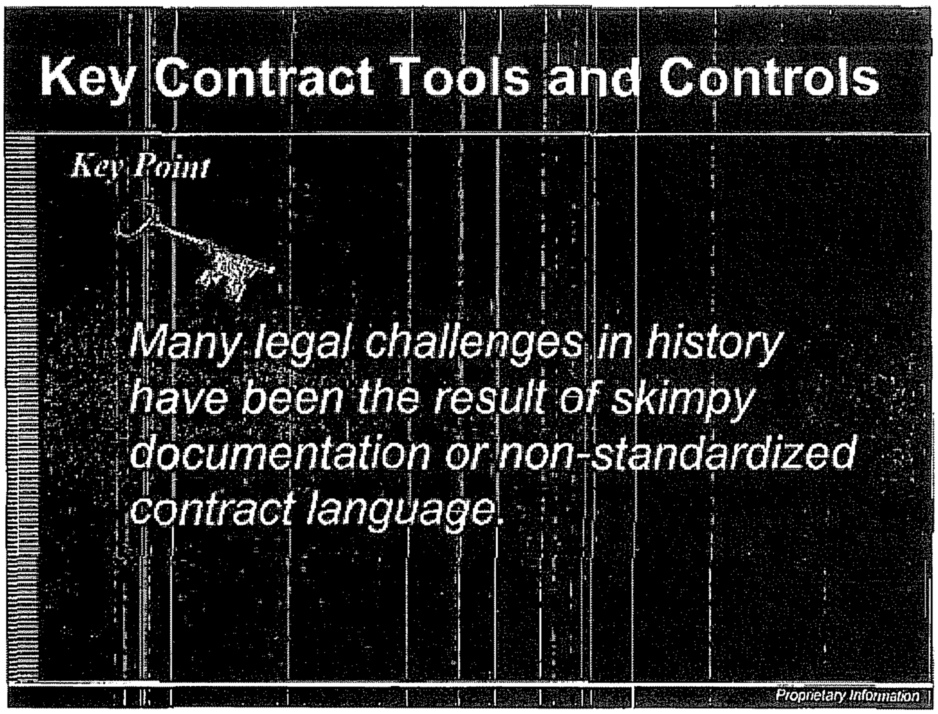
      ____

- Many people maintain a daily credit watch on all of their counterparties.
- Threshold limits established based on original security and negotiations.
- Additional security requested if limits exceeded or credit has been downgraded.

- Key contract tools and controls:

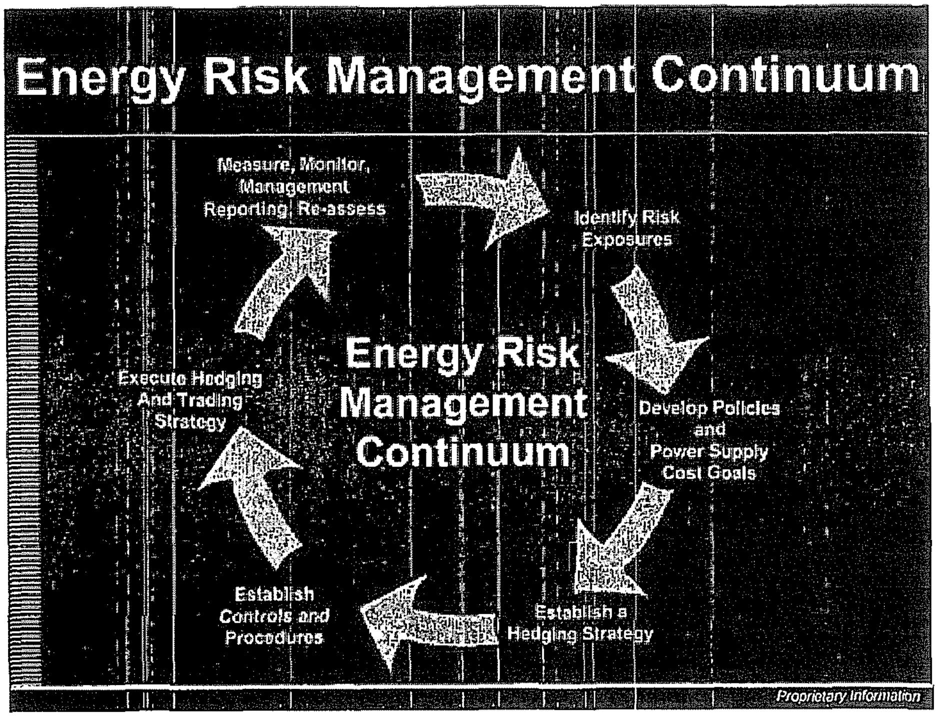
- Types of contracts:

- Standardized contracts are becoming the industry norm. However, some companies are still doing business under old, non-standard vintage contracts.
- Daily contract administration entails monitoring expirations, ensuring written confirmations are properly executed, and ensuring that all trading activities are consistent with contractual agreements.
- Be certain you have enforceable documentation, including:
    - Signatures, are they authorized signatories? For:
        - Contracts
        - Written confirmations
    - Verbal confirmations and recordings
        - Are they acceptable for trade type?
        - Are they legally binding?
        - Is the trader authorized to make deal?

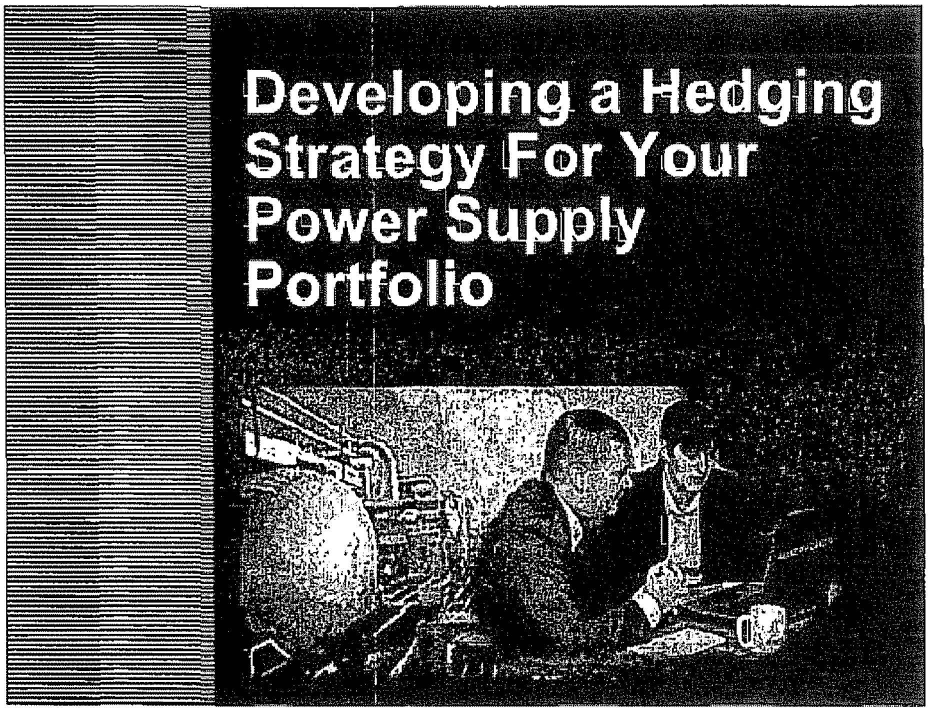


- Many legal challenges in history have been the result of skimpy documentation or non-standardized contract language.
    - Note that the first thing you will do when a deal goes bad is go back and look at the contract.
- It is important to talk to an attorney. It can be dangerous to do transactions under old, vintage contracts. If something happens, the contract may not be enforceable. All existing and new contracts should be reviewed by professionals to ensure that they are in line with new-world energy practices.
- Contract controls should be put in place to ensure:
    - Contracts are appropriate.
    - Any transactions that occur are aligned with the master contract.

- Enhancements may be needed to the company's software, hardware, and technology.
    - Systems are needed for:
        - Monitoring trading positions
        - Measuring trading activity against market prices
        - Measuring risk exposure of trading activity
        - Monitoring credit risk and limits
        - Monitoring contractual compliance
        - Business continuity and disaster recovery
- You will have a true technology challenge in establishing good trading controls. Energy risk management is different for everyone. There is no cookie cutter system.
- There are professionals that can assist you in this process.



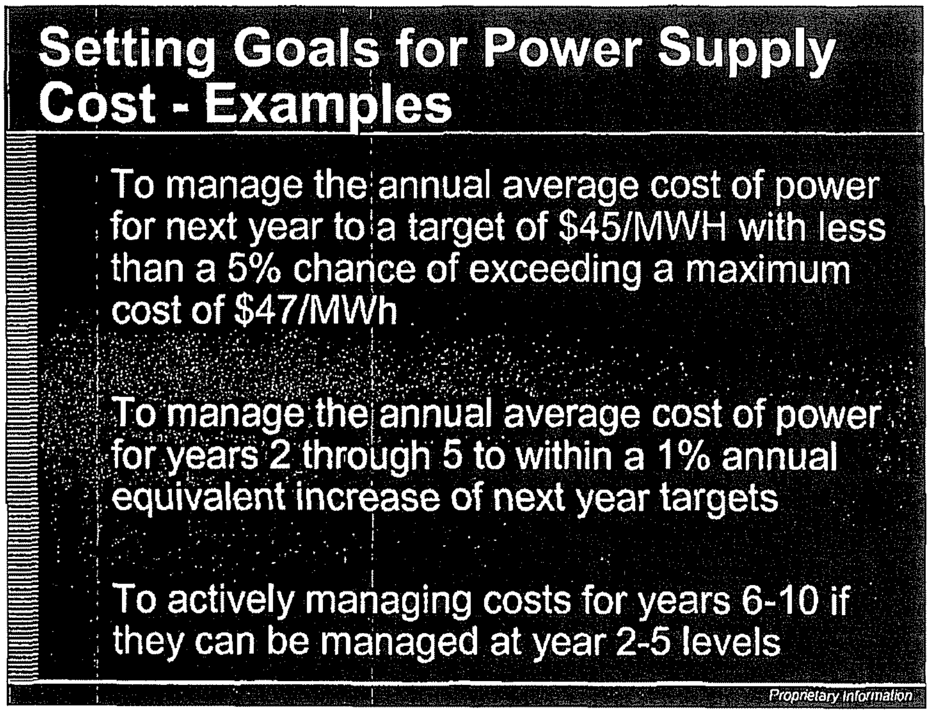
- The Risk Management Continuum:
  - Identify risk exposures
  - Develop policies and power supply cost goals
  - Establish a hedging strategy
  - Establish controls and procedures
  - Execute the hedging and trading strategy
  - Measure, monitor, management reporting, and reassessment
- This is an on-going process.



- Developing a hedging strategy for your power supply portfolio.

- Now that you've seen the importance of controls, and the cycle we need to go through to manage risk, you will want to establish risk management goals and power supply cost policies.
  - First you have to understand what is possible. Start with your power supply cost goal.
  - Your power supply cost goals must be objective, specific, and realistic:
    - If you say "lowest possible cost," what does lowest possible cost" mean?
      - Given what risk tolerance?
      - Given what time horizon?
    - What does "at or below market" mean?
      - Today's market price?
      - Prices in the future?
    - What does "reduce price volatility" mean?
      - Define risks that the co-op is willing to accept
      - Consider tradeoff between cost and risk
- The power supplier's cost will translate directly into the price of power for the distribution cooperative.
- So how are we going to meet our power supply cost goal? Though hedging.

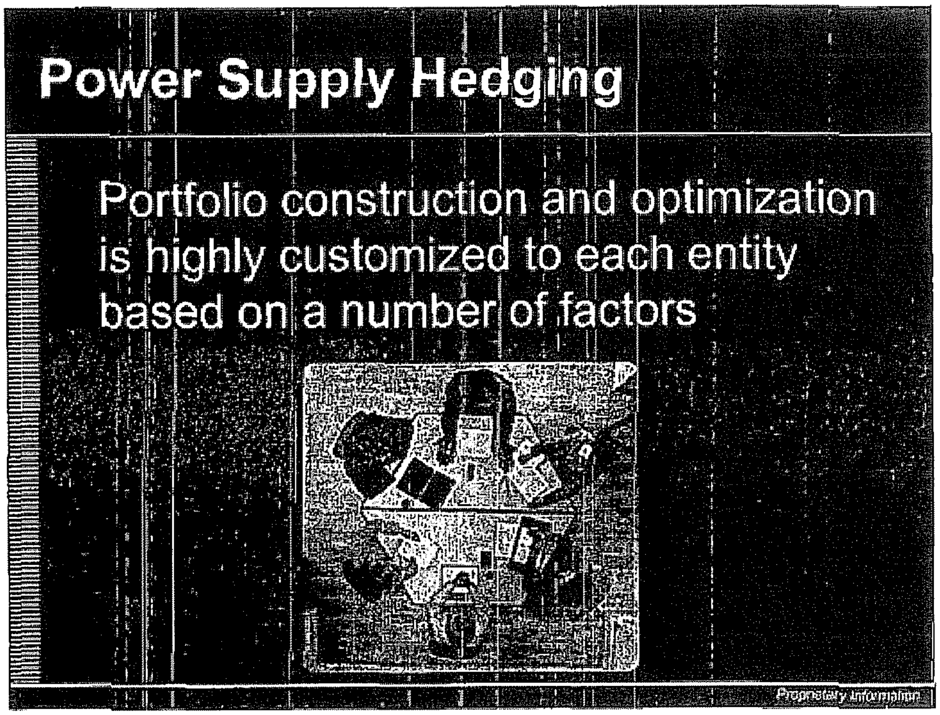
Case No. 2012-00535
Attachment 1 for Response to AG 2-7
Witness: Mark A. Bailey



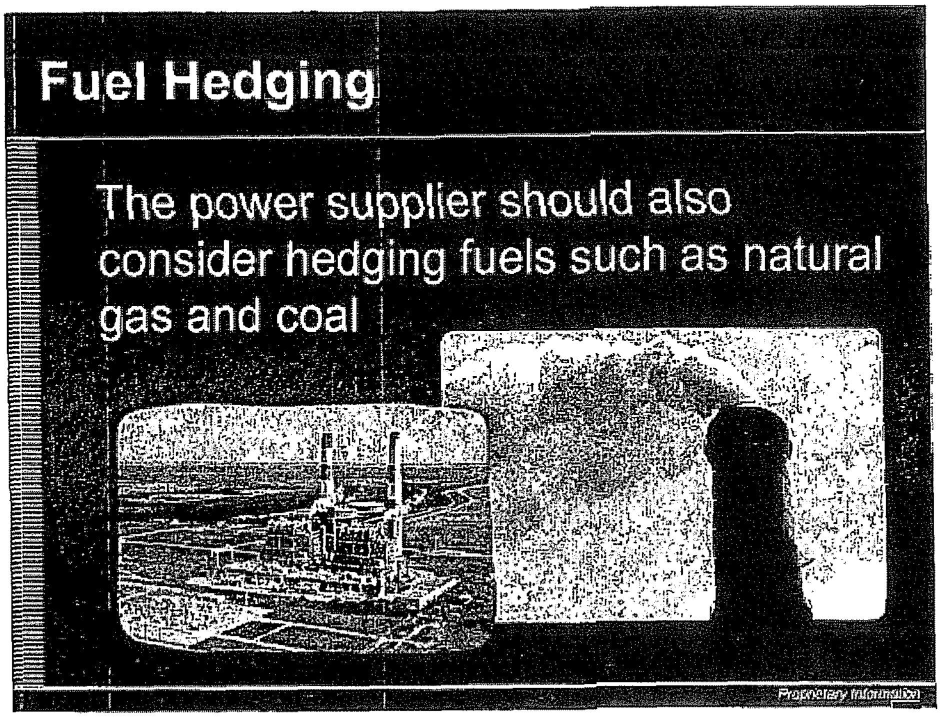
- These goals must be realistically set and based on modeled conditions that can be achieved for the power supplier. The power supply cost goals must also be set based upon the risk inherent in the power suppliers
- Examples of goals:
  - To manage the annual average cost of power for 2003 to a target of $45/MWH with less than a 5% chance of exceeding a maximum cost of $47/MWh.
  - To manage the annual average cost of power for the years 2004-2010 within a 1% annual equivalent increase of the 2003 target and maximum price goal.

- What is hedging? As defined in Energy and Power Risk Management, a hedge is:
  - Any transaction that moves the corporate risk profile toward the shareholder's desired risk profile in the most efficient manner possible.
- The Management and Board should strive to achieve a consistent understanding of what a "hedge" means to the G&T.
- Hedging can partially or totally eliminate your power supply cost risks.

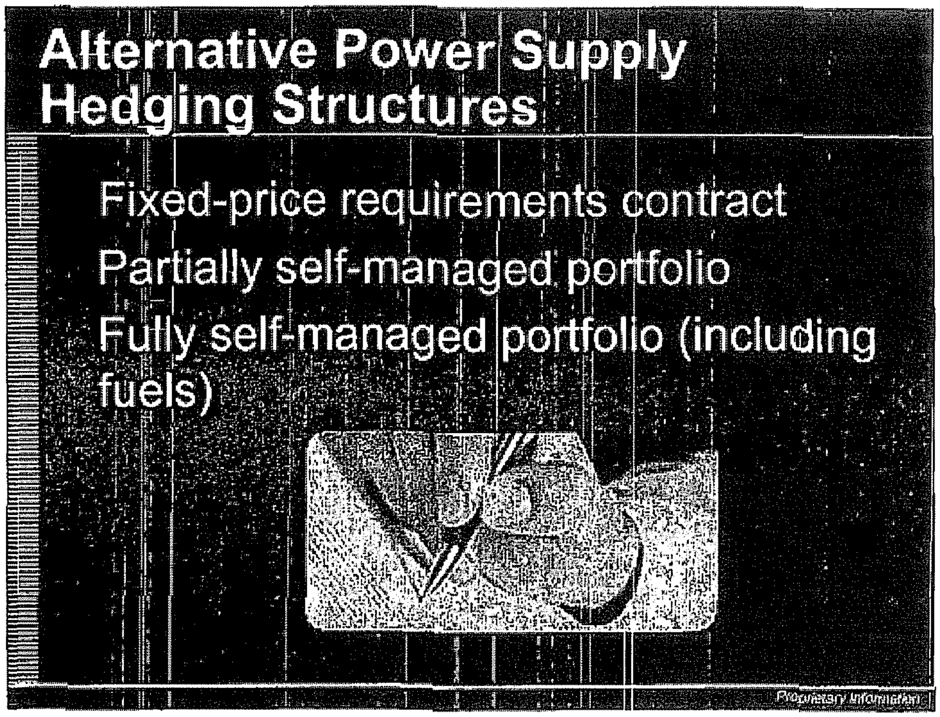
- Concept of developing hedging strategies.
  - G&Ts have commitments to supply power to distribution co-ops. The G&Ts, therefore, need supply to meet this demand.
  - Many tools exist to efficiently hedge, to buy supplies, but perfect hedges can be very costly.
- Example:
  - The G&T has a portfolio of supply resources of 1,000 MW (e.g., power plants, power supply contracts).
  - It is expected that load growth amount its 10 member distribution co-ops will result in a forecasted peak load next year of 1,100 MW.
  - The G&T is 100 MW short on supply. To hedge this position, the G&T would need to go out and buy power supply of 100 MW.



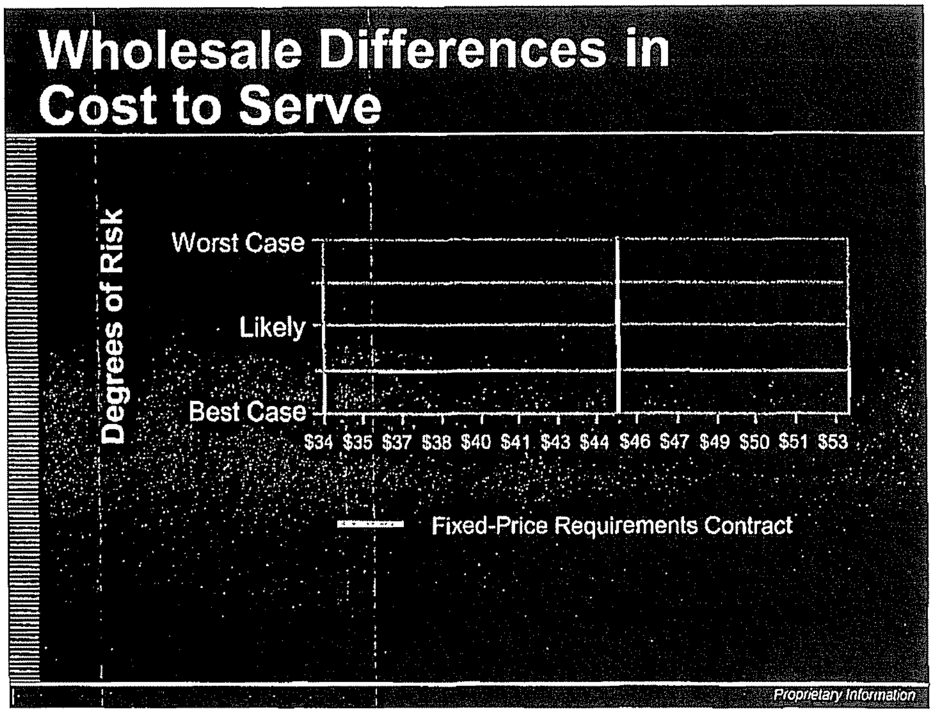
- Portfolio construction and optimization is highly customized to each cooperative based on a number of factors. Hedging strategies for one co-op's portfolio may be very different from another's. Factors include:
  - Risk management and power supply goal (and risk tolerance)
  - Market prices (not necessarily cost)
  - Customer base and length of sales obligations
  - Company skill set
  - Location - you will construct your portfolio differently depending on where you are located. Location issues to consider are:
    - Transmission: Independent System Operator (ISO) or Regional Transmission Organization (RTO) constraints
    - Market rules and structure (hourly pool)
    - Generation issues (types, reserve margins)
    - Market liquidity (instruments available in your region)
  - Reliability council rules for:
    - Planning reserves
    - Capacity requirements



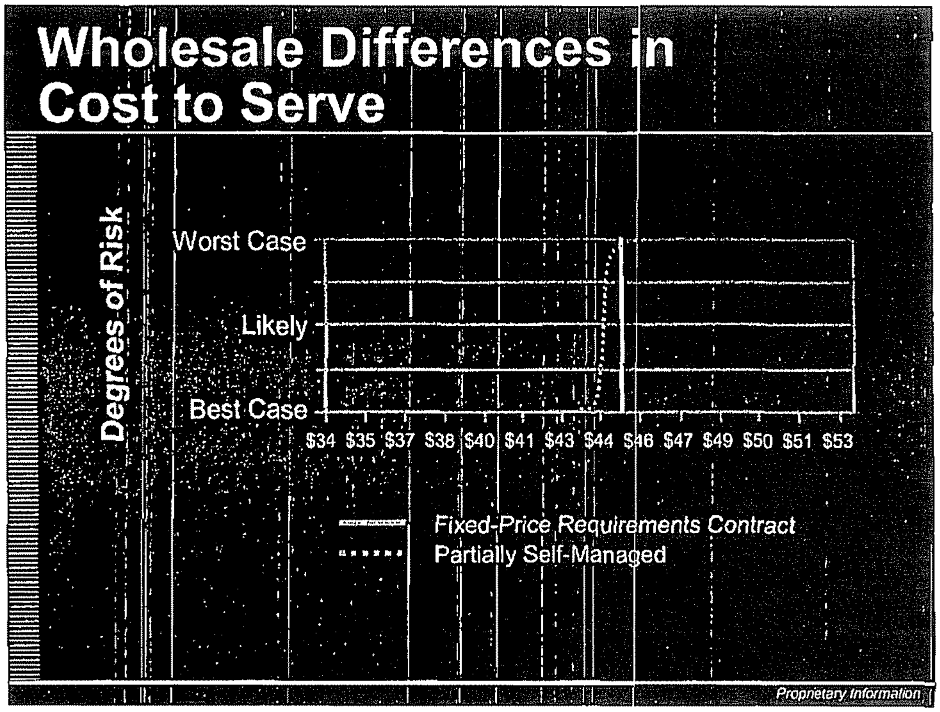
- Concept of fuel hedging:
  - Fuels such as natural gas and coal can be hedged for expected needs to serve native load plus any firm sales obligations.



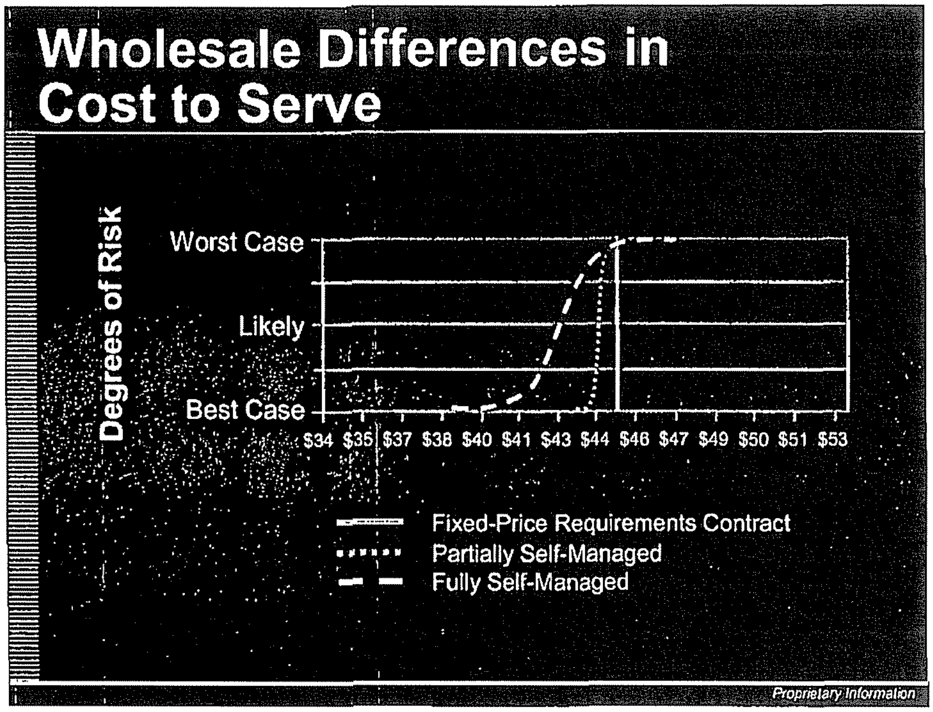
- There are alternative power supply hedging structures. When you hedge your portfolio, you can do it three ways:
  - Full requirements contract - at a fixed price where someone is going to take all of your risks (note: this is different from a G&T)
    - Limited (or no) price volatility
    - Limited operations and no trading infrastructures
    - Very little risk at guaranteed fixed price
  - Partially self-managed portfolio - you can also construct a portfolio where someone is taking some of the risks.
    - Self-manage limited risks, e.g., fuel cost risk
    - Moderate operations and trading infrastructures
  - Fully self-managed portfolio (including fuels)
    - Self-manage risks with trading tools and derivatives
    - Extensive operations and trading infrastructures
- Some G&Ts and cooperatives have already decided to go these different routes. Some have gone with full requirements contracts. Others have accepted the full range of risks.



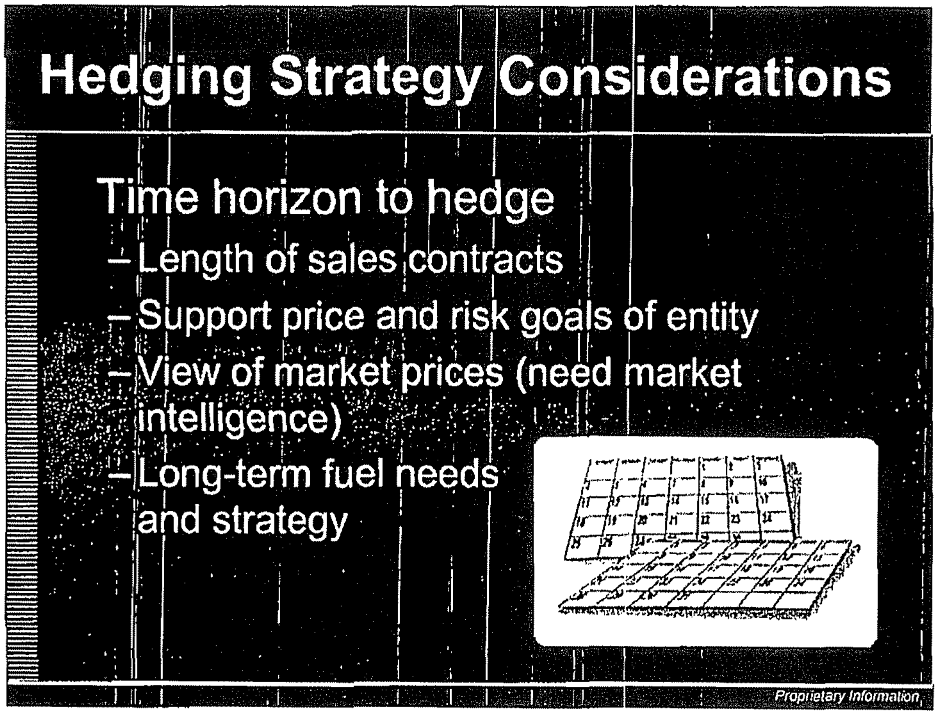
- The wholesale differences in cost to serve and the varying degrees of risk (worst-to-best case). First:
    - A fixed-price requirements contract is illustrated by the solid line - no matter what happens you will have a single price per MWh (in this case about $45). They've taken away all of your risks and uncertainties and guaranteed you a fixed price. This is your least risky and most costly option.



- The wholesale differences in cost to serve and the varying degrees of risk (worst-to-best case).
    - A partially self-managed portfolio is illustrated by the dotted line. Here there are alternatives to manage risk and move to a less risky position. However, it will be more costly. Here the cost range is from about $43 to $46.

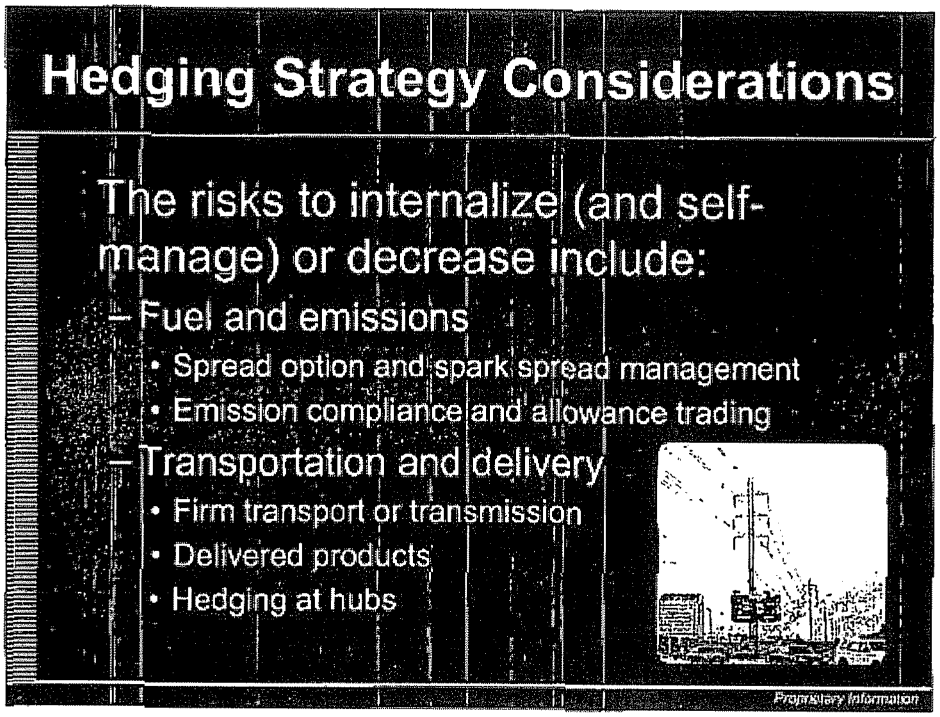


- The wholesale differences in cost to serve and the varying degrees of risk (worst-to-best case).
    - A fully self-managed portfolio assumes (and manages) all of the potential risks - this is illustrated by the dashed line. Here the cost range is about $39 - $48.
- These costs can be illustrated statistically through risk modeling. Where you "draw the line" is directly related to your defined risk tolerance.

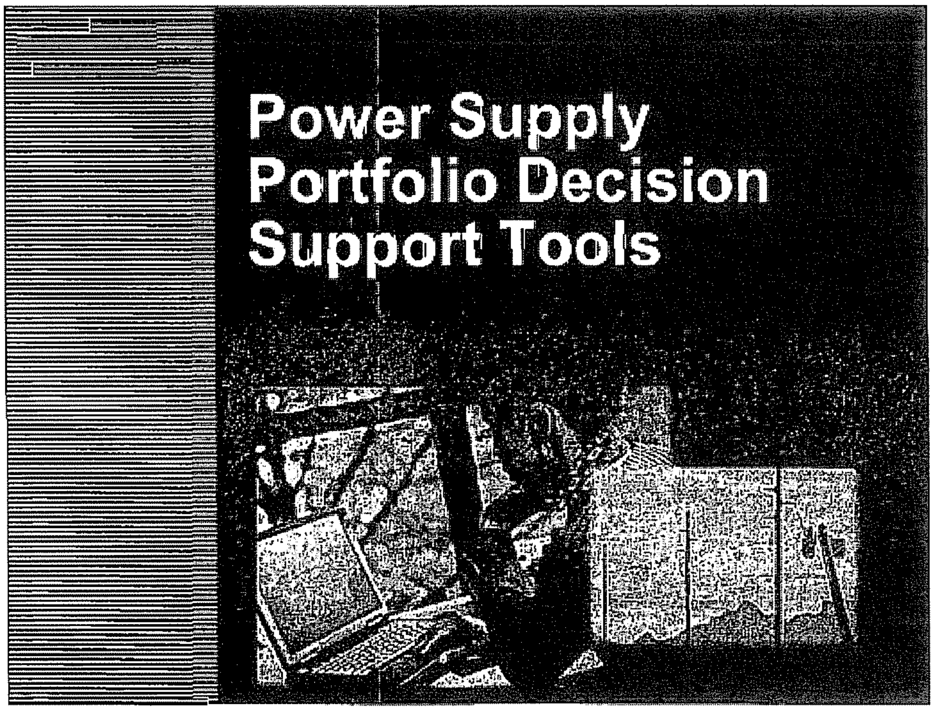


- Hedging strategy considerations:
  - Determine time horizon to hedge:
    - Length of sales contracts
    - Support price and risk goals of entity
    - View of market prices (you need market intelligence)
    - Long-term fuel needs and strategy

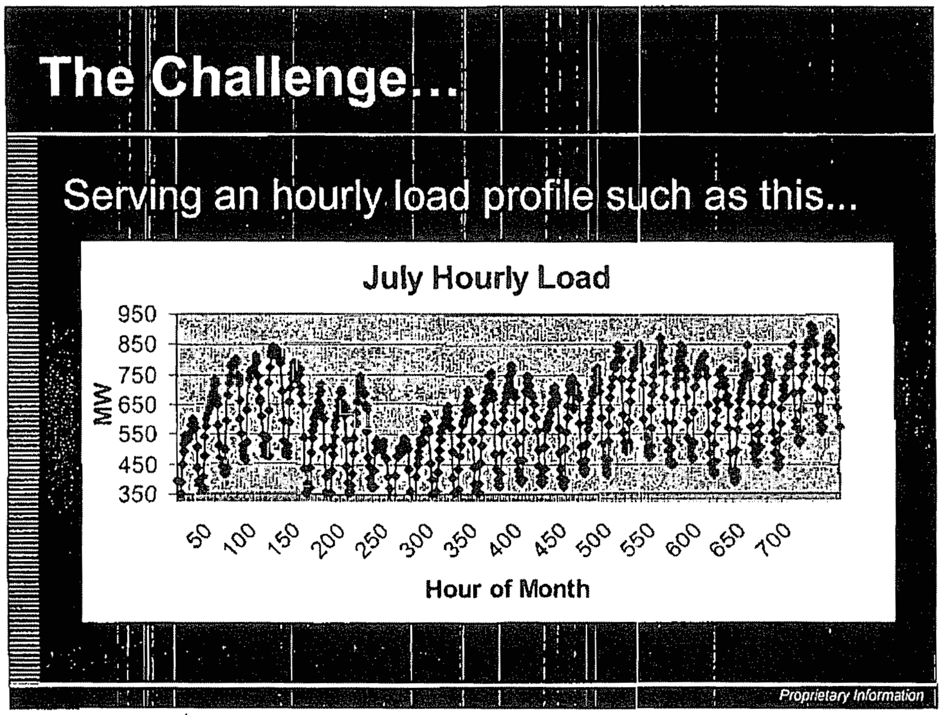
- Risks to internalize (and self-manage) or decrease such as:
  - Outage risk:
    - Unit contingent vs. firm or backed up purchases
    - Owned generation
  - Volumetric risk:
    - Mismatch between hedge products and hourly load profile
    - Hourly balancing risks
    - Load forecast error



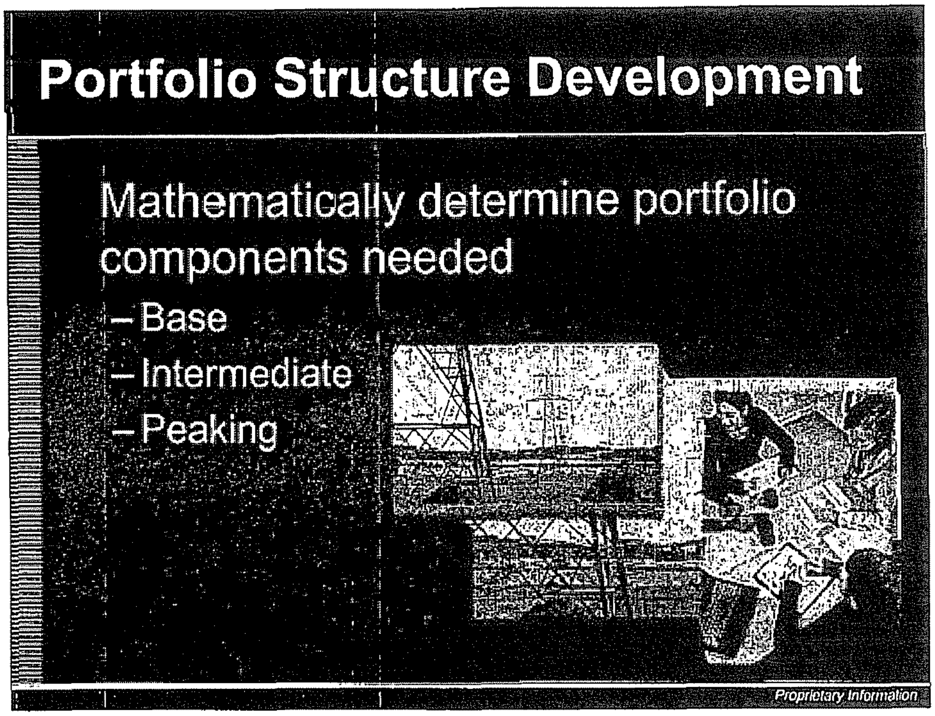
- Other risks to internalize (and self-manage) or decrease:
    - Fuel and emissions:
        - Spread option and spark spread management
        - Emission compliance and allowance trading
    - Transportation and delivery:
        - Firm transport or transmission
        - Delivered products
        - Hedging at hubs
- You've learned about hedging and some of the things to consider. Now you will want to develop your portfolio. There are a number of tools to help you do this.



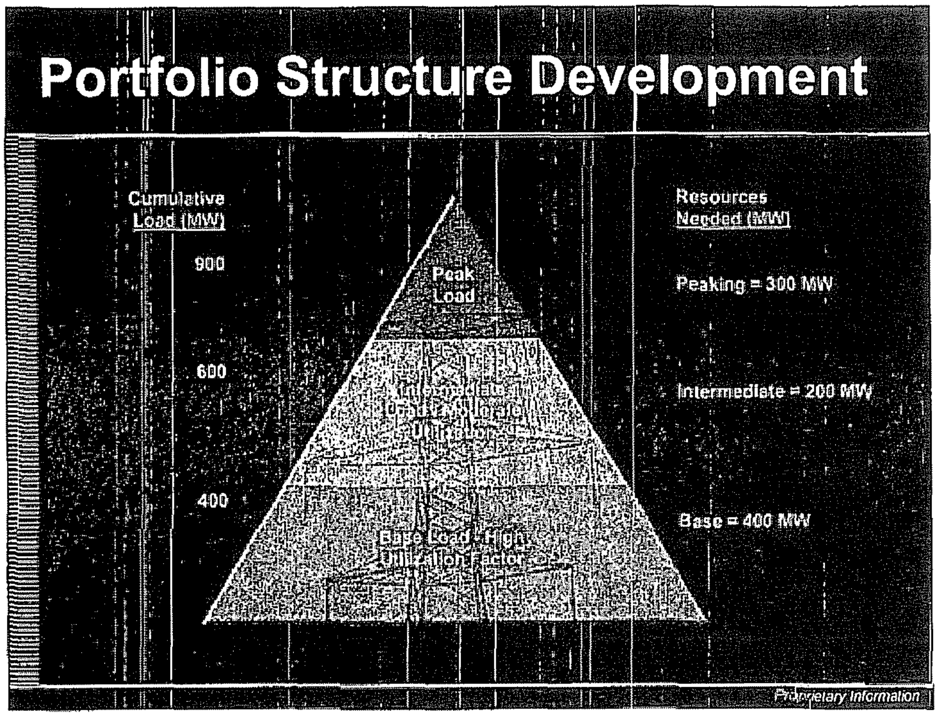
- This topic covers power supply portfolio decision support tools.



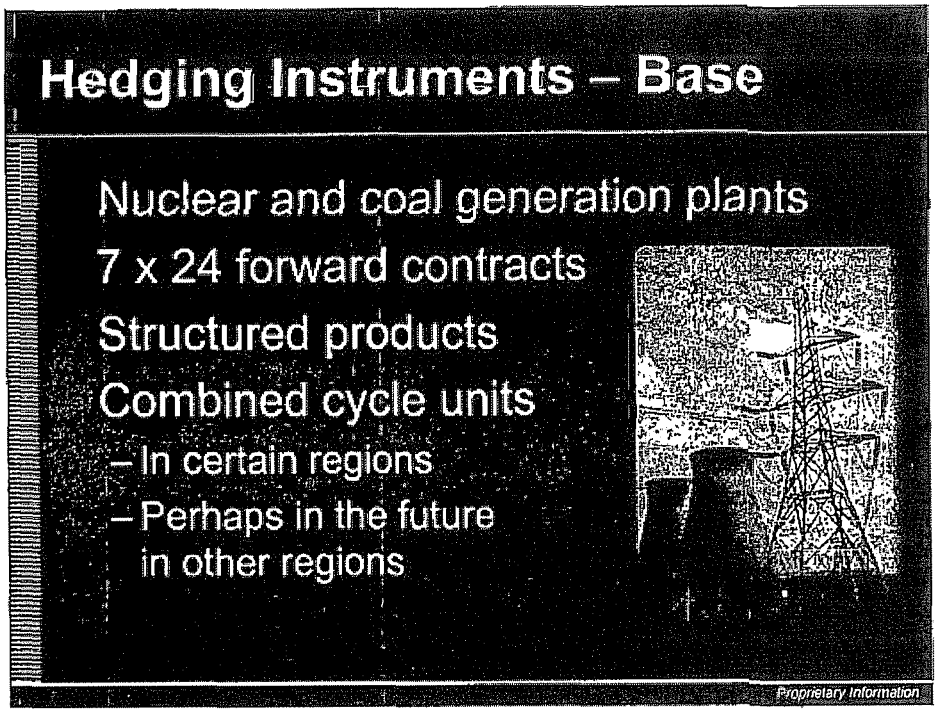
- This is the load profile of a distribution cooperative such as yourself.
- The power supplier is trying to meet this demand and its very difficult.
- There are challenges of serving an hourly load profile such as the one shown here.



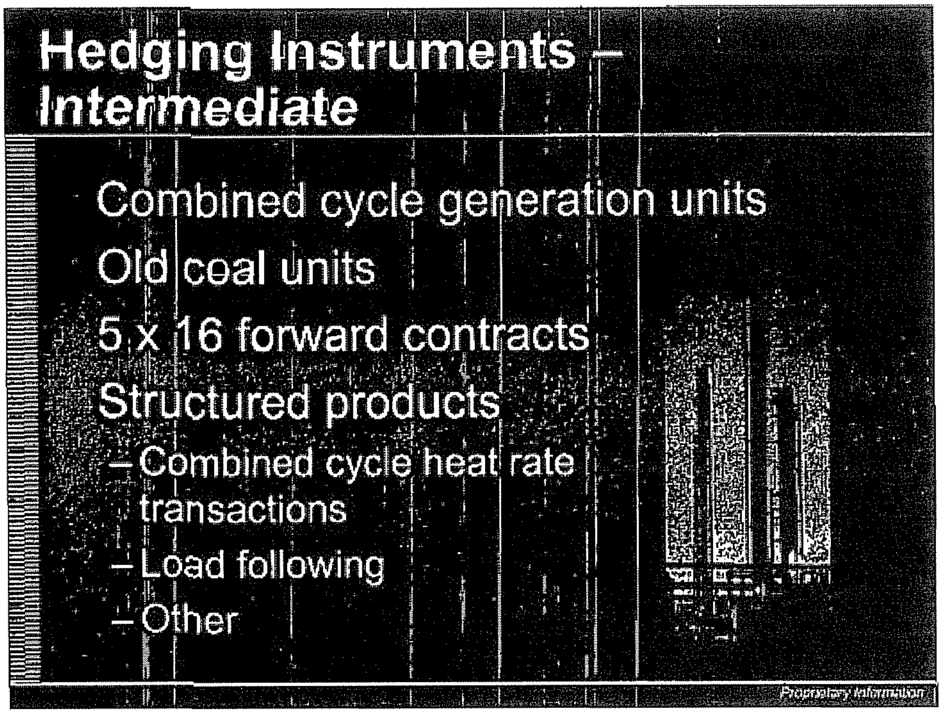
- There are sophisticated, computer driven models that will help you develop the structure of your power supply portfolio:
  - Mathematically determine the portfolio components that are needed:
    - Base component
      - High annual load factor
      - High capital-cost and low variable-cost
    - Intermediate component
      - Moderate annual load factor
      - Moderate capital-cost and moderate variable-cost
    - Peaking component
      - Low annual load factor
      - Low capital-cost and high variable-cost



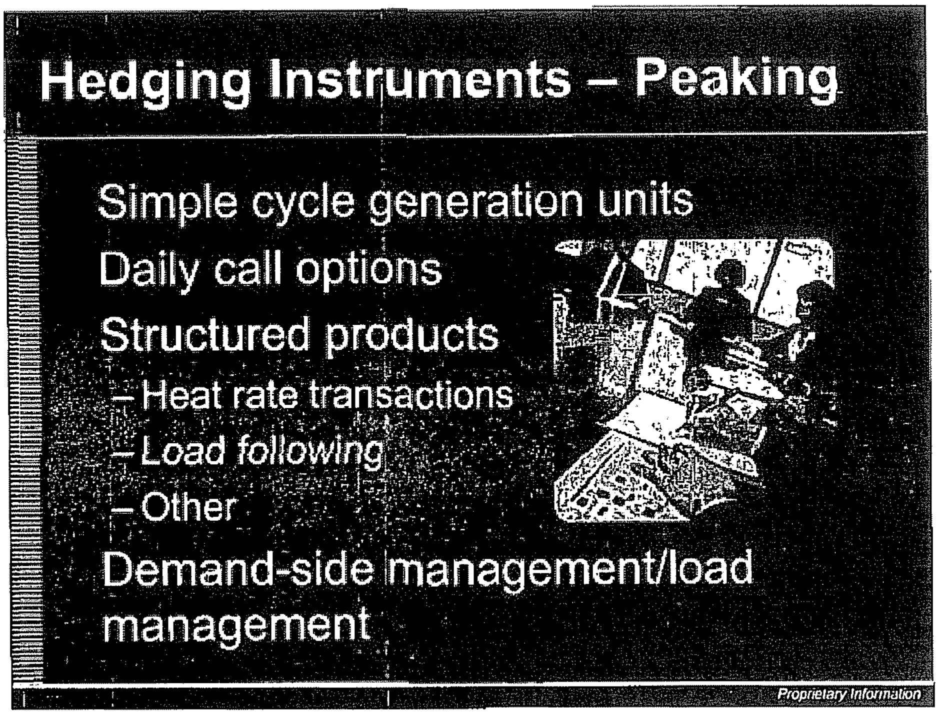
- This is the basic model for portfolio structure development.
    - Base load is that portion of your load that you know you will have every hour. You would buy base load types of resources that are most efficiently utilized with a high load factor.
    - Intermediate load - this portion of load is served during business hours or hot or cold weather.
    - Peak load -this magnitude of demand occurs during a limited number of hours in each year.
- It is important to buy resources that adequately match your base, intermediate, and peaking load profile.
- Like a balanced diet, this simplified graphic illustrates the concept of a balanced portfolio. Be aware that this model ignores issues such as diversifying each component with a variety of resources and potential reserve requirements.
- *Note: This graphic is not to scale.*



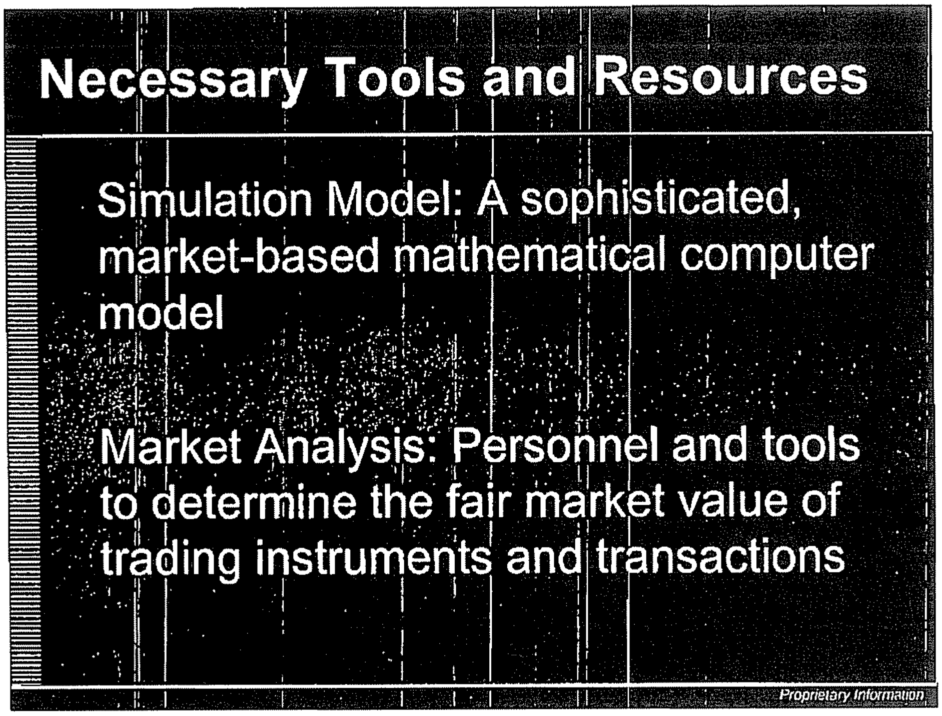
- Hedging instruments for base requirements:
  - Nuclear and coal generation plants
  - 7 x 24 forward contracts - you've purchased power in the future 7 days a week, 24 hours a day to meet your base load.
  - Some structured products will serve base load needs
  - Combined cycle units
    - In certain regions (e.g., natural gas providing regions)
    - Perhaps in the future in other regions



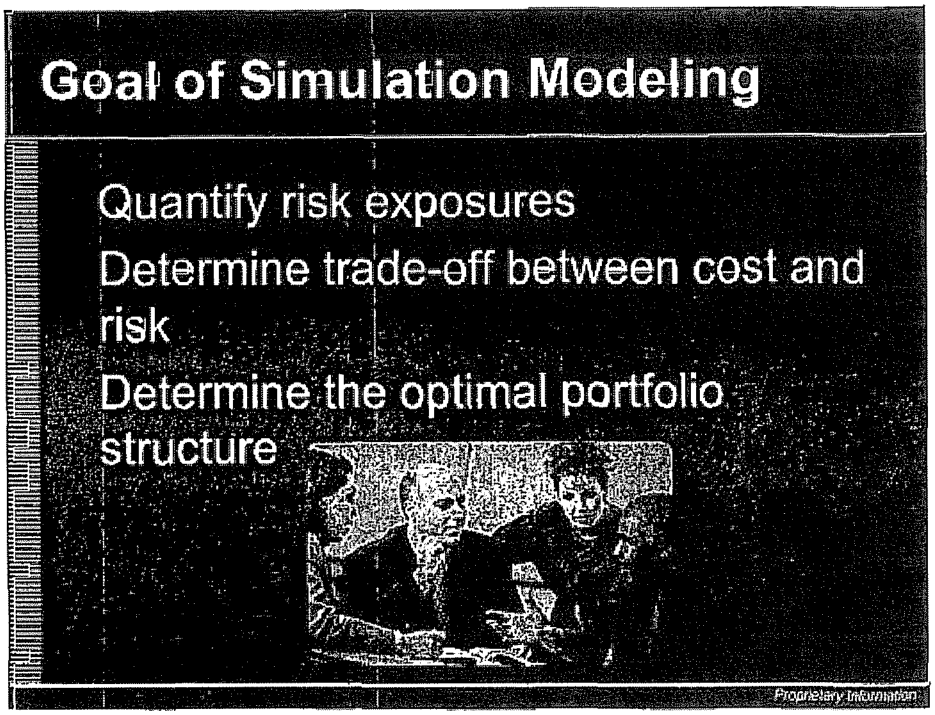
- Hedging instruments for intermediate requirements:
  - Combined cycle generation units - high efficiency natural gas units produce power at a reasonable cost.
  - Old coal units
  - 5 x 16 forward contracts - power supply contract where supplier will provide power for 5 days, 16 hours a day (i.e., during business hours)
  - Different structured products
    - Combined cycle heat rate transactions
    - Load following
    - Other



- Hedging instruments for peaking requirements:
    - Simple cycle generation units (also known as "CTs") - most widely used. They are cheap to build but are not highly efficient so it costs a lot more to run them.
    - Daily call options - this is where you have the right to buy power but not the obligation.
    - Structured products:
        - Heat rate transactions
        - Load following
        - Other
    - Demand-side management and load management can be an effective management resource by lowering demand.
- Refer to Appendix C Exhibit 7 (page C-10) to explore a potential portfolio of resources and hedges that a 900 MW system may possess.

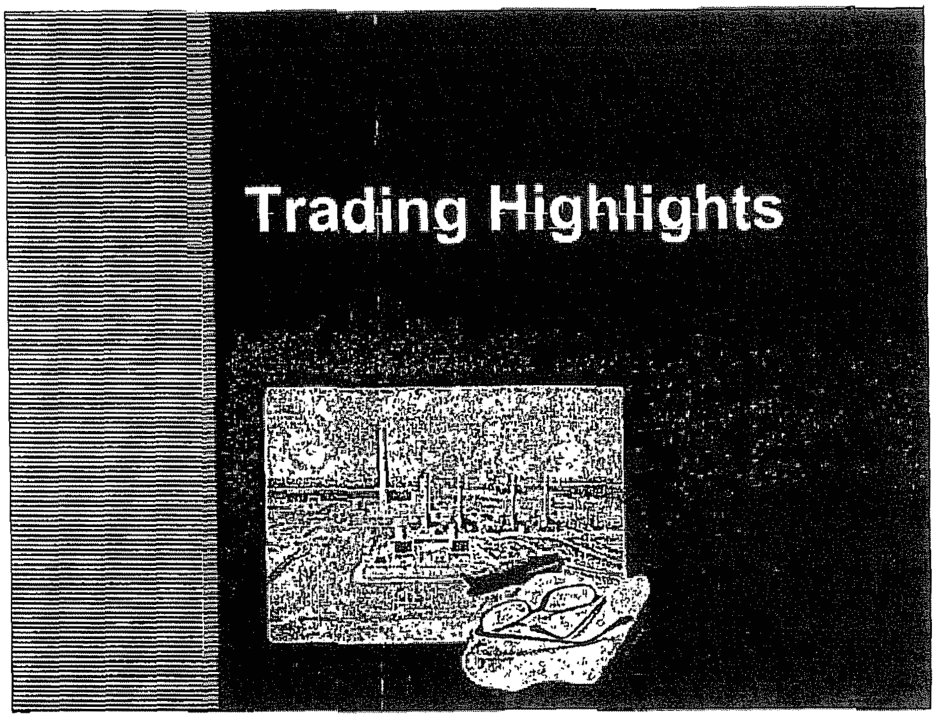


- Power can be a very difficult commodity to understand the value of. You cannot store it or inventory it. Price volatility is extreme.
- There are tools and resources that are available to help:
    - Simulation models are sophisticated, market-based, mathematical computer models.
    - Market analysis uses personnel and tools to determine the fair market value of trading instruments and transactions. This enables you to know you're getting the best value.

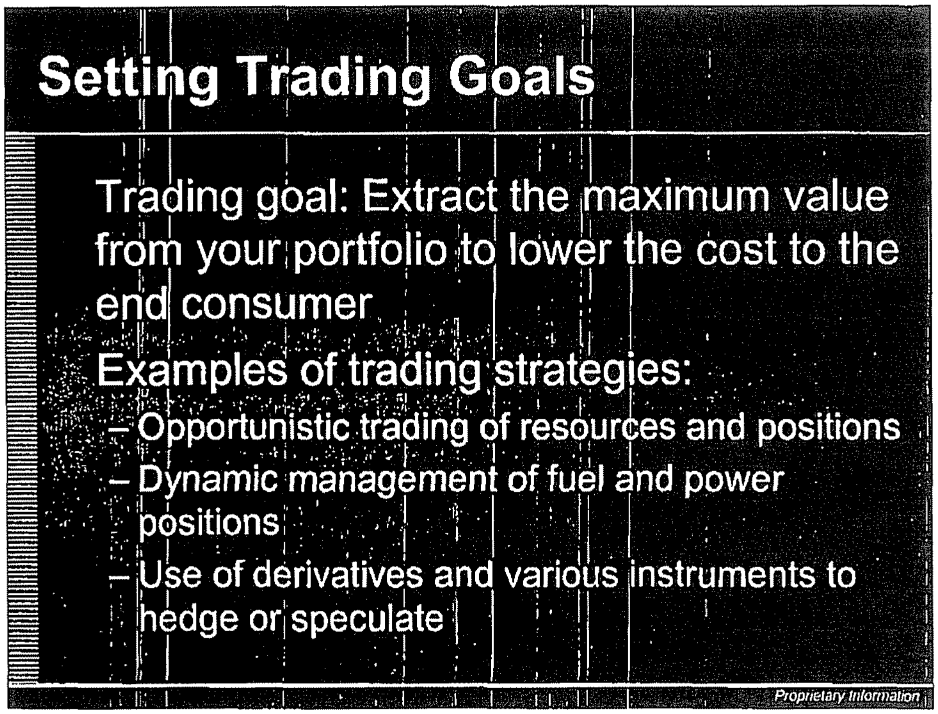


- Gals of simulation modeling:
  - Quantify risk exposures. The simulation model will help you determine your risk exposure.
  - Determine trade-off between cost and risk. This is where we get the lines on the Wholesale Differences in Costs to Serve chart on page 74 of your Participant Guide.
  - Determine the optimal portfolio structure.

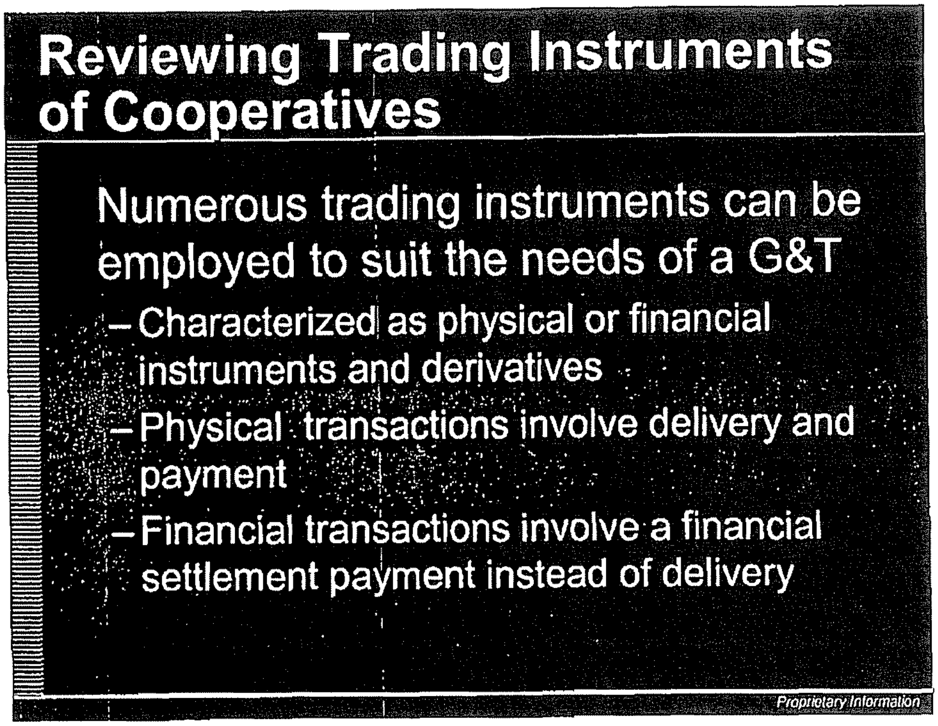
- Goals of market analysis:
    - Recognize the value of various power supply products
    - Negotiate the lowest cost power supply deals
    - Make decisions with confidence
- Small mistakes can result in large losses.



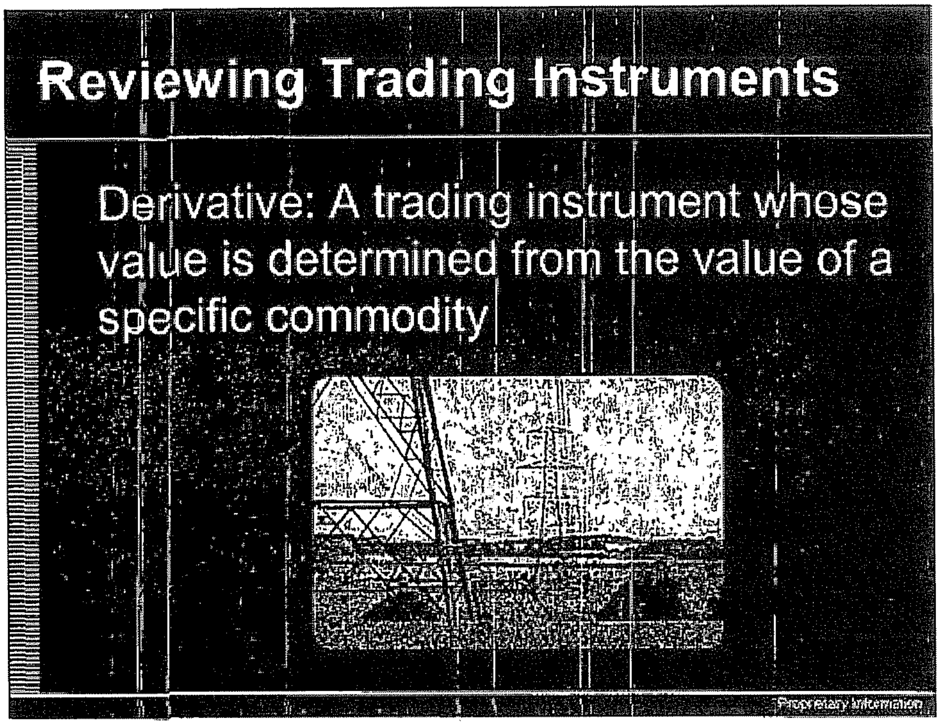
- This topic will discuss some trading highlights.



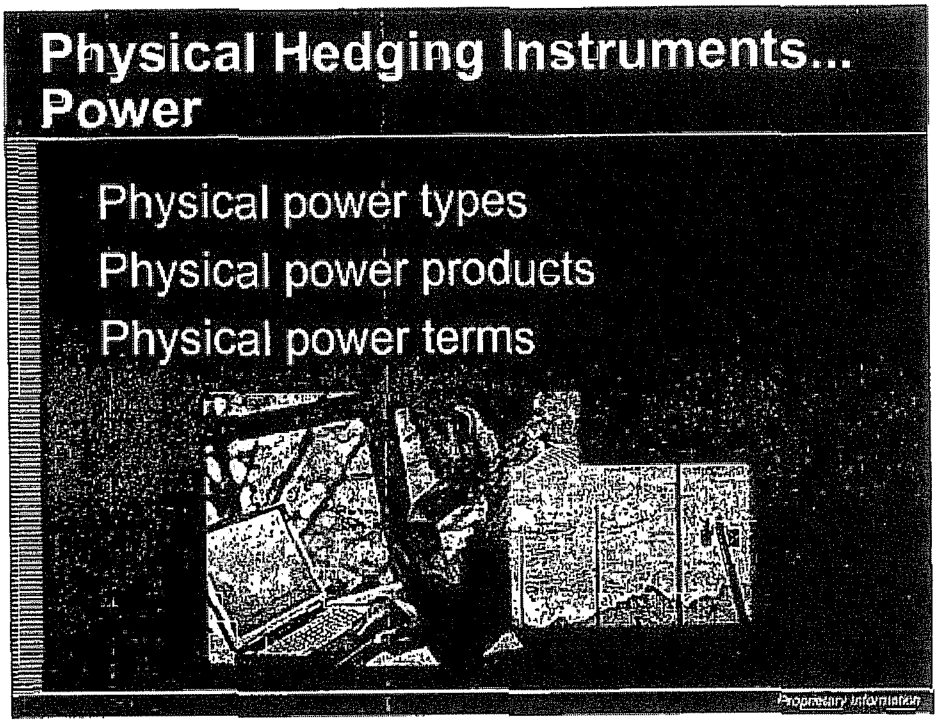
- Trading is all of the things that you do to manage your risk.
  - Your trading goal is to extract the maximum value from your portfolio to lower the cost to the end consumer.
  - Examples of trading strategies include:
    - Opportunistic trading of resources and positions.
    - Dynamic management of fuel and power positions.
    - Use of derivatives and various instruments to hedge or speculate.
- Example:
  - In the fall, a G&T buys natural gas to run its plants next summer. Two months later, gas prices for next summer have risen substantially, while summer power prices have fallen. By actively managing the portfolio power positions of the G&T, the natural gas can be sold at a profit and power can be purchased more cheaply - at a price that is less than producing it with the natural gas fired generation units. This activity would reduce the overall power supply cost of the G&T.
- Is your responsibility to look out for your organization.
- Refer to Appendix C Exhibit 8 (page C-11) for an example of opportunistic trading.



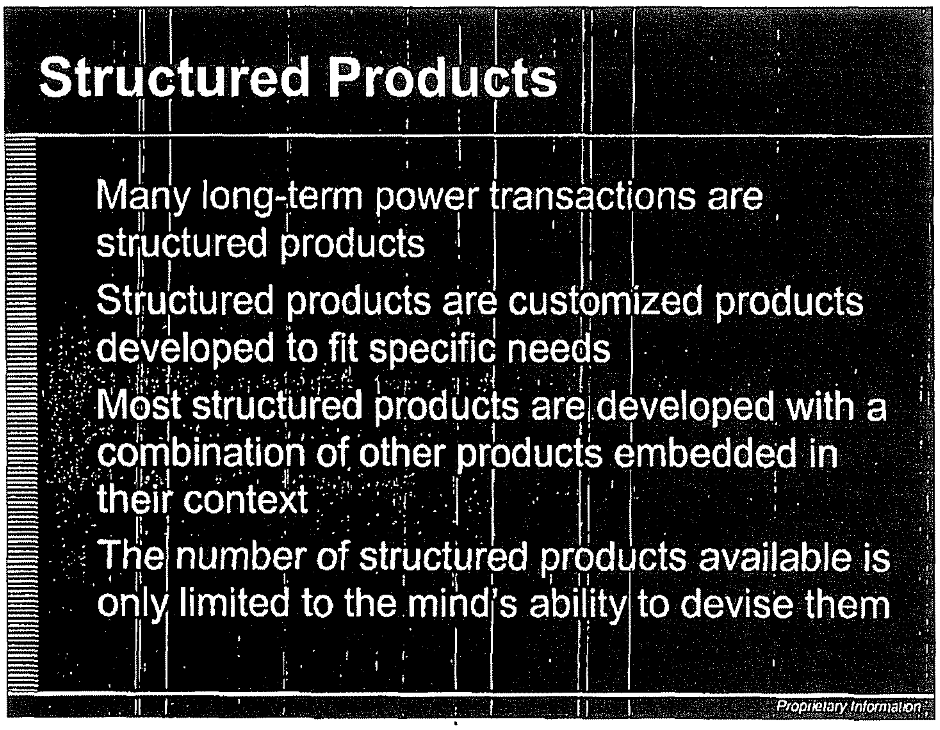
- Trading instruments of cooperatives:
  - Numerous trading instruments can be employed to suit the needs of a G&T:
    - Characterized as physical or financial instruments and derivatives
    - Physical transactions involve delivery and payment while;
    - Financial transactions involve a financial settlement payment instead of delivery.



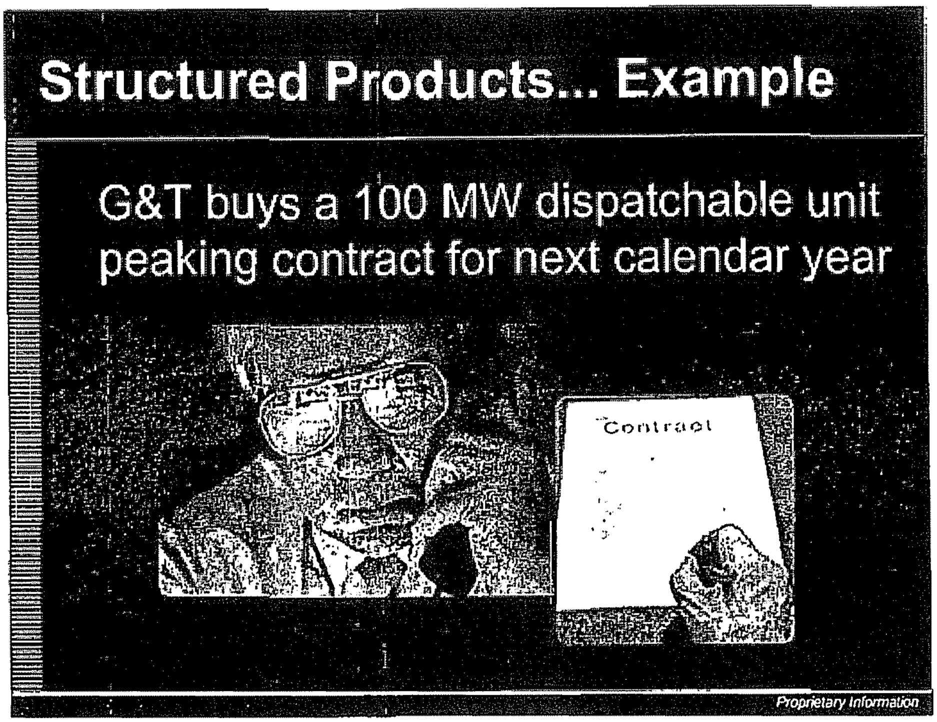
- Derivative:
  - A trading instrument whose value is determined from the value of a specific commodity.
- "Put Option" example:
  - A wheat farmer has risk that wheat prices may fall substantially and wants to protect his revenues by purchasing a put option.
  - Assuming wheat prices for October delivery are $3.7/bushel now, he may buy a $3.2/bushel put option and pay $.15/bushel for the option.
  - If wheat prices fall below $3.2/bushel at delivery time, then the farmer has the right (but not obligation) to sell his wheat at $3.2/bushel to the counterparty that sold him the put option.
  - If prices are above $3.2/bushel he would simply sell his wheat at the market price at delivery time.
  - Hence he has reduced his risk of prices going below $3.2/bushel and he paid $.15/bushel to do so.



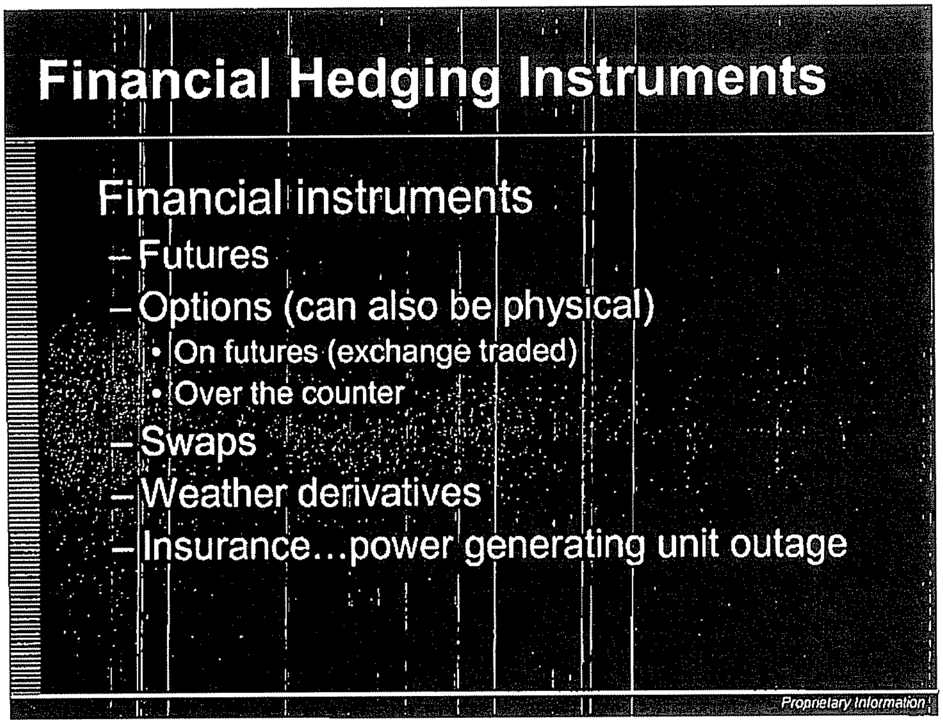
- Physical power types
  - Firm (liquidated damages)
  - Non-firm
  - Unit contingent
  - System firm
- Physical power products
  - Daily put/call options
  - Monthly put/call options
  - Daily index
  - Monthly index
  - Hourly pool index
  - Power plants
  - Structured products (e.g., full requirements, heat rate)
- Physical power terms
  - Hourly
  - Daily
  - Balance of (week, month)
  - Monthly, seasonal, annual
  - Long-term (> 1 year)
  - 5X16 (Mon-Fri on peak block)
  - 6X16 (Mon-Sat on peak block)
  - 5X8 (Mon-Fri off peak block)
  - 2X24 (Sat, Sun block)
  - 7X8 (Mon-Sun off peak block)
  - Wrap (5X8, 2x24)



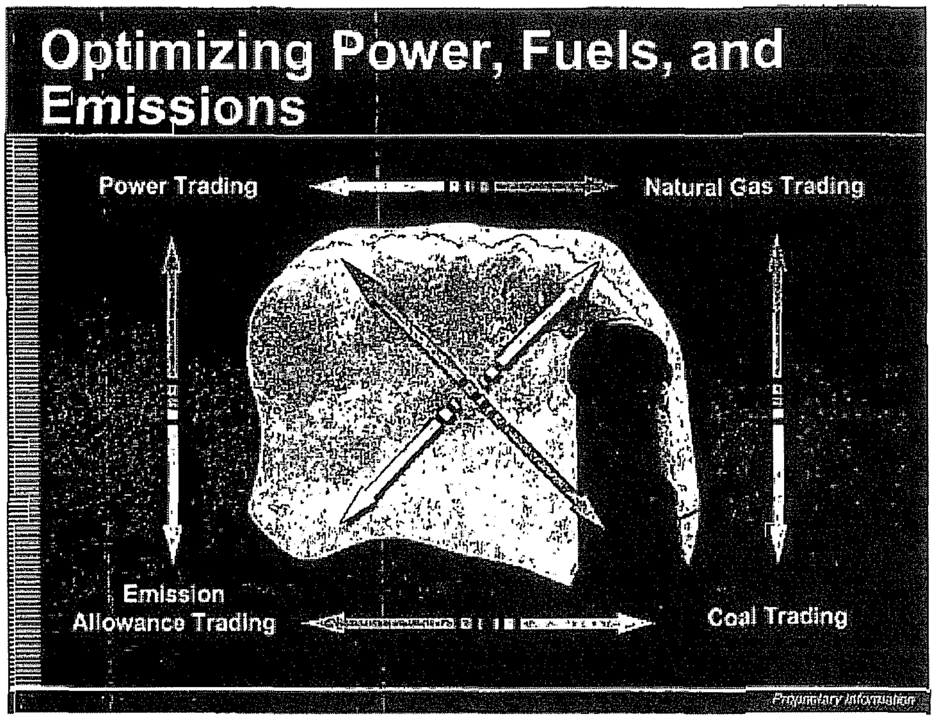
- Structured product definition:
    - A customized contract involving a bulk power transaction negotiated between two parties. A structured product addresses specific needs of the buyer that may involve numerous physical, financial, and derivative components bundled into a single contract. A full requirements contract is one example of a structured product.
- Structured products:
    - Many long-term power transactions are structured products.
    - Structured products are customized products developed to fit specific needs.
    - Most structured products are developed with a combination of other products embedded in their context.
    - The number of structured products available is only limited to the mind's ability to devise them.



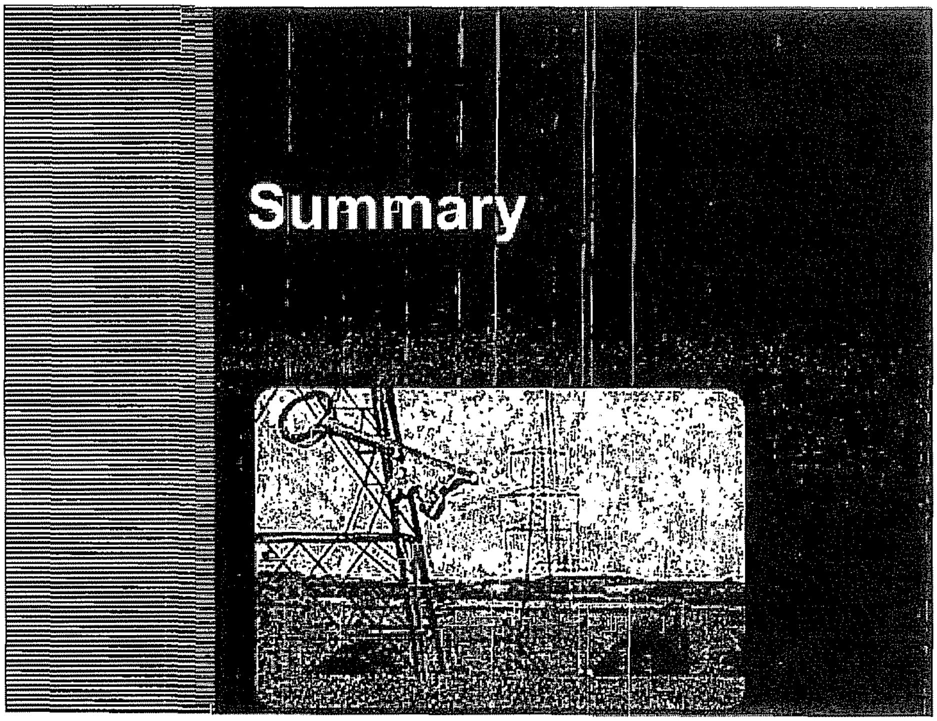
- Example of a structured product:
  - G&T buys a 100 MW dispatchable unit peaking contract for next calendar year.
    - Buyer pays premium of $36,000/MW/Year
    - Energy must be scheduled 2 hours in advance
    - Minimum run time is 4 hours
    - Maximum ramp rate of 40 MW's per hour
    - Energy priced at 10,500 heat rate multiplied by Gas Daily index plus $.30 with a $75/MWh cap
    - Seller guarantees 99% availability during Jun-Aug



- Financial hedging instruments:
  - Futures
  - Options (can also be physical)
    - On futures
    - Over the counter (OTC)
  - Swaps
  - Weather derivatives
  - Insurance…power generating unit outage

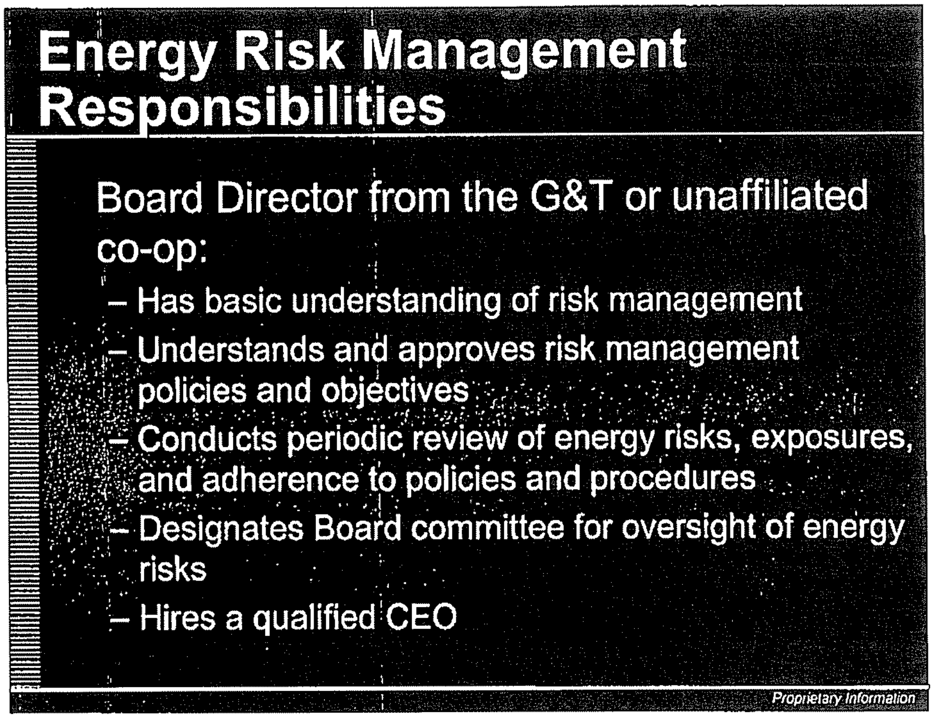


- Optimizing power, fuels, and emissions through different types of trading.
- These are all of the things involved in your energy portfolio. Its not just gas and power - it's the whole energy value chain.

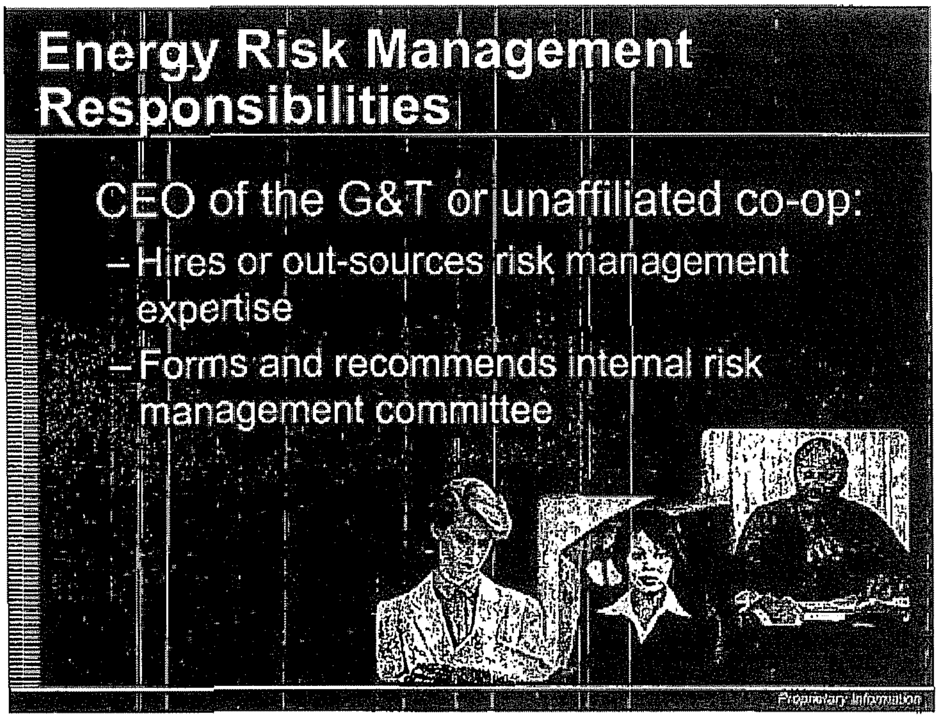


- Keys to Success.

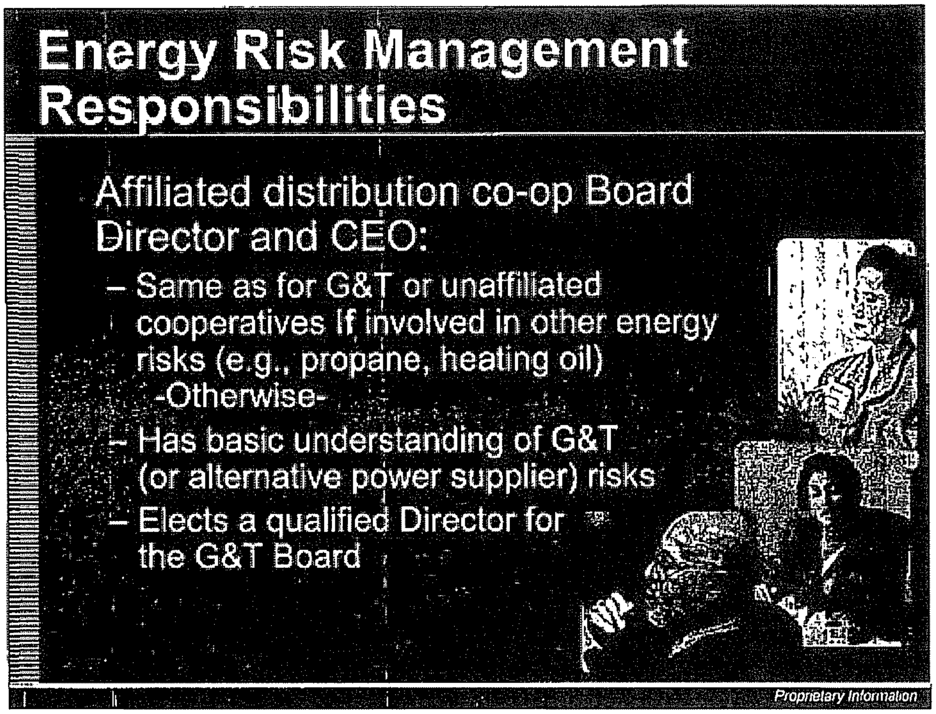
Case No. 2012-00535
Attachment 1 for Response to AG 2-7
Witness: Mark A. Bailey



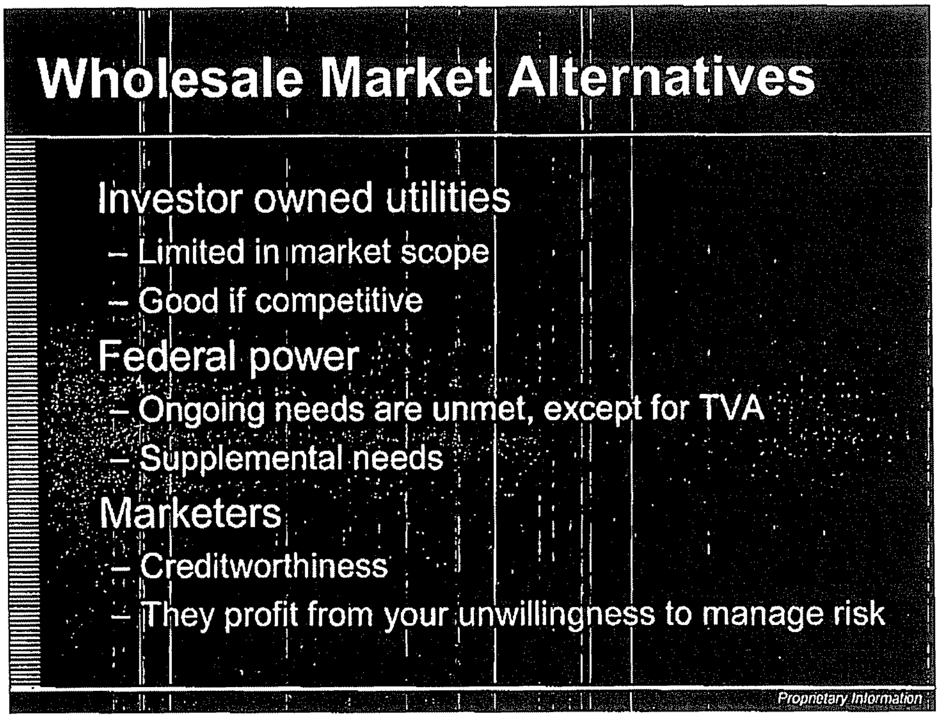
- Review of the responsibilities of the Board Director from the G&T or unaffiliated cooperative:
    - Has a basic understanding of risk management.
    - Understands and approves risk management objectives and policies.
    - Conducts periodic review of energy risks, exposures, and adherence to policies and procedures.
    - Designates Board committee for oversight of energy risks (e.g., audit committee, risk oversight committee).
    - Hires a qualified CEO.



- Review of the responsibilities of the CEO of the G&T or unaffiliated cooperative:
  - Hires or outsources risk management expertise.
  - Forms and recommends an internal risk management committee that:
    - Possesses broad expertise in risk management.
    - Assures risk management policies and procedures are implemented and executed.
    - Regularly reviews energy risks and exposures.
    - Recommends policy changes to board oversight committee.

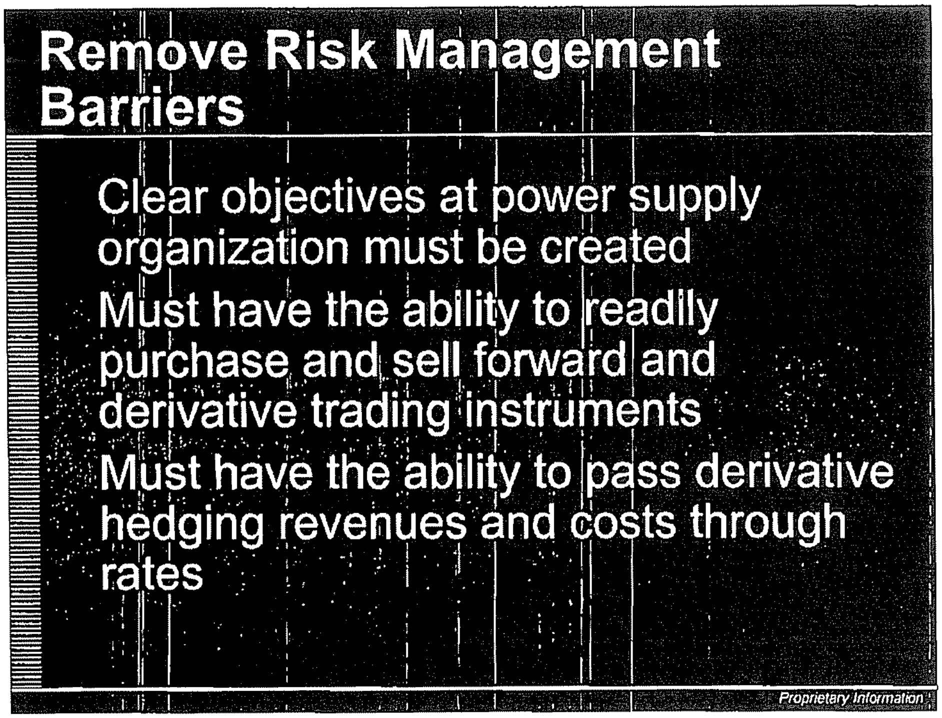


- The energy risk management responsibilities of the Board Director and CEO of the affiliated distribution cooperative:
    - Same as that for G&T or unaffiliated cooperatives if involved in other energy risks (e.g., propane, heating oil).
    - Has a basic understanding of G&T (or alternative power supplier) risks.
    - Elects a qualified Director for the G&T Board.

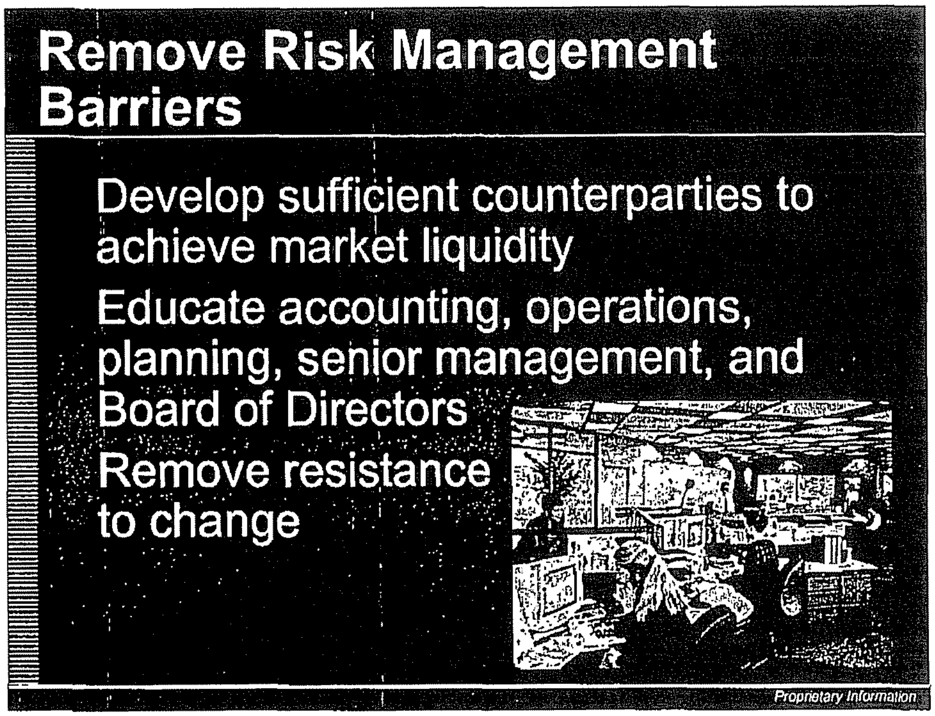


- There are many alternatives the cooperative power supplier can pursue in managing their energy risk. If a cooperative power supplier elects to do a fixed price full requirements contract with and investor owned, federal power agency, or a marketer then their energy risk management needs will be reduced to assessing risk counterparty risks and risks associated with contract expiration. If they choose to partially or fully manage their energy risk, then they have different alternatives that can be taken in addressing energy risk management needs.
- Wholesale market alternatives, such as:
    - IOUs have less incentive to sell at market rates now particularly in times of low market prices.
    - Federal power (Bonneville Power Admin., TVA, SWAPA, WAPA, SEPA) is an alternative, but with the exception of TVA, they cannot meet supplemental needs or load growth.
    - Marketers have tried to serve wholesale needs under a variety of arrangements, but their viability has become questionable over the past year. Marketers have had trouble providing the required operational support needed to supply end users.

- Designated agents with proper staffing and infrastructures have trading and risk management skills equivalent to other alternatives. Any savings generated by the legal agent goes back to the cooperative. Their approach is participative in that they are partners in managing the risk of the cooperative, which does not lose any control over its destiny.
- Consultants are not in the market for effective strategy execution. They can provide pieces of risk management but do not have the expertise, systems, or infrastructures to actually develop and execute and actively manage hedging and trading strategies.
- Doing it yourself is an alternative, but to have the personnel, information, and infrastructures is very costly.
- Many combinations of all the above can be employed, but be careful that some risk exposures are not ignored



- It is important to remove the barriers to energy risk management:
  - Clear objectives at the power supply organization must be created.
  - Must have the ability to readily purchase and sell forward and derivative trading instruments.
  - Must have the ability to pass derivative hedging revenues and costs through the rates.



- Other important ways of removing barriers to energy risk management:
  - Develop sufficient counterparties to achieve market liquidity.
  - Educate accounting, operations, planning, senior management, and Board of Directors.
  - Remove resistance to change
- Other ideas:

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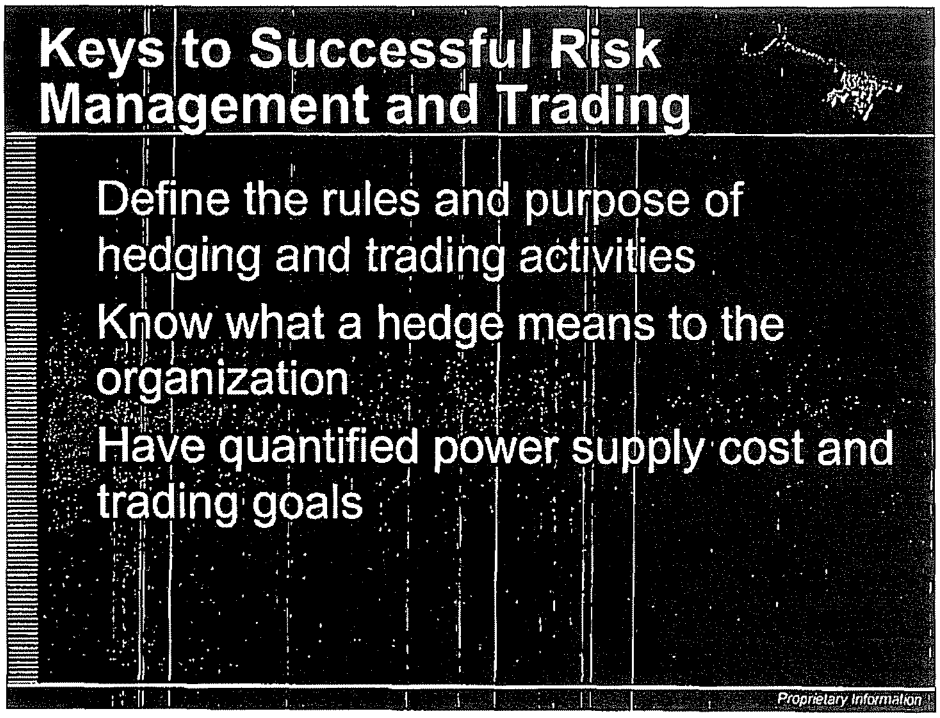
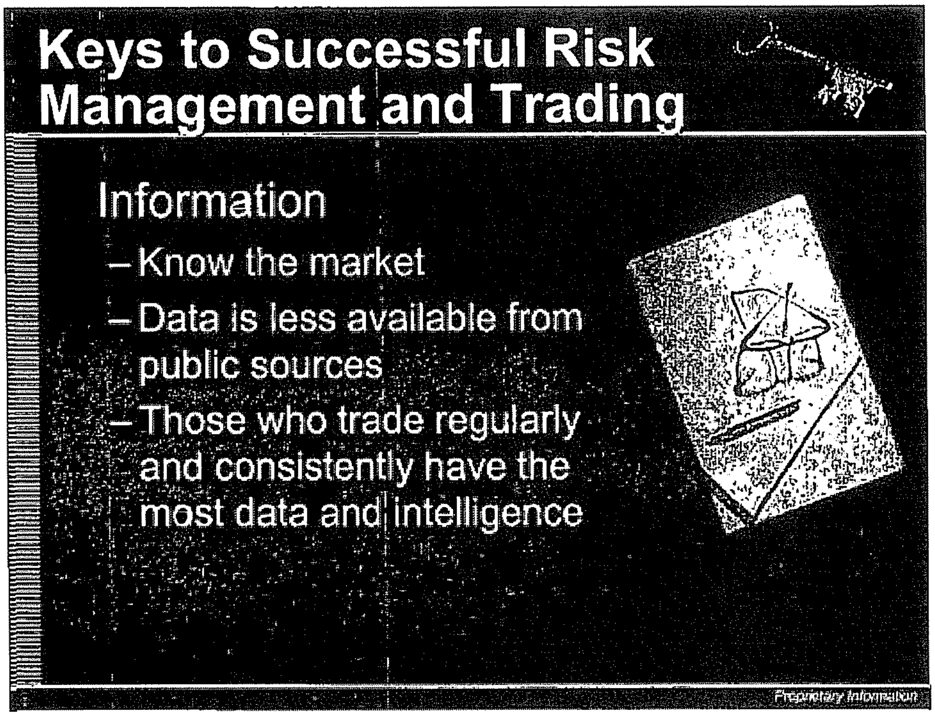


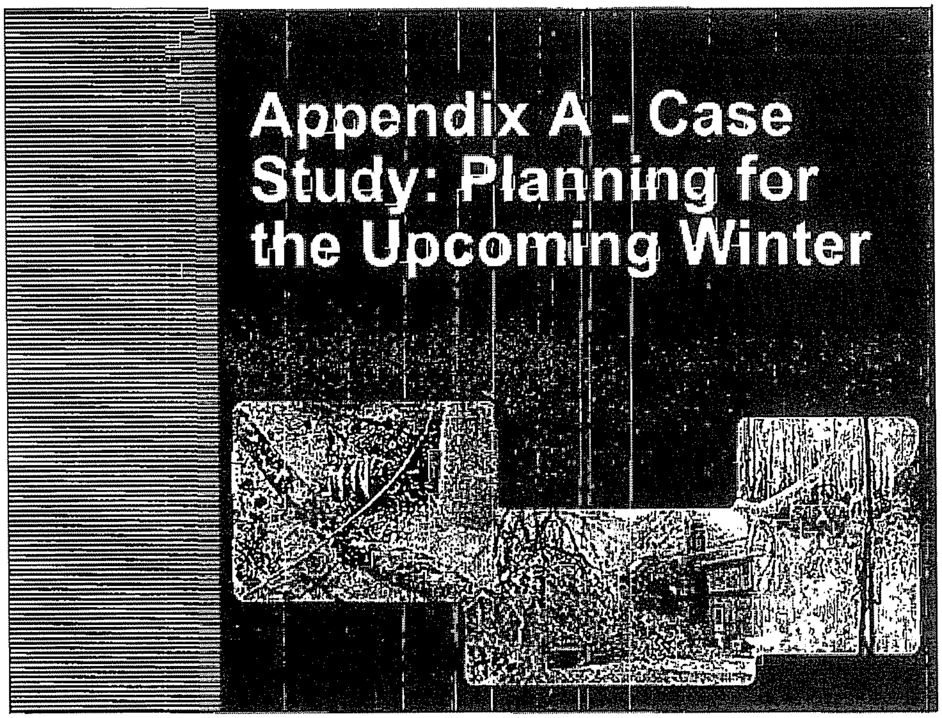
- Trading is the means of managing risk. You should:
  - Define the rules and purpose of hedging and trading activities.
  - Know what a hedge means to the organization.
  - Have quantified power supply cost and trading goals, for example:
    - Reduce price volatility
    - Beat budgeted expenses
    - Opportunistic trading
    - Manage fuel and hedge transactions



- Importance of information:
    - Know the market.
    - Be aware that data is less available from public sources.
    - Those who trade regularly and consistently have the most data and intelligence.

- Importance of interpretation:
  - Develop more specialized market expertise.
  - Accurate judgments will need to be made by experts who have incomplete data.
  - Gain a wider perspective and better analytical tools.
  - You need to know the local, regional, and national markets to fully understand trends.

- Importance of execution:
    - Establish trading controls systems and procedures
    - Establish authority matrices
    - Empower selected staff to make rapid decisions
    - Have proper trading systems (software, hardware and technology)
    - Identify physical and financial trading expertise
    - Review credit and contracts
    - Integrate fuels and power transactions



- Case Study: Planning for the Upcoming Winter.

Winter Peaking G&T

- 18 member systems
- Assumptions and data as of July
- 1,400 MW forecasted for upcoming winter peak
  - Annual sales of 6,000,000 MWh
  - 700 MW average hourly load
  - Load composition
    - 70% residential
    - 15% small commercial
    - 15% one large industrial
- Historical average member price of $45/MWh

Proprietary Information

- Notes:

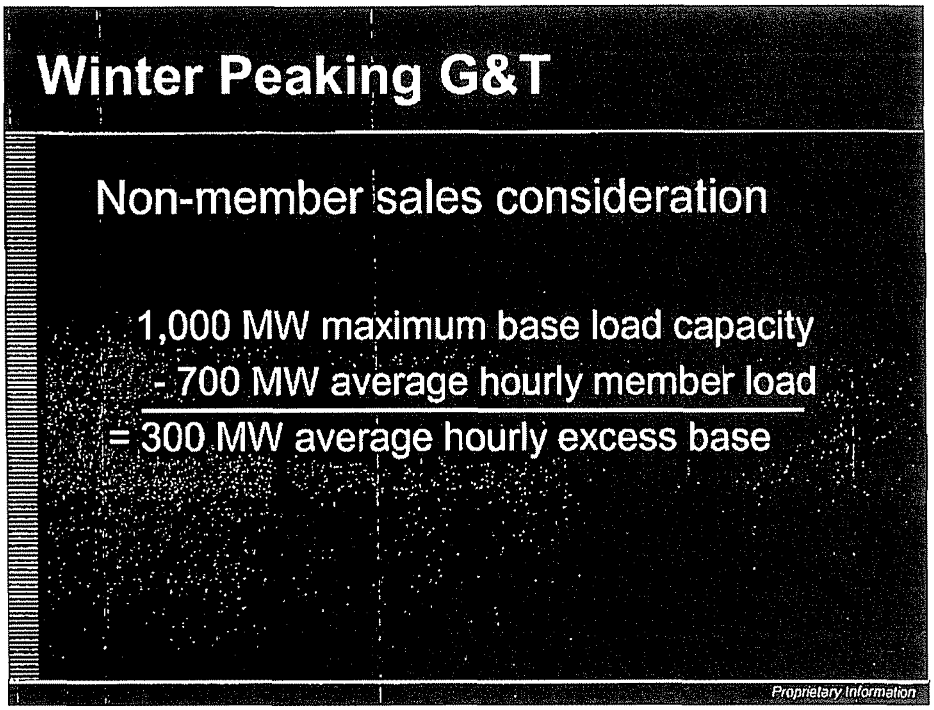
Case No. 2012-00535
Attachment 1 for Response to AG 2-7
Witness: Mark A. Bailey

Winter Peaking G&T

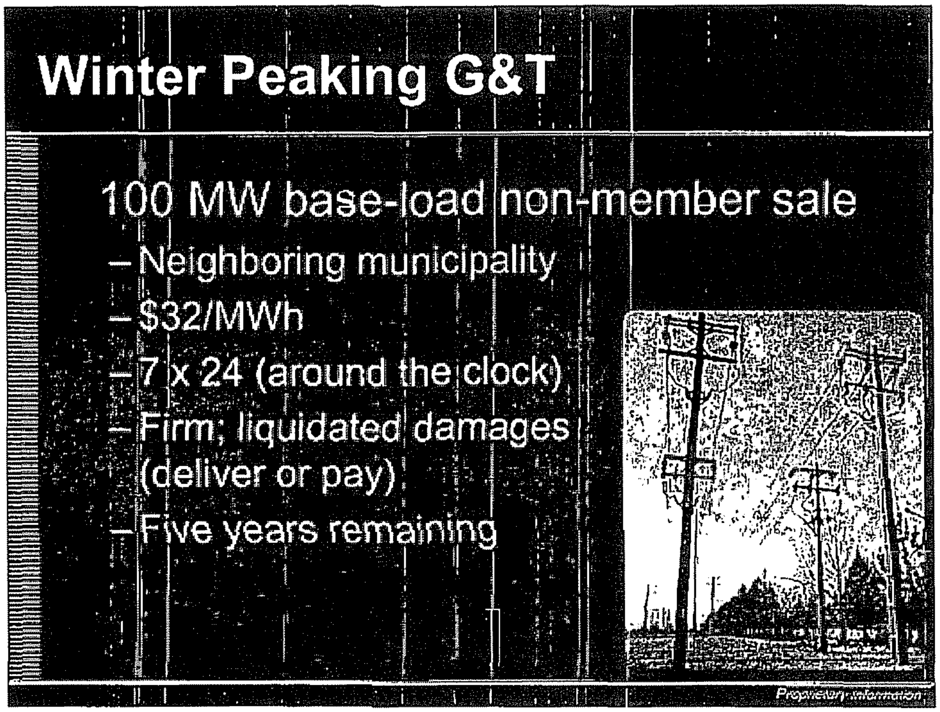
- Located in cold northern state
- 1,000 MW base load capacity
  - Two 29-year old coal fired steam units
    - 500 MW each
    - $15/MWh energy cost (long term coal contract)
  - 150 MW peaking capacity
    - Two natural gas combustion turbines
    - 75 MW each
    - Energy based on natural gas market prices
  - 1,150 MW total owned generation

Proprietary Information

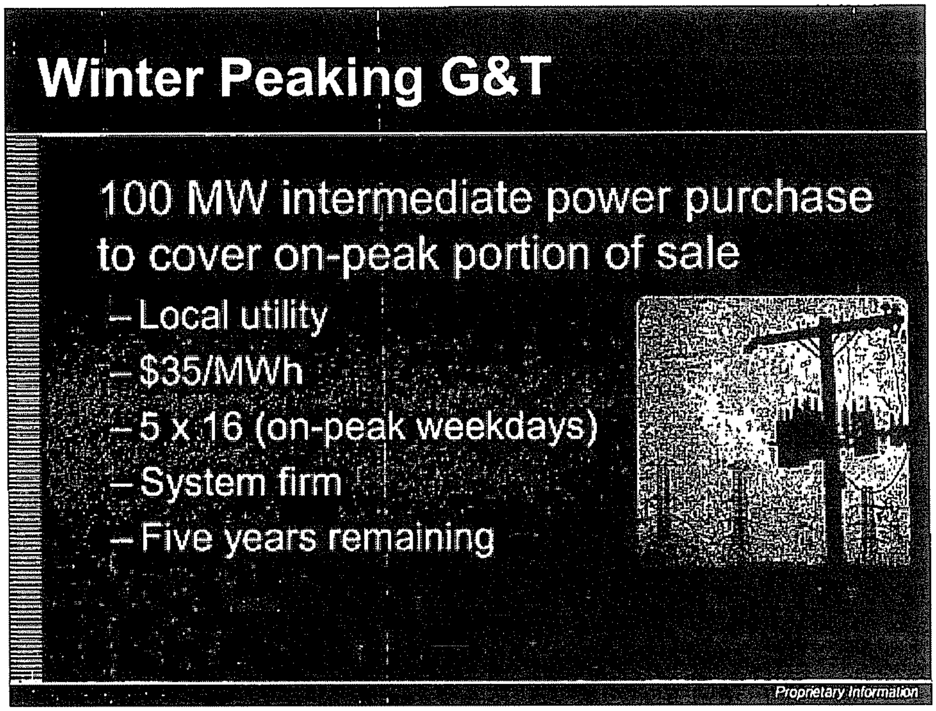
- Notes:


Winter Peaking G&T
Non-member sales consideration
1,000 MW maximum base load capacity
- 700 MW average hourly member load
= 300 MW average hourly excess base
Proprietary Information

- Notes:


Winter Peaking G&T
100 MW base-load non-member sale
– Neighboring municipality
– $32/MWh
– 7 x 24 (around the clock)
– Firm; liquidated damages (deliver or pay)
– Five years remaining
Proprietary Information

• Notes:


Winter Peaking G&T
100 MW intermediate power purchase to cover on-peak portion of sale
– Local utility
– $35/MWh
– 5 x 16 (on-peak weekdays)
– System firm
– Five years remaining
Proprietary Information

• Notes:

Winter Peaking G&T

Summary of load and resources

1,400 MW forecasted member peak
+ 100 MW non-member sale
= 1,500 MW forecasted total peak demand
- 1,150 MW total owned generation
- 100 MW power purchase agreement
= 250 MW minimum potential shortfall

Proprietary Information

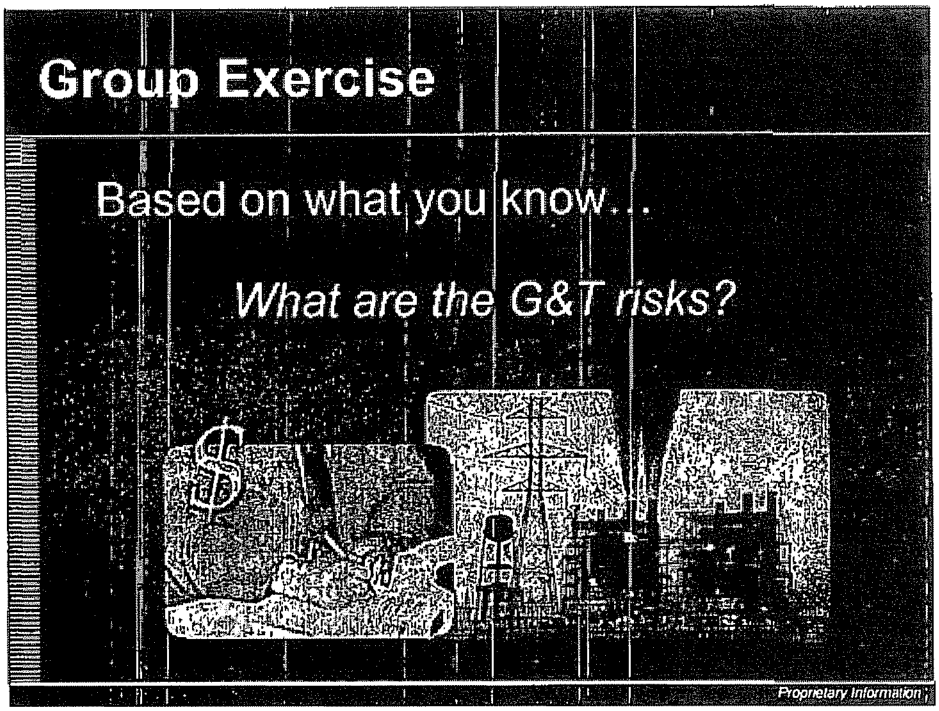
- Notes:

Winter Peaking G&T

- Today's commodity prices for January and February
  - Electricity: $32/MWh for 5 x 16
  - Natural gas: $4.55/MMBtu delivered
- Budgeted commodity prices – 1st quarter
  - On-peak electricity: $35/MWh
  - Electricity prices on 20 coldest days: $45/MWh
  - Natural gas: $4.5/MMBtu delivered

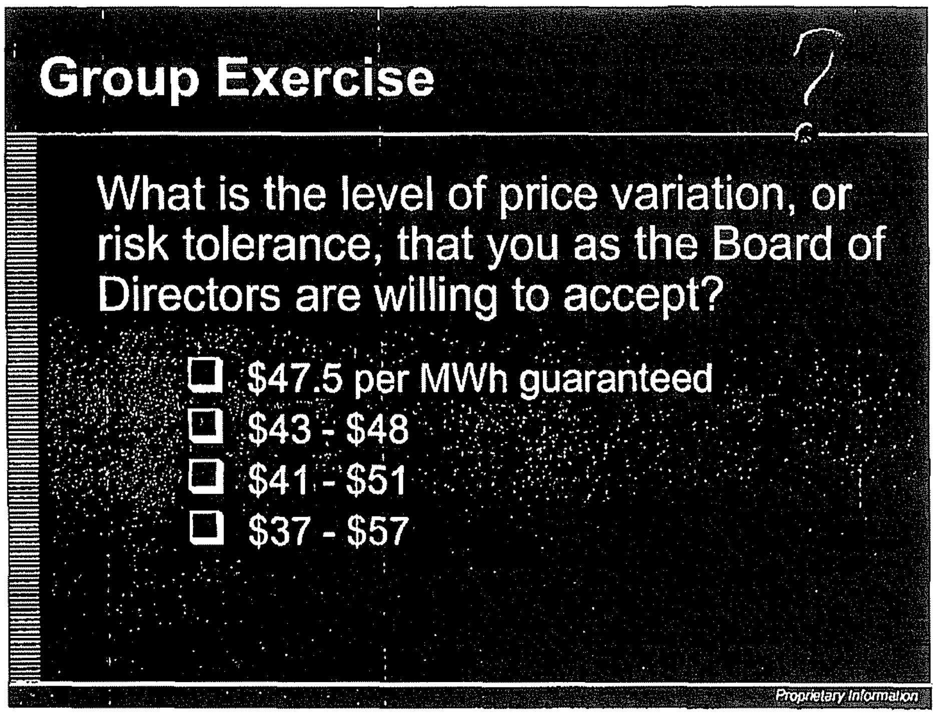
Proprietary Information

- Notes:



- Based on what you know... What are the G&T risks?
- List the risks below:

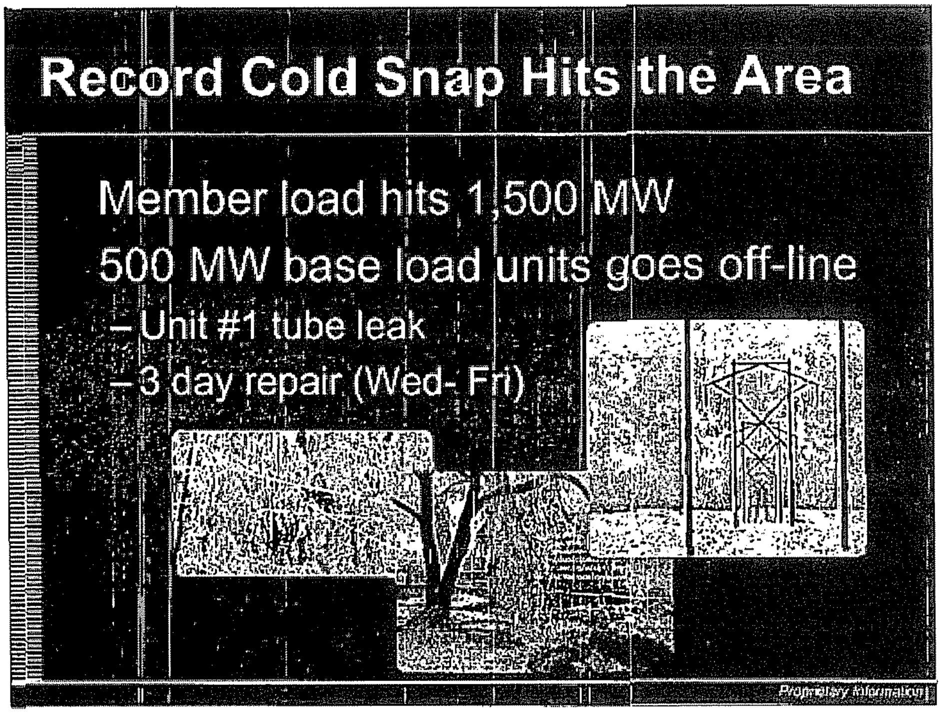
1.__________
2.__________
3.__________
4.__________
5.__________
6.__________
7.__________
8.__________
9.__________
10.__________



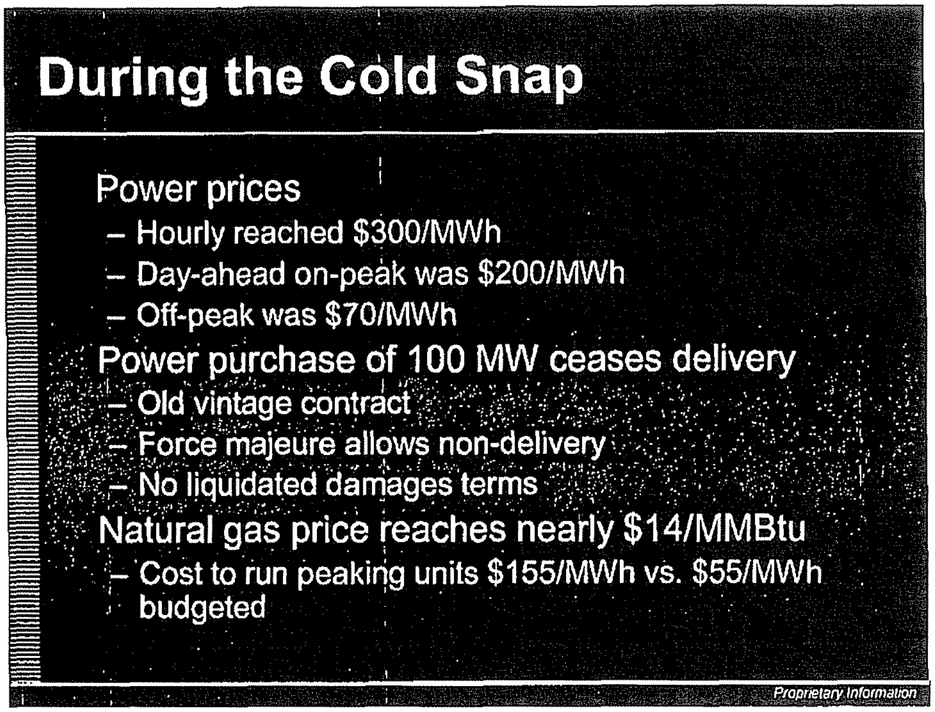
- What is the level of price variation, or risk tolerance, that you as the Board of Directors are willing to accept? Check your answer.

  - ☐ $47.5 per MWh guaranteed
  - ☐ $43 - $48
  - ☐ $41 - $51
  - ☐ $37 - $57

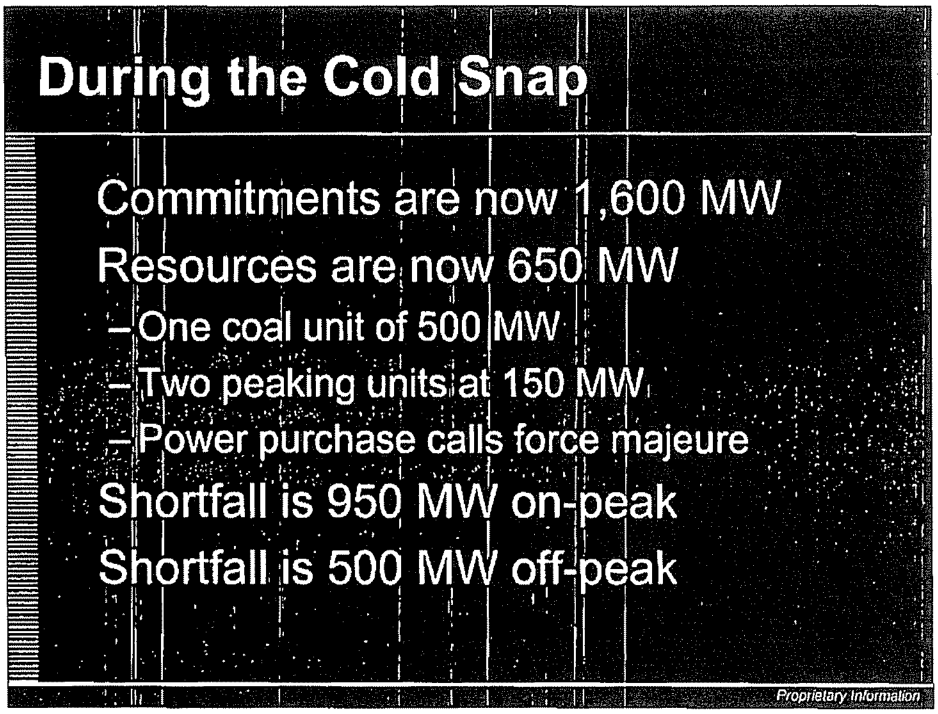
- Notes:


Record Cold Snap Hits the Area
Member load hits 1,500 MW
500 MW base load units goes off-line
– Unit #1 tube leak
– 3 day repair (Wed- Fri)
Proprietary Information

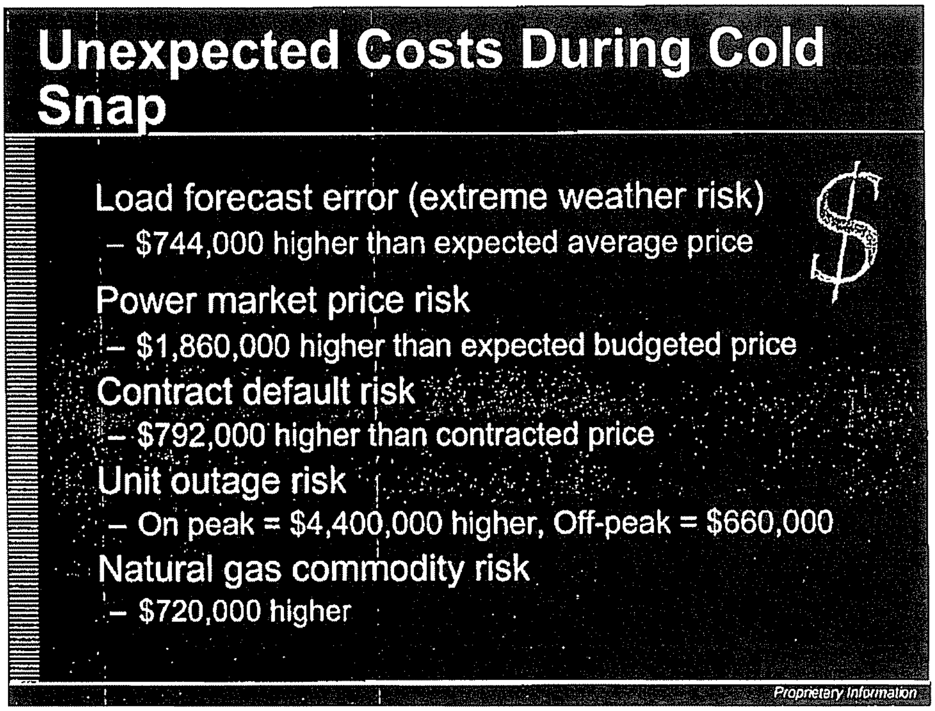
• Notes:


During the Cold Snap
Power prices
– Hourly reached $300/MWh
– Day-ahead on-peak was $200/MWh
– Off-peak was $70/MWh
Power purchase of 100 MW ceases delivery
– Old vintage contract
– Force majeure allows non-delivery
– No liquidated damages terms
Natural gas price reaches nearly $14/MMBtu
– Cost to run peaking units $155/MWh vs. $55/MWh budgeted
Proprietary Information

- Notes:


During the Cold Snap
Commitments are now 1,600 MW
Resources are now 650 MW
– One coal unit of 500 MW
– Two peaking units at 150 MW
– Power purchase calls force majeure
Shortfall is 950 MW on-peak
Shortfall is 500 MW off-peak
Proprietary Information

- Notes:



- Unexpected costs that were incurred during the cold snap:
  - Load forecast error (extreme weather risk):
    - 100 MW for higher load on-peak for 3 days (48 total hours) was $960,000 (48 hours x 100MW x $200/MWh); or $744,000 higher than expected average price of $45/MWh.
  - Power market price risk:
    - 250 MW for un-hedged supply risk for 3 days was $2,400,000 or $1,860,000 higher than expected budgeted price of $45/MWh.
  - Contract default risk:
    - 100 MW for contract default for 3 days was $960,000 or $792,000 (100 MW x 48 hrs. x $165/MWh) higher than contracted price of $35/MWh.
  - Unit outage risk:
    - 500 MW for 48 hours on-peak at $200/MWh vs. $15/MWh = $4,400,000 higher than expected.
    - 500 MW for 24 hours off-peak at $70/MWh vs. $15/MWh = $660,000 higher than expected.
  - Natural gas commodity price risk:
    - 150 MW of higher gas costs for on-peak for 3 days ($155/MWh versus expected of $55/MWh) was $720,000 higher than expected.

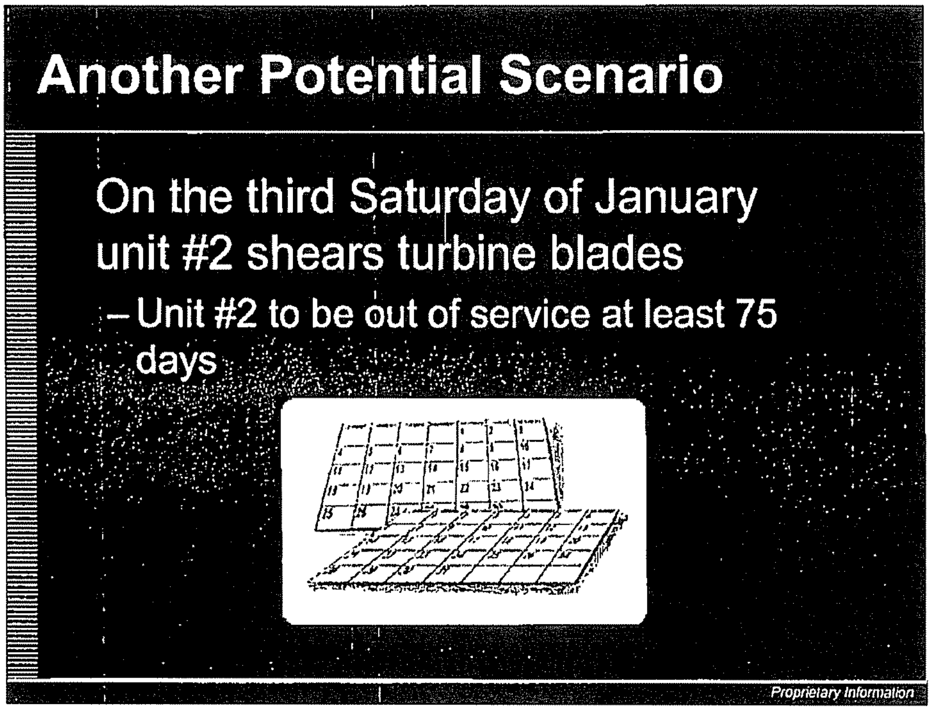
Unexpected Costs During Cold Snap

Total additional cost during cold snap was $9,176,000

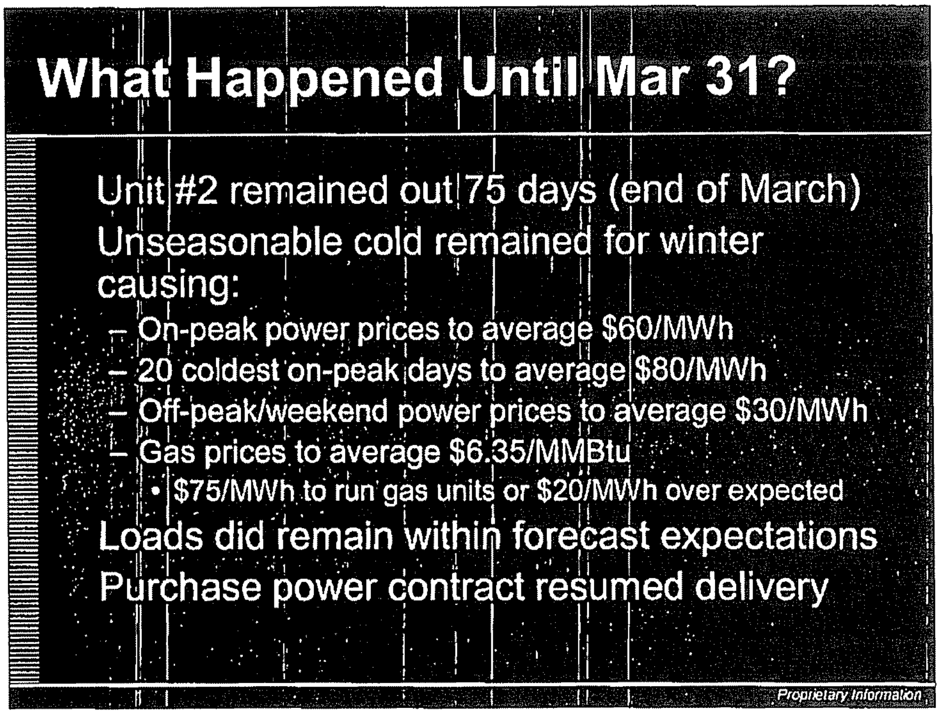
- Extreme weather risk = $744,000
- Commodity price risk cost = $2,580,000
  - Power = $1,860,000
  - Natural gas = $720,000
- Contract default risk cost = $792,000
- Unit outage risk cost = $5,060,000
  - On-peak $4,400,000
  - Off-peak $660,000

Proprietary Information

- Notes:


Another Potential Scenario
On the third Saturday of January unit #2 shears turbine blades
– Unit #2 to be out of service at least 75 days
Proprietary Information

- Notes:


What Happened Until Mar 31?
Unit #2 remained out 75 days (end of March)
Unseasonable cold remained for winter causing:
– On-peak power prices to average $60/MWh
– 20 coldest on-peak days to average $80/MWh
– Off-peak/weekend power prices to average $30/MWh
– Gas prices to average $6.35/MMBtu
• $75/MWh to run gas units or $20/MWh over expected
Loads did remain within forecast expectations
Purchase power contract resumed delivery
Proprietary Information

- Notes:

Additional Costs Through Mar 31

Unit #2 outage replacement cost: 500 MW

- On-peak
  - 55 days (16 hours each); or 880 hours at $60/MWh
  - At $45/MWh over cost of coal unit ($60 -15) this is an additional cost of $19,800,000 (500 MW x 880 hrs x $45)
- Off-peak
  - 55 days (8 hours) and 20 weekend days (24 hours); or 920 hours at $30/MWh
  - At $15/MWh over cost of coal unit ($30 -15) this is an additional cost of $6,900,000 (500 MW x 880 hrs x $45)
- Total cost of $26,700,000

Proprietary Information

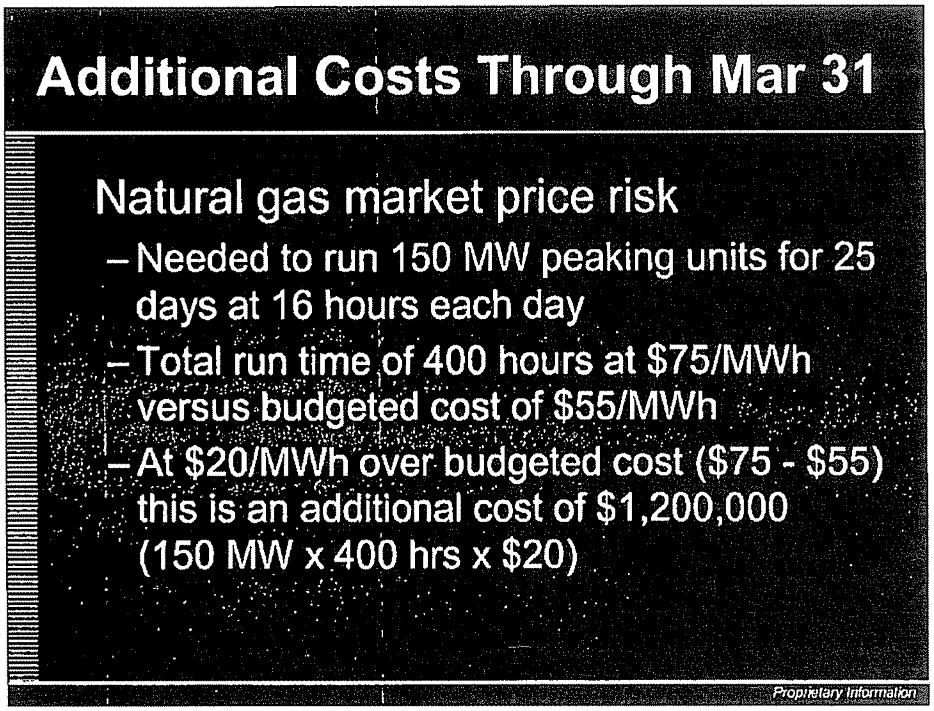
• Notes:

Additional Costs Through Mar 31

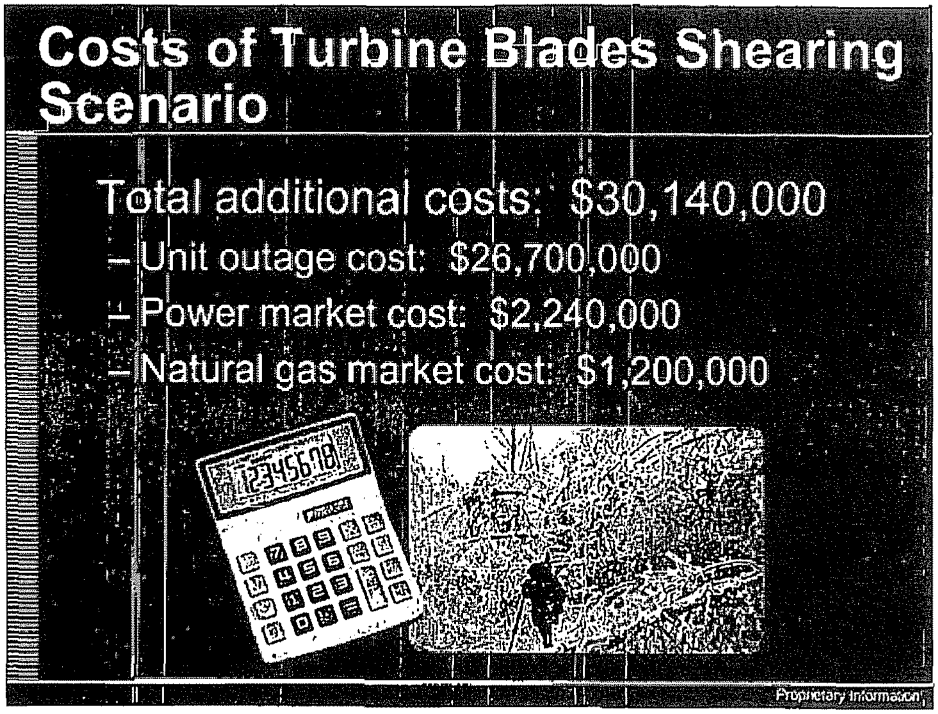
Power market price risk
- Short of supply by 200 MW on 20 coldest on-peak days (un-hedged supply)
- Needed 200 MW on-peak for 20 days (16 hours) or 320 hours at $80/MWh
- At $35/MWh over budgeted cost ($80 - $45) this is an additional cost of $2,240,000 (200 MW x 320 hrs x $35)

Proprietary Information

- Notes:


Additional Costs Through Mar 31
Natural gas market price risk
– Needed to run 150 MW peaking units for 25 days at 16 hours each day
– Total run time of 400 hours at $75/MWh versus budgeted cost of $55/MWh
– At $20/MWh over budgeted cost ($75 - $55) this is an additional cost of $1,200,000 (150 MW x 400 hrs x $20)
Proprietary Information

• Notes:



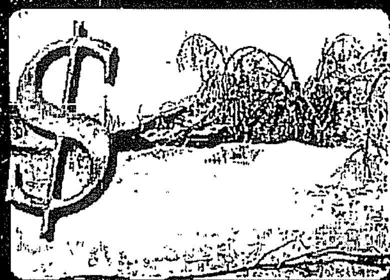
- Notes:

Case No. 2012-00535
Attachment 1 for Response to AG 2-7
Witness: Mark A. Bailey

Total Unexpected Costs if Both Events Occurred

Total costs of $39,316,000

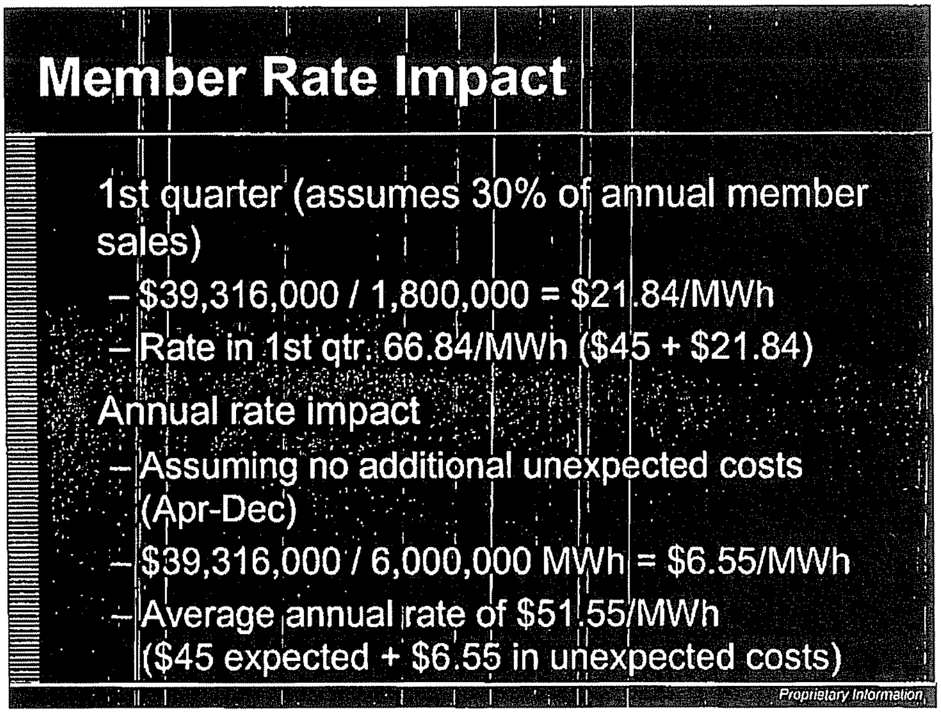
- 3 day cold snap cost $9,176,000
- Turbine blades shearing during winter season cost $30,140,000 plus turbine repair cost



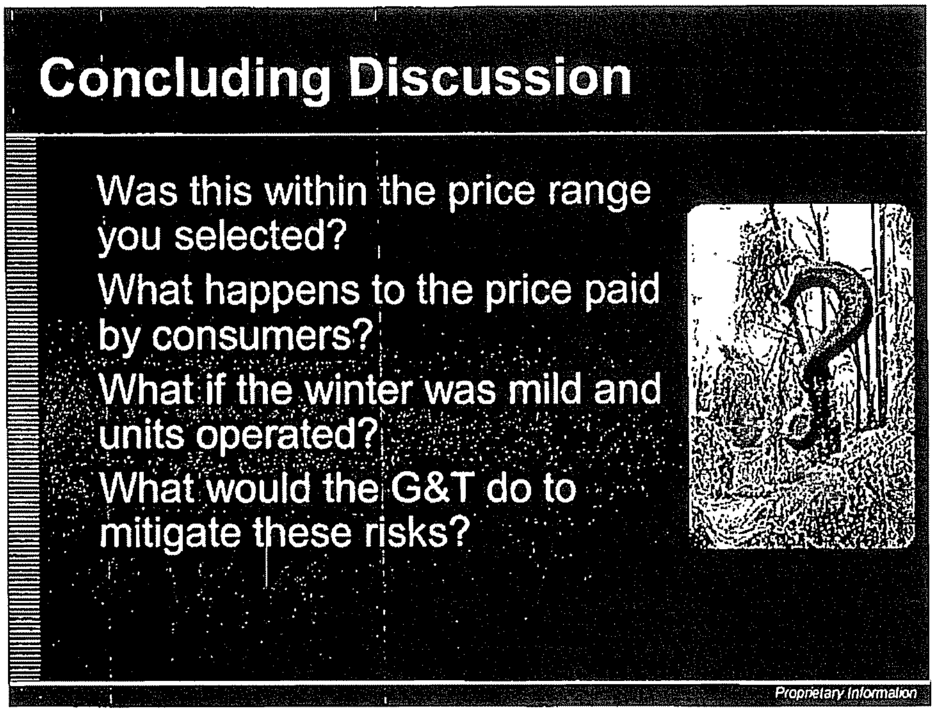
Proprietary Information

• Notes:

Case No. 2012-00535
Attachment 1 for Response to AG 2-7
Witness: Mark A. Bailey


Member Rate Impact
1st quarter (assumes 30% of annual member sales)
– $39,316,000 / 1,800,000 = $21.84/MWh
– Rate in 1st qtr. 66.84/MWh ($45 + $21.84)
Annual rate impact
– Assuming no additional unexpected costs (Apr-Dec)
– $39,316,000 / 6,000,000 MWh = $6.55/MWh
– Average annual rate of $51.55/MWh ($45 expected + $6.55 in unexpected costs)
Proprietary Information

- Notes:

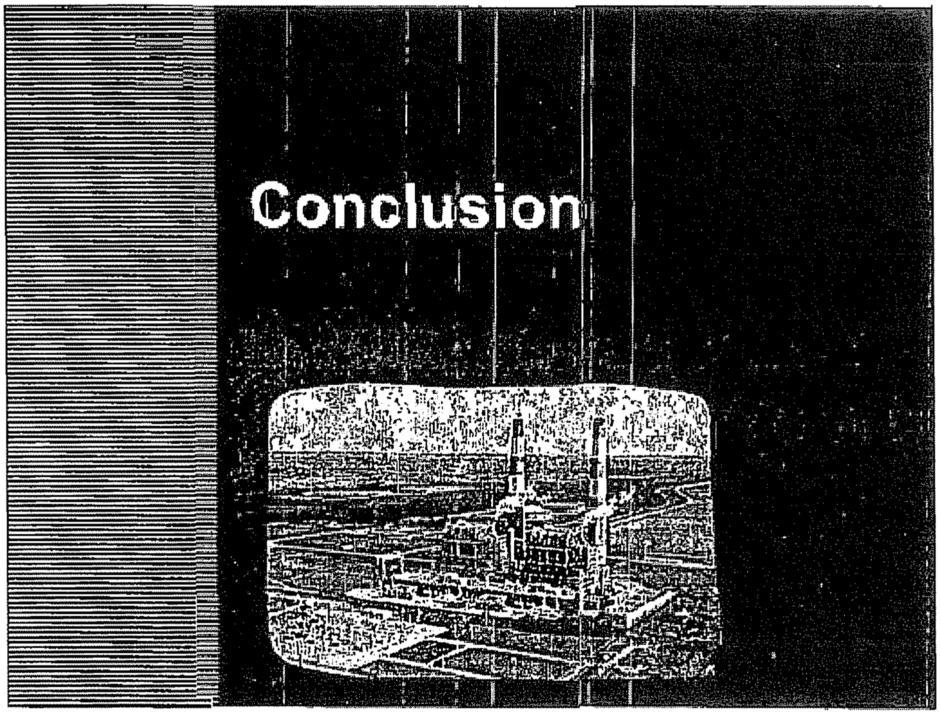


- Was this within the price range you selected?

- What happens to the price paid by consumers?

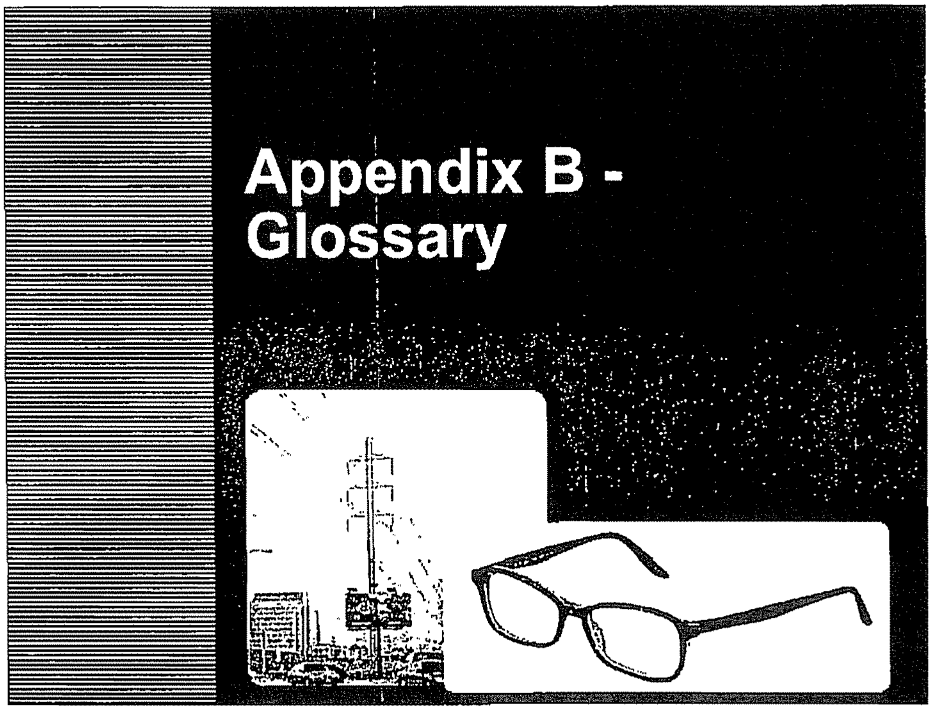
- What if the winter was mild and units operated?

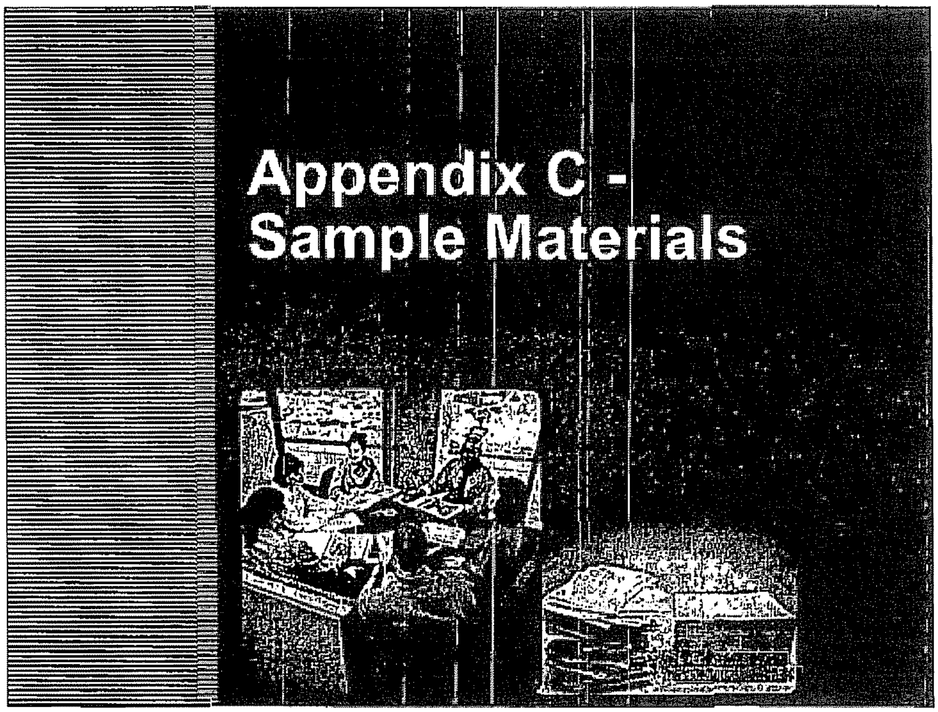
- Things that the G&T could do to mitigate these risks:
  - Purchase unit outage insurance.
  - Purchase supplies to cover extreme peak demand.
    - Market power supply products (forwards and/or options).
    - Buy or build additional generating units.
  - Hedge natural gas risk by purchasing forwards, futures, or options .
  - Avoid buying system-firm to back up firm sale.
  - Seek to arrange an equitable interruptible contract via the distribution cooperative with its large industrial (200 MW).



- Please complete the Evaluation Form and return it to the instructor. Your comments and suggestions are important.

- Thank you for your participation in this course.


Appendix B -
Glossary



- Appendix C contains the following sample materials:
  - Exhibit 1 - The Energy Risk Management Process (page C-1)
  - Exhibit 2 - Calculation of Liquidated Damages and Examples of Force Majeure Language (page C-2)
  - Exhibit 3 - Mark to Market Calculation for Cash Margining (page C-3)
  - Exhibit 4 - Assessing Your Risk Tolerance (page C-4)
  - Exhibit 5:
    - Generic Board Energy Risk Management Policy Outline (page C-5)

      Note: This is for sample purposes only and should not be considered a model. Consult a professional before developing your board policy.
    - Generic Board Energy Risk Management Policy - Key Examples and Descriptions (pages C-6 through C-8)
  - Exhibit 6 - Generic Power Trading Authority Matrix (page C-9)
  - Exhibit 7 - Properly Balanced 2003 Portfolio For a 900 MW Peak Demand System (page C-10)
  - Exhibit 8 - Optimizing Natural Gas and Power Transactions (pages C-11 and C-12)

Appendix B – Glossary

Purpose: The Glossary is designed to provide you with key "lingo," terms, and definitions pertinent to energy risk management.

Agent	Performs risk management and trading service for an entity for a fee. Agents do not take market price risk, but work on behalf of an entity to manage or mitigate risk.
Alternative Dispute Resolution (ADR)	A process by which parties agree to be found by arbitration or some other dispute resolution mechanism rather than fully litigate issues before a judge.
Arbitrage	The simultaneous purchase of one commodity against the sale of another in order to profit from fluctuations in the usual price relationships.
Ask	In the futures market, an ask is a motion to sell. Also called an offer.
At the Market	A transaction order placed at the market is executed immediately at the price available when the order reaches the trading floor.
At the Money Price	An option whose strike price is equal to the forward price.
Basis	The difference in price between the cost of a futures or forward contract, and the cash price of the same commodity at another physical location.
Bid	A motion to buy a forward contract at a given price.
Bid/Ask (Offer)	In financial and commodity markets, the bid price represents the price at which the buyer is willing to commit. The ask (offer) is the price at which the seller is willing to commit.
Broker	A person who executes the buy and sell orders of a customer in return for a commission or fee.
Bulk Power Transaction	A contractual agreement to purchase or sell wholesale electricity between utility companies or marketers.

Appendix B – Glossary (continued)

Bull — One who anticipates a commodity price increase.

Call Option — A contract that establishes a right to buy a commodity for a specified time period at a specified price (the strike price).

Cash Margin Risk — The risk associated with inadequate cash flow resulting from cash margin requirements of a contractual agreement.

Cash Market — The market for a commodity when physical delivery is expected within the next few days or months.

Commission — The fee charged by a broker for the execution of an order.

Commodity Price Risk — Commodity price risk: The risk of loss associated with changes in commodity prices.

Commodity Futures Trading Commission (CFTC) — The federal regulatory body that oversees commodity futures trading activities, standards and practices.

Contract Risk — Contract risk is specific to the risks involving contractual performance. See also counterparty contract and credit risk.

Counterparty — An entity who is part of a contract, agreement, or transaction with another entity.

Counterparty Contract and Credit Risk — The risk of loss associated with the non-performance or non-payment by a counterparty to an agreement.

- Contract risk is specific to the risks involving contractual performance.
- Credit risk is associated with a counterparty's inability to pay its contractual obligation.

Counterparty Risk — The risk of default by the counterparty; associated with over the counter or physical delivery products. The potential for an adverse occurrence that a party may experience if a counterparty to an agreement fails to perform. See also counterparty contract and credit risk.

Credit Risk — The potential for adverse occurrence if a counterparty in unable to pay its obligation. Credit risk is associated with a counterparty's inability to pay its contractual obligation. See also counterparty contract and credit risk.

Appendix B – Glossary (continued)

Delivery Month
The month specified in a given futures or forward contract for delivery of the actual physical commodity.

Derivative
A trading instrument whose value is "derived" from the value of an underlying commodity. Examples: Forwards, Futures, Swaps, and Options. Any financial instrument, such as a futures contract, forward, swap or option, which derives its value from the value of an underlying security or physical commodity.

Edison Electric Institute (EEI)
An association representing electric utilities. 701 Pennsylvania Avenue NW, Washington, DC 20001-2696. Telephone: 202-508-5000

Exercise Price
Also known as the strike price. The price at which you will buy or sell the commodity if an option is exercised.

Expiration
The date and time after which an option may no longer be exercised. Also known as option expiration.

Extrinsic Value
The price of an option less its intrinsic value. Also known as time premium or time value.

Federal Energy Regulatory Commission (FERC)
The government agency charged with developing interstate energy policy. A federal agency created in 1977 to regulate, among other things, interstate wholesale sales and transportation of gas at "just and reasonable" rates.

Financial Instrument
Contracts in which the primary underlying purpose is to manage price risk, as opposed to the more traditional "physical contracts," which are primarily designed to deliver a commodity. Some financial contracts contemplate physical delivery, like the futures contract, but the primary purpose is to manage price risk rather than deliver or receive the physical product.

Fixed Price Contract
A contract or agreement that has a defined fixed price with no variation.

Force Majeure
An "Act of God" or unexpected and disruptive event beyond the control of buyer or seller that interferes with a party's ability to perform under a contract. A force majeure event may relieve a party from a contract obligation.

Appendix B – Glossary (continued)

Forward Contract

An obligation to buy or sell a negotiated over the counter (OTC) or physical delivery product. A cash market transaction between two parties in which the specified commodity is not deliverable immediately but rather, at an agreed-upon future date. A forward contract can be distinguished from a futures contract in that a forward contract involves anticipated delivery and non-standardized terms that result from direct negotiation between the buyer and seller. These contracts are typically nontransferable and can only be canceled with the consent of both parties.

Forward Price Curve

An identifiable market price (index) for a commodity for future delivery dates. All market participants share the same forward price curve in liquid markets.

Front Month

Also referred to as the nearby or spot month. This it the most current month in which the futures contract is being traded, and the month in which delivery of the contract is executed.

Full Requirements Contract

An agreement to purchase or sell the entire energy requirements needed by an entity. A full requirements contract is not necessarily a fixed price contract. Also known as an "All requirements contract."

Fundamental Analysis

The study of pertinent supply and demand factors that influence the specific price behavior of commodities.

Futures Contract

Standardized contract for the purchase of sale of a commodity that is traded for future delivery under the provisions of exchange regulations. The contract terms are set by exchange rules which specify the unit of sale, how it is quoted in dollars, minimum and maximum price fluctuations, when and at what times the contract is traded, how delivery is made and over what period and penalties for failure to make or take delivery if one is holding a long or short position at the termination of trading. Futures contracts, to be legal, must be traded on a futures exchange regulated by the Commodity Futures Trading Commission.

Futures Options

An option on a futures contract. See call option and put option.

Hedge

Entering a transaction that is an opposite position to a transaction created in the market place with another supplier or customer.

Hedging

Taking a derivatives position that is equal and opposite to a physical position with the sole aim of controlling price risk.

Appendix B – Glossary (continued)

Henry Hub	A pipeline interchange near Erath, LA, where a number of interstate and intrastate pipelines interconnect through a header system operated by Sabine Pipe Line. One of the delivery points for the first New York Mercantile Exchange natural gas futures contract.
Implied Volatility	A measurement of the volatility of the underlying instrument's price based upon market traded option premiums, as opposed to the calculation of volatility from historical prices of the underlying instruments.
Independent Power Producer (IPP)	Wholesale electric producer unaffiliated with the franchised utility in the area in which it is selling power. Now generally known as an Exempt Wholesale Generator (EWG).
Independent System Operator (ISO)	Entity that would control and administer nondiscriminatory access to electric transmission in a region, or across several systems, independent from the owners of the facilities.
Indexing	Tying the commodity price in a contact to other published prices, such as NYMEX prices, spot prices or general indexes.
Interconnection	A specific connection between one utility to another. NERC's definition: "When capitalized any one of the four bulk electric system networks in North America: Eastern, Western ERCOT and Quebec. When not capitalized the facilities that connect two systems or control areas."
In-the-Money	An option that can be exercised and immediately closed out against the underlying market for a financial gain. The option is in-the-money if the underlying futures price is above a call option's strike price, or below a put option's strike price.
Intrinsic Value	The amount by which an option is in-the-money.
Kilowatt-hour (KWh)	The basic unit for pricing electric energy at retail; equal to one kilowatt of power supplied continuously for one hour. (Or the amount of electricity needed to light ten 100-watt light bulbs for one hour.) One kilowatt hour equals 1,000 watthours. One KW hour = 3,306 cubic feet of natural gas.
Last Trading Day	The final day for a particular delivery month futures contract or option contract. Any futures contracts left open following this session must be settled by delivery.

Appendix B – Glossary (continued)

Limit	The maximum amount a futures price may advance or decline in any one day's trading session.
Limit Order	A contingent order for a futures or options trade specifying a certain maximum (or minimum) price, beyond which the order is not to be executed. Probably the most popular type of order among hedgers.
Liquidate	Exiting a commodity or derivative position by entering an equal but opposite purchase or sale.
Liquidation	The closing out of future and options positions.
Liquidity	A market is said to be "liquid" when it has a high level of trading activity and open interest. That is, a market in which it is easy to regularly buy and sell forward and derivative instruments.
Load Following	An electric system's ability to regulate its generation to follow instantaneous changes in customer demand.
Load Shape	Variation in the magnitude of the power load over a hourly, daily, weekly or yearly period.
Long Position	A contractual obligation to purchase a commodity at a predetermined date(s). The position of a futures or forward contract buyer whose purchase obligates him to accept delivery unless he liquidates his contract with an offsetting sale.
Margin	Funds or good faith deposits posted during the trading life of a futures or forward contract to guarantee fulfillment of the contract obligation.
Margin Call	A demand for additional or variation margin funds when futures or forward prices move adversely to an entities position.
Mark to Market	The difference in the entry price of a position and the current market price.
Marked to Market	The process of redetermining the value of all open futures and forward positions after each trading day.

Appendix B – Glossary (continued)

Market Risk	Market Risk: Potential fluctuations in prices, volumes, and market rules that may affect a company's buying and selling activity. Usually comprised or created because of: • Operational risk • Volumetric risk • Counterparty contract and credit risk • Commodity price risk
Market Order	An order to be filled immediately at the current price.
Market-based or Market-responsive Pricing	Basing a contract or rate schedule on published current market prices of competing supplies or alternate electricity or fuels.
Net Position	The net of all positions. For example, if the long positions are greater than the short positions, then the net position is long. In futures trading, the difference between an entity's open long contracts and the open short contracts in any one commodity.
New York Mercantile Exchange (NYMEX)	The commodity exchange based in New York City where electricity and natural gas futures and options contracts and other energy commodity futures are traded.
Offer	A motion to sell a futures or options contract at a specified price. Also called an ask.
Open Outcry System	A method of public auction for making verbal bids and offers for contracts in the trading pits or rings of commodity exchanges.
Operational Risk	The risk of loss that directly or indirectly is the result of failed systems, processes, contracts, or people.
Optimization	Plans and procedures used to mathematically and systematically make a function as effective as possible. Note: This term is used here to refer to power supply planning and trading.
Option	A contract that gives the holder the right, but not the obligation to purchase or sell the underlying commodity, which could be a futures contract, a derivative or the commodity itself.

Appendix B – Glossary (continued)

Order — When buying or selling a futures contract, the broker will ask for specific instructions. The most popular orders are "market," "limit" and "stop."

Organizational Risk — The risks associated with the lack of risk management and trading expertise, systems, or internal policies and procedures that are designed to manage energy risks.

OTC — Over the counter: a non-exchange market consisting of individual buyers and sellers doing business directly between one another(e.g., utilities, marketer, independent power producers, G&Ts).

Out-of-the-Money — An option that has no intrinsic value. For calls, an option whose exercise price is above the market price of the underlying future. For puts, an option whose exercise price is below the futures price.

Portfolio — The collective supply resources and demand obligations of an entity.

Portfolio Model — A decision support tool used to measure risk exposures and assist in developing an executable hedging strategy.

Position — A contractual obligation to purchase or sell a commodity.

Power — The time rate of generating, transferring or using electric energy, usually expressed in kilowatts (KW). Used synonymously with electricity.

Premium — The price of an option.

Price Transparency — The ability to quickly and accurately determine the price of a commodity.

Principals — One who executes trades on his or her own behalf by taking title to the product.

Put Option — A contract that establishes a right to sell a commodity for a specified time period at a specified price (the strike price).

Regulatory/ Environmental Risk — The current and prospective risks associated with regulatory and environmental market regulations and potential changes in these regulatory rules

Appendix B – Glossary (continued)

Right of First Refusal	A general principle that allows a party to maintain a contract of service beyond the contract expiration date by matching another offer for the same service.
Risk Adversity/ Tolerance	The amount of risk that an entity is willing to accept in running its business.
Short or Short Position	1) The market position of the futures or forward contract seller whose sale obligates him or her to deliver the commodity. 2) An entity whose net position in the market shows an excess of sales over purchases. 3) The holder of a short position. 4) In the options market, the position of the seller of a call or a put option. The short in the options market is obliged to take a futures position if he or she is assigned for exercise. Opposite of Long.
Shoulder Months	Normally defined as spring and fall months when energy demand is lowest.
Sleeve or Sleeving	An arrangement where a more financially reputable entity acts as middleman for a smaller, undercapitalized entity in the sale of power.
Speculate	Assuming market risk by purchasing or selling a commodity or derivative instrument solely for the hope of a gain.
Speculator	An entity that trades commodities with the objective of achieving profits by successfully anticipating price movements.
Spot transaction	Term which describes a one-time market transaction, where a commodity is purchased "on the spot" at current market rates. Spot transactions are in contrast to term sales, which specify a steady supply of product over a period of time.
Spot Market	A market characterized by short-term transactions over the next few days or weeks of physically delivered commodity, The bulk of the natural gas spot market trades on a monthly basis, while power marketers sell spot supplies mostly on an hourly or daily basis.
Spot Month	The futures contract closest to maturity. The nearby delivery month.
Strike Price	The strike price is the price that the exchange of commodity will be set upon exercise of the option. The strike price is set before an option transaction price is negotiated. Also known as the exercise price.

Appendix B – Glossary (continued)

Structured Product A customized contract involving a bulk power transaction negotiated between two parties. A structured product addresses specific needs of the buyer that may involve numerous physical, financial, and derivative components bundled into a single contract. A full requirements contract is one example of a structured product.

Swap A custom-tailored, individually negotiated transaction designed to manage financial risk. In a typical commodity or price swap, parties exchange payments based on changes in physical commodity prices. The transaction enables each party to manage exposure to commodity prices or index values. Settlements are made in cash.

Time Value Also know as extrinsic value or time premium.

Tolling Agreement In the electric power market, an agreement where the owner of a power plant agrees to accept a certain amount of fuel and return electricity in its stead.

Trading Instrument A purchase or sale transaction used to manage or hedge an entity's energy portfolio.

Transactional Costs The costs attributable to signing a contract, like brokerage fees or legal expenses.

Transactional Liquidity A sufficient volume of transactions such that a party coming to a market center can be assured of the existence of a courterparty.

Underlying In the case of an option, the futures contract that the option holder has the right to buy or sell. In the case of a future, the physical commodity that provides the basis for the futures contract.

Value at Risk (VAR) A measurement of risk exposure of a portfolio.

Volatility The degree to which the price of a commodity tends to fluctuate over time. The market's price range and movement within that range. The direction of the price move, whether up or down, is not relevant. Historic volatility indicates how much prices have changed in the past and is derived by using daily settlement prices for futures. Implied volatility measures how much the market thinks prices will change in the future, obtained from daily settlement prices for options.

Volume The total number of futures contracts traded during each day.

Appendix B – Glossary (continued)

Wholesale Electricity Bulk power that is bought and sold among utilities, non-utility generators and other wholesale entities, such as municipalities.

Appendix C – Exhibit 1
The Energy Risk Management Process

Critical Energy Risk Management Steps (In Random Order)

5 • Execute Hedging Plan
3 • Measure, Monitor, and Re-assess Risk
1 • Identify Risk Exposures
2 • Develop Risk Management Policy
4 • Develop Hedging Plan

Put the list above in the order by which they should be completed by an entity managing energy risk:

1. ______________________________
2. ______________________________
3. ______________________________
4. ______________________________
5. ______________________________

Turn to page 3 of the Participant Guide.

Appendix C – Exhibit 2
Calculation of Liquidated Damages

Co-op Enters a Liquidated Damages Contract

- Liquidated damages can apply in cases where the contract specifies that the non-performing party to a transaction must pay financial damages to the counterparty in the event of default.
- Assume that a co-op buys a forward contract for 100 MW at $50/MWh from a utility for on-peak delivery during next July and August.
- The transaction was executed under a new standardized EEI contract that had strict provisions for force majeure and liquidated damages

Counterparty Defaults on Transaction

- On the hottest day of the month counterparty informs G&T that it will not be delivering the 100 MW for the on-peak period (16 hours or a total of 1,600 MWh's)
- Market prices on day of default are $1,050/MWh so the G&T must go out and buy replacement power at this price
- Liquidated damages are calculated as the difference between the replacement cost of power and the agreed upon price multiplied by the volume (in MWh's).

Exercise Question

1. What is the total value of liquidated damages that the G&T experienced because of default? ____________________

1600

Turn to page 33 of the Participant Guide.

Appendix C – Exhibit 3
Mark to Market Calculation for Cash Margining

Co-op Makes a Purchase

- Mark to market (MTM) on a Transaction = Change in value of the forward transaction at today's market rates. (Transaction price – Today's Value)
- Assume co-op is approved for a $2 million collateral threshold
- Assume purchase of 100 MW on peak @ $40/MWh for 5 years from July 2003 through Jun 2008
- Co-op cannot control MTM exposure
- Value at time of purchase is 4,032 hrs/yr x 5 yrs x 100mw x $40 = $80,640,000

Market Prices Change Causing Cash Margin Requirement

- Market price drops $2 to $38/MWh
- Today's value 4032 hrs/yr x 5 yrs x 100 mw x $38 = $76,608,000

4,032,000

Exercise Questions

1. MTM loss to buyer = ____________________
2. MTM gain to seller = ____________________
3. Seller's Cash Margin Requirement = 2,032,000 (MTM gain minus credit threshold)
4. Co-op needs to post $________________ cash or Letter of Credit with seller

Mechanics of Cash Margining

- All contracts with a counterparty are marked to market and net valued at + or -
- Margin call is made to the counterparty, which exceeded its threshold
- Cash or Letter of Credit must be posted within 2 days of the margin call
- Failure to post margin places all contracts with the counterparty in default

Turn to page 34 of the Participant Guide.

Appendix C – Exhibit 4
Assessing Your Risk Tolerance

There is a Spectrum of Alternatives in Managing Energy Risk

- Assume you represent an unaffiliated cooperative whose full requirements contract will expire in 2 years.
- They are considering the following 4 supply alternatives for their 400 MW demand to address the next 5 years

1. Buy everything from the hourly spot market
2. Build or buy a 400 MW generating unit
3. Enter a fixed price full requirements contract
4. Construct a portfolio of purchased power

Potential Annual Costs

Alternative 1

Target Price	$42/MWh	
Best Case Price	$30/MWh –	Key Factor: Possible low cost but risky
Worse Case Price	$65/MWh	

Alternative 2

Target Price	$43/MWh	
Best Case Price	$36/MWh –	Key Factor: Long term stability in owning asset,
Worse Case Price	$50/MWh	Capital cost, Non-diversified supply

Alternative 3

Target Price	$46/MWh	
Best Case Price	$46/MWh –	Key Factors: Uncertainty after expiration,
Worse Case Price	$46/MWh	Credit risk with one party

Alternative 4

Target Price	$42/MWh	
Best Case Price	$40/MWh –	Key Factor: Uncertainty after expiration,
Worse Case Price	$47/MWh	Diversified supply

Exercise Questions

1. As a Board Member which alternative would be most appealing to you? (Circle 1)
   a. Alternative 1
   b. Alternative 2
   c. Alternative 3
   d. Alternative 4
   e. Other
2. Why? 4 – Diversify risk – Continue to look at ~~[illegible]~~ options perhaps / 200 MW unit.

Turn to page 43 of the Participant Guide.

Appendix C – Exhibit 5
Generic Board Energy Risk Management Policy Outline

1. Policy Purpose
2. Risk Management Objectives
3. Risk Management Oversight/Control Responsibilities
    a. Board of Directors
        i. Responsibilities and Oversight
        ii. Required Transaction Authorizations
    b. Board Risk Oversight Committee
        i. Members
        ii. Responsibilities and Oversight
    c. CEO
        i. Responsibilities and Oversight
        ii. Transaction Authority Limits and Staff/Agent Limits
    d. Staff Risk Management Committee
        i. Organizational Reporting and Separation of Functions
        ii. Risk Reporting, Recommendations, Compliance Monitoring, and Oversight Responsibilities
    e. Independent Risk Function
        i. Independence From Risk "Creation" Function
        ii. Responsibilities
        iii. Organizational Reporting and Authority
4. Scope of Business Activity Governed by this Policy (Could be expanded to enterprise risk management if desired)
    a. Member Wholesale Energy Activity
        i. Member Portfolio Business Objectives
            1. Power Supply Cost Goal (Trade off in cost and risk)
            2. Use of Derivatives and Trading Instruments
        ii. Strategy to Manage Portfolio
            1. Portfolio Structure
            2. Short, Intermediate and Long Term Strategies
        iii. Risk Controls and Measurement Methods for Managing Risk
    b. Non-Member Wholesale Energy Activity
        i. Non-Member Business Objectives
        ii. Strategy to Manage Non-Member Activity
        iii. Risk Controls and Measurement Methods for Managing Risk
    c. Other Enterprise Risk Management Activities

Appendix C – Exhibit 5
Generic Board Energy Risk Management Policy - Key Examples and Descriptions

1. Policy Purpose
   - To define energy risk management (ERM) objectives, oversight, control structure, policies, procedures, and authorized energy business activities.
   - To support the companies strategic business plan
   - To ensure proper management of energy risks

2. Risk Management Objectives
   - To reduce energy business risks
   - To mitigate price volatility to the member systems
   - To enhance the value of the companies assets/resources
   - Leverage opportunities to increase value to member systems \

3. Risk Management Oversight/Control Responsibilities

   Board of Directors
   - Responsible for approving ERM policy and updates, creating and approving members of board "risk oversight committee", review periodic risk updates.
   - Establishes limits for management and staff trading authority, and annual price target and maximum acceptable price (risk tolerance)

   Risk Oversight Committee (ROC)
   - Defines members
   - Responsible for oversight of risk management activity, recommends policy changes to Board, approves trading tools, products, and locations
   - Defines periodicity of review of risk exposures and compliance

   CEO
   - Recommends, for ROC approval, and appoints (about 5) management individuals to serve as members on the internal Risk Management Committee (see below).
   - Defines CEO authority to transact and delegations to management or outsourced companies.

Appendix C – Exhibit 5
Generic Board Energy Risk Management Policy - Key Examples and Descriptions (continued)

Internal Risk Management Committee (IRMC)

- Defines ground rules of the committee (e.g. all members have equal say, quorums) and reporting requirements to CEO
- Approves risk mitigation procedures
- Determines proper separation of energy risk management functions
- Ensures functional area risk procedures are in compliance with this policy.
- Meets not less than monthly to: review risk exposures; approve methods for measuring and monitoring risk; approves strategies and practices to manage exposures; approves recommendations for policy, procedure, or strategy changes; recommends limit and control changes to ROC,

Independent Risk Management Function

- Names and defines responsibilities of a staff member who is independent from those who create or directly manage risk.
- Responsibilities of this person include: administration of risk policy; oversee risk management activities; organizes and runs IRMC meetings; directs execution and management of approved risk management strategies; ensure and monitors compliance with risk management policies; regularly reports to IRMC risk exposures, stress test values; positions limits, and any ERM policy violations, recommends to IRMC modifications of control or policy to meet changing business needs, review adequacy and accuracy of reports; reviews proposed financial, legal, credit, operational, and marketing activities that impact risk and ensure policy compliance (or report deficiencies).

4. Scope of Business Activity Governed by this Policy (Could be expanded to enterprise risk management if desired). Examples of Scope include
   - Member Wholesale Energy Activity
   - Non-Member Wholesale Energy Activity
   - Plant and Construction Activity
   - Environmental and Regulatory Activity
   - Enterprise Risk Management if Desired (list areas)

Appendix C – Exhibit 5
Generic Board Energy Risk Management Policy - Key Examples and Descriptions (continued)

5. Member Wholesale Energy Activity
   - Member Portfolio Business Objectives
     - Power Supply Cost Goal (Trade off in cost and risk)
     - Use of Derivatives and Trading Instruments
   - Strategy to Manage Portfolio
     - Portfolio Structure
     - Short, Intermediate and Long Term Strategies
     - Risk Controls and Measurement Methods for Managing Risk

6. Non-Member Wholesale Energy Activity
   - Non-Member Business Objectives
   - Strategy to Manage Non-Member Activity
   - Risk Controls and Measurement Methods for Managing Risk
   - Other Enterprise Risk Management Activities

Turn to page 54 of the Participant Guide.

Appendix C – Exhibit 6
Generic Power Trading Authority Matrix

Designated Trading Authorizations
Wholesale Electricity Trading Transaction Limits
(Example of a System With a 900 MW Peak Demand With a 250 MW Coal Unit)

Transaction Term	Limit Attributes (up to)	Hourly Trader	Term Trader	Trading Manager	Director of Trading	V.P of Trading	CEO	Board of Directors
Long Term (More than 5 yrs)	MW / Transaction	0	0	0	0	0	200	No Max.
	Max. Price for On-Peak Energy/Mwh	$0	$0	$0	$0	$0	$50	No Max.
	Max. Price for Transmission/Mw-Year	$0	$0	$0	$0	$0	$30,000	No Max.
Intermediate Term (1 yr <Term< 5 yrs)	MW / Transaction	0	0	0	50	100	400	No Max.
	Max. Price for On-Peak Energy/Mwh	$0	$0	$0	$40	$43	$48	No Max.
	Max. Price for Transmission/Mw-Year	$0	$0	$0	$20,000	$24,000	$30,000	No Max.
Short Term (Mo<Term<= 1 yr.)	MW / Transaction	0	0	100	200	400	700	No Max.
	Max. Price for On-Peak Energy/Mwh	$0	$0	$40	$43	$45	$48	No Max.
	Max. Price for Transmission/Mw-Year	$0	$0	$20,000	$22,000	$26,000	$30,000	No Max.
Monthly or Less	MW / Transaction	0	100	200	300	500	700	No Max.
	Max. Price for On-Peak Energy/Mwh	$0	$80	$100	$150	$200	$250	No Max.
	Max. Price for Transmission/Mw-Month	$0	$2,000	$2,200	$2,400	$2,600	$2,800	No Max.
Weekly	MW / Transaction	0	300	400	500	600	700	No Max.
	Max. Price for On-Peak Energy/Mwh	$0	$100	$200	$300	$500	$1,000	No Max.
	Max. Price for Transmission/Mw-Week	$0	$400	$400	$500	$600	$700	No Max.
Daily	MW / Transaction	0	300	400	500	600	700	No Max.
	Max. Price for On-Peak Energy/Mwh	$0	$250	$300	$400	$500	$2,000	No Max.
	Max. Price for Transmission/Mw-Day	$0	$75	$80	$85	$90	$95	No Max.
Hourly	MW / Transaction	300	300	400	500	600	700	No Max.
	Max. Price for On-Peak Energy/Mwh	$300	$300	$500	$500	$1,000	$2,000	No Max.
	Max. Price for Transmission/Mwh	$10	$10	$10	$10	$10	$10	No Max.

Employee Signature

____

Date

____

Director of Trading Control

____

Date

____

Other Policies and Procedures Required in Support of this Authority Matrix

1. Entity Transaction Limits: Identifies the maximum cumulative transaction quantities for the entire entity for a given time period.
2. Credit and Contract Policy: Identifies the contractual provisions and credit limits that must be adhered to by the authorized traders.
3. Sanctions Policy: Identifies the consequences of failing to adhere to the Authority matrix and the credit and control policies.

Turn to page 59 of the Participant Guide.

Appendix C – Exhibit 7
Properly Balanced 2004 Portfolio for a 900 MW Peak Demand System

Portfolio Example For a Mid-Western G&T						
Resource	Resource Utilization	2004	2005	2006	2007	2008
Old Coal Unit #1	Baseload	250	250	250	250	250
Joint Owned Coal Unit	Baseload	150	150	150	150	150
Federal Hydro Contract	Intermediate	68	68	68	68	68
Efficient Nat Gas Unit #1	Intermediate	120	120	120	120	120
Market Purchase - 5X16	Intermediate	50	50	50	0	0
Peaking Unit #1	Peaking	75	75	75	75	75
Peaking Unit #2	Peaking	75	75	75	75	75
Peaking Unit #3	Peaking	75	75	75	75	75
Member Diesel Units	Peaking	22	22	22	22	22
Market Purchase - Call Option	Peaking	50	0	0	0	0
Demand Side Management	Peaking	75	75	75	75	75
Total Resources		1,010	960	960	910	910

Forecasted Peak Demand	900	918	936	955	974
Calculated Reserve Requirement *	12%	12%	12%	12%	12%
Peak Plus Reserves	1,008	1,028	1,049	1,070	1,091
Expected Net Position	2	(68)	(89)	(160)	(181)

* Calculated reserve requirement accounts for mandatory reliability council reserves, probabilistic unit outages or unavailability, and statistically valid forecasted peak demand extremes.

Questions:

1. List the Operational and Volumetric Risks the G&T Might Face
   a. CTs May Not Start
   b. Examine F.O. rates on unit
   c. fuel supply & cost
   d.
   e.
   f.
2. List the fuels that need to be examined for risk
   a. availability / Price of fuel
   b.
   c.
3. List some ways the G&T can mitigate the risks identified above
   a. Purchase call option
   b. Outage manage
   c. Hedge natural gas fuel supply
   d. build 250 MW Baseload
   e.

Turn to page 85 of the Participant Guide.

Appendix C – Exhibit 8
Optimizing Natural Gas and Power Transactions

Co-op Hedges Natural Gas For Next July

- Purchased 225,000 MMBtu at $4.00/MMBtu for expected need of running combined cycle gas units during on-peak hours of the month. (Heat rate of 7,000 btu/kwh or 7.0 MMBtu/MWh)
- With this gas, co-op can produce 32,000/MWh of on-peak power
- At time of gas purchase on-peak power was $33/MWh
- The cost to produce power from gas is calculated by multiplying the ratio of MMBTU/MWh (based on heat rate efficiency) times the gas price $/MMBtu.
- The Spark Spread is the calculated difference between the cost of market power versus the cost to produce power from a gas generating unit(Cost of market power – cost to produce power).

Exercise Questions

1. How much would it cost in $/MWh to produce power from the given unit (ignoring operation and maintenance costs)? 28
2. What is the spark spread ($/MWh) under this market condition for the given heat rate? 5
3. Can the spark spread be positive at some times and negative at others?
   √a. Yes
   b. No
4. If the spark spread is positive then an entity owning gas generation should?
   √a. Consider buying gas
   b. Consider buying power
5. If the spark spread is negative then an entity owning gas generation should?
   a. Consider buying gas
   √b. Consider buying power

In this example, at time of purchase it was more economic to plan on running combined cycle units versus buying from market.

Appendix C – Exhibit 8
Optimizing Natural Gas and Power Transactions (continued)

Market Prices Change

- Gas price rises to $5.00/MMBtu
- Power prices remain unchanged at $33/MWh

Exercise Questions

1. How much would it cost in $/MWH to produce power at current gas prices? 35
2. Now what is the spark spread in $/MWh? -2

How to Create Opportunity

- Can sell gas at $1.00 gain or $225,000 profit ($1 X 225,000 MMBtu)
- Can buy power at $33/MWh or $5/MWh more than initial hedged price ($33 vs. $28), offsetting gas profits by $160,000.
- Generated profit of $65,000 ($225,000 - $160,000) plus;
- Gas unit becomes available for additional transaction opportunities or they could immediately sell the rights to the units for instant profit

This opportunity could reverse and repeat itself several times before next July.

Your policies and controls should allow traders to seek and readily execute these opportunities.

Turn to page 90 of the Participant Guide.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

Response to the Office of the Attorney General's
Supplemental Set of Data Requests
Dated March 14, 2013

March 28, 2013

Item 8) *Referencing Big Rivers' confidential response to AG 1-25(g):*

a. At page 1: [BEGIN CONFIDENTIAL] [redacted] *[END CONFIDENTIAL].*

i. Please provide any and all presentation materials, and any and all other documents provided to the Board.

ii. Please state actions taken by the Board regarding the subject of [BEGIN CONFIDENTIAL[redacted] *[END CONFIDENTIAL]*

b. At page 4, [BEGIN CONFIDENTIAL] [redacted] *[END CONFIDENTIAL] were discussed. Please provide the [BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL] together with any and all materials and documents associated therewith.*

c. At page 22, [BEGIN CONFIDENTIAL[redacted]*[END CONFIDENTIAL]:*

i. Please state precisely where this estimation can be found in the rate case filing workpapers;

ii. Please provide documents which show the[BEGIN CONFIDENTIAL] [redacted] *[END CONFIDENTIAL] estimation of these costs; and,* *iii. Please provide any and all documents on this subject which were provided to the Board.*

d. At pages 3 and 7, accuracy of financial forecasting, [BEGIN CONFIDENTIAL] [redacted] *[END CONFIDENTIAL] . Please provide any and all documents:*

i. [BEGIN CONFIDENTIAL] [redacted] *[END CONFIDENTIAL];*

ii. supporting [BEGIN CONFIDENTIAL] [redacted] *[END CONFIDENTIAL];*

iii. showing [BEGIN CONFIDENTIAL] [redacted] *[END CONFIDENTIAL] for FY 2012 to present;*

iv. associated with the "Financial Reports" items in the Minutes for April – May, and July – December 2012 meetings.

e. At page 1: [BEGIN CONFIDENTIAL] [redacted] *[END CONFIDENTIAL]*

i. Please provide any and all presentation materials and any and all documents provided to the Board in this regard.

ii. Please state actions taken by the Board regarding the subject of [BEGIN CONFIDENTIAL] [redacted] *[END*

CONFIDENTIAL], and provide any and all documents associated with such action.

f. At page 23, looking [BEGIN CONFIDENTIAL] [redacted] *[END CONFIDENTIAL]*

Response)

[redacted]

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

Response to the Office of the Attorney General's
Supplemental Set of Data Requests
Dated March 14, 2013

March 28, 2013

[redacted]

Witness) Robert W. Berry (subparts a-c, e)
Billie J. Richert (subparts d, f)

All AG 2-8 attachments have been omitted from the public filing. They have been provided under a petition for confidential treatment.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

Response to the Office of the Attorney General's
Supplemental Set of Data Requests
Dated March 14, 2013

March 28, 2013

Item 9) *Referencing Big Rivers' response to AG 1-27, where it states the need for securing "a three-year credit facility loan through CFC for bridge financing ... until long term financing with RUS is in place with a Rural Utilities Service ("RUS") Guaranteed Federal Financing Bank ("FFB") Loan":*

a. Describe the circumstances which cause the "gap" to occur which must be "bridged";

b. Does the three year term coincide with the earliest point Big Rivers anticipates RUS FFB financing will be available to it?;

c. What are the circumstances which impair or obviate "immediate" RUS financing from FFB?; and,

d. What is the earliest point Big Rivers believes FFB financing could reasonably be available to it?

Response)

a. Please see the attachment to this response for a copy of a presentation by the RUS dated August 25, 2011 regarding the loan application and approval process for RUS Electric Programs. As stated on page 16 of the attachment, "RUS funds will take longer to be made available than private sector sources of financing. Generally speaking 12-18 months *from time of loan submission* – therefore borrowers need to plan ahead and submit a loan 12-18 months before funds are needed." If funds are needed in the interim, "borrowers typically use short term borrowings from other lending institutions which are repaid by the long-term RUS loan funds."

b. No. The three year term coincides with the latest point Big Rivers anticipates RUS FFB financing will be available to it, not the earliest point.

c. The RUS loan application and approval process, and the time required for each, prevent "immediate" RUS financing from FFB.

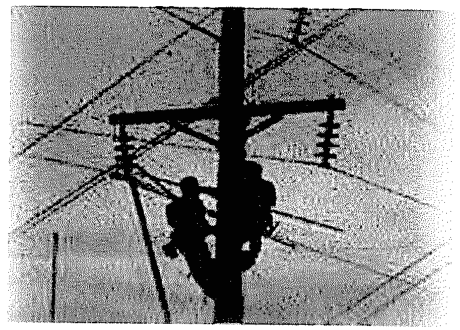
d. The earliest point Big Rivers believes FFB financing could reasonably be available to it is 12 months from the time of submitting the loan application, which Big Rivers plans to submit during the first half of 2013.

Witness) Billie J. Richert

USDA Rural Development
RUS Electric Programs

Tribal Renewable Energy Business Development & Finance Workshop
August 25, 2011
Denver, Colorado

John P. Rabaglia
RUS General Field Representative



Case No. 2012-00535
Attachment for Response to AG 2-9(a)
Witness: Billie J. Richert
Page 1 of 30

Today's Topics

- RUS Electric Programs – authorization, loan programs, eligibility
- Requirements for First Time RUS Borrowers
- RUS Loan Compliance and Administration

USDA Rural Development

RUS ELECTRIC PROGRAMS

All Federal regulations can be found at Regulations.gov and customers can search, review and submit comments on Federal documents that are open for comment and published in the Federal Register http://www.gpoaccess.gov/fr/.

The direct link to the Code of Federal Regulation (CFR) Title 7 Agriculture, Subtitle B, Volumes 11 &12, Parts 1700-1799, governing the RUS Electric Programs is:

http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&sid=6c8f47d1af5f28c4894678b8682b7088&rgn=div5&view=text&node=7:11.1.2.1.1&idno=7

USDA Rural Development

RUS ELECTRIC PROGRAMS

Since its origin in May 1935, the Electric Programs, has made loans and guarantees of loans to the Federal Financing Bank (FFB) to rural nonprofit and cooperative associations, public bodies, and other utilities. For program purposes rural is presently defined as a city, town or unincorporated area with less than 20,000 population. Areas that are determined to be urban are not eligible for RUS Electric Programs financing.

RUS ELECTRIC PROGRAMS

The Electric Programs maintain a staff of General Field Representatives (GFR) around the country, a single point of contact type program delivery system which has been part and parcel of the program since its inception. In addition to assisting in the development of loan applications and handling of other loan related matters, GFRs are available to discuss a wide range of business matters which may be of interest to a borrower.

RUS ELECTRIC PROGRAMS

As of FYE 2010 there were about 620 active borrowers in the program representing total historical loan obligations of about $100 B:

-- about $54 B has been obligated since 2008;

- about $37 B total in current outstanding;

- about 1/2 with Distribution entities, 1/2 with Generation & Transmission (G&T) entities.

RUS ELECTRIC PROGRAMS

Since 2008 only two types of loan programs have been authorized for RUS:

FFB (Federal Financing Bank) Guarantee Loan and Hardship Loan.

In Fiscal Year 2010 RUS Electric Programs obligated $6.5 B in loans - $6.5B of FFB guarantee plus $100M Hardship loans.

About 70% of outstanding loan obligations are FFB, 15% Hardship and 15% all other loan types previously authorized for RUS.

RUS ELIGIBILITY

FFB Guaranteed Loans

Eligible Facilities: Distribution, transmission (bulk and sub-transmission), generation and headquarters (office, service and warehouse) facilities
Eligible Borrowers: Retail and power supply providers
Interest Rate: Interest rates will be established daily by the United States Treasury. Added to that rate is 1/8 of one percent. The interest rate is determined at the time of each advance
Supplemental Financing Required: No
Loan Term: Term of loan not to exceed useful life of the facilities being financed, with a maximum term of 35 years. Power supply borrowers' loan term is also based on the term of its wholesale power contracts.

Hardship Loans

Eligible Facilities: Distribution, sub-transmission and headquarters (service & warehouse) facilities
Eligible Borrowers: Retail providers that meet rate disparity thresholds and whose consumers fall below average per capita and household income thresholds or that have suffered a severe, unavoidable hardship, such as a natural disaster, as determined by the RUS Administrator
Interest Rate: 5%
Supplemental Financing Required: No
Loan Term: Term of loan not to exceed useful life of the facilities being financed, with a maximum term of 35 years

RUS ELECTRIC PROGRAMS

Through February 2011 a total of about $628 M has been obligated by RUS Electric Programs for renewal energy projects, all but $84 M to G&T entities. RUS expects an additional $90 M renewal energy project for a distribution entity will be obligated by the end of FY 2011 (9/30/2011).

Requirements for First Time RUS Borrowers

Process of Becoming A RUS Borrower

- Seeking an Eligibility "Determination Letter"
- Determination of Eligible Portions of Service Area
- RUS Audit Review of Financials & Acct. System
- Engineering Certification of National Electric Safety Code (NESC) Compliance
- Development & Approval of Primary Planning Docs.
- Development of Primary Loan Application Docs.

RUS Planning Requirements

- Required Utility Planning Documents
  - Load (and Resource) Forecast Study
  - Long Range System Plan
  - Construction Work Plan
  - Environmental Report
- Long Range Financial Forecast

USDA Rural Development

RUS Electrical System Requirements

- Existing Electrical System Code Compliance
- Electric System Design Standards & Approvals
- Electric System Construction Standards
- Electric System Materials Standards
- Electric System Operations and Maintenance (O&M) Standards & Reviews
- Professional Engineering & Architect's Requirements

USDA Rural Development

Committed to the future of rural communities

RUS Financial Reporting

- RUS Uniform System of Accounts
- RUS Financial Reporting Requirements
- RUS Plant Accounting Requirements
- RUS External Auditing Requirements
- RUS Field Audits

Loan Application Highlights

- Relatively simple process
- Need normal documents such as a construction work plan – 2, 3 or 4 year
- Updated Load Forecast Study
- Financial Forecast
- Current System Operations and Maintenance Review
- Attorney Opinion Letter
- Miscellaneous borrower certifications and documents

Loan Timing

- RUS funds will take longer to be made available than private sector sources of financing.
- Generally speaking 12-18 months *from time of loan submission* – therefore borrowers need to plan ahead and submit a loan 12-18 months before funds are needed.
- In funds needed in the interim, borrowers typically use short term borrowings from other lending institutions which are repaid by the long-term RUS loan funds.

Other Business Considerations

- Multiple Funding Sources vs. "Sole Sourcing"
- Short-term lending vs. Reimbursement Lending
- Utility's "Corporate Culture"
- Employee Attitudes toward change
- Non-Financial Benefits of RUS Participation

RUS Loan Compliance and Administration

RUS LOAN CONTRACT – THE BIG FOUR

Section 5.4 Rates To Provide Revenue Sufficient to Meet Coverage Ratios Requirements

- (a) *Prospective Requirement.* The Borrower shall design and implement rates for utility service furnished by it to provide sufficient revenue (along with other revenue available to the Borrower in the case of TIER and DSC) (i) to pay all fixed and variable expenses when and as due, (ii) to provide and maintain reasonable working capital, and (iii) to maintain, on an annual basis, the Coverage Ratios. In designing and implementing rates under this paragraph, such rates should be capable of producing at least enough revenue to meet the requirements of this paragraph under the assumption that average weather conditions in the Borrower's service territory shall prevail in the future, including average Utility System damage and outages due to weather and the related costs.

RUS LOAN CONTRACT – THE BIG FOUR

Section 5.4 Rates To Provide Revenue Sufficient to Meet Coverage Ratios Requirements

- (b) The average Coverage Ratios achieved by the Borrower in the 2 best years out of the 3 most recent calendar years must be not less than any of the following:

TIER (Times Interest Earned Ratio)=1.25

DSC (Debt Service Coverage)=1.25

OTIER (Operating TIER)=1.1

ODSC Operating DSC)=1.1

RUS LOAN CONTRACT – THE BIG FOUR

Section 5.4 Rates To Provide Revenue Sufficient to Meet Coverage Ratios Requirements

Times Interest Earned Ratio" ("TIER") shall have the meaning provided in the Mortgage.

Times Interest Earned Ratio ("TIER") shall mean the ratio determined as follows: for each calendar year: add (i) patronage capital or margins of the Mortgagor and (ii) Interest Expense on Total Long-Term Debt of the Mortgagor and divide the total so obtained by Interest Expense on Total Long-Term Debt of the Mortgagor, provided, however, that in computing Interest Expense on Total Long-Term Debt, there shall be added, to the extent not otherwise included, an amount equal to 33–1/3% of the excess of Restricted Rentals paid by the Mortgagor over 2% of the Mortgagor's Equity.

RUS LOAN CONTRACT – THE BIG FOUR

Section 5.4 Rates To Provide Revenue Sufficient to Meet Coverage Ratios Requirements

- "Operating TIER" or "OTIER" shall mean Operating Times Interest Earned Ratio calculated as: OTIER = (A+B)/A

  Where:
- All amounts are for the same calendar year and are computed pursuant to RUS Accounting Requirements and RUS Form 7;
- A=Interest Expense on Total Long-Term Debt of the Electric System, except that such Interest Expense shall be increased by 1/3 of the amount, if any, by which Restricted Rentals of the Electric System exceed 2 percent of the Mortgagor's Equity; and
- B=Patronage capital & operating margins of the Electric System, (which equals operating revenue and patronage capital of Electric System operations, less total cost of electric service, including Interest Expense on Total Long-Term Debt of the Electric System) plus cash received from the retirement of patronage capital by suppliers of electric power and by lenders for credit extended for the Electric System.

RUS LOAN CONTRACT – THE BIG FOUR

Section 5.4 Rates To Provide Revenue Sufficient to Meet Coverage Ratios Requirements

Debt Service Coverage Ratio" ("DSC") shall have the meaning provided in the Mortgage.

Debt Service Coverage Ratio ("DSC") shall mean the ratio determined as follows: for each calendar year add (i) Patronage Capital or Margins of the Mortgagor, (ii) Interest Expense on Total Long Term Debt of the Mortgagor (as computed in accordance with the principles set forth in the definition of TIER) and (iii) Depreciation and Amortization Expense of the Mortgagor, and divide the total so obtained by an amount equal to the sum of all payments of principal and interest required to be made on account of Total Long-Term Debt during such calendar year increasing said sum by any addition to interest expense on account of Restricted Rentals as computed with respect to the Times Interest Earned Ratio herein.

RUS LOAN CONTRACT – THE BIG FOUR

Section 5.4 Rates To Provide Revenue Sufficient to Meet Coverage Ratios Requirements

- Operating DSC" or "ODSC" shall mean Operating Debt Service Coverage calculated as:

  ODSC = (A+B+C)/D Where:

- All amounts are for the same calendar year and are computed pursuant to RUS Accounting Requirements and RUS form 7;
- A=Depreciation and Amortization Expense of the Electric System;
- B=Interest Expense on Total Long-Term Debt of the Electric System, except that such Interest Expense shall be increased by1/3of the amount, if any, by which the Restricted Rentals of the Electric System exceed 2 percent of the Mortgagor's Equity;
- C=Patronage capital & operating margins of the Electric System, (which equals operating revenue and patronage capital of Electric System operations, less total cost of electric service, including Interest Expense on Total Long-Term Debt of the Electric System) plus cash received from the retirement of patronage capital by suppliers of electric power and by lenders for credit extended for the Electric System; and
- D=Debt service billed which equals the sum of all payments of principal and interest required to be made on account of Total Long-Term Debt of the Electric System during the calendar year, plus1/3of the amount, if any, by which Restricted Rentals of the Electric System exceed 2 percent of the Mortgagor's Equity.

RUS LOAN CONTRACT – THE BIG FOUR

Section 5.4 Rates To Provide Revenue Sufficient to Meet Coverage Ratios Requirements

- (c) *Prospective Notice of Change in Rates.* The Borrower shall give thirty (30) days prior written notice of any proposed change in its general rate structure to RUS if RUS has requested in writing that it be notified in advance of such changes.

- (d) *Routine Reporting of Coverage Ratios.* Promptly following the end of each calendar year, the Borrower shall report, in writing, to RUS the TIER, Operating TIER, DSC and Operating DSC levels which were achieved during that calendar year.

- (e) *Reporting Non-achievement of Retrospective Requirement. If the Borrower fails to achieve the average levels required by paragraph (b) of this section, it must promptly notify RUS in writing to that effect.*

USDA Rural Development

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RUS LOAN CONTRACT – THE BIG FOUR

Section 5.4 Rates To Provide Revenue Sufficient to Meet Coverage Ratios Requirements

- (f) Corrective Plans. Within 30 days of sending a notice to RUS under paragraph (e) of this section, or of being notified by RUS, whichever is earlier, the Borrower in consultation with RUS, shall provide a written plan satisfactory to RUS setting forth the actions that shall be taken to achieve the required Coverage Ratios on a timely basis.

- *(g) Noncompliance. Failure to design and implement rates pursuant to paragraph (a) of this section and failure to develop and implement the plan called for in paragraph (f) of this section shall constitute an Event of Default under this Agreement in the event that REA so notifies the Borrower to that effect under section [7.1(d)] of this Agreement.*

RUS LOAN CONTRACT

Article VII—Default, *Section 7.1. Events of Default*

- The following shall be Events of Default under this Agreement:
- (a) *Representations and Warranties.* Any representation or warranty made by the Borrower in Article II hereof or any certificate furnished to RUS hereunder or under the Mortgage shall prove to have been incorrect in any material respect at the time made and shall at the time in question be untrue or incorrect in any material respect and remain uncured;
- (b) *Payment.* Default shall be made in the payment of or on account of interest on or principal of the Note when and as the same shall be due and payable, whether by acceleration or otherwise, which shall remain unsatisfied for five (5) Business Days;
- (c) *Borrowing Under the Mortgage in Violation of the Loan Contract.* Default by the Borrower in the observance or performance of any covenant or agreement contained in Section 6.14 of this Agreement.
- (d) *Other Covenants.* Default by the Borrower in the observance or performance of any other covenant or agreement contained in any of the Loan Documents, which shall remain unremedied for 30 calendar days after written notice thereof shall have been given to the Borrower by RUS;
- (e) *Corporate Existence.* The Borrower shall forfeit or otherwise be deprived of its corporate charter, franchises, permits, easements, consents or licenses required to carry on any material portion of its business;
- (f) *Other Obligations.* Default by the Borrower in the payment of any obligation, whether direct or contingent, for borrowed money or in the performance or observance of the terms of any instrument pursuant to which such obligation was created or securing such obligation;

RUS LOAN CONTRACT

Article VII—Default, *Section 7.1. Events of Default*

- (g) *Bankruptcy.* A court having jurisdiction in the premises shall enter a decree or order for relief in respect of the Borrower in an involuntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect, or appointing a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official, or ordering the winding up or liquidation of its affairs, and such decree or order shall remain unstayed and in effect for a period of ninety (90) consecutive days or the Borrower shall commence a voluntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect, or under any such law, or consent to the appointment or taking possession by a receiver, liquidator, assignee, custodian or trustee, of a substantial part of its property, or make any general assignment for the benefit of creditors; and

- (h) *Dissolution or Liquidation.* Other than as provided in the immediately preceding subsection, the dissolution or liquidation of the Borrower, or failure by the Borrower promptly to forestall or remove any execution, garnishment or attachment of such consequence as shall impair its ability to continue its business or fulfill its obligations and such execution, garnishment or attachment shall not be vacated within 30 days. The term "dissolution or liquidation of the Borrower", as used in this subsection, shall not be construed to include the cessation of the corporate existence of the Borrower resulting either from a merger or consolidation of the Borrower into or with another corporation following a transfer of all or substantially all its assets as an entirety, under the conditions permitting such actions.

RUS LOAN CONTRACT

Article VIII—Remedies

- *Section 8.1. Generally*
- Upon the occurrence of an Event of Default, then RUS may pursue all rights and remedies available to RUS that are contemplated by this Agreement or the Mortgage in the manner, upon the conditions, and with the effect provided in this Agreement or the Mortgage, including, but not limited to, a suit for specific performance, injunctive relief or damages. Nothing herein shall limit the right of RUS to pursue all rights and remedies available to a creditor following the occurrence of an Event of Default listed in Article VII hereof. Each right, power and remedy of RUS shall be cumulative and concurrent, and recourse to one or more rights or remedies shall not constitute a waiver of any other right, power or remedy.

- *Section 8.2. Suspension of Advances*
- In addition to the rights, powers and remedies referred to in the immediately preceding section, RUS may, in its absolute discretion, suspend making Advances hereunder if (i) any Event of Default, or any occurrence which with the passage of time or giving of notice would be an Event of Default, occurs and is continuing; (ii) there has occurred a change in the business or condition, financial or otherwise, of the Borrower which in the opinion of RUS materially and adversely affects the Borrower's ability to meet its obligations under the Loan Documents, or (iii) RUS is authorized to do so under RUS Regulations.

Committed to the future of rural communities.

www.usda.gov/rus/electric

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BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

Response to the Office of the Attorney General's
Supplemental Set of Data Requests
Dated March 14, 2013

March 28, 2013

Item 10) *Referencing Big Rivers' response to AG 1-39 related to Management Business Plans and budgeted CAPEX for 2013 and 2014, address the following:*

a. Explain why the CAPEX budgets at AG 1-39 for years 2013 and 2014 are substantially less than the CAPEX amounts for 2013 and 2014 included in the Company's filing at Tab 25 Attachment (Berry and Crockett).

b. Provide an explanation and reconciliation by project between the CAPEX amounts at AG 1-39 and the CAPEX amounts at Tab 25 for 2013 and 2014 (including a reconciliation between different months/time periods), and identify all 2012 CAPEX amounts (and all other prior year CAPEX amounts for years before 2012) from AG 1-39 that were deferred to 2013 and 2014 at Tab 25 (along with all other necessary reconciliation and explanation).

c. Reconcile amounts in (a) and (b) above to CAPEX projects and related plant costs (by account number) that are included in the forecasted test period ending August 31, 2014 and explain all differences.

d. If there are any differences, reconcile amounts in (c) above, to construction projects for the forecasted test period ending August 31, 2014 provided in the Confidential response to PSC 1-17 (pages 39 to 51).

Response)

a. The CAPEX budgets provided in response to AG 1-39 included only the projects budgeted for the production department. The CAPEX budgets provided in Tab 25 of Big Rivers' Application included the projects budgeted for the entire company, including Administrative, Information Technology and Transmission departments.

b. See the attachments to this response for the reconciliation between the 2013 and 2014 CAPEX budgets provided in the response to AG 1-39 and in Tab 25 of Big Rivers' Application, in summary, and by project. The reconciliation sheets attached tie the two previous submissions together. There were no CAPEX amounts prior to 2013 included in Big Rivers' response to AG 1-39 and there are no other differences to reconcile. The attachments are being provided under a petition for confidential treatment.

c. See the response to subpart (b), above.

d. See the response to subpart (b), above.

Witness) Robert W. Berry

All AG 2-10(b) attachments have been omitted from the public filing. They have been provided under a petition for confidential treatment.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

**Response to the Office of the Attorney General's
Supplemental Set of Data Requests
Dated March 14, 2013**

March 28, 2013

Item 11) ***Referencing the response to the immediately preceding data request (AG 2-10), and the response to AG 1-39, CAPEX amounts for 2013/2014 included at Tab 25 Attachment of the Company's filing, and construction projects for August 31, 2014 provided in response to PSC 1-17 (pages 39 to 51), address the following:***

a. ***Explain and show how depreciation expense for the forecasted test period ending August 31, 2014 was calculated, by providing an Excel spreadsheet showing plant amount by account number (and description) multiplied by the related depreciation rate (and reconcile the plant amounts used in the depreciation expense calculation to plant amounts provided at AG 1-39, CAPEX amounts for 2013/2014 included at Tab 25 of the Company's filing, and to construction projects for August 31, 2014 provided in response to PSC 1-17 (pages 39 to 51).***

b. ***Reconcile, explain, and provide calculations showing the amount of accumulated depreciation included in the forecasted test period ending August 31, 2014 as reconciled to the related depreciation expense and plant amounts addressed in (a) above. Explain if accumulated depreciation for the test period ending August 31, 2014 includes a full year of the related depreciation expense for the period, or explain and show the method used by BREC.***

c. ***Reconcile, explain, and provide calculations showing the amount of accumulated deferred income tax included in the forecasted test period***

ending August 31, 2014 as reconciled to the related depreciation expense and plant amounts addressed in (a) and (b) above.

Response)

a. Big Rivers objects that the reconciliation sought in this request is not reasonably calculated to lead to the discovery of admissible evidence and is unduly burdensome because the requested reconciliation does not seek a comparison between or among like sets of data. Notwithstanding these objections and without waiving them, Big Rivers states as follows.

Attached is a schedule showing the gross plant balances, depreciation rates, and the depreciation expense, including the adjustments reflected in response to PSC 2-36, by account number for the forecasted test period ending August 31, 2014. In addition, a listing of account numbers and related descriptions is also provided.

The gross plant balances used in the depreciation expense calculation reflect construction projects when completed and closed to plant in service. Depreciation expense on capital and construction projects closed to plant in service begins the month following the month in which the costs are closed to plant in service (e.g. depreciation expense for September 2013 is based on plant in service balances as of August 31, 2013). The plant amounts provided in response to AG 1-39, CAPEX amounts for 2013/2014 included at Tab 25 of Big Rivers' Application, and construction projects for August 31, 2014 provided in the attachment for the response to PSC 1-17 (pages 39 to 51) are budgeted amounts showing anticipated expenditures.

b. Big Rivers objects that the reconciliation sought in this request is not reasonably calculated to lead to the discovery of admissible evidence and is unduly burdensome because accumulated depreciation is not tracked by account number like the depreciation expense amounts set forth in subpart (a). Notwithstanding these objections, but without waiving them, Big Rivers states as follows. The test period ending August 31, 2014 balance in accumulated depreciation includes a full year of related test period depreciation expense. However, test period accumulated depreciation is reduced by estimated retirements. A reconciliation of test period accumulated depreciation is attached.

c. There is no accumulated deferred income tax included in the forecasted test period ending August 31, 2014.

Witness) Billie J. Richert

Big Rivers ctric Corporation
Case No. 2012-00535
Attachment for Response to AG 2-11(a)
Depreciation Expense
For the Forecasted Test Period Twelve Months Ending 8/31/2014

Account No.	Gross Plant Balances 8/31/2013	9/30/2013	10/31/2013	11/30/2013	12/31/2013	1/31/2014
3010	420	420	420	420	420	420
3020	66,476	66,476	66,476	66,476	66,476	66,476
3030	0	0	0	0	0	0
3101	83,342	83,342	83,342	83,342	83,342	83,342
3102	1,124,665	1,124,665	1,124,665	1,124,665	1,124,665	1,124,665
3103	1,110,712	1,110,712	1,110,712	1,110,712	1,110,712	1,110,712
3104	2,218,858	2,218,858	2,218,858	2,218,858	2,218,858	2,218,858
3111	3,272,769	3,272,769	3,272,769	3,272,769	3,272,769	3,272,769
3112	19,733,154	19,733,154	19,733,154	19,733,154	19,733,154	19,733,154
3113	27,160,045	27,160,045	27,160,045	27,160,045	27,160,045	27,160,045
3114	73,609,725	73,609,725	73,609,725	73,609,725	73,609,725	73,609,725
3115	547,305	547,305	547,305	547,305	547,305	547,305
3116	687,683	722,303	722,303	722,303	722,303	722,303
3117	1,069,889	1,069,889	1,069,889	1,069,889	1,069,889	1,069,889
3119	846,217	846,217	846,217	846,217	846,217	846,217
3120	127,281	127,281	127,281	127,281	127,281	127,281
312A	731,401	731,401	731,401	731,401	731,401	731,401
3121	7,416,312	7,416,312	7,416,312	7,416,312	7,416,312	8,566,312
312B	5,083,686	5,083,686	5,083,686	5,105,941	5,105,941	5,105,941
312L	0	0	0	0	0	0
312V	23,762	23,762	23,762	23,762	23,762	23,762

Big Rivers ectric Corporation
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Attachment for Response to AG 2-11(a)
Depreciation Expense
For the Forecasted Test Period Twelve Months Ending 8/31/2014

Account No.	Gross Plant Balances					
	8/31/2013	9/30/2013	10/31/2013	11/30/2013	12/31/2013	1/31/2014
3122	87,021,456	87,043,221	87,057,731	87,090,378	87,090,378	87,104,888
312C	124,298,820	124,298,820	124,298,820	124,298,820	124,298,820	124,298,820
312M	0	0	0	0	0	0
312W	528,707	608,511	608,511	608,511	608,511	608,511
3123	172,255,490	172,572,873	172,795,961	172,795,961	172,795,961	173,347,333
312D	117,858,483	118,003,581	118,003,581	118,003,581	118,003,581	118,003,581
312N	724,984	724,984	724,984	724,984	724,984	724,984
312X	233,098	233,098	233,098	233,098	233,098	233,098
3124	405,391,793	405,916,975	410,143,821	410,683,512	410,683,512	410,683,512
312E	262,941,852	262,941,852	262,941,852	262,941,852	262,941,852	262,941,852
312P	6,615,946	6,615,946	6,615,946	6,615,946	6,615,946	6,615,946
312Y	0	0	0	0	0	0
3125	23,562,507	23,562,507	23,571,436	23,571,436	23,571,436	23,571,436
312F&312K	69,270,748	69,333,252	69,333,252	69,333,252	69,333,252	69,333,252
312Q	5,227,879	5,227,879	5,227,879	5,227,879	5,227,879	5,227,879
312Z	156,635	156,635	156,635	156,635	156,635	156,635
3126	2,891,054	2,925,674	2,925,674	2,975,130	2,975,130	3,383,146
312G	1,956,202	1,956,202	1,956,202	1,956,202	1,956,202	1,956,202
3127	591,389	591,389	591,389	591,389	591,389	591,389
3128	741,408	741,408	741,408	741,408	741,408	741,408
312J	15,438	15,438	15,438	15,438	15,438	15,438

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Depreciation Expense
For the Forecasted Test Period Twelve Months Ending 8/31/2014

Account No.	Gross Plant Balances					
	8/31/2013	9/30/2013	10/31/2013	11/30/2013	12/31/2013	1/31/2014
3140	0	0	0	0	0	0
3141	4,586,466	4,586,466	4,586,466	4,586,466	4,586,466	4,586,466
3142	34,340,957	34,340,957	34,348,212	34,348,212	34,355,467	34,355,467
3143	59,019,853	59,183,088	59,183,088	59,183,088	59,183,088	59,183,088
3144	129,205,258	129,205,258	129,248,787	129,248,787	129,248,787	129,248,787
3145	7,549,872	7,594,518	7,594,518	7,594,518	7,594,518	7,594,518
3146	260,303	260,303	260,303	260,303	260,303	260,303
3147	31,346	31,346	31,346	31,346	31,346	31,346
3151	1,490,459	1,490,459	1,490,459	1,490,459	1,490,459	1,490,459
3152	9,571,863	9,571,863	9,571,863	9,571,863	9,571,863	9,571,863
3153	17,080,178	17,189,001	17,189,001	17,189,001	17,189,001	17,189,001
3154	35,319,436	35,319,436	35,319,436	35,319,436	35,319,436	35,319,436
3155	190,888	190,888	190,888	190,888	190,888	190,888
3157	57,489	57,489	57,489	57,489	57,489	57,489
3159	43,548	43,548	43,548	43,548	43,548	43,548
3160	56,008	56,008	56,008	56,008	56,008	56,008
3161	1,227	1,227	1,227	1,227	1,227	1,227
3162	1,262,009	1,262,009	1,262,009	1,262,009	1,262,009	1,262,009
3163	2,440,698	2,498,737	2,498,737	2,498,737	2,498,737	2,553,875
3164	1,332,611	1,354,375	1,354,375	1,354,375	1,354,375	1,354,375
3165	405,272	405,272	405,272	405,272	405,272	405,272

Big Rivers ectric Corporation
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Depreciation Expense
For the Forecasted Test Period Twelve Months Ending 8/31/2014

Account No.	Gross Plant Balances 8/31/2013	9/30/2013	10/31/2013	11/30/2013	12/31/2013	1/31/2014
3166	453,453	453,453	453,453	470,762	470,762	470,762
3167	415,443	440,272	440,272	440,272	440,272	440,272
3169	548,462	548,462	548,462	548,462	548,462	548,462
3401	475,968	475,968	475,968	475,968	475,968	475,968
3410	154,233	154,233	154,233	154,233	154,233	154,233
3420	1,442,387	1,442,387	1,442,387	1,442,387	1,442,387	1,442,387
3430	4,952,277	4,952,277	4,952,277	4,952,277	4,952,277	4,952,277
3440	1,102,964	1,102,964	1,102,964	1,102,964	1,102,964	1,102,964
3450	399,274	399,274	399,274	399,274	399,274	399,274
3460	0	0	0	0	0	0
3500	13,602,242	13,602,242	13,602,242	13,602,242	13,602,242	13,602,242
3501	704,868	704,868	704,868	704,868	704,868	704,868
3520	5,882,134	5,882,134	5,882,134	5,882,134	5,882,134	5,882,134
3521	20,369	20,369	20,369	20,369	20,369	20,369
3522	157,305	157,305	157,305	157,305	157,305	157,305
3524	719,703	719,703	719,703	719,703	719,703	719,703
3525	185,107	185,107	185,107	185,107	185,107	185,107
3530	85,725,667	85,907,390	86,237,270	87,486,890	87,548,152	87,617,829
3531	3,427,148	3,427,148	3,427,148	3,427,148	3,427,148	3,427,148
3532	5,672,660	5,672,660	5,672,660	5,672,660	5,672,660	5,672,660
3533	5,947,214	5,947,214	5,947,214	5,947,214	5,947,214	5,947,214

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Attachment for Response to AG 2-11(a)
Depreciation Expense
For the Forecasted Test Period Twelve Months Ending 8/31/2014

Account No.	Gross Plant Balances 8/31/2013	9/30/2013	10/31/2013	11/30/2013	12/31/2013	1/31/2014
3534	22,440,902	22,440,902	22,440,902	22,440,902	22,440,902	22,440,902
3535	6,511,341	6,511,341	6,511,341	6,511,341	6,511,341	6,511,341
3536	0	0	0	0	0	0
3537	0	0	0	0	0	0
3538	0	0	0	0	0	0
3539	0	0	0	0	0	0
3540	8,134,239	8,134,239	8,134,239	8,134,239	8,134,239	8,134,239
3541	146,747	146,747	146,747	146,747	146,747	146,747
3545	312,558	312,558	312,558	312,558	312,558	312,558
3550	44,211,093	44,267,436	44,299,776	44,299,776	44,299,776	44,357,065
3551	234,314	234,314	234,314	234,314	234,314	234,314
3555	79,207	79,207	79,207	79,207	79,207	79,207
3560	47,608,001	47,738,978	47,869,954	47,961,695	48,034,482	48,106,185
3561	86,901	86,901	86,901	86,901	86,901	86,901
3565	104,571	104,571	104,571	104,571	104,571	104,571
3890	407,251	407,251	407,251	407,251	407,251	407,251
3900	5,325,369	5,325,369	5,325,369	5,325,369	5,325,369	5,325,369
3910	797,493	797,493	797,922	797,922	797,922	797,922
3912	25,030,618	25,143,884	25,229,809	25,319,640	25,378,226	25,378,226
3913	0	0	0	0	0	0
3916	7,758	7,758	7,758	7,758	7,758	7,758

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Account No.	Gross Plant Balances					
	8/31/2013	9/30/2013	10/31/2013	11/30/2013	12/31/2013	1/31/2014
3917	28,617	28,617	28,617	28,617	28,617	28,617
3922	2,770,050	2,770,050	2,770,050	2,770,050	2,770,050	2,770,050
3923	1,257,240	1,257,240	1,257,240	1,257,240	1,257,240	1,257,240
3930	98,766	98,766	98,766	98,766	98,766	98,766
3940	743,627	746,361	746,361	746,361	746,361	746,361
3950	221,279	221,279	221,279	221,279	221,279	221,279
3960	435,191	435,191	669,533	703,122	703,122	703,122
3961	183,074	183,074	183,074	183,074	183,074	183,074
3970	1,701,797	1,701,797	1,701,797	1,701,797	1,701,797	1,701,797
3980	260,726	260,726	260,726	260,726	260,726	260,726
3986	0	0	0	0	0	0
3987	1,625	1,625	1,625	1,625	1,625	1,625
Total	**2,032,572,567**	**2,034,699,920**	**2,040,037,970**	**2,042,164,111**	**2,042,364,000**	**2,044,741,704**

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Account No.	Gross Plant Balances					
	2/28/2014	3/31/2014	4/30/2014	5/31/2014	6/30/2014	7/31/2014
3010	420	420	420	420	420	420
3020	66,476	66,476	66,476	66,476	66,476	66,476
3030	0	0	0	0	0	0
3101	83,342	83,342	83,342	83,342	83,342	83,342
3102	1,124,665	1,124,665	1,124,665	1,124,665	1,124,665	1,124,665
3103	1,110,712	1,110,712	1,110,712	1,110,712	1,110,712	1,110,712
3104	2,218,858	2,218,858	2,218,858	2,218,858	2,218,858	2,218,858
3111	3,272,769	3,272,769	3,272,769	3,272,769	3,272,769	3,272,769
3112	19,733,154	19,733,154	19,733,154	19,733,154	19,841,977	19,841,977
3113	27,160,045	27,160,045	27,160,045	27,160,045	27,160,045	27,450,241
3114	73,609,725	73,609,725	73,609,725	73,645,999	73,645,999	73,645,999
3115	547,305	547,305	547,305	547,305	547,305	547,305
3116	722,303	722,303	722,303	722,303	722,303	736,851
3117	1,069,889	1,069,889	1,069,889	1,069,889	1,069,889	1,069,889
3119	846,217	846,217	846,217	846,217	846,217	846,217
3120	127,281	127,281	127,281	127,281	127,281	127,281
312A	731,401	803,950	981,695	981,695	981,695	981,695
3121	8,566,312	8,566,312	8,566,312	8,566,312	8,584,449	8,584,449
312B	5,105,941	5,105,941	5,105,941	5,120,451	5,120,451	5,120,451
312L	0	0	0	0	0	0
312V	23,762	23,762	23,762	23,762	23,762	23,762

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Account No.	Gross Plant Balances					
	2/28/2014	3/31/2014	4/30/2014	5/31/2014	6/30/2014	7/31/2014
3122	87,191,946	87,318,907	91,553,196	92,645,057	92,659,567	92,674,077
312C	124,298,820	124,316,958	124,712,349	125,017,055	125,017,055	125,035,192
312M	0	0	0	0	0	0
312W	608,511	608,511	706,452	706,452	706,452	793,511
3123	173,347,333	173,564,980	173,564,980	175,385,232	175,733,467	175,755,232
312D	118,003,581	119,227,065	119,561,824	121,386,027	121,400,536	121,690,732
312N	724,984	724,984	724,984	724,984	724,984	724,984
312X	233,098	233,098	233,098	320,157	378,196	378,196
3124	410,683,512	410,701,649	410,701,649	410,756,061	410,828,610	410,828,610
312E	262,941,852	262,941,852	262,959,990	262,959,990	262,959,990	262,959,990
312P	6,615,946	6,615,946	6,615,946	6,615,946	6,615,946	6,615,946
312Y	0	0	0	0	0	0
3125	23,571,436	23,571,436	24,695,608	24,865,261	24,878,306	24,878,306
312F&312K	69,333,252	69,333,252	70,355,912	70,371,538	70,371,538	70,371,538
312Q	5,227,879	5,227,879	5,227,879	5,227,879	5,227,879	5,227,879
312Z	156,635	156,635	190,120	627,645	627,645	627,645
3126	3,383,146	3,410,347	3,422,711	3,469,694	3,501,215	3,559,408
312G	1,956,202	1,956,202	1,956,202	1,956,202	1,956,202	1,956,202
3127	591,389	591,389	591,389	591,389	591,389	591,389
3128	741,408	741,408	741,408	741,408	741,408	741,408
312J	15,438	15,438	15,438	15,438	15,438	15,438

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Account No.	Gross Plant Balances					
	2/28/2014	3/31/2014	4/30/2014	5/31/2014	6/30/2014	7/31/2014
3140	0	0	0	0	0	0
3141	4,586,466	4,586,466	4,586,466	4,586,466	4,703,995	4,703,995
3142	34,355,467	34,355,467	35,461,112	35,577,191	35,577,191	35,577,191
3143	59,183,088	59,992,734	59,998,175	60,143,273	60,143,273	60,143,273
3144	129,248,787	129,248,787	129,248,787	129,248,787	129,248,787	129,248,787
3145	7,594,518	7,594,518	7,907,036	7,907,036	7,907,036	7,907,036
3146	260,303	260,303	260,303	260,303	260,303	260,303
3147	31,346	31,346	31,346	31,346	53,535	53,535
3151	1,490,459	1,490,459	1,490,459	1,490,459	1,490,459	1,490,459
3152	9,571,863	9,571,863	10,014,412	10,014,412	10,014,412	10,072,451
3153	17,189,001	17,261,550	17,624,295	18,226,451	18,226,451	18,226,451
3154	35,319,436	35,319,436	35,319,436	35,319,436	35,319,436	35,319,436
3155	190,888	190,888	860,571	860,571	860,571	860,571
3157	57,489	57,489	57,489	57,489	57,489	57,489
3159	43,548	43,548	43,548	43,548	43,548	43,548
3160	56,008	56,008	56,008	56,008	56,008	56,008
3161	1,227	1,227	1,227	1,227	1,227	1,227
3162	1,396,224	1,396,224	1,410,734	1,421,616	1,421,616	1,421,616
3163	2,553,875	2,553,875	2,553,875	2,553,875	2,553,875	2,562,943
3164	1,354,375	1,354,375	1,354,375	1,361,630	1,361,630	1,361,630
3165	405,272	405,272	405,272	405,272	405,272	405,272

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Account No.	Gross Plant Balances					
	2/28/2014	3/31/2014	4/30/2014	5/31/2014	6/30/2014	7/31/2014
3166	470,762	488,071	488,071	488,071	492,921	509,893
3167	440,272	440,272	440,272	440,272	443,354	443,354
3169	548,462	672,521	672,521	672,521	672,521	672,521
3401	475,968	475,968	475,968	475,968	475,968	475,968
3410	154,233	154,233	154,233	154,233	154,233	154,233
3420	1,442,387	1,442,387	1,442,387	1,442,387	1,442,387	1,442,387
3430	4,952,277	4,952,277	4,952,277	4,952,277	4,952,277	4,952,277
3440	1,102,964	1,102,964	1,102,964	1,102,964	1,102,964	1,102,964
3450	399,274	399,274	399,274	399,274	399,274	399,274
3460	0	0	0	0	0	0
3500	13,602,242	13,602,242	13,602,242	13,602,242	13,602,242	13,602,242
3501	704,868	704,868	704,868	704,868	704,868	704,868
3520	5,882,134	5,901,162	5,925,232	5,928,691	5,932,151	5,935,610
3521	20,369	20,369	20,369	20,369	20,369	20,369
3522	157,305	157,305	157,305	157,305	157,305	157,305
3524	719,703	719,703	719,703	719,703	719,703	719,703
3525	185,107	185,107	185,107	185,107	185,107	185,107
3530	87,739,398	87,850,196	87,979,259	88,119,644	88,218,623	88,350,650
3531	3,427,148	3,427,148	3,427,148	3,427,148	3,427,148	3,427,148
3532	5,672,660	5,672,660	5,672,660	5,672,660	5,672,660	5,672,660
3533	5,947,214	5,947,214	5,947,214	5,947,214	5,947,214	5,947,214

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Account No.	Gross Plant Balances 2/28/2014	3/31/2014	4/30/2014	5/31/2014	6/30/2014	7/31/2014
3534	22,440,902	22,440,902	22,440,902	22,440,902	22,440,902	22,440,902
3535	6,511,341	6,511,341	6,511,341	6,511,341	6,511,341	6,511,341
3536	0	0	0	0	0	0
3537	0	0	0	0	0	0
3538	0	0	0	0	0	0
3539	0	0	0	0	0	0
3540	8,134,239	8,134,239	8,134,239	8,134,239	8,134,239	8,134,239
3541	146,747	146,747	146,747	146,747	146,747	146,747
3545	312,558	312,558	312,558	312,558	312,558	312,558
3550	44,415,743	44,474,421	44,531,711	44,589,000	44,646,290	44,703,579
3551	234,314	234,314	234,314	234,314	234,314	234,314
3555	79,207	79,207	79,207	79,207	79,207	79,207
3560	48,230,406	48,333,929	48,480,350	48,625,129	48,772,830	48,788,368
3561	86,901	86,901	86,901	86,901	86,901	86,901
3565	104,571	104,571	104,571	104,571	104,571	104,571
3890	407,251	407,251	407,251	407,251	407,251	407,251
3900	5,325,369	5,325,369	5,325,369	5,325,369	5,325,369	5,325,369
3910	801,264	801,694	803,646	805,990	805,990	805,990
3912	25,414,939	25,493,053	25,657,093	25,743,018	25,946,114	26,071,097
3913	0	0	0	0	0	0
3916	7,758	7,758	7,758	7,758	7,758	7,758

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Account No.	Gross Plant Balances					
	2/28/2014	3/31/2014	4/30/2014	5/31/2014	6/30/2014	7/31/2014
3917	28,617	28,617	28,617	28,617	28,617	28,617
3922	2,931,174	2,931,174	2,931,174	2,931,174	2,931,174	2,931,174
3923	1,257,240	1,257,240	1,257,240	1,257,240	1,257,240	1,257,240
3930	98,766	98,766	98,766	98,766	98,766	98,766
3940	746,361	751,048	751,751	752,532	752,532	752,532
3950	221,279	221,279	221,279	221,279	221,279	221,279
3960	703,122	703,122	703,122	703,122	703,122	703,122
3961	183,074	183,074	183,074	183,074	183,074	183,074
3970	1,701,797	1,701,797	1,701,797	1,701,797	1,701,797	1,701,797
3980	260,726	260,726	260,726	260,726	260,726	260,726
3986	0	0	0	0	0	0
3987	1,625	1,625	1,625	1,625	1,625	1,625
Total	**2,045,468,627**	**2,048,571,561**	**2,059,459,134**	**2,066,678,632**	**2,068,016,175**	**2,069,228,156**

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Account No.	Depreciation Rates					
	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
3010						
3020						
3030						
3101						
3102						
3103						
3104						
3111	0.001152	0.001152	0.001152	0.001152	0.001152	0.001152
3112	0.001152	0.001152	0.001152	0.001152	0.001152	0.001152
3113	0.001152	0.001152	0.001152	0.001152	0.001152	0.001152
3114	0.001152	0.001152	0.001152	0.001152	0.001152	0.001152
3115	0.001152	0.001152	0.001152	0.001152	0.001152	0.001152
3116	0.001152	0.001152	0.001152	0.001152	0.001152	0.001152
3117	0.001152	0.001152	0.001152	0.001152	0.001152	0.001152
3119	0.001152	0.001152	0.001152	0.001152	0.001152	0.001152
3120	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
312A	0.002022	0.002022	0.002022	0.002022	0.002022	0.002022
3121	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
312B	0.002022	0.002022	0.002022	0.002022	0.002022	0.002022
312L	0.013292	0.013292	0.013292	0.013292	0.013292	0.013292
312V	0.021153	0.021153	0.021153	0.021153	0.021153	0.021153

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Account No.	Depreciation Rates					
	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
3122	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
312C	0.002022	0.002022	0.002022	0.002022	0.002022	0.002022
312M	0.013292	0.013292	0.013292	0.013292	0.013292	0.013292
312W	0.021153	0.021153	0.021153	0.021153	0.021153	0.021153
3123	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
312D	0.002022	0.002022	0.002022	0.002022	0.002022	0.002022
312N	0.013292	0.013292	0.013292	0.013292	0.013292	0.013292
312X	0.021153	0.021153	0.021153	0.021153	0.021153	0.021153
3124	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
312E	0.002022	0.002022	0.002022	0.002022	0.002022	0.002022
312P	0.013292	0.013292	0.013292	0.013292	0.013292	0.013292
312Y	0.021153	0.021153	0.021153	0.021153	0.021153	0.021153
3125	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
312F&312K	0.002022	0.002022	0.002022	0.002022	0.002022	0.002022
312Q	0.013292	0.013292	0.013292	0.013292	0.013292	0.013292
312Z	0.021153	0.021153	0.021153	0.021153	0.021153	0.021153
3126	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
312G	0.002022	0.002022	0.002022	0.002022	0.002022	0.002022
3127	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
3128	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
312J	0.002022	0.002022	0.002022	0.002022	0.002022	0.002022

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Account No.	Depreciation Rates					
	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
3140	0.001631	0.001631	0.001631	0.001631	0.001631	0.001631
3141	0.001631	0.001631	0.001631	0.001631	0.001631	0.001631
3142	0.001631	0.001631	0.001631	0.001631	0.001631	0.001631
3143	0.001631	0.001631	0.001631	0.001631	0.001631	0.001631
3144	0.001631	0.001631	0.001631	0.001631	0.001631	0.001631
3145	0.001631	0.001631	0.001631	0.001631	0.001631	0.001631
3146	0.001631	0.001631	0.001631	0.001631	0.001631	0.001631
3147	0.001631	0.001631	0.001631	0.001631	0.001631	0.001631
3151	0.001690	0.001690	0.001690	0.001690	0.001690	0.001690
3152	0.001690	0.001690	0.001690	0.001690	0.001690	0.001690
3153	0.001690	0.001690	0.001690	0.001690	0.001690	0.001690
3154	0.001690	0.001690	0.001690	0.001690	0.001690	0.001690
3155	0.001690	0.001690	0.001690	0.001690	0.001690	0.001690
3157	0.001690	0.001690	0.001690	0.001690	0.001690	0.001690
3159	0.001690	0.001690	0.001690	0.001690	0.001690	0.001690
3160	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369
3161	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369
3162	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369
3163	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369
3164	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369
3165	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369

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Account No.	Depreciation Rates					
	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
3166	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369
3167	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369
3169	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369
3401						
3410	0.000882	0.000882	0.000882	0.000882	0.000882	0.000882
3420	0.008265	0.008265	0.008265	0.008265	0.008265	0.008265
3430	0.002514	0.002514	0.002514	0.002514	0.002514	0.002514
3440	0.000294	0.000294	0.000294	0.000294	0.000294	0.000294
3450	0.002438	0.002438	0.002438	0.002438	0.002438	0.002438
3460						
3500						
3501						
3520	0.001617	0.001617	0.001617	0.001617	0.001617	0.001617
3521	0.001617	0.001617	0.001617	0.001617	0.001617	0.001617
3522	0.001617	0.001617	0.001617	0.001617	0.001617	0.001617
3524	0.001617	0.001617	0.001617	0.001617	0.001617	0.001617
3525	0.001617	0.001617	0.001617	0.001617	0.001617	0.001617
3530	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3531	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3532	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3533	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909

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Account No.	Depreciation Rates					
	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
3534	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3535	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3536	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3537	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3538	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3539	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3540	0.001135	0.001135	0.001135	0.001135	0.001135	0.001135
3541	0.001135	0.001135	0.001135	0.001135	0.001135	0.001135
3545	0.001135	0.001135	0.001135	0.001135	0.001135	0.001135
3550	0.001688	0.001688	0.001688	0.001688	0.001688	0.001688
3551	0.001688	0.001688	0.001688	0.001688	0.001688	0.001688
3555	0.001688	0.001688	0.001688	0.001688	0.001688	0.001688
3560	0.001511	0.001511	0.001511	0.001511	0.001511	0.001511
3561	0.001511	0.001511	0.001511	0.001511	0.001511	0.001511
3565	0.001511	0.001511	0.001511	0.001511	0.001511	0.001511
3890						
3900	0.003137	0.003137	0.003137	0.003137	0.003137	0.003137
3910	0.007595	0.007595	0.007595	0.007595	0.007595	0.007595
3912	0.008235	0.008235	0.008235	0.008235	0.008235	0.008235
3913	0.008235	0.008235	0.008235	0.008235	0.008235	0.008235
3916	0.007595	0.007595	0.007595	0.007595	0.007595	0.007595

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Account No.	Depreciation Rates					
	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
3917	0.007595	0.007595	0.007595	0.007595	0.007595	0.007595
3922	0.007154	0.007154	0.007154	0.007154	0.007154	0.007154
3923	0.006923	0.006923	0.006923	0.006923	0.006923	0.006923
3930	0.004978	0.004978	0.004978	0.004978	0.004978	0.004978
3940	0.005065	0.005065	0.005065	0.005065	0.005065	0.005065
3950	0.005100	0.005100	0.005100	0.005100	0.005100	0.005100
3960	0.003910	0.003910	0.003910	0.003910	0.003910	0.003910
3961	0.003910	0.003910	0.003910	0.003910	0.003910	0.003910
3970	0.005212	0.005212	0.005212	0.005212	0.005212	0.005212
3980	0.005041	0.005041	0.005041	0.005041	0.005041	0.005041
3986	0.005041	0.005041	0.005041	0.005041	0.005041	0.005041
3987	0.005041	0.005041	0.005041	0.005041	0.005041	0.005041

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Account No.	Depreciation Rates					
	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14
3010						
3020						
3030						
3101						
3102						
3103						
3104						
3111	0.001152	0.001152	0.001152	0.001152	0.001152	0.001152
3112	0.001152	0.001152	0.001152	0.001152	0.001152	0.001152
3113	0.001152	0.001152	0.001152	0.001152	0.001152	0.001152
3114	0.001152	0.001152	0.001152	0.001152	0.001152	0.001152
3115	0.001152	0.001152	0.001152	0.001152	0.001152	0.001152
3116	0.001152	0.001152	0.001152	0.001152	0.001152	0.001152
3117	0.001152	0.001152	0.001152	0.001152	0.001152	0.001152
3119	0.001152	0.001152	0.001152	0.001152	0.001152	0.001152
3120	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
312A	0.002022	0.002022	0.002022	0.002022	0.002022	0.002022
3121	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
312B	0.002022	0.002022	0.002022	0.002022	0.002022	0.002022
312L	0.013292	0.013292	0.013292	0.013292	0.013292	0.013292
312V	0.021153	0.021153	0.021153	0.021153	0.021153	0.021153

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Account No.	Depreciation Rates					
	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14
3122	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
312C	0.002022	0.002022	0.002022	0.002022	0.002022	0.002022
312M	0.013292	0.013292	0.013292	0.013292	0.013292	0.013292
312W	0.021153	0.021153	0.021153	0.021153	0.021153	0.021153
3123	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
312D	0.002022	0.002022	0.002022	0.002022	0.002022	0.002022
312N	0.013292	0.013292	0.013292	0.013292	0.013292	0.013292
312X	0.021153	0.021153	0.021153	0.021153	0.021153	0.021153
3124	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
312E	0.002022	0.002022	0.002022	0.002022	0.002022	0.002022
312P	0.013292	0.013292	0.013292	0.013292	0.013292	0.013292
312Y	0.021153	0.021153	0.021153	0.021153	0.021153	0.021153
3125	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
312F&312K	0.002022	0.002022	0.002022	0.002022	0.002022	0.002022
312Q	0.013292	0.013292	0.013292	0.013292	0.013292	0.013292
312Z	0.021153	0.021153	0.021153	0.021153	0.021153	0.021153
3126	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
312G	0.002022	0.002022	0.002022	0.002022	0.002022	0.002022
3127	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
3128	0.001681	0.001681	0.001681	0.001681	0.001681	0.001681
312J	0.002022	0.002022	0.002022	0.002022	0.002022	0.002022

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Witness: Billie J. Richert

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Account No.	Depreciation Rates					
	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14
3140	0.001631	0.001631	0.001631	0.001631	0.001631	0.001631
3141	0.001631	0.001631	0.001631	0.001631	0.001631	0.001631
3142	0.001631	0.001631	0.001631	0.001631	0.001631	0.001631
3143	0.001631	0.001631	0.001631	0.001631	0.001631	0.001631
3144	0.001631	0.001631	0.001631	0.001631	0.001631	0.001631
3145	0.001631	0.001631	0.001631	0.001631	0.001631	0.001631
3146	0.001631	0.001631	0.001631	0.001631	0.001631	0.001631
3147	0.001631	0.001631	0.001631	0.001631	0.001631	0.001631
3151	0.001690	0.001690	0.001690	0.001690	0.001690	0.001690
3152	0.001690	0.001690	0.001690	0.001690	0.001690	0.001690
3153	0.001690	0.001690	0.001690	0.001690	0.001690	0.001690
3154	0.001690	0.001690	0.001690	0.001690	0.001690	0.001690
3155	0.001690	0.001690	0.001690	0.001690	0.001690	0.001690
3157	0.001690	0.001690	0.001690	0.001690	0.001690	0.001690
3159	0.001690	0.001690	0.001690	0.001690	0.001690	0.001690
3160	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369
3161	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369
3162	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369
3163	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369
3164	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369
3165	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369

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Account No.	Depreciation Rates					
	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14
3166	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369
3167	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369
3169	0.003369	0.003369	0.003369	0.003369	0.003369	0.003369
3401						
3410	0.000882	0.000882	0.000882	0.000882	0.000882	0.000882
3420	0.008265	0.008265	0.008265	0.008265	0.008265	0.008265
3430	0.002514	0.002514	0.002514	0.002514	0.002514	0.002514
3440	0.000294	0.000294	0.000294	0.000294	0.000294	0.000294
3450	0.002438	0.002438	0.002438	0.002438	0.002438	0.002438
3460						
3500						
3501						
3520	0.001617	0.001617	0.001617	0.001617	0.001617	0.001617
3521	0.001617	0.001617	0.001617	0.001617	0.001617	0.001617
3522	0.001617	0.001617	0.001617	0.001617	0.001617	0.001617
3524	0.001617	0.001617	0.001617	0.001617	0.001617	0.001617
3525	0.001617	0.001617	0.001617	0.001617	0.001617	0.001617
3530	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3531	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3532	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3533	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909

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Account No.	Depreciation Rates					
	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14
3534	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3535	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3536	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3537	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3538	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3539	0.001909	0.001909	0.001909	0.001909	0.001909	0.001909
3540	0.001135	0.001135	0.001135	0.001135	0.001135	0.001135
3541	0.001135	0.001135	0.001135	0.001135	0.001135	0.001135
3545	0.001135	0.001135	0.001135	0.001135	0.001135	0.001135
3550	0.001688	0.001688	0.001688	0.001688	0.001688	0.001688
3551	0.001688	0.001688	0.001688	0.001688	0.001688	0.001688
3555	0.001688	0.001688	0.001688	0.001688	0.001688	0.001688
3560	0.001511	0.001511	0.001511	0.001511	0.001511	0.001511
3561	0.001511	0.001511	0.001511	0.001511	0.001511	0.001511
3565	0.001511	0.001511	0.001511	0.001511	0.001511	0.001511
3890						
3900	0.003137	0.003137	0.003137	0.003137	0.003137	0.003137
3910	0.007595	0.007595	0.007595	0.007595	0.007595	0.007595
3912	0.008235	0.008235	0.008235	0.008235	0.008235	0.008235
3913	0.008235	0.008235	0.008235	0.008235	0.008235	0.008235
3916	0.007595	0.007595	0.007595	0.007595	0.007595	0.007595

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Account No.	Depreciation Rates					
	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14
3917	0.007595	0.007595	0.007595	0.007595	0.007595	0.007595
3922	0.007154	0.007154	0.007154	0.007154	0.007154	0.007154
3923	0.006923	0.006923	0.006923	0.006923	0.006923	0.006923
3930	0.004978	0.004978	0.004978	0.004978	0.004978	0.004978
3940	0.005065	0.005065	0.005065	0.005065	0.005065	0.005065
3950	0.005100	0.005100	0.005100	0.005100	0.005100	0.005100
3960	0.003910	0.003910	0.003910	0.003910	0.003910	0.003910
3961	0.003910	0.003910	0.003910	0.003910	0.003910	0.003910
3970	0.005212	0.005212	0.005212	0.005212	0.005212	0.005212
3980	0.005041	0.005041	0.005041	0.005041	0.005041	0.005041
3986	0.005041	0.005041	0.005041	0.005041	0.005041	0.005041
3987	0.005041	0.005041	0.005041	0.005041	0.005041	0.005041

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Account No.	Depreciation Expense					
	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
3010						
3020						
3030						
3101						
3102						
3103						
3104						
3111	-	-	-	-	-	-
3112	22,733	22,733	22,733	22,733	22,733	22,733
3113	31,288	31,288	31,288	31,288	31,288	31,288
3114	84,798	84,798	84,798	84,798	84,798	84,798
3115	630	630	630	630	630	630
3116	792	832	832	832	832	832
3117	1,233	1,233	1,233	1,233	1,233	1,233
3119	975	975	975	975	975	975
3120	214	214	214	214	214	214
312A	1,479	1,479	1,479	1,479	1,479	1,479
3121	12,467	12,467	12,467	12,467	12,467	14,400
312B	10,279	10,279	10,279	10,324	10,324	10,324
312L	-	-	-	-	-	-
312V	503	503	503	503	503	503

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Account No.	Depreciation Expense					
	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
3122	146,283	146,320	146,344	146,399	146,399	146,423
312C	251,332	251,332	251,332	251,332	251,332	251,332
312M	-	-	-	-	-	-
312W	11,184	12,872	12,872	12,872	12,872	12,872
3123	289,561	290,095	290,470	290,470	290,470	291,397
312D	238,310	238,603	238,603	238,603	238,603	238,603
312N	9,636	9,636	9,636	9,636	9,636	9,636
312X	4,931	4,931	4,931	4,931	4,931	4,931
3124	681,464	682,346	689,452	690,359	690,359	690,359
312E	531,668	531,668	531,668	531,668	531,668	531,668
312P	87,939	87,939	87,939	87,939	87,939	87,939
312Y	-	-	-	-	-	-
3125	39,609	39,609	39,624	39,624	39,624	39,624
312F&312K	140,065	140,192	140,192	140,192	140,192	140,192
312Q	69,489	69,489	69,489	69,489	69,489	69,489
312Z	3,313	3,313	3,313	3,313	3,313	3,313
3126	4,860	4,918	4,918	5,001	5,001	5,687
312G	3,955	3,955	3,955	3,955	3,955	3,955
3127	994	994	994	994	994	994
3128	1,246	1,246	1,246	1,246	1,246	1,246
312J	31	31	31	31	31	31

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Account No.	Depreciation Expense					
	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
3140	-	-	-	-	-	-
3141	7,481	7,481	7,481	7,481	7,481	7,481
3142	56,010	56,010	56,022	56,022	56,034	56,034
3143	96,261	96,528	96,528	96,528	96,528	96,528
3144	210,734	210,734	210,805	210,805	210,805	210,805
3145	12,314	12,387	12,387	12,387	12,387	12,387
3146	425	425	425	425	425	425
3147	51	51	51	51	51	51
3151	2,519	2,519	2,519	2,519	2,519	2,519
3152	16,176	16,176	16,176	16,176	16,176	16,176
3153	28,866	29,049	29,049	29,049	29,049	29,049
3154	59,690	59,690	59,690	59,690	59,690	59,690
3155	323	323	323	323	323	323
3157	97	97	97	97	97	97
3159	74	74	74	74	74	74
3160	189	189	189	189	189	189
3161	4	4	4	4	4	4
3162	4,252	4,252	4,252	4,252	4,252	4,252
3163	8,223	8,418	8,418	8,418	8,418	8,604
3164	4,490	4,563	4,563	4,563	4,563	4,563
3165	1,365	1,365	1,365	1,365	1,365	1,365

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Account No.	Depreciation Expense					
	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
3166	1,528	1,528	1,528	1,586	1,586	1,586
3167	1,400	1,483	1,483	1,483	1,483	1,483
3169	1,848	1,848	1,848	1,848	1,848	1,848
3401						
3410	136	136	136	136	136	136
3420	11,921	11,921	11,921	11,921	11,921	11,921
3430	12,450	12,450	12,450	12,450	12,450	12,450
3440	324	324	324	324	324	324
3450	973	973	973	973	973	973
3460						
3500	-	-	-	-	-	-
3501	-	-	-	-	-	-
3520	9,511	9,511	9,511	9,511	9,511	9,511
3521	-	-	-	-	-	-
3522	254	254	254	254	254	254
3524	1,164	1,164	1,164	1,164	1,164	1,164
3525	299	299	299	299	299	299
3530	163,650	163,997	164,627	167,012	167,129	167,262
3531	6,542	6,542	6,542	6,542	6,542	6,542
3532	10,829	10,829	10,829	10,829	10,829	10,829
3533	11,353	11,353	11,353	11,353	11,353	11,353

Big Rivers Electric Corporation
Case No. 2012-00535
Attachment for Response to AG 2-11(a)
Depreciation Expense
For the Forecasted Test Period Twelve Months Ending 8/31/2014

Account No.	Depreciation Expense					
	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
3534	42,840	42,840	42,840	42,840	42,840	42,840
3535	12,430	12,430	12,430	12,430	12,430	12,430
3536						
3537						
3538						
3539						
3540	9,232	9,232	9,232	9,232	9,232	9,232
3541	167	167	167	167	167	167
3545	355	355	355	355	355	355
3550	74,628	74,723	74,778	74,778	74,778	74,875
3551	-	-	-	-	-	-
3555	134	134	134	134	134	134
3560	71,936	72,134	72,332	72,470	72,580	72,688
3561	-	-	-	-	-	-
3565	158	158	158	158	158	158
3890	-	-	-	-	-	-
3900	16,706	16,706	16,706	16,706	16,706	16,706
3910	6,057	6,057	6,060	6,060	6,060	6,060
3912	206,127	207,060	207,767	208,507	208,990	208,990
3913	-	-	-	-	-	-
3916	59	59	59	59	59	59

Big Rivers . ctric Corporation
Case No. 2012-00535
Attachment for Response to AG 2-11(a)
Depreciation Expense
For the Forecasted Test Period Twelve Months Ending 8/31/2014

Account No.	Depreciation Expense					
	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14
3917	217	217	217	217	217	217
3922	19,817	19,817	19,817	19,817	19,817	19,817
3923	8,704	8,704	8,704	8,704	8,704	8,704
3930	492	492	492	492	492	492
3940	3,766	3,780	3,780	3,780	3,780	3,780
3950	1,129	1,129	1,129	1,129	1,129	1,129
3960	1,702	1,702	2,618	2,749	2,749	2,749
3961	-	-	-	-	-	-
3970	8,870	8,870	8,870	8,870	8,870	8,870
3980	1,314	1,314	1,314	1,314	1,314	1,314
3986	-	-	-	-	-	-
3987	8	8	8	8	8	8
Total	**3,913,835**	**3,919,955**	**3,930,067**	**3,934,609**	**3,935,331**	**3,939,425**
Rounding Difference	(1)	1	1	3	2	2
PSC 2-36	**3,913,834**	**3,919,956**	**3,930,068**	**3,934,612**	**3,935,333**	**3,939,427**

Big Rivers ctric Corporation
Case No. 2012-00535
Attachment for Response to AG 2-11(a)
Depreciation Expense
For the Forecasted Test Period Twelve Months Ending 8/31/2014

Account No.	Depreciation Expense					
	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14
3010						
3020						
3030						
3101						
3102						
3103						
3104						
3111	-	-	-	-	-	-
3112	22,733	22,733	22,733	22,733	22,858	22,858
3113	31,288	31,288	31,288	31,288	31,288	31,623
3114	84,798	84,798	84,798	84,840	84,840	84,840
3115	630	630	630	630	630	630
3116	832	832	832	832	832	849
3117	1,233	1,233	1,233	1,233	1,233	1,233
3119	975	975	975	975	975	975
3120	214	214	214	214	214	214
312A	1,479	1,626	1,985	1,985	1,985	1,985
3121	14,400	14,400	14,400	14,400	14,430	14,430
312B	10,324	10,324	10,324	10,354	10,354	10,354
312L	-	-	-	-	-	-
312V	503	503	503	503	503	503

Big Rivei ..lectric Corporation
Case No. 2012-00535
Attachment for Response to AG 2-11(a)
Depreciation Expense
For the Forecasted Test Period Twelve Months Ending 8/31/2014

Account No.	Depreciation Expense					
	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14
3122	146,570	146,783	153,901	155,736	155,761	155,785
312C	251,332	251,369	252,168	252,784	252,784	252,821
312M	-	-	-	-	-	-
312W	12,872	12,872	14,944	14,944	14,944	16,785
3123	291,397	291,763	291,763	294,823	295,408	295,445
312D	238,603	241,077	241,754	245,443	245,472	246,059
312N	9,636	9,636	9,636	9,636	9,636	9,636
312X	4,931	4,931	4,931	6,772	8,000	8,000
3124	690,359	690,389	690,389	690,481	690,603	690,603
312E	531,668	531,668	531,705	531,705	531,705	531,705
312P	87,939	87,939	87,939	87,939	87,939	87,939
312Y	-	-	-	-	-	-
3125	39,624	39,624	41,513	41,799	41,820	41,820
312F&312K	140,192	140,192	142,260	142,291	142,291	142,291
312Q	69,489	69,489	69,489	69,489	69,489	69,489
312Z	3,313	3,313	4,022	13,277	13,277	13,277
3126	5,687	5,733	5,754	5,833	5,886	5,983
312G	3,955	3,955	3,955	3,955	3,955	3,955
3127	994	994	994	994	994	994
3128	1,246	1,246	1,246	1,246	1,246	1,246
312J	31	31	31	31	31	31

Big Rivers ctric Corporation
Case No. 2012-00535
Attachment for Response to AG 2-11(a)
Depreciation Expense
For the Forecasted Test Period Twelve Months Ending 8/31/2014

Account No.	Depreciation Expense					
	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14
3140	-	-	-	-	-	-
3141	7,481	7,481	7,481	7,481	7,672	7,672
3142	56,034	56,034	57,837	58,026	58,026	58,026
3143	96,528	97,848	97,857	98,094	98,094	98,094
3144	210,805	210,805	210,805	210,805	210,805	210,805
3145	12,387	12,387	12,896	12,896	12,896	12,896
3146	425	425	425	425	425	425
3147	51	51	51	51	87	87
3151	2,519	2,519	2,519	2,519	2,519	2,519
3152	16,176	16,176	16,924	16,924	16,924	17,022
3153	29,049	29,172	29,785	30,803	30,803	30,803
3154	59,690	59,690	59,690	59,690	59,690	59,690
3155	323	323	1,454	1,454	1,454	1,454
3157	97	97	97	97	97	97
3159	74	74	74	74	74	74
3160	189	189	189	189	189	189
3161	4	4	4	4	4	4
3162	4,704	4,704	4,753	4,789	4,789	4,789
3163	8,604	8,604	8,604	8,604	8,604	8,635
3164	4,563	4,563	4,563	4,587	4,587	4,587
3165	1,365	1,365	1,365	1,365	1,365	1,365

Big Rivei. ectric Corporation
Case No. 2012-00535
Attachment for Response to AG 2-11(a)
Depreciation Expense
For the Forecasted Test Period Twelve Months Ending 8/31/2014

Account No.	Depreciation Expense					
	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14
3166	1,586	1,644	1,644	1,644	1,661	1,718
3167	1,483	1,483	1,483	1,483	1,494	1,494
3169	1,848	2,266	2,266	2,266	2,266	2,266
3401						
3410	136	136	136	136	136	136
3420	11,921	11,921	11,921	11,921	11,921	11,921
3430	12,450	12,450	12,450	12,450	12,450	12,450
3440	324	324	324	324	324	324
3450	973	973	973	973	973	973
3460						
3500	-	-	-	-	-	-
3501	-	-	-	-	-	-
3520	9,511	9,542	9,581	9,587	9,592	9,598
3521	-	-	-	-	-	-
3522	254	254	254	254	254	254
3524	1,164	1,164	1,164	1,164	1,164	1,164
3525	299	299	299	299	299	299
3530	167,495	167,706	167,952	168,220	168,409	168,661
3531	6,542	6,542	6,542	6,542	6,542	6,542
3532	10,829	10,829	10,829	10,829	10,829	10,829
3533	11,353	11,353	11,353	11,353	11,353	11,353

Big Rivers ...ctric Corporation
Case No. 2012-00535
Attachment for Response to AG 2-11(a)
Depreciation Expense
For the Forecasted Test Period Twelve Months Ending 8/31/2014

Account No.	Depreciation Expense					
	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14
3534	42,840	42,840	42,840	42,840	42,840	42,840
3535	12,430	12,430	12,430	12,430	12,430	12,430
3536						
3537						
3538						
3539						
3540	9,232	9,232	9,232	9,232	9,232	9,232
3541	167	167	167	167	167	167
3545	355	355	355	355	355	355
3550	74,974	75,073	75,170	75,266	75,363	75,460
3551	-	-	-	-	-	-
3555	134	134	134	134	134	134
3560	72,876	73,033	73,254	73,473	73,696	73,719
3561	-	-	-	-	-	-
3565	158	158	158	158	158	158
3890	-	-	-	-	-	-
3900	16,706	16,706	16,706	16,706	16,706	16,706
3910	6,086	6,089	6,104	6,121	6,121	6,121
3912	209,292	209,935	211,286	211,994	213,666	214,695
3913	-	-	-	-	-	-
3916	59	59	59	59	59	59

Big Rivei lectric Corporation
Case No. 2012-00535
Attachment for Response to AG 2-11(a)
Depreciation Expense
For the Forecasted Test Period Twelve Months Ending 8/31/2014

Account No.	Depreciation Expense					
	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14
3917	217	217	217	217	217	217
3922	20,970	20,970	20,970	20,970	20,970	20,970
3923	8,704	8,704	8,704	8,704	8,704	8,704
3930	492	492	492	492	492	492
3940	3,780	3,804	3,808	3,812	3,812	3,812
3950	1,129	1,129	1,129	1,129	1,129	1,129
3960	2,749	2,749	2,749	2,749	2,749	2,749
3961	-	-	-	-	-	-
3970	8,870	8,870	8,870	8,870	8,870	8,870
3980	1,314	1,314	1,314	1,314	1,314	1,314
3986	-	-	-	-	-	-
3987	8	8	8	8	8	8
Total	**3,942,025**	**3,948,425**	**3,971,009**	**3,994,687**	**3,999,346**	**4,003,914**
Rounding Difference	(1)	(1)	0	1	2	2
PSC 2-36	**3,942,024**	**3,948,424**	**3,971,009**	**3,994,688**	**3,999,348**	**4,003,916**

Big Rivers Electric Corporation
Case No. 2012-00535
Attachment for Response to AG 2-11(a)
Depreciation Expense
For the Forecasted Test Period Twelve Months Ending 8/31/2014

Account Descriptions

3010	ORGANIZATION
3020	FRANCHISES AND CONSENTS
3101	LAND AND LAND RIGHTS REID
3102	LAND AND LAND RIGHTS COLEMAN
3103	LAND AND LAND RIGHTS GREEN
3104	LAND AND LAND RIGHTS WILSON
3111	STRUCTURES AND IMROVEMENTS REID
3112	STRUCTURES AND IMROVEMENTS COLEMAN
3113	STRUCTURES AND IMROVEMENTS GREEN
3114	STRUCTURES AND IMROVEMENTS WILSON
3115	HMP&L STATION 2-STRUCTURES
3116	COMMON FOR REID & STATION 2-STRUCTURES
3117	COMMON FOR REID, GREEN & STATION 2
3119	STRUCTURES-CENTRAL MACHINE SHOP
3120	CENTRAL LAB EQUIPMENT-COAL ANALYSIS
312A	CENTRAL LAB EQUIP-COAL-CLEAN AIR
3121	BOILER PLANT EQUIPMENT REID
312B	BOILER PLANT EQUIP-CLEAN AIR-REID
312L	BOILER-SHORT LIFE-CLEAN AIR-RE
312V	BOILER-SHORT LIFE-REID
3122	BOILER PLANT EQUIPMENT COLEMAN
312C	BOILER PLANT EQUIP-CLEAN AIR-COLEMAN
312M	BOILER-SHORT LIFE-CLEAN AIR-CO
312W	BOILER-SHORT LIFE-COLEMAN
3123	BOILER PLANT EQUIPMENT GREEN
312D	BOILER PLANT EQUIP-CLEAN AIR-GREEN
312N	BOILER-SHORT LIFE-CLEAN AIR-GR
312X	BOILER-SHORT LIFE-GREEN
3124	BOILER PLANT EQUIPMENT WILSON
312E	BOILER PLANT EQUIP-CLEAN AIR-WILSON
312P	BOILER-SHORT LIFE-CLEAN AIR-WI
312Y	BOILER-SHORT LIFE-WILSON
3125	HMP&l STATION II-BOILER PLANT EQUIPMENT
312F&312K	BOILER PLANT EQUIP-CLEAN AIR-HMP&L/SCRUBBER
312Q	BOILER-SHORT LIFE-CLEAN AIR-HM
312Z	BOILER-SHORT LIFE-HMPL

Depreciation Expense
For the Forecasted Test Period Twelve Months Ending 8/31/2014

Account Descriptions

3126	BOILER PLANT EQUIPMENT-REID/STATION TWO
312G	BOILER PLANT EQUIP-CLEAN AIR-REID/HMP&L
3127	BOILER PLANT EQUIPMENT-REID/GREEN/STA 2
3128	BOILER PLANT EQUIPMENT-BARGES
312J	BOILER PLANT EQUIP-CLEAN AIR-GREEN/HMP&L
3141	TURBO-GENERATOR UNITS REID
3142	TURBO-GENERATOR UNITS COLEMAN
3143	TURBO-GENERATOR UNITS GREEN
3144	TURBO-GENERATOR UNITS WILSON
3145	TURBO GENERATOR UNITS-HMP&L-STATION TWO
3146	COMMON FOR REID & STATION 2
3147	COMMON FOR REID, GREEN & STATION 2
3151	ACCESSORY ELECTRIC EQUIPMENT REID
3152	ACCESSORY ELECTRIC EQUIPMENT COLEMAN
3153	ACCESSORY ELECTRIC EQUIPMENT GREEN
3154	ACCESSORY ELECTRIC EQUIPMENT WILSON
3155	HMP&L STATION 2-ACCESS,ELECTRIC EQUIP.
3157	COMMON FOR REID,GREEN,STATION II
3159	CENTRAL MACHINE SHOP
3160	CENTRAL LAB EQUIPMENT-GENERAL
3161	MISC. POWER PLANT EQUIPMENT REID
3162	MISC. POWER PLANT EQUIPMENT COLEMAN
3163	MISC. POWER PLANT EQUIPMENT GREEN
3164	MISC. POWER PLANT EQUIPMENT WILSON
3165	HMP&L STATION 2-MISC PLANT EQUIPMENT
3166	COMMON FOR REID & STATION 2
3167	COMMON FOR REID, GREEN & STATION TWO
3169	MISC EQUIPMENT-CENTRAL MACHINE SHOP
3401	LAND/LAND RIGHTS-COMBUSTION TURBINE
3410	STRUCTURES AND IMPROVEMENTS-GAS TURBINE
3420	FUEL HOLDERS, PRODUCERS & ACCESSORIES-GAS TURBINE
3430	PRIME MOVERS-GAS TURBINE
3440	GENERATORS-GAS TURBINE
3450	ACCESSORY ELECTRIC EQUIPMENT-GAS TURBINE
3460	MISC POWER PLANT EQUIPMENT-GAS TURBINE
3500	LAND RIGHT OF WAYS-TRANSMISSION

Big Rivers Electric Corporation
Case No. 2012-00535
Attachment for Response to AG 2-11(a)
Depreciation Expense
For the Forecasted Test Period Twelve Months Ending 8/31/2014

Account Descriptions

3501	LAND-TRANSMISSION
3520	STRUCTURES AND IMPROVEMENTS TRANSMISSION
3521	STRUCTURES-REID SWITCHYARD
3522	STRUCTURES-COLEMAN SWITCHYARD
3524	STRUCTURES-WILSON SWITCHYARD
3525	STRUCTURES AND IMPROVEMENTS-KU
3530	STATION EQUIPMENT
3531	STATION EQUIPMENT-REID SWITCHYARD
3532	STATION EQUIPMENT-COLEMAN SWITCHYARD
3533	STATION EQUIPMENT-GREEN SWITCHYARD
3534	STATION EQUIPMENT-WILSON SWITCHYARD
3535	STATION EQUIPMENT-KU
3540	TOWERS AND FIXTURES
3541	TOWERS-REID SWITCHYARD
3545	TOWERS-KU
3550	POLES AND FIXTURES
3551	POLES AND FIXTURES - SPECIAL
3555	POLES AND FIXTURES-KU
3560	OVERHEAD CONDUCTOR AND DEVICES
3561	OVERHEAD CONDUCTOR AND DEVICES - SPECIAL
3565	OVHD CONDUCTORS AND DEVICES-KU
3890	LAND AND LAND RIGHTS GENERAL PLANT
3900	STRUCTURES AND IMPROVEMENTS GENERAL PLT
3910	OFFICE FURNITURE AND EQUIPMENT
3912	COMPUTER EQUIPMENT AND SOFTWARE
3913	ENGINEERING COMPUTER
3916	OFFICE FURN & EQUIP-REID, STATION TWO
3917	OFFICE FURN & EQUIP-REID, GREEN, STA TWO
3922	TRANSPORTATION EQUIPMENT-AUTO
3923	TRANSPORTATION EQUIP-TRANSMISSION
3930	STORES EQUIPMENT
3940	TOOLS, SHOP, AND GARAGE EQUIPMENT
3950	LABORATORY EQUIPMENT
3960	POWER OPERATED EQUIPMENT
3961	GO-TRACT VEHICLE #103
3970	COMMUNICATION EQUIPMENT

Big Rivers Electric Corporation
Case No. 2012-00535
Attachment for Response to AG 2-11(a)
Depreciation Expense
For the Forecasted Test Period Twelve Months Ending 8/31/2014

Account Descriptions

3980	MISCELLANEOUS EQUIPMENT
3986	MISC EQUIPMENT-REID, STATION TWO
3987	MISC EQUIPMENT-REID, GREEN, STATION TWO

Big Rivers Electric Corporation
Case No. 2012-00535
Attachment for Response to AG 2-11(b)
Reconciliation of Test Period Accumulated Depreciation

Accumulated Depreciation (August 31, 2013)	$	988,888,850
Depreciation Expense (Test Period)*		47,432,639
Estimated Retirements (Test Period)		(12,486,614)
Accumulated Depreciation (August 31, 2014)	$	1,023,834,875

*Includes Station Two depreciation expense charged to account 555 Purchased Power.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

**Response to the Office of the Attorney General's
Supplemental Set of Data Requests
Dated March 14, 2013**

March 28, 2013

Item 12) ***Reference Big Rivers response to PSC 2-5. Does Big Rivers response reflect and take into account the additional changes to its application filed in Case No. 2012-00492, which were made via the testimony of Billie Richert during the hearing on February 28, 2013?***

- ***a. If not, please provide an amended answer in light of the above-referenced testimony.***
- ***b. Assuming that all capital expenditures since August 2012 reduce the $60,000,000 CoBank secured loan, please confirm that the balance after February 28, 2013, is $38,328,265.***
- ***c. If the PSC approves Big Rivers application in Case No 2012-00492, as amended by Billie Richert's testimony on February 28, 2013, please confirm that Big Rivers will have approximately $13.3 million remaining in funds designated for ordinary capital expenditures.***
- ***d. If the PSC approves Big Rivers application in Case No 2012-00492, as amended by Billie Richert's testimony on February 28, 2013, please confirm that the total funding for ordinary capital expenditures for 2012, 2013 and 2014 will not exceed $35 million.***
- ***e. If Big Rivers confirms the sums referenced in (c) and (d), please explain how Big Rivers will cut the estimated $60 million in ordinary capital expenditures to accommodate the reduced level of funding?***

Response) Yes, Big Rivers' response to PSC 2-5 reflects and takes into account the additional changes to its application filed in Case No. 2012-00492, which were made via the testimony of Billie Richert during the hearing on February 28, 2013.

a. Not applicable. See above.
b. Confirmed.
c. Big Rivers cannot confirm that there will be approximately $13.3 million remaining because if the Commission approves Big Rivers' application in Case No 2012-00492, as amended, the entire $35,000,000 Transition Reserve becomes available for capital expenditures.
d. Big Rivers cannot confirm that the total ordinary capital expenditures for 2012, 2013 and 2014 will not exceed $35 million, as this is incorrect.
e. Not applicable. Neither subpart (c) nor (d) is being confirmed.

Witness) Billie J. Richert

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2012-00535

Response to the Office of the Attorney General's Supplemental Set of Data Requests Dated March 14, 2013

March 28, 2013

Item 13) ***Referencing Big Rivers' response to AG 1-40, please provide the following reports for FY 2011 through 2013 YTD:***

- ***a. Corporate Scorecard and dashboard;***
- ***b. Professional Services Report;***
- ***c. Financial Report; and,***
- ***d. Internal Risk Management Committee Update.***

Response)

a. Please see attached reports.

b. Please see attached reports.

c. Financial reports for December 2010 through April 2011 are attached. Please refer to Tab 38 of Big Rivers' Application for financial reports from May 2011 through October 2012. Additionally, financial reports from November 2012 through 2013 YTD have been filed in connection with Tab 38 of Big Rivers' Application.

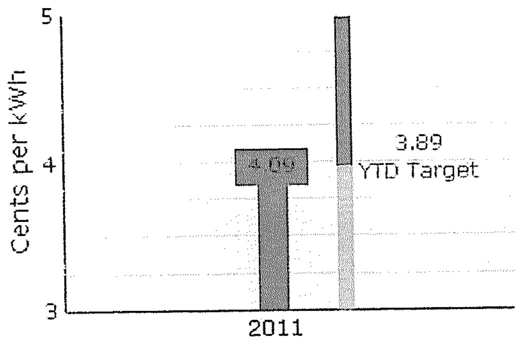
d. Please see attached reports for January 2011 through December 2011 and February and March 2013 submitted under petition for confidential treatment. Please refer to AG 1-25(g) for January 2012 through January 2013 IRMC minutes.

Witnesses) Billie J. Richert, Mark A. Bailey, Robert W. Berry

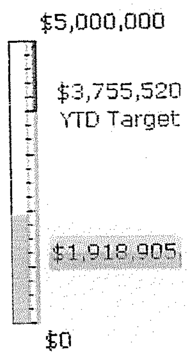
Big Rivers ELECTRIC CORPORATION

CORPORATE DASHBOARD
January 2011

NORTH STAR
Member Cost/kWh YTD

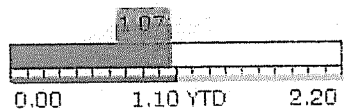


CAPITAL EXPENDITURES
YTD

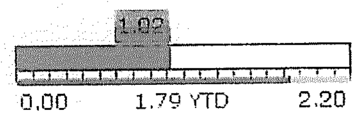


TIMES INTEREST EARNED RATIO (TIER)

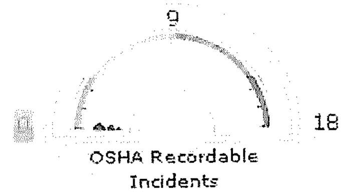
12 MONTHS ENDING

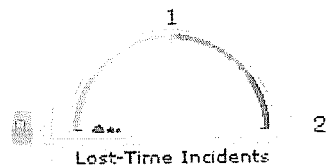


YEAR-TO-DATE



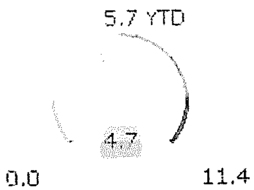
SAFETY YTD



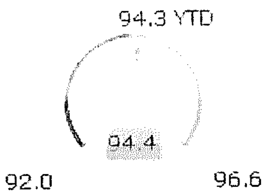


PLANT PERFORMANCE
YTD

Equivalent Forced Outage Rate (EFOR)



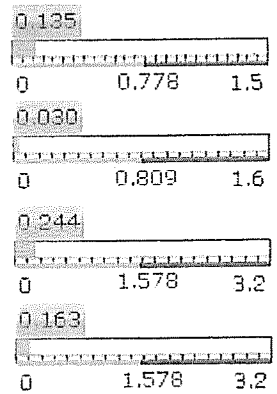
Equivalent Availability Factor (EAF)



Combined Heat Rate

[redacted]

TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING



Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Big Rivers ELECTRIC CORPORATION

CORPORATE SCORECARD
January 2011

Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2011 Target
Financial	North Star	C. Warren	Member Cost/kWh	0.040867	0.040867	YTD	0.038915	0.044766
	Capital Expenditures	J. Stone	Aggregate Capital Expenditures	$1,918,905	$1,918,905	YTD	$3,755,520	$55,231,214
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt	1.02	1.07	12M	1.10	1.10
					1.02	YTD	1.79	1.10
	Net Margin	C. Warren	Revenues less Expenses	$98,246	$98,246	YTD	$3,175,482	$6,067,087
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$21,255,546	12M		$21,500,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.366	12M		0.365
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$676,480	12M		$ 685,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.471	12M		0.470
Production	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs +Forced Outage Hrs	4.7	4.7	YTD	5.7	5.9
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	94.4	94.4	YTD	94.3	91.0
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.135	12M		0.778
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		0.030	12M		0.809
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.244	12M		1.578
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.163	12M		1.578
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	0	YTD		1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	0	0	YTD		9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		0	YTD		1.52

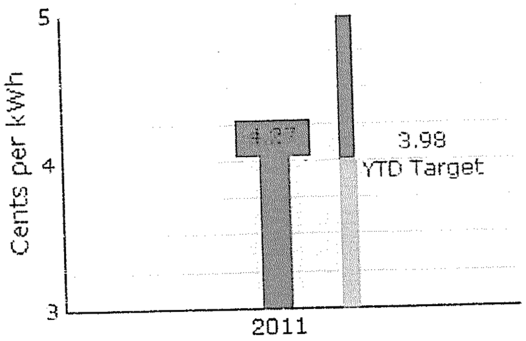
Performing At or Better than Target | Performing Worse than Target

Performance is measured against YTD targets/budgets when available.

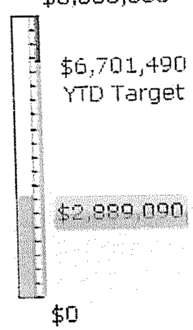
Big Rivers
ELECTRIC CORPORATION

CORPORATE DASHBOARD
February 2011

NORTH STAR
Member Cost/kWh YTD

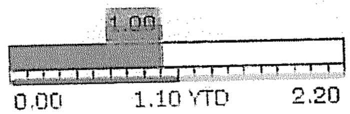


CAPITAL EXPENDITURES
YTD

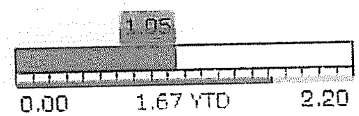


TIMES INTEREST EARNED RATIO (TIER)

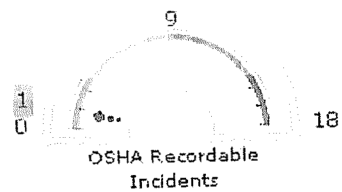
12 MONTHS ENDING

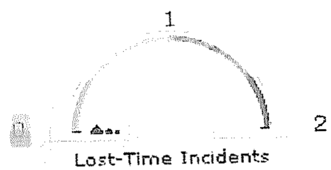


YEAR-TO-DATE



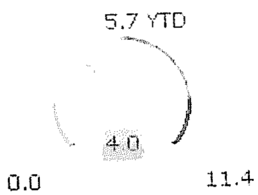
SAFETY YTD



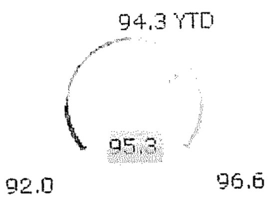


PLANT PERFORMANCE
YTD

Equivalent Forced Outage Rate (EFOR)



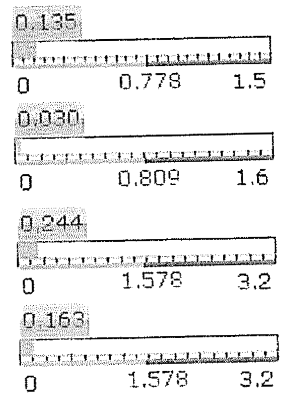
Equivalent Availability Factor (EAF)



Combined Heat Rate

[redacted]

TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING



Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert

CORPORATE SCORECARD
February 2011

Big Rivers Electric Corporation

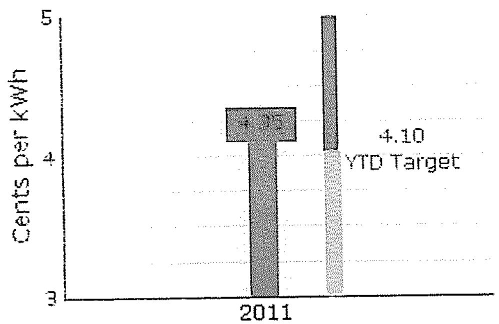
Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2011 Target
Financial	North Star	C. Warren	Member Cost/kWh	0.044112	0.042734	YTD	0.039775	0.044766
	Capital Expenditures	J. Stone	Aggregate Capital Expenditures	$970,185	$2,889,090	YTD	$6,701,490	$55,231,214
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt	1.08	1.00	12M	1.10	1.10
					1.05	YTD	1.67	1.10
	Net Margin	C. Warren	Revenues less Expenses	$309,648	$407,894	YTD	$5,152,995	$6,067,087
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$21,284,267	12M		$21,500,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.366	12M		0.365
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$670,804	12M		$ 685,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.471	12M		0.470
Production	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs + Forced Outage Hrs	3.8	4.0	YTD	5.7	5.9
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	96.3	95.3	YTD	94.3	91.0
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.135	12M		0.778
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		0.030	12M		0.809
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.244	12M		1.578
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.163	12M		1.578
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	0	YTD		1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	1	1	YTD		9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		0.97	YTD		1.52

Performing At or Better than Target — Performing Worse than Target

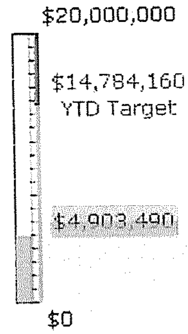
Performance is measured against YTD targets/budgets when available.

CORPORATE DASHBOARD
March 2011

NORTH STAR
Member Cost/kWh YTD

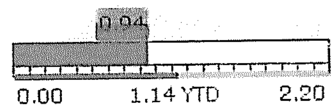


CAPITAL EXPENDITURES
YTD

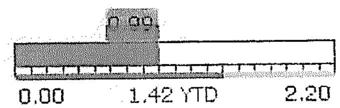


TIMES INTEREST EARNED RATIO (TIER)

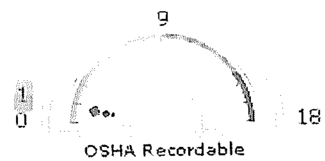
12 MONTHS ENDING



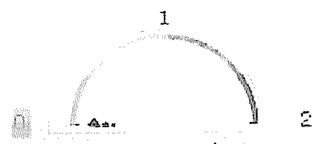
YEAR-TO-DATE



SAFETY YTD



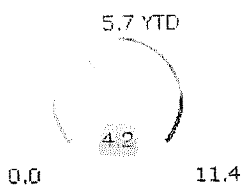
OSHA Recordable Incidents



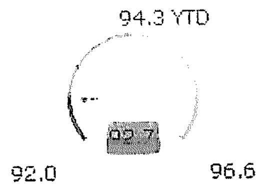
Lost-Time Incidents

PLANT PERFORMANCE
YTD

Equivalent Forced Outage Rate (EFOR)



Equivalent Availability Factor (EAF)



Combined Heat Rate

[redacted]

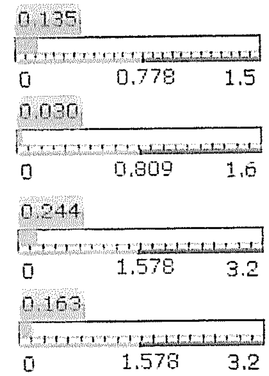
TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING

Jackson Purchase Electric Corporation

Meade County RECC

Kenergy Corp.

System Wide



Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Big Rivers
ELECTRIC CORPORATION

CORPORATE SCORECARD
March 2011

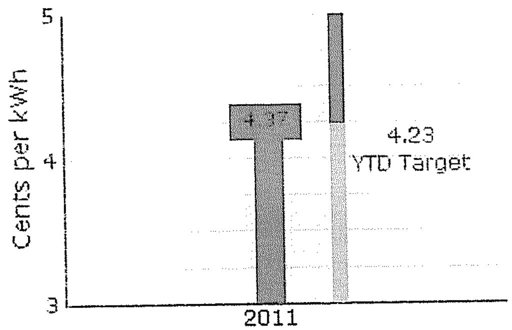
Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2011 Target
Financial	North Star	C. Warren	Member Cost/kWh	0.045767	0.043512	YTD	0.040958	0.044766
	Capital Expenditures	J. Stone	Aggregate Capital Expenditures	$2,000,551	$4,903,490	YTD	$14,784,160	$55,231,214
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt	0.87	0.94	12M	1.14	1.10
					0.99	YTD	1.42	1.10
	Net Margin	C. Warren	Revenues less Expenses	($505,464)	($97,570)	YTD	$4,847,073	$6,067,087
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$21,329,685	12M		$21,500,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.370	12M		0.365
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$667,332	12M		$ 685,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.570	12M		0.470
Production	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs +Forced Outage Hrs	4.6	4.2	YTD	5.7	5.9
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	87.6	92.7	YTD	94.3	91.0
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.135	12M		0.778
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		0.030	12M		0.809
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.244	12M		1.578
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.163	12M		1.578
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	0	YTD		1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	0	1	YTD		9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		0.66	YTD		1.52

Performing At or Better than Target   Performing Worse than Target   Performance is measured against YTD targets/budgets when available.

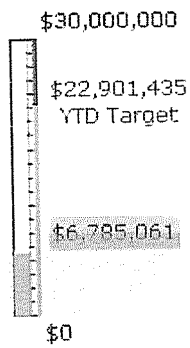
Big Rivers ELECTRIC CORPORATION

CORPORATE DASHBOARD
April 2011

NORTH STAR
Member Cost/kWh YTD

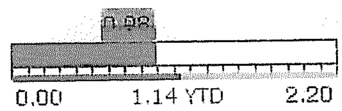


CAPITAL EXPENDITURES
YTD

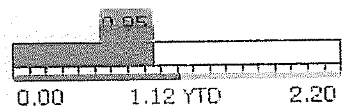


TIMES INTEREST EARNED RATIO (TIER)

12 MONTHS ENDING

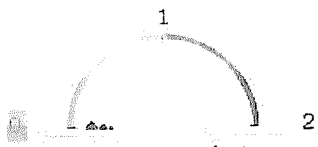


YEAR-TO-DATE



SAFETY YTD

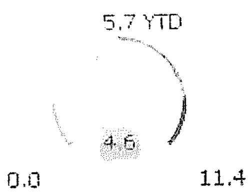
OSHA Recordable Incidents



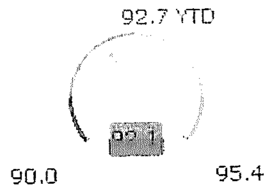
Lost-Time Incidents

PLANT PERFORMANCE
YTD

Equivalent Forced Outage Rate (EFOR)



Equivalent Availability Factor (EAF)



Combined Heat Rate

[redacted]

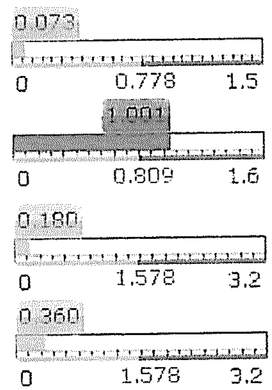
TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING

Jackson Purchase Electric Corporation

Meade County RECC

Kenergy Corp.

System Wide



Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert

Big Rivers ELECTRIC CORPORATION

CORPORATE SCORECARD
April 2011

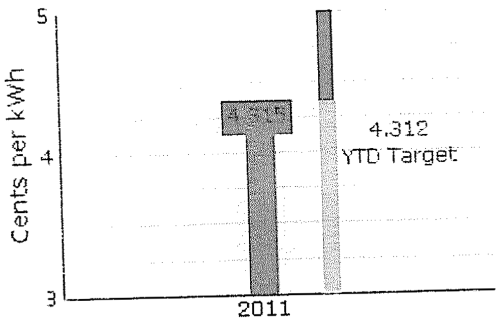
Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2011 Target
Financial	North Star	C. Warren	Member Cost/kWh	0.044344	0.043713	YTD	0.042306	0.044766
	Capital Expenditures	J. Stone	Aggregate Capital Expenditures	$1,895,419	$6,785,061	YTD	$22,901,435	$55,231,214
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt	0.83	0.98	12M	1.14	1.10
					0.95	YTD	1.12	1.10
	Net Margin	C. Warren	Revenues less Expenses	($634,399)	($731,970)	YTD	$1,847,577	$6,067,087
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$21,427,374	12M		$21,500,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.348	12M		0.365
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$659,579	12M		$ 685,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.498	12M		0.470
Production	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs + Forced Outage Hrs	5.6	4.6	YTD	5.7	5.9
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	90.9	92.1	YTD	92.7	91.0
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.073	12M		0.778
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		1.001	12M		0.809
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.180	12M		1.578
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.360	12M		1.578
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	0	YTD		1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	1	3	YTD		9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.47	YTD		1.52

Performing At or Better than Target   Performing Worse than Target   Performance is measured against YTD targets/budgets when available

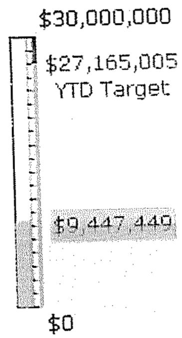
Big Rivers
ELECTRIC CORPORATION

CORPORATE DASHBOARD
May 2011

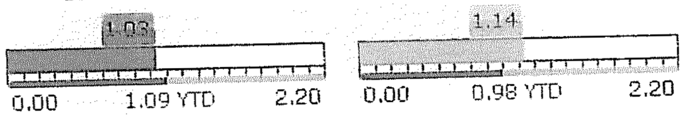
NORTH STAR
Member Cost/kWh YTD



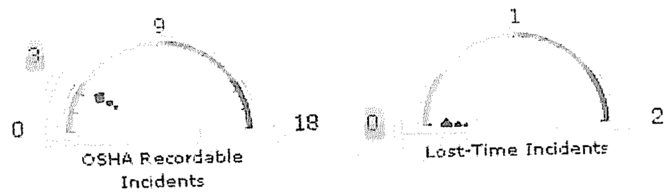
CAPITAL EXPENDITURES
YTD



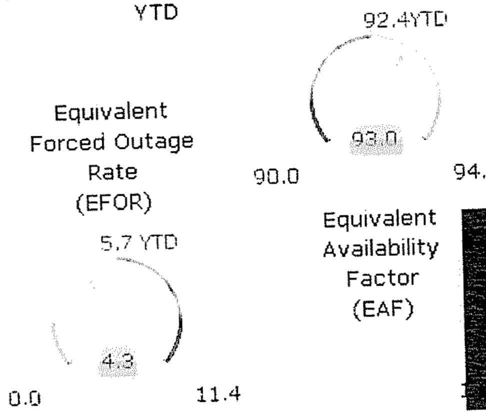
TIMES INTEREST EARNED RATIO (TIER)



SAFETY YTD



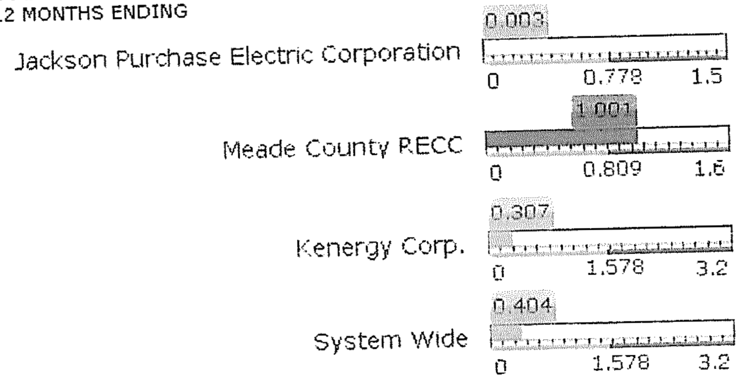
PLANT PERFORMANCE
YTD



Combined Heat Rate

[redacted]

TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING



Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Big Rivers
ELECTRIC CORPORATION

CORPORATE SCORECARD
May 2011

Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2011 Target
Financial	North Star	C. Warren	Member Cost/kWh	0.040991	0.043155	YTD	0.043124	0.044766
	Capital Expenditures	J. Stone	Aggregate Capital Expenditures	$2,662,388	$9,447,449	YTD	$27,165,005	$55,231,214
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt	1.87	1.03	12M	1.09	1.10
					1.14	YTD	0.98	1.10
	Net Margin	C. Warren	Revenues less Expenses	$3,375,695	$2,643,725	YTD	($404,957)	$6,067,087
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$21,514,165	12M		$21,500,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.359	12M		0.365
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$654,981	12M		$ 685,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.516	12M		0.470
Production	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs + Forced Outage Hrs	3.4	4.3	YTD	5.7	5.9
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	96.5	93.0	YTD	92.4	91.0
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.003	12M		0.778
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		1.001	12M		0.809
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.307	12M		1.578
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.404	12M		1.578
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	0	YTD		1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	0	3	YTD		9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.17	YTD		1.52

Performing At or Better than Target   Performing Worse than Target

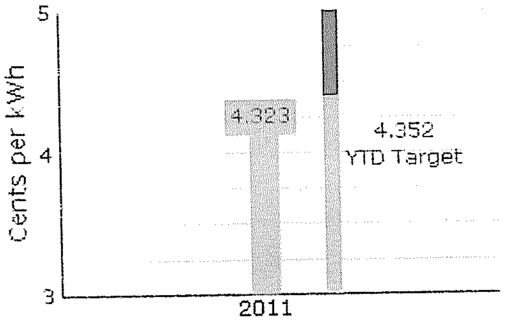
Performance is measured against YTD targets/budgets when available.

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert

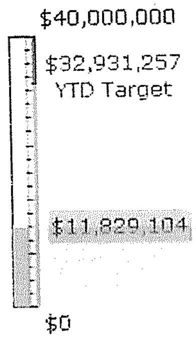
Big Rivers
ELECTRIC CORPORATION

CORPORATE DASHBOARD
June 2011

NORTH STAR
Member Cost/kWh YTD

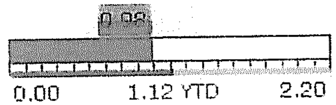


CAPITAL EXPENDITURES
YTD

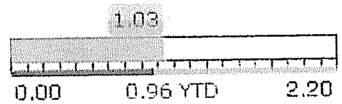


TIMES INTEREST EARNED RATIO (TIER)

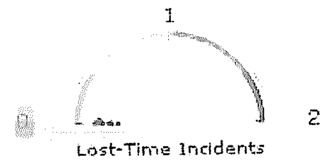
12 MONTHS ENDING



YEAR-TO-DATE

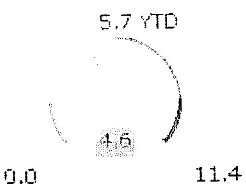


SAFETY YTD

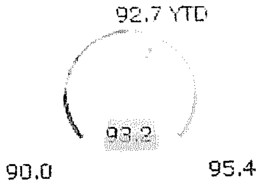


PLANT PERFORMANCE
YTD

Equivalent Forced Outage Rate (EFOR)



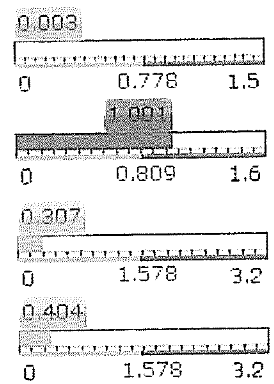
Equivalent Availability Factor (EAF)



Combined Heat Rate

[redacted]

TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING



Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Big Rivers
ELECTRIC CORPORATION

CORPORATE SCORECARD
June 2011

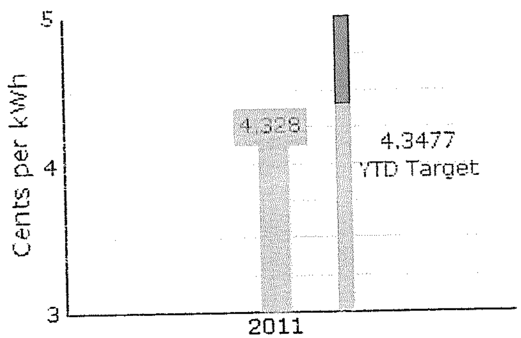
Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2011 Target
Financial	North Star	C. Warren	Member Cost/kWh	0.045032	0.043226	YTD	0.043518	0.044766
	Capital Expenditures	J. Stone	Aggregate Capital Expenditures	$2,381,655	$11,829,104	YTD	$32,931,257	$55,231,214
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt	0.46	0.98	12M	1.12	1.10
					1.03	YTD	0.96	1.10
	Net Margin	C. Warren	Revenues less Expenses	($1,948,594)	$695,131	YTD	($944,509)	$6,067,087
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$21,586,833	12M		$21,500,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.385	12M		0.365
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$647,213	12M		$ 685,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.573	12M		0.470
Production	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs +Forced Outage Hrs	5.9	4.6	YTD	5.7	5.9
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	94.1	93.2	YTD	92.7	91.0
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.003	12M		0.778
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		1.001	12M		0.809
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.307	12M		1.578
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.404	12M		1.578
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	0	YTD		1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	0	3	YTD		9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		0.98	YTD		1.52

Performing At or Better than Target   Performing Worse than Target   Performance is measured against YTD targets/budgets when available.

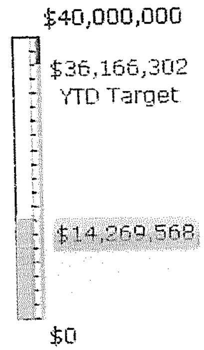
Big Rivers ELECTRIC CORPORATION

CORPORATE DASHBOARD
July 2011

NORTH STAR
Member Cost/kWh YTD

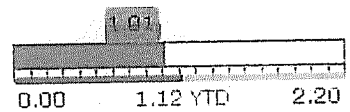


CAPITAL EXPENDITURES
YTD

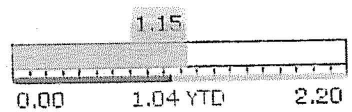


TIMES INTEREST EARNED RATIO (TIER)

12 MONTHS ENDING

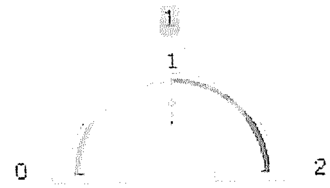


YEAR-TO-DATE



SAFETY YTD

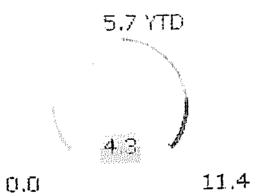
OSHA Recordable Incidents



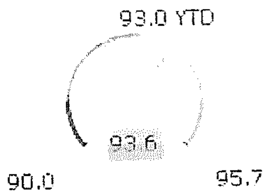
Lost-Time Incidents

PLANT PERFORMANCE
YTD

Equivalent Forced Outage Rate (EFOR)



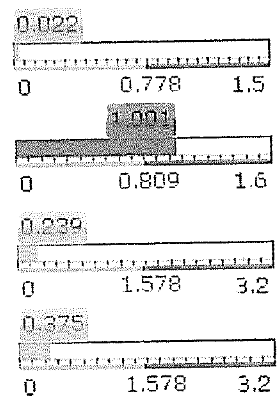
Equivalent Availability Factor (EAF)



Combined Heat Rate

[redacted]

TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING



Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert

Big Rivers ELECTRIC CORPORATION

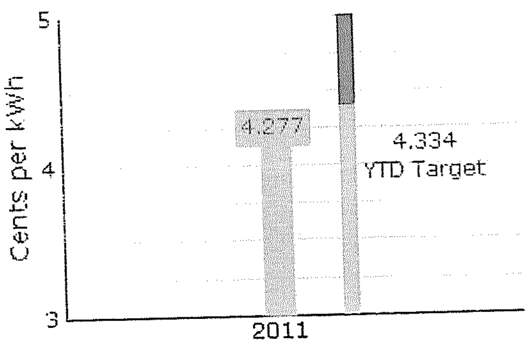
CORPORATE SCORECARD
July 2011

Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2011 Target
Financial	North Star	C. Warren	Member Cost/kWh	0.043593	0.043283	YTD	0.043477	0.044766
	Capital Expenditures	J. Stone	Aggregate Capital Expenditures	$2,439,922	$14,269,568	YTD	$36,166,302	$55,231,214
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt	1.84	1.01	12M	1.12	1.10
					1.15	YTD	1.04	1.10
	Net Margin	C. Warren	Revenues less Expenses	$3,239,647	$3,934,778	YTD	$1,061,767	$6,067,087
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$21,659,713	12M		$21,500,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.372	12M		0.365
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$640,206	12M		$ 685,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.536	12M		0.470
Production	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs + Forced Outage Hrs	2.4	4.3	YTD	5.7	5.9
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	96.0	93.6	YTD	93.0	91.0
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.022	12M		0.778
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		1.001	12M		0.809
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.239	12M		1.578
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.375	12M		1.578
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	1	YTD		1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0.28	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	3	6	YTD		9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.69	YTD		1.52

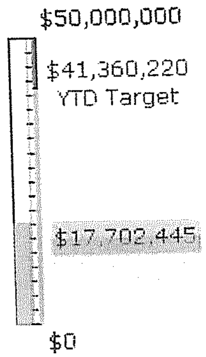
Performing At or Better than Target   Performing Worse than Target   Performance is measured against YTD targets/budgets when available.

CORPORATE DASHBOARD
August 2011

NORTH STAR
Member Cost/kWh YTD

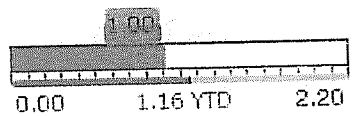


CAPITAL EXPENDITURES
YTD

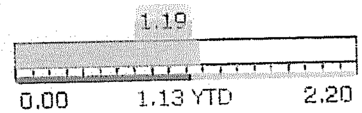


TIMES INTEREST EARNED RATIO (TIER)

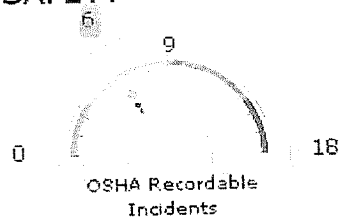
12 MONTHS ENDING



YEAR-TO-DATE

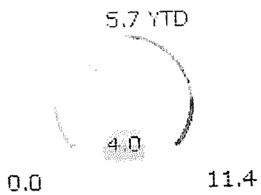


SAFETY YTD

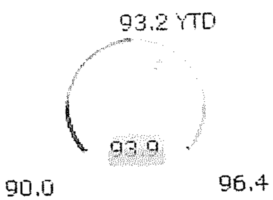


PLANT PERFORMANCE
YTD

Equivalent Forced Outage Rate (EFOR)



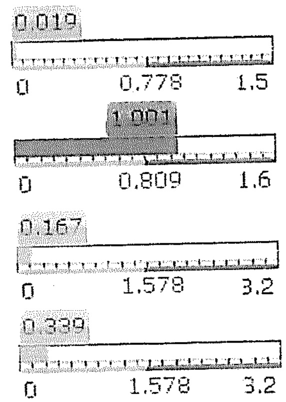
Equivalent Availability Factor (EAF)



Combined Heat Rate

[redacted]

TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING



Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert

Big Rivers
ELECTRIC CORPORATION

CORPORATE SCORECARD
August 2011

Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2011 Target
Financial	North Star	C. Warren	Member Cost/kWh	0.042392	0.042769	YTD	0.043344	0.044766
	Capital Expenditures	J. Stone	Aggregate Capital Expenditures	$3,432,877	$17,702,446	YTD	$41,360,220	$55,231,214
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt	1.53	1.00	12M	1.16	1.10
					1.19	YTD	1.13	1.10
	Net Margin	C. Warren	Revenues less Expenses	$2,028,655	$5,963,433	YTD	$4,080,361	$6,067,087
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$21,749,990	12M		$21,500,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.370	12M		0.365
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$633,651	12M		$ 685,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.530	12M		0.470
Production	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs +Forced Outage Hrs	2.1	4.0	YTD	5.7	5.9
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	95.9	93.9	YTD	93.2	91.0
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.019	12M		0.778
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		1.001	12M		0.809
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.167	12M		1.578
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.339	12M		1.578
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	1	YTD		1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0.25	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	0	6	YTD		9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.49	YTD		1.52

Performing At or Better than Target — Performing Worse than Target — Performance is measured against YTD targets/budgets when available.

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert

Big Rivers
ELECTRIC CORPORATION

CORPORATE SCORECARD
September 2011

Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2011 Target
Financial	North Star	C. Warren	Member Cost/kWh	0.045697	0.043083	YTD	0.043818	0.044766
	Capital Expenditures	J. Stone	Aggregate Capital Expenditures	$3,997,635	$21,700,080	YTD	$48,094,634	$56,231,214
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt	1.78	1.12	12M	1.21	1.10
					1.26	YTD	1.14	1.10
	Net Margin	C. Warren	Revenues less Expenses	$2,935,017	$8,898,461	YTD	$4,951,179	$6,067,087
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$21,797,017	12M		$21,500,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.370	12M		0.365
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$633,651	12M		$ 685,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.505	12M		0.470
Production	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs +Forced Outage Hrs	4.6	4.1	YTD	5.8	5.9
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	94.3	94.0	YTD	92.6	91.0
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.019	12M		0.778
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		1.001	12M		0.809
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.167	12M		1.578
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.339	12M		1.578
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	1	YTD		1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0.44	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	2	9	YTD		9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.74	YTD		1.52

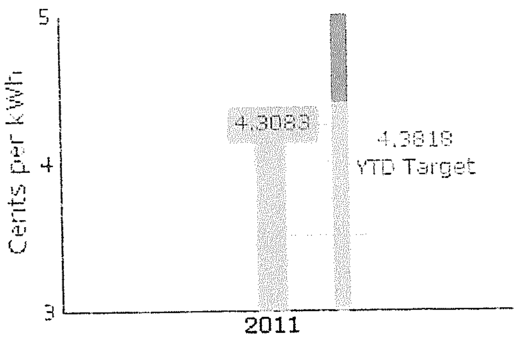
Performing At or Better than Target   Performing Worse than Target   Performance is measured against YTD targets/budgets when available.

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert

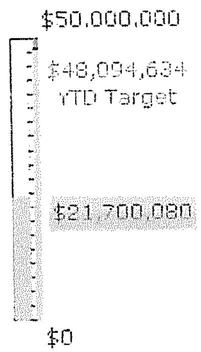
Big Rivers ELECTRIC CORPORATION

CORPORATE DASHBOARD
September 2011

NORTH STAR
Member Cost/kWh YTD

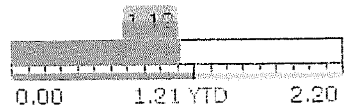


CAPITAL EXPENDITURES
YTD

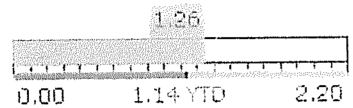


TIMES INTEREST EARNED RATIO (TIER)

12 MONTHS ENDING



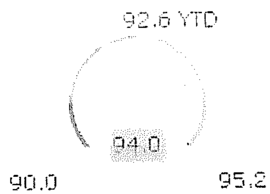
YEAR-TO-DATE



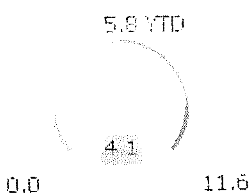
SAFETY YTD

PLANT PERFORMANCE
YTD

Equivalent Availability Factor (EAF)



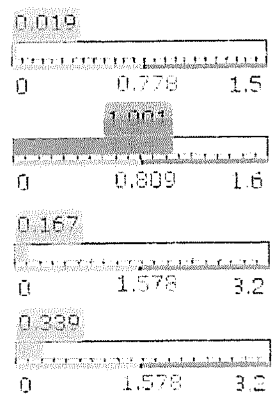
Equivalent Forced Outage Rate (EFOR)



Combined Heat Rate

[redacted]

TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING



Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert

Big Rivers
ELECTRIC CORPORATION

CORPORATE SCORECARD
October 2011

Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2011 Target
Financial	North Star	C. Warren	Member Cost/kWh	0.043152	0.043090	YTD	0.044291	0.044766
	Capital Expenditures	J. Stone	Aggregate Capital Expenditures	$6,227,161	$27,927,241	YTD	$52,382,620	$55,231,214
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt	1.18	1.22	12M	1.19	1.10
					1.25	YTD	1.10	1.10
	Net Margin	C. Warren	Revenues less Expenses	$691,757	$9,590,208	YTD	$3,797,134	$6,067,087
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$21,299,330	12M		$21,500,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.348	12M		0.365
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$652,496	12M		$ 685,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.463	12M		0.470
Production	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs + Forced Outage Hrs	3.4	4.0	YTD	5.8	5.9
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	89.7	93.5	YTD	91.1	91.0
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.019	12M		0.778
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		1.002	12M		0.809
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.167	12M		1.578
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.339	12M		1.578
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	2	YTD	0.83	1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0.39	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	0	9	YTD	7.5	9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.76	YTD		1.52

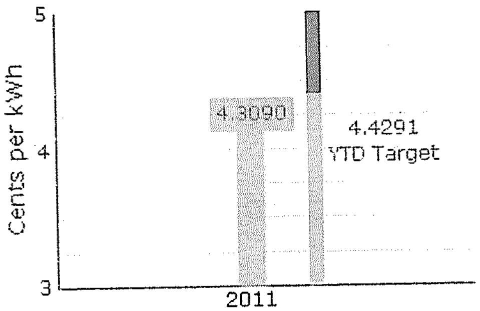
Performing At or Better than Target — Performing Worse than Target — Performance is measured against YTD targets/budgets when available.

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert

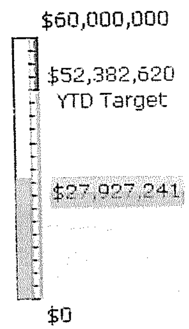
Big Rivers
ELECTRIC CORPORATION

CORPORATE DASHBOARD
October 2011

NORTH STAR
Member Cost/kWh YTD

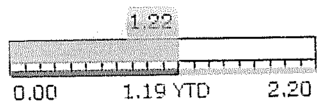


CAPITAL EXPENDITURES
YTD

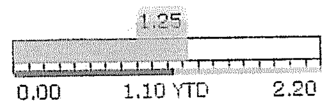


TIMES INTEREST EARNED RATIO (TIER)

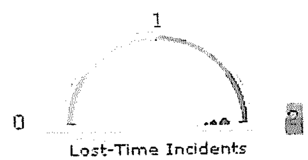
12 MONTHS ENDING



YEAR-TO-DATE

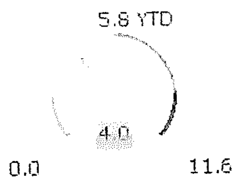


SAFETY YTD

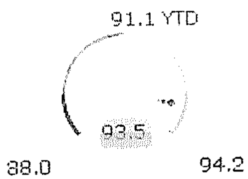


PLANT PERFORMANCE
YTD

Equivalent Forced Outage Rate (EFOR)



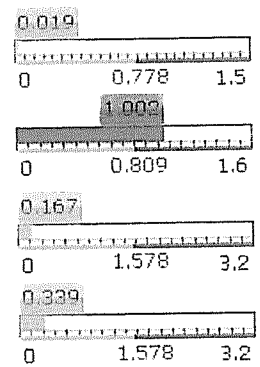
Equivalent Availability Factor (EAF)



Combined Heat Rate

[redacted]

TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING



Performing At or Better than Target

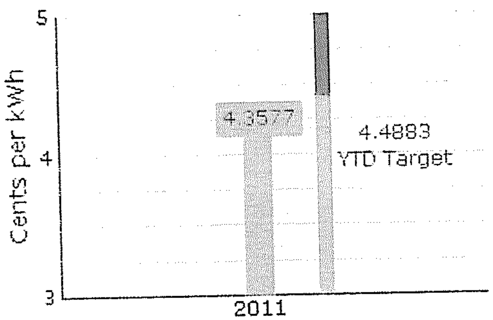
Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

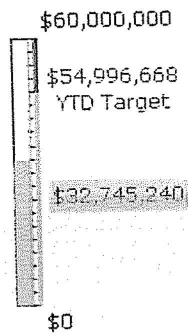
Big Rivers
ELECTRIC CORPORATION

CORPORATE DASHBOARD
November 2011

NORTH STAR
Member Cost/kWh YTD

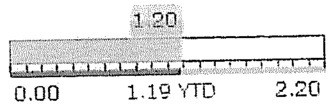


CAPITAL EXPENDITURES
YTD

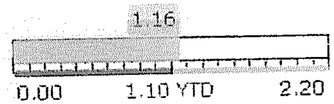


TIMES INTEREST EARNED RATIO (TIER)

12 MONTHS ENDING



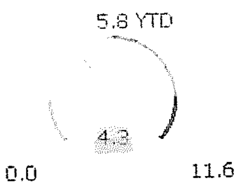
YEAR-TO-DATE



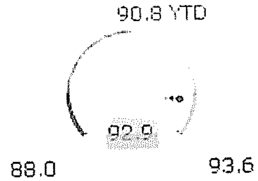
SAFETY YTD

PLANT PERFORMANCE
YTD

Equivalent
Forced Outage
Rate
(EFOR)



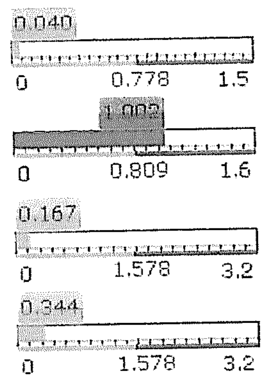
Equivalent
Availability
Factor
(EAF)



Combined
Heat Rate

[redacted]

TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING



Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Big Rivers
ELECTRIC CORPORATION

CORPORATE SCORECARD
November 2011

Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2011 Target
Financial	North Star	C. Warren	Member Cost/kWh	0.048462	0.043577	YTD	0.044883	0.044766
	Capital Expenditures	J. Williams	Aggregate Capital Expenditures	$4,817,999	$32,745,240	YTD	$54,996,668	$55,231,214
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt	0.26	1.20	12M	1.19	1.10
					1.16	YTD	1.10	1.10
	Net Margin	C. Warren	Revenues less Expenses	($2,715,934)	$6,874,273	YTD	$1,220,578	$6,067,087
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$22,047,957	12M		$21,500,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.340	12M		0.365
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$641,916	12M		$ 685,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.420	12M		0.470
Production	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs + Forced Outage Hrs	7.2	4.3	YTD	5.8	5.9
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	87.1	92.9	YTD	90.8	91.0
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.040	12M		0.778
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		1.002	12M		0.809
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.167	12M		1.578
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.344	12M		1.578
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	3	YTD	0.92	1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0.53	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	2	11	YTD	8.25	9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.96	YTD		1.52

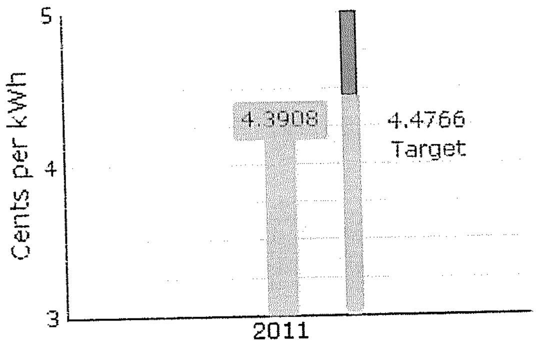
Performing At or Better than Target   Performing Worse than Target   Performance is measured against YTD targets/budgets when available.

Big Rivers ELECTRIC CORPORATION

CORPORATE DASHBOARD
December 2011

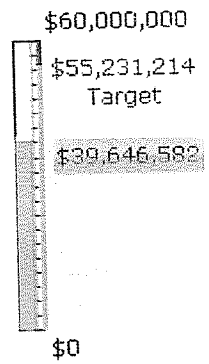
NORTH STAR

Member Cost/kWh YTD

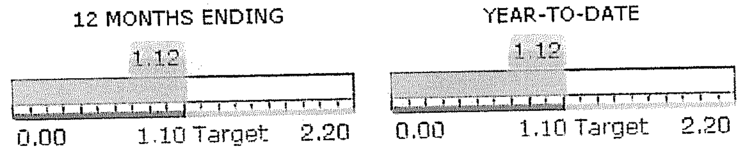


CAPITAL EXPENDITURES

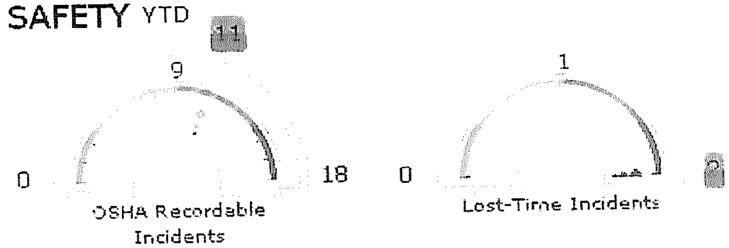
YTD



TIMES INTEREST EARNED RATIO (TIER)



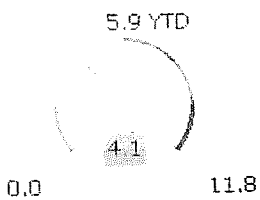
SAFETY YTD



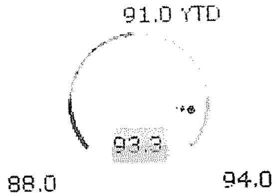
PLANT PERFORMANCE

YTD

Equivalent Forced Outage Rate (EFOR)



Equivalent Availability Factor (EAF)

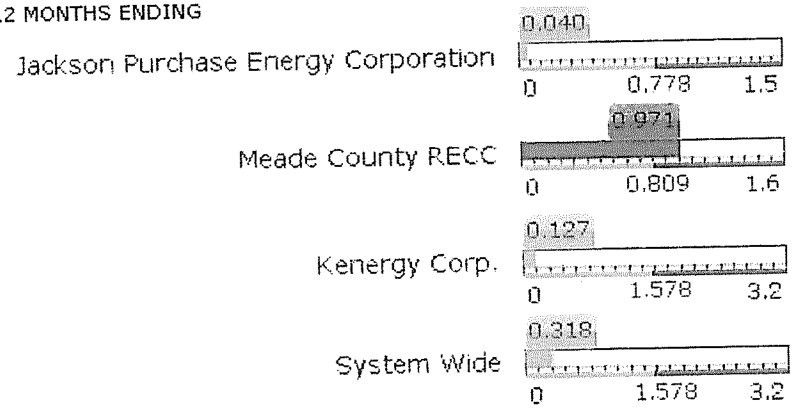


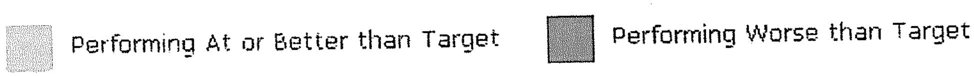
Combined Heat Rate

[redacted]

TRANSMISSION SAIDI Hrs/Yr

12 MONTHS ENDING





Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert

Big Rivers ELECTRIC CORPORATION

CORPORATE SCORECARD
December 2011

Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2011 Target
Financial	North Star	C. Warren	Member Cost/kWh	0.047270	0.043908	YTD	0.044766	0.044766
	Capital Expenditures	J. Williams	Aggregate Capital Expenditures	$6,901,342	$39,646,582	YTD	$55,231,214	$55,231,214
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt		1.12	12M	1.10	1.10
					1.12	YTD	1.10	1.10
	Net Margin	C. Warren	Revenues less Expenses	($1,273,893)	$5,600,381	YTD	$6,067,087	$6,067,087
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$22,047,957	12M		$21,500,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.370	12M		0.365
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$641,916	12M		$ 685,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.420	12M		0.470
Production	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs +Forced Outage Hrs	3.5	4.1	YTD	5.9	5.9
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	95.8	93.3	YTD	91.0	91.0
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.040	12M		0.778
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		0.971	12M		0.809
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.127	12M		1.578
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.318	12M		1.578
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	2	YTD	1	1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0.33	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	0	11	YTD	9	9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.81	YTD		1.52

Performing At or Better than Target

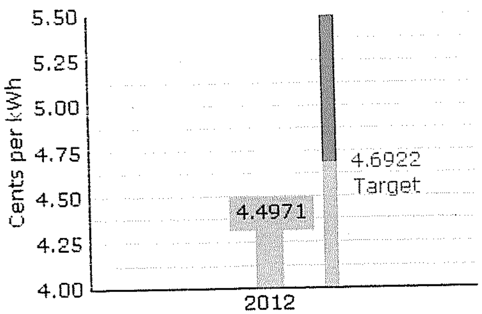
Performing Worse than Target

Performance is measured against YTD targets/budgets when available.

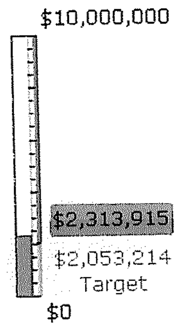
Big Rivers
ELECTRIC CORPORATION

CORPORATE DASHBOARD
January 2012

NORTH STAR
Member Cost/kWh YTD

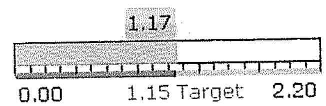


CAPITAL EXPENDITURES
YTD

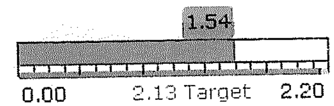


TIMES INTEREST EARNED RATIO (TIER)

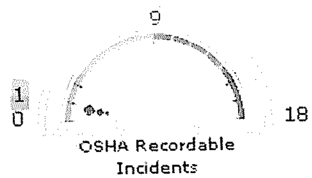
12 MONTHS ENDING

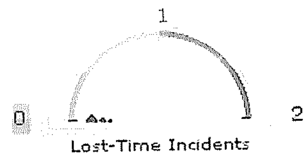


YEAR-TO-DATE



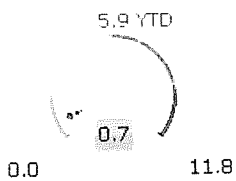
SAFETY



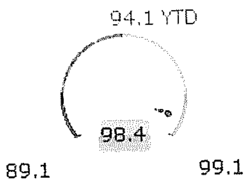


PLANT PERFORMANCE
YTD

Equivalent Forced Outage Rate (EFOR)



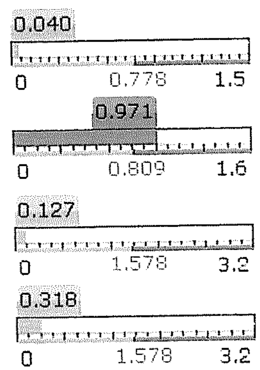
Equivalent Availability Factor (EAF)



Combined Heat Rate

[redacted]

TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING



Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert
Page 1 of 2

Big Rivers
ELECTRIC CORPORATION

CORPORATE SCORECARD
January 2012

Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2012 Target
Financial	North Star	C. Warren	Member Cost/kWh	0.044971	0.044971	YTD	0.046922	0.050925
	Capital Expenditures	J. Williams	Aggregate Capital Expenditures	$2,313,915	$2,313,915	YTD	$2,053,214	$86,939,631
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt		1.17	12M	1.15	1.10
					1.54	YTD	2.13	1.10
	Net Margin	C. Warren	Revenues less Expenses	$2,051,591	$2,051,591	YTD	$4,267,210	$6,697,096
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$19,638,255	12M		$22,000,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.370	12M		0.370
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$654,528	12M		$645,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.340	12M		0.420
Production	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs + Forced Outage Hrs	0.7	0.7	YTD	5.9	5.5
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	98.4	98.4	YTD	94.1	88.3
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.040	12M		0.541
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		0.971	12M		0.741
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.127	12M		1.013
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.318	12M		1.013
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	0	YTD	0.083	1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	1	1	YTD	0.75	9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.98	YTD		1.49

Performing At or Better than Target

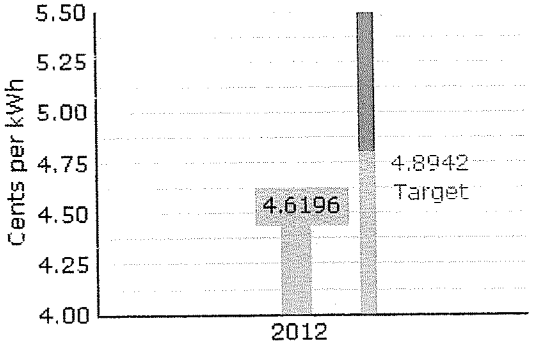
Performing Worse than Target

Performance is measured against YTD targets/budgets when available.

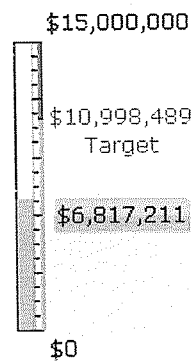
Big Rivers
ELECTRIC CORPORATION

CORPORATE DASHBOARD
February 2012

NORTH STAR
Member Cost/kWh YTD

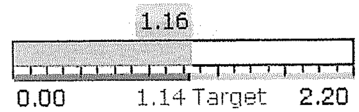


CAPITAL EXPENDITURES
YTD

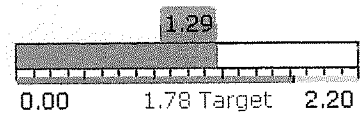


TIMES INTEREST EARNED RATIO (TIER)

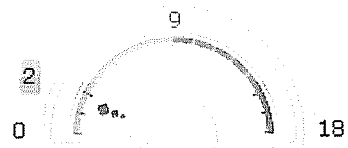
12 MONTHS ENDING



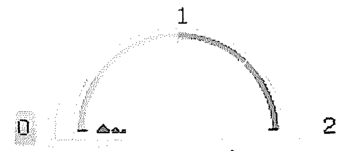
YEAR-TO-DATE



SAFETY



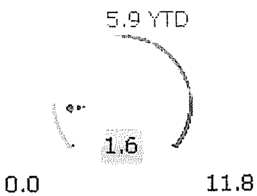
OSHA Recordable Incidents



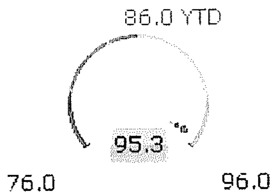
Lost-Time Incidents

PLANT PERFORMANCE
YTD

Equivalent Forced Outage Rate (EFOR)



Equivalent Availability Factor (EAF)



Combined Heat Rate

[redacted]

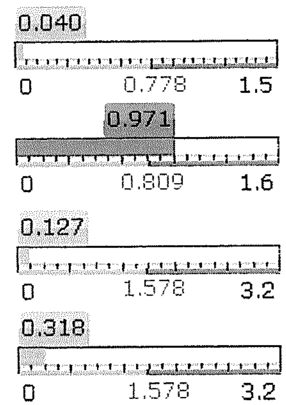
TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING

Jackson Purchase Energy Corporation

Meade County RECC

Kenergy Corp.

System Wide



Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Big Rivers
ELECTRIC CORPORATION

CORPORATE SCORECARD
February 2012

Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2012 Target
Financial	North Star	C. Warren	Member Cost/kWh	0.047528	0.046196	YTD	0.048942	0.050925
	Capital Expenditures	J. Williams	Aggregate Capital Expenditures	$4,503,296	$6,817,211	YTD	$10,998,489	$86,939,631
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt		1.16	12M	1.14	1.10
					1.29	YTD	1.78	1.10
	Net Margin	C. Warren	Revenues less Expenses	$93,429	$2,145,020	YTD	$5,717,550	$6,697,096
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$22,216,209	12M		$22,000,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.390	12M		0.370
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$654,528	12M		$645,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.310	12M		0.420
Production	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs +Forced Outage Hrs	2.5	1.6	YTD	5.9	5.5
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	92.0	95.3	YTD	86.0	88.3
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.040	12M		0.541
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		0.971	12M		0.741
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.127	12M		1.013
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.318	12M		1.013
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	0	YTD	0.167	1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	1	2	YTD	1.5	9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.94	YTD		1.49

Performing At or Better than Target

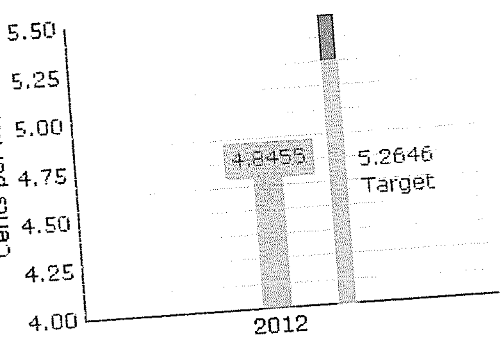
Performing Worse than Target

Performance is measured against YTD targets/budgets when available

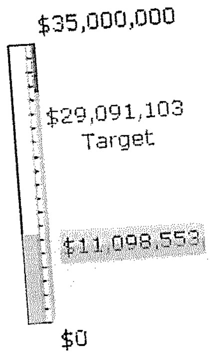
Big Rivers
ELECTRIC CORPORATION

CORPORATE DASHBOARD
March 2012

NORTH STAR
Member Cost/kWh YTD

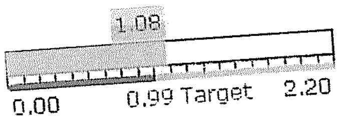


CAPITAL EXPENDITURES
YTD

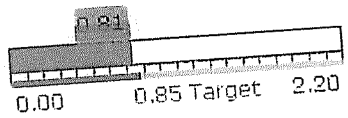


TIMES INTEREST EARNED RATIO (TIER)

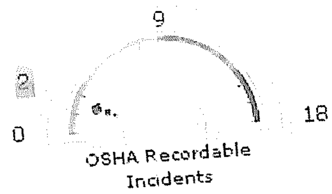
12 MONTHS ENDING

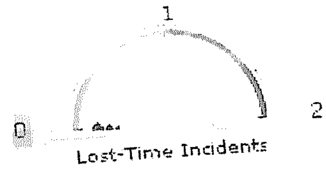


YEAR-TO-DATE

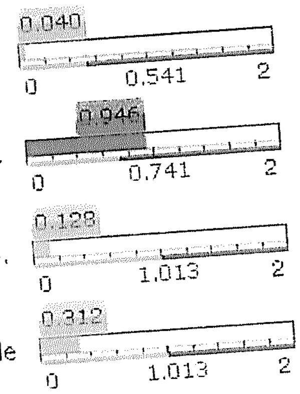


SAFETY

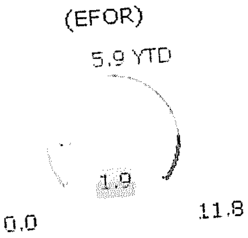


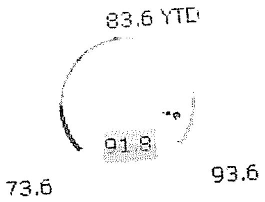


TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING



PLANT PERFORMANCE
YTD





Combined Heat Rate

[redacted]

Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert

Big Rivers ELECTRIC CORPORATION

CORPORATE SCORECARD
March 2012

Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2012 Target
Financial	North Star	C. Warren	Member Cost/kWh	0.053065	0.048455	YTD	0.052646	0.050925
	Capital Expenditures	J. Williams	Aggregate Capital Expenditures	$4,281,342	$11,098,553	YTD	$29,091,103	$86,939,631
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt		1.08		0.99	1.10
					0.81		0.85	1.10
	Net Margin	C. Warren	Revenues less Expenses	($4,248,534)	($2,103,514)	YTD	($1,641,413)	$6,697,096
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$19,802,398	12M		$22,000,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.390	12M		0.370
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$686,186	12M		$645,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.310	12M		0.420
Production	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs + Forced Outage Hrs	2.6	1.9	YTD	5.9	5.5
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	85.1	91.8	YTD	83.6	88.3
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.040	12M		0.541
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		0.946	12M		0.741
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.128	12M		1.013
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.312	12M		1.013
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	0	YTD	0.250	1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	0	2	YTD	2.25	9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.26	YTD		1.49

Performing At or Better than Target

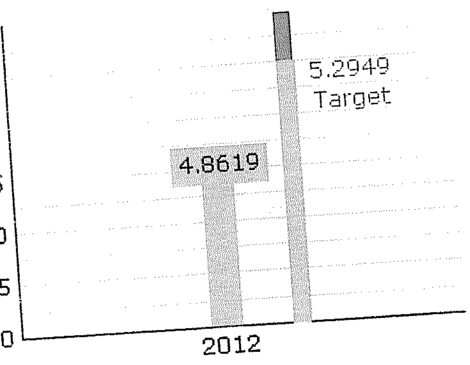
Performing Worse than Target

Performance is measured against YTD targets/budgets when available.

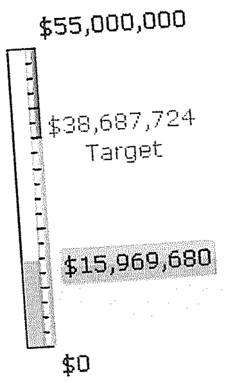
Big Rivers ELECTRIC CORPORATION

CORPORATE DASHBOARD
April 2012

NORTH STAR
Member Cost/kWh YTD

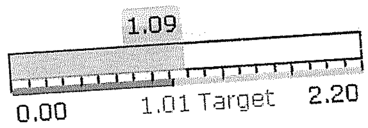


CAPITAL EXPENDITURES
YTD

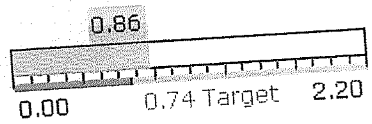


TIMES INTEREST EARNED RATIO (TIER)

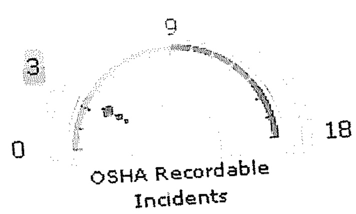
12 MONTHS ENDING

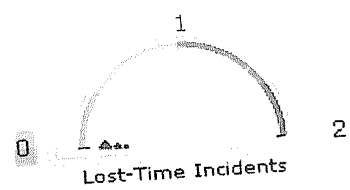


YEAR-TO-DATE

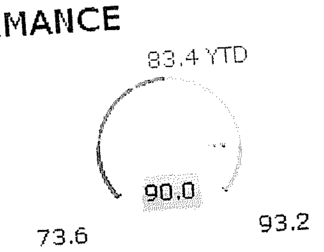


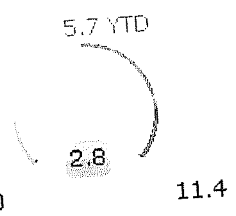
SAFETY





NT PERFORMANCE
YTD

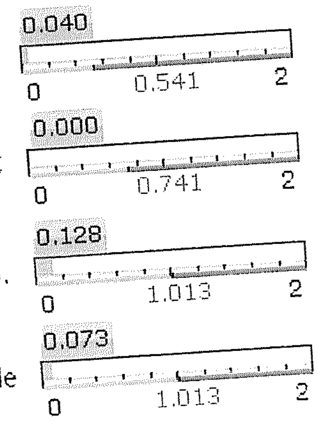




Combined Heat Rate

[redacted]

TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING



Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert

3ig Rivers
ELECTRIC CORPORATION

CORPORATE SCORECARD
April 2012

ea ocus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2012 Target
	North Star	C. Warren	Member Cost/kWh	0.049140	0.048619	YTD	0.052949	0.050925
	Capital Expenditures	J. Williams	Aggregate Capital Expenditures	$4,871,127	$15,969,680	YTD	$38,687,724	$86,939,631
ancial	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt		1.09	12M	1.01	1.10
					0.86	YTD	0.74	1.10
	Net Margin	C. Warren	Revenues less Expenses	$21,512	($2,082,002)	YTD	($3,809,920)	$6,697,096
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$19,861,752	12M		$22,000,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.417	12M		0.370
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$697,628	12M		$645,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.353	12M		0.420
roduction	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs + Forced Outage Hrs	5.4	2.8	YTD	5.7	5.5
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	85.2	90.0	YTD	83.4	88.3
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.040	12M		0.541
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		0.000	12M		0.741
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.128	12M		1.013
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.073	12M		1.013
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident	0	0	YTD	0.333	1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work	1	3	YTD	3	9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.44	YTD		1.49

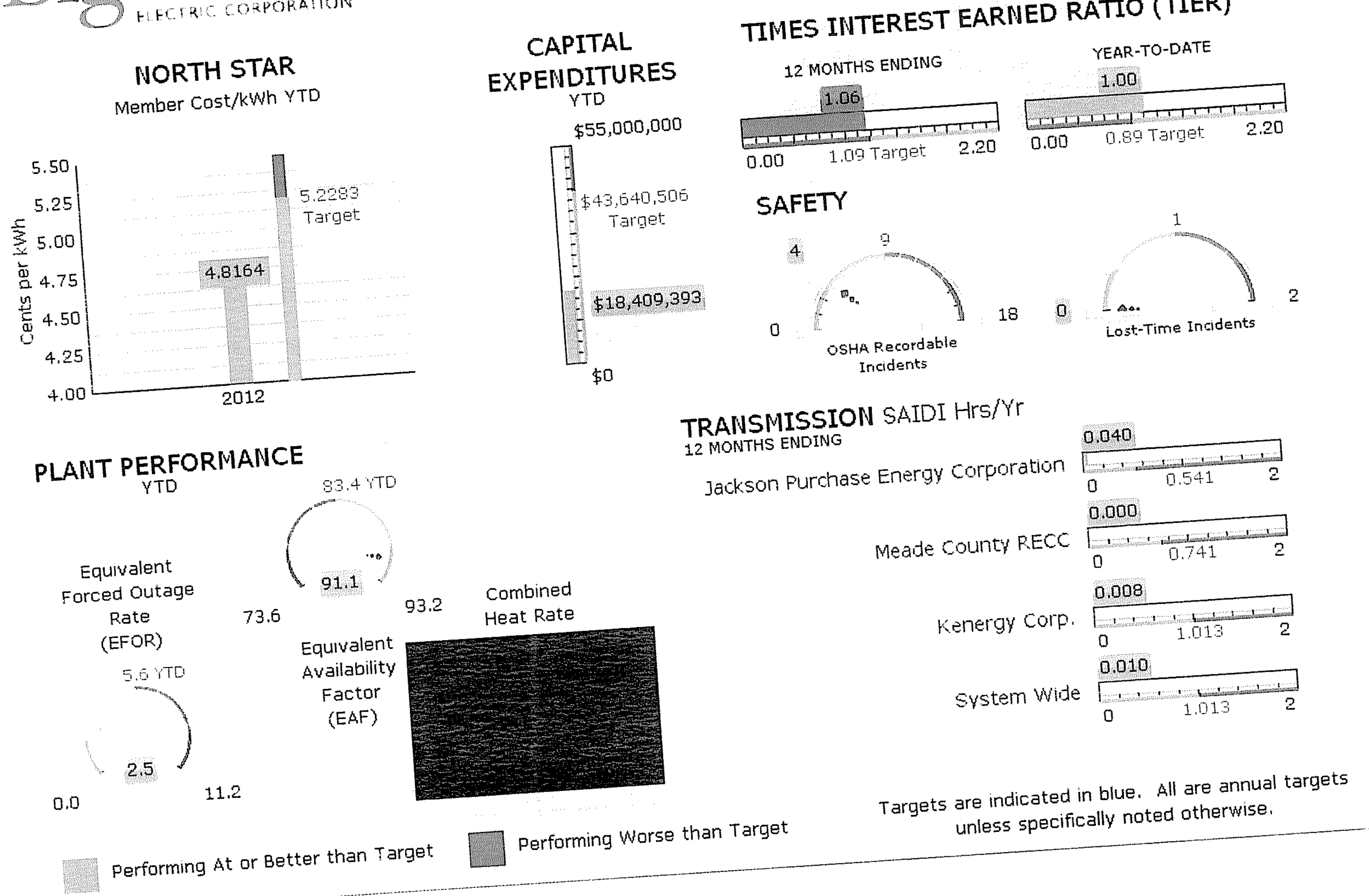
Performance is measured against YTD targets/budgets when available.

Performing At or Better than Target

Performing Worse than Target

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert

CORPORATE DASHBOARD
May 2012



Case No. 2012-00535
Attachment for Response to AG 2-13(a)
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Page 1 of 2

Big Rivers ELECTRIC CORPORATION

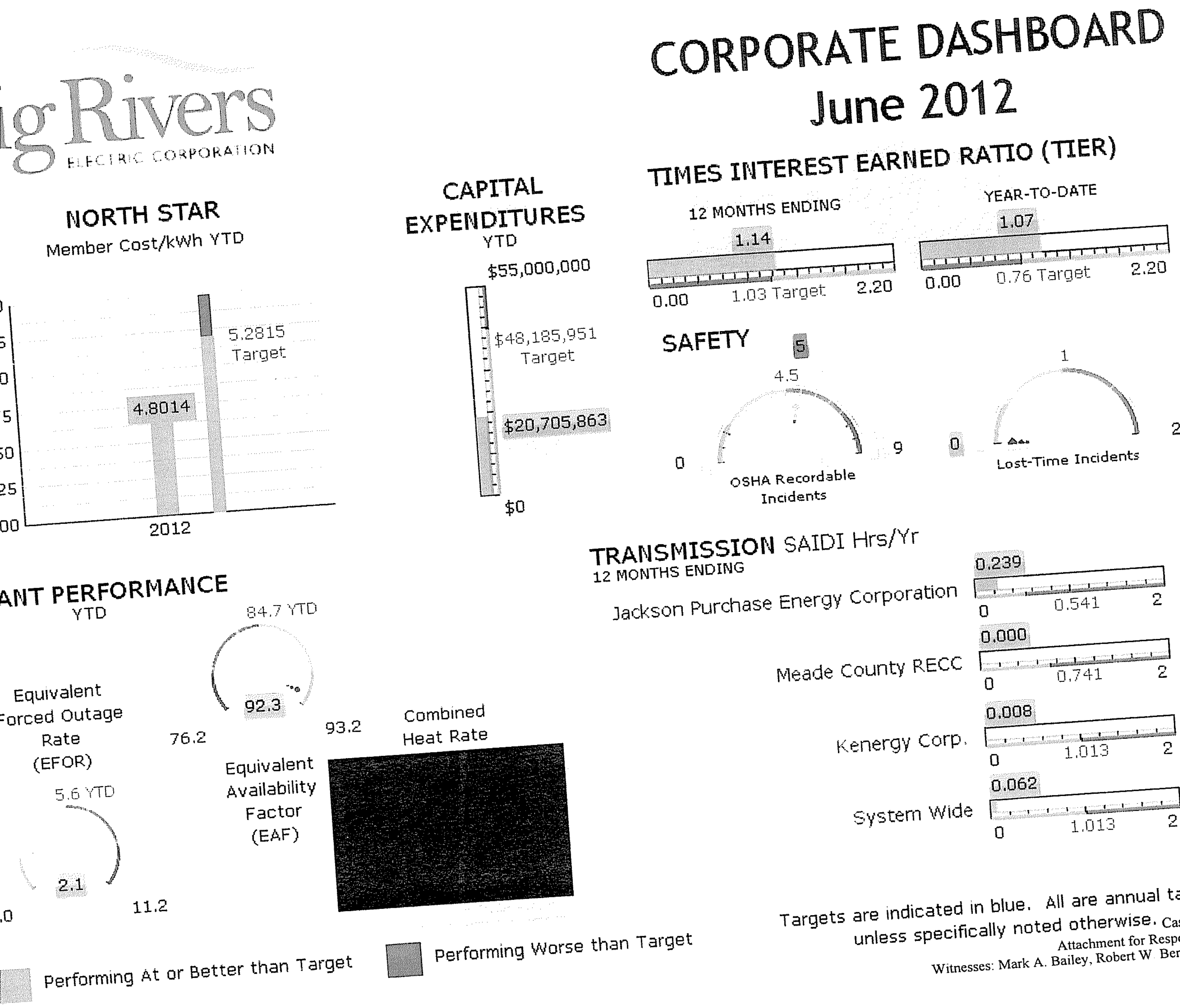
CORPORATE SCORECARD
May 2012

Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2012 Target
	North Star	C. Warren	Member Cost/kWh	0.046393	0.048164	YTD	0.052283	0.050925
	Capital Expenditures	J. Williams	Aggregate Capital Expenditures	$2,439,713	$18,409,393	YTD	$43,640,506	$86,939,631
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt		1.06	12M	1.09	1.10
					1.00	YTD	0.89	1.10
Financial	Net Margin	C. Warren	Revenues less Expenses	$2,012,892	($69,110)	YTD	($2,079,657)	$6,697,096
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$22,473,058	12M		$22,000,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.040	12M		0.370
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$708,786	12M		$645,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.350	12M		0.420
Production	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs + Forced Outage Hrs	1.3	2.5	YTD	5.6	5.5
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	94.7	91.1	YTD	83.4	88.3
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.040	12M		0.541
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		0.000	12M		0.741
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.008	12M		1.013
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.010	12M		1.013
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	0	YTD	0.417	1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work	1	4	YTD	3.75	9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.54	YTD		1.49

Performing At or Better than Target

Performing Worse than Target

Performance is measured against YTD targets/budgets when available.



Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W Berry, Billie J. Richert
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Big Rivers ELECTRIC CORPORATION

CORPORATE SCORECARD
June 2012

rea ocus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2012 Target
nancial	North Star	C. Warren	Member Cost/kWh	0.047278	0.048014	YTD	0.052815	0.050925
	Capital Expenditures	J. Williams	Aggregate Capital Expenditures	$2,296,470	$20,705,863	YTD	$48,185,951	$86,939,631
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt		1.14	12M	1.03	1.10
					1.07	YTD	0.76	1.10
	Net Margin	C. Warren	Revenues less Expenses	$1,704,480	$1,635,370	YTD	($5,401,698)	$6,697,096
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$22,559,493	12M		$22,000,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.370	12M		0.370
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$721,060	12M		$645,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.340	12M		0.420
roduction	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs +Forced Outage Hrs	0.5	2.1	YTD	5.6	5.5
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	98.2	92.3	YTD	84.7	88.3
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.239	12M		0.541
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		0.000	12M		0.741
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.008	12M		1.013
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.062	12M		1.013
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident	0	0	YTD	0.500	1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0.00	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work	1	5	YTD	4.5	9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.61	YTD		1.49

Performing At or Better than Target   Performing Worse than Target

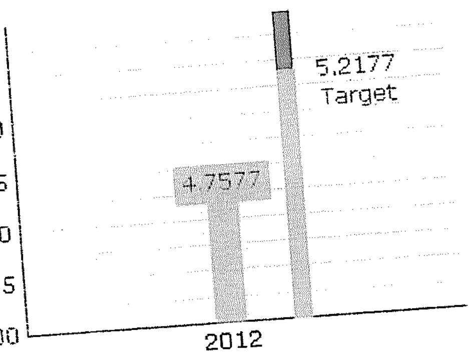
Performance is measured against YTD targets/budgets when available.

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert

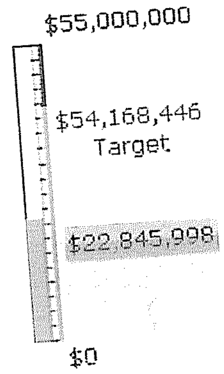
g Rivers
ELECTRIC CORPORATION

CORPORATE DASHBOARD
July 2012

NORTH STAR
Member Cost/kWh YTD

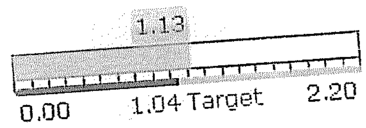


CAPITAL EXPENDITURES
YTD

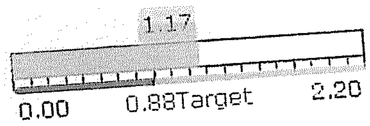


TIMES INTEREST EARNED RATIO (TIER)

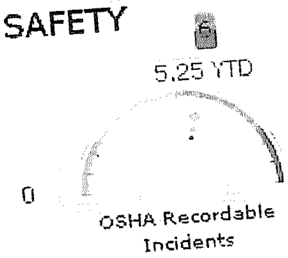
12 MONTHS ENDING

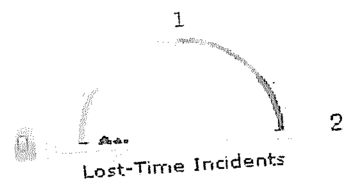


YEAR-TO-DATE

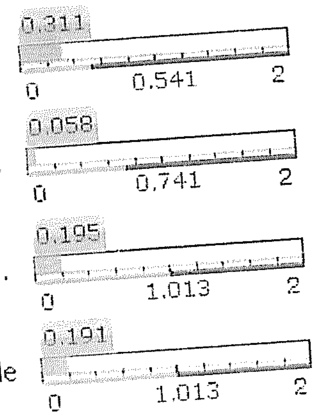


SAFETY



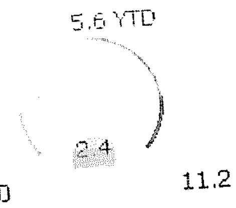


TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING

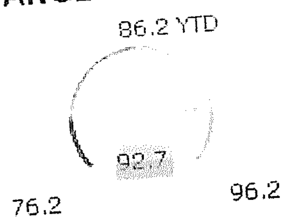


ANT PERFORMANCE
YTD

Equivalent Forced Outage Rate (EFOR)



Equivalent Availability Factor (EAF)



Combined Heat Rate

[redacted]

Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Case No. 2012-00535
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Big Rivers ELECTRIC CORPORATION

CORPORATE SCORECARD
July 2012

ea ocus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2012 Target
	North Star	C. Warren	Member Cost/kWh	0.045211	0.047577	YTD	0.052177	0.050925
	Capital Expenditures	J. Williams	Aggregate Capital Expenditures	$2,140,135	$22,845,998	YTD	$54,168,446	$86,939,631
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt		1.13 1.17	YTD	1.04 0.88	1.10 1.10
nancial	Net Margin	C. Warren	Revenues less Expenses	$2,773,009	$4,408,380	YTD	($3,231,453)	$6,697,096
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$20,114,838	12M		$22,000,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.370	12M		0.370
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$734,076	12M		$645,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.310	12M		0.420
	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs +Forced Outage Hrs	3.7	2.4	YTD	5.6	5.5
Production	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	95.1	92.7	YTD	86.2	88.3
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.311	12M		0.541
Members' Reliability	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		0.058	12M		0.741
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.195	12M		1.013
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.191	12M		1.013
	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	0	YTD	0.583	1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0.00	YTD		0.17
Safety	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	1	6	YTD	5.25	9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.66	YTD		1.49

Performance is measured against YTD targets/budgets when available.

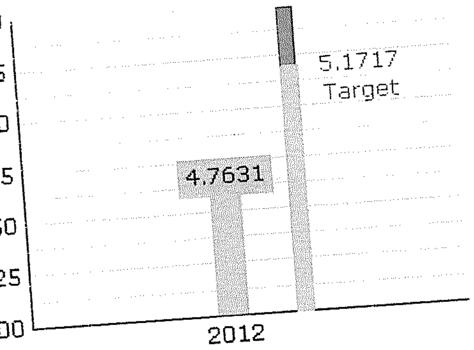
Performing At or Better than Target

Performing Worse than Target

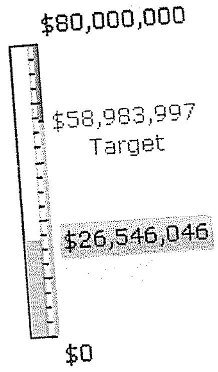
Big Rivers Electric Corporation

CORPORATE DASHBOARD
August 2012

NORTH STAR
Member Cost/kWh YTD

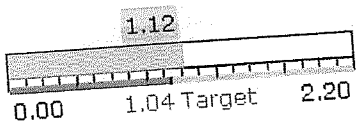


CAPITAL EXPENDITURES
YTD

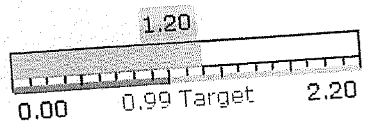


TIMES INTEREST EARNED RATIO (TIER)

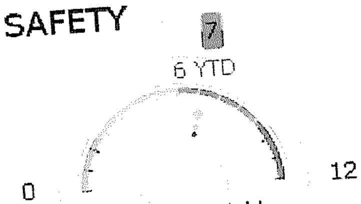
12 MONTHS ENDING

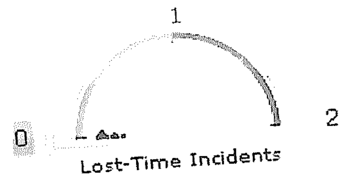


YEAR-TO-DATE

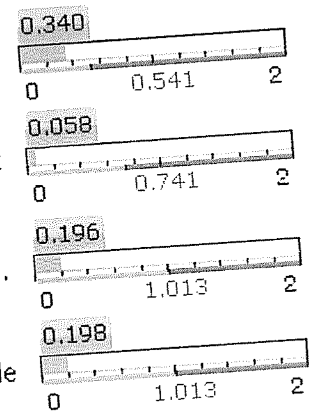


SAFETY



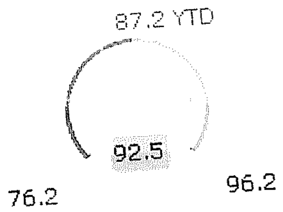


TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING

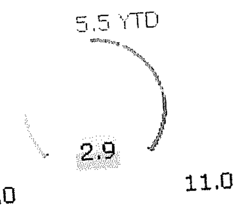


PLANT PERFORMANCE
YTD

Equivalent Availability Factor (EAF)



Equivalent Forced Outage Rate (EFOR)



Combined Heat Rate

[redacted]

Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

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Big Rivers ELECTRIC CORPORATION

CORPORATE SCORECARD
August 2012

Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2012 Target
	North Star	C. Warren	Member Cost/kWh	0.047998	0.047631	YTD	0.051717	0.050925
	Capital Expenditures	J. Williams	Aggregate Capital Expenditures	$3,700,048	$26,546,046	YTD	$58,983,997	$86,939,631
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt		1.12	12M	1.04	1.10
					1.20	YTD	0.99	1.10
Financial	Net Margin	C. Warren	Revenues less Expenses	$1,481,610	$5,889,990	YTD	($176,258)	$6,697,096
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$22,692,790	12M		$22,000,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.370	12M		0.370
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$643,829	12M		$645,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.350	12M		0.420
	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs +Forced Outage Hrs	6.4	2.9	YTD	5.5	5.5
Production	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	91.5	92.5	YTD	87.2	88.3
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.340	12M		0.541
Members' Reliability	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		0.058	12M		0.741
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.196	12M		1.013
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.198	12M		1.013
	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	0	YTD	0.667	1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0.00	YTD		0.17
Safety	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work	1	7	YTD	6	9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.69	YTD		1.49

Performing At or Better than Target

Performing Worse than Target

Performance is measured against YTD targets/budgets when available.

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert

g Rivers
ELECTRIC CORPORATION

CORPORATE DASHBOARD
September 2012

NORTH STAR
Member Cost/kWh YTD

4.7550

5.1468
Target

2012

CAPITAL EXPENDITURES
YTD

$80,000,000

$63,398,666
Target

$29,421,909

$0

TIMES INTEREST EARNED RATIO (TIER)

12 MONTHS ENDING

1.11

0.00 1.05 Target 2.20

YEAR-TO-DATE

1.24

0.00 1.03 Target 2.20

SAFETY

7

6.75 YTD

0 9

OSHA Recordable Incidents

0

1

2

Lost-Time Incidents

TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING

Jackson Purchase Energy Corporation
0.713
0 0.541 2

Meade County RECC
0.058
0 0.741 2

Kenergy Corp.
0.196
0 1.013 2

System Wide
0.295
0 1.013 2

ANT PERFORMANCE
YTD

Equivalent
orced Outage
Rate
(EFOR)

5.5 YTD

3.0

0 11.0

87.8 YTD

92.8

79.8 95.8

Equivalent
Availability
Factor
(EAF)

Combined
Heat Rate

[redacted]

Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

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Big Rivers
ELECTRIC CORPORATION

CORPORATE SCORECARD
September 2012

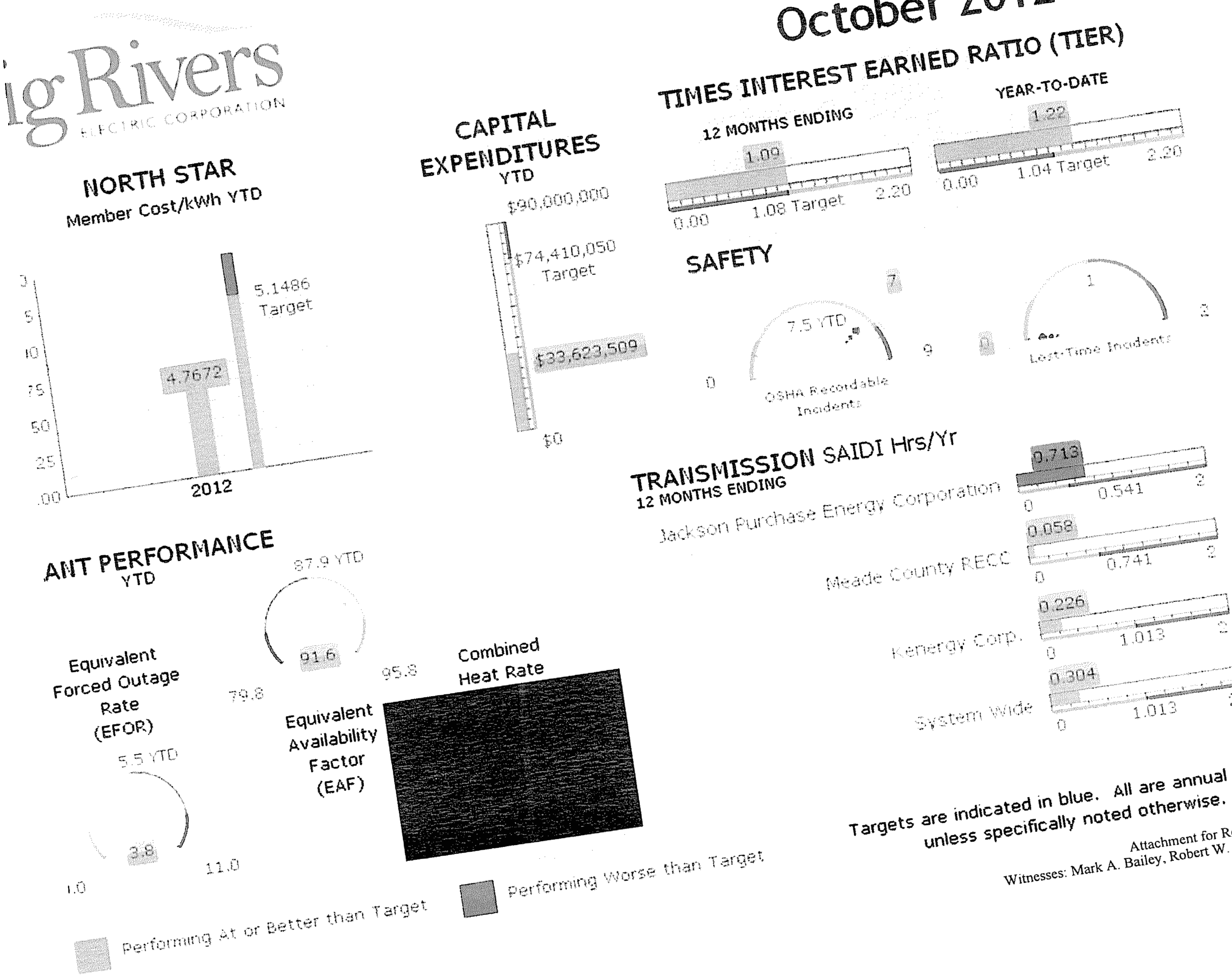
rea Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2012 Target
	North Star	C. Warren	Member Cost/kWh	0.046865	0.047550	YTD	0.051468	0.050925
	Capital Expenditures	J. Williams	Aggregate Capital Expenditures	$2,875,863	$29,421,909	YTD	$63,398,666	$86,939,631
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt		1.11	12M	1.05	1.10
					1.24	YTD	1.03	1.10
inancial	Net Margin	C. Warren	Revenues less Expenses	$2,235,673	$8,125,663	YTD	$1,051,991	$6,697,096
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$22,764,101	12M		$22,000,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.350	12M		0.370
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$755,418	12M		$645,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.390	12M		0.420
Production	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs +Forced Outage Hrs	3.9	3.0	YTD	5.5	5.5
	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	95.3	92.8	YTD	87.8	88.3
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
Members' Reliability	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.713	12M		0.541
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		0.058	12M		0.741
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.196	12M		1.013
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.295	12M		1.013
Safety	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident	0	0	YTD	0.75	1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0.00	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work	0	7	YTD	6.75	9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.51	YTD		1.49

Performance is measured against YTD targets/budgets when available.

Performing At or Better than Target

Performing Worse than Target

CORPORATE DASHBOARD
October 2012



Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

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Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert

Big Rivers ELECTRIC CORPORATION

CORPORATE SCORECARD
October 2012

Area of Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2012 Target
	North Star	C. Warren	Member Cost/kWh	0.048801	0.047672	YTD	0.051486	0.050925
	Capital Expenditures	J. Williams	Aggregate Capital Expenditures	$4,201,600	$33,623,509	YTD	$74,410,050	$86,939,631
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt		1.09	12M	1.08	1.10
					1.22	YTD	1.04	1.10
Financial	Net Margin	C. Warren	Revenues less Expenses	($3,231)	$8,122,431	YTD	$1,337,682	$6,697,096
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$22,804,037	12M		$22,000,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.360	12M		0.370
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$770,247	12M		$645,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.480	12M		0.420
	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs + Forced Outage Hrs	10.2	3.8	YTD	5.5	5.5
Production	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	81.0	91.6	YTD	87.9	88.3
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.713	12M		0.541
Members' Reliability	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		0.058	12M		0.741
	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.226	12M		1.013
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.304	12M		1.013
	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident	0	0	YTD	0.83	1
Safety	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0.00	YTD		0.17
	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work	0	7	YTD	7.5	9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.36	YTD		1.49

Performance is measured against YTD targets/budgets when available.

Performing At or Better than Target

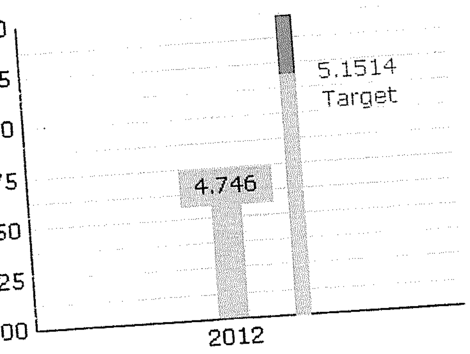
Performing Worse than Target

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert

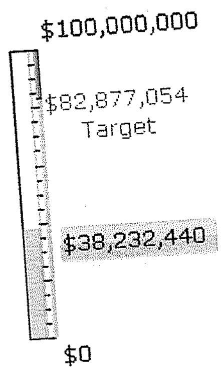
ig Rivers
ELECTRIC CORPORATION

CORPORATE DASHBOARD
November 2012

NORTH STAR
Member Cost/kWh YTD

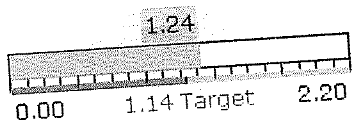


CAPITAL EXPENDITURES
YTD

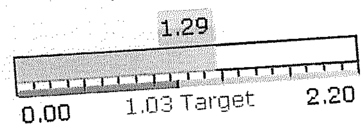


TIMES INTEREST EARNED RATIO (TIER)

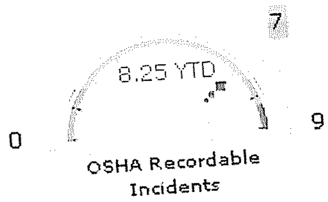
12 MONTHS ENDING

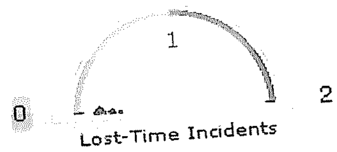


YEAR-TO-DATE

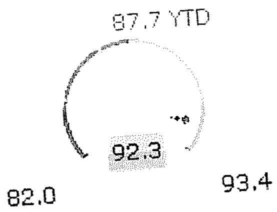


SAFETY

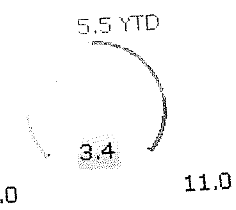




PLANT PERFORMANCE
YTD



Equivalent Availability Factor (EAF)

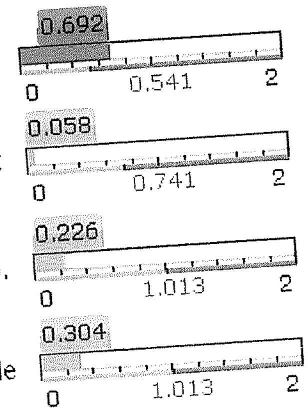


Equivalent Forced Outage Rate (EFOR)

Combined Heat Rate

[redacted]

TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING



Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Performing At or Better than Target

Performing Worse than Target

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert
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Big Rivers ELECTRIC CORPORATION

CORPORATE SCORECARD
November 2012

Focus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2012 Target
	North Star	C. Warren	Member Cost/kWh	0.045305	0.047461	YTD	0.051514	0.050925
	Capital Expenditures	J. Williams	Aggregate Capital Expenditures	$4,608,931	$38,232,440	YTD	$82,877,054	$86,939,631
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt		1.24	12M	1.14	1.10
					1.29	YTD	1.03	1.10
...cial	Net Margin	C. Warren	Revenues less Expenses	$3,902,883	$12,025,314	YTD	$1,311,181	$6,697,096
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$22,799,577	12M		$22,000,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.380	12M		0.370
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$778,269	12M		$645,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.490	12M		0.420
	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs + Forced Outage Hrs	0.4	3.4	YTD	5.5	5.5
...uction	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	98.4	92.3	YTD	87.7	88.3
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.692	12M		0.541
...embers'	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		0.058	12M		0.741
...liability	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.226	12M		1.013
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.304	12M		1.013
	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	0	YTD	0.92	1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0.00	YTD		0.17
Safety	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	0	7	YTD	8.25	9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.24	YTD		1.49

Performing At or Better than Target

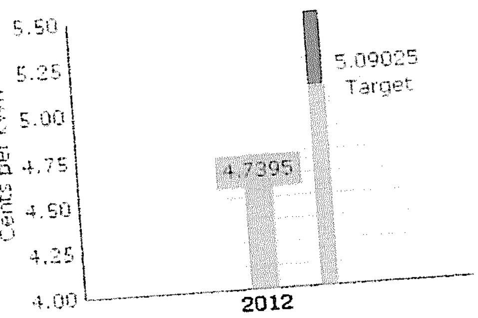
Performing Worse than Target

Performance is measured against YTD targets/budgets when available.

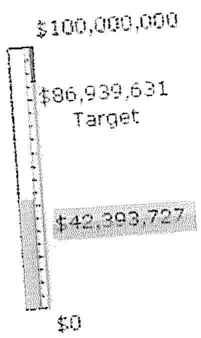
Big Rivers ELECTRIC CORPORATION

CORPORATE DASHBOARD
December 2012

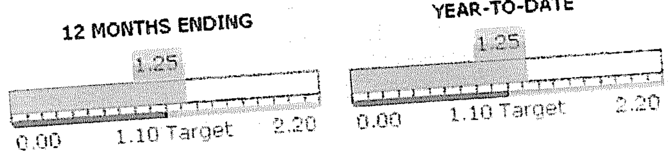
NORTH STAR
Member Cost/kWh



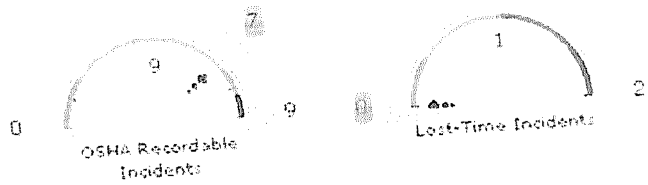
CAPITAL EXPENDITURES



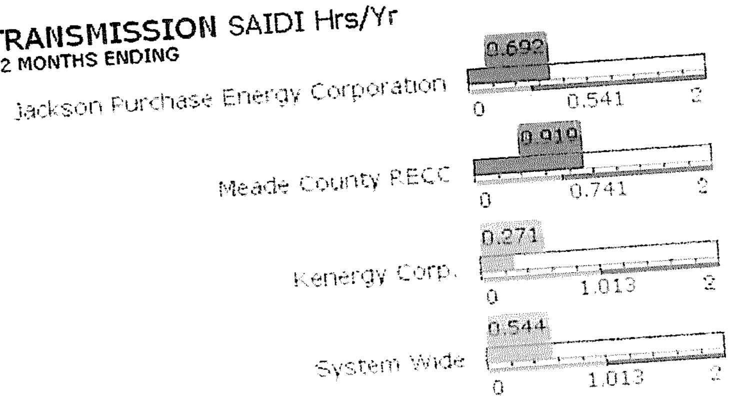
TIMES INTEREST EARNED RATIO (TIER)



SAFETY

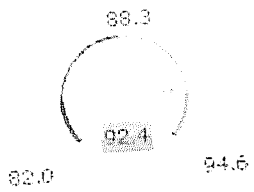


TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING

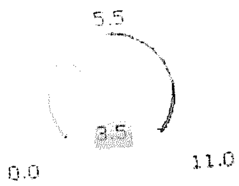


PLANT PERFORMANCE

Equivalent Availability Factor (EAF)



Equivalent Forced Outage Rate (EFOR)



Combined Heat Rate

[redacted]

Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Case No. 2012-00535
Attachment for Response to AG 2-13(a)
Witnesses: Mark A. Bailey, Robert W. Berry, Billie J. Richert
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Big Rivers ELECTRIC CORPORATION

CORPORATE SCORECARD
December 2012

a cus	Key Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2012 Target
	North Star	C. Warren	Member Cost/kWh	0.046691	0.047395	YTD	0.050925	0.050925
	Capital Expenditures	J. Williams	Aggregate Capital Expenditures	$4,161,287	$42,393,727	YTD	$86,939,631	$86,939,631
	Times Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt		1.25	12M	1.10	1.10
					1.25	YTD	1.10	1.10
ncial	Net Margin	C. Warren	Revenues less Expenses		$11,277,091	YTD	$6,697,096	$6,697,096
	Production Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$22,298,404	12M		$22,000,000
	Production Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.370	12M		0.370
	Transmission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$848,650	12M		$645,000
	Transmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.470	12M		0.420
	Equivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs +Forced Outage Hrs	4.1	3.5	YTD	5.5	5.5
duction	Equivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	94.2	92.4	YTD	88.3	88.3
	Heat Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (KWHs)	[redacted]				
	SAIDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.692	12M		0.541
	SAIDI - Meade County	T. Tapp	Customer Hours of Interruption		0.919	12M		0.741
embers' eliability	SAIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.271	12M		1.013
	SAIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.544	12M		1.013
	Lost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	0	YTD	1	1
	Lost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked		0.00	YTD		0.17
Safety	OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	0	7	YTD	9	9
	OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked		1.24	YTD		1.49

Performance is measured against YTD targets/budgets when available.

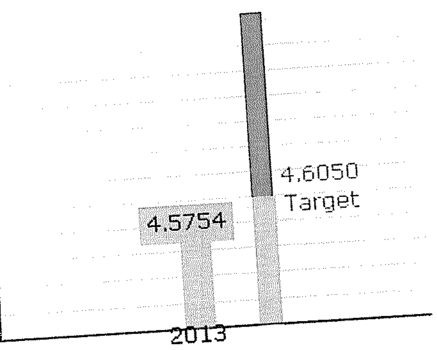
Performing At or Better than Target

Performing Worse than Target

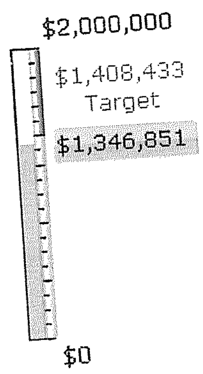
CORPORATE DASHBOARD
January 2013

Big Rivers ELECTRIC CORPORATION

NORTH STAR
Member Cost/kWh

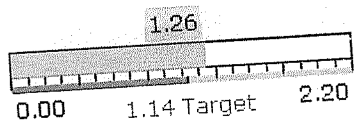


CAPITAL EXPENDITURES

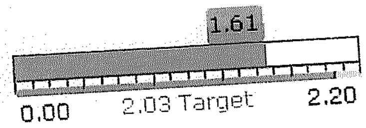


TIMES INTEREST EARNED RATIO (TIER)

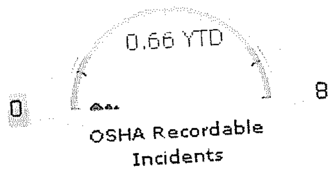
12 MONTHS ENDING

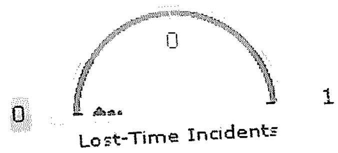


YEAR-TO-DATE

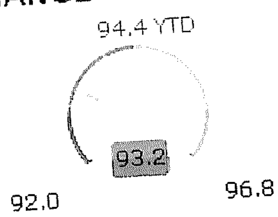


SAFETY



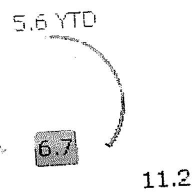


T PERFORMANCE



Equivalent Availability Factor (EAF)

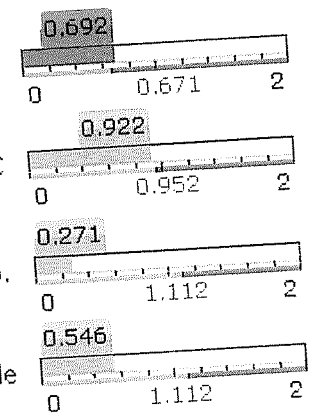
quivalent
ced Outage
Rate
(EFOR)



Combined Heat Rate

[redacted]

TRANSMISSION SAIDI Hrs/Yr
12 MONTHS ENDING



Performing At or Better than Target

Performing Worse than Target

Targets are indicated in blue. All are annual targets unless specifically noted otherwise.

Rivers
ELECTRIC CORPORATION

CORPORATE SCORECARD
January 2013

ey Performance Indicator	Responsible Party	Formula/Definition	Current Month	YTD or 12 mo. Ending		YTD Target/Budget	2013 Target
Star	C. Warren	Member Cost/kWh	0.045754	0.045754	YTD	0.046050	0.053136
l Expenditures	J. Williams	Aggregate Capital Expenditures	$1,346,851	$1,346,851	YTD	$1,408,433	$83,738,227
Interest Earned Ratio (TIER)	C. Warren	(Net Margins + Interest on LT Debt) / Interest on LT Debt	1.26	1.26	12M	1.14	1.10
			1.61	1.61	YTD	2.03	1.10
largin	C. Warren	Revenues less Expenses	$2,301,731	$2,301,731	YTD	$3,906,587	$4,946,073
uction Inventory	E. Harris	Production Inventory Balance (12 Mo. Avg.)		$22,800,479	12M		$22,000,000
uction Inventory Turnover	E. Harris	Turnover Rate of Production Inventory $		0.370	12M		0.370
smission Inventory	E. Harris	Transmission Inventory Balance (12 Mo. Avg.)		$795,989	12M		$800,000
ısmission Inventory Turnover	E. Harris	Turnover Rate of Transmission Inventory $		0.480	12M		0.470
iivalent Forced Outage Rate (EFOR)	Braunecker	Equiv. Forced Derated Hrs + Forced Outage Hrs / Service Hrs +Forced Outage Hrs	6.7	6.7	YTD	5.6	5.7
uivalent Availability Factor (EAF)	Braunecker	(Service Hrs + Res. Hrs) - Equiv. Unit Derated Hrs / Period Hrs	93.2	93.2	YTD	94.4	92.4
at Rate	Braunecker	Fuel Heating Value (BTUs) / Net Generation Produced (kWHs)	[redacted]				
IDI - Jackson Purchase	T. Tapp	Customer Hours of Interruption		0.692	12M		0.671
IDI - Meade County	T. Tapp	Customer Hours of Interruption		0.922	12M		0.952
AIDI - Kenergy	T. Tapp	Customer Hours of Interruption		0.271	12M		1.112
AIDI - System Wide	T. Tapp	Customer Hours of Interruption		0.546	12M		1.112
ost-time Incidents	T. Stovall	An injury or illness that causes an employee to miss one or more scheduled full workday(s) following the incident.	0	0	YTD	0	0
ost-time Incident Rates	T. Stovall	Number of Lost-Time Incidents x 200,000 / Number of Hours Worked	0	0.00	YTD	0.00	0.00
OSHA Recordables	T. Stovall	An injury or illness that results in medical attention beyond first aid and/or results in modified work duty and/or lost time from work.	0	0	YTD	0.66	8
OSHA Recordable Incident Rates	T. Stovall	Number of Recordable Incidents x 200,000 / Number of Hours Worked	0	0.00	YTD	0.11	1.33

Performance is measured against YTD targets/budgets when available.

Performing At or Better than Target

Performing Worse than Target

Big Rivers Electrical Corporation
Professional Services
Year-To-Date January 31, 2011

Vendor	Current Month	Year-to-Date
Black and Veatch Corp	1,254.88	1,254.88
Burns & McDonnell Engineering Co., Inc.	85,191.60	85,191.60
Fidelity Insitutional Operations Co., Inc.	3,750.00	3,750.00
GDS Associates Inc.	2,740.04	2,740.04
HR Solutions, Inc	5,220.25	5,220.25
McBrayer, McGinnis	2,200.00	2,200.00
Preston Osborne	9,325.00	9,325.00
Prime Group LLC/The	38,464.00	38,464.00
Total Professional Services for 0	**$ 148,145.77**	**$ 148,145.77**
Less: Amount charged to the Balance Sheet	**$ 2,948.23**	**2,948.23**
Total Professional Services Charged to the Income Statement	**$ 145,197.54**	**$ 145,197.54**
Less: Amount charged to Other Deductions	**$ 1,100.00**	**1,100.00**
Total Professional Services Charged to Administrative & General	**$ 144,097.54**	**$ 144,097.54**

Big Rivers Electric Corporation
Professional Services
Year-To-Date February 28, 2011

Vendor	Current Month	Year-to-Date
American Management Consulting	$ 13,446.68	$ 13,446.68
Black and Veatch Corp	0.00	1,254.88
Burns & McDonnell Engineering Co., Inc.	0.00	85,191.60
Fidelity Insitutional Operations Co., Inc.	0.00	3,750.00
GDS Associates Inc.	10,339.58	13,079.62
HR Solutions, Inc	5,652.50	10,872.75
Jerry T. Baker	5,212.40	5,212.40
KPMG LLP	21,046.00	21,046.00
Mercer Inc./Wm. M.	27,158.00	27,158.00
McBrayer, McGinnis	0.00	2,200.00
Navigant Consulting, Inc.	20,000.00	20,000.00
Preston Osborne	0.00	9,325.00
Prime Group LLC/The	37,976.06	76,440.06
Sullivan, Mountjoy, Stainback and Miller	86,658.94	86,658.94
Ziemer, Stayman, Weitzel	228.00	228.00
Total Professional Services for 0	**$ 227,718.16**	**$ 375,863.93**

Big Rivers Electric Corporation
Professional Services
Year-To-Date March 31, 2011

Vendor	Current Month	Year-to-Date
American Management Consulting	$ 14,850.15	$ 28,296.83
Black and Veatch Corp	32,106.98	33,361.86
Burns & McDonnell Engineering Co., Inc.	0.00	85,191.60
DB Consulting LLC	3,426.10	3,426.10
Fidelity Insitutional Operations Co., Inc.	0.00	3,750.00
GDS Associates Inc.	0.00	13,079.62
Hogan & Lovells, LLP	190,184.66	190,184.66
HR Solutions, Inc	6,606.78	17,479.53
Jerry T. Baker	1,059.00	6,271.40
KAEC	~~15,000.00~~	~~15,000.00~~
KPMG LLP	13,197.00	34,243.00
McBrayer, McGinnis	4,483.04	6,683.04
Mercer Inc./Wm. M.	9,667.00	36,825.00
Navigant Consulting, Inc.	0.00	20,000.00
Orrick, Herrington & Sutcliffe	2,527.79	2,527.79
Power Cost Inc./PCI	9,033.20	9,033.20
Preston Osborne	9,325.00	18,650.00
Prime Group LLC/The	74,503.98	150,944.04
Sullivan, Mountjoy, Stainback and Miller	96,882.79	183,541.73
Ziemer, Stayman, Weitzel	1,225.50	1,453.50
Total Professional Services for 0	**$ 484,078.97**	**$ 859,942.90**

Big Rivers Electric Corporation
Professional Fees
Year-To-Date April 30, 2011

Vendor	Current Month	Year-to-Date
.merican Management Consulting	$ 13,281.82	$ 41,578.65
Black and Veatch Corp	0.00	33,361.86
Burns & McDonnell Engineering Co., Inc.	0.00	85,191.60
Dana Thornberry Appraisals, LLC	4,950.00	4,950.00
DB Consulting LLC	2,492.17	5,918.27
Fidelity Insitutional Operations Co., Inc.	29,150.00	32,900.00
GDS Associates Inc.	17,832.44	30,912.06
Hogan & Lovells, LLP	122,920.32	313,104.98
HR Solutions, Inc	5,266.80	22,746.33
Jerry T. Baker	0.00	6,271.40
KAEC	0.00	15,000.00
KPMG LLP	7,025.00	41,268.00
McBrayer, McGinnis	2,234.83	8,917.87
ercer Inc./Wm. M.	11,165.00	47,990.00
Navigant Consulting, Inc.	0.00	20,000.00
Ohio Valley National Bank	28,518.96	28,518.96
Orrick, Herrington & Sutcliffe	10,510.89	13,038.68
Power Cost Inc./PCI	0.00	9,033.20
Preston Osborne	9,325.00	27,975.00
Prime Group LLC/The	19,978.96	170,923.00
Public Financial Management	25,000.00	25,000.00
Steptoe & Johnson LLP	7,240.50	7,240.50
Sullivan, Mountjoy, Stainback and Miller	77,970.60	261,512.33
Ziemer, Stayman, Weitzel	114.00	1,567.50
Total Professional Services for #REF!	**$ 394,977.29**	**$ 1,254,920.19**

Big Rivers Electric Corporation
Professional Services
Year-To-Date May 31, 2011

̦endor	Current Month	Year-to-Date
American Management Consulting	$ 17,181.62	$ 58,760.27
Black and Veatch Corp	0.00	33,361.86
Burns & McDonnell Engineering Co., Inc.	0.00	85,191.60
Dana Thornberry Appraisals, LLC	0.00	4,950.00
DB Consulting LLC	1,980.85	7,899.12
Fidelity Insitutional Operations Co., Inc.	0.00	32,900.00
GDS Associates Inc.	22,350.31	53,262.37
Hogan & Lovells, LLP	0.00	313,104.98
HR Solutions, Inc	3,411.46	26,157.79
Jerry T. Baker	0.00	6,271.40
KAEC	0.00	15,000.00
KPMG LLP	0.00	41,268.00
:cBrayer, McGinnis	0.00	8,917.87
Mercer Inc./Wm. M.	10,204.00	58,194.00
Navigant Consulting, Inc.	3,000.00	23,000.00
Ohio Valley National Bank	0.00	28,518.96
Orrick, Herrington & Sutcliffe	16,832.16	29,870.84
Power Cost Inc./PCI	0.00	9,033.20
Preston Osborne	9,000.00	36,975.00
Prime Group LLC/The	38,574.57	209,497.57
Public Financial Management	0.00	25,000.00
Southwest Power Pool	5,000.00	5,000.00
Steptoe & Johnson LLP	0.00	7,240.50
Sullivan, Mountjoy, Stainback and Miller	165,426.28	426,938.61
The Raleigh Company	3,000.00	3,000.00
	3,419.00	4,986.50

Big Rivers Electric Corporation
Professional Services
Year-To-Date June 30, 2011

.endor	Current Month	Year-to-Date
American Management Consulting	$ 19,869.11	$ 78,629.38
Black and Veatch Corp	45,333.58	78,695.44
Burns & McDonnell Engineering Co., Inc.	0.00	85,191.60
Dana Thornberry Appraisals, LLC	0.00	4,950.00
DB Consulting LLC	1,874.44	9,773.56
Fidelity Insitutional Operations Co., Inc.	0.00	32,900.00
GDS Associates Inc.	0.00	53,262.37
Hogan & Lovells, LLP	186,088.61	499,193.59
HR Solutions, Inc	0.00	26,157.79
Jerry T. Baker	0.00	6,271.40
KAEC	0.00	15,000.00
KPMG LLP	7,500.00	48,768.00
cBrayer, McGinnis	4,462.93	13,380.80
Mercer Inc./Wm. M.	0.00	58,194.00
Navigant Consulting, Inc.	0.00	23,000.00
Ohio Valley National Bank	0.00	28,518.96
Orrick, Herrington & Sutcliffe	2,703.93	32,574.77
Power Cost Inc./PCI	0.00	9,033.20
Preston Osborne	0.00	36,975.00
Prime Group LLC/The	74,201.12	283,698.69
Public Financial Management	0.00	25,000.00
Southwest Power Pool	0.00	5,000.00
Steptoe & Johnson LLP	0.00	7,240.50
Sullivan, Mountjoy, Stainback and Miller	101,492.98	528,431.59
The Raleigh Company	0.00	3,000.00
	228.00	5,214.50

Big Rivers Electric Corporation
Professional Services
Year-To-Date July 31, 2011

‹endor	Current Month	Year-to-Date
American Management Consulting	$ 20,390.86	$ 99,020.24
Black and Veatch Corp	0.00	78,695.44
Burns & McDonnell Engineering Co., Inc.	17,719.17	102,910.77
Dana Thornberry Appraisals, LLC	0.00	4,950.00
DB Consulting LLC	0.00	9,773.56
Fidelity Insitutional Operations Co., Inc.	19,925.00	52,825.00
GDS Associates Inc.	10,405.63	63,668.00
Hogan & Lovells, LLP	460,918.89	960,112.48
HR Solutions, Inc	0.00	26,157.79
Jerry T. Baker	0.00	6,271.40
KAEC	0.00	15,000.00
KPMG LLP	0.00	48,768.00
McBrayer, McGinnis	0.00	13,380.80
Mercer Inc./Wm. M.	6,506.00	64,700.00
avigant Consulting, Inc.	0.00	23,000.00
Neel, Crafton & Phillips	9,124.50	9,124.50
Ohio Valley National Bank	28,599.70	57,118.66
Orrick, Herrington & Sutcliffe	6,257.70	38,832.47
Power Cost Inc./PCI	0.00	9,033.20
Preston Osborne	27,325.00	64,300.00
Prime Group LLC/The	54,322.81	338,021.50
Public Financial Management	54,166.04	79,166.04
Southwest Power Pool	0.00	5,000.00
Steptoe & Johnson LLP	0.00	7,240.50
Sullivan, Mountjoy, Stainback and Miller	109,516.85	637,948.44
The Raleigh Company	0.00	3,000.00
Towers Watson Delaware Inc.	500.00	500.00
Ziemer, Stayman, Weitzel	513.00	5,727.50
Total Professional Services for 0	**$ 826,191.15**	**$ 2,824,246.29**

Big Rivers Electric Corporation
Professional Fees
Year-To-Date August 31, 2011

Vendor	Current Month	Year-to-Date
nerican Management Consulting	$ 2,700.00	$ 101,720.24
Black and Veatch Corp	30,000.00	108,695.44
The Brattle Group	1,575.00	1,575.00
Burns & McDonnell Engineering Co., Inc.	0.00	102,910.77
Dana Thornberry Appraisals, LLC	0.00	4,950.00
DB Consulting LLC	3,243.56	13,017.12
Fidelity Insitutional Operations Co., Inc.	0.00	52,825.00
GDS Associates Inc.	21,956.92	85,624.92
Hogan & Lovells, LLP	61,655.34	1,021,767.82
HR Solutions, Inc	0.00	26,157.79
Integrity Development Consultants	9,935.68	9,935.68
Jerry T. Baker	0.00	6,271.40
KAEC	0.00	15,000.00
KPMG LLP	0.00	48,768.00
McBrayer, McGinnis	4,472.00	17,852.80
Mercer Inc./Wm. M.	21,094.00	85,794.00
avigant Consulting, Inc.	0.00	23,000.00
Neel, Crafton & Phillips	31,500.00	40,624.50
Ohio Valley National Bank	0.00	57,118.66
Orrick, Herrington & Sutcliffe	0.00	38,832.47
Power Cost Inc./PCI	0.00	9,033.20
Preston Osborne	0.00	64,300.00
Prime Group LLC/The	7,962.50	345,984.00
Public Financial Management	0.00	79,166.04
Southwest Power Pool	0.00	5,000.00
Steptoe & Johnson LLP	0.00	7,240.50
Sullivan, Mountjoy, Stainback and Miller	29,601.00	667,549.44
The Raleigh Company	0.00	3,000.00
Towers Watson Delaware Inc.	0.00	500.00
Ziemer, Stayman, Weitzel	0.00	5,727.50
Total Professional Services for	**$ 225,696.00**	**$ 3,049,942.29**

Big Rivers Electric Corporation
Professional Services
Year-To-Date September 30, 2011

Vendor		Current Month		Year-to-Date
American Management Consulting	$	14,749.65	$	116,469.89
Black and Veatch Corp		0.00		108,695.44
The Brattle Group		0.00		1,575.00
Burns & McDonnell Engineering Co., Inc.		8,615.21		111,525.98
Cardwell Energy Associates Inc.		9,750.00		9,750.00
Dana Thornberry Appraisals, LLC		0.00		4,950.00
DB Consulting LLC		2,059.49		15,076.61
Fidelity Insitutional Operations Co., Inc.		0.00		52,825.00
GDS Associates Inc		4,460.12		90,085.04
Hogan & Lovells, LLP		0.00		1,021,767.82
HR Solutions, Inc		0.00		26,157.79
Integrity Development Consultants		2,422.50		12,358.18
Jerry T. Baker		0.00		6,271.40
KAEC		0.00		15,000.00
KPMG LLP		57,500.00		106,268.00
McBrayer, McGinnis		0.00		17,852.80
Mercer Inc /Wm. M.		23,255.00		109,049.00
Navigant Consulting, Inc.		0.00		23,000.00
Neel, Crafton & Phillips		4,475.50		45,100.00
Ohio Valley National Bank		0.00		57,118.66
Orrick, Herrington & Sutcliffe		1,517.72		40,350.19
Power Cost Inc /PCI		0.00		9,033.20
Preston Osborne		0.00		64,300.00
Prime Group LLC/The		1,200.00		347,184.00
Public Financial Management		0.00		79,166.04
Southwest Power Pool		0.00		5,000.00
Steptoe & Johnson LLP		0.00		7,240.50
Sullivan, Mountjoy, Stainback and Miller		62,889.50		730,438.94
The Raleigh Company		0.00		3,000.00
Towers Watson Delaware Inc.		0.00		500.00
Ziemer, Stayman, Weitzel		7,581.00		13,308.50

Big Rivers Electric Corporation
Professional Services
Year-To-Date October 31, 2011

ndor	Current Month	Year-to-Date
American Management Consulting	$ 10,626.09	$ 127,095.98
Black and Veatch Corp	0.00	108,695.44
The Brattle Group	0.00	1,575.00
Burns & McDonnell Engineering Co., Inc.	0.00	111,525.98
Cardwell Energy Associates Inc.	0.00	9,750.00
Dana Thornberry Appraisals, LLC	0.00	4,950.00
DB Consulting LLC	889.51	15,966.12
Fidelity Insitutional Operations Co., Inc.	20,275.00	73,100.00
GDS Associates Inc.	819.50	90,904.54
Hogan & Lovells, LLP	16,790.82	1,038,558.64
HR Solutions, Inc	0.00	26,157.79
Integrity Development Consultants	1,857.50	14,215.68
Jerry T. Baker	0.00	6,271.40
KAEC	0.00	15,000.00
KPMG LLP	0.00	106,268.00
:Brayer, McGinnis	2,036.00	19,888.80
Mercer Inc./Wm. M.	21,640.00	130,689.00
Navigant Consulting, Inc.	0.00	23,000.00
Neel, Crafton & Phillips	10,500.00	55,600.00
Ohio Valley National Bank	0.00	57,118.66
Orrick, Herrington & Sutcliffe	4,253.57	44,603.76
Power Cost Inc./PCI	0.00	9,033.20
Preston Osborne	9,000.00	73,300.00
Prime Group LLC/The	2,112.50	349,296.50
Public Financial Management	0.00	79,166.04
Southwest Power Pool	0.00	5,000.00
Steptoe & Johnson LLP	0.00	7,240.50
Sullivan, Mountjoy, Stainback and Miller	64,210.95	794,649.89
The Raleigh Company	0.00	3,000.00
Towers Watson Delaware Inc.	0.00	500.00
[illegible]	4,627.12	17,935.62

Big Rivers Electric Corporation
Professional Services
Year-To-Date November 30, 2011

Vendor		Current Month		Year-to-Date
American Management Consulting	$	32,737.32	$	159,833.30
Black and Veatch Corp		0.00		108,695.44
The Brattle Group		0.00		1,575.00
Burns & McDonnell Engineering Co., Inc.		0.00		111,525.98
Cardwell Energy Associates Inc.		0.00		9,750.00
Dana Thornberry Appraisals, LLC		0.00		4,950.00
DB Consulting LLC		1,696.94		17,663.06
Fidelity Insitutional Operations Co., Inc.		0.00		73,100.00
GDS Associates Inc.		660.00		91,564.54
Hogan & Lovells, LLP		8,055.80		1,046,614.44
HR Solutions, Inc		0.00		26,157.79
Integrity Development Consultants		1,436.00		15,651.68
Jerry T. Baker		0.00		6,271.40
KAEC		0.00		15,000.00
L ROBERT KIMBALL		50,512.00		50,512.00
KPMG LLP		0.00		106,268.00
McBrayer, McGinnis		4,472.00		24,360.80
Mercer Inc./Wm. M.		33,188.00		163,877.00
Navigant Consulting, Inc.		0.00		23,000.00
Neel, Crafton & Phillips		0.00		55,600.00
Ohio Valley National Bank		0.00		57,118.66
Orrick, Herrington & Sutcliffe		0.00		44,603.76
Power Cost Inc./PCI		0.00		9,033.20
Preston Osborne		0.00		73,300.00
Prime Group LLC/The		17,658.40		366,954.90
Public Financial Management		0.00		79,166.04
Southwest Power Pool		(614.12)		4,385.88
Steptoe & Johnson LLP		0.00		7,240.50
Sullivan, Mountjoy, Stainback and Miller		37,582.59		832,232.48
The Raleigh Company		0.00		3,000.00
Towers Watson Delaware Inc.		0.00		500.00
Ziemer, Stayman, Weitzel		7,543.68		25,479.30
		194,928.61	$	**3,614,985.15**

Big Rivers Electric Corporation
Professional Services
Year-To-Date December 31, 2011

Vendor	Current Month	Year-to-Date
American Management Consulting	$ 10,169.12	$ 170,002.42
Black and Veatch Corp	0.00	108,695.44
The Brattle Group	0.00	1,575.00
Burns & McDonnell Engineering Co., Inc.	0.00	111,525.98
Cardwell Energy Associates Inc.	6,500.00	16,250.00
Dana Thornberry Appraisals, LLC	0.00	4,950.00
DB Consulting LLC	1,722.43	19,385.49
Fidelity Insitutional Operations Co., Inc.	0.00	73,100.00
GDS Associates Inc.	330.00	91,894.54
Hogan & Lovells, LLP	37,257.28	1,083,871.72
HR Solutions, Inc	0.00	26,157.79
Integrity Development Consultants	4,330.00	19,981.68
Jerry T. Baker	0.00	6,271.40
KAEC	0.00	15,000.00
L ROBERT KIMBALL	0.00	50,512.00
KPMG LLP	60,029.00	166,297.00
McBrayer, McGinnis	2,236.00	26,596.80
Mercer Inc./Wm. M.	33,471.00	197,348.00
Navigant Consulting, Inc.	0.00	23,000.00
Neel, Crafton & Phillips	0.00	55,600.00
Ohio Valley National Bank	25,922.96	83,041.62
Orrick, Herrington & Sutcliffe	552.23	45,155.99
Power Cost Inc./PCI	0.00	9,033.20
Preston Osborne	36,000.00	109,300.00
Prime Group LLC/The	8,525.00	375,479.90
Public Financial Management	0.00	79,166.04
Southwest Power Pool	0.00	4,385.88
Steptoe & Johnson LLP	0.00	7,240.50
Sullivan, Mountjoy, Stainback and Miller	147,660.19	979,892.67
The Raleigh Company	0.00	3,000.00
Towers Watson Delaware Inc.	18,725.00	19,225.00
Ziemer, Stayman, Weitzel	3,869.75	29,349.05

Big Rivers Electric Corporation
Professional Services
Year-To-Date January 31, 2012

vendor	Current Month	Year-to-Date
DB Consulting LLC	$ 1,104.72	$ 1,104.72
Fidelity Insitutional Operations Co., Inc.	20,450.00	20,450.00
GDS Associates Inc.	165.00	165.00
Integrity Development Consultants	1,517.50	1,517.50
KAEC	15,000.00	15,000.00
KPMG LLP	15,000.00	15,000.00
McBrayer, McGinnis	2,238.00	2,238.00
Ohio Valley Financial Group	29,761.36	29,761.36
Orrick, Herrington & Sutcliffe	41,747.50	41,747.50
Sullivan, Mountjoy, Stainback & Miller	102,196.19	102,196.19
Total Professional Services for 0	**$ 229,180.27**	**$ 229,180.27**
Less: Amount charged to the Balance Sheet	**$ 3,002.64**	**3,002.64**
Total Professional Services Charged to the Statement of Operations	**$ 226,177.63**	**$ 226,177.63**
Less: Amount charged to Other Deductions	**$ 1,119.00**	**$ 1,119.00**
Less: Amount charged to Station Two Purch Power	**$ 5,513.96**	**5,513.96**
Total Professional Services Charged to Administrative & General	**$ 219,544.67**	**$ 219,544.67**

Big Rivers Electric Corporation
Professional Services
Year-To-Date February 28, 2012

Vendor	Current Month	Year-to-Date
American Management Consulting	$ 11,344.07	$ 11,344.07
DB Consulting LLC	1,604.12	$ 2,708.84
Fidelity Insitutional Operations Co., Inc.	0.00	20,450.00
GDS Associates Inc.	0.00	165.00
Hogan & Lovells, LLP	177,914.92	177,914.92
Integrity Development Consultants	0.00	1,517.50
KAEC	0.00	15,000.00
KPMG LLP	5,000.00	20,000.00
McBrayer, McGinnis	2,238.00	4,476.00
Mercer Inc./Wm. M	33,880.00	33,880.00
Navigant Consulting, Inc.	20,000.00	20,000.00
Ohio Valley Financial Group	10,227.41	39,988.77
Orrick, Herrington & Sutcliffe	177,576.67	219,324.17
Prime Group LLC	16,686.53	16,686.53
Sullivan, Mountjoy, Stainback & Miller	89,878.50	192,074.69
Towers Watson Delaware Inc.	18,725.00	18,725.00
Ziemer, Stayman, Weitzel	2,935.50	2,935.50
Total Professional Services for 0	**$ 568,010.72**	**$ 797,190.99**
Less: Amount charged to the Balance Sheet	**$ 336,724.71**	**339,727.35**
Total Professional Services Charged to the Statement of Operations	**$ 231,286.01**	**$ 457,463.64**
Less: Amount charged to Other Deductions	**$ 1,119.00**	**$ 2,238.00**
Less: Amount charged to Station Two Purch Power	**$ 10,537.58**	**16,051.54**
Total Professional Services Charged to Administrative & General	**$ 219,629.43**	**$ 439,174.10**

Big Rivers Electric Corporation
Professional Services
Year-To-Date March 31, 2012

ndor	Current Month	Year-to-Date
American Management Consulting LLC	$ 22,642.09	$ 33,986.16
Burns and McDonnell Engineering Co., Inc.	5,675.33	5,675.33
DB Consulting LLC	2,384.35	5,093.19
Fidelity Insitutional Operations Co., Inc.	-	20,450.00
GDS Associates Inc.	765.00	930.00
Global PTM Inc.	16,404.36	16,404.36
Hogan & Lovells, LLP	197,928.32	375,843.24
Integrity Development Consultants Inc.	1,984.00	3,501.50
KAEC	-	15,000.00
KPMG LLP	19,250.00	39,250.00
McBrayer, McGinnis, Leslie	2,254.93	6,730.93
Mercer Inc./Wm. M	-	33,880.00
Navigant Consulting, Inc.	-	20,000.00
hio Valley Financial Group	9,837.85	49,826.62
Orrick, Herrington & Sutcliffe	37,838.37	257,162.54
Prime Group LLC	38,857.98	55,544.51
Shipman and Goodwin	7,714.50	7,714.50
Siemens Industry Inc.	43,332.50	43,332.50
Sullivan, Mountjoy, Stainback & Miller	106,870.76	298,945.45
Towers Watson Delaware Inc.	-	18,725.00
Ziemer, Stayman, Weitzel	1,168.50	4,104.00
Total Professional Services for 0	**$ 514,908.84**	**$ 1,312,099.83**
Less: Amount charged to the Balance Sheet	**208,882.58**	**548,609.93**
Total Professional Services Charged to the Statement of Operations	**$ 306,026.26**	**$ 763,489.90**
Less: Amount charged to Other Deductions	**1,127.46**	**3,365.46**
Less: Amount charged to Station Two Purch Power	**11,549.57**	**27,601.11**

Big Rivers Electric Corporation
Professional Services
Year-To-Date April 30, 2012

Vendor	Current Month	Year-to-Date
American Management Consulting LLC (assist in transition/HMP&L arbitration/rate case/environ. surcharge)	$ 10,221.93	$ 44,208.09
Burns and McDonnell Engineering Co., Inc. (rate case)	-	5,675.33
DB Consulting LLC (monitor MISO groups)	1,757.52	6,850.71
Duke Energy Ohio Inc. (MISO VITO & MSAT cost sharing of professional services)	24,223.87	24,223.87
Fidelity Insitutional Operations Co., Inc. (deferred comp & barg/sal savings plans)	19,825.00	40,275.00
GDS Associates Inc. (energy efficiency-DSM programs/Load Forecast)	517.70	1,447.70
Global PTM Inc. (assist in defining Oracle eAM improvement plan)	-	16,404.36
Hogan & Lovells, LLP	84,348.85	460,192.09
Integrity Development Consultants Inc. (mining engineering consulting & mine inspection)	-	3,501.50
KAEC (government strategies consultant)	-	15,000.00
KPMG LLP (financial audit & corporate tax returns)	-	39,250.00
McBrayer, McGinnis, Leslie	2,238.00	8,968.93
Mercer Inc./Wm. M (retirement plans/health & benefits)	6,436.00	40,316.00
Navigant Consulting, Inc. (GKS benchmarking)	-	20,000.00
Ohio Valley Financial Group (management/trustee fees for retirement plans)	9,939.77	59,766.39
Orrick, Herrington & Sutcliffe	-	257,162.54
Prime Group LLC (ECP/DSM/Rate Case rehearing)	-	55,544.51
Sargent and Lundy LLC (ECP)	32,641.00	32,641.00
Shipman and Goodwin	-	7,714.50
Siemens Industry Inc. (ECP)	-	43,332.50
Sullivan, Mountjoy, Stainback & Miller	97,397.81	396,343.26
Towers Watson Delaware Inc. (salary study)	-	18,725.00
TSE Services, Inc. (customer satisfaction surveys/residential SAT tracking/FGI data collection)	42,414.00	42,414.00
Ziemer, Stayman, Weitzel	1,563.50	5,667.50
Total Professional Services for Year-To-Date April 30, 2012	$ 333,524.95	$ 1,645,624.78
Less: Amount charged to the Balance Sheet	138,839.94	687,449.87
Total Professional Services Charged to the Statement of Operations	$ 194,685.01	$ 958,174.91
	1,119.00	4,484.46

Big Rivers Electric Corporation
Professional Services
Year-To-Date May 31, 2012

Vendor	Current Month	Year-to-Date
American Management Consulting LLC (assist in transition/HMP&L arbitration/rate case/environ. surcharge)	$ -	$ 44,208.09
Associated Engineers Inc. (interim coal & petcoke inventory-Wilson Station)	$ 2,200.00	$ 2,200.00
Burns and McDonnell Engineering Co., Inc. (rate case)	-	5,675.33
DB Consulting LLC (monitor MISO groups)	1,806.77	8,657.48
Duke Energy Ohio Inc. (MISO VITO & MSAT cost sharing of professional services)	-	24,223.87
Fidelity Insitutional Operations Co., Inc. (deferred comp & barg/sal savings plans)	-	40,275.00
GDS Associates Inc. (energy efficiency-DSM programs/Load Forecast)	2,550.00	3,997.70
Global PTM Inc. (assist in defining Oracle eAM improvement plan)	-	16,404.36
Hogan & Lovells, LLP	85,507.95	545,700.04
Integrity Development Consultants Inc. (mining engineering consulting & mine inspection)	-	3,501.50
KAEC (government strategies consultant)	-	15,000.00
KPMG LLP (financial audit & corporate tax returns)	28,750.00	68,000.00
McBrayer, McGinnis, Leslie	2,238.00	11,206.93
Mercer Inc./Wm. M (retirement plans/health & benefits)	21,166.00	61,482.00
Navigant Consulting, Inc. (GKS benchmarking)	-	20,000.00
Ohio Valley Financial Group (management/trustee fees for retirement plans)	9,510.56	69,276.95
Orrick, Herrington & Sutcliffe	78,507.53	335,670.07
Prime Group LLC (ECP/DSM/Rate Case rehearing)	39,674.40	95,218.91
Sargent and Lundy LLC (ECP)	-	32,641.00
Shipman and Goodwin	-	7,714.50
Siemens Industry Inc. (ECP)	-	43,332.50
Sullivan, Mountjoy, Stainback & Miller	136,541.00	532,884.26
Towers Watson Delaware Inc. (salary study)	-	18,725.00
TSE Services, Inc. (customer satisfaction surveys/residential SAT tracking/FGI data collection)	-	42,414.00
Ziemer, Stayman, Weitzel	-	5,667.50
Total Professional Services for Year-To-Date May 31, 2012	$ 408,452.21	$ 2,054,076.99
Less: Amount charged to the Balance Sheet	176,705.07	864,154.94
Total Professional Services Charged to the Statement of Operations	$ 231,747.14	$ 1,189,922.05
	[illegible]	5.603.46

Big Rivers Electric Corporation
Professional Services
Year-To-Date June 30, 2012

Vendor	Current Month	Year-to-Date
ACES Power Marketing LLC (ECP)	$ 6,855.23	$ 6,855.23
American Management Consulting LLC (assist in transition/HMP&L arbitration/2011 rate case/environ. surcharge)	20,703.39	64,911.48
Associated Engineers Inc. (interim coal & petcoke inventory-Wilson Station)	-	2,200.00
Burns and McDonnell Engineering Co., Inc. (2011 rate case)	11,010.95	16,686.28
Catalyst Consulting LLC (2011 rate case/ECP/DSM)	12,426.51	12,426.51
DB Consulting LLC (monitor MISO groups)	1,905.95	10,563.43
Duke Energy Ohio Inc. (MISO VITO & MSAT cost sharing of professional services)	-	24,223.87
Fidelity Insitutional Operations Co., Inc. (deferred comp & barg/sal savings plans)	-	40,275.00
GDS Associates Inc. (energy efficiency-DSM programs/Load Forecast)	680.00	4,677.70
Global PTM Inc. (assist in defining Oracle eAM improvement plan)	-	16,404.36
Hogan & Lovells, LLP	11,526.25	557,226.29
Integrity Development Consultants Inc. (mining engineering consulting & mine inspection)	694.13	4,195.63
KAEC (government strategies consultant)	-	15,000.00
KPMG LLP (financial audit/corporate tax returns/debt refinancing)	3,625.00	71,625.00
Latham and Watkins LLP	138,316.94	138,316.94
McBrayer, McGinnis, Leslie	2,238.00	13,444.93
Mercer Inc./Wm. M (retirement plans/health & benefits)	32,979.00	94,461.00
Navigant Consulting, Inc. (GKS benchmarking)	3,000.00	23,000.00
Ohio Valley Financial Group (management/trustee fees for retirement plans)	9,186.19	78,463.14
Orrick, Herrington & Sutcliffe	72,758.79	408,428.86
Prime Group LLC (ECP/DSM/2011 rate case rehearing)	1,575.00	96,793.91
Sargent and Lundy LLC (ECP)	25,870.50	58,511.50
Shipman and Goodwin	-	7,714.50
Siemens Industry Inc. (ECP)	-	43,332.50
Sullivan, Mountjoy, Stainback & Miller	127,053.58	659,937.84
Towers Watson Delaware Inc. (salary study)	-	18,725.00
TSE Services, Inc. (customer satisfaction surveys/residential & business SAT tracking/FGI data collection)	24,414.00	66,828.00
Vantage Energy Consulting LLP (ECP)	36,020.00	36,020.00
Ziemer, Stayman, Weitzel	2,419.00	8,086.50
Total Professional Services for Year-To-Date May 31, 2012	$ 545,258.41	$ 2,599,335.40
Less: Amount charged to the Balance Sheet	262,737.20	1,126,892.14
[illegible] Charged to the Statement of Operations	$ 282,521.21	$ 1,472,443.26

Big Rivers Electric Corporation
Professional Services
Year-To-Date July 31, 2012

Vendor	Current Month	Year-to-Date
ACES Power Marketing LLC (ECP)	$ 8,298.00	$ 15,153.23
American Management Consulting LLC (assist in transition/HMP&L arbitration/2011 rate case/environ. surcharge)	11,071.49	75,982.97
Associated Engineers Inc. (interim coal & petcoke inventory-Wilson Station)	-	2,200.00
Burns and McDonnell Engineering Co., Inc. (2011 rate case)	9,979.25	26,665.53
Catalyst Consulting LLC (2011 rate case rehearing/ECP/DSM/2013 rate case/HMP&L MISO dispute)	23,672.27	36,098.78
DB Consulting LLC (monitor MISO groups)	1,725.83	12,289.26
DLA Piper LLP	1,012.50	1,012.50
Duke Energy Ohio Inc. (MISO VITO & MSAT cost sharing of professional services)	5,996.65	30,220.52
Fidelity Insitutional Operations Co., Inc. (deferred comp & barg/sal savings plans)	3,750.00	44,025.00
GDS Associates Inc. (energy efficiency-DSM programs/Load Forecast/ECP)	510.00	5,187.70
Global PTM Inc. (assist in defining Oracle eAM improvement plan)	-	16,404.36
Hogan & Lovells, LLP	48,277.06	605,503.35
Integrity Development Consultants Inc. (mining engineering consulting & mine inspection)	3,175.86	7,371.49
KAEC (government strategies consultant)	-	15,000.00
KPMG LLP (financial audit/corporate tax returns/debt refinancing)	3,775.00	75,400.00
Latham and Watkins LLP	27,644.52	165,961.46
McBrayer, McGinnis, Leslie	2,238.00	15,682.93
Mercer Inc./Wm. M (retirement plans/health & benefits)	43,249.00	137,710.00
Myriad CPA Group (formerly Neel, Crafton & Phillips) (Focused Audit-barg & salaried savings plans)	7,500.00	7,500.00
Navigant Consulting, Inc. (GKS benchmarking)	-	23,000.00
Ohio Valley Financial Group (management/trustee fees for retirement plans)	9,157.90	87,621.04
Orrick, Herrington & Sutcliffe	136,231.05	544,659.91
Prime Group LLC (ECP/DSM/2011 rate case rehearing)	-	96,793.91
Sargent and Lundy LLC (ECP)	16,161.21	74,672.71
Shipman and Goodwin	17,206.30	24,920.80
Siemens Industry Inc. (ECP)	7,993.13	51,325.63
Sullivan, Mountjoy, Stainback & Miller	110,691.24	770,629.08
Towers Watson Delaware Inc. (salary study)	-	18,725.00
TSE Services, Inc. (customer satisfaction surveys/residential & business SAT tracking/FGI data collection)	-	66,828.00
Vantage Energy Consulting LLP (ECP)	-	36,020.00
Ziemer, Stayman, Weitzel	2,389.50	10,476.00
Total Professional Services for Year-To-Date July 31, 2012	$ 501,705.76	$ 3,101,041.16
Less: Amount charged to the Balance Sheet	225,841.77	1,352,733.91
	[illegible]	$ 1,748,307.25

Big Rivers Electric Corporation
Professional Services
Year-To-Date August 31, 2012

Vendor	Current Month	Year-to-Date
ACES Power Marketing LLC (ECP)	$ 30,558.84	$ 45,712.07
American Management Consulting LLC (assist in transition/HMP&L arbitration/2011 rate case/environ. Surcharge/DSM/asbestos claim)	5,655.49	81,638.46
Associated Engineers Inc. (interim coal & petcoke inventory-Wilson Station)	-	2,200.00
Burns and McDonnell Engineering Co., Inc. (2011 rate case/rehearing)	1,031.70	27,697.23
Catalyst Consulting LLC (2011 rate case rehearing/ECP/DSM/2013 rate case-Cost of Service Study/HMP&L MISO dispute)	26,785.84	62,884.62
DB Consulting LLC (monitor MISO groups)	4,262.21	16,551.47
DLA Piper LLP	-	1,012.50
Doe Anderson (public relations services)	9,686.80	9,686.80
Duke Energy Ohio Inc. (MISO VITO & MSAT cost sharing of professional services)	-	30,220.52
Fidelity Insitutional Operations Co., Inc. (deferred comp & barg/sal savings plans)	-	44,025.00
GDS Associates Inc. (energy efficiency-DSM programs/Load Forecast/ECP)	3,602.10	8,789.80
Global PTM Inc. (assist in defining Oracle eAM improvement plan)	-	16,404.36
Hogan & Lovells, LLP	22,317.71	627,821.06
Integrity Development Consultants Inc. (mining engineering consulting & mine inspection)	496.00	7,867.49
KAEC (government strategies consultant)	-	15,000.00
KPMG LLP (financial audit/corporate tax returns/debt refinancing)	43,750.00	119,150.00
Latham and Watkins LLP	-	165,961.46
McBrayer, McGinnis, Leslie	2,238.00	17,920.93
Mercer Inc./Wm. M (retirement plans/health & benefits)	37,046.00	174,756.00
Myriad CPA Group (formerly Neel, Crafton & Phillips) (Focused Audit-barg & salaried savings plans)	-	7,500.00
Navigant Consulting, Inc. (GKS benchmarking)	-	23,000.00
Ohio Valley Financial Group (management/trustee fees for retirement plans)	9,171.84	96,792.88
Orrick, Herrington & Sutcliffe	96,249.25	640,909.16
Prime Group LLC (ECP/DSM/2011 rate case rehearing)	-	96,793.91
Sargent and Lundy LLC (ECP)	28,865.78	103,538.49
Shipman and Goodwin	-	24,920.80
Siemens Industry Inc. (ECP/MISO forecast & testimony)	92,183.01	143,508.64
Sullivan, Mountjoy, Stainback & Miller	143,749.87	914,378.95
Towers Watson Delaware Inc. (salary study)	-	18,725.00
TSE Services, Inc. (customer satisfaction surveys/residential & business SAT tracking/FGI data collection)	-	66,828.00
Vantage Energy Consulting LLP (ECP)	77,551.78	113,571.78
Ziemer, Stayman, Weitzel	3,127.00	13,603.00
Total Professional Services for Year-To-Date August 31, 2012	$ 638,329.22	$ 3,739,370.38
Less: Amount charged to the Balance Sheet	130,839.34	1,483,573.25
Charged to the Statement of Operations	$ 507,489.88	$ 2,255,797.13

Big Rivers Electric Corporation
Professional Services
Year-To-Date September 31, 2012

Vendor	Current Month	Year-to-Date
ACES Power Marketing LLC (ECP)	$ -	$ 45,712.07
American Management Consulting LLC (assist in transition/HMP&L arbitration/2011 rate case/environ Surcharge/DSM/asbestos claim/2012 rate case)	5,650.94	87,289.40
Associated Engineers Inc. (interim coal & petcoke inventory-Wilson Station)	-	2,200.00
Burns and McDonnell Engineering Co., Inc. (2011 rate case/rehearing/Wilson & Station II FGD Study for CSAPR)	55,177.59	82,874.82
Cardwell Energy Associates Inc. (Ky PSC FAC 6 month review)	1,000.00	1,000.00
Catalyst Consulting LLC (2011 rate case rehearing/ECP/DSM/2013 rate case-Cost of Service Study/HMP&L MISO dispute)	17,524.52	80,409.14
DB Consulting LLC (monitor MISO groups)	-	16,551.47
DLA Piper LLP	-	1,012.50
Doe Anderson (public relations services)	4,100.00	13,786.80
Duke Energy Ohio Inc. (MISO VITO & MSAT cost sharing of professional services)	-	30,220.52
Fidelity Insitutional Operations Co., Inc. (deferred comp & barg/sal savings plans)	-	44,025.00
GDS Associates Inc. (energy efficiency-DSM programs/Load Forecast/ECP)	-	8,789.80
Global PTM Inc. (assist in defining Oracle eAM improvement plan)	-	16,404.36
Hogan & Lovells, LLP	3,438.05	631,259.11
Hunton & Williams LLP	49,648.23	49,648.23
Integrity Development Consultants Inc. (mining engineering consulting & mine inspection)	1,528.50	9,395.99
KAEC (government strategies consultant)	-	15,000.00
KPMG LLP (financial audit/corporate tax returns/debt refinancing)	-	119,150.00
Latham and Watkins LLP	-	165,961.46
McBrayer, McGinnis, Leslie	2,260.18	20,181.11
Mercer Inc./Wm. M (retirement plans/health & benefits)	43,314.00	218,070.00
Myriad CPA Group (formerly Neel, Crafton & Phillips) (Focused Audit-barg & salaried savings plans)	7,500.00	15,000.00
Navigant Consulting, Inc. (GKS benchmarking)	-	23,000.00
Ohio Valley Financial Group (management/trustee fees for retirement plans)	9,097.99	105,890.87
Orrick, Herrington & Sutcliffe	42,588.20	683,497.36
Prime Group LLC (ECP/DSM/2011 rate case rehearing)	-	96,793.91
Sargent and Lundy LLC (ECP)	-	103,538.49
Shipman and Goodwin	-	24,920.80
Siemens Industry Inc. (ECP/MISO forecast & testimony)	-	143,508.64
Sullivan, Mountjoy, Stainback & Miller	106,179.33	1,020,558.28
Towers Watson Delaware Inc. (salary study)	-	18,725.00
TSE Services, Inc. (customer satisfaction surveys/residential & business SAT tracking/FGI data collection)	24,414.00	91,242.00
Vantage Energy Consulting LLP (ECP)	-	113,571.78
	3,038.50	16,641.50

Big Rivers Electric Corporation
Professional Services
Year-To-Date September 31, 2012

Vendor		Current Month		Year-to-Date
Less: Amount charged to the Balance Sheet		75,979.47		1,559,552.72
Total Professional Services Charged to the Statement of Operations	$	300,480.56	$	2,556,277.69
Less: Amount charged to Other Deductions		1,130.09		10,090.55
Less: Amount charged to Station Two Purchased Power		5,740.21		53,033.65
Total Professional Services Charged to Administrative & General	$	293,610.26	$	2,493,153.49

Big Rivers Electric Corporation
Professional Services
Year-To-Date October 31, 2012

Vendor	Current Month	Year-to-Date
ACES Power Marketing LLC (ECP)	$ -	$ 45,712.07
American Management Consulting LLC (HMP&L arbitration/2011 rate case/environ Surcharge/DSM/asbestos claim/2012 rate case/patent infringement/economic develop tariff)	5,703.31	92,992.71
Associated Engineers Inc. (interim coal & petcoke inventory-Wilson Station)	-	2,200.00
Burns and McDonnell Engineering Co., Inc. (2011 rate case & rehearing/Wilson & Station II FGD Study for CSAPR)	10,060.96	92,935.78
Cardwell Energy Associates Inc. (Ky PSC FAC 6 month review)	-	1,000.00
Catalyst Consulting LLC (2011 rate case rehearing/ECP/DSM/2013 rate case-Cost of Service Study & rates review/HMP&L MISO dispute)	22,319.44	102,728.58
DB Consulting LLC (monitor MISO groups)	1,711.09	18,262.56
Dinsmore & Shohl LLP	42,729.04	42,729.04
DLA Piper LLP	-	1,012.50
Doe Anderson (public relations services)	2,345.00	16,131.80
Duke Energy Ohio Inc. (MISO VITO & MSAT cost sharing of professional services)	-	30,220.52
Fidelity Institutional Operations Co., Inc. (deferred comp & barg/sal savings plans)	3,750.00	47,775.00
GDS Associates Inc. (energy efficiency-DSM programs/Load Forecast/ECP)	-	8,789.80
Global PTM Inc. (assist in defining Oracle eAM improvement plan)	-	16,404.36
Hogan & Lovells, LLP	1,975.05	633,234.16
Hunton & Williams LLP	213.90	49,862.13
Integrity Development Consultants Inc. (mining engineering consulting & mine inspection)	-	9,395.99
KAEC (government strategies consultant)	-	15,000.00
L Robert Kimball (coal & petcoke physical inventory)	50,392.00	50,392.00
KPMG LLP (financial audit/corporate tax returns/debt refinancing)	-	119,150.00
Latham and Watkins LLP	-	165,961.46
McBrayer, McGinnis, Leslie	2,238.00	22,419.11
Mercer Inc./Wm. M (retirement plans/health & benefits)	45,209.00	263,279.00
Myriad CPA Group (formerly Neel, Crafton & Phillips) (Focused Audit-barg & salaried savings plans)	-	15,000.00
Navigant Consulting, Inc. (GKS benchmarking)	-	23,000.00
Ohio Valley Financial Group (management/trustee fees for retirement plans)	-	105,890.87
Orrick, Herrington & Sutcliffe	27,604.48	711,101.84
Power Cost Inc/PCI (MISO consulting)	6,950.95	6,950.95
Prime Group LLC (ECP/DSM/2011 rate case rehearing)	-	96,793.91
Sargent and Lundy LLC (ECP)	-	103,538.49
Shipman and Goodwin	-	24,920.80
Siemens Industry Inc. (ECP/MISO forecast & testimony)	-	143,508.64
Sullivan, Mountjoy, Stainback & Miller	105,880.89	1,126,439.17

Big Rivers Electric Corporation
Professional Services
Year-To-Date October 31, 2012

Vendor		Current Month		Year-to-Date
Towers Watson Delaware Inc. (salary study)		-		18,725.00
TSE Services, Inc. (customer satisfaction surveys/residential & business SAT tracking/FGI data collection)		-		91,242.00
Vantage Energy Consulting LLP (ECP)		-		113,571.78
Ziemer, Stayman, Weitzel		-		16,641.50
Total Professional Services for Year-To-Date October 31, 2012	$	329,083.11	$	4,444,913.52
Less: Amount charged to the Balance Sheet		760,894.56		2,320,447.28
Total Professional Services Charged to the Statement of Operations	$	(431,811.45)	$	2,124,466.24
Less: Amount charged to Other Deductions		1,119.00		11,209.55
Less: Amount charged to Station Two Purchased Power		5,772.44		58,806.09
Total Professional Services Charged to Administrative & General	$	(438,702.89)	$	2,054,450.60

Note: The negative balance charged to the Statement of Operations for October is due to:

ECP expenses reclassified to the Balance Sheet for deferral/amortization per PSC order	(768,668.35)
2012 Rate Case expenses reclassified to the Balance Sheet for deferral/amortization pending PSC approval	(22,250.11)
Unrecoverable Westlake expenses reclassified to the Statement of Operations from accounts receivable	179,238.51
Net amount reclassified	(611,679.95)

Big Rivers Electric Corporation
Professional Services
Year-To-Date November 30, 2012

Vendor	Current Month	Year-to-Date
ACES Power Marketing LLC	$ -	$ 45,712.07
(ECP)		
American Management Consulting LLC	5,668.98	98,661.69
(HMP&L arbitration/2011 rate case/environ. Surcharge/DSM/asbestos claim/2012 rate case/patent infringement/economic develop tariff/ wholesale power contract/Station Two/Ky Statutes research)		
Associated Engineers Inc.	-	2,200.00
(interim coal & petcoke inventory-Wilson Station)		
Burns and McDonnell Engineering Co., Inc.	62,513.39	155,449.17
(2011 rate case & rehearing/Wilson & Station II FGD Study for CSAPR/2012 Depreciation Study)		
Cardwell Energy Associates Inc.	-	1,000.00
(Ky PSC FAC 6 month review)		
Catalyst Consulting LLC	36,477.04	139,205.62
(2011 rate case rehearing/ECP/DSM/2013 rate case-Cost of Service Study & rates review/HMP&L MISO dispute)		
DB Consulting LLC	2,737.78	21,000.34
(monitor MISO groups)		
Dinsmore & Shohl LLP	49,100.95	91,829.99
DLA Piper LLP	-	1,012.50
Doe Anderson	-	16,131.80
(public relations services)		
Duke Energy Ohio Inc.	-	30,220.52
(MISO VITO & MSAT cost sharing of professional services)		
Fidelity Institutional Operations Co., Inc.	-	47,775.00
(deferred comp & barg/sal savings plans)		
GDS Associates Inc.	510.00	9,299.80
(energy efficiency-DSM programs/Load Forecast/ECP)		
Global PTM Inc.	-	16,404.36
(assist in defining Oracle eAM improvement plan)		
Hogan & Lovells, LLP	5,990.22	639,224.38
Hunton & Williams LLP	-	49,862.13
Integrity Development Consultants Inc.	-	9,395.99
(mining engineering consulting & mine inspection)		
KAEC	-	15,000.00
(government strategies consultant)		
L Robert Kimball	-	50,392.00
(coal & petcoke physical inventory)		
KPMG LLP	30,639.00	149,789.00
(financial audit/corporate tax returns/debt refinancing)		
Latham and Watkins LLP	-	165,961.46
McBrayer, McGinnis, Leslie	2,238.00	24,657.11
Mercer Inc./Wm. M	45,792.00	309,071.00
(retirement plans/health & benefits)		
Myriad CPA Group (formerly Neel, Crafton & Phillips)	-	15,000.00
(Focused Audit-barg & salaried savings plans)		
Navigant Consulting, Inc.	-	23,000.00
(GKS benchmarking)		
Ohio Valley Financial Group	18,234.95	124,125.82
(management/trustee fees for retirement plans)		
Orrick, Herrington & Sutcliffe	274,085.11	985,186.95
Power Cost Inc/PCI	-	6,950.95
(MISO consulting)		
Prime Group LLC	-	96,793.91
(ECP/DSM/2011 rate case rehearing)		
Sargent and Lundy LLC	-	103,538.49
(ECP)		
Shipman and Goodwin	4,273.50	29,194.30
Siemens Industry Inc.	-	143,508.64

Big Rivers Electric Corporation
Professional Services
Year-To-Date November 30, 2012

Vendor	Current Month	Year-to-Date
Southwest Power Pool	(2,040.72)	(2,040.72)
(partial refund of 2009 payment for LGE/KU System Impact Study)		
Sullivan, Mountjoy, Stainback & Miller	81,774.04	1,208,213.21
Towers Watson Delaware Inc.	-	18,725.00
(salary study)		
TSE Services, Inc.	-	91,242.00
(customer satisfaction surveys/residential & business SAT tracking/FGI data collection)		
Vantage Energy Consulting LLP	-	113,571.78
(ECP)		
Ziemer, Stayman, Weitzel	1,652.00	18,293.50
Total Professional Services for Year-To-Date November 30, 2012	$ 619,646.24	$ 5,064,559.76
Less: Amount charged to the Balance Sheet	376,184.46	2,696,631.74
Total Professional Services Charged to the Statement of Operations	$ 243,461.78	$ 2,367,928.02
Less: Amount charged to Other Deductions	1,119.00	12,328.55
Less: Amount charged to Station Two Purchased Power	44,262.64	103,068.73
Total Professional Services Charged to Administrative & General	$ 198,080.14	$ 2,252,530.74

Big Rivers Electric Corporation
Professional Services
Year-To-Date December 31, 2012

Vendor	Current Month	Year-to-Date	* Reimbursable Amount Included In Year-to-Date Total
ACES Power Marketing LLC (ECP)	$ -	$ 45,712.07	$ -
American Management Consulting LLC (HMP&L arbitration/2011 rate case/environ Surcharge/DSM/asbestos claim/2012 rate case/patent infringement/economic develop tariff/ wholesale power contract/Station Two/Ky Statutes research/HMP&L general)	13,629.37	112,291.06	2,597.09
Associated Engineers Inc. (interim coal & petcoke inventory-Wilson Station)	-	2,200.00	
Burns and McDonnell Engineering Co., Inc. (2011 rate case & rehearing/Wilson & Station II FGD Study for CSAPR/2012 Depreciation Study)	13,125.23	168,574.40	
Cardwell Energy Associates Inc. (Ky PSC FAC 6 month review)	-	1,000.00	
Catalyst Consulting LLC (2011 rate case rehearing/ECP/DSM/2013 rate case-Cost of Service Study & rates review/HMP&L MISO dispute)	33,955.53	173,161.15	
DB Consulting LLC (monitor MISO groups)	1,187.40	22,187.74	
Dinsmore & Shohl LLP	79,336.00	171,165.99	78,785.10
DLA Piper LLP	-	1,012.50	759.38
Doe Anderson (public relations services)	125.00	16,256.80	
Duke Energy Ohio Inc. (MISO VITO & MSAT cost sharing of professional services)	14,838.99	45,059.51	
Fidelity Institutional Operations Co., Inc. (deferred comp & barg/sal savings plans)	-	47,775.00	
GDS Associates Inc. (energy efficiency-DSM programs/Load Forecast/ECP)	-	9,299.80	
Global PTM Inc. (assist in defining Oracle eAM improvement plan)	-	16,404.36	
Hogan & Lovells, LLP	1,848.00	641,072.38	326,289.00
Hunton & Williams LLP	-	49,862.13	
Integrity Development Consultants Inc. (mining engineering consulting & mine inspection)	-	9,395.99	
KAEC (government strategies consultant)	-	15,000.00	
L Robert Kimball (coal & petcoke physical inventory)	-	50,392.00	
KPMG LLP (financial audit/corporate tax returns/debt refinancing)	-	149,789.00	
Latham and Watkins LLP	-	165,961.46	
McBrayer, McGinnis, Leslie	4,650.16	29,307.27	
Mercer Inc./Wm. M (retirement plans/health & benefits)	27,409.00	336,480.00	
Midwest ISO (Century Aluminum escrow project)	70,000.00	70,000.00	70,000.00
Myriad CPA Group (formerly Neel, Crafton & Phillips) (Focused Audit-barg & salaried savings plans)	-	15,000.00	
Navigant Consulting, Inc. (GKS benchmarking)	-	23,000.00	
Ohio Valley Financial Group (management/trustee fees for retirement plans)	9,001.74	133,127.56	
Orrick, Herrington & Sutcliffe	195,517.12	1,180,704.07	244,336.81
Power Cost Inc/PCI (MISO consulting)	-	6,950.95	
Prime Group LLC (ECP/DSM/2011 rate case rehearing/MISO committee meetings-Technical Consortium)	1,046.38	97,840.29	
Sargent and Lundy LLC	-	103,538.49	

Big Rivers Electric Corporation
Professional Services
Year-To-Date December 31, 2012

Vendor	Current Month	Year-to-Date	* Reimbursable Amount Included In Year-to-Date Total
Siemens Industry Inc. (ECP/MISO forecast & testimony)	-	143,508.64	
Southwest Power Pool (partial refund of 2009 payment for LGE/KU System Impact Study)	-	(2,040.72)	
Sullivan, Mountjoy, Stainback & Miller	85,544.74	1,293,757.95	186,389.15
Towers Watson Delaware Inc. (salary study/market pricing for new positions)	600.00	19,325.00	
TSE Services, Inc. (customer satisfaction surveys/residential & business SAT tracking/FGI data collection)	24,414.00	115,656.00	
Vantage Energy Consulting LLP (ECP)	-	113,571.78	
Walker/Daniel M. (2012 rate case)	5,750.00	5,750.00	
Ziemer, Stayman, Weitzel	6,159.86	24,453.36	
Total Professional Services for YTD December 31, 2012	$ 588,138.52	$ 5,652,698.28	$ 909,156.53
Less: Amount charged to the Balance Sheet	431,701.19	3,128,332.93	909,156.53
Total Professional Services Charged to the Statement of Operations	$ 156,437.33	$ 2,524,365.35	$ -
Less: Amount charged to Other Deductions	2,325.07	14,653.62	-
Less: Amount charged to Station Two Purchased Power	7,042.50	110,111.23	-
Total Professional Services Charged to Administrative & General	$ 147,069.76	$ 2,399,600.50	$ -

*** Reimbursable amounts include expenses for Century negotiations, HMP&L Litigation, Vectren 345KV Line, Westlake negotiations, Smithland Hydroelectric project & Matanzas Substation project**

Big Rivers Electric Corporation
Professional Services
Year-To-Date January 31, 2013

Vendor		Current Month		Year-to-Date		* Reimbursable Amount Included In Year-to-Date Total
Catalyst Consulting LLC (2012 rate case-Cost of Service Study & rates review/DSM/2011 rate case rehearing)		24,354.73		24,354.73		
Dinsmore & Shohl LLP		23,735.82		23,735.82		12,096.60
Fidelity Institutional Operations Co., Inc. (deferred comp & barg/sal savings plans)		3,750.00		3,750.00		
KAEC (government strategies consultant)		15,000.00		15,000.00		
KPMG LLP (2012 financial audit)		28,750.00		28,750.00		
Mercer Inc./Wm. M (retirement plans/health & benefits)		18,405.00		18,405.00		
Navigant Consulting, Inc. (GKS benchmarking)		20,000.00		20,000.00		
Ohio Valley Financial Group (management/trustee fees for retirement plans)		10,367.05		10,367.05		
Orrick, Herrington & Sutcliffe LLP		185,802.64		185,802.64		140,529.19
Sullivan, Mountjoy, Stainback & Miller P.S.C.		111,081.58		111,081.58		3,627.00
The Prime Group, LLC (MISO task forces & working groups)		3,758.55		3,758.55		
Ziemer, Stayman, Weitzel		2,717.25		2,717.25		
Total Professional Services for YTD January 31, 2013	$	447,722.62	$	447,722.62	$	156,252.79
Less: Amount charged to the Balance Sheet		275,922.16		275,922.16		156,252.79
Total Professional Services Charged to the Statement of Operations	$	171,800.46	$	171,800.46	$	-
Less: Amount charged to Other Deductions		-		-		
Less: Amount charged to Station Two Purchased Power		6,457.04		6,457.04		
Total Professional Services Charged to Administrative & General	$	165,343.42	$	165,343.42		

*** Reimbursable amounts include expenses for Century negotiations, HMP&L Litigation, and Vectren 345KV Line**

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

Financial Report
December 2010
($ in Thousands)

Board Meeting Date: February 18, 2011

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

Summary of Operations
YTD - December

	Actual	Budget	Fav/(UnFav) Variance
Revenues	527,324	508,843	18,481
Cost of Electric Service	523,067	504,489	(18,578)
Operating Margins	4,257	4,354	(97)
Interest Income/Other	2,733	454	2,279
Net Margins - YTD	6,990	4,808	2,182

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION
[illegible] Energy Cooperative

Statement of Operations – December

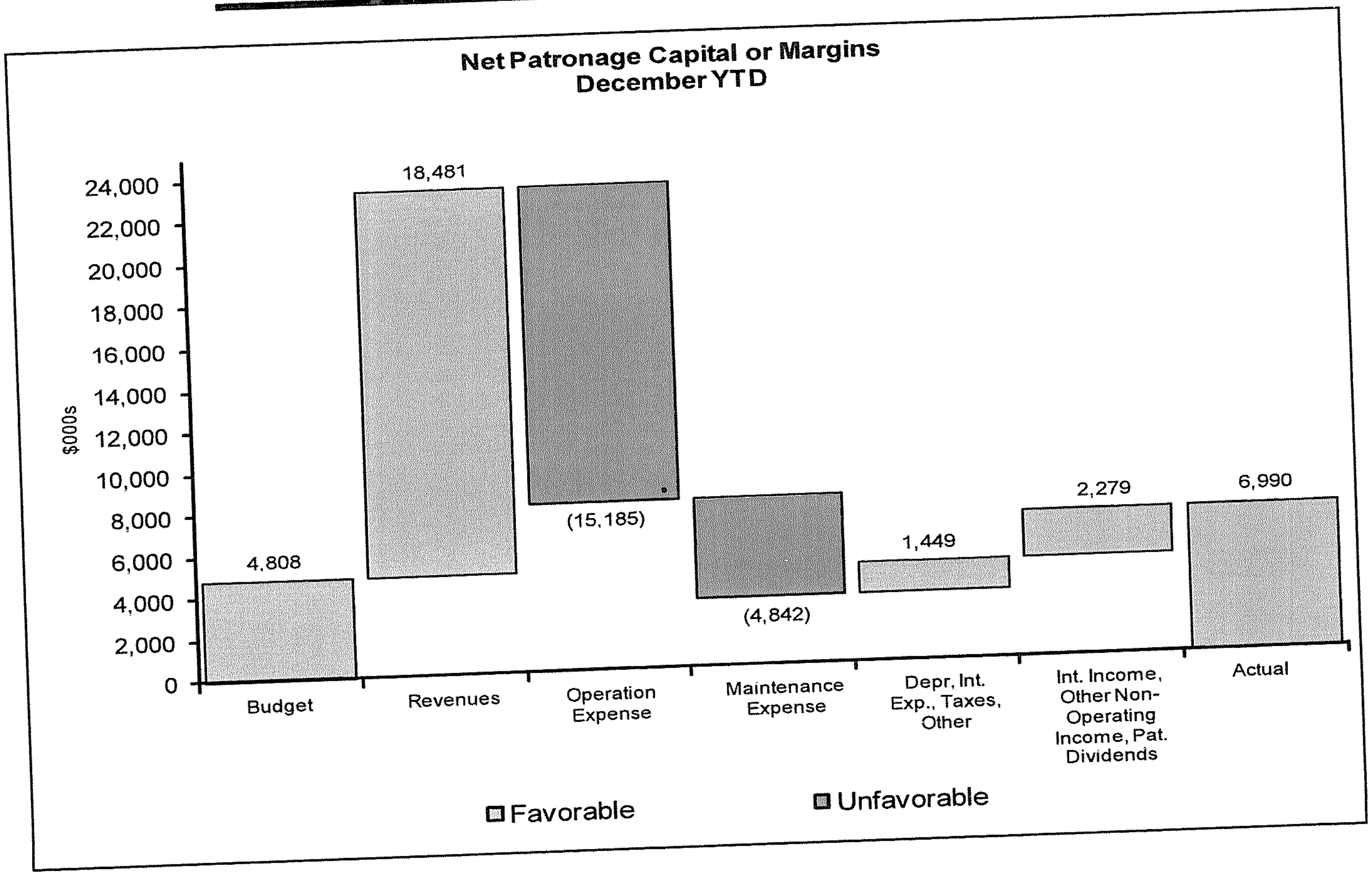
	Current Month			Year-to-Date			
	Actual	Budget	Variance Fav/(UnFav)	Actual	Budget	Variance Fav/(UnFav)	Explanation
LECTRIC ENERGY REVENUES	47,175	46,727	448	514,490	501,361	13,129	[A] Pages 5, 10-12
ICOME FROM LEASED PROPERTY - NET	0	0	0	0	0	0	
THER OPERATING REVENUE AND INCOME	152	624	(472)	12,834	7,482	5,352	[B], [C] Page 24
OTAL OPER REVENUES & PATRONAGE CAPITAL	47,327	47,351	(24)	527,324	508,843	18,481	
OPERATION EXPENSE-PRODUCTION-EXCL FUEL	3,921	4,703	782	52,507	56,903	4,396	[A] Pages 5, 10-12, [B] 25
OPERATION EXPENSE-PRODUCTION-FUEL	19,007	15,259	(3,748)	207,748	167,029	(40,719)	[A] Pages 5, 10-12
OPERATION EXPENSE-OTHER POWER SUPPLY	8,561	10,615	2,054	99,421	116,944	17,523	[A] Pages 5, 10-12, [B] 24,25
OPERATION EXPENSE-TRANSMISSION	1,045	664	(381)	8,122	7,908	(214)	
CONSUMER SERVICE & INFORMATIONAL EXPENSE	17	66	49	446	729	283	
OPERATION EXPENSE-SALES	50	126	76	240	614	374	
OPERATION EXPENSE-ADMINISTRATIVE & GENERAL	2,800	2,227	(573)	26,462	29,634	3,172	[C] Page 26
TOTAL OPERATION EXPENSE	35,401	33,660	(1,741)	394,946	379,761	(15,185)	
MAINTENANCE EXPENSE-PRODUCTION	3,109	2,725	(384)	42,157	37,404	(4,753)	[C] Page 27
MAINTENANCE EXPENSE-TRANSMISSION	243	375	132	4,473	4,576	103	
MAINTENANCE EXPENSE-GENERAL PLANT	78	4	(74)	250	58	(192)	
TOTAL MAINTENANCE EXPENSE	3,430	3,104	(326)	46,880	42,038	(4,842)	
DEPRECIATION & AMORTIZATION EXPENSE	2,857	2,947	90	34,242	34,833	591	
TAXES	65	21	(44)	263	249	(14)	
INTEREST ON LONG-TERM DEBT	4,104	4,107	3	47,064	48,078	1,014	
INTEREST CHARGED TO CONSTRUCTION-CREDIT	(103)	(46)	57	(683)	(575)	108	
OTHER INTEREST EXPENSE	21	0	(21)	189	0	(189)	
OTHER DEDUCTIONS	68	8	(60)	166	105	(61)	
TOTAL COST OF ELECTRIC SERVICE	45,843	43,801	(2,042)	523,067	504,489	(18,578)	
OPERATING MARGINS	1,484	3,550	(2,066)	4,257	4,354	(97)	
INTEREST INCOME	57	42	15	391	454	(63)	
ALLOWANCE FOR FUNDS USED DURING CONST	0	0	0	0	0	0	
OTHER NON-OPERATING INCOME - NET	621	0	621	2,321	0	2,321	[B], [C] Page 28
OTHER CAPITAL CREDITS & PAT DIVIDENDS	1	0	1	21	0	21	
EXTRAORDINARY ITEMS	0	0	0	0	0	0	
NET PATRONAGE CAPITAL OR MARGINS	2,163	3,592	(1,429)	6,990	4,808	2,182	

Attachment for Response to AG 2-13(c)

Explanations: [A] Net Sales Margin, [B] 10% and $250,000 line item or [C] 10% and $500,000 margins.

Rivers
ELECTRIC CORPORATION

Variance Analysis Summary



Financial commentary

Year-to-Date

- Net Margins YTD were $2,182 better than budget.
  - Electric Energy Revenues were favorable $13,129 primarily due to higher sales volume, mostly off-system (see pg. 10).
  - Other Revenue was favorable $5,352 primarily due to a larger power supply transmission reservation, which is off-set in Operations Expense – Other Power Supply (see pg. 24).
  - Operation Expense was unfavorable $15,185 – variable cost was unfavorable $13,415 primarily due to higher sales volume, off-system, while fixed cost was unfavorable $1,770 primarily due to the higher transmission reservation (see pgs. 11, 25 and 26).
  - Maintenance Expense was unfavorable $4,842 primarily due to the Coleman planned outage (see pg. 27).
  - Depreciation and Interest Expense was lower $1,449 due to lower capital expenses and pre-payment of debt.

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION
...hstone Energy Cooperative

MRSM
YTD December

	Actual 2010	Budget 2010	Variance
...SM - $/MWh			
...ral	(8.08)	(7.69)	(0.39)
...rge Industrial	(8.08)	(7.69)	(0.39)
...tal	(8.08)	(7.69)	(0.39)
...RSM - Thousands of $			
...ral	(20,044)	(18,564)	(1,480)
...rge Industrial	(7,513)	(7,395)	(118)
...tal	(27,557)	(25,959)	(1,598)

	Actual 2010	Budget 2010	Variance
Net Revenue - $/MWh			
Rural	37.07	37.37	(0.30)
Large Industrial	33.81	32.58	1.23
Total	36.18	36.00	0.18
Net Revenue - Thousands of $			
Rural	91,989	90,225	1,764
Large Industrial	31,455	31,338	117
Total	123,444	121,563	1,881

Economic Reserve Balance

	Actual	Budget	Variance
Original Deposit	$ 157,000		
Interest Earnings	1,864		
Withdrawals	(37,644)		
Cumulative through Dec 31st	$ 121,220	$ 121,319	$ (99)

Based on the first 16.5 months of experience, the Economic Reserve will be depleted mid-2015.

Attachment for Response to AG 2-13(c)

Rivers
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...stone Energy Cooperative

Cash & Temporary Investments

	Actual	Budget	Fav/(Unfav)
December 31, 2010	**44,755**	**58,014**	**(13,259)**

: December 31st unfavorable cash balance is primarily due to an additional net $14 ion of voluntary prepayment of RUS debt ($24 million total less $10 million 3ank Advance). Note that the RUS Series A Note prepaid status is $12 million at /2011, and the next quarterly payment is due 7/1/11.

Lines of Credit As of December 31	
Original Amount	$ 100,000
Letters of Credit Outstanding	(5,929)
Advances Outstanding	(10,000)
Available Lines of Credit	$ 84,071

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION
stone Energy Cooperative

North Star – YTD 12/31/2010 *

	Actual	Budget	Fav/(UnFav)
l Cost of Electric Service, As Adjusted	520,434	508,042	(12,392)
er Operating Revenues & Income	(12,834)	(7,482)	5,352
System Sales, Incl. Smelter Surplus "Make-Whole" Pmt.	[redacted]		
est Income	(391)	(454)	(63)
er Non-Operating Income	(2,321)	0	2,321
er Capital Credits & Pat. Dividends	(21)	0	21
et Member Cost	[redacted]		
mber MWh Sales	9,759,988	10,673,339	(913,351)
th Star - $/kWh	[redacted]		

Computation excludes the 2010 Incentive Pay Award accrual, which was not budgeted.

Attachment for Response to AG 2-13(c)

Rivers
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Touchstone Energy Cooperative

TIER

	Actual	Budget	Fav/(Unfav)
Interest on Long Term Debt	47,064	48,078	1,014
Net Margins	6,991	4,808	2,183
TIER	1.15	1.10	0.05

Notes:

TIER = (Net Margins + Interest on Long-Term Debt) divided by Interest on Long-Term Debt

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

Capital Expenditures*

	Actual	Budget	Fav/(UnFav)
IT	8,361	5,601	(2,760)
Generation	25,419	24,201	(1,218)
Transmission	10,563	15,537	4,974
Other	1,742	1,863	121
Total	**46,085**	**47,202**	**1,117**

Explanation:

T unfavorable due to Oracle.

Generation unfavorable primarily due to Transmission funding Green Boiler Painting $1,024.

Transmission favorable primarily due to the delay of the Two-Way Radio Project $4,998.

Other favorable primarily due to the headquarters remodel.

* Gross of the City's share of Station Two and capitalized interest.

Big Rivers ELECTRIC CORPORATION

A Touchstone Energy Cooperative

Revenue
YTD December

	Actual 2010	Budget 2010	Variance
MWh Sales			
Rural	2,481,391	2,414,538	66,853
Large Industrial	930,168	961,808	(31,640)
Smelter	6,348,431	7,296,993	(948,562)
Off-System/Other	[redacted]		
Total			

Revenue - $/MWh			
Rural	45.15	45.06	0.09
Large Industrial	41.89	40.27	1.62
Smelter	44.05	42.86	1.19
Off-System/Other	[redacted]		
Total			

Revenue - Thousands of $			
Rural	112,033	108,789	3,244
Large Industrial	38,968	38,733	235
Smelter	279,665	312,726	(33,061)
Off-System/Other	[redacted]		
Total			

Revenue Price / Volume Analysis
YTD December

	Price / Volume		
	Price	Volume	Total
Rural	232	3,012	3,244
Large Industrial	1,510	(1,275)	235
Smelter	7,591	(40,652)	(33,061)
Off-System/Other	[redacted]		

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION
stone Energy Cooperative

Variable Operations Cost
YTD December

	Actual 2010	Budget 2010	Variance
Variable Operations (VO) Cost - $/MWh			
Rural	25.01	24.69	(0.32)
Large Industrial	25.01	24.69	(0.32)
Smelter	23.95	23.78	(0.17)
Off-System/Other	[redacted]		
Total			

	Actual 2010	Budget 2010	Variance
VO Cost - Thousands of $			
Rural	62,058	59,615	(2,443)
Large Industrial	23,263	23,747	484
Smelter	152,055	173,531	21,476
Off-System/Other	[redacted]		
Total			

YTD December
Variable Operations Expense

	Actual	Budget	Fav/(UnFav)	Price Variance Fav/(UnFav)	Volume Variance Fav/(UnFav)	Fav/(UnFav)
gent	27,074	31,668	4,594	8,152	(3,558)	4,594
	236,716	194,402	(42,314)	287	(42,601)	(42,314)
chased Power	20,801	45,647	24,846	(7,424)	32,269	24,845
-FAC PPA (Non-Smelter)	3,609	3,068	(541)	(509)	(31)	(540)
	288,200	274,785	(13,415)	506	(13,921)	(13,415)

NOTE: The higher fuel expense is driven by 1,728,665 more MWh generated YTD than budget.

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

Net Sales Margin
YTD December

Net Sales Margin - $/MWh	Actual 2010	Budget 2010	Variance
Rural	20.14	20.37	(0.23)
Large Industrial	16.88	15.58	1.30
Smelter	20.10	19.08	1.02
Off-System/Other	[redacted]		
Total			

Net Sales Margin - Thousands of $	Actual 2010	Budget 2010	Variance
Rural	49,975	49,174	801
Large Industrial	15,705	14,986	719
Smelter	127,610	139,195	(11,585)
Off-System/Other	[redacted]		
Total			

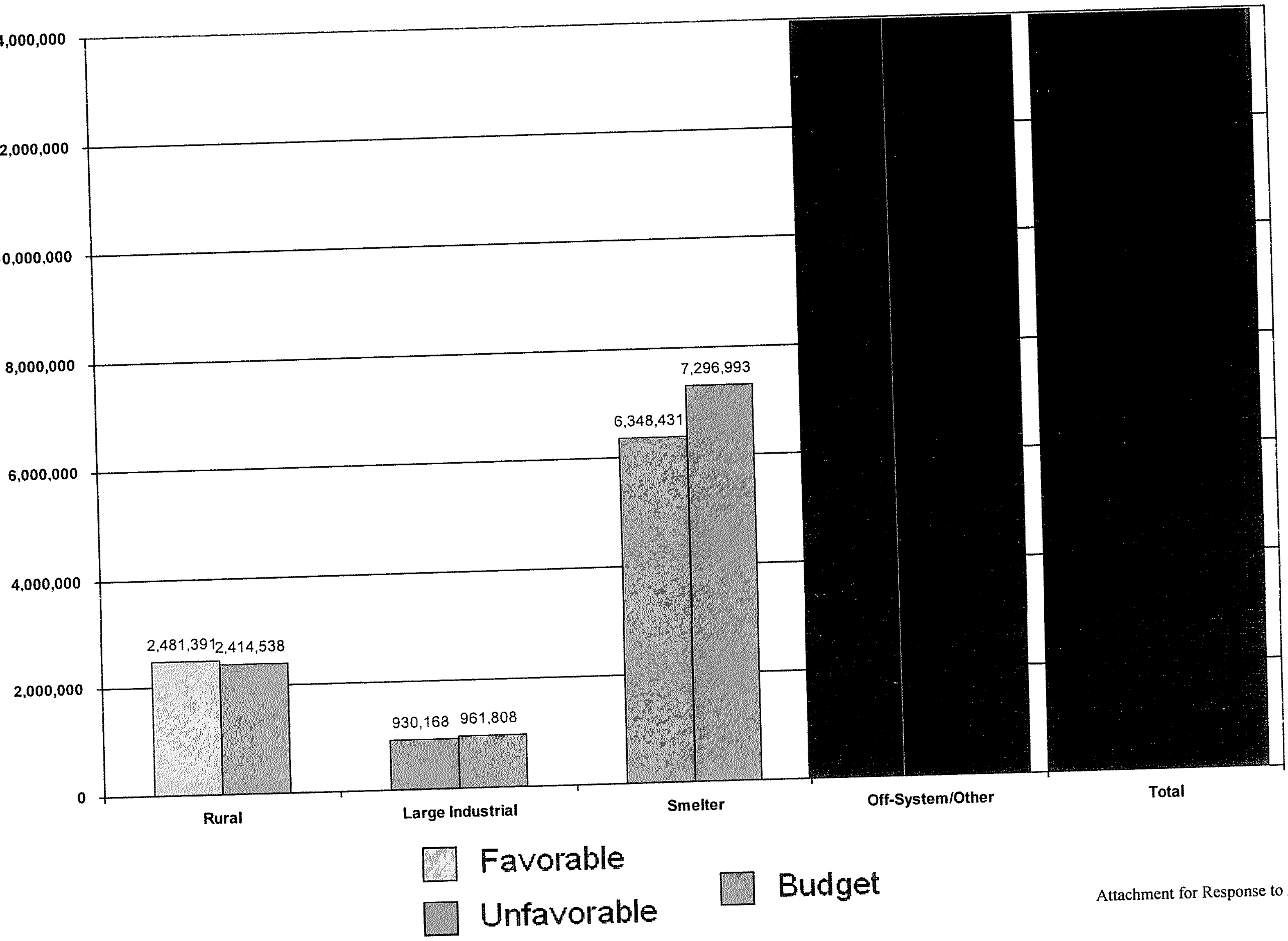
Net Sales Margin
Price / Volume Analysis
YTD December

	Price / Volume		
	Price	Volume	Total
Rural	(560)	1,361	801
Large Industrial	1,212	(493)	719
Smelter	6,509	(18,094)	(11,585)
Off-System/Other	[redacted]		

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

MWH Sales
YTD – December



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Rivers
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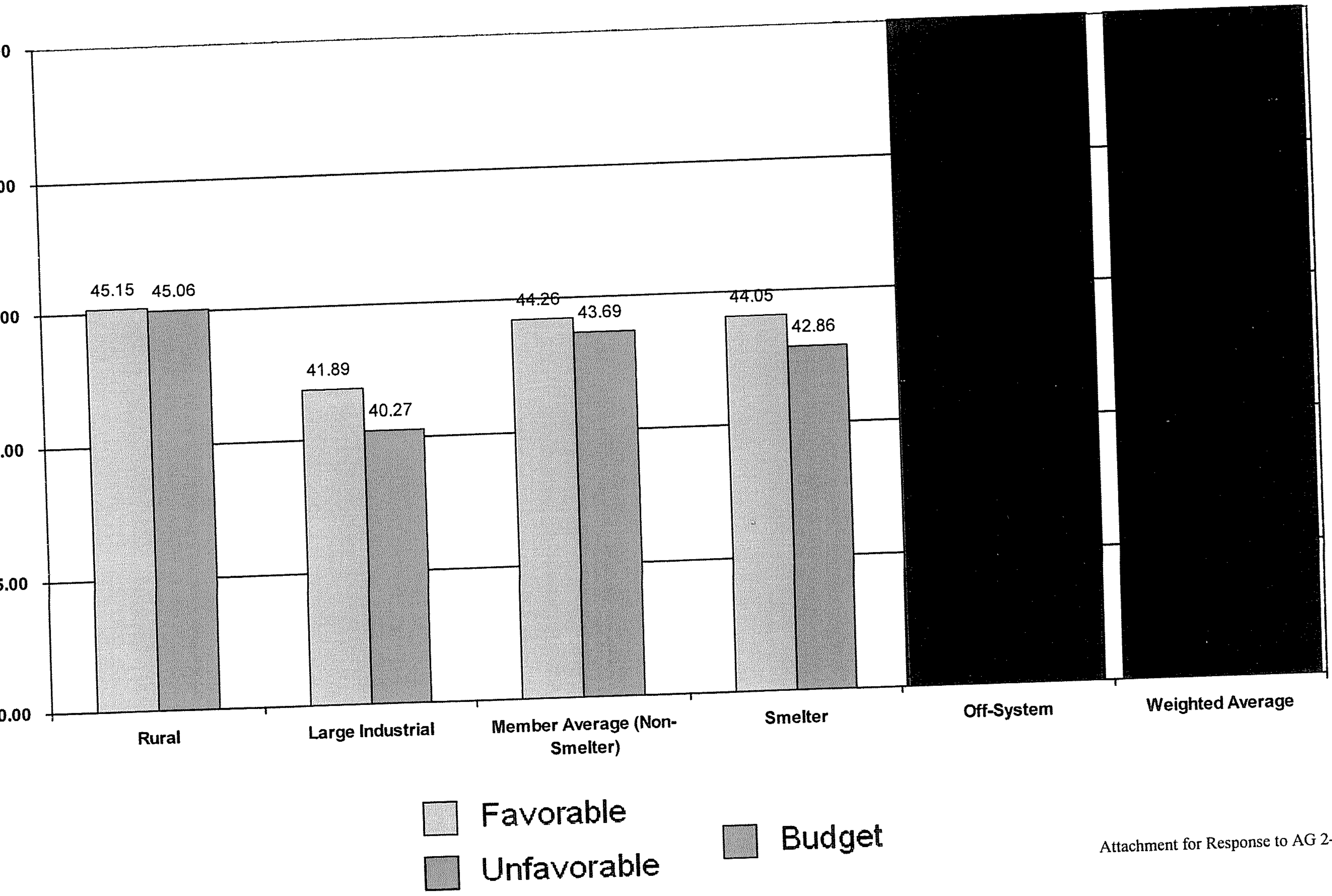
Revenue - $/MWh Sold
YTD - December



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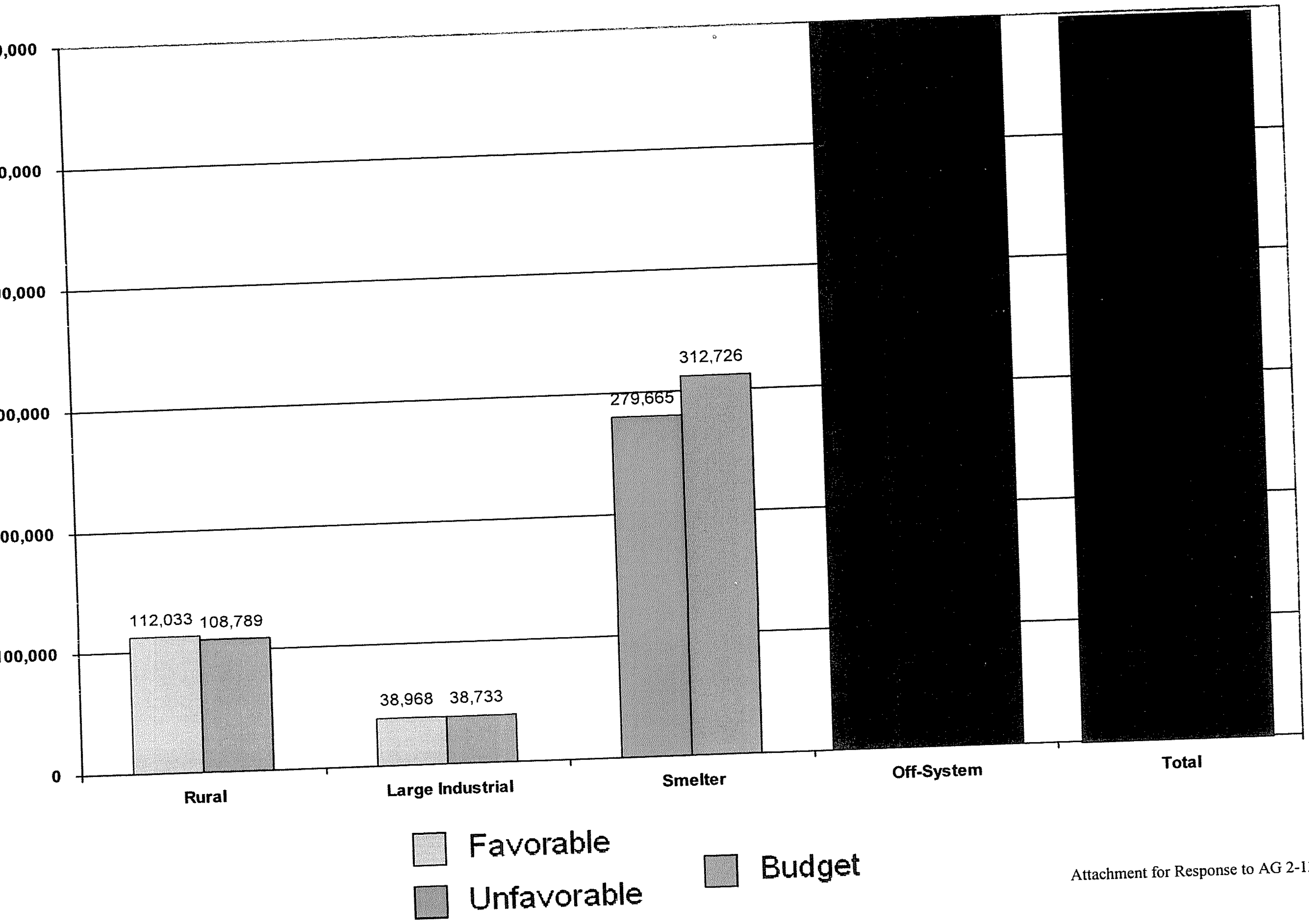
Revenue
YTD - December



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Rivers
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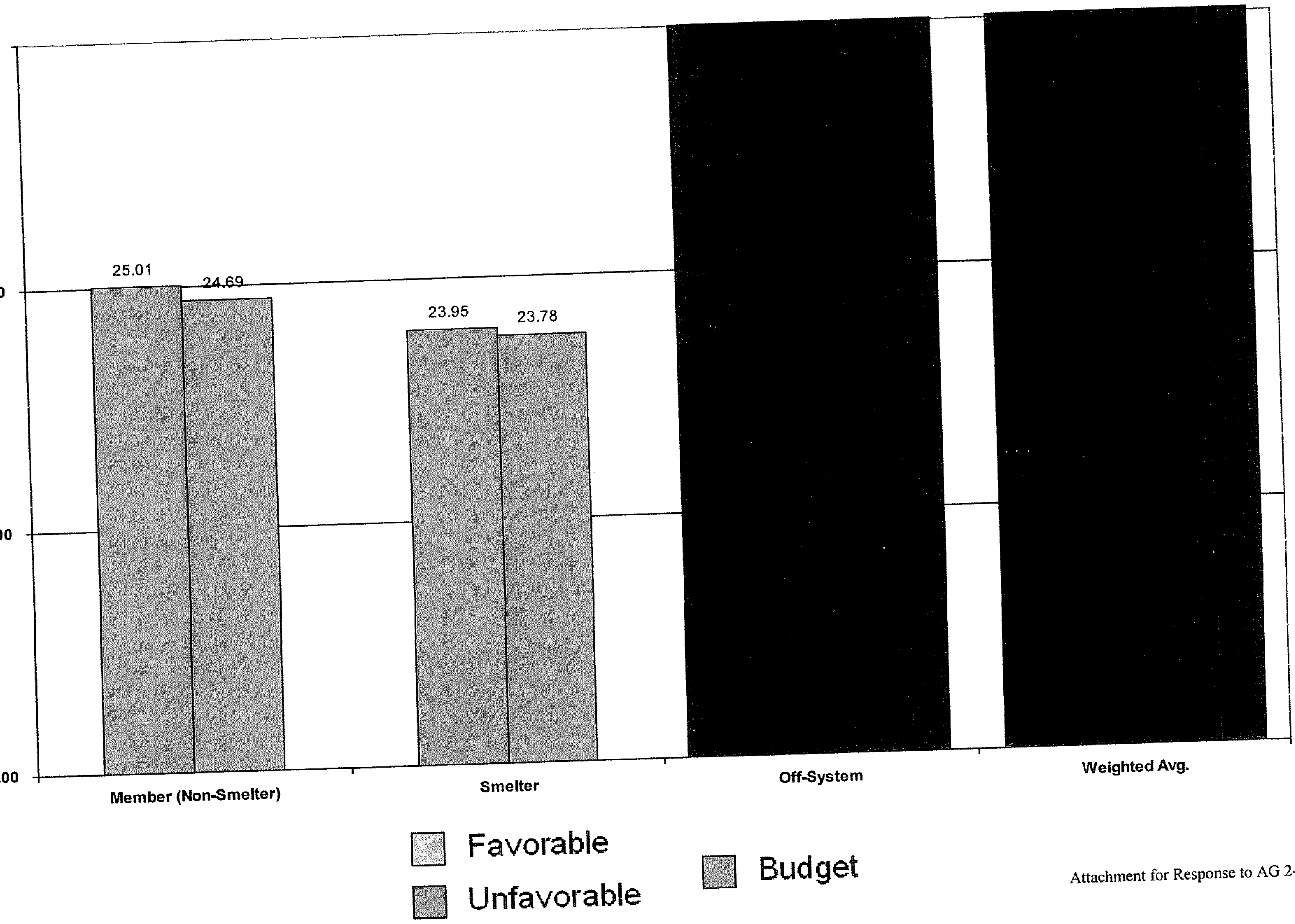
Power Cost - $/MWh Sold
YTD – December



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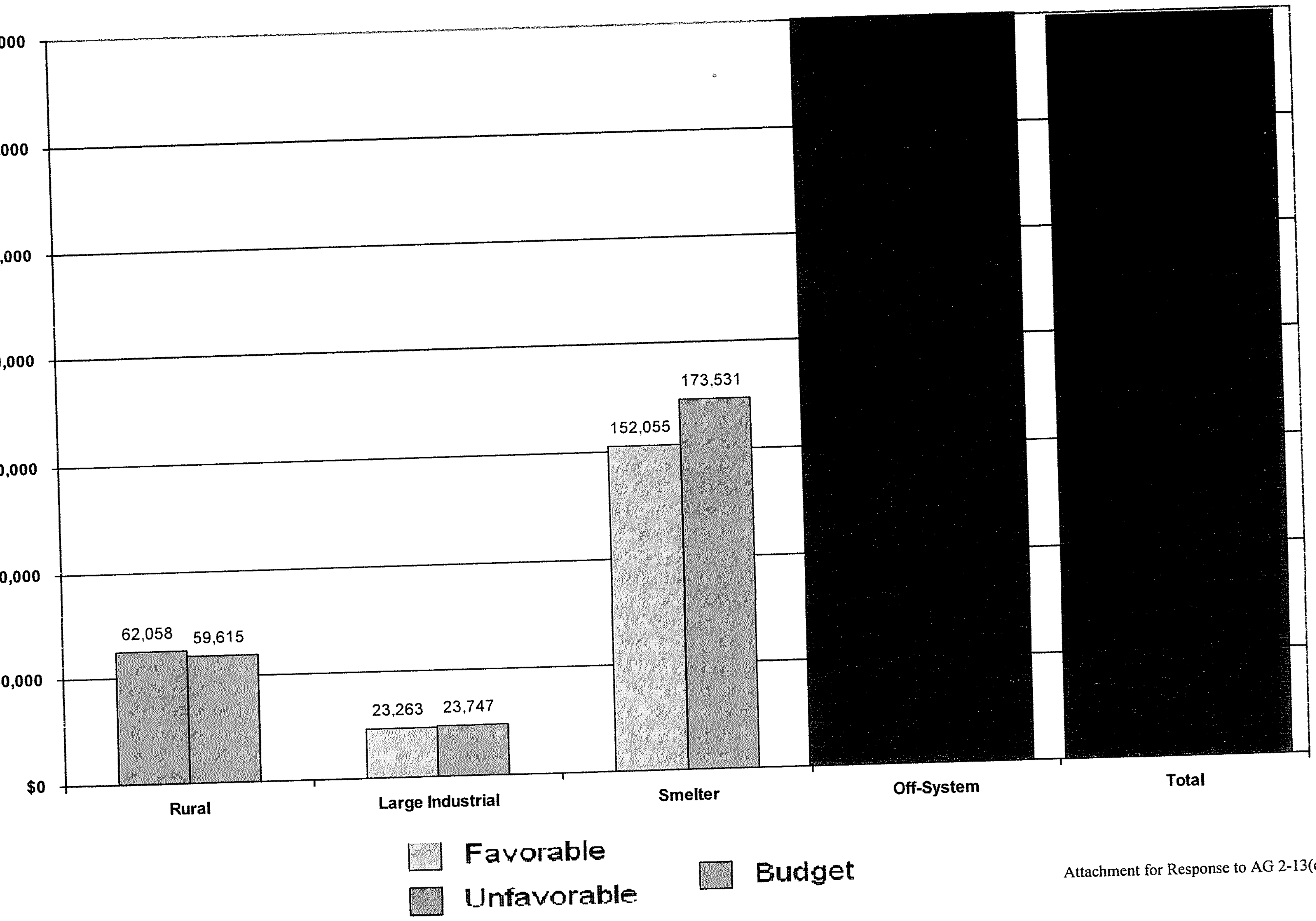
Power Cost
YTD - December



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Rivers
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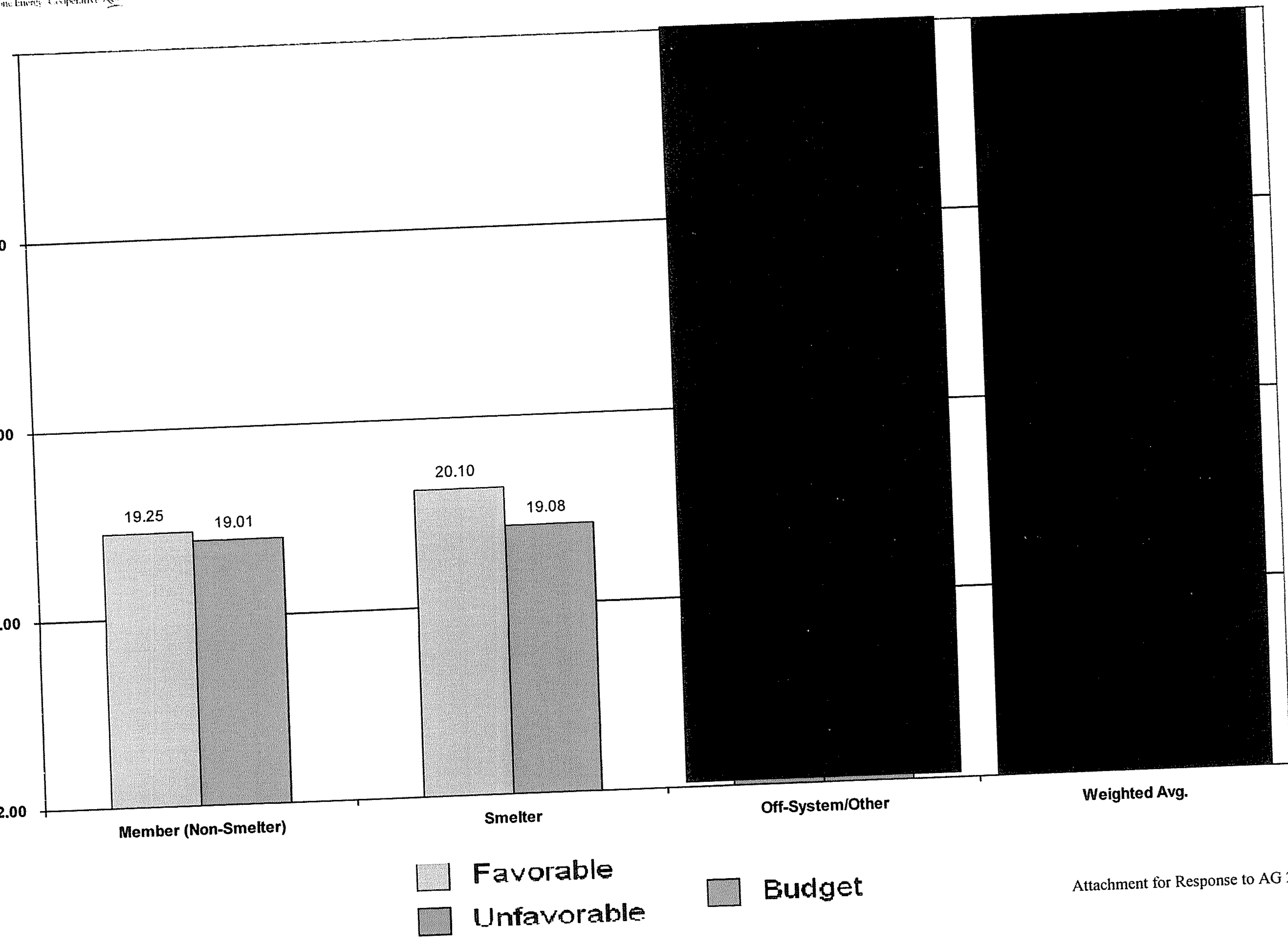
Sales Margin - $/MWh
YTD – December



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Rivers
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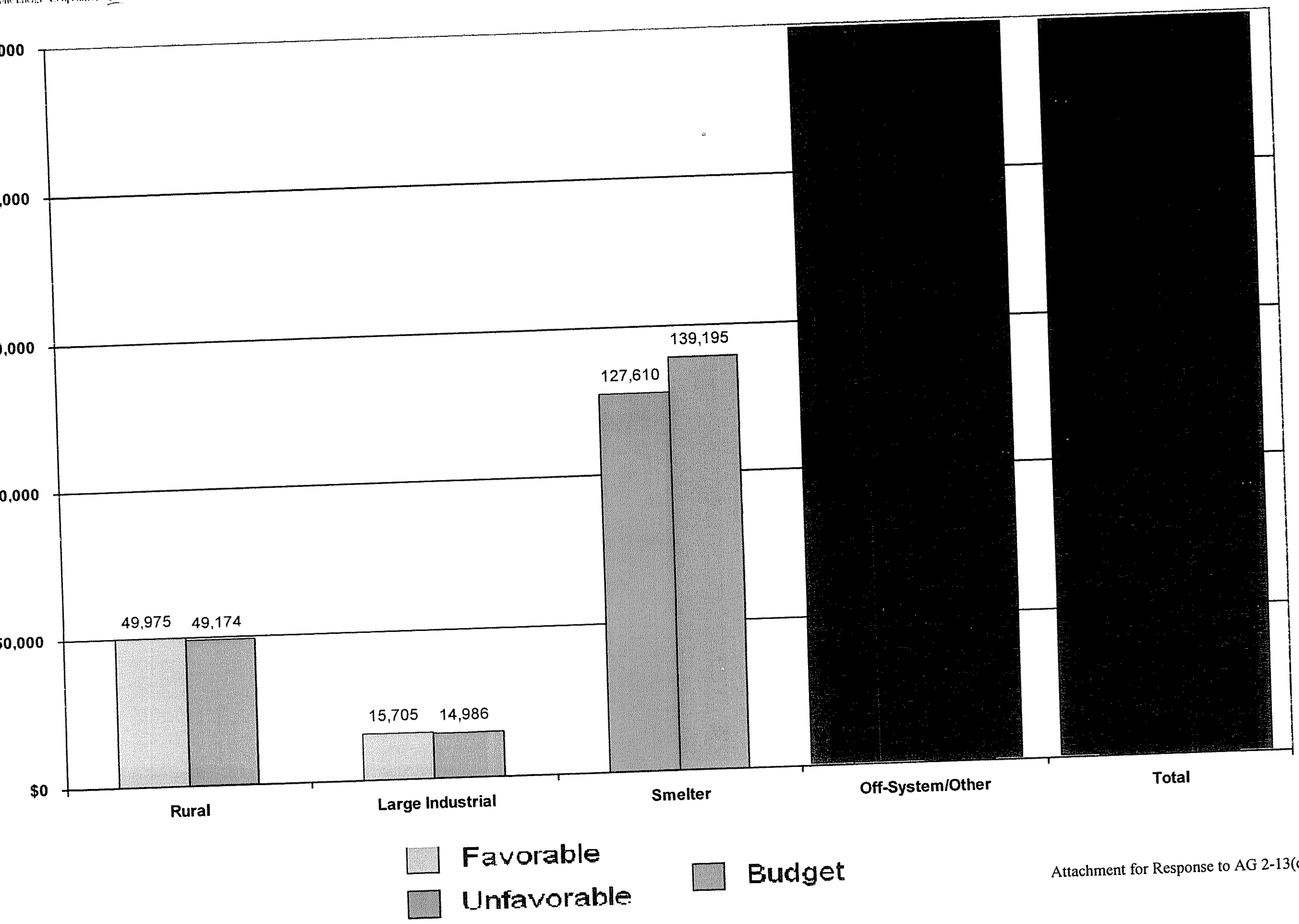
Sales Margin
YTD - December



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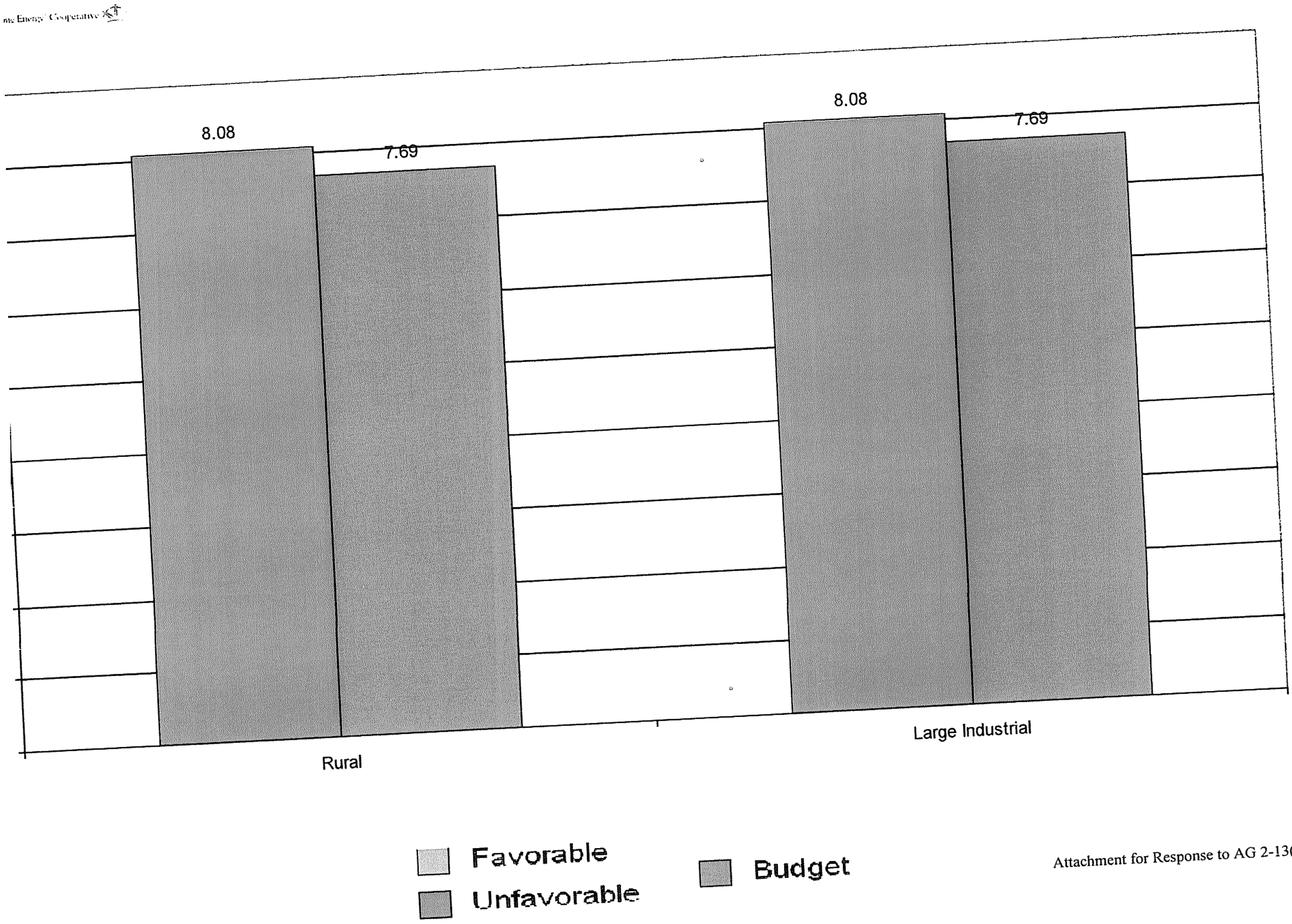
MRSM - $/MWh
YTD - December



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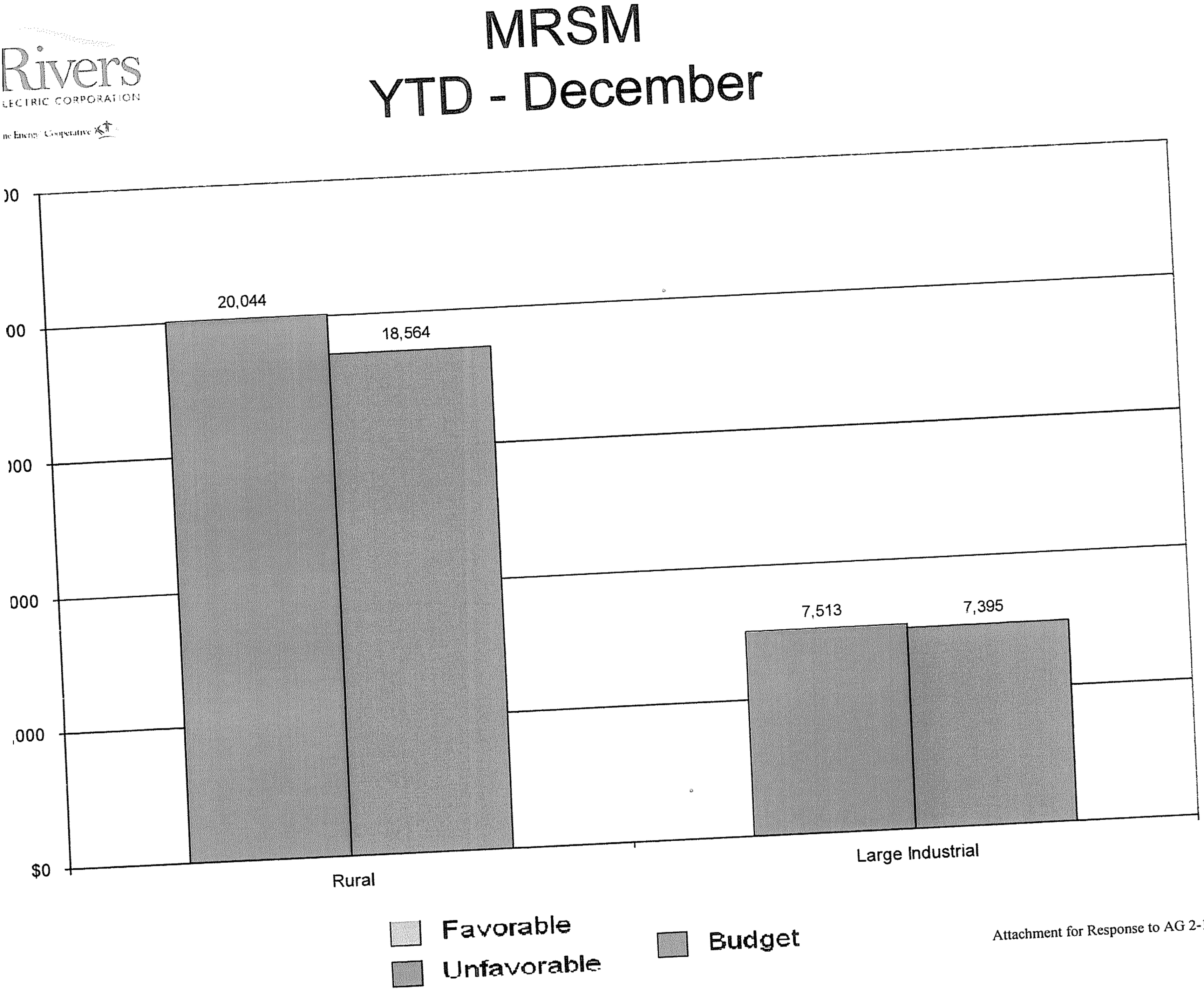
MRSM
YTD - December



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Rivers
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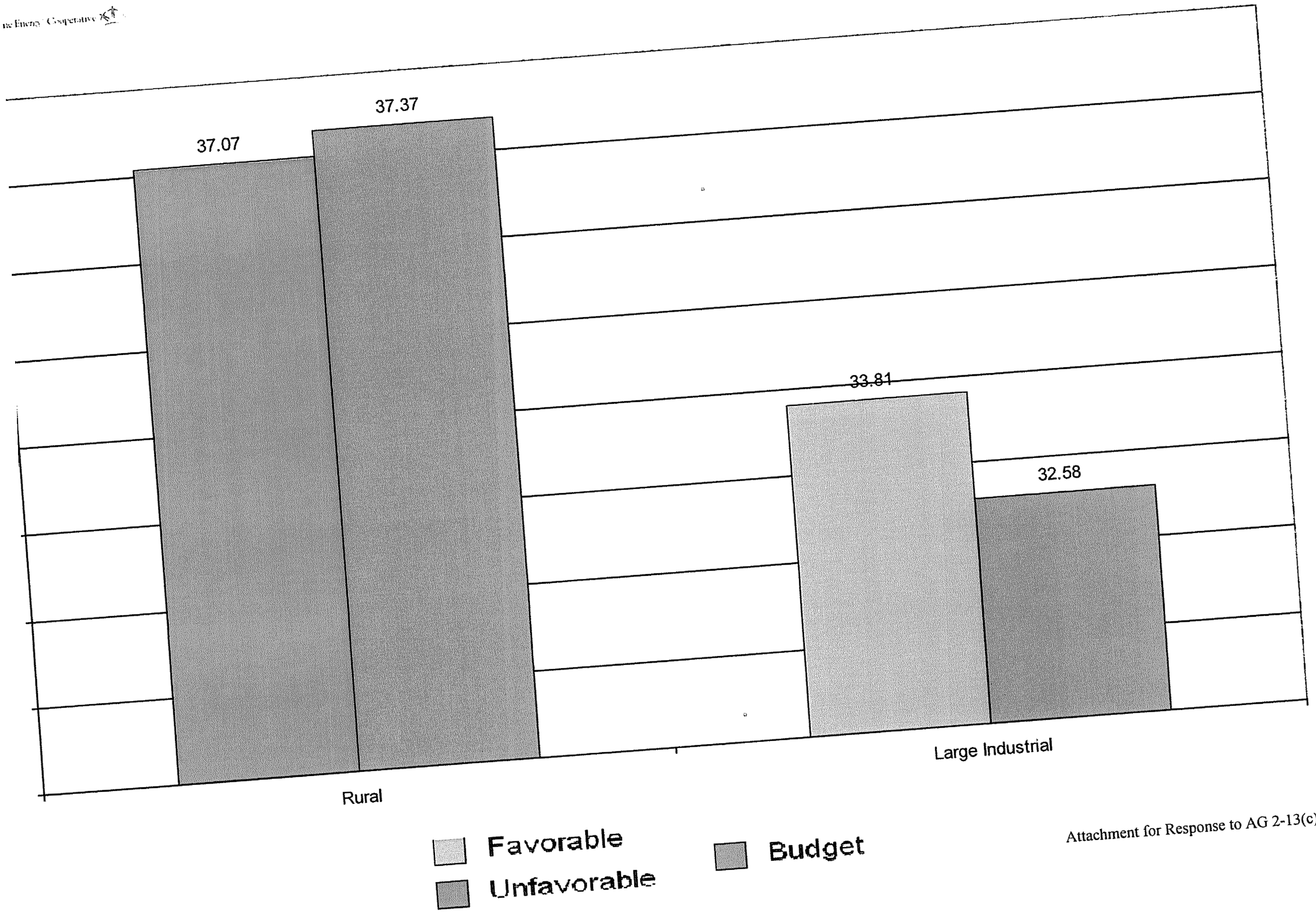
Net Revenue (Excl. MRSM) - $/MWh
YTD – December



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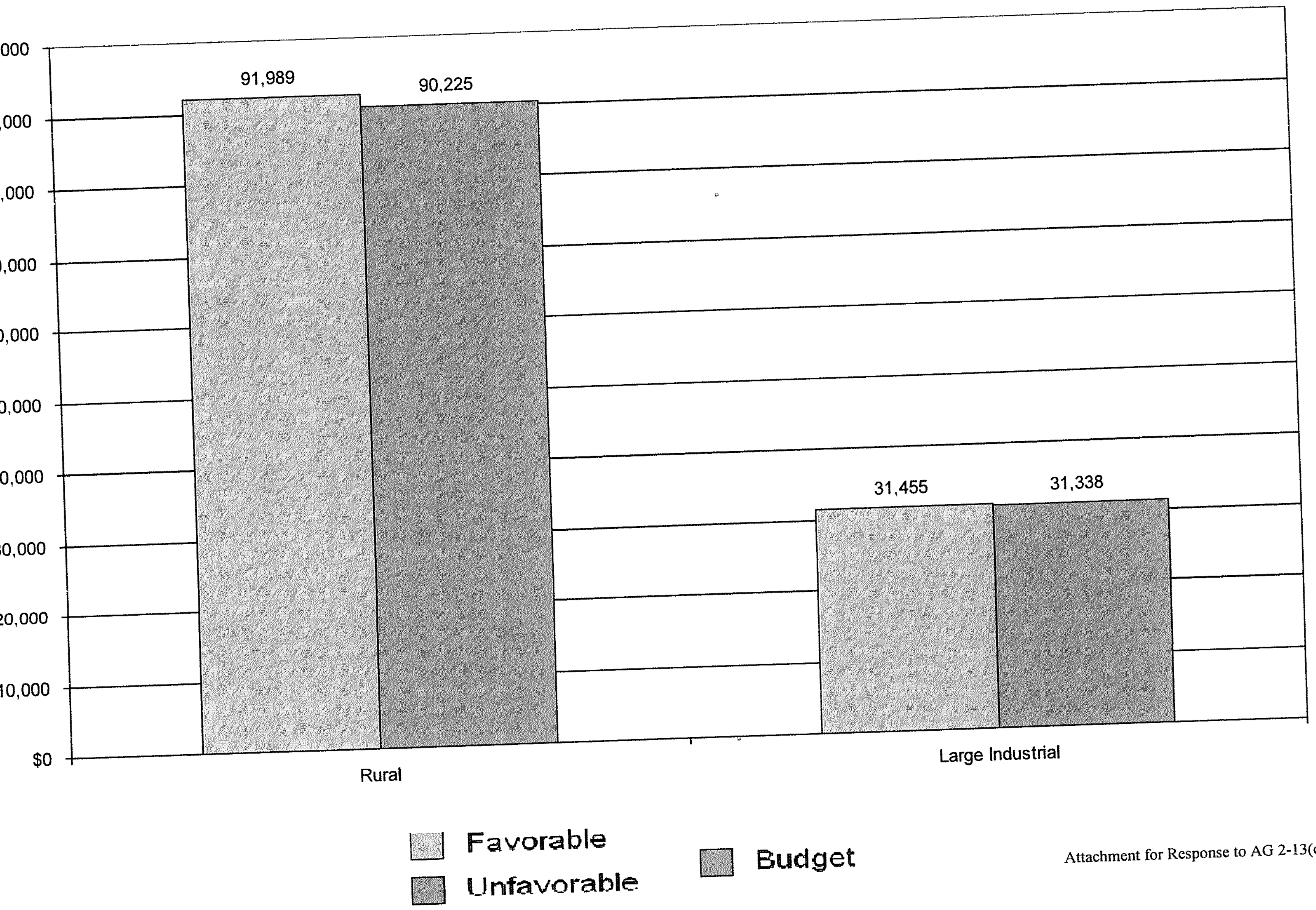
Net Revenue (Excl. MRSM)
YTD - December



Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

Other Operating Revenue and Income

	Actual	Budget	Variance Fav/(Unfav)
December YTD	12,834	7,482	5,352

Favorable primarily due to power supply transmission reservation, which is offset in Operation Expense – Other Power Supply.

Rivers
ELECTRIC CORPORATION

Non-Variable Production and Other Power Supply – Operations

	Actual	Budget	Variance Fav/(Unfav)
December YTD	71,476	66,091	(5,385)

	Fav/(UnFav)
er Supply - Transmission Reservation	(5,251)
r	(134)
Non-Variable Production and Other Power Supply - Operations	(5,385)

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

Operation Expense – Admin & General

	Actual	Budget	Variance Fav/(Unfav)
December YTD	26,462	29,634	3,172

Explanation:

Favorable primarily due to reduction in IT expense for HP due to the Oracle "go-live" delay, and various other company-wide administrative support expenses.

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION
...one Energy Cooperative

Maintenance Expense – Production

	Actual	Budget	Variance Fav/(Unfav)
December YTD	42,157	37,404	(4,753)

Explanation:

Unfavorable primarily due to the Coleman 2 planned outage and FGD work.

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

Other Non-Operating Income

	Actual	Budget	Variance Fav/(Unfav)
December YTD	2,321	0	2,321

Explanation:

Favorable primarily due to the write-off of the M&S inventory obsolescence reserve and the settlement with Alstom related to the Station Two SCR.

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

Financial Report
January 2011
($ in Thousands)

Board Meeting Date: March 18, 2011

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION
...ne Energy Cooperative

Summary of Operations
January

	2011 Actual	2011 Budget	Fav/(UnFav) Variance	2010 Actual	Fav/(UnFav) Variance
...ues	45,370	48,020	(2,650)	47,453	(2,083)
...f Electric Service	45,304	44,879	(425)	43,619	(1,685)
...ting Margins	66	3,141	(3,075)	3,834	(3,768)
...st Income/Other	32	33	(1)	31	1
...argins - YTD	98	3,174	(3,076)	3,865	(3,767)

Attachment for Response to AG 2-13(c)

Statement of Operations – January

Variance to Budget

Big Rivers Electric Corporation

	Actual	Budget	Variance Fav/(UnFav)	Explanation
ELECTRIC ENERGY REVENUES	45,224	46,430	(1,206)	[A] Pages 7, 12-14
INCOME FROM LEASED PROPERTY - NET	0	0	0	
OTHER OPERATING REVENUE AND INCOME	146	1,590	(1,444)	[B], [C] Page 26
TOTAL OPER REVENUES & PATRONAGE CAPITAL	45,370	48,020	(2,650)	
OPERATION EXPENSE-PRODUCTION-EXCL FUEL	4,221	5,179	958	[A] Pages 7, 12-14, [B] 27
OPERATION EXPENSE-PRODUCTION-FUEL	19,915	17,319	(2,596)	[A] Pages 7, 12-14
OPERATION EXPENSE-OTHER POWER SUPPLY	8,468	8,833	365	[A] Pages 7, 12-14, [B] 26,27
OPERATION EXPENSE-TRANSMISSION	897	1,392	495	[B] Page 28
CONSUMER SERVICE & INFORMATIONAL EXPENSE	25	94	69	
OPERATION EXPENSE-SALES	6	60	54	
OPERATION EXPENSE-ADMINISTRATIVE & GENERAL	1,981	2,103	122	
TOTAL OPERATION EXPENSE	35,513	34,980	(533)	
MAINTENANCE EXPENSE-PRODUCTION	2,779	2,593	(186)	
MAINTENANCE EXPENSE-TRANSMISSION	281	251	(30)	
MAINTENANCE EXPENSE-GENERAL PLANT	15	9	(6)	
TOTAL MAINTENANCE EXPENSE	3,075	2,853	(222)	
DEPRECIATION & AMORTIZATION EXPENSE	2,860	2,965	105	
TAXES	0	21	21	
INTEREST ON LONG-TERM DEBT	3,945	4,030	85	
INTEREST CHARGED TO CONSTRUCTION-CREDIT	(124)	(3)	121	
OTHER INTEREST EXPENSE	21	21	0	
OTHER DEDUCTIONS	14	12	(2)	
TOTAL COST OF ELECTRIC SERVICE	45,304	44,879	(425)	
OPERATING MARGINS	66	3,141	(3,075)	
INTEREST INCOME	30	33	(3)	
ALLOWANCE FOR FUNDS USED DURING CONST	0	0	0	
OTHER NON-OPERATING INCOME - NET	2	0	2	
OTHER CAPITAL CREDITS & PAT DIVIDENDS	0	0	0	
EXTRAORDINARY ITEMS	0	0	0	
NET PATRONAGE CAPITAL OR MARGINS	98	3,174	(3,076)	

Attachment for Response to AG 2-13(c)

Explanations: [A] Net Sales Margin, [B] 10% and $250,000 line item or [C] 10% and $500,000 margins.

Rivers Electric Corporation

Statement of Operations – January

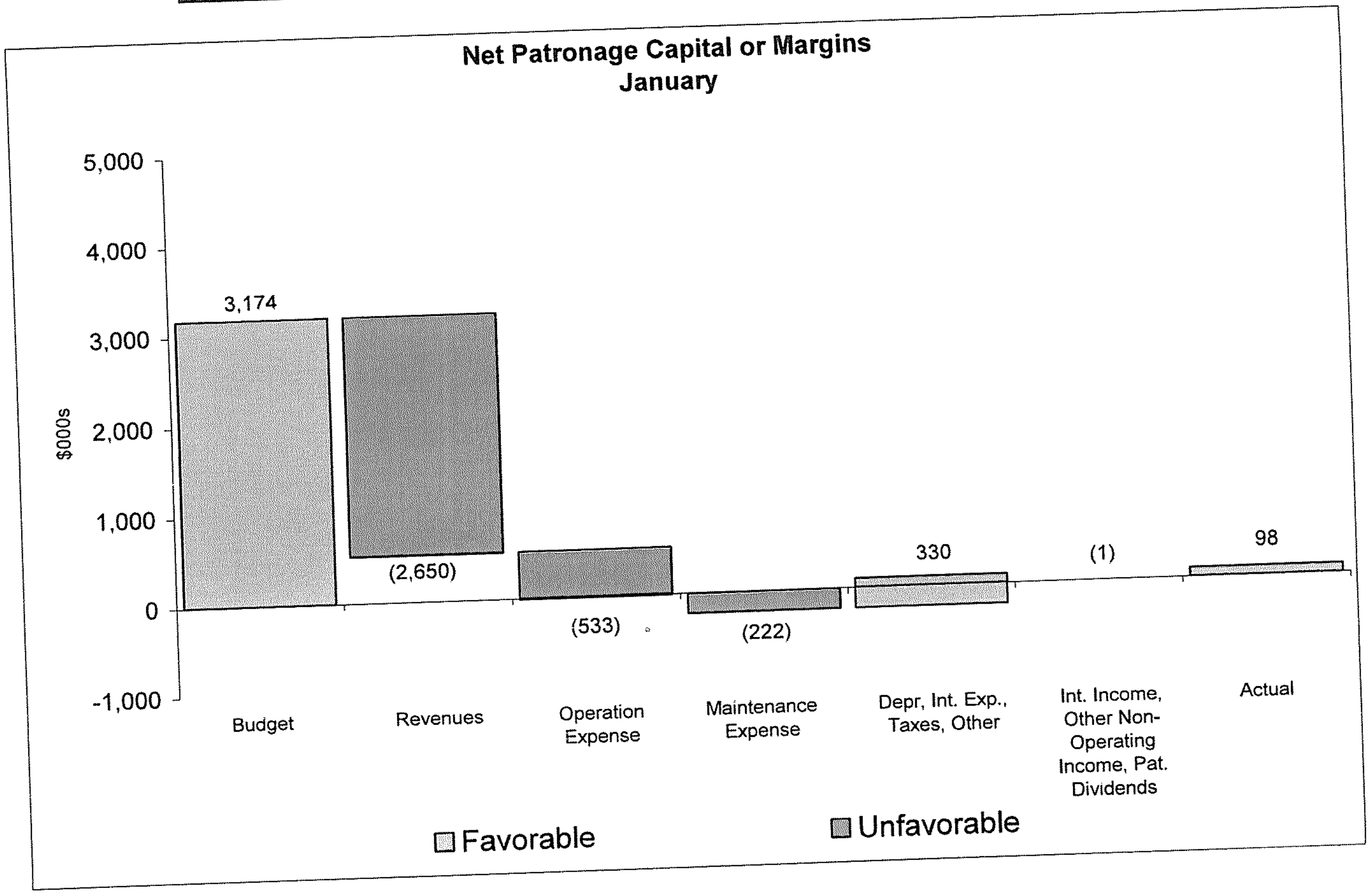
Variance to Prior-Year

	Actual	Prior Year	Variance Fav/(UnFav)	Explanation
ELECTRIC ENERGY REVENUES	45,224	46,300	(1,076)	[A] Pages 7, 12-14
INCOME FROM LEASED PROPERTY - NET	0	0	0	
OTHER OPERATING REVENUE AND INCOME	146	1,153	(1,007)	[B], [C] Page 26
TOTAL OPER REVENUES & PATRONAGE CAPITAL	45,370	47,453	(2,083)	
OPERATION EXPENSE-PRODUCTION-EXCL FUEL	4,221	4,018	(203)	[A] Pages 7, 12-14
OPERATION EXPENSE-PRODUCTION-FUEL	19,915	19,108	(807)	[A] Pages 7, 12-14
OPERATION EXPENSE-OTHER POWER SUPPLY	8,468	8,418	(50)	[A] Pages 7, 12-14, [B] 26
OPERATION EXPENSE-TRANSMISSION	897	605	(292)	[B] Page 28
CONSUMER SERVICE & INFORMATIONAL EXPENSE	25	41	16	
OPERATION EXPENSE-SALES	6	7	1	
OPERATION EXPENSE-ADMINISTRATIVE & GENERAL	1,981	2,037	56	
TOTAL OPERATION EXPENSE	35,513	34,234	(1,279)	
MAINTENANCE EXPENSE-PRODUCTION	2,779	2,111	(668)	[B],[C] Page 29
MAINTENANCE EXPENSE-TRANSMISSION	281	208	(73)	
MAINTENANCE EXPENSE-GENERAL PLANT	15	15	0	
TOTAL MAINTENANCE EXPENSE	3,075	2,334	(741)	
DEPRECIATION & AMORTIZATION EXPENSE	2,860	2,830	(30)	
TAXES	0	0	0	
INTEREST ON LONG-TERM DEBT	3,945	4,235	290	
INTEREST CHARGED TO CONSTRUCTION-CREDIT	(124)	(19)	105	
OTHER INTEREST EXPENSE	21	0	(21)	
OTHER DEDUCTIONS	14	5	(9)	
TOTAL COST OF ELECTRIC SERVICE	45,304	43,619	(1,685)	
OPERATING MARGINS	66	3,834	(3,768)	
INTEREST INCOME	30	29	1	
ALLOWANCE FOR FUNDS USED DURING CONST	0	0	0	
OTHER NON-OPERATING INCOME - NET	2	2	0	
OTHER CAPITAL CREDITS & PAT DIVIDENDS	0	0	0	
EXTRAORDINARY ITEMS	0	0	0	
NET PATRONAGE CAPITAL OR MARGINS	98	3,865	(3,767)	

Attachment for Response to AG 2-13(c)

Explanations: [A] Net Sales Margin, [B] 10% and $250,000 line item or [C] 10% and $500,000 margins.

Variance Analysis Summary



Financial Commentary

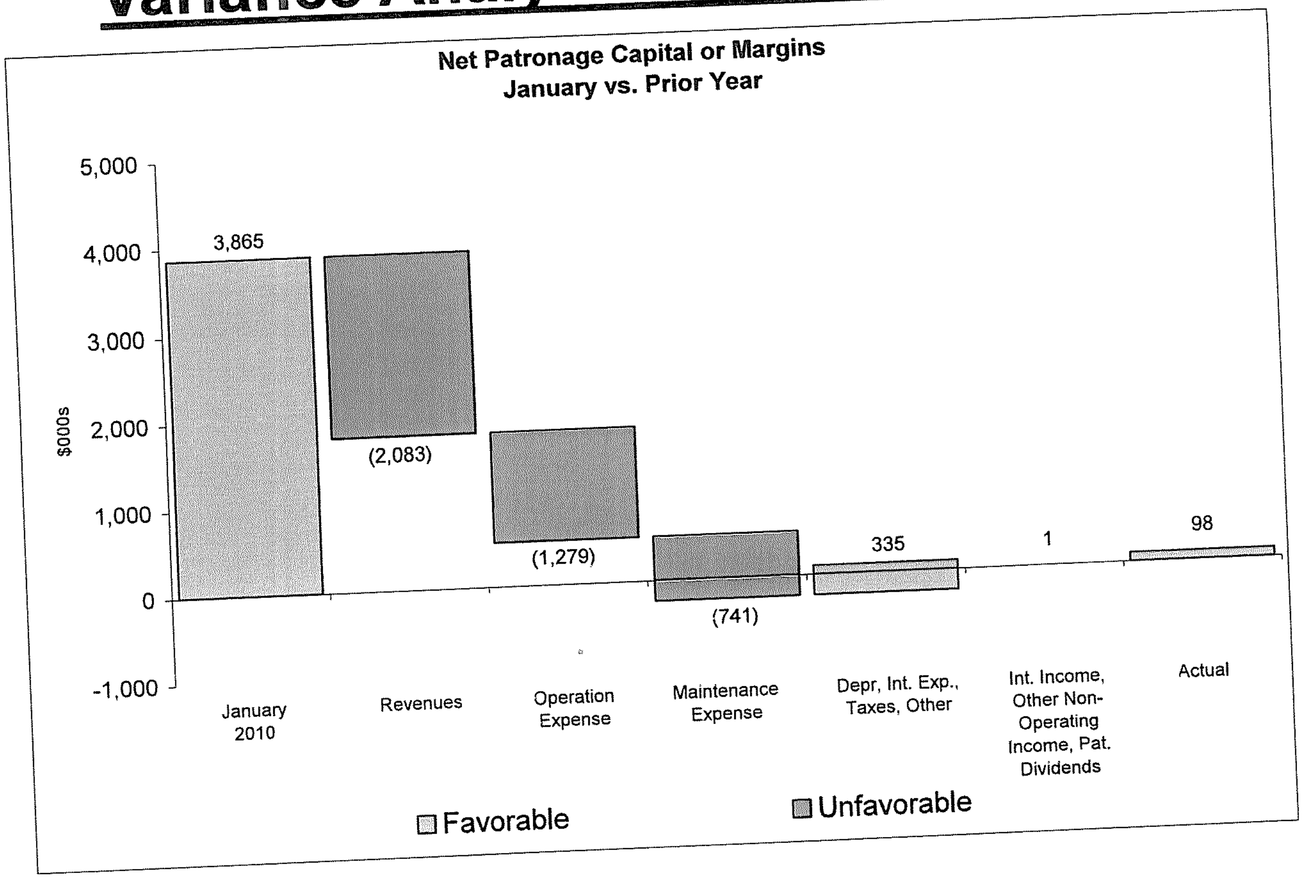
Year-to-Date

- Net Margins YTD were $3,076 lower than budget.
  - Electric Energy Revenues were unfavorable $1,206 primarily due to lower member and off-system pricing (see pg. 12).
  - Other Revenue was unfavorable $1,444 primarily due to a lower power supply transmission reservation, which is off-set in Operations Expense – Other Power Supply (see pg. 26).
  - Operation Expense was unfavorable $533 – driven by higher variable costs $2,439, partially offset by lower transmission reservation and favorable timing of fixed expenses (see pgs. 13, 26 and 27).
  - Maintenance Expense was unfavorable $222 primarily due timing of plant expenses.
  - Depreciation and Interest Expense was lower $330.

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

Variance Analysis Summary



Financial Commentary

Year-to-Date

- Net Margins YTD were $3,767 worse than January 2010.
  - Electric Energy Revenues were unfavorable $1,076 primarily due to lower member and off-system pricing (see pg. 12).
  - Other Revenue was unfavorable $1,007 primarily due to a lower power supply transmission reservation, which is off-set in Operations Expense – Other Power Supply (see pg. 26).
  - Operation Expense was unfavorable $1,279 – driven by higher variable costs $1,650, partially offset by lower transmission reservation (see pgs. 13 and 27).
  - Maintenance Expense was unfavorable $741 primarily due to an unplanned outage at Coleman this year and higher planned maintenance activities at the plants (pg. 29).
  - Depreciation and Interest Expense was lower $335.

Attachment for Response to AG 2-13(c)

Rivers
ECTRIC CORPORATION
Energy Cooperative

MRSM
January

	Actual 2011	Budget 2011	2011 Variance	Actual 2010	2010 Variance
Wh					
	(4.94)	(6.43)	1.49	(10.33)	5.39
trial	(4.94)	(6.43)	1.49	(10.33)	5.39
	(4.94)	(6.43)	1.49	(10.33)	5.39
usands of $					
	(1,279)	(1,646)	367	(2,719)	1,440
trial	(395)	(488)	93	(775)	380
	(1,674)	(2,134)	460	(3,494)	1,820

	Actual 2011	Budget 2011	2011 Variance	Actual 2010	2010 Variance
Net Revenue - $/MWh					
Rural	36.21	37.82	(1.61)	33.25	2.96
Large Industrial	34.60	34.43	0.17	31.29	3.31
Total	35.83	37.04	(1.21)	32.82	3.01
Net Revenue - Thousands of $					
Rural	9,393	9,670	(277)	8,754	639
Large Industrial	2,762	2,629	133	2,349	413
Total	12,155	12,299	(144)	11,103	1,052

Economic Reserve Balance

	Actual	Budget	Variance
Original Deposit	$ 157,000		
Interest Earnings	1,956		
Withdrawals	(40,097)		
Cumulative through Jan 31st	$ 118,859	$ 119,967	$ (1,108)

Attachment for Response to AG 2-13(c)

Rivers
LECTRIC CORPORATION
...ne Energy Cooperative

Cash & Temporary Investments

	Actual	Budget	Fav/(Unfav)	2010 Actual	Fav/(Unfav)
January 31, 2011	49,448	36,547	12,901	30,213	19,235

anuary 31st cash balance compared to budget is favorable primarily due to a higher ing balance, lower capital expenditures and a reduction in fuel inventory.

anuary 31st cash balance compared to prior year is favorable primarily due to the ary pre-payment of RUS debt that was made in January 2010.

Lines of Credit As of January 31	
Original Amount	$ 100,000
Letters of Credit Outstanding	(5,929)
Advances Outstanding	(10,000)
Available Lines of Credit	$ 84,071

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

North Star – YTD 1/31/2011

	Actual	Budget	Fav/(UnFav)	2010 Actual	Fav/(UnFav)
st of Electric Service	45,304	44,878	(426)	43,619	(1,685)
erating Revenues & Income	(146)	(1,590)	(1,444)	(1,153)	(1,007)
em Sales	[redacted]				
ncome	(30)	(33)	(3)	(29)	1
on-Operating Income	(2)	0	2	(2)	0
apital Credits & Pat. Dividends	0	0	0	0	0
	[redacted]				
r MWh	885,532	951,029	(65,497)	881,729	3,803
tar - $/kWh	[redacted]				

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

TIER

	Actual	Budget	Fav/(Unfav)
rest on Long Term Debt	3,945	4,030	85
Margins	98	3,175	(3,077)
R	1.02	1.79	(0.77)
ER (12 months ending 1/31)	1.07	1.10	(0.03)

Notes:

TIER = (Net Margins + Interest on Long-Term Debt) divided by Interest on Long-Term Debt

Attachment for Response to AG 2-13(c)

Rivers
LECTRIC CORPORATION
ne Energy Cooperative

Capital Expenditures*

	Actual	Budget	Fav/(UnFav)
IT	238	20	(218)
Generation	300	1,865	1,565
Transmission	1,381	1,092	(289)
Other	0	779	779
Total	**1,919**	**3,756**	**1,837**

:xplanation:

T unfavorable due to Oracle.

3eneration favorable primarily due to the timing of projects. The Cathodic Protection & Feedwater Heater Extraction it Station Two was moved from January to April causing a favorable variance of $308. Green Station was favorable ;1,016 due to several projects being moved from January to the Spring. These include Condenser Water Box Coating, Clarifier Coating, Sample & Analyzers and Drum Camera Replacements.

Transmission unfavorable primarily due to the timing of the Wilson Line 19F Terminal.

Other favorable primarily due to the delay in purchasing the PCI Software and the Operator Training Simulator.

* Gross of the City's share of Station Two and capitalized interest.

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

Revenue
January

MWh Sales	Actual 2011	Budget 2011	2011 Variance	Actual 2010	2010 Variance
Rural	259,369	255,727	3,642	263,265	(3,896)
Large Industrial	79,846	76,290	3,556	75,056	4,790
Smelter	546,317	619,012	(72,695)	543,408	2,909
Off-System/Other	[redacted]				
Total					

Revenue - $/MWh	Actual 2011	Budget 2011	2011 Variance	Actual 2010	2010 Variance
Rural	41.15	44.25	(3.10)	43.58	(2.43)
Large Industrial	39.54	40.86	(1.32)	41.62	(2.08)
Smelter	41.11	41.60	(0.49)	43.35	(2.24)
Off-System/Other	[redacted]				
Total					

Revenue - Thousands of $	Actual 2011	Budget 2011	2011 Variance	Actual 2010	2010 Variance
Rural	10,672	11,316	(644)	11,473	(801)
Large Industrial	3,157	3,117	40	3,124	33
Smelter	22,458	25,751	(3,293)	23,555	(1,097)
Off-System/Other	[redacted]				
Total					

Revenue Price / Volume Analysis
YTD January

	Price / Volume: Price	Volume	Total
Rural	(805)	161	(644)
Large Industrial	(106)	146	40
Smelter	(269)	(3,024)	(3,293)
Off-System/Other	[redacted]		

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION
tone Energy Cooperative

Variable Operations Cost
January

	Actual 2011	Budget 2011	2011 Variance	Actual 2010	2010 Variance
riable Operations (VO) Cost - $/MWh					
ural	25.44	23.81	(1.63)	25.05	(0.39)
rge Industrial	25.45	23.82	(1.63)	25.05	(0.40)
melter	24.13	22.40	(1.73)	24.56	0.43
ff-System/Other	[redacted]				
otal					
O Cost - Thousands of $					
ural	6,599	6,090	(509)	6,595	(4)
arge Industrial	2,032	1,817	(215)	1,880	(152)
melter	13,182	13,868	686	13,345	163
ff-System/Other	[redacted]				
otal					

January 2011
Variable Operations Expense

	Actual	Budget	Fav/(UnFav)	Price Variance Fav/(UnFav)	Volume Variance Fav/(UnFav)	Fav/(UnFav)
gent	2,469	2,976	507	386	121	507
l	22,438	20,089	(2,349)	(2,030)	(319)	(2,349)
chased Power	2,250	1,630	(620)	(707)	87	(620)
-FAC PPA (Non-Smelter)	446	469	23	33	(10)	23
	27,603	25,164	(2,439)	(2,318)	(121)	(2,439)

Attachment for Response to AG 2-13(c)

Net Sales Margin
January

Rivers
ELECTRIC CORPORATION
stone Energy Cooperative

	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
et Sales Margin - $/MWh					
ural	15.71	20.44	(4.73)	18.53	(2.82)
arge Industrial	14.09	17.04	(2.95)	16.57	(2.48)
melter	16.98	19.20	(2.22)	18.79	(1.81)
ff-System/Other	[redacted]				
otal					
et Sales Margin - Thousands of $					
ural	4,073	5,226	(1,153)	4,878	(805)
arge Industrial	1,125	1,300	(175)	1,244	(119)
melter	9,276	11,883	(2,607)	10,210	(934)
ff-System/Other	[redacted]				
otal					

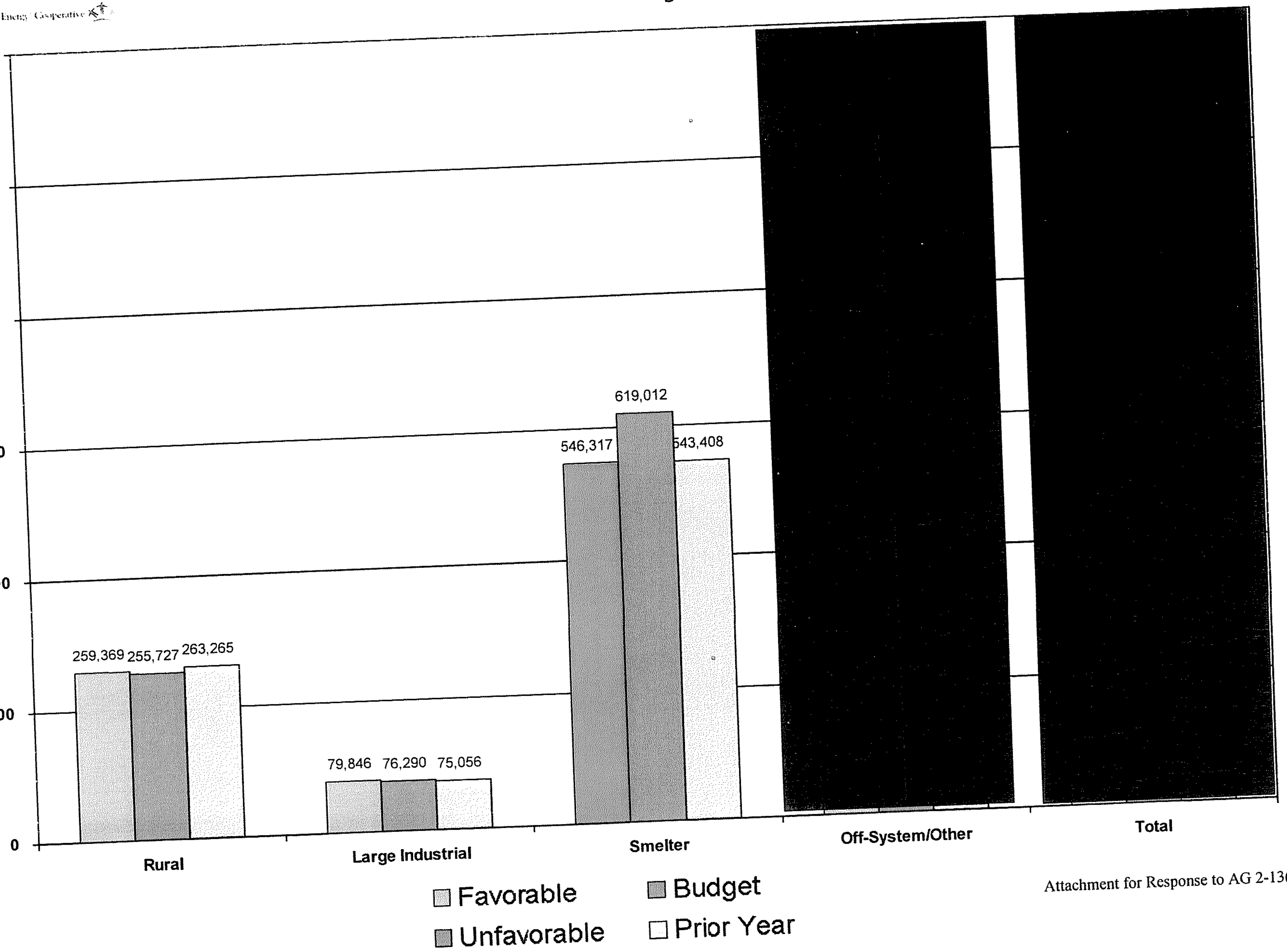
Net Sales Margin
Price / Volume Analysis
YTD January

	Price / Volume: Price	Price / Volume: Volume	Total
Rural	(1,227)	74	(1,153)
Large Industrial	(236)	61	(175)
Smelter	(1,211)	(1,396)	(2,607)
Off-System/Other	[redacted]		

[redacted]ttachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

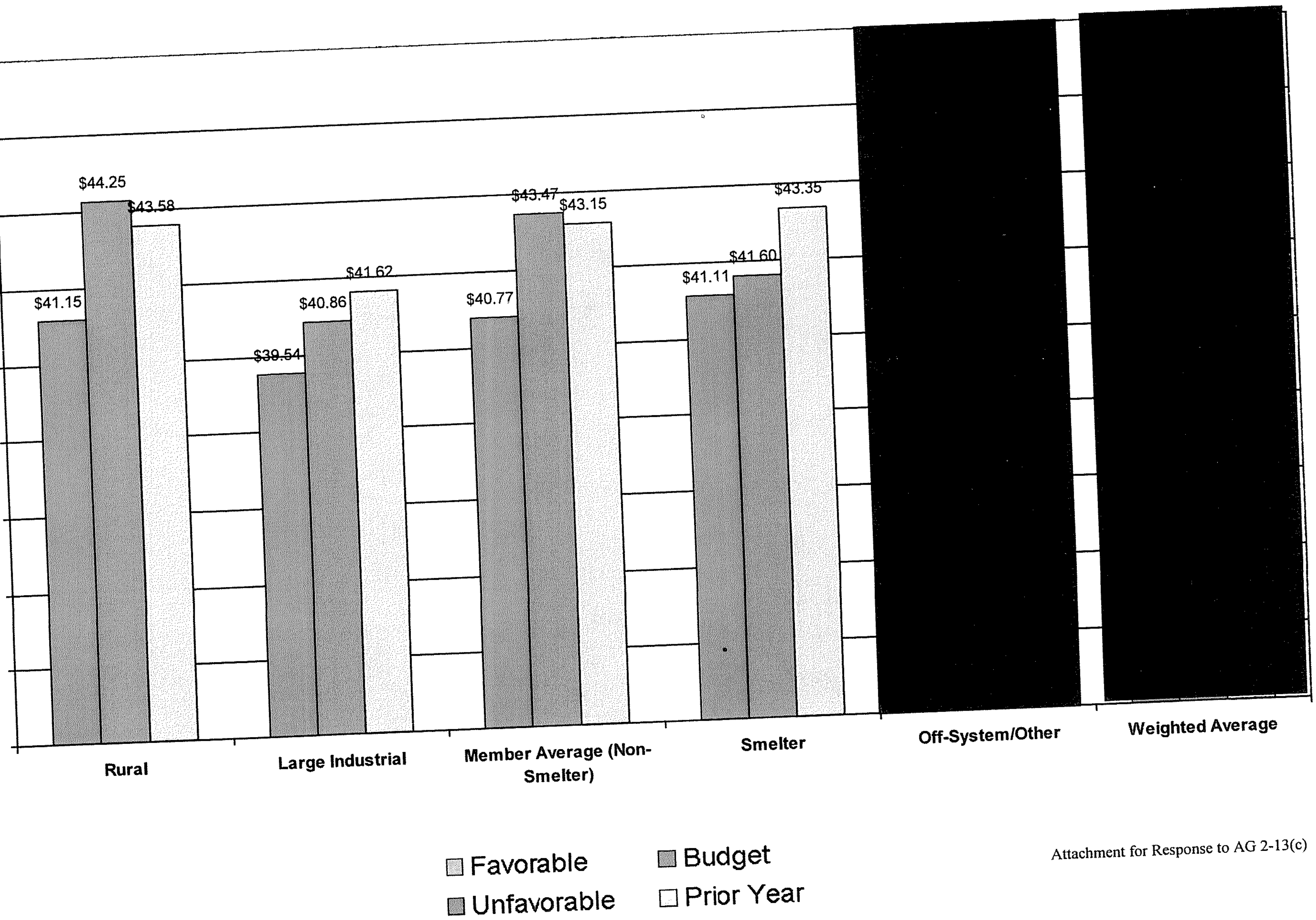
MWH Sales
January



Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

Revenue - $/MWh Sold
January



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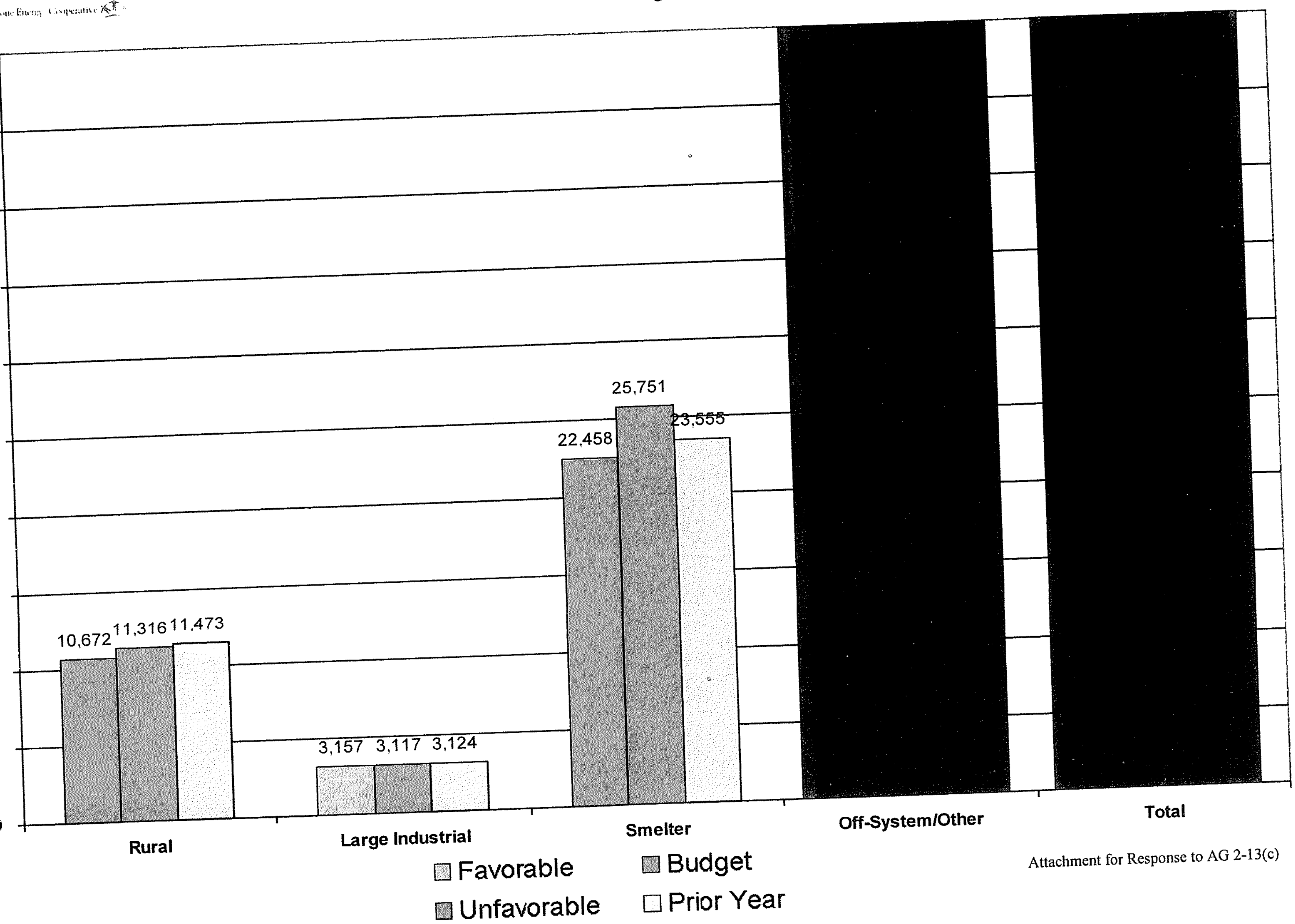
ELECTRIC CORPORATION

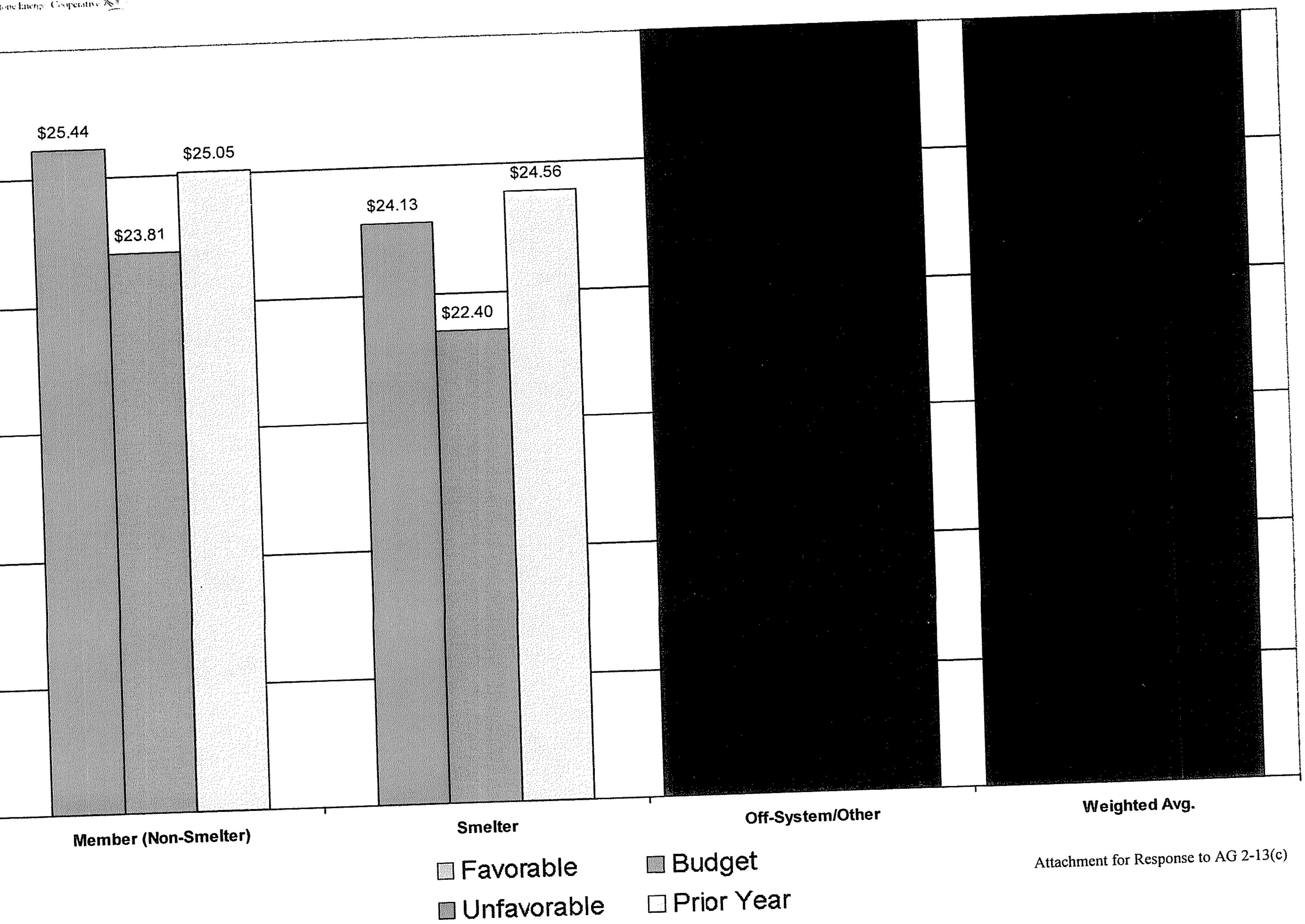
Revenue
January



Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

Power Cost - $/MWh Sold
January



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Rivers
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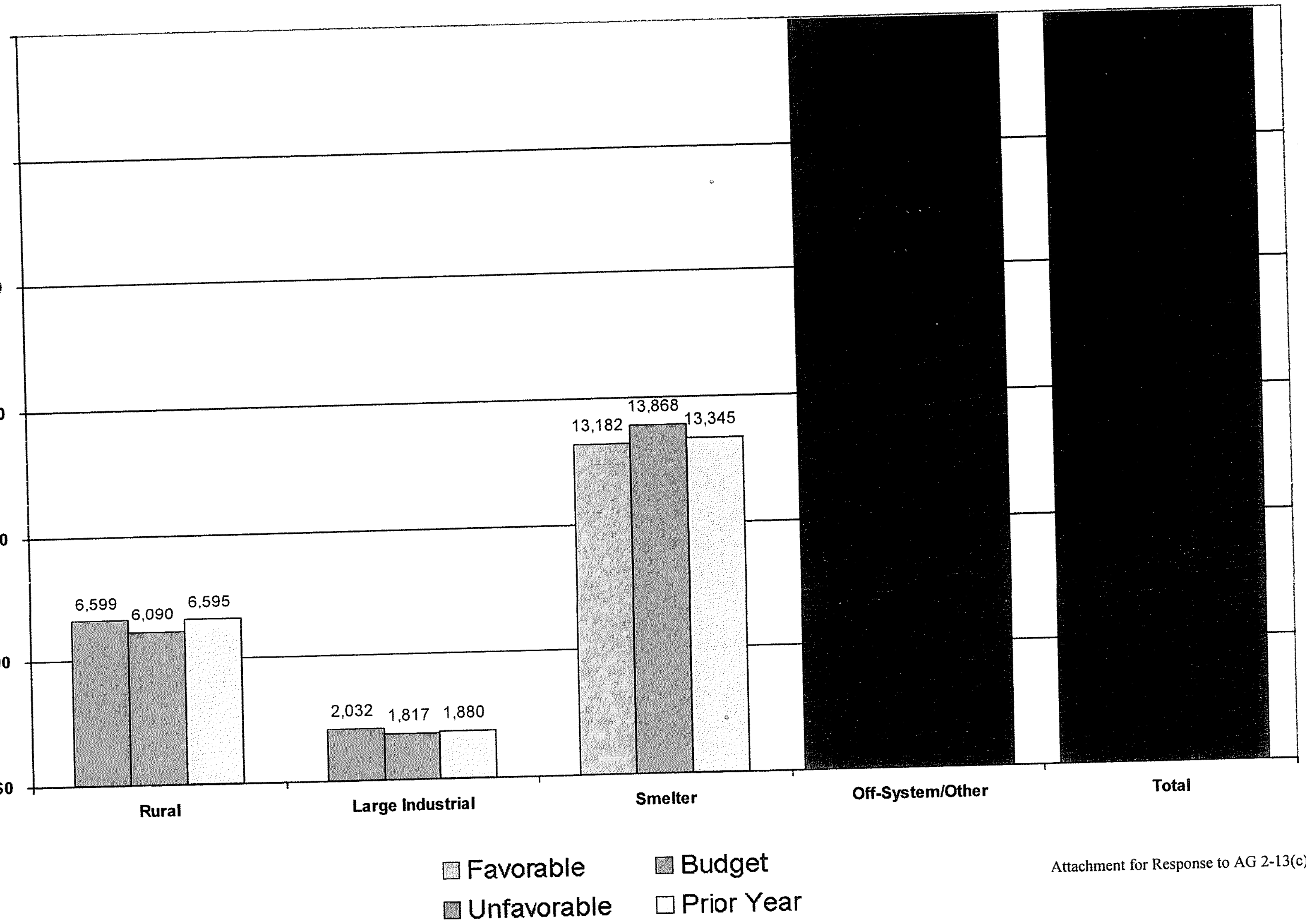
Power Cost
January



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Rivers
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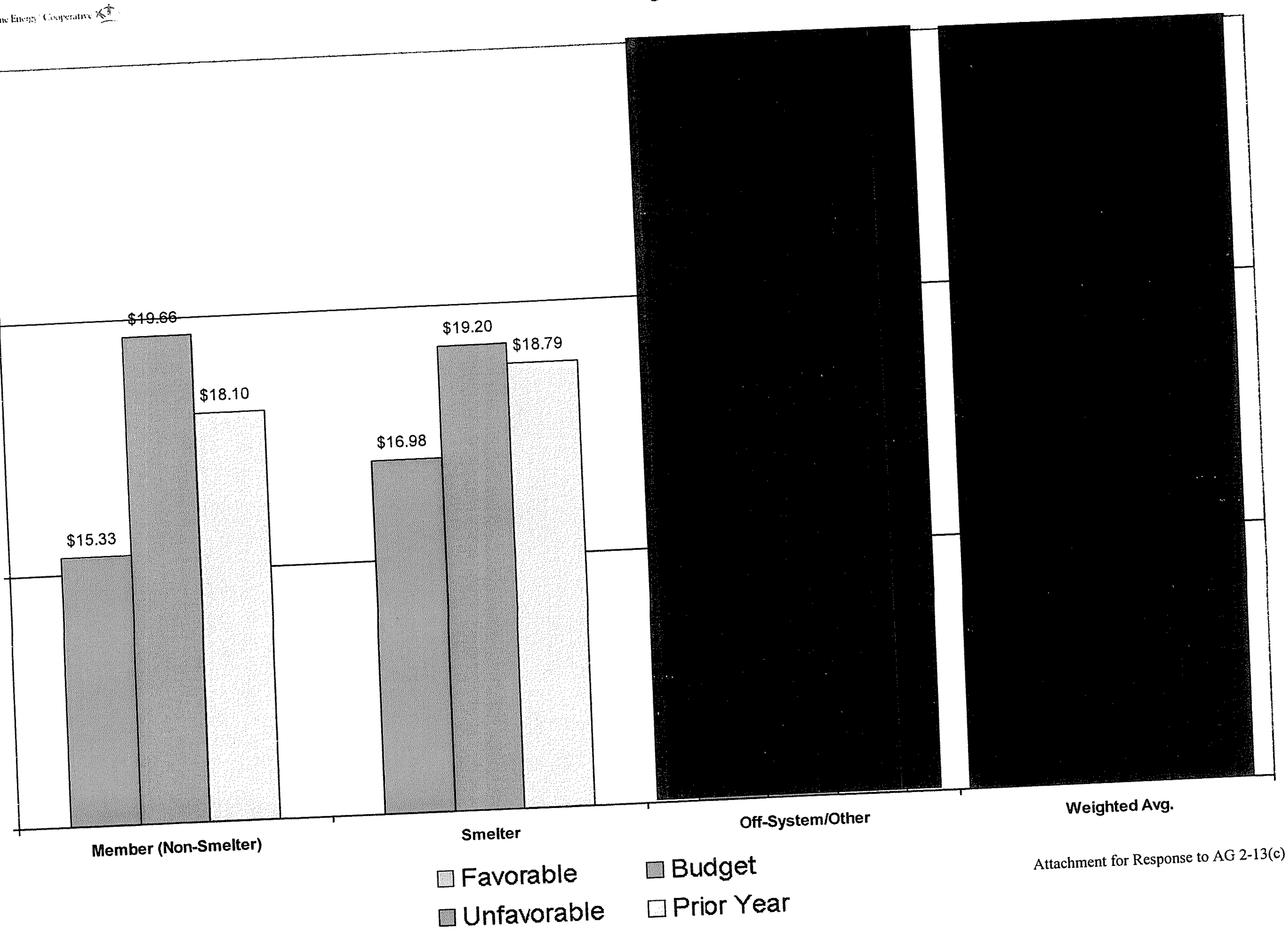
Sales Margin - $/MWh
January



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Rivers
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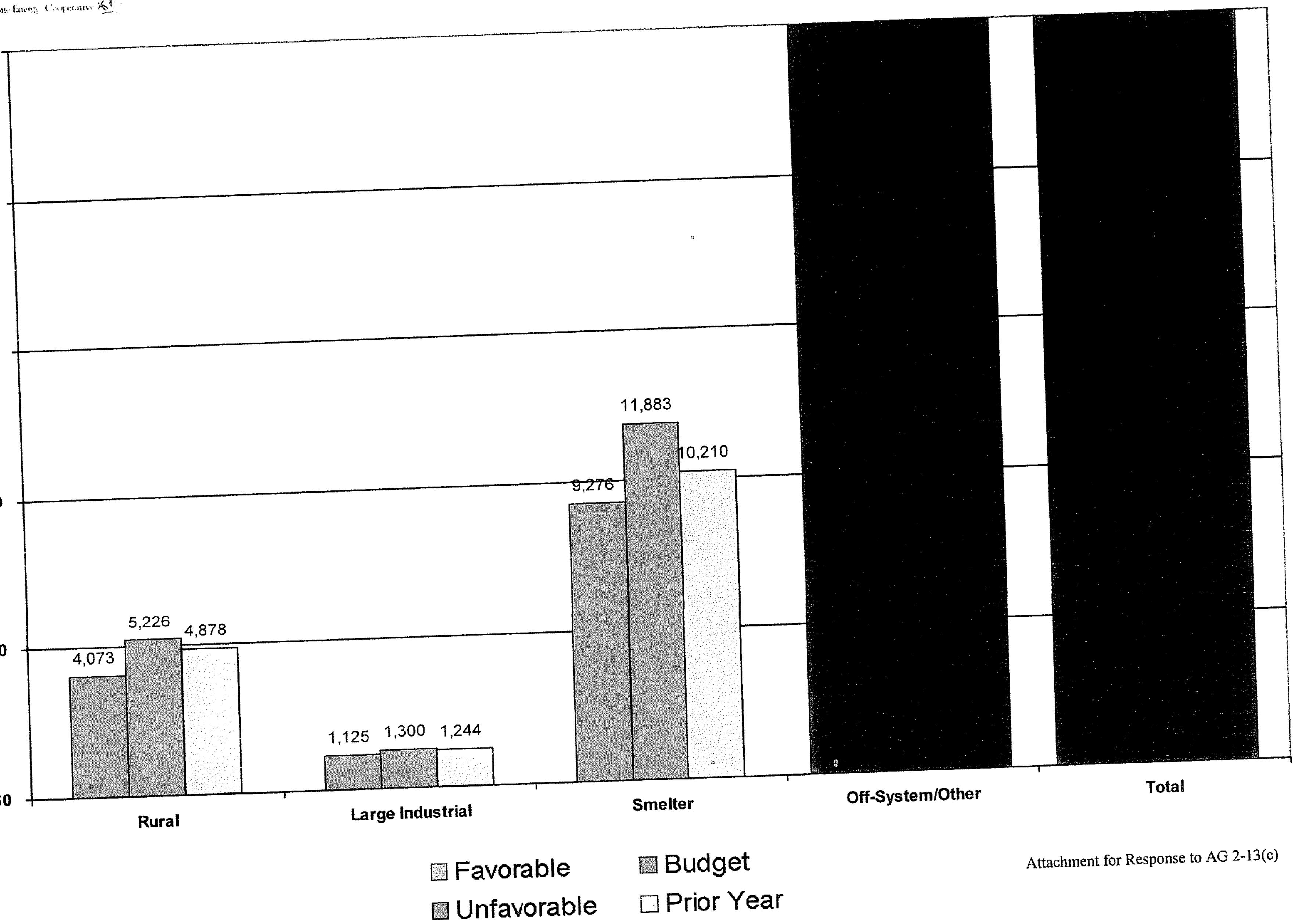
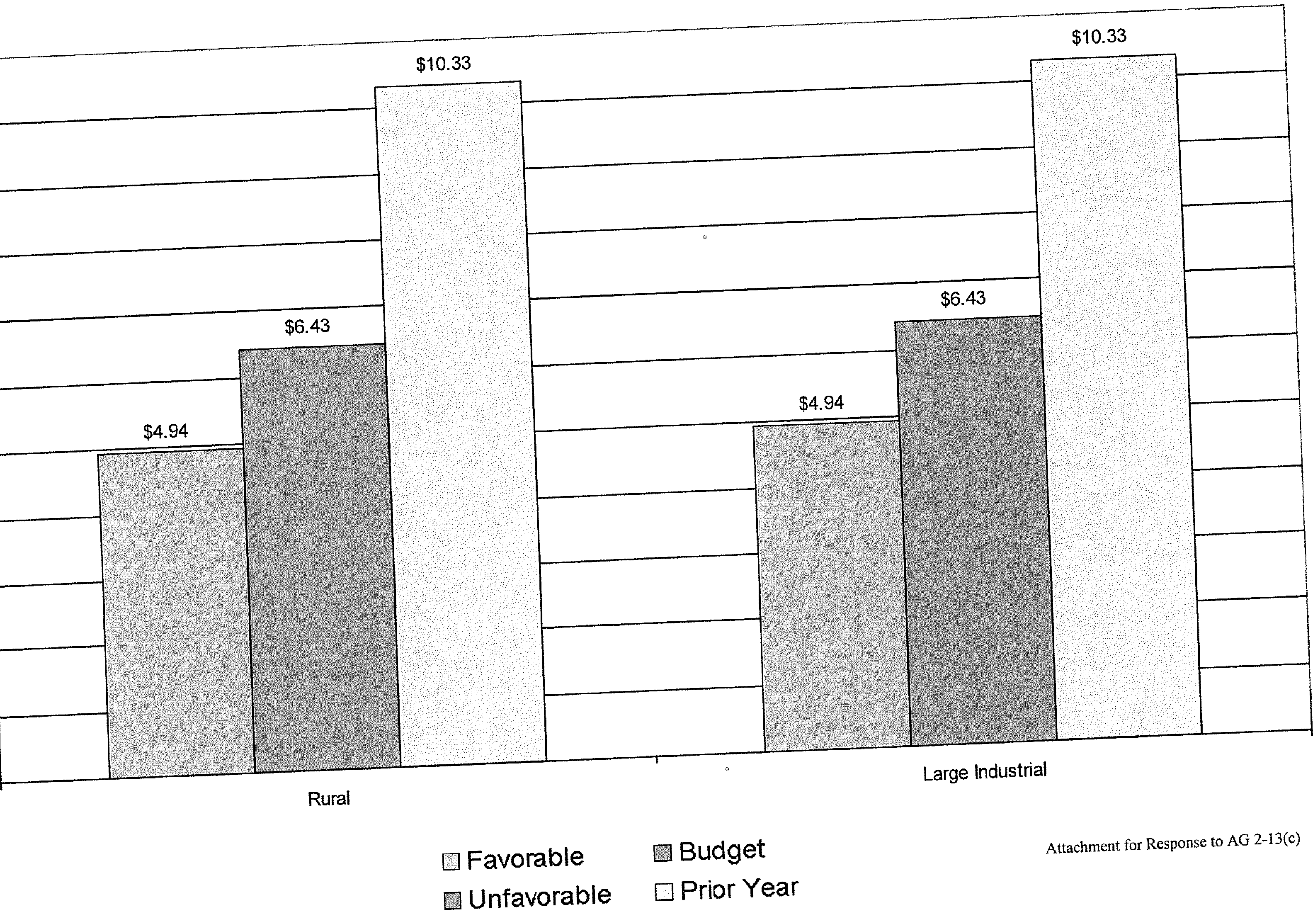
Sales Margin
January



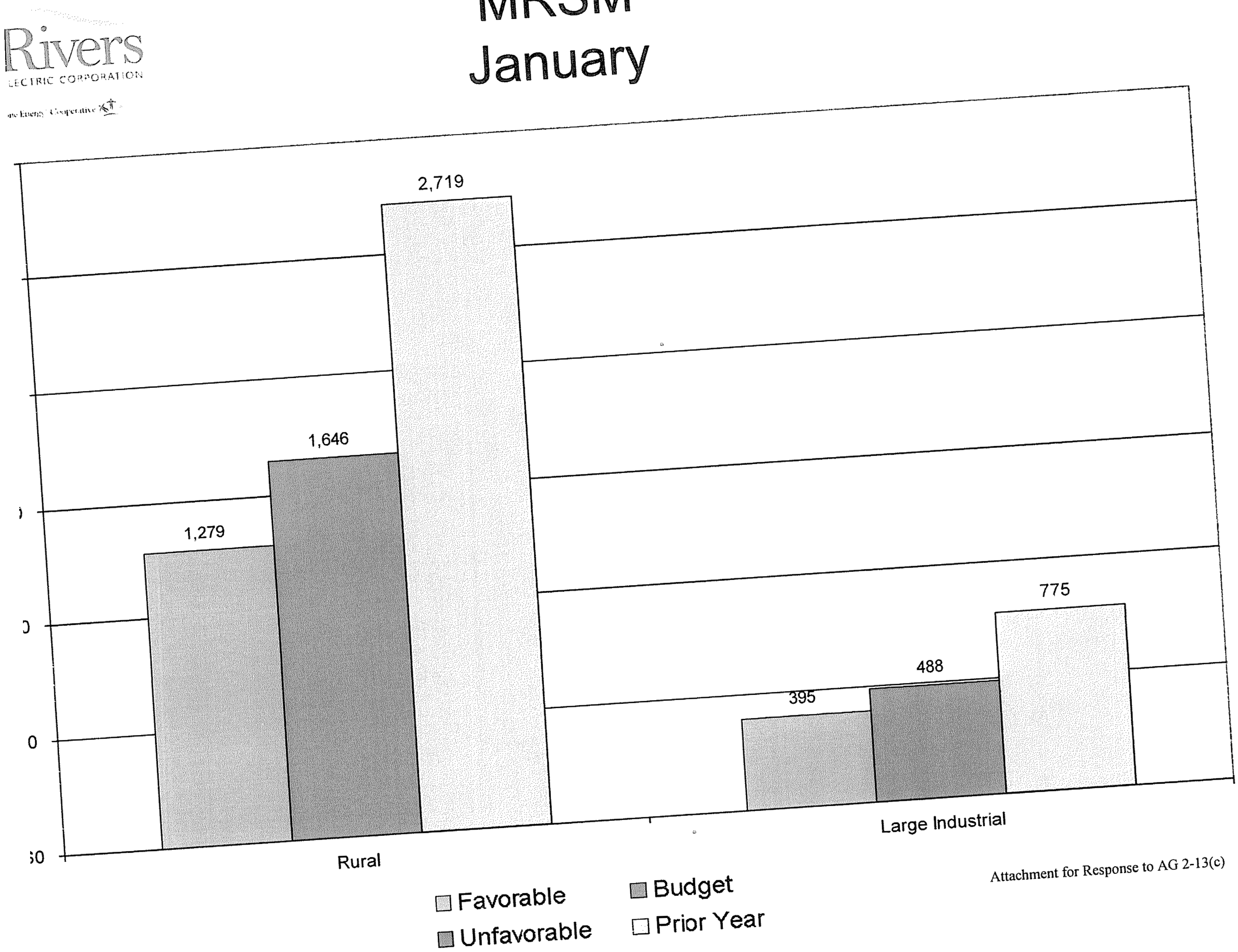
Attachment for Response to AG 2-13(c)

MRSM - $/MWh
January



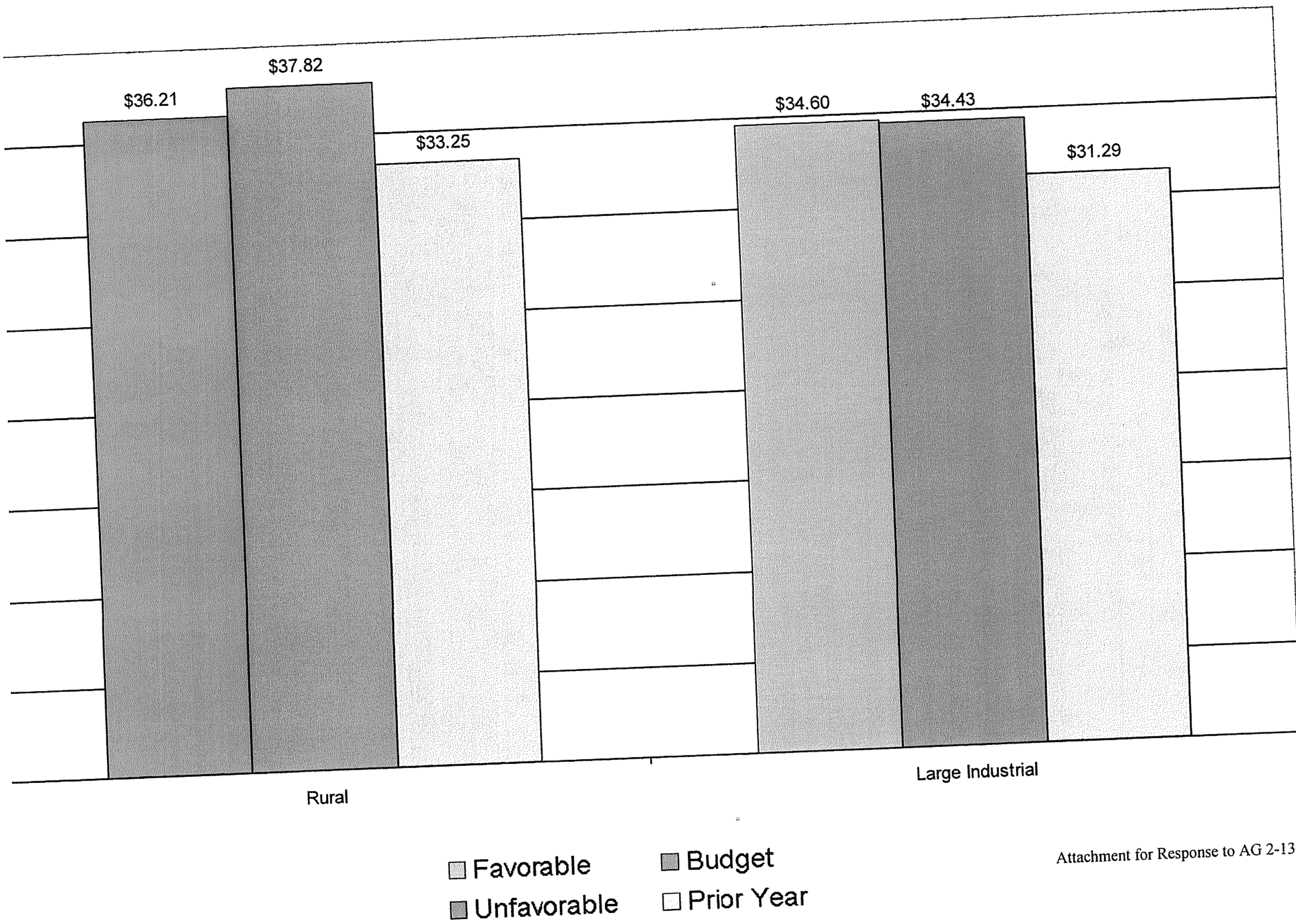
Attachment for Response to AG 2-13(c)

MRSM
January



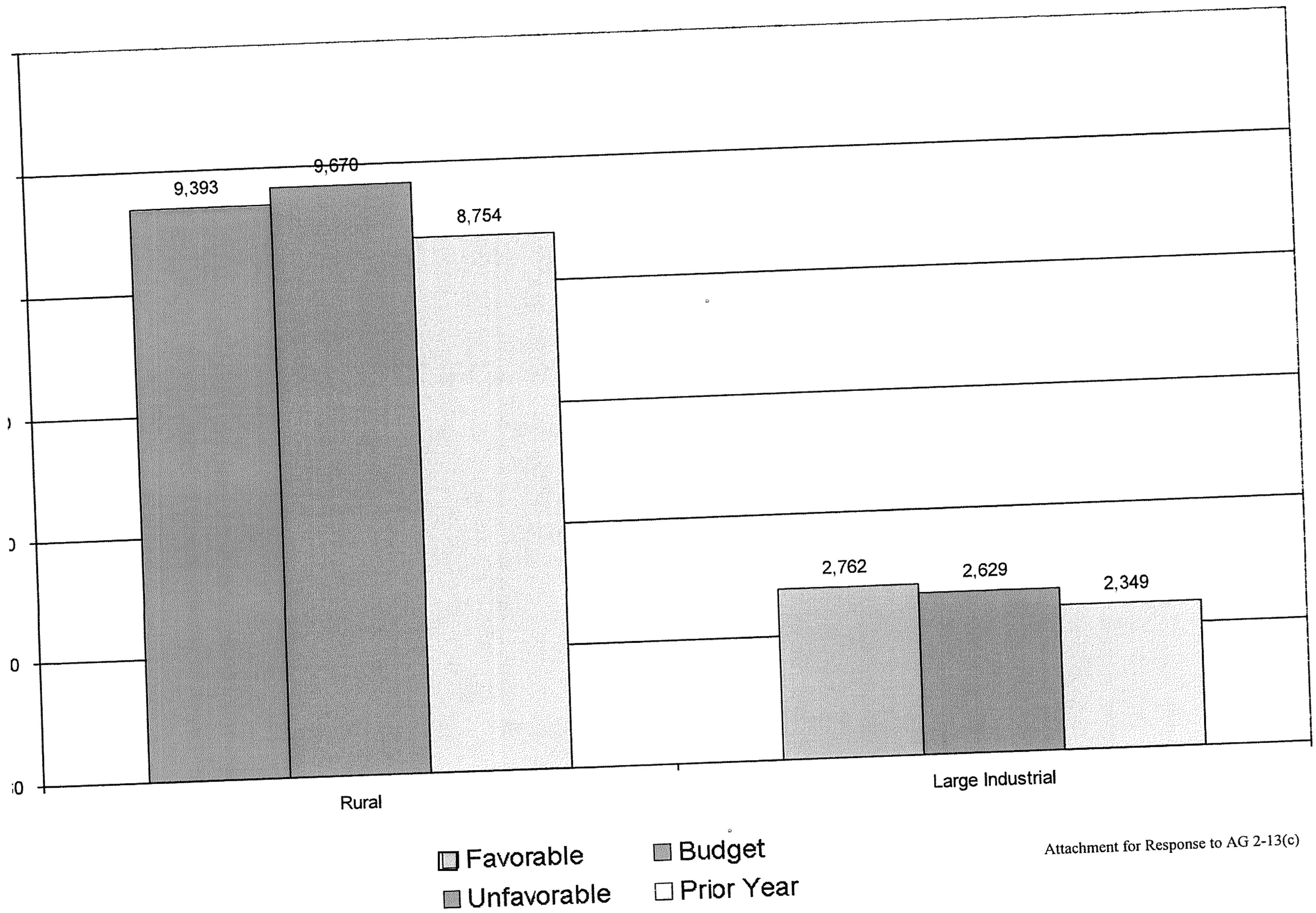
Attachment for Response to AG 2-13(c)

Net Revenue (Excl. MRSM) - $/MWh
January



Attachment for Response to AG 2-13(c)

Net Revenue (Excl. MRSM)
January



Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

Other Operating Revenue and Income

	Actual	Budget	Variance Fav/(Unfav)	2010 Actual	Variance Fav/(Unfav)
January YTD	146	1,590	(1,444)	1,153	(1,007)

Current year and prior year both unfavorable primarily due to lower power supply transmission reservation, which is offset in Operation Expense – Other Power Supply.

Rivers
ELECTRIC CORPORATION
...ne Energy Cooperative

Non-Variable Production and Other Power Supply – Operations

	Actual	Budget	Variance Fav/(Unfav)
January YTD	5,001	6,167	1,166

	Fav/(UnFav)
	1,193
...r Supply - Transmission Reservation	(27)
Non-Variable Production and Other Power Supply - Operations	1,166

Rivers
ELECTRIC CORPORATION
...one Energy Cooperative

Operation Expense – Transmission

	Actual	Budget	Variance Fav/(Unfav)	2010 Actual	Variance Fav/(Unfav)
January YTD	897	1,392	495	605	(292)

Favorable to budget primarily due to lower MISO related expenses.

Unfavorable to prior year due to MISO related expenses this year.

Attachment for Response to AG 2-13(c)

Maintenance Expense – Production

	2011 Actual	2010 Actual	Variance Fav/(Unfav)
January YTD	2,779	2,111	(668)

Unfavorable to prior year due to higher planned maintenance activities this year and an unplanned outage at Coleman.

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

Financial Report
February 2011
($ in Thousands)

Board Meeting Date: April 15, 2011

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

Summary of Operations
February

	2011			2010	
	Actual	Budget	Fav/(UnFav) Variance	Actual	Fav/(UnFav) Variance
enues	87,595	90,176	(2,581)	92,105	(4,510)
of Electric Service	87,249	85,085	(2,164)	84,925	(2,324)
ating Margins	346	5,091	(4,745)	7,180	(6,834)
est Income/Other	62	62	0	59	3
Margins - YTD	408	5,153	(4,745)	7,239	(6,831)

Attachment for Response to AG 2-13(c)

Rivers
LECTRIC CORPORATION
ve Energy Cooperative

Statement of Operations – February
Variance to Budget

	Current Month			Year-to-Date			
	Actual	Budget	Variance Fav/(UnFav)	Actual	Budget	Variance Fav/(UnFav)	Explanation
?IC ENERGY REVENUES	41,982	43,742	(1,760)	87,206	90,172	(2,966)	[A] Pages 7, 12-14
E FROM LEASED PROPERTY - NET	0	0	0	0	0	0	
OPERATING REVENUE AND INCOME	243	2	241	389	4	385	
OPER REVENUES & PATRONAGE CAPITAL	42,225	43,744	(1,519)	87,595	90,176	(2,581)	
TION EXPENSE-PRODUCTION-EXCL FUEL	3,841	4,791	950	8,062	9,970	1,908	[A] Pages 7, 12-14
TION EXPENSE-PRODUCTION-FUEL	18,070	16,559	(1,511)	37,979	33,878	(4,101)	[A] Pages 7, 12-14
TION EXPENSE-OTHER POWER SUPPLY	6,800	6,850	50	15,269	14,094	(1,175)	[A] Pages 7, 12-14
TION EXPENSE-TRANSMISSION	987	1,354	367	1,890	2,746	856	[B] Page 27
JMER SERVICE & INFORMATIONAL EXPENSE	44	66	22	70	160	90	
TION EXPENSE-SALES	(17)	53	70	(12)	113	125	
TION EXPENSE-ADMINISTRATIVE & GENERAL	2,669	1,911	(758)	4,650	4,014	(636)	[B], [C] Page 28
OPERATION EXPENSE	32,394	31,584	(810)	67,908	64,975	(2,933)	
ENANCE EXPENSE-PRODUCTION	2,870	3,347	477	5,649	5,939	290	
ENANCE EXPENSE-TRANSMISSION	283	237	(46)	563	488	(75)	
ENANCE EXPENSE-GENERAL PLANT	21	9	(12)	36	18	(18)	
MAINTENANCE EXPENSE	3,174	3,593	419	6,248	6,445	197	
ECIATION & AMORTIZATION EXPENSE	2,858	2,971	113	5,718	5,936	218	
S	(2)	21	23	(2)	42	44	
EST ON LONG-TERM DEBT	3,679	3,608	(71)	7,624	7,638	14	
EST CHARGED TO CONSTRUCTION-CREDIT	(188)	(10)	178	(311)	(13)	298	
R INTEREST EXPENSE	19	19	0	40	40	0	
R DEDUCTIONS	11	11	0	24	22	(2)	
L COST OF ELECTRIC SERVICE	41,945	41,797	(148)	87,249	85,085	(2,164)	
ATING MARGINS	280	1,947	(1,667)	346	5,091	(4,745)	
REST INCOME	27	30	(3)	57	62	(5)	
WANCE FOR FUNDS USED DURING CONST	0	0	0	0	0	0	
ER NON-OPERATING INCOME - NET	2	0	2	5	0	5	
ER CAPITAL CREDITS & PAT DIVIDENDS	0	0	0	0	0	0	
AORDINARY ITEMS	0	0	0	0	0	0	
PATRONAGE CAPITAL OR MARGINS	309	1,977	(1,668)	408	5,153	(4,745)	

Explanations: [A] Net Sales Margin, [B] 10% and $250,000 line item or [C] 10% and $500,000 margins.

Attachment for Response to AG 2-13(c)

Rivers
.ECTRIC CORPORATION
e Energy Cooperative

Statement of Operations – February

Variance to Prior-Year

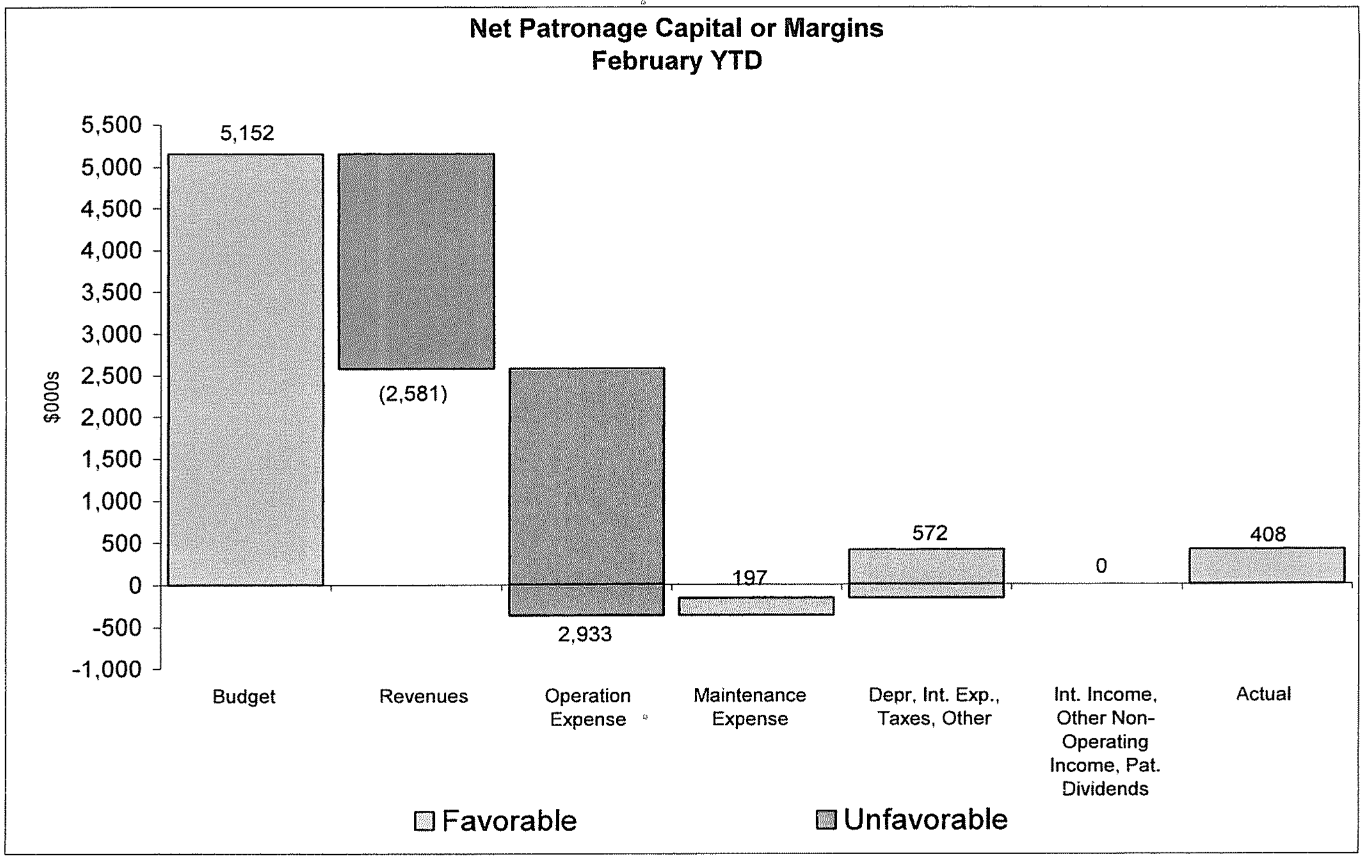
	Current Month			Year-to-Date			
	Actual	Prior Year	Variance Fav/(UnFav)	Actual	Prior Year	Variance Fav/(UnFav)	Explanation
:CTRIC ENERGY REVENUES	41,982	43,507	(1,525)	87,206	89,807	(2,601)	[A] Pages 7, 12-14
OME FROM LEASED PROPERTY - NET	0	0	0	0	0	0	
HER OPERATING REVENUE AND INCOME	243	1,145	(902)	389	2,298	(1,909)	[B], [C] Page 26
TAL OPER REVENUES & PATRONAGE CAPITAL	42,225	44,652	(2,427)	87,595	92,105	(4,510)	
ERATION EXPENSE-PRODUCTION-EXCL FUEL	3,841	4,058	217	8,062	8,076	14	[A] Pages 7, 12-14
ERATION EXPENSE-PRODUCTION-FUEL	18,070	17,644	(426)	37,979	36,752	(1,227)	[A] Pages 7, 12-14
ERATION EXPENSE-OTHER POWER SUPPLY	6,800	7,173	373	15,269	15,591	322	[A] Pages 7, 12-14, [B] 26
ERATION EXPENSE-TRANSMISSION	987	676	(311)	1,890	1,281	(609)	[B] Page 27
NSUMER SERVICE & INFORMATIONAL EXPENSE	44	42	(2)	70	83	13	
ERATION EXPENSE-SALES	(17)	4	21	(12)	11	23	
ERATION EXPENSE-ADMINISTRATIVE & GENERAL	2,669	2,555	(114)	4,650	4,592	(58)	
TAL OPERATION EXPENSE	32,394	32,152	(242)	67,908	66,386	(1,522)	
INTENANCE EXPENSE-PRODUCTION	2,870	2,164	(706)	5,649	4,275	(1,374)	[B],[C] Page 29
INTENANCE EXPENSE-TRANSMISSION	283	342	59	563	550	(13)	
INTENANCE EXPENSE-GENERAL PLANT	21	45	24	36	60	24	
TAL MAINTENANCE EXPENSE	3,174	2,551	(623)	6,248	4,885	(1,363)	
PRECIATION & AMORTIZATION EXPENSE	2,858	2,824	(34)	5,718	5,654	(64)	
(ES	(2)	0	2	(2)	0	2	
EREST ON LONG-TERM DEBT	3,679	3,796	117	7,624	8,031	407	
EREST CHARGED TO CONSTRUCTION-CREDIT	(188)	(24)	164	(311)	(42)	269	
HER INTEREST EXPENSE	19	0	(19)	40	0	(40)	
HER DEDUCTIONS	11	7	(4)	24	11	(13)	
TAL COST OF ELECTRIC SERVICE	41,945	41,306	(639)	87,249	84,925	(2,324)	
ERATING MARGINS	280	3,346	(3,066)	346	7,180	(6,834)	
EREST INCOME	27	25	2	57	54	3	
OWANCE FOR FUNDS USED DURING CONST	0	0	0	0	0	0	
HER NON-OPERATING INCOME - NET	2	2	0	5	5	0	
HER CAPITAL CREDITS & PAT DIVIDENDS	0	0	0	0	0	0	
TRAORDINARY ITEMS	0	0	0	0	0	0	
T PATRONAGE CAPITAL OR MARGINS	309	3,373	(3,064)	408	7,239	(6,831)	

[A] Net Sales Margin, [B] 10% and $250,000 line item or [C] 10% and $500,000 margins.

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

Variance Analysis Summary



Financial Commentary

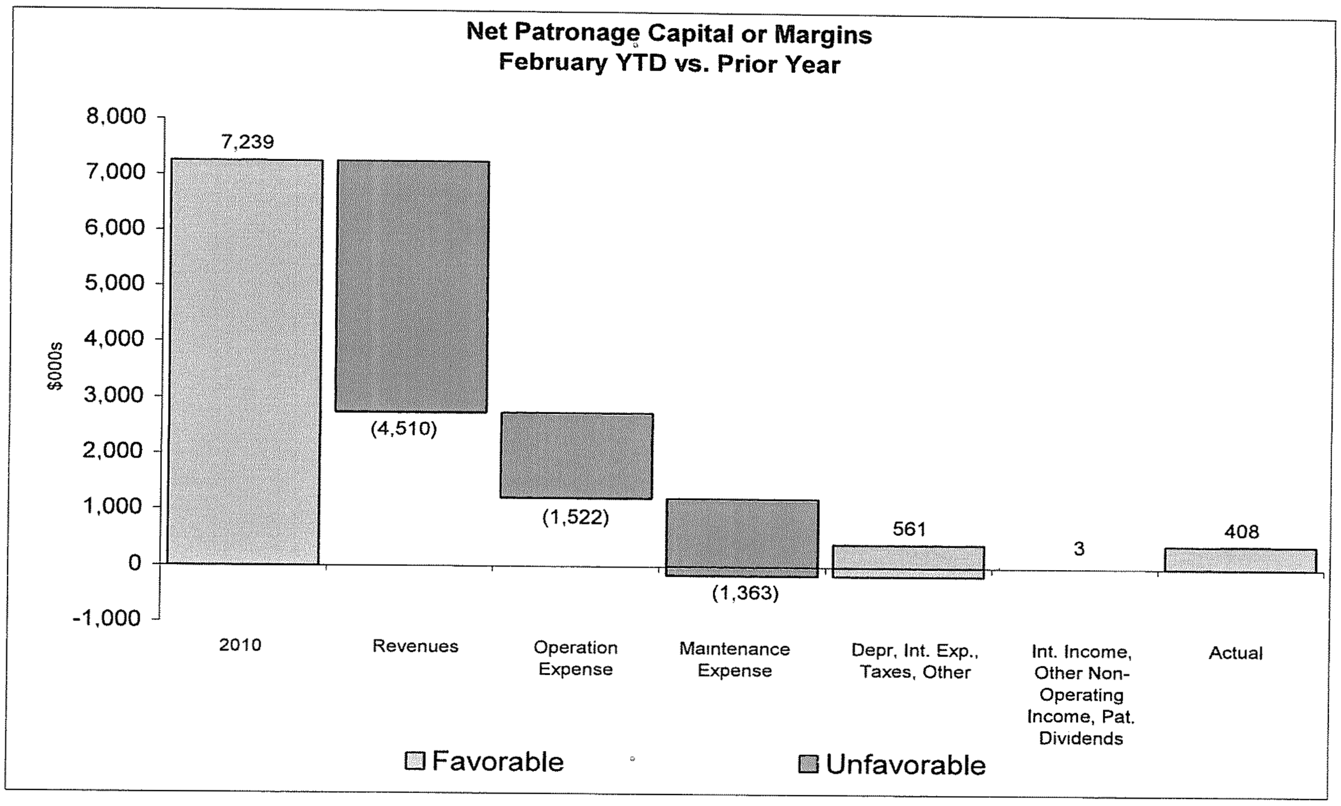
Year-to-Date

- Net Margins YTD were $4,745 lower than budget.
  - Electric Energy Revenues were unfavorable $2,966 primarily due to lower off-system pricing (see pg. 12).
  - Other Revenue was favorable $385.
  - Operation Expense was unfavorable $2,933 – driven by higher variable costs $2,932 (see pgs. 13, 27 and 28).
  - Maintenance Expense was favorable $197 primarily due timing of plant expenses.
  - Depreciation and Interest Expense was lower $572 due to lower depreciation and higher capitalized interest.

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION

Variance Analysis Summary



Financial Commentary

Year-to-Date

- Net Margins YTD were $6,831 lower than YTD February 2010.
  - Electric Energy Revenues were unfavorable $2,601 primarily due to lower off-system pricing (see pg. 12).
  - Other Revenue was unfavorable $1,909 primarily due to a lower power supply transmission reservation, which is off-set in Operations Expense – Other Power Supply (see pg. 26).
  - Operation Expense was unfavorable $1,522 – driven by higher variable costs $2,176, partially offset by lower transmission reservation (see pg. 13).
  - Maintenance Expense was unfavorable $1,363 primarily due to an unplanned outage at Coleman this year and higher planned maintenance activities at the plants (pg. 29).
  - Depreciation and Interest Expense combined was lower $561

Attachment for Response to AG 2-13(c)

ivers
TRIC CORPORATION
ny Cooperative

MRSM
February

	Actual 2011	Budget 2011	2011 Variance	Actual 2010	2010 Variance
h					
	(5.65)	(6.79)	1.14	(9.18)	3.53
ial	(5.65)	(6.79)	1.14	(9.18)	3.53
	(5.65)	(6.79)	1.14	(9.18)	3.53
sands of $					
	(2,606)	(3,268)	662	(4,495)	1,889
ial	(865)	(1,012)	147	(1,330)	465
	(3,471)	(4,280)	809	(5,825)	2,354

	Actual 2011	Budget 2011	2011 Variance	Actual 2010	2010 Variance
Net Revenue - $/MWh					
Rural	38.23	37.66	0.57	34.55	3.68
Large Industrial	35.57	34.66	0.91	32.89	2.68
Total	37.57	36.95	0.62	34.17	3.40
Net Revenue - Thousands of $					
Rural	17,632	18,100	(468)	16,880	752
Large Industrial	5,455	5,180	275	4,794	661
Total	23,087	23,280	(193)	21,674	1,413

Economic Reserve Balance

	Actual	Budget	Variance
Original Deposit	$ 157,000		
Interest Earnings	2,041		
Withdrawals	(41,772)		
Cumulative through Feb 28th	$ 117,269	$ 117,911	$ (642)

Attachment for Response to AG 2-13(c)

Rivers
ELECTRIC CORPORATION
Energy Cooperative

Cash & Temporary Investments

	Actual	Budget	Fav/(Unfav)	2010 Actual	Fav/(Unfav)
February 28	**55,865**	**41,494**	**14,371**	**45,890**	**9,975**

ruary 28, 2011 cash balance compared to budget is favorable primarily due to a eginning balance, lower capital expenditures and a reduction in fuel inventory.

ruary 28, 2011 cash balance compared to prior year is favorable primarily due to ntary pre-payment of RUS debt that was made in January 2010.

: 5.75% RUS Series A e, prepaid status as of /11: voluntary = 478; ition Reserve = 35,000

Lines of Credit
As of January 31

Original Amount	$ 100,000
Letters of Credit Outstanding	(5,354)
Advances Outstanding	(10,000)
Available Lines of Credit	$ 84,646

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

North Star – YTD February

	Actual	Budget	Fav/(UnFav)	2010 Actual	Fav/(UnFav)
Total Cost of Electric Service	87,249	88,262	1,013	84,925	(2,324)
Other Operating Revenues & Income	(389)	(3,181)	(2,792)	(2,298)	(1,909)
Off-System Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Interest Income	(57)	(62)	(5)	(54)	3
Other Non-Operating Income	(5)	0	5	(5)	0
Other Capital Credits & Pat. Dividends	0	0	0	0	0
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Member MWh	1,653,629	1,808,077	(154,448)	1,666,937	(13,308)
North Star - $/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

TIER

	Actual	Budget	Fav/(Unfav)
Interest on Long Term Debt	7,624	7,638	14
Net Margins	408	5,153	(4,745)
TIER	1.05	1.67	(0.62)
TIER (12 months ending 2/28)	1.00	1.13	(0.13)

Notes:

TIER = (Net Margins + Interest on Long-Term Debt) divided by Interest on Long-Term Debt

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Capital Expenditures*

	Actual	Budget	Fav/(UnFav)
IT	414	80	(334)
Generation	1,055	3,072	2,017
Transmission	1,419	2,660	1,241
Other	0	890	890
Total	**2,888**	**6,702**	**3,814**

Explanation:

IT unfavorable due to on-going Oracle "steady-state" issues; continue to capitalize certain costs.

Generation favorable primarily due to the timing of projects. Green Station was favorable $1,016 due to several projects being moved from January to the Spring. These include Condenser Water Box Coating, Clarifier Coating, Sample & Analyzers and Drum Camera Replacements. Coleman was favorable $1,088 due to the delay of several projects including C2 Aux Transformer, Control Room and Start-up 480v MCC replacement.

Transmission favorable primarily due to the timing of the Wilson Line 19F Terminal and Two Way Radio Replacement.

Other favorable primarily due to the delay in purchasing the PCI Software and the Operator Training Simulator.

* Gross of the City's share of Station Two.

Attachment for Response to AG 2-13(c)

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

Revenue
YTD February

MWh Sales	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	461,230	480,695	(19,465)	488,739	(27,509)
Large Industrial	153,321	149,358	3,963	145,567	7,754
Smelter	1,039,077	1,178,024	(138,947)	1,032,631	6,446
Off-System/Other	[redacted]				
Total					

Revenue - $/MWh	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	43.88	44.45	(0.57)	43.73	0.15
Large Industrial	41.22	41.45	(0.23)	42.07	(0.85)
Smelter	42.27	42.03	0.24	43.21	(0.94)
Off-System/Other	[redacted]				
Total					

Revenue - Thousands of $	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	20,238	21,368	(1,130)	21,375	(1,137)
Large Industrial	6,320	6,192	128	6,124	196
Smelter	43,921	49,510	(5,589)	44,621	(700)
Off-System/Other	[redacted]				
Total					

Revenue Price / Volume Analysis
YTD February 2011

	Price / Volume		
	Price	Volume	Total
Rural	(265)	(865)	(1,130)
Large Industrial	(36)	164	128
Smelter	251	(5,840)	(5,589)
Off-System/Other	[redacted]		

Attachment for Response to AG 2-13(c)

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

Variable Operations Cost
YTD February

Variable Operations (VO) Cost - $/MWh	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	25.56	24.23	(1.33)	24.46	(1.10)
Large Industrial	25.57	24.23	(1.34)	24.46	(1.11)
Smelter	24.07	22.81	(1.26)	24.00	(0.07)
Off-System/Other	[redacted]				
Total					

VO Cost - Thousands of $	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	11,789	11,646	(143)	11,957	168
Large Industrial	3,921	3,619	(302)	3,561	(360)
Smelter	25,007	26,876	1,869	24,788	(219)
Off-System/Other	[redacted]				
Total					

YTD February 2011
Variable Operations Expense

	Actual	Budget	Fav/(UnFav)	Price Variance Fav/(UnFav)	Volume Variance Fav/(UnFav)	Fav/(UnFav)
Reagent	4,520	5,717	1,197	696	501	1,197
Fuel	42,171	39,369	(2,802)	(3,390)	588	(2,802)
Purchased Power	4,330	3,030	(1,300)	(1,134)	(166)	(1,300)
Non-FAC PPA (Non-Smelter)	[redacted]					

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Net Sales Margin
YTD February

Net Sales Margin - $/MWh	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	18.32	20.22	(1.90)	19.27	(0.95)
Large Industrial	15.65	17.22	(1.57)	17.61	(1.96)
Smelter	18.20	19.22	(1.02)	19.21	(1.01)
Off-System/Other	[redacted]				
Total					

Net Sales Margin - Thousands of $	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	8,449	9,721	(1,272)	9,418	(969)
Large Industrial	2,399	2,573	(174)	2,563	(164)
Smelter	18,914	22,634	(3,720)	19,833	(919)
Off-System/Other	[redacted]				
Total					

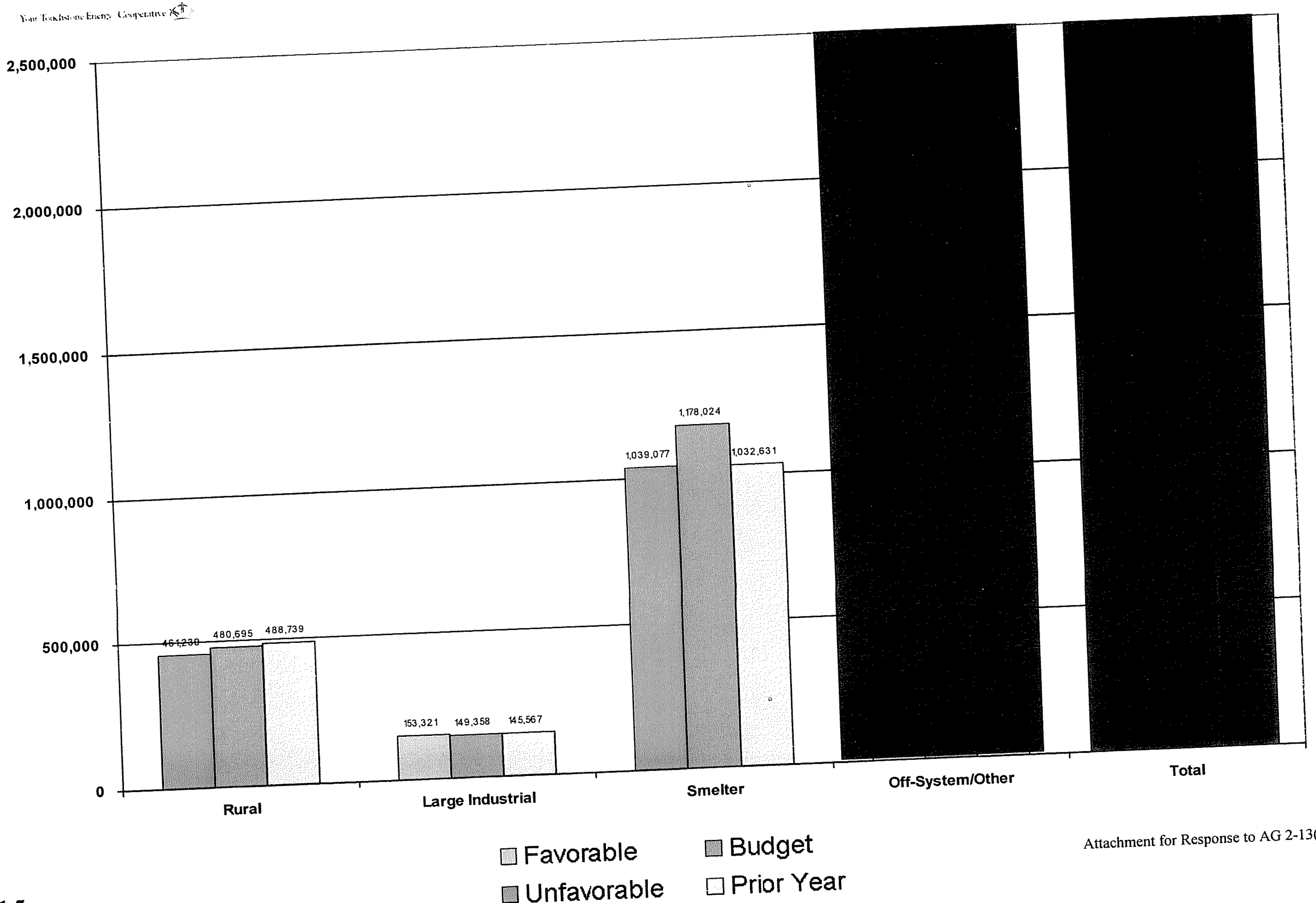
Net Sales Margin
Price / Volume Analysis
YTD February

	Price / Volume		
	Price	Volume	Total
Rural	(878)	(394)	(1,272)
Large Industrial	(242)	68	(174)
Smelter	(1,050)	(2,670)	(3,720)
Off-System/Other	[redacted]		

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

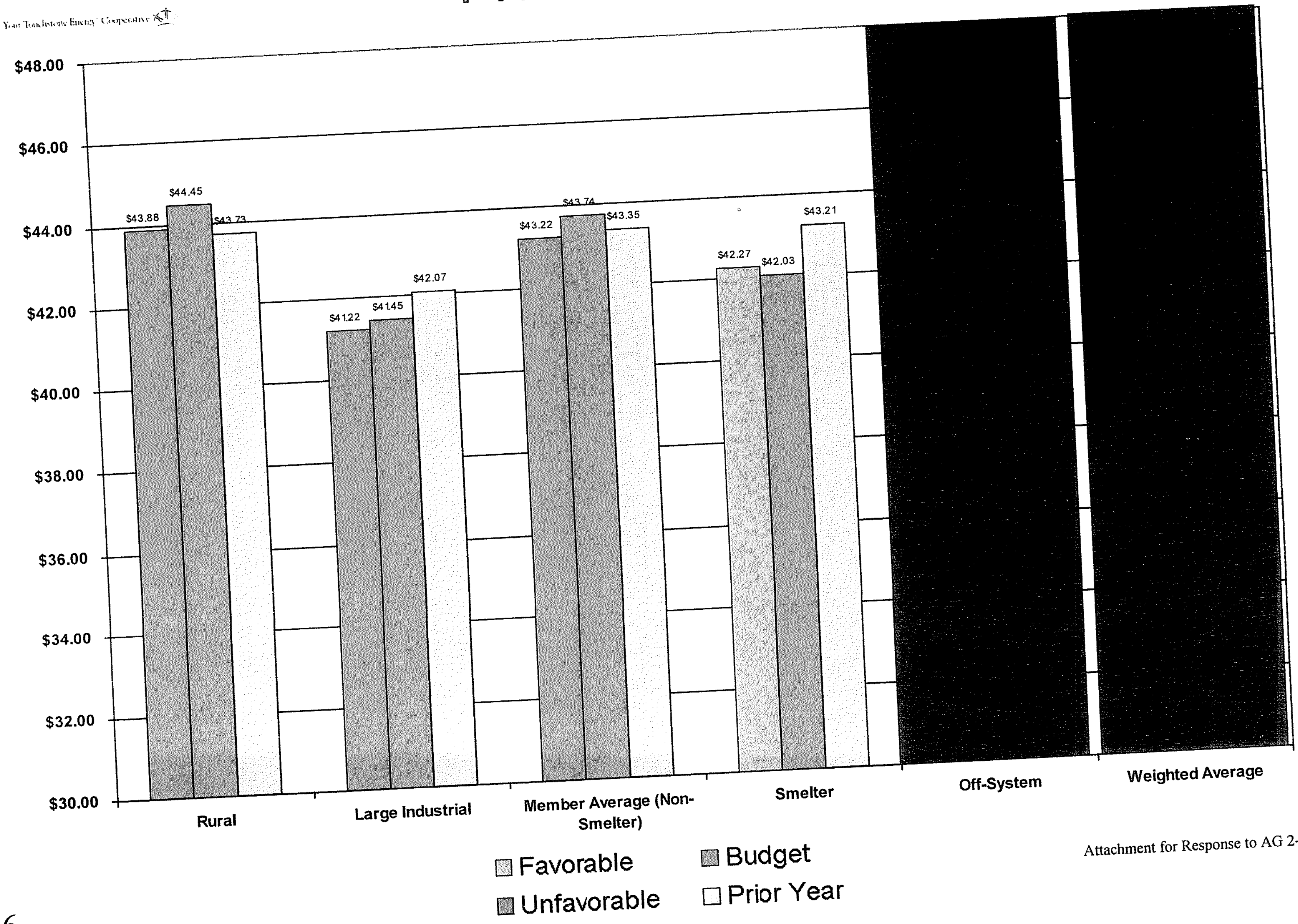
MWH Sales
YTD - February



Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Revenue - $/MWh Sold
YTD - February



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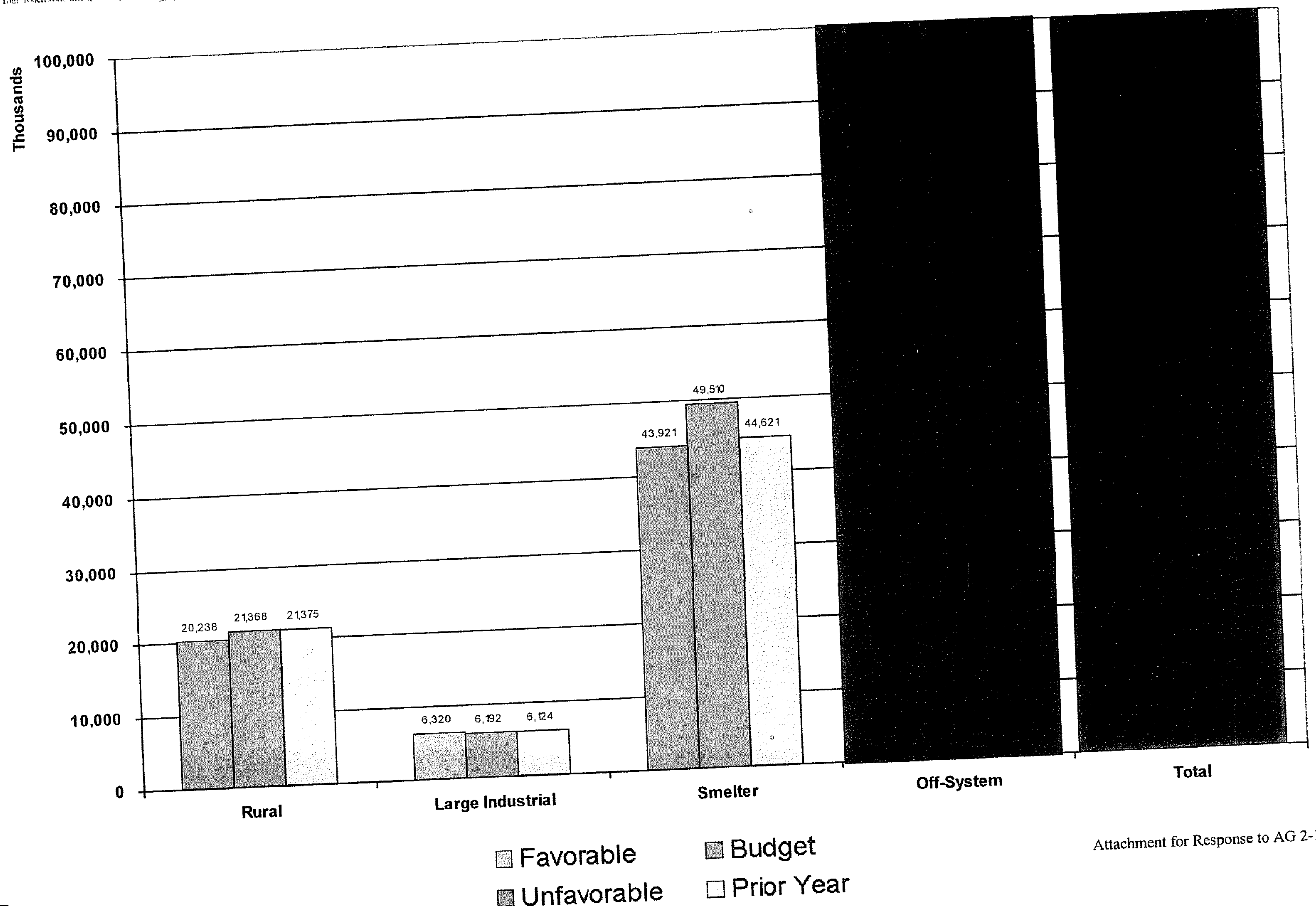
Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

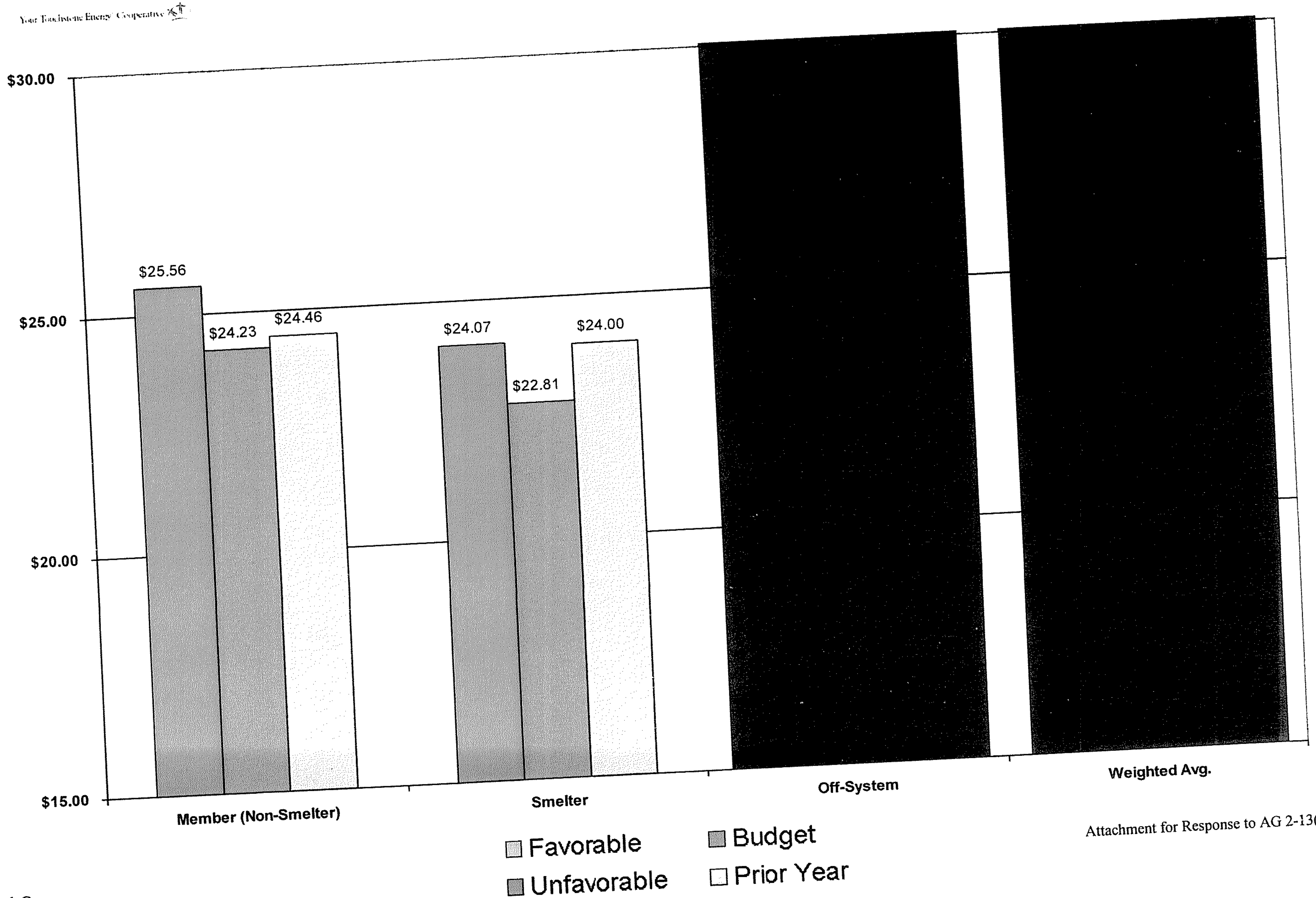
Revenue
YTD - February



Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

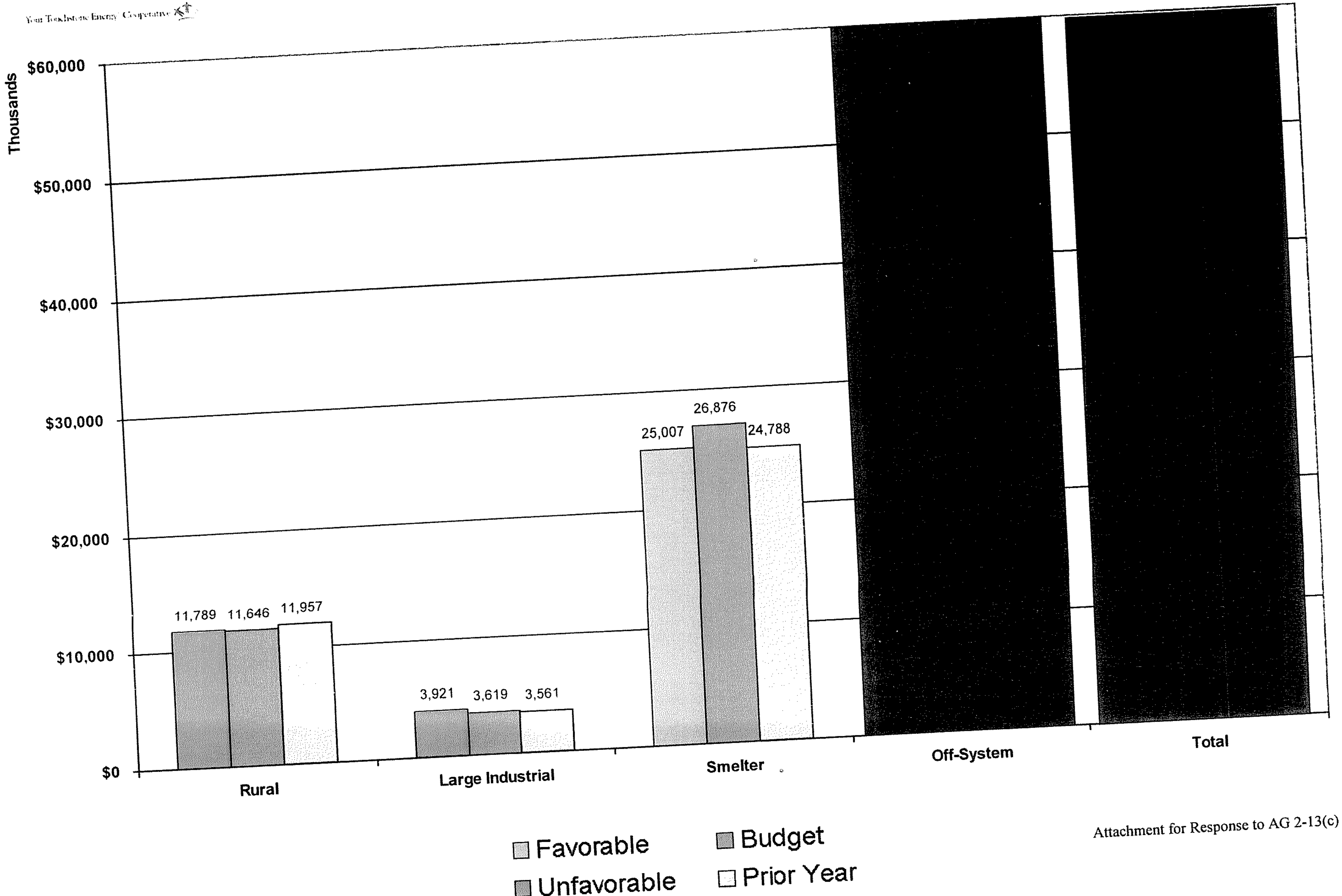
Power Cost - $/MWh Sold
YTD - February



Attachment for Response to AG 2-13(c)

Big Rivers ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Power Cost
YTD - February

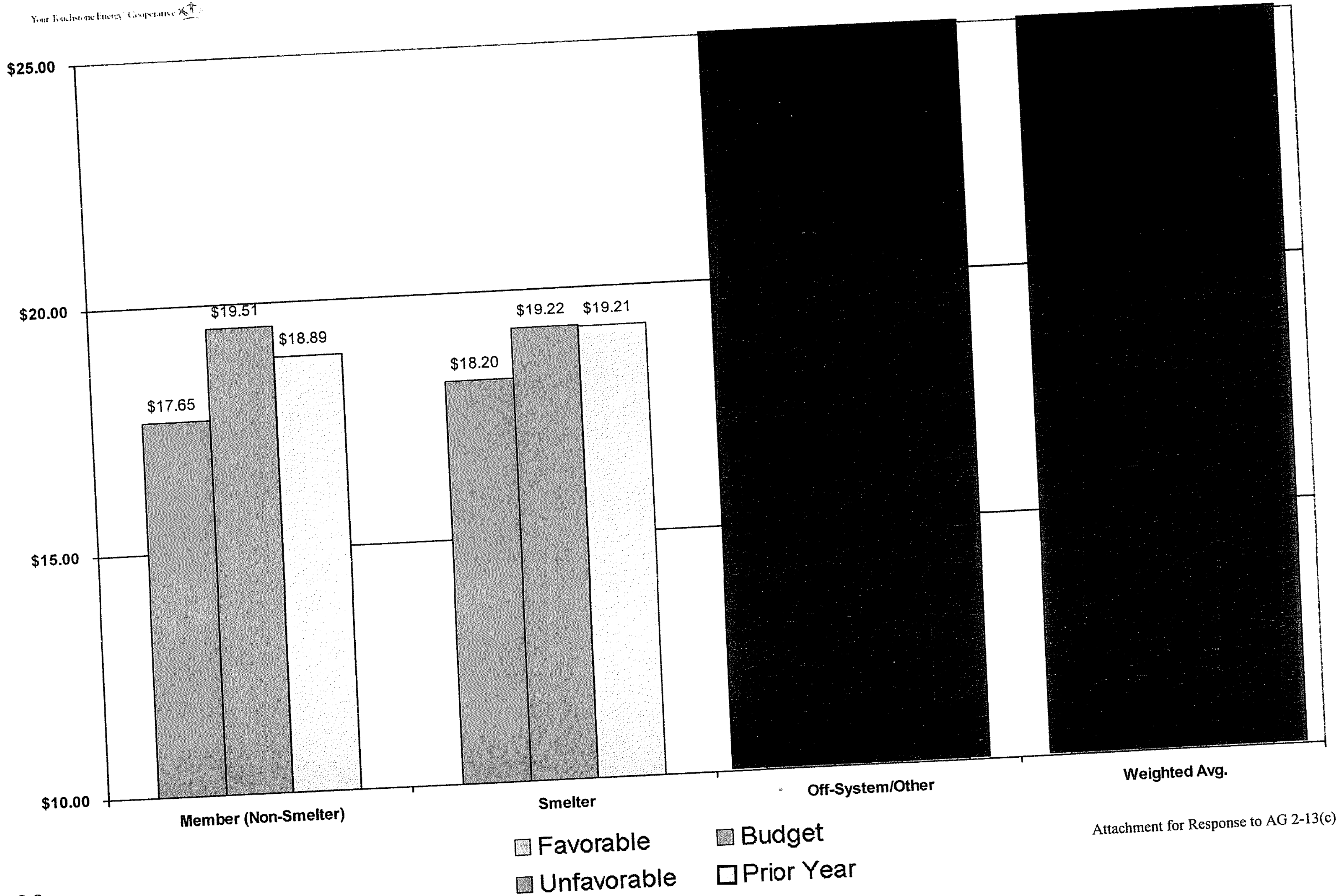


Attachment for Response to AG 2-13(c)

Big Rivers Electric Corporation

Your Touchstone Energy Cooperative

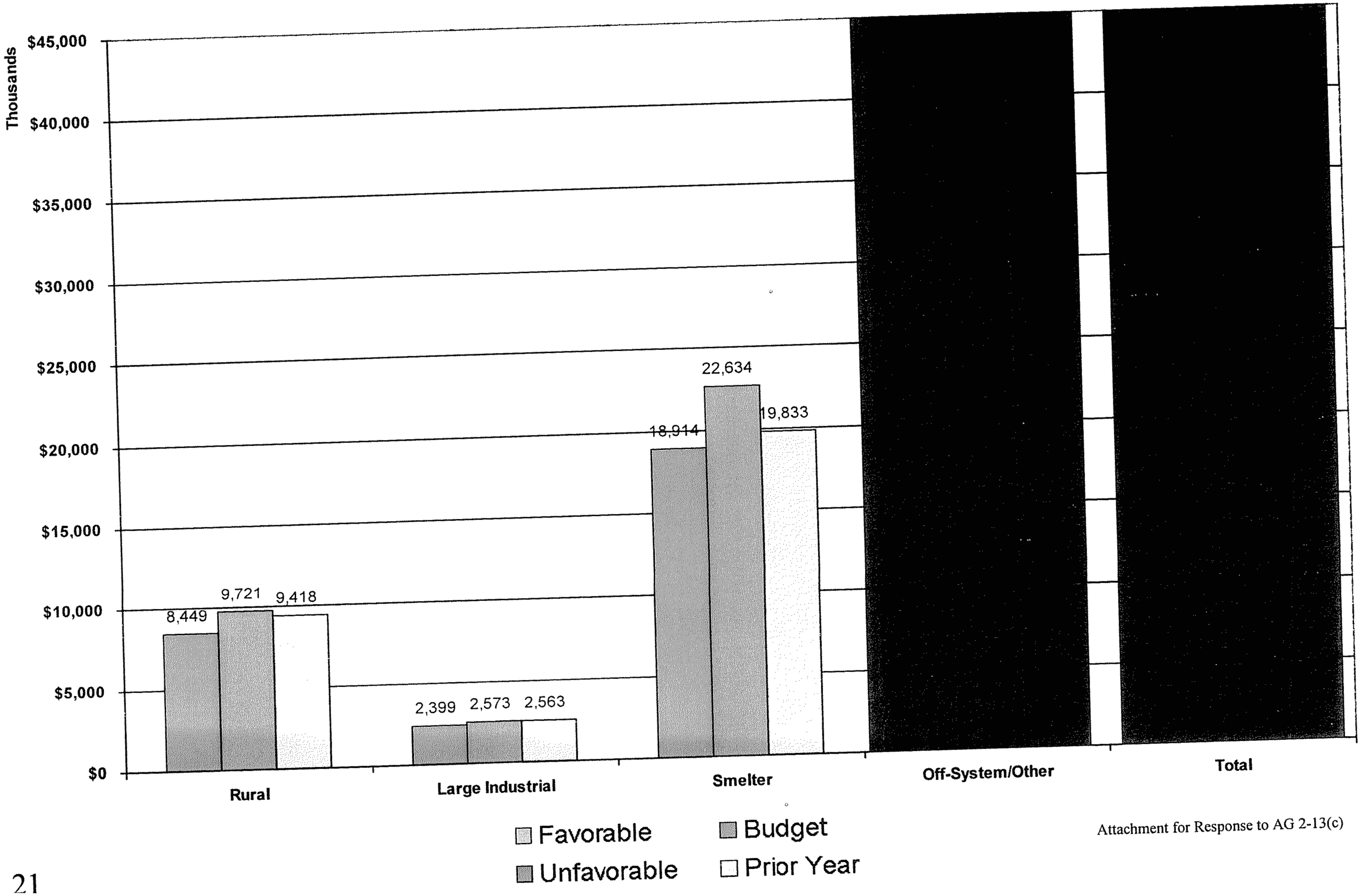
Sales Margin - $/MWh
YTD - February



Attachment for Response to AG 2-13(c)

Big Rivers ELECTRIC CORPORATION

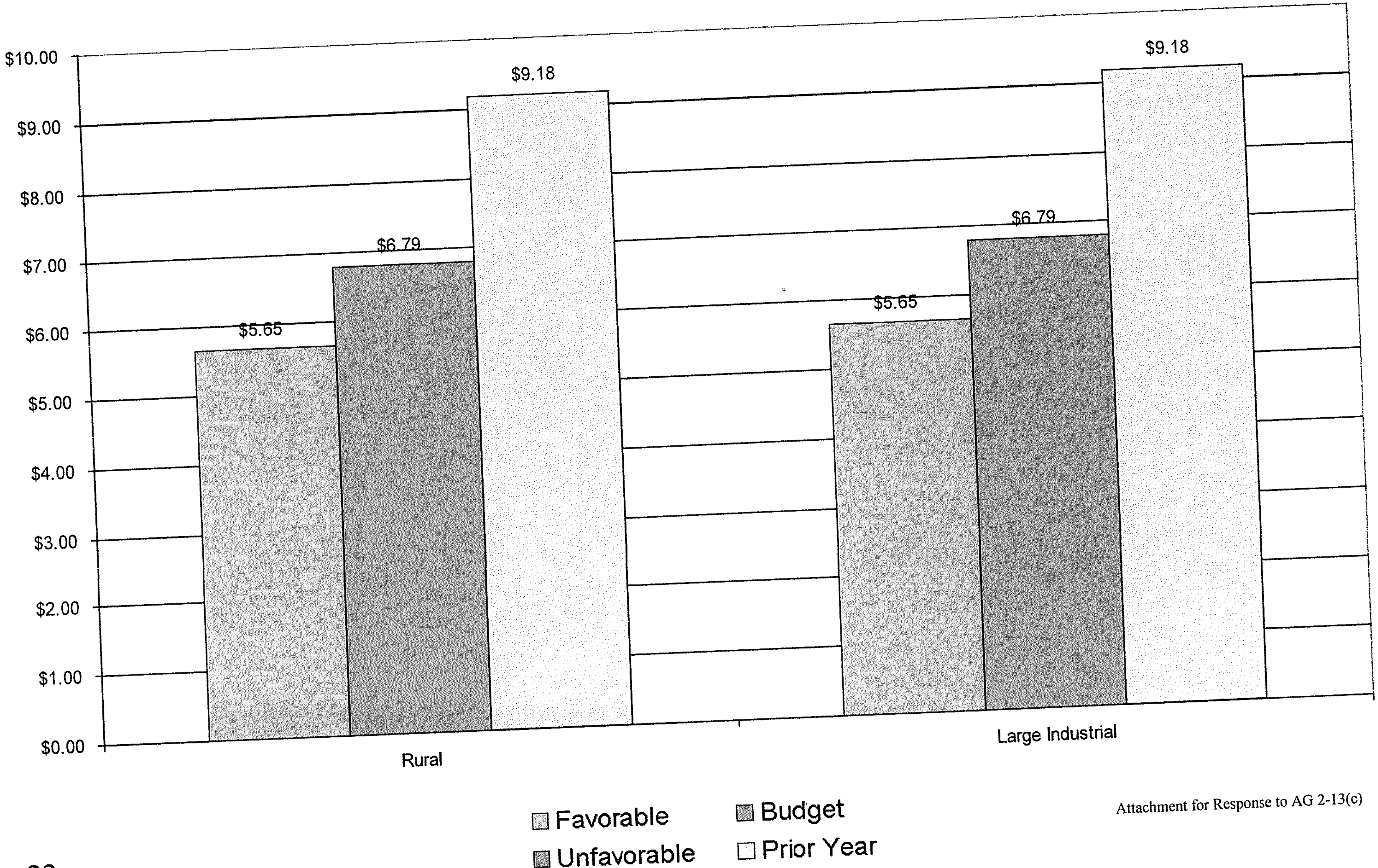
Sales Margin
YTD - February



Attachment for Response to AG 2-13(c)

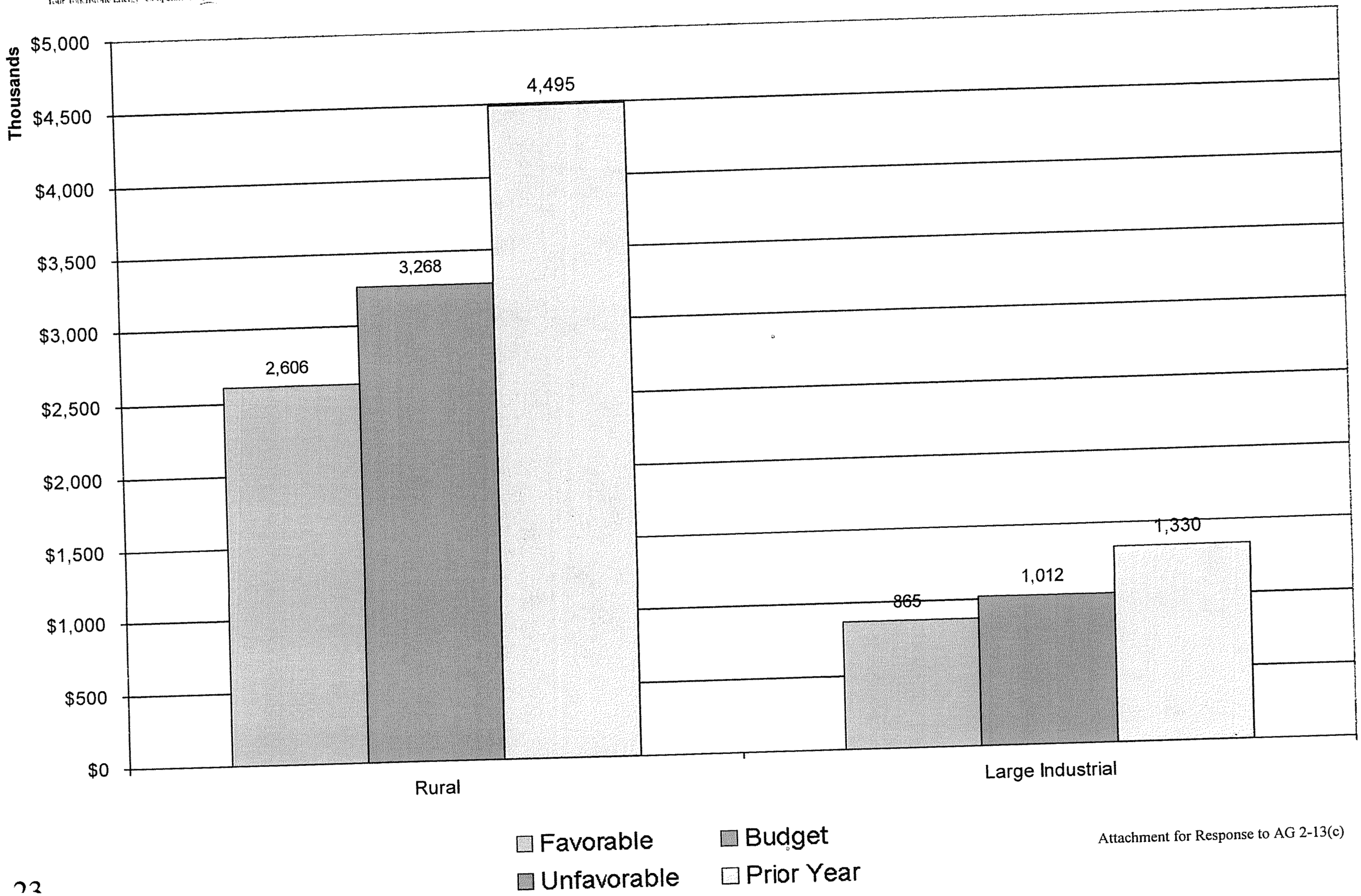
Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

MRSM - $/MWh
YTD - February



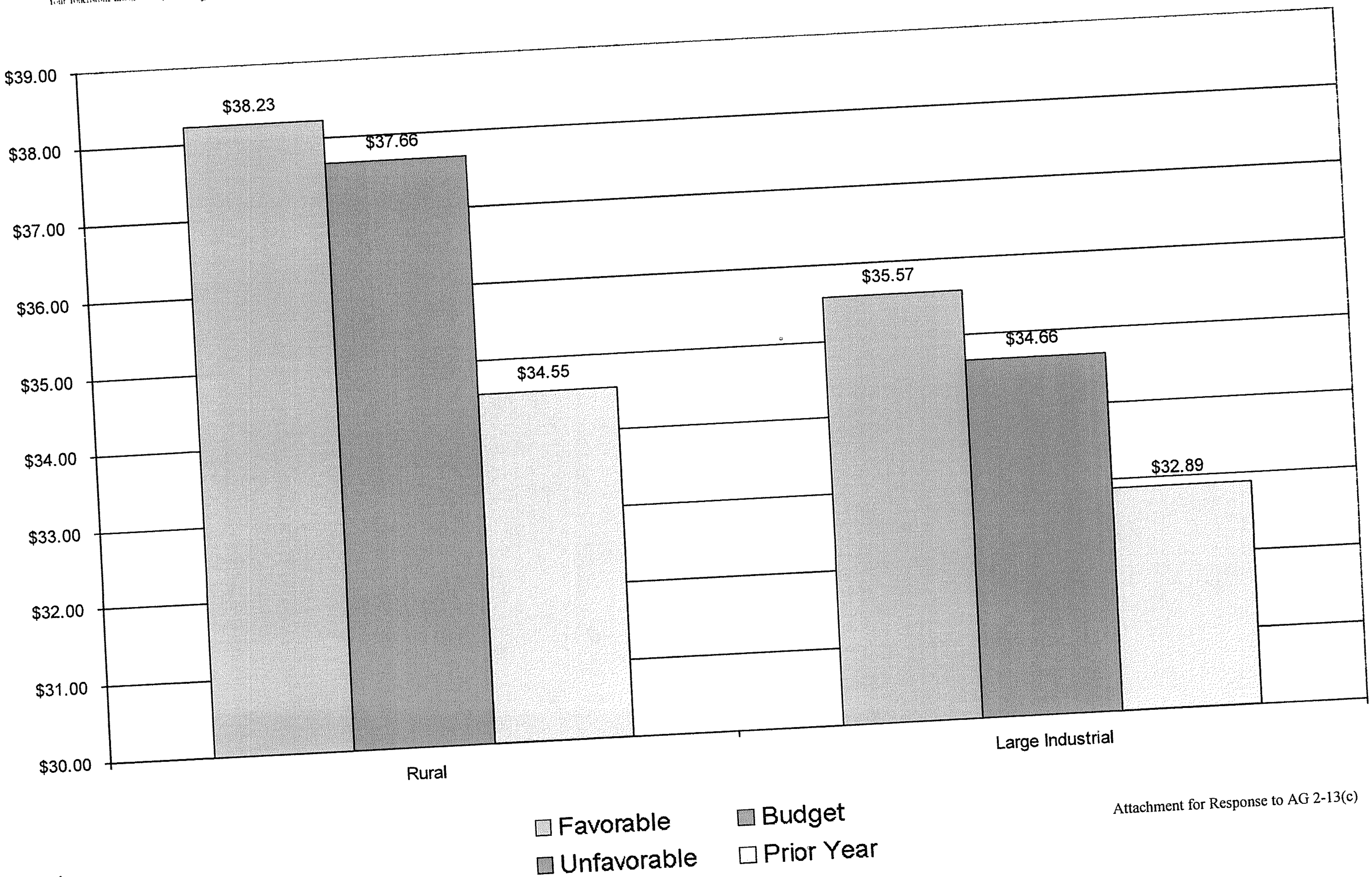
Attachment for Response to AG 2-13(c)

MRSM
YTD - February



Attachment for Response to AG 2-13(c)

Net Revenue (Excl. MRSM) - $/MWh
YTD - February



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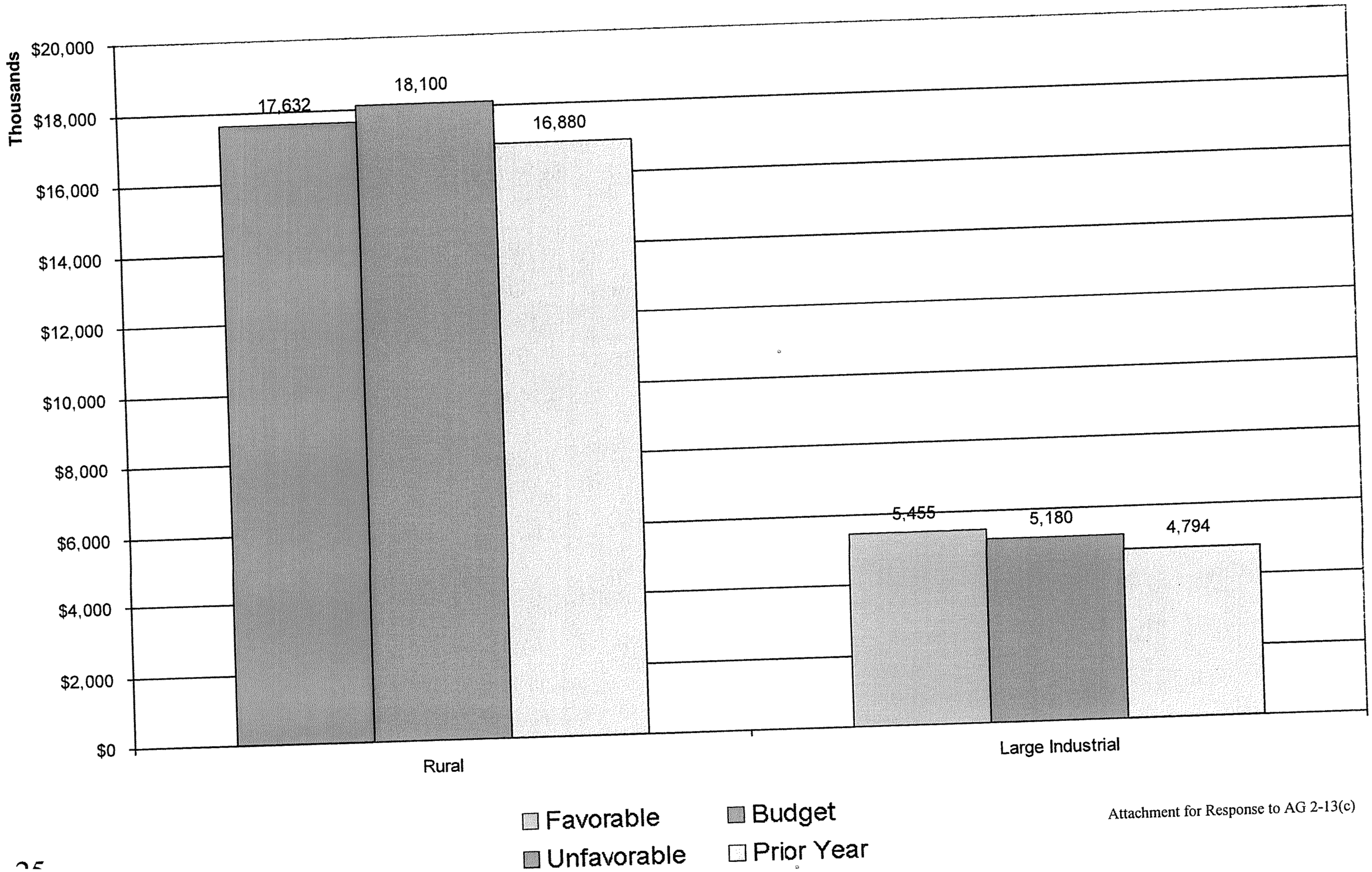
Big Rivers ELECTRIC CORPORATION

Net Revenue (Excl. MRSM) YTD - February



Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Other Operating Revenue and Income

	2011			2010	
	Actual	Budget	Variance Fav/(Unfav)	2010 Actual	Variance Fav/(Unfav)
February YTD	389	4	385	2,298	(1,909)

Prior year unfavorable primarily due to lower power supply transmission reservation this year.

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Operation Expense – Transmission

	2011			2010	
	Actual	Budget	Variance Fav/(Unfav)	2010 Actual	Variance Fav/(Unfav)
February YTD	1,890	2,746	856	1,281	(609)

Favorable to budget primarily due to lower than anticipated MISO related expenses.

Unfavorable to prior year due to integration into MISO, resulting in higher expenses this year.

Big Rivers
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Your Touchstone Energy Cooperative

Operation Expense – Administrative & General

	2011		
	Actual	Budget	Variance Fav/(Unfav)
February YTD	4,650	4,014	(636)

Unfavorable to budget primarily due to (a) higher IT for HP (170), E.ON (80) and Oracle (140), and (b) outside professional services for the rate case (100).

Additional Notes: HP costs are unfavorable due to Oracle R12 not yet being at "steady state". The E.ON IT Support Services Agreement wasn't terminated until 1/15/11. The Oracle maintenance contract was budgeted throughout the year (timing).

Attachment for Response to AG 2-13(c)

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

Maintenance Expense – Production

	2011 Actual	2010 Actual	Variance Fav/(Unfav)
February YTD	5,649	4,275	(1,374)

Unfavorable to prior year due to higher planned maintenance activities this year and an unplanned outage at Coleman.

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

Financial Report

March 2011

($ in Thousands)

Board Meeting Date: May 20, 2011

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Summary of Operations
YTD March

	Actual	Budget	Fav/(UnFav) Variance	Actual	Fav/(UnFav) Variance
Revenues	134,225	136,058	(1,833)	137,194	(2,969)
Cost of Electric Service	134,512	131,306	(3,206)	127,765	(6,747)
Operating Margins	(287)	4,752	(5,039)	9,429	(9,716)
Interest Income/Other	188	95	93	103	85
Net Margins	(99)	4,847	(4,946)	9,532	(9,631)

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Statement of Operations – March
Variance to Budget

	Current Month			Year-to-Date			
	Actual	Budget	Variance Fav/(UnFav)	Actual	Budget	Variance Fav/(UnFav)	Explanation
ELECTRIC ENERGY REVENUES	46,395	45,882	513	133,601	136,052	(2,451)	[A] Pages 7, 12-14
INCOME FROM LEASED PROPERTY - NET	0	0	0	0	0	0	
OTHER OPERATING REVENUE AND INCOME	235	2	233	624	6	618	
TOTAL OPER REVENUES & PATRONAGE CAPITAL	46,630	45,884	746	134,225	136,058	(1,833)	
OPERATION EXPENSE-PRODUCTION-EXCL FUEL	4,087	5,407	1,320	12,149	15,378	3,229	[A] Pages 7, 12-14
OPERATION EXPENSE-PRODUCTION-FUEL	18,347	17,905	(442)	56,326	51,783	(4,543)	[A] Pages 7, 12-14
OPERATION EXPENSE-OTHER POWER SUPPLY	10,591	7,671	(2,920)	25,861	21,765	(4,096)	[A] Pages 7, 12-14
OPERATION EXPENSE-TRANSMISSION	940	1,492	552	2,830	4,238	1,408	[B] Page 27
CONSUMER SERVICE & INFORMATIONAL EXPENSE	31	80	49	100	240	140	
OPERATION EXPENSE-SALES	12	172	160	1	284	283	
OPERATION EXPENSE-ADMINISTRATIVE & GENERAL	2,146	2,146	0	6,796	6,160	(636)	[B], [C] Page 28
TOTAL OPERATION EXPENSE	36,154	34,873	(1,281)	104,063	99,848	(4,215)	
MAINTENANCE EXPENSE-PRODUCTION	3,768	4,047	279	9,417	9,986	569	
MAINTENANCE EXPENSE-TRANSMISSION	361	299	(62)	924	786	(138)	
MAINTENANCE EXPENSE-GENERAL PLANT	(34)	8	42	2	26	24	
TOTAL MAINTENANCE EXPENSE	4,095	4,354	259	10,343	10,798	455	
DEPRECIATION & AMORTIZATION EXPENSE	2,963	2,978	15	8,681	8,913	232	
TAXES	0	21	21	(2)	62	64	
INTEREST ON LONG-TERM DEBT	3,987	3,995	8	11,611	11,633	22	
INTEREST CHARGED TO CONSTRUCTION-CREDIT	(12)	(31)	(19)	(322)	(44)	278	
OTHER INTEREST EXPENSE	18	21	3	59	62	3	
OTHER DEDUCTIONS	55	12	(43)	79	34	(45)	
TOTAL COST OF ELECTRIC SERVICE	47,260	46,223	(1,037)	134,512	131,306	(3,206)	
OPERATING MARGINS	(630)	(339)	(291)	(287)	4,752	(5,039)	
INTEREST INCOME	29	33	(4)	86	95	(9)	
ALLOWANCE FOR FUNDS USED DURING CONST	0	0	0	0	0	0	
OTHER NON-OPERATING INCOME - NET	0	0	0	5	0	5	
OTHER CAPITAL CREDITS & PAT DIVIDENDS	97	0	97	97	0	97	
EXTRAORDINARY ITEMS	0	0	0	0	0	0	
NET PATRONAGE CAPITAL OR MARGINS	(504)	(306)	(198)	(99)	4,847	(4,946)	

Explanations: [A] Net Sales Margin, [B] 10% and $250,000 line item or [C] 10% and $500,000 margins.

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Statement of Operations – March

Variance to Prior-Year

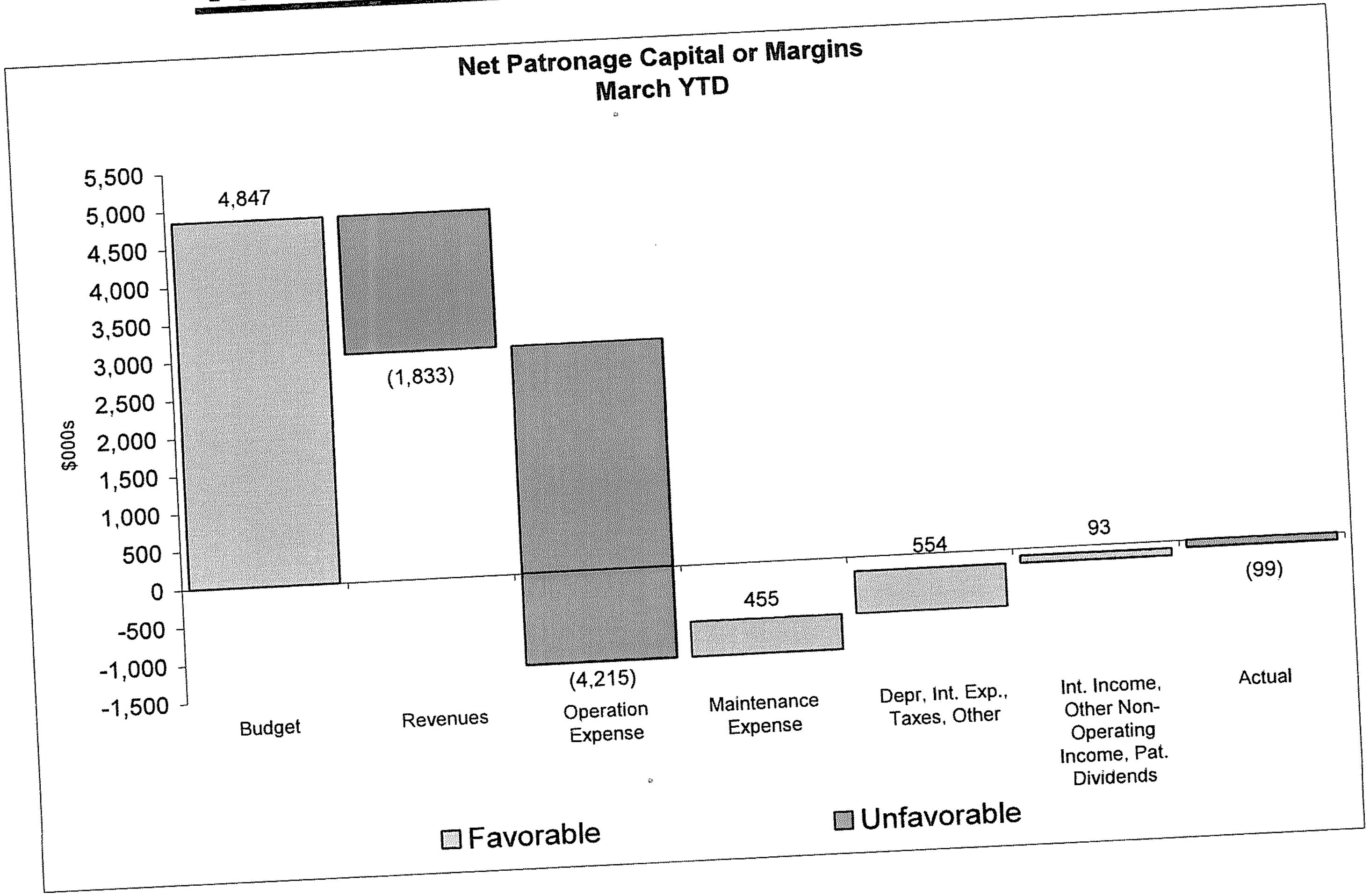
	Current Month			Year-to-Date			
	Actual	**Prior Year**	**Variance Fav/(UnFav)**	**Actual**	**Prior Year**	**Variance Fav/(UnFav)**	**Explanation**
ELECTRIC ENERGY REVENUES	46,395	44,019	2,376	133,601	133,826	(225)	[A] Pages 7, 12-14
INCOME FROM LEASED PROPERTY - NET	0	0	0	0	0	0	
OTHER OPERATING REVENUE AND INCOME	235	1,070	(835)	624	3,368	(2,744)	[B], [C] Page 26
TOTAL OPER REVENUES & PATRONAGE CAPITAL	46,630	45,089	1,541	134,225	137,194	(2,969)	
OPERATION EXPENSE-PRODUCTION-EXCL FUEL	4,087	4,431	344	12,149	12,507	358	[A] Pages 7, 12-14
OPERATION EXPENSE-PRODUCTION-FUEL	18,347	17,192	(1,155)	56,326	53,944	(2,382)	[A] Pages 7, 12-14
OPERATION EXPENSE-OTHER POWER SUPPLY	10,591	7,680	(2,911)	25,861	23,272	(2,589)	[A] Pages 7, 12-14, [B] 26
OPERATION EXPENSE-TRANSMISSION	940	713	(227)	2,830	1,994	(836)	[B] Page 27
CONSUMER SERVICE & INFORMATIONAL EXPENSE	31	53	22	100	136	36	
OPERATION EXPENSE-SALES	12	21	9	1	32	31	
OPERATION EXPENSE-ADMINISTRATIVE & GENERAL	2,146	2,709	563	6,796	7,301	505	
TOTAL OPERATION EXPENSE	36,154	32,799	(3,355)	104,063	99,186	(4,877)	
MAINTENANCE EXPENSE-PRODUCTION	3,768	2,700	(1,068)	9,417	6,975	(2,442)	[B],[C] Page 29
MAINTENANCE EXPENSE-TRANSMISSION	361	378	17	924	928	4	
MAINTENANCE EXPENSE-GENERAL PLANT	(34)	15	49	2	74	72	
TOTAL MAINTENANCE EXPENSE	4,095	3,093	(1,002)	10,343	7,977	(2,366)	
DEPRECIATION & AMORTIZATION EXPENSE	2,963	2,824	(139)	8,681	8,478	(203)	
TAXES	0	1	1	(2)	1	3	
INTEREST ON LONG-TERM DEBT	3,987	4,133	146	11,611	12,165	554	
INTEREST CHARGED TO CONSTRUCTION-CREDIT	(12)	(17)	(5)	(322)	(60)	262	
OTHER INTEREST EXPENSE	18	1	(17)	59	1	(58)	
OTHER DEDUCTIONS	55	6	(49)	79	17	(62)	
TOTAL COST OF ELECTRIC SERVICE	47,260	42,840	(4,420)	134,512	127,765	(6,747)	
OPERATING MARGINS	(630)	2,249	(2,879)	(287)	9,429	(9,716)	
INTEREST INCOME	29	29	0	86	83	3	
ALLOWANCE FOR FUNDS USED DURING CONST	0	0	0	0	0	0	
OTHER NON-OPERATING INCOME - NET	0	2	(2)	5	7	(2)	
OTHER CAPITAL CREDITS & PAT DIVIDENDS	97	13	84	97	13	84	
EXTRAORDINARY ITEMS	0	0	0	0	0	0	
NET PATRONAGE CAPITAL OR MARGINS	(504)	2,293	(2,797)	(99)	9,532	(9,631)	

Attachment for Response to AG 2-13(c)

[A] Net Sales Margin, [B] 10% and $250,000 line item or [C] 10% and $500,000 margins.

Big Rivers ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Variance Analysis Summary



Financial Commentary

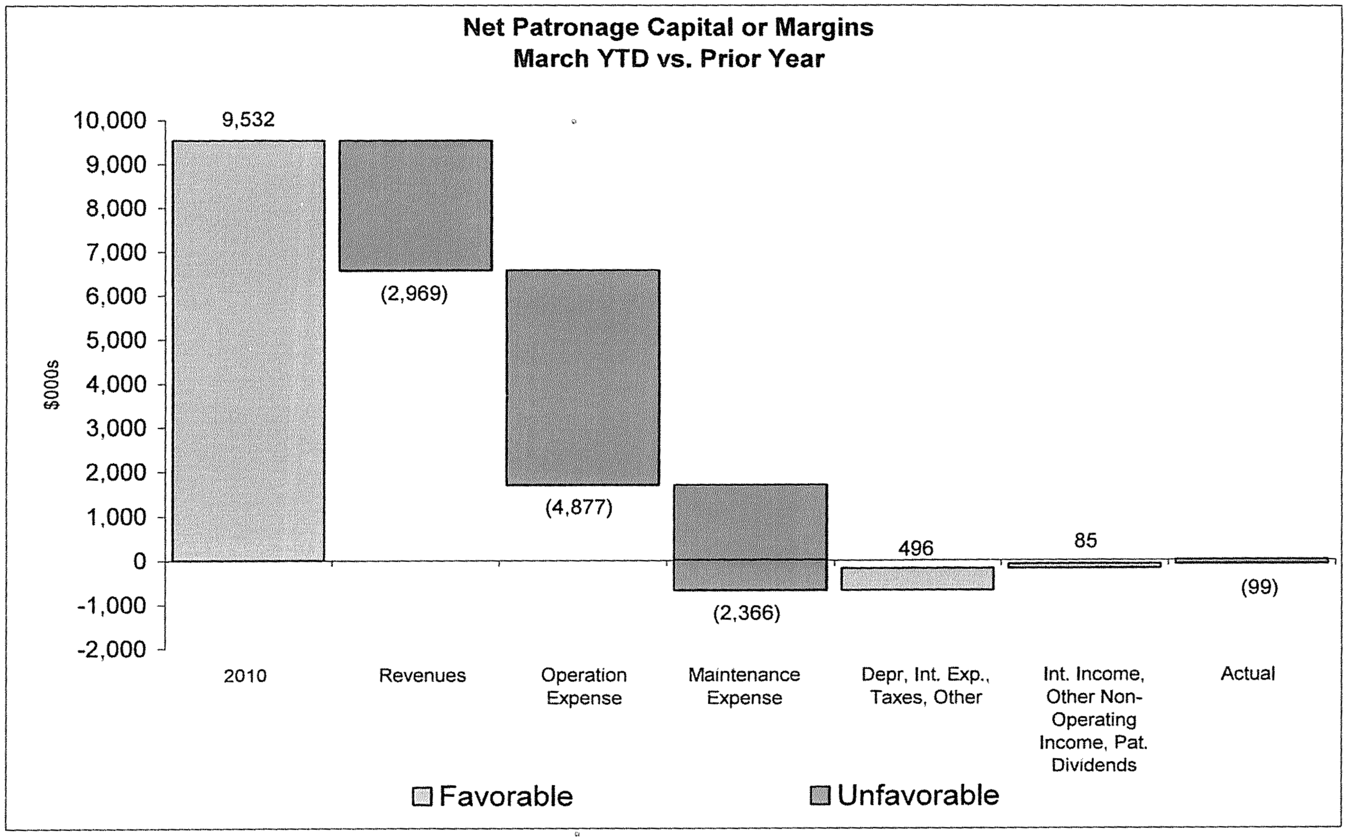
Year-to-Date

- YTD March 2011 Margins were $4,946 unfavorable to budget.
  - Electric Energy Revenues were unfavorable $2,451 primarily due to lower off-system pricing (see pg. 12).
  - Other Revenue was favorable $618
  - Operation Expense was unfavorable $4,215 – driven by higher variable costs $4,706 (see pgs. 13, 27 and 28).
  - Maintenance Expense was favorable $455 primarily due timing of plant expenses.
  - Depreciation and Interest Expense was favorable $554 due to lower depreciation and higher capitalized interest.

Attachment for Response to AG 2-13(c)

Big Rivers ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Variance Analysis Summary



Financial Commentary

Year-to-Date

- YTD 2011 margins were $9,631 unfavorable to YTD March 2010.
  - Electric Energy Revenues were unfavorable $225 primarily due to lower off-system pricing (see pg. 12).
  - Other Revenue was unfavorable $2,744 primarily due to a lower power supply transmission reservation, which is off-set in Operations Expense – Other Power Supply (see pg. 26).
  - Operation Expense was unfavorable $4,877 – driven by higher variable costs $6,235, partially offset by lower transmission reservation (see pg. 13).
  - Maintenance Expense was unfavorable $2,366 primarily due to unplanned outages at Coleman and Green this year, the planned outage at Wilson this year and higher planned maintenance activities at the plants (pg. 29).
  - Depreciation and Interest Expense combined was lower $496

Attachment for Response to AG 2-13(c)

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

Member Rate Stability Mechanism
March

MRSM - $/MWh	Actual 2011	Budget 2011	2011 Variance	Actual 2010	2010 Variance
Rural	(6.61)	(7.12)	0.51	(9.39)	2.78
Large Industrial	(6.61)	(7.12)	0.51	(9.39)	2.78
Total	(6.61)	(7.12)	0.51	(9.39)	2.78
MRSM - Thousands of $					
Rural	(4,269)	(4,857)	588	(6,274)	2,005
Large Industrial	(1,560)	(1,617)	57	(2,100)	540
Total	(5,829)	(6,474)	645	(8,374)	2,545

Net Revenue - $/MWh	Actual 2011	Budget 2011	2011 Variance	Actual 2010	2010 Variance
Rural	37.94	37.31	0.63	35.05	2.89
Large Industrial	35.23	34.09	1.14	32.90	2.33
Total	37.21	36.50	0.71	34.51	2.70
Net Revenue - Thousands of $					
Rural	24,502	25,430	(928)	23,423	1,079
Large Industrial	8,306	7,755	551	7,359	947
Total	32,808	33,185	(379)	30,782	2,026

Economic Reserve Balance

	Actual	Budget	Variance
Original Deposit	$ 157,000		
Interest Earnings	2,127		
Withdrawals	(43,572)		
Cumulative through Mar 31st	$ 115,555	$ 116,011	$ (456)

Attachment for Response to AG 2-13(c)

Big Rivers
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Your Touchstone Energy Cooperative

Cash & Temporary Investments

	Actual	Budget	Fav/(Unfav)	2010 Actual	Fav/(Unfav)
March 31	55,928	40,187	15,741	60,220	(4,292)

The March 31, 2011 cash balance compared to budget is favorable primarily due to a higher beginning balance $2,700, lower capital expenditures $9,894 and a reduction in fuel inventory $8,501, partially offset by lower YTD margins $4,906.

The March 31, 2011 cash balance compared to prior year is unfavorable primarily due to voluntarily prepaying the RUS Series A Note during 2010, that was "clawed back" by April 1, 2011.

Note: 5.75% RUS Series A Note, prepaid status as of 4/1/11: voluntary = 478; Transition Reserve = 35,000

Lines of Credit
As of March 31

Original Amount	$ 100,000
Letters of Credit Outstanding	(5,354)
Advances Outstanding	(10,000)
Available Lines of Credit	$ 84,646

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy® Cooperative

North Star – YTD March

	2011			2010	
	Actual	Budget	Fav/(UnFav) Variance	Actual	Fav/(UnFav) Variance
Total Cost of Electric Service	134,510	136,071	1,561	127,765	(6,745)
Other Operating Revenues & Income	(612)	(4,771)	(4,159)	(3,368)	(2,756)
Off-System Sales	[redacted]				
Interest Income	(86)	(95)	(9)	(83)	3
Other Non-Operating Income	(5)	0	5	(7)	(2)
Other Capital Credits & Pat. Dividends	(97)	0	97	(13)	84
	[redacted]				
Member MWh	2,487,472	2,706,170	(218,698)	2,464,044	23,428
North Star - $/kWh	[redacted]				

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

TIER

	Actual	Budget	Fav/(Unfav)
Interest on Long Term Debt	11,611	11,633	22
Net Margins	(98)	4,847	(4,945)
TIER (3 months ending 3/31)	0.99	1.42	(0.43)
TIER (12 months ending 3/31)	0.94	1.14	(0.20)

Notes:

TIER = (Net Margins + Interest on Long-Term Debt) divided by Interest on Long-Term Debt

Attachment for Response to AG 2-13(c)

Big Rivers
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Your Touchstone Energy® Cooperative

Capital Expenditures*

	Actual	Budget	Fav/(UnFav)
IT	416	155	(261)
Generation	2,755	8,575	5,820
Transmission	1,635	4,604	2,969
Other	84	1,450	1,366
Total	**4,890**	**14,784**	**9,894**

Explanation:

IT unfavorable due to on-going Oracle "steady-state" issues; continue to capitalize certain costs.

Generation favorable primarily due to the timing of projects. Coleman was favorable $2,020 due to the delay of several projects including C2 Aux Transformer, Control Room, Start-up 480v MCC replacement and Interposing Logic System Controls. Station Two was favorable $2,770 due to reducing the scope of the HMPL 1 spring outage. Green Station was favorable $646 due to several projects being moved to later in the year. These include Condenser Water Box Coating, Clarifier Coating, Sample & Analyzers and Drum Camera Replacements.

Transmission favorable primarily due to the timing of the Wilson Line 19F Terminal and Two Way Radio Replacement.

Other favorable primarily due to the delay in purchasing the PCI Software, Operator Training Simulator and analyzers and a chromatograph for the Environmental Department.

* Gross of the City's share of Station Two.

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Revenue
YTD March

MWh Sales	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	645,798	681,724	(35,926)	668,189	(22,391)
Large Industrial	235,825	227,410	8,415	223,694	12,131
Smelter	1,605,848	1,797,036	(191,188)	1,572,162	33,686
Off-System/Other	[redacted]				
Total					

Revenue - $/MWh	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	44.55	44.43	0.12	44.44	0.11
Large Industrial	41.84	41.21	0.63	42.29	(0.45)
Smelter	43.27	42.31	0.96	43.89	(0.62)
Off-System/Other	[redacted]				
Total					

Revenue - Thousands of $	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	28,771	30,287	(1,516)	29,697	(926)
Large Industrial	9,866	9,372	494	9,459	407
Smelter	69,487	76,027	(6,540)	68,997	490
Off-System/Other	[redacted]				
Total					

Revenue Price / Volume Analysis
YTD March 2011

	Price / Volume Price	Volume	Total
Rural	80	(1,596)	(1,516)
Large Industrial	148	346	494
Smelter	1,548	(8,088)	(6,540)
Off-System/Other	[redacted]		

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Variable Operations Cost
YTD March

Variable Operations (VO) Cost - $/MWh	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	25.77	24.52	(1.25)	24.19	(1.58)
Large Industrial	25.83	24.52	(1.31)	24.19	(1.64)
Smelter	24.26	23.09	(1.17)	23.51	(0.75)
Off-System/Other	[redacted]				
Total					

VO Cost - Thousands of $	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	16,643	16,716	73	16,167	(476)
Large Industrial	6,091	5,576	(515)	5,412	(679)
Smelter	38,952	41,497	2,545	36,959	(1,993)
Off-System/Other	[redacted]				
Total					

YTD March 2011
Variable Operations Expense

	Actual	Budget	Fav/(UnFav)	Price Variance Fav/(UnFav)	Volume Variance Fav/(UnFav)	Fav/(UnFav)
Reagent	6,753	8,673	1,920	1,078	842	1,920
Fuel	63,364	60,271	(3,093)	(4,350)	1,257	(3,093)
Purchased Power	7,844	4,384	(3,460)	(4,720)	1,260	(3,460)
Non-FAC PPA (Non-Smelter)	1,371	1,298	(73)	(112)	39	(73)
	79,332	74,626	(4,706)	(8,104)	3,398	(4,706)

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Net Sales Margin
YTD March

Net Sales Margin - $/MWh	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	18.78	19.91	(1.13)	20.25	(1.47)
Large Industrial	16.01	16.69	(0.68)	18.09	(2.08)
Smelter	19.01	19.22	(0.21)	20.38	(1.37)
Off-System/Other	[redacted]				
Total					

Net Sales Margin - Thousands of $	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	12,128	13,571	(1,443)	13,530	(1,402)
Large Industrial	3,775	3,796	(21)	4,047	(272)
Smelter	30,535	34,530	(3,995)	32,038	(1,503)
Off-System/Other	[redacted]				
Total					

Net Sales Margin
Price / Volume Analysis
YTD March 2011

	Price / Volume		
	Price	Volume	Total
Rural	(728)	(715)	(1,443)
Large Industrial	(161)	140	(21)
Smelter	(321)	(3,674)	(3,995)
Off-System/Other	[redacted]		

Attachment for Response to AG 2-13(c)

Big Rivers
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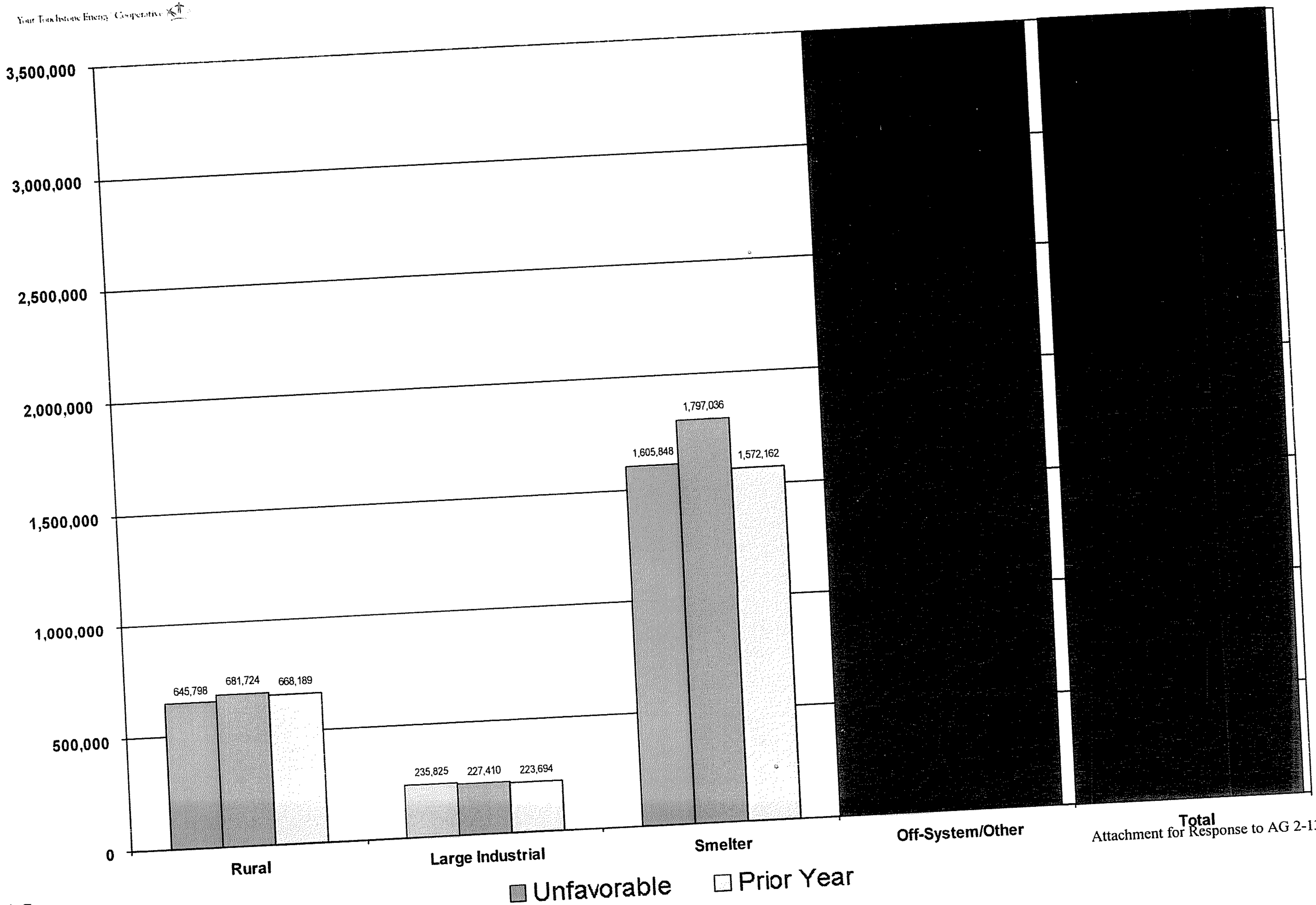
MWH Sales
YTD - March



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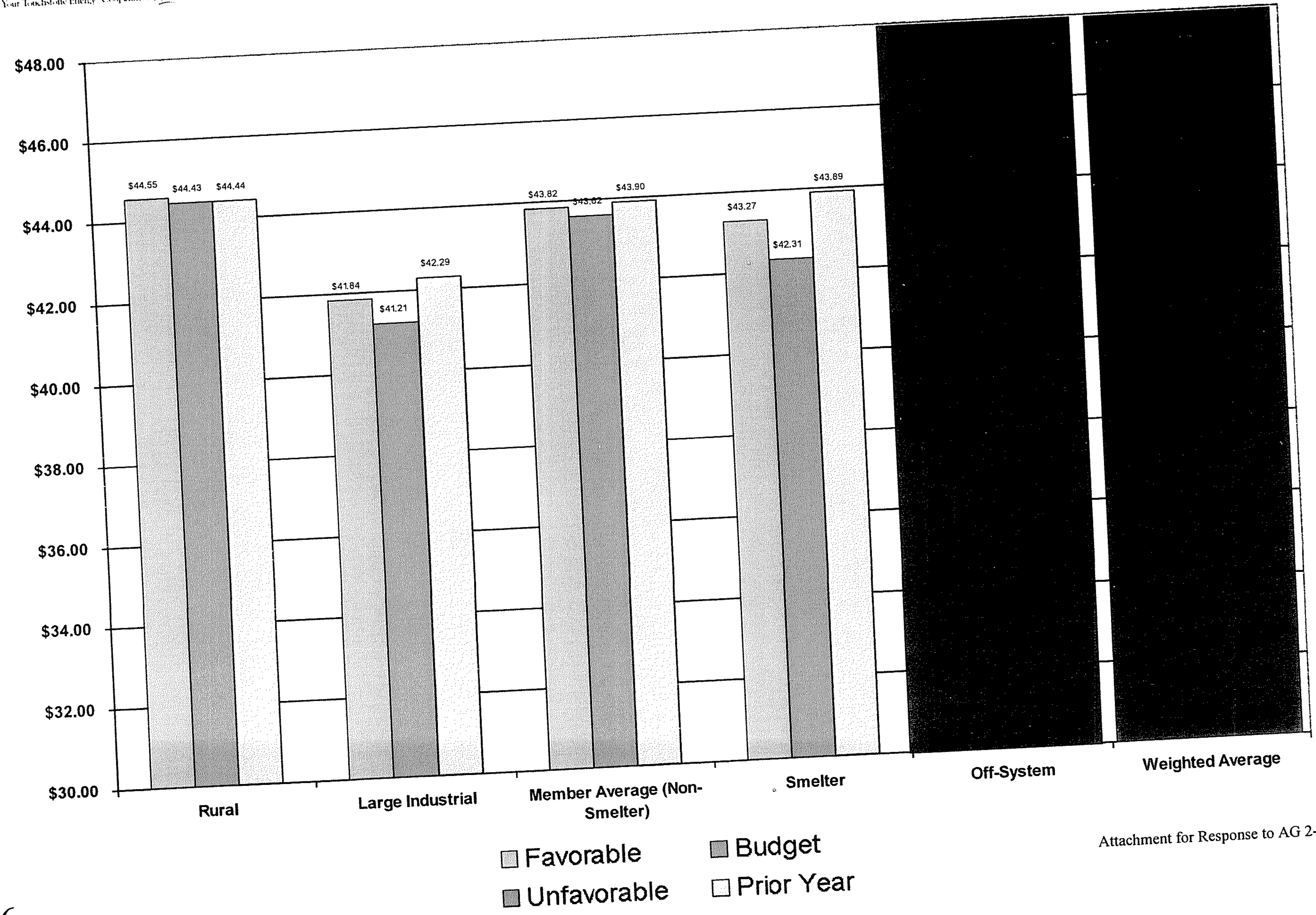
Revenue - $/MWh Sold
YTD - March



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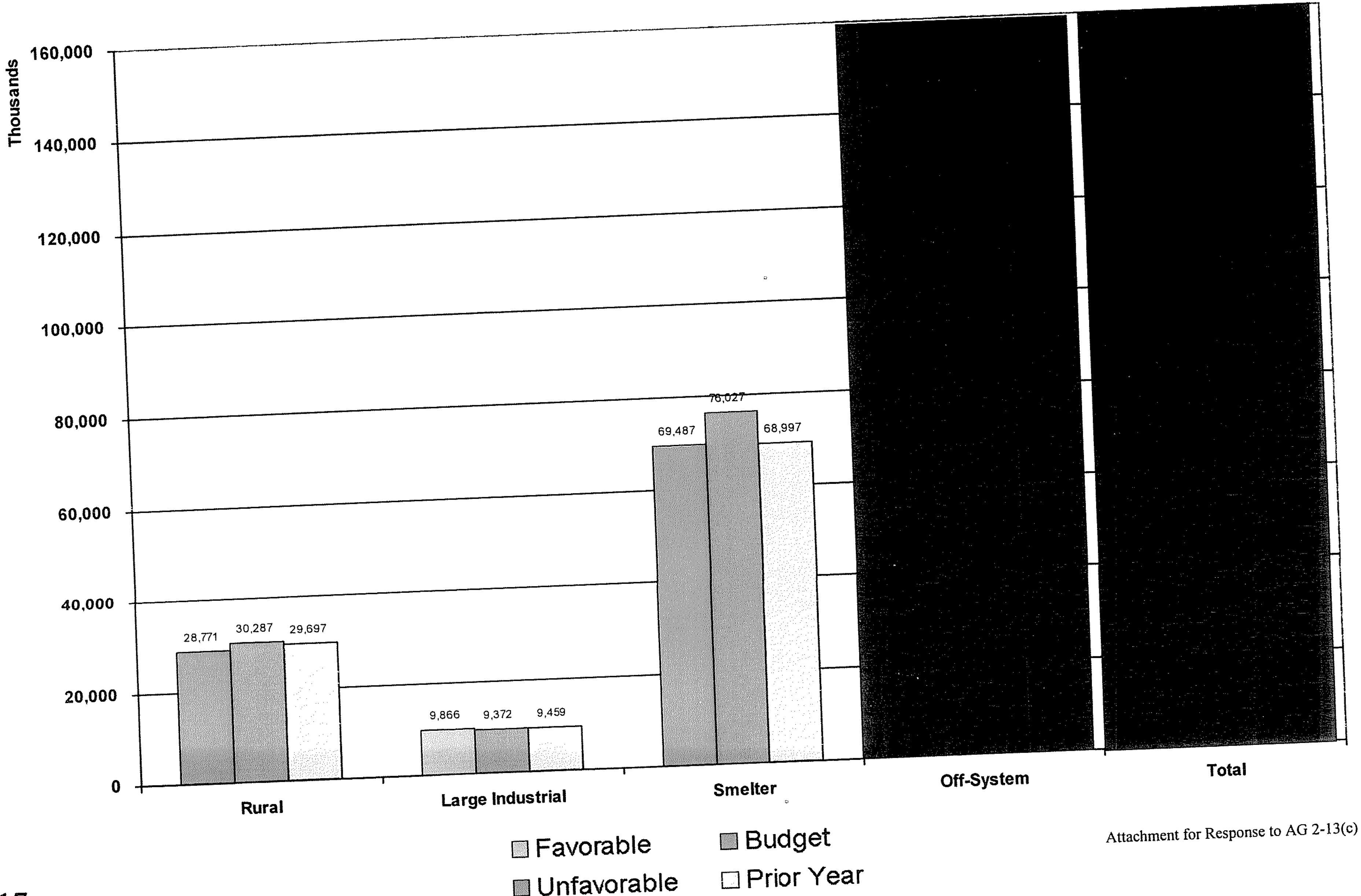
Big Rivers
ELECTRIC CORPORATION

Revenue
YTD - March



Attachment for Response to AG 2-13(c)

Power Cost - $/MWh Sold
YTD - March

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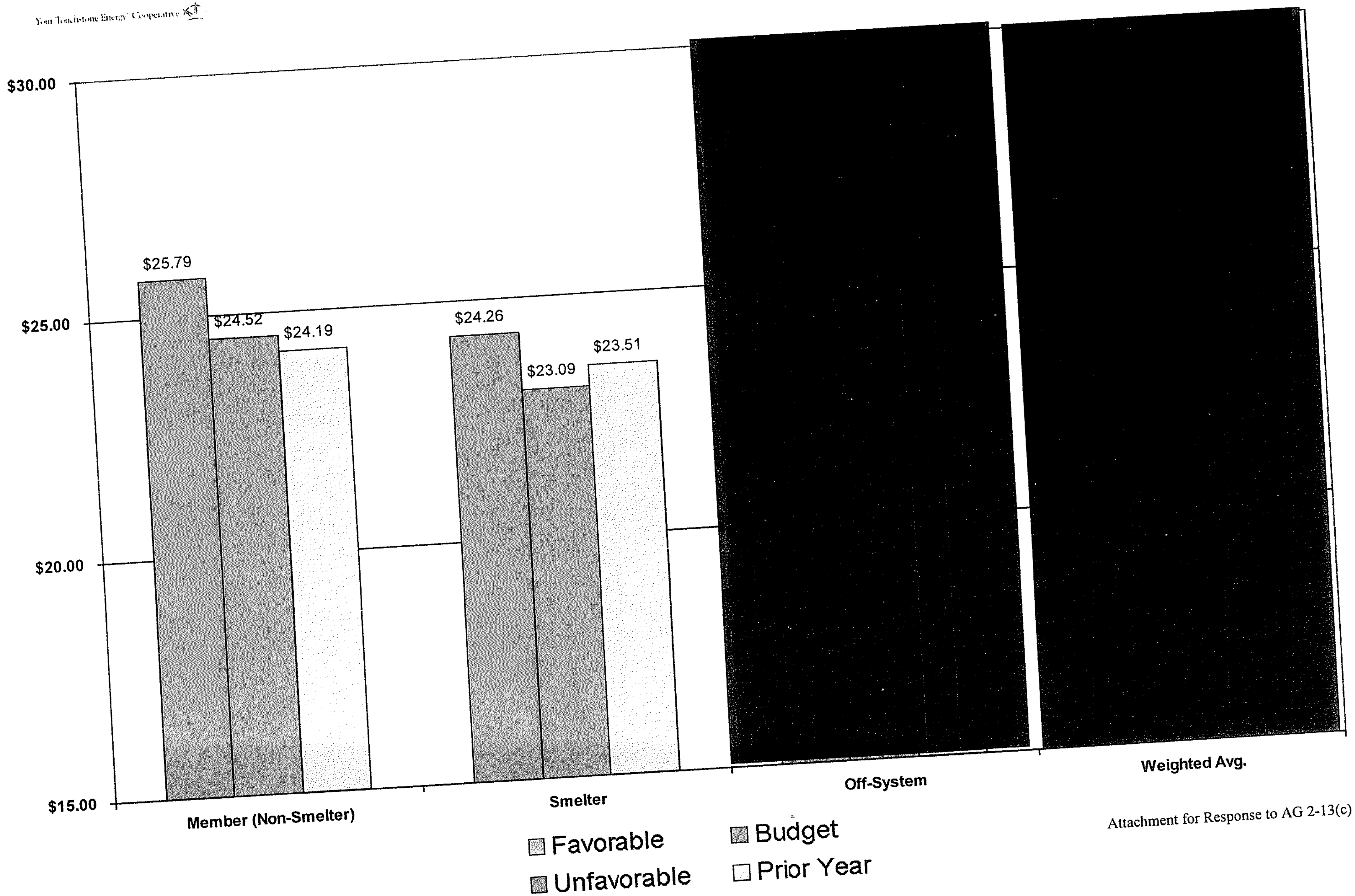
Your Touchstone Energy® Cooperative



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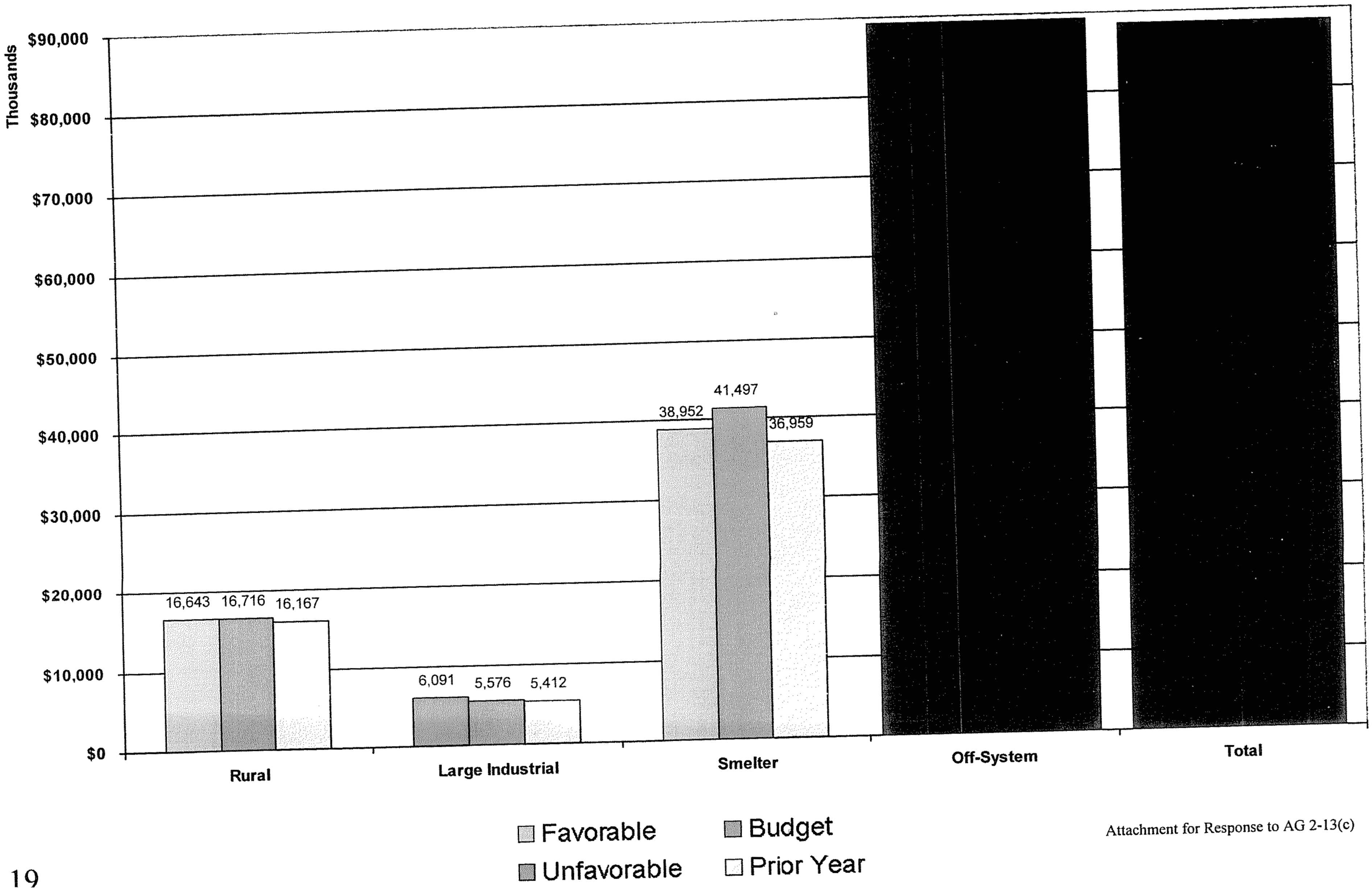
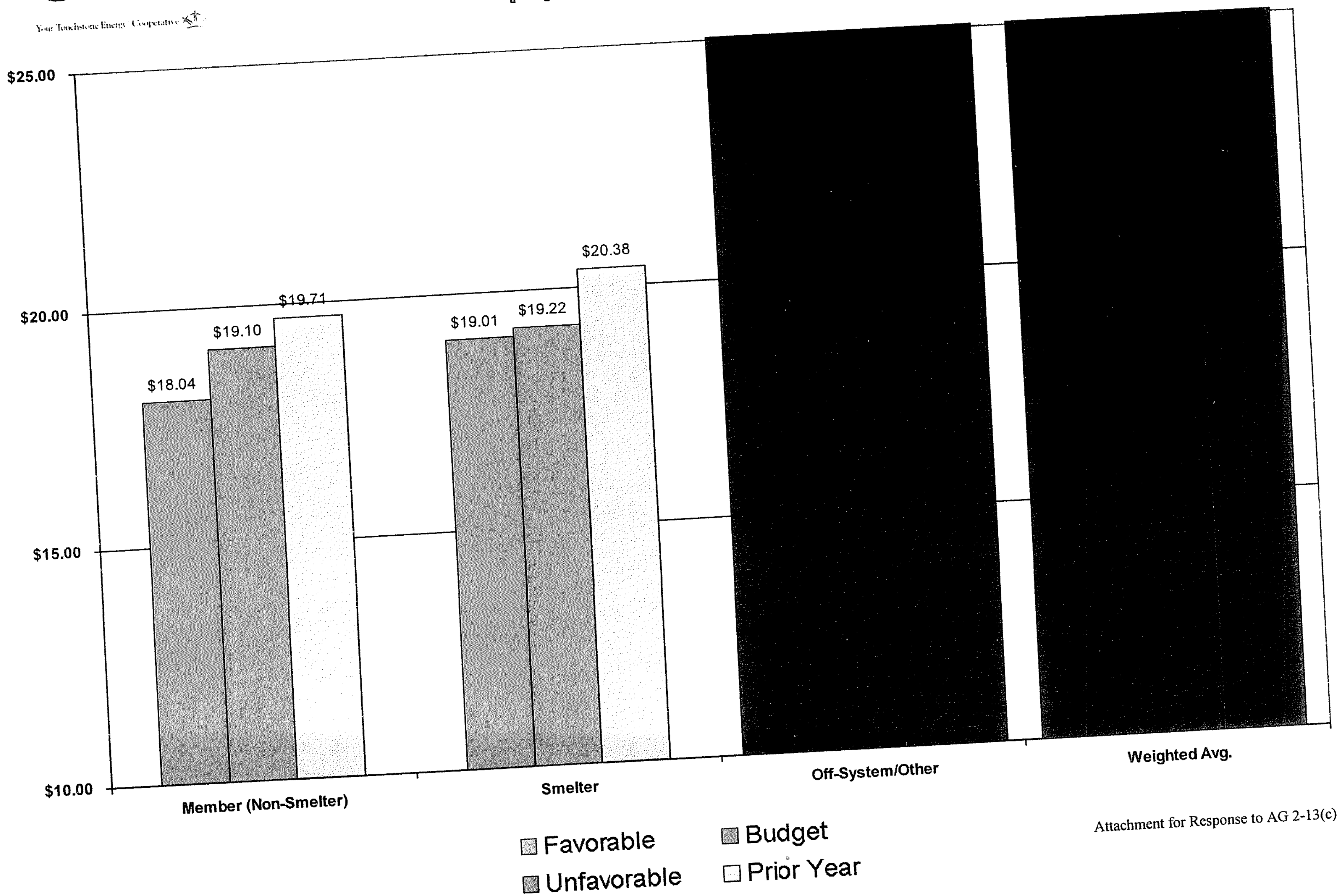
Power Cost
YTD - March



Attachment for Response to AG 2-13(c)

Sales Margin - $/MWh
YTD - March



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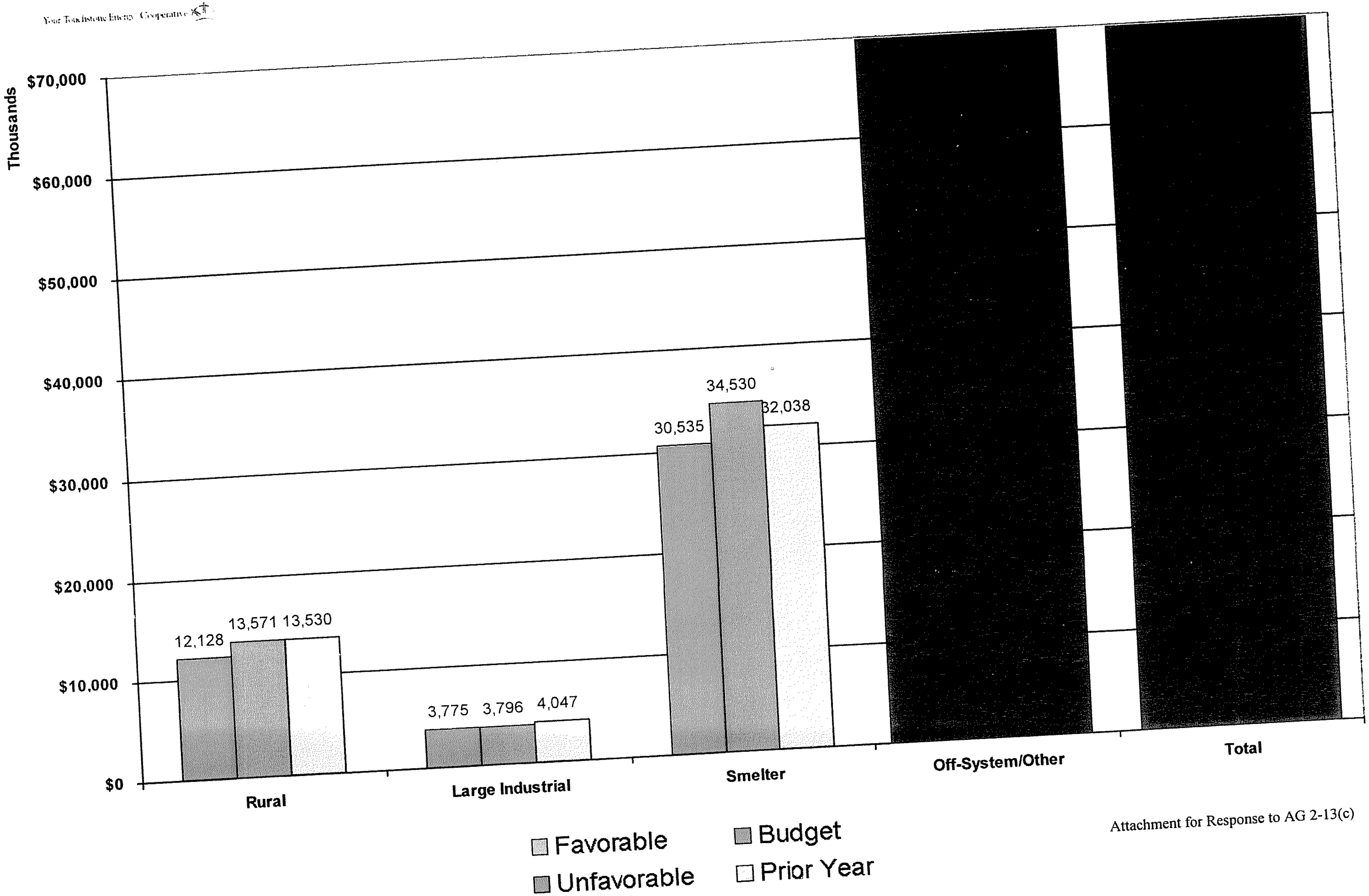
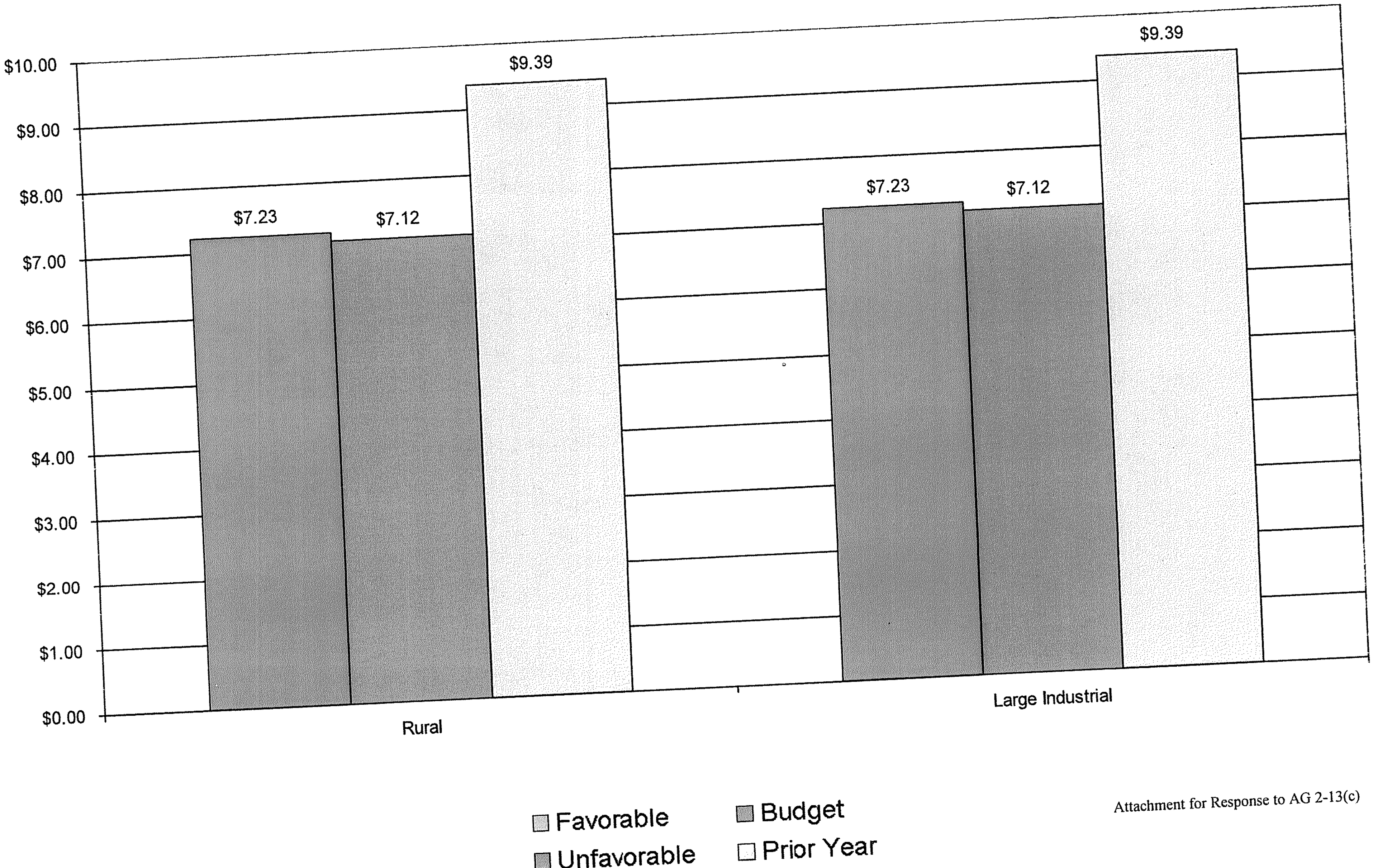
Your Touchstone Energy Cooperative

Sales Margin
YTD - March



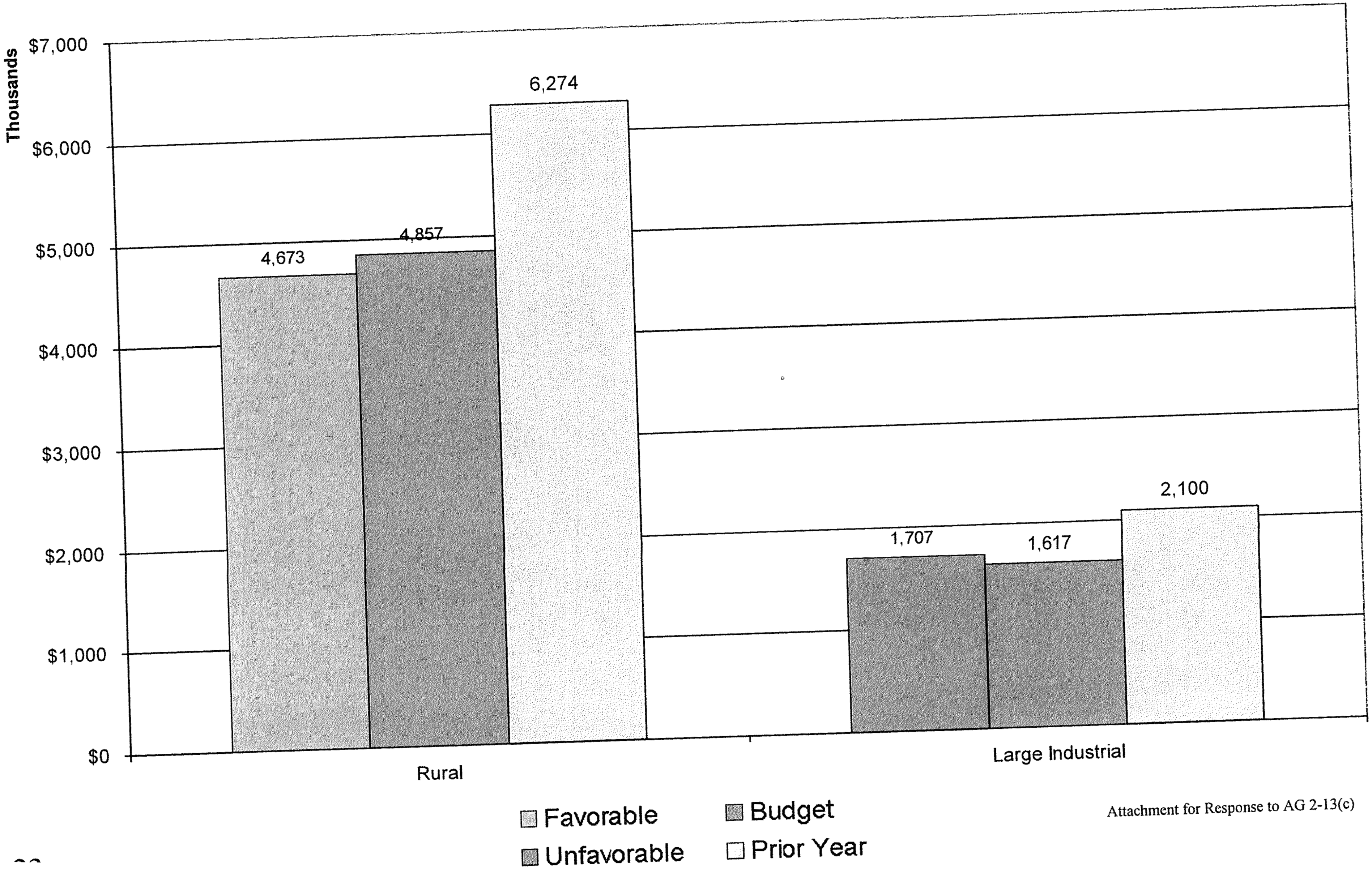
Attachment for Response to AG 2-13(c)

MRSM - $/MWh
YTD - March



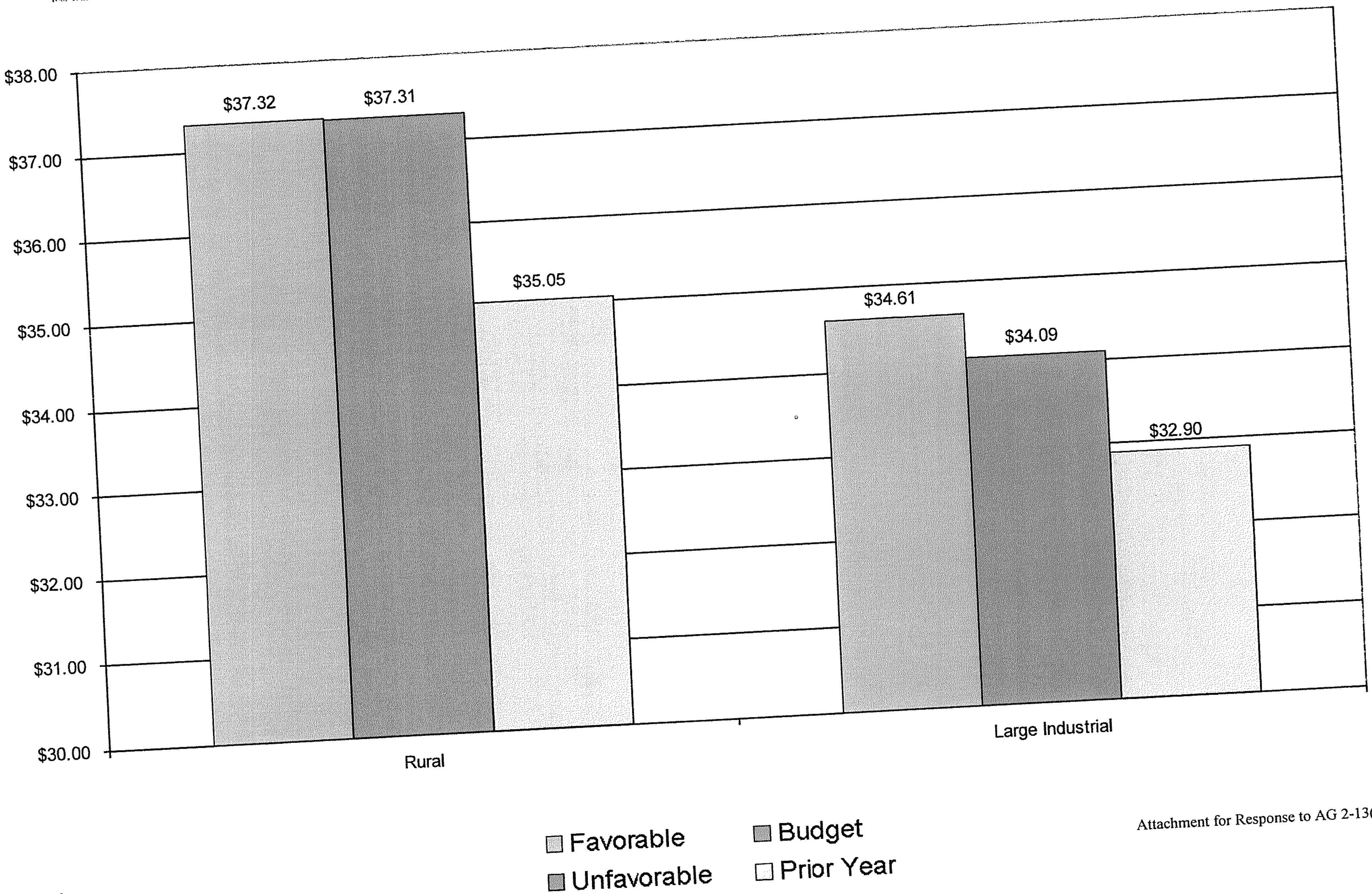
Attachment for Response to AG 2-13(c)

MRSM
YTD - March



Attachment for Response to AG 2-13(c)

Net Revenue (Excl. MRSM) - $/MWh
YTD - March



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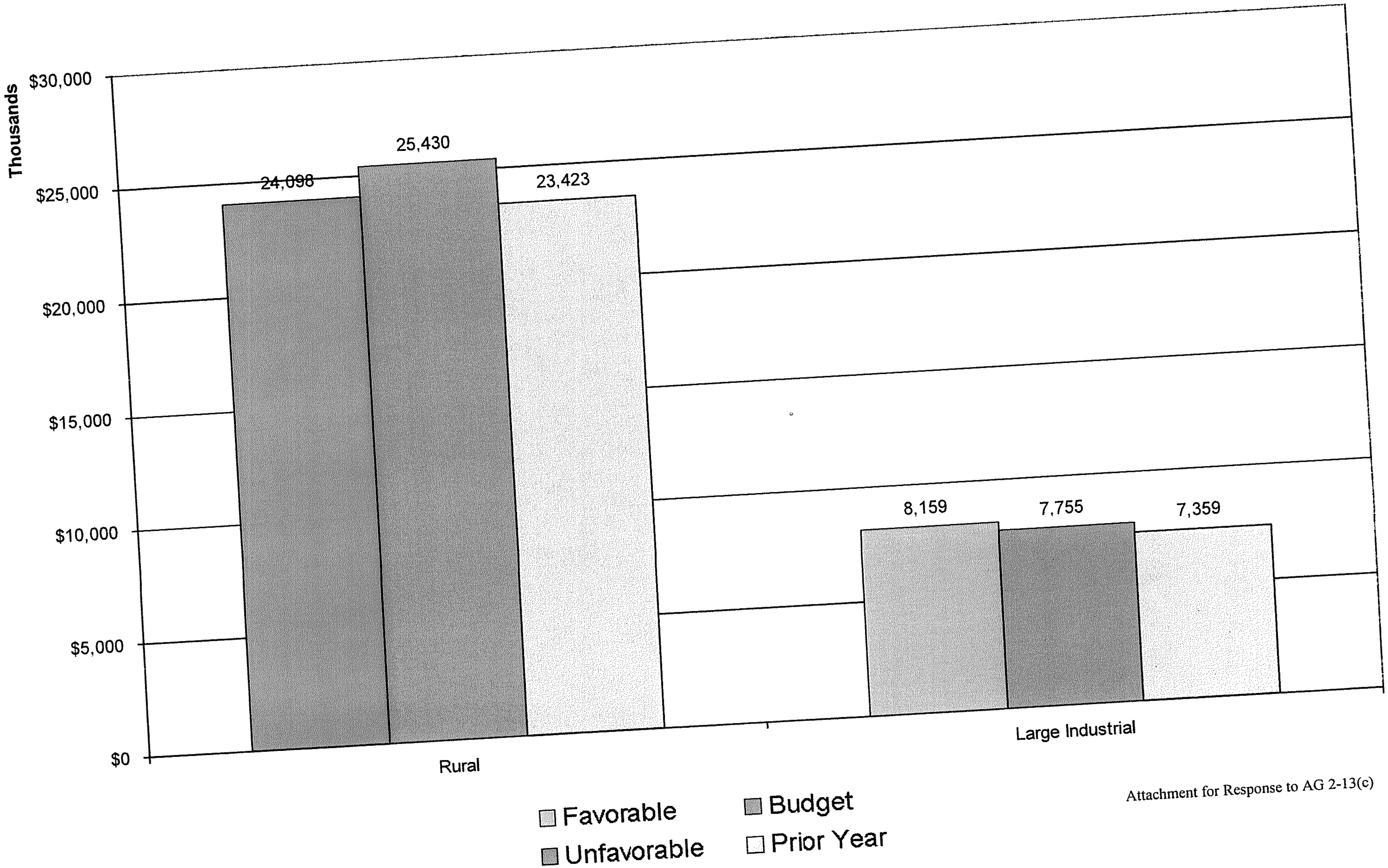
Net Revenue (Excl. MRSM)
YTD - March



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Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy® Cooperative

Other Operating Revenue and Income

	2011			2010	
	Actual	Budget	Variance Fav/(Unfav)	2010 Actual	Variance Fav/(Unfav)
March YTD	624	6	618	3,368	(2,744)

Favorable to Budget due to (intentional) omission of power supply transmission reservation. Unfavorable to prior year due to a lower power supply transmission reservation.

Big Rivers
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Your Touchstone Energy Cooperative

Operation Expense – Transmission

	2011			2010	
	Actual	Budget	Variance Fav/(Unfav)	2010 Actual	Variance Fav/(Unfav)
March YTD	2,830	4,238	1,408	1,994	(836)

Favorable to budget primarily due to 1) lower than anticipated MISO related expenses $687, 2) unfilled positions and more labor capitalized than budgeted $337, and 3) various stations and lines fixed departmental expenses $384.

Unfavorable to prior year due to MISO membership.

Attachment for Response to AG 2-13(c)

Big Rivers
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Your Touchstone Energy Cooperative

Operation Expense – Administrative & General

	2011		
	Actual	Budget	Variance Fav/(Unfav)
March YTD	6,796	6,160	(636)

Unfavorable to budget primarily due to (a) labor expenses $209, (b) IT expenses for HP and Oracle $322, and (c) outside professional services for the rate case $102.

Additional Notes: HP costs are unfavorable due to Oracle R12 not yet being at "steady state". The E.ON IT Support Services Agreement was not terminated until 1/15/11 (Originally planned for 11/30/2010). The Oracle maintenance contract was budgeted throughout the year (timing).

Attachment for Response to AG 2-13(c)

Big Rivers
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Maintenance Expense – Production

	2011 Actual	2010 Actual	Variance Fav/(Unfav)
March YTD	9,417	6,975	(2,442)

Unfavorable to prior year due to higher planned maintenance activities this year, the planned outage at Wilson and higher unplanned outages at Green and Coleman.

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

Financial Report

April 2011

($ in Thousands)

Board Meeting Date: June 17, 2011

Attachment for Response to AG 2-13(c)

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

Summary of Operations
YTD April

	2011			2010	
	Actual	Budget *	Fav/(UnFav) Variance	Actual	Fav/(UnFav) Variance
Revenues	178,664	176,592	2,072	175,892	2,772
Cost of Electric Service	179,592	174,967	(4,625)	168,802	(10,790)
Operating Margins	(928)	1,625	(2,553)	7,090	(8,018)
Interest Income/Other	196	223	(27)	134	62
Net Margins - YTD	(732)	1,848	(2,580)	7,224	(7,956)

* Budget Revenues and Cost of Electric Service revised to remove the power supply transmission reservation (off-setting).

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

Statement of Operations – April

Variance to Budget

	Current Month Actual	Current Month Budget	Current Month Variance Fav/(UnFav)	Year-to-Date Actual	Year-to-Date Budget	Year-to-Date Variance Fav/(UnFav)	Explanation
ELECTRIC ENERGY REVENUES	44,069	40,533	3,536	177,670	176,584	1,086	[A] Pages 7, 12-14
INCOME FROM LEASED PROPERTY - NET	0	0	0	0	0	0	
OTHER OPERATING REVENUE AND INCOME	370	2	368	994	8	986	
TOTAL OPER REVENUES & PATRONAGE CAPITAL	44,439	40,535	3,904	178,664	176,592	2,072	
OPERATION EXPENSE-PRODUCTION-EXCL FUEL	3,955	5,140	1,185	16,104	20,517	4,413	[A] Pages 7, 12-14, 27
OPERATION EXPENSE-PRODUCTION-FUEL	19,417	16,877	(2,540)	75,743	68,659	(7,084)	[A] Pages 7, 12-14
OPERATION EXPENSE-OTHER POWER SUPPLY	8,680	6,820	(1,860)	34,542	28,585	(5,957)	[A] Pages 7, 12-14, 27
OPERATION EXPENSE-TRANSMISSION	1,185	1,201	16	4,016	5,439	1,423	[B] Page 28
CONSUMER SERVICE & INFORMATIONAL EXPENSE	34	70	36	134	310	176	
OPERATION EXPENSE-SALES	(6)	53	59	(6)	339	345	
OPERATION EXPENSE-ADMINISTRATIVE & GENERAL	1,958	2,243	285	8,754	8,403	(351)	
TOTAL OPERATION EXPENSE	35,223	32,404	(2,819)	139,287	132,252	(7,035)	
MAINTENANCE EXPENSE-PRODUCTION	2,726	4,144	1,418	12,143	14,130	1,987	[B], [C] Page 29
MAINTENANCE EXPENSE-TRANSMISSION	397	241	(156)	1,321	1,027	(294)	
MAINTENANCE EXPENSE-GENERAL PLANT	25	14	(11)	28	39	11	
TOTAL MAINTENANCE EXPENSE	3,148	4,399	1,251	13,492	15,196	1,704	
DEPRECIATION & AMORTIZATION EXPENSE	2,877	2,994	117	11,558	11,907	349	
TAXES	66	21	(45)	63	83	20	
INTEREST ON LONG-TERM DEBT	3,770	3,874	104	15,380	15,507	127	
INTEREST CHARGED TO CONSTRUCTION-CREDIT	(16)	(61)	(45)	(337)	(105)	232	
OTHER INTEREST EXPENSE	0	21	21	59	82	23	
OTHER DEDUCTIONS	14	11	(3)	90	45	(45)	
TOTAL COST OF ELECTRIC SERVICE	45,082	43,663	(1,419)	179,592	174,967	(4,625)	
OPERATING MARGINS	(643)	(3,128)	2,485	(928)	1,625	(2,553)	
INTEREST INCOME	9	32	(23)	94	127	(33)	
ALLOWANCE FOR FUNDS USED DURING CONST	0	0	0	0	0	0	
OTHER NON-OPERATING INCOME - NET	0	0	0	5	0	5	
OTHER CAPITAL CREDITS & PAT DIVIDENDS	0	96	(96)	97	96	1	
EXTRAORDINARY ITEMS	0	0	0	0	0	0	
NET PATRONAGE CAPITAL OR MARGINS	(634)	(3,000)	2,366	(732)	1,848	(2,580)	

Attachment for Response to AG 2-13(c)

Explanations: [A] Net Sales Margin, [B] 10% and $250,000 line item or [C] 10% and $500,000 margins.

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Statement of Operations – April
Variance to Prior-Year

	Current Month			Year-to-Date			
	Actual	Prior Year	Variance Fav/(UnFav)	Actual	Prior Year	Variance Fav/(UnFav)	Explanation
ELECTRIC ENERGY REVENUES	44,069	44,019	50	177,670	171,384	6,286	[A] Pages 7, 12-14
INCOME FROM LEASED PROPERTY - NET	0	0	0	0	0	0	
OTHER OPERATING REVENUE AND INCOME	370	1,070	(700)	994	4,508	(3,514)	[B], [C] Page 26
TOTAL OPER REVENUES & PATRONAGE CAPITAL	44,439	45,089	(650)	178,664	175,892	2,772	
OPERATION EXPENSE-PRODUCTION-EXCL FUEL	3,955	4,431	476	16,104	16,671	567	[A] Pages 7, 12-14
OPERATION EXPENSE-PRODUCTION-FUEL	19,417	17,192	(2,225)	75,743	69,816	(5,927)	[A] Pages 7, 12-14
OPERATION EXPENSE-OTHER POWER SUPPLY	8,680	7,680	(1,000)	34,542	31,617	(2,925)	[A] Pages 7, 12-14, [B] 26
OPERATION EXPENSE-TRANSMISSION	1,185	713	(472)	4,016	2,575	(1,441)	[B] Page 27
CONSUMER SERVICE & INFORMATIONAL EXPENSE	34	53	19	134	179	45	
OPERATION EXPENSE-SALES	(7)	21	28	(6)	(4)	2	
OPERATION EXPENSE-ADMINISTRATIVE & GENERAL	1,958	2,709	751	8,754	9,773	1,019	
TOTAL OPERATION EXPENSE	35,222	32,799	(2,423)	139,287	130,627	(8,660)	
MAINTENANCE EXPENSE-PRODUCTION	2,726	2,700	(26)	12,143	9,541	(2,602)	[B],[C] Page 29
MAINTENANCE EXPENSE-TRANSMISSION	397	378	(19)	1,321	1,242	(79)	
MAINTENANCE EXPENSE-GENERAL PLANT	26	15	(11)	28	83	55	
TOTAL MAINTENANCE EXPENSE	3,149	3,093	(56)	13,492	10,866	(2,626)	
DEPRECIATION & AMORTIZATION EXPENSE	2,877	2,824	(53)	11,558	11,302	(256)	
TAXES	66	1	(65)	63	66	3	
INTEREST ON LONG-TERM DEBT	3,770	4,133	363	15,380	16,013	633	
INTEREST CHARGED TO CONSTRUCTION-CREDIT	(16)	(17)	(1)	(337)	(108)	229	
OTHER INTEREST EXPENSE	0	1	1	59	22	(37)	
OTHER DEDUCTIONS	14	6	(8)	90	14	(76)	
TOTAL COST OF ELECTRIC SERVICE	45,082	42,840	(2,242)	179,592	168,802	(10,790)	
OPERATING MARGINS	(643)	2,249	(2,892)	(928)	7,090	(8,018)	
INTEREST INCOME	9	29	(20)	94	111	(17)	
ALLOWANCE FOR FUNDS USED DURING CONST	0	0	0	0	0	0	
OTHER NON-OPERATING INCOME - NET	0	2	(2)	5	10	(5)	
OTHER CAPITAL CREDITS & PAT DIVIDENDS	0	13	(13)	97	13	84	
EXTRAORDINARY ITEMS	0	0	0	0	0	0	
NET PATRONAGE CAPITAL OR MARGINS	(634)	2,293	(2,927)	(732)	7,224	(7,956)	

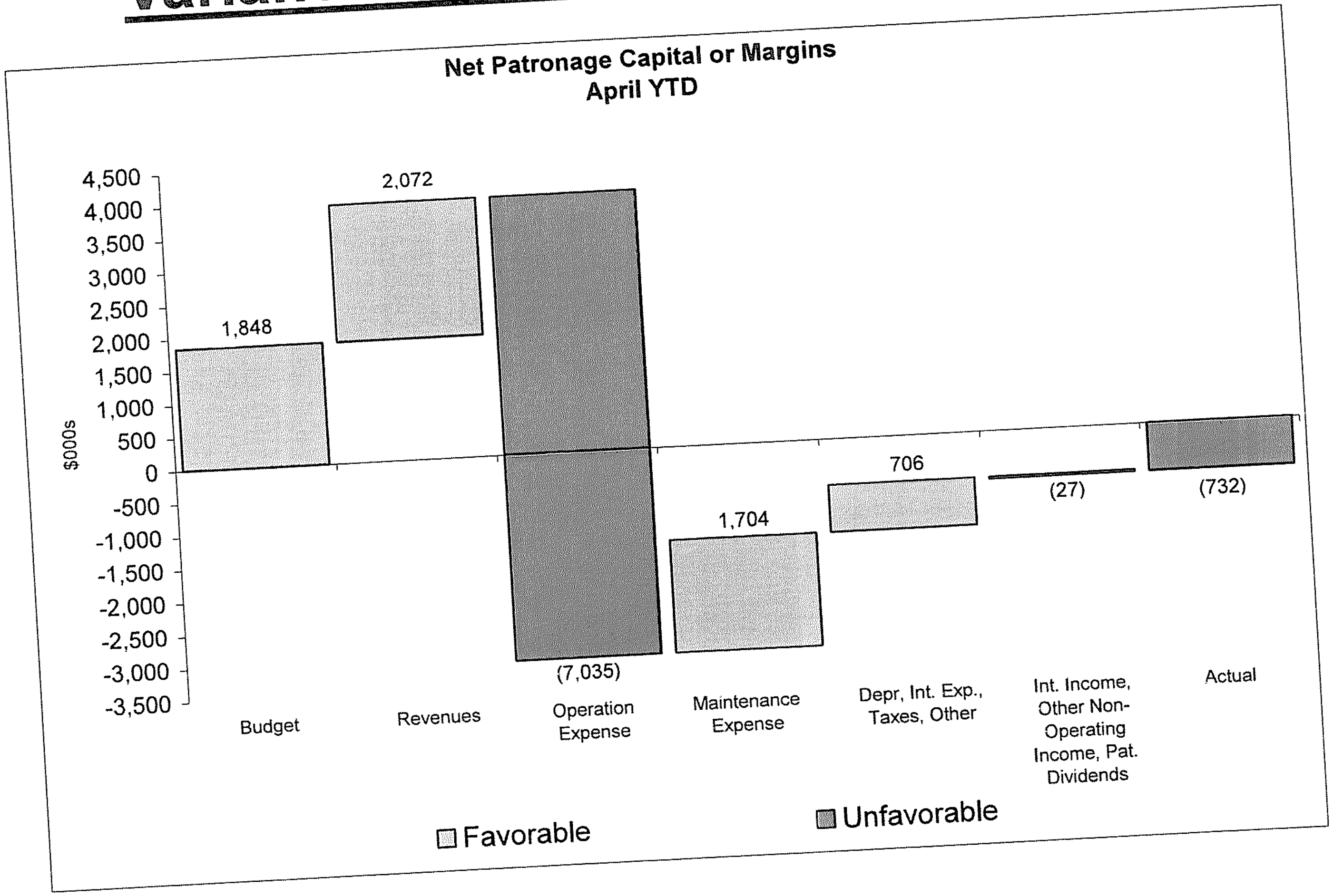
Attachment for Response to AG 2-13(c)

Explanations: [A] Net Sales Margin, [B] 10% and $250,000 line item or [C] 10% and $500,000 margins.

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

Variance Analysis Summary



Financial Commentary

Year-to-Date

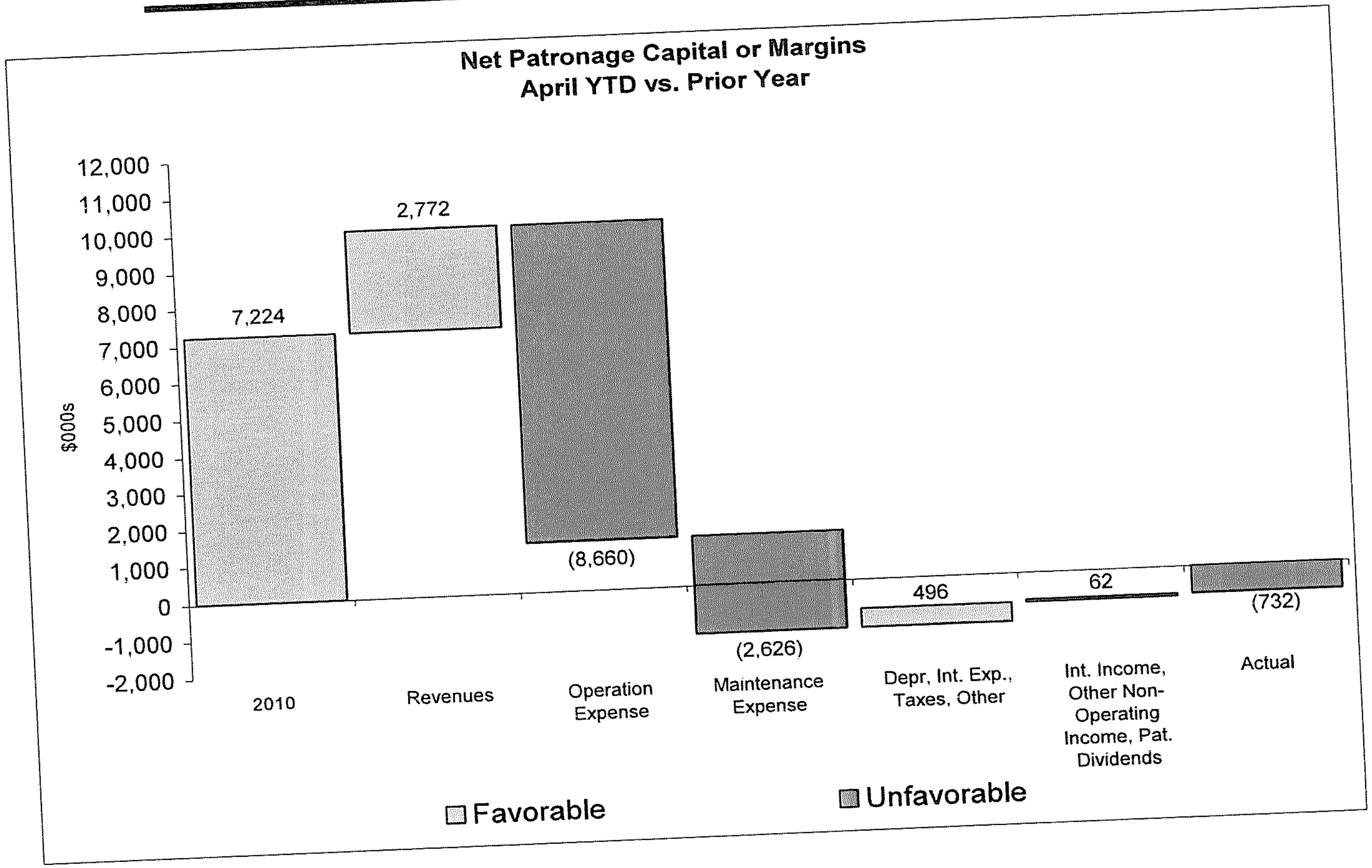
- YTD April 2011 Margins were $2,580 unfavorable to budget.
  - Electric Energy Revenues were favorable $1,086 primarily due to higher off-system volume (see pg. 12).
  - Other Revenue was favorable $986 (see pg. 26).
  - Operation Expense was unfavorable $7,035 – driven by higher variable costs $8,304, partially offset by the reduction in scope of the HMPL 1 planned outage and favorable timing of operating expenses at Station Two and transmission (see pgs. 13, 27 and 28).
  - Maintenance Expense was favorable $1,704 primarily due timing of plant expenses (see pg. 29).
  - Depreciation and Interest Expense was favorable $706 due to lower depreciation and higher capitalized interest.

Attachment for Response to AG 2-13(c)

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

Variance Analysis Summary



Financial Commentary

Year-to-Date

- YTD 2011 margins were $7,956 unfavorable to YTD April 2010.
  - Electric Energy Revenues were favorable $6,286 primarily due to higher off-system volumes (see pg. 12).
  - Other Revenue was unfavorable $3,514 primarily due to a lower power supply transmission reservation, which is off-set in Operations Expense – Other Power Supply (see pg. 26).
  - Operation Expense was unfavorable $8,660 – driven by higher variable costs $11,252, partially offset by lower transmission reservation (see pg. 13) and lower administrative costs.
  - Maintenance Expense was unfavorable $2,626 primarily due to unplanned outages at Coleman and Green this year, the planned outage at Wilson this year and higher planned maintenance activities at the plants (pg. 29).
  - Depreciation and Interest Expense combined was lower $496

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Member Rate Stability Mechanism
April

	Actual 2011	Budget 2011	2011 Variance	Actual 2010	2010 Variance
MRSM - $/MWh					
Rural	(7.14)	(6.87)	(0.27)	(9.08)	1.94
Large Industrial	(7.14)	(6.87)	(0.27)	(9.08)	1.94
Total	(7.14)	(6.87)	(0.27)	(9.08)	1.94
MRSM - Thousands of $					
Rural	(5,661)	(5,826)	165	(7,354)	1,693
Large Industrial	(2,220)	(2,075)	(145)	(2,741)	521
Total	(7,881)	(7,901)	20	(10,095)	2,214

	Actual 2011	Budget 2011	2011 Variance	Actual 2010	2010 Variance
Net Revenue - $/MWh					
Rural	37.59	37.56	0.03	35.27	2.32
Large Industrial	34.78	34.38	0.40	32.74	2.04
Total	36.80	36.73	0.07	34.58	2.22
Net Revenue - Thousands of $					
Rural	29,796	31,873	(2,077)	28,545	1,251
Large Industrial	10,817	10,374	443	9,879	938
Total	40,613	42,247	(1,634)	38,424	2,189

Economic Reserve Balance

	Actual	Budget	Variance
Original Deposit	$ 157,000		
Interest Earnings	2,210		
Withdrawals	(45,923)		
Cumulative through April 30th	$ 113,287	$ 114,481	$ (1,194)

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Cash & Temporary Investments

	Actual	Budget	Fav/(Unfav)	2010 Actual	Fav/(Unfav)
April 30th	61,501	29,879	31,622	50,815	10,686

The April 30th, 2011 cash balance compared to budget is favorable primarily due to lower capital expenditures $16,116 and a reduction in fuel inventory $18,000, partially offset by lower YTD margins $2,580.

The April 30th, 2011 cash balance compared to prior year is favorable primarily due to voluntarily prepaying the RUS Series A Note during 2010.

Note: 5.75% RUS Series A Note, prepaid status as of 5/1/11: voluntary = 478; Transition Reserve = 35,000

Lines of Credit As of April 30th	
Original Amount	$ 100,000
Letters of Credit Outstanding	(5,604)
Advances Outstanding	0
Available Lines of Credit	$ 94,396

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

North Star – YTD April

	2011			2010	
	Actual	Budget	Fav/(UnFav) Variance	Actual	Fav/(UnFav) Variance
Total Cost of Electric Service	179,592	181,321	1,729	168,802	(10,790)
Other Operating Revenues & Income	(982)	(6,361)	(5,379)	(4,508)	(3,526)
Off-System Sales	[redacted]				
Interest Income	(94)	(127)	(33)	(111)	(17)
Other Non-Operating Income	(5)	0	5	(10)	(5)
Other Capital Credits & Pat. Dividends	(97)	(96)	1	(13)	84
	[redacted]				
Member MWh	3,280,005	3,547,251	(267,246)	3,204,120	75,885
North Star - $/kWh	[redacted]				

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

TIER

	Actual	Budget	Fav/(Unfav)
Interest on Long Term Debt	15,337	15,507	170
Net Margins	(732)	1,848	(2,580)
TIER (4 months ending 4/30)	0.95	1.12	(0.17)
TIER (12 months ending 4/30)	0.98	1.14	(0.16)

Notes:

TIER = (Net Margins + Interest on Long-Term Debt) divided by Interest on Long-Term Debt

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Capital Expenditures*

	Actual	Budget	Fav/(UnFav)
IT	411	270	(141)
Generation	4,506	14,778	10,272
Transmission	1,551	5,970	4,419
Other	317	1,883	1,566
Total	**6,785**	**22,901**	**16,116**

Explanation:

IT unfavorable due to on-going Oracle "steady-state" issues; continue to capitalize certain costs.

Generation favorable primarily due to the timing or cancellation of projects. Coleman was favorable $3,230 due to the cancellation of several projects including Interposing Logic System Controls and control room upgrade. The delay of several projects including the C2 Aux Transformer and circulating water pump added to the favorability. Station Two was favorable $2,890 due to reducing the scope of the HMPL 1 spring outage. Green Station was favorable $2,294 due to several projects being moved to later in the year. These include FGD rehab , IUCS Controls, Sample & Analyzers and OFA Jordan drives. The Wilson facility was favorable $1,858 due to the delay of the barge un-loader and the secondary air-heater work.

Transmission favorable primarily due to the timing of the Wilson Line 19F Terminal, Two-Way Radio Replacement and Paradise Terminal Upgrade.

Other favorable primarily due to the delay in purchasing the PCI Software, Operator Training Simulator and analyzers and a chromatograph for the Environmental Department.

* Gross of the City's share of Station Two.

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Revenue
YTD April

MWh Sales	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	792,638	848,440	(55,802)	809,509	(16,871)
Large Industrial	311,029	301,772	9,257	301,780	9,249
Smelter	2,176,336	2,397,039	(220,703)	2,092,832	83,504
Off-System/Other	[redacted]				
Total					

Revenue - $/MWh	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	44.73	44.43	0.30	44.35	0.38
Large Industrial	41.92	41.25	0.67	41.82	0.10
Smelter	43.26	42.46	0.80	43.73	(0.47)
Off-System/Other	[redacted]				
Total					

Revenue - Thousands of $	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	35,457	37,699	(2,242)	35,899	(442)
Large Industrial	13,037	12,449	588	12,620	417
Smelter	94,140	101,767	(7,627)	91,512	2,628
Off-System/Other	[redacted]				
Total					

Revenue Price / Volume Analysis
YTD April 2011

	Price / Volume: Price	Volume	Total
Rural	237	(2,479)	(2,242)
Large Industrial	206	381	587
Smelter	1,743	(9,369)	(7,626)
Off-System/Other	[redacted]		

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Variable Operations Cost
YTD April

Variable Operations (VO) Cost - $/MWh	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	25.84	24.66	(1.18)	24.27	(1.57)
Large Industrial	25.90	24.66	(1.24)	24.27	(1.63)
Smelter	24.45	23.23	(1.22)	23.47	(0.98)
Off-System/Other	[redacted]				
Total					

VO Cost - Thousands of $	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	20,481	20,923	442	19,648	(833)
Large Industrial	8,056	7,442	(614)	7,325	(731)
Smelter	53,206	55,682	2,476	49,125	(4,081)
Off-System/Other	[redacted]				
Total					

YTD April 2011
Variable Operations Expense

	Actual	Budget	Fav/(UnFav)	Price Variance Fav/(UnFav)	Volume Variance Fav/(UnFav)	Fav/(UnFav)
Reagent	8,824	11,183	2,359	1,587	772	2,359
Fuel	84,467	78,345	(6,122)	(5,171)	(951)	(6,122)
Purchased Power	10,847	6,286	(4,561)	(2,048)	(2,513)	(4,561)
Non-FAC PPA (Non-Smelter)	1,626	1,646	20	(47)	67	20
	105,764	97,460	(8,304)	(5,679)	(2,625)	(8,304)

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Net Sales Margin
YTD April

Net Sales Margin - $/MWh	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	18.89	19.77	(0.88)	20.08	(1.19)
Large Industrial	16.02	16.59	(0.57)	17.55	(1.53)
Smelter	18.81	19.23	(0.42)	20.26	(1.45)
Off-System/Other	[redacted]				
Total					

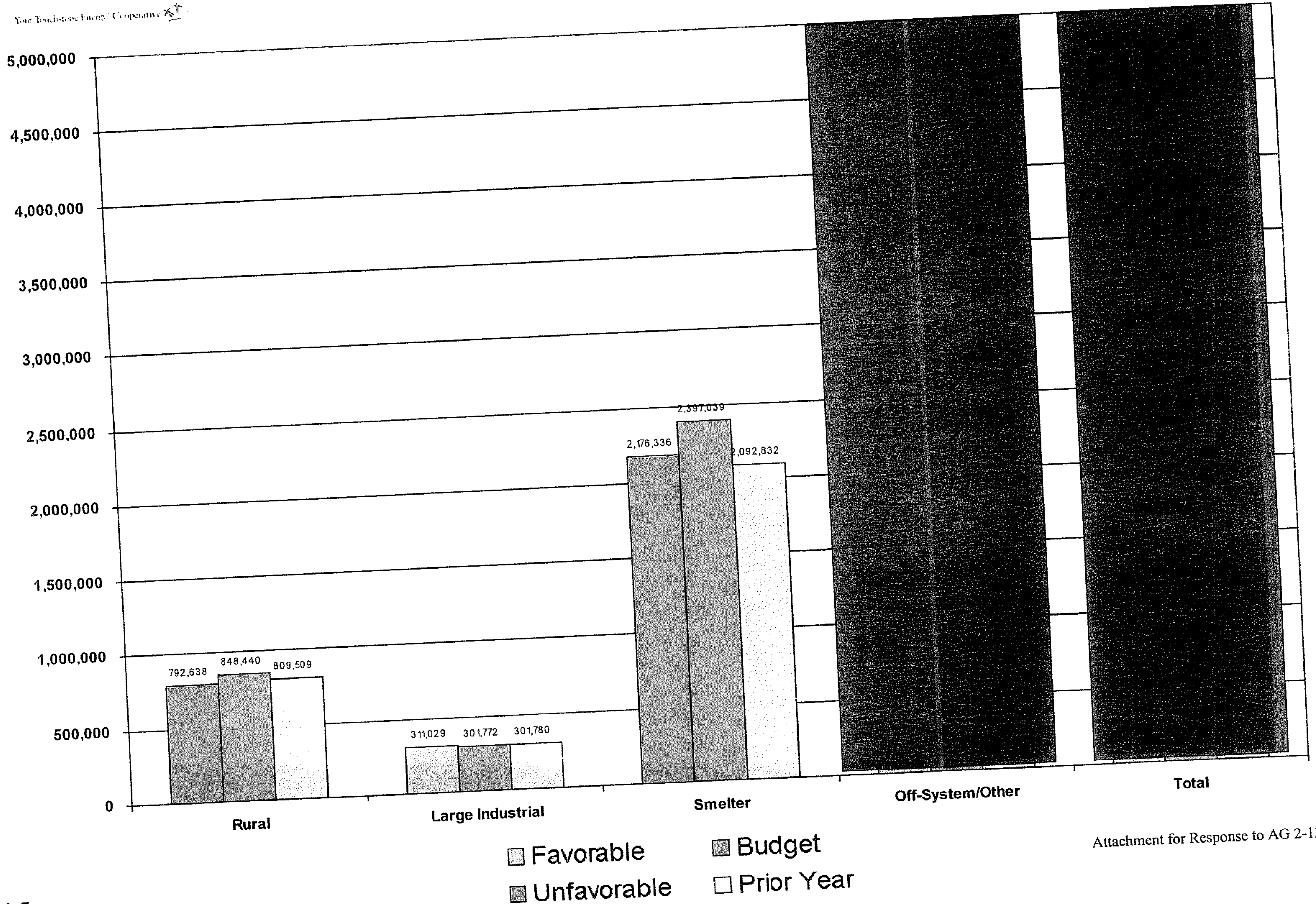
Net Sales Margin - Thousands of $	Actual 2011	Budget 2011	Variance	Actual 2010	2010 Variance
Rural	14,976	16,776	(1,800)	16,251	(1,275)
Large Industrial	4,981	5,007	(26)	5,295	(314)
Smelter	40,934	46,085	(5,151)	42,386	(1,452)
Off-System/Other	[redacted]				
Total					

Net Sales Margin
Price / Volume Analysis
YTD April 2011

	Price / Volume		
	Price	Volume	Total
Rural	(697)	(1,103)	(1,800)
Large Industrial	(180)	154	(26)
Smelter	(908)	(4,243)	(5,151)
Off-System/Other	[redacted]		

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy® Cooperative

MWH Sales
YTD - April

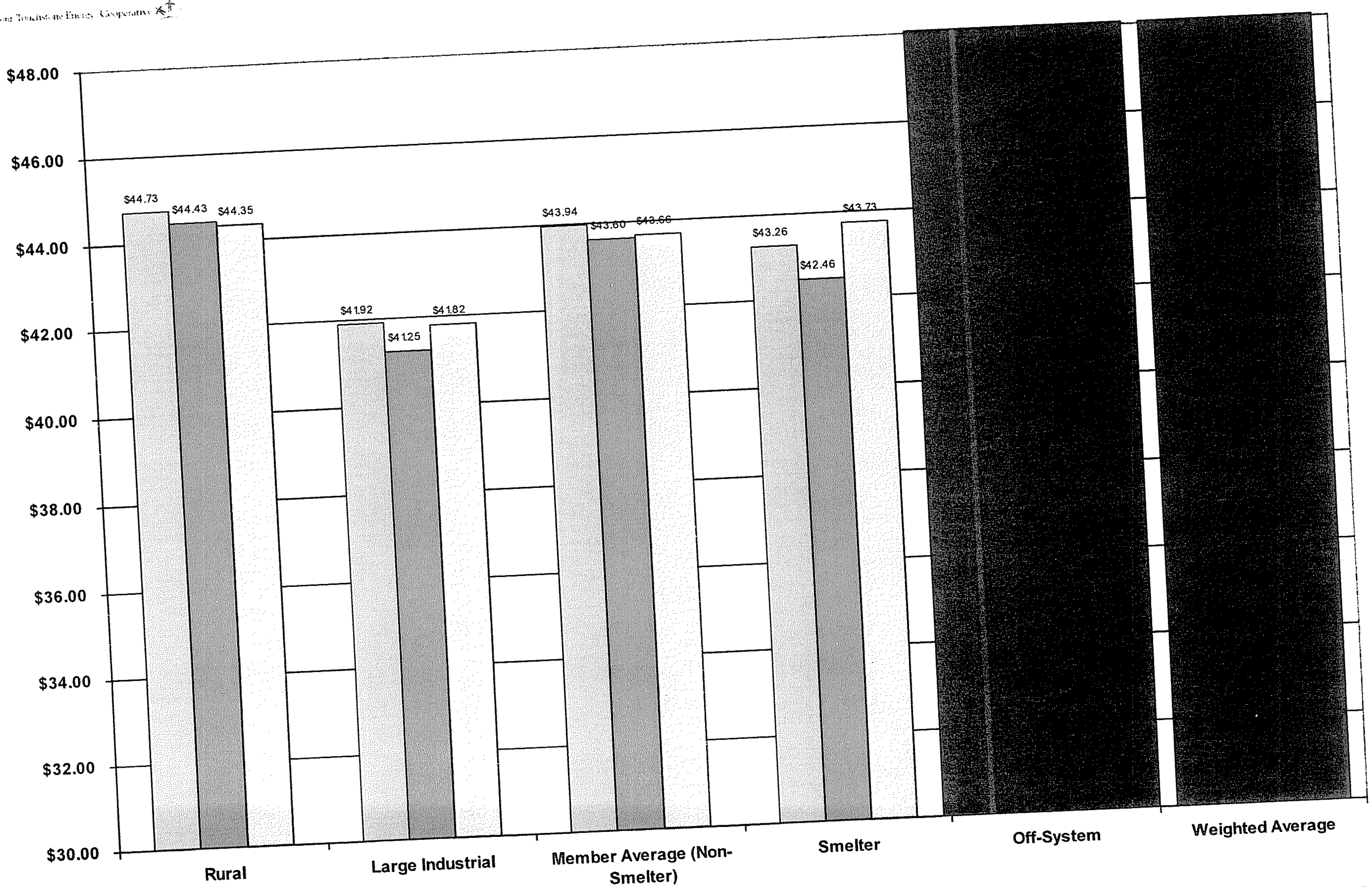


Attachment for Response to AG 2-13(c)

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

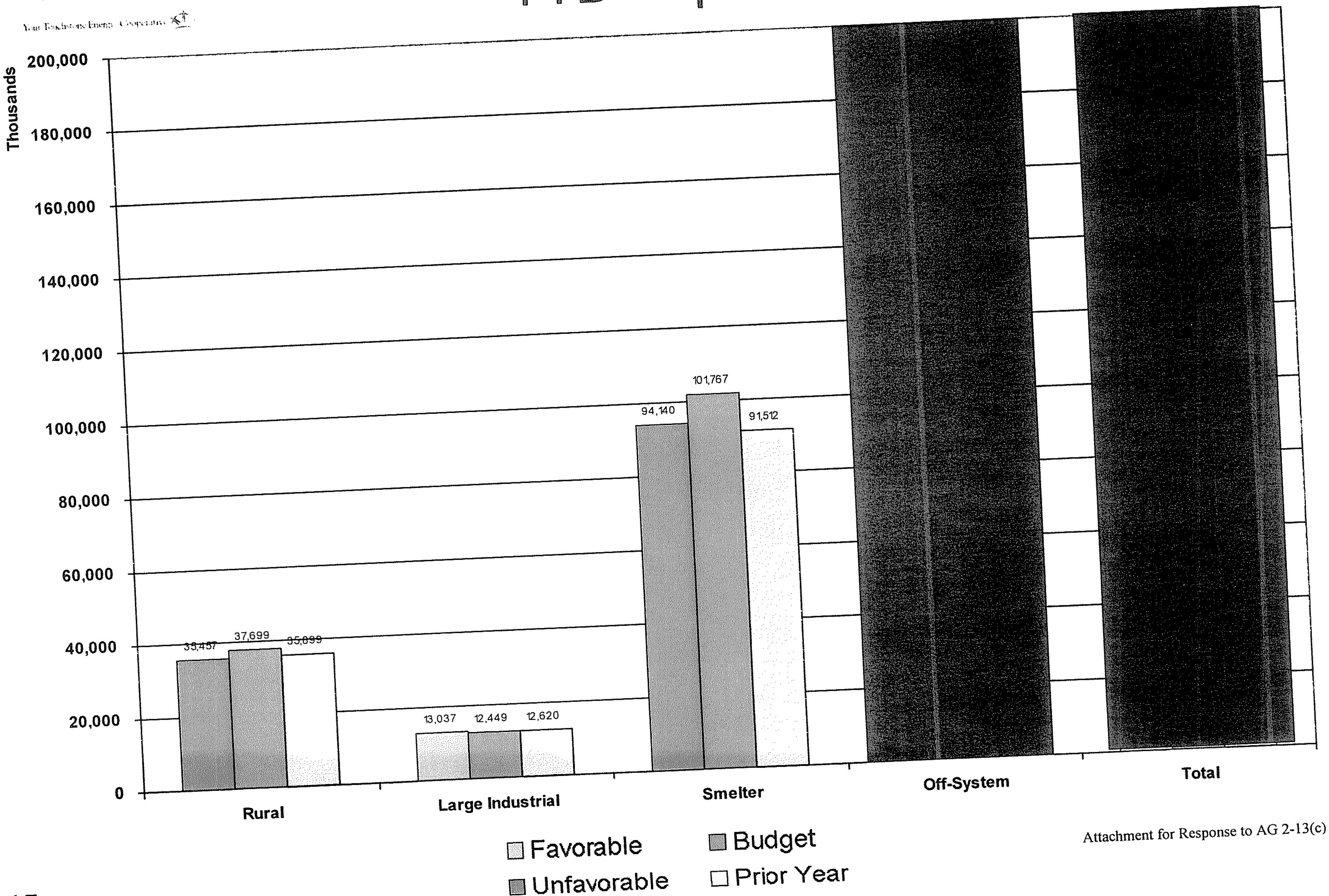
Revenue - $/MWh Sold
YTD - April



Favorable
Unfavorable
Budget
Prior Year

Attachment for Response to AG 2-13(c)

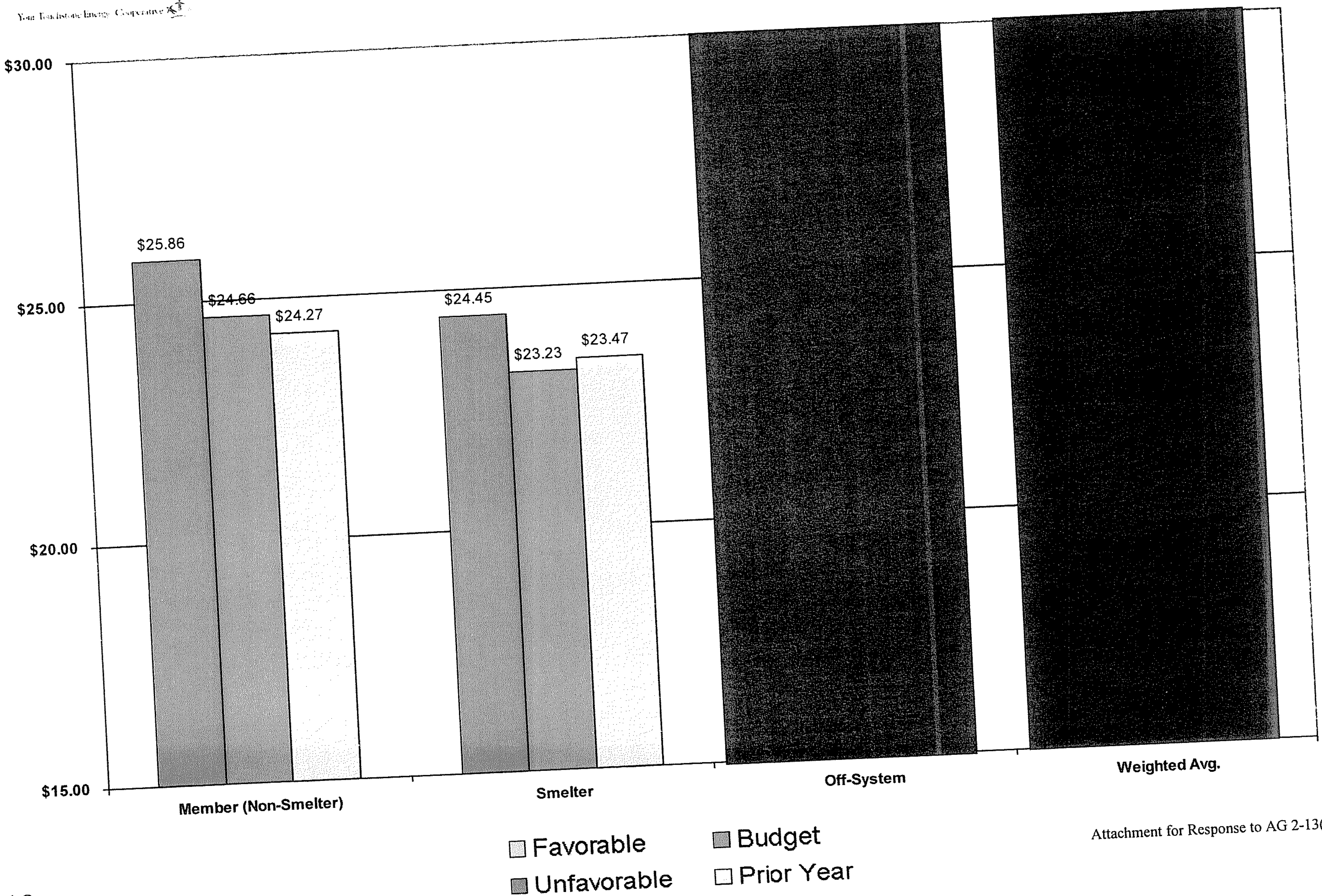
Revenue
YTD - April



Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Power Cost - $/MWh Sold
YTD - April



Attachment for Response to AG 2-13(c)

Big Rivers
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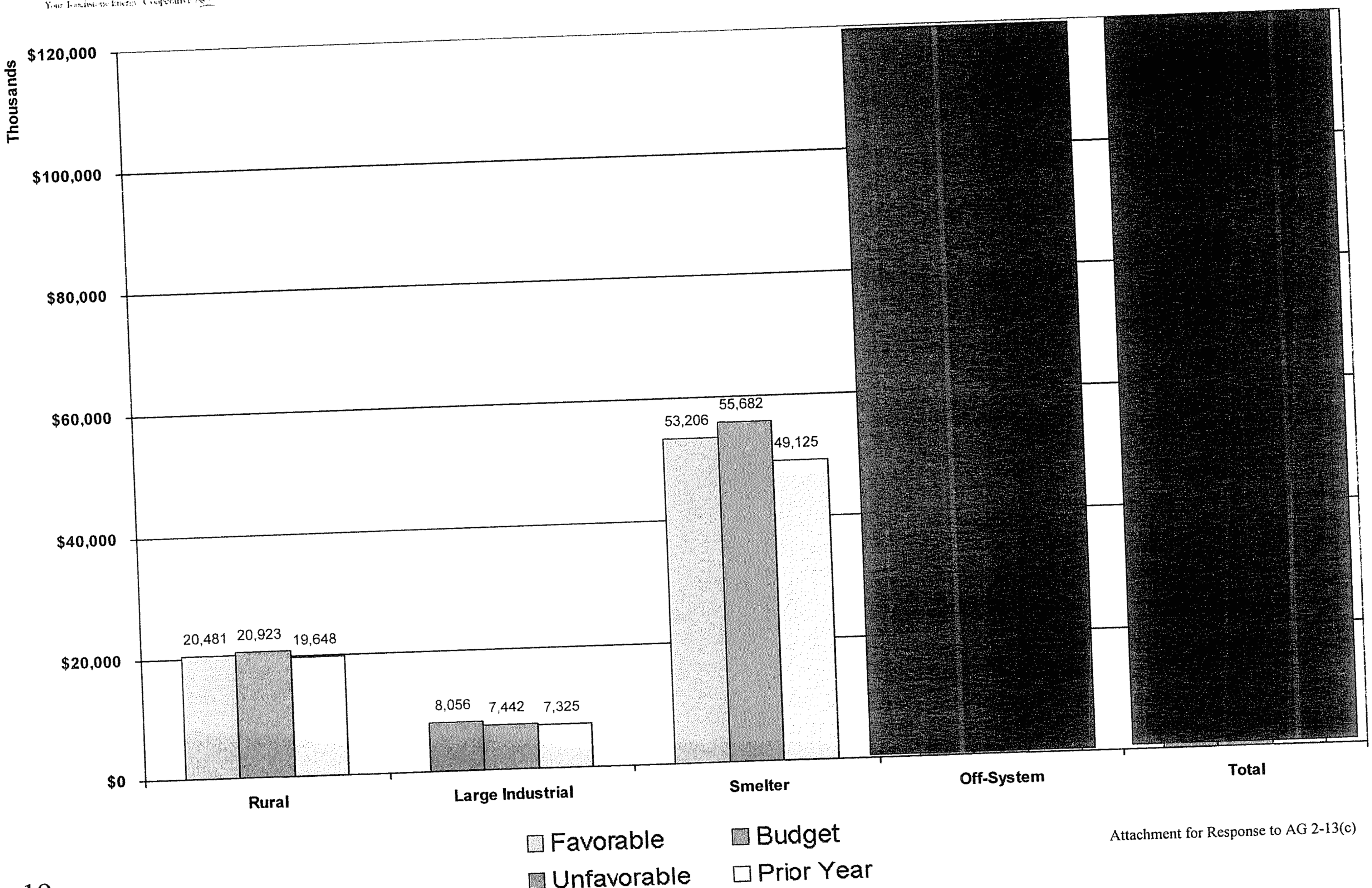
Your Touchstone Energy Cooperative

Power Cost
YTD – April



Attachment for Response to AG 2-13(c)

Sales Margin - $/MWh
YTD - April

Big Rivers
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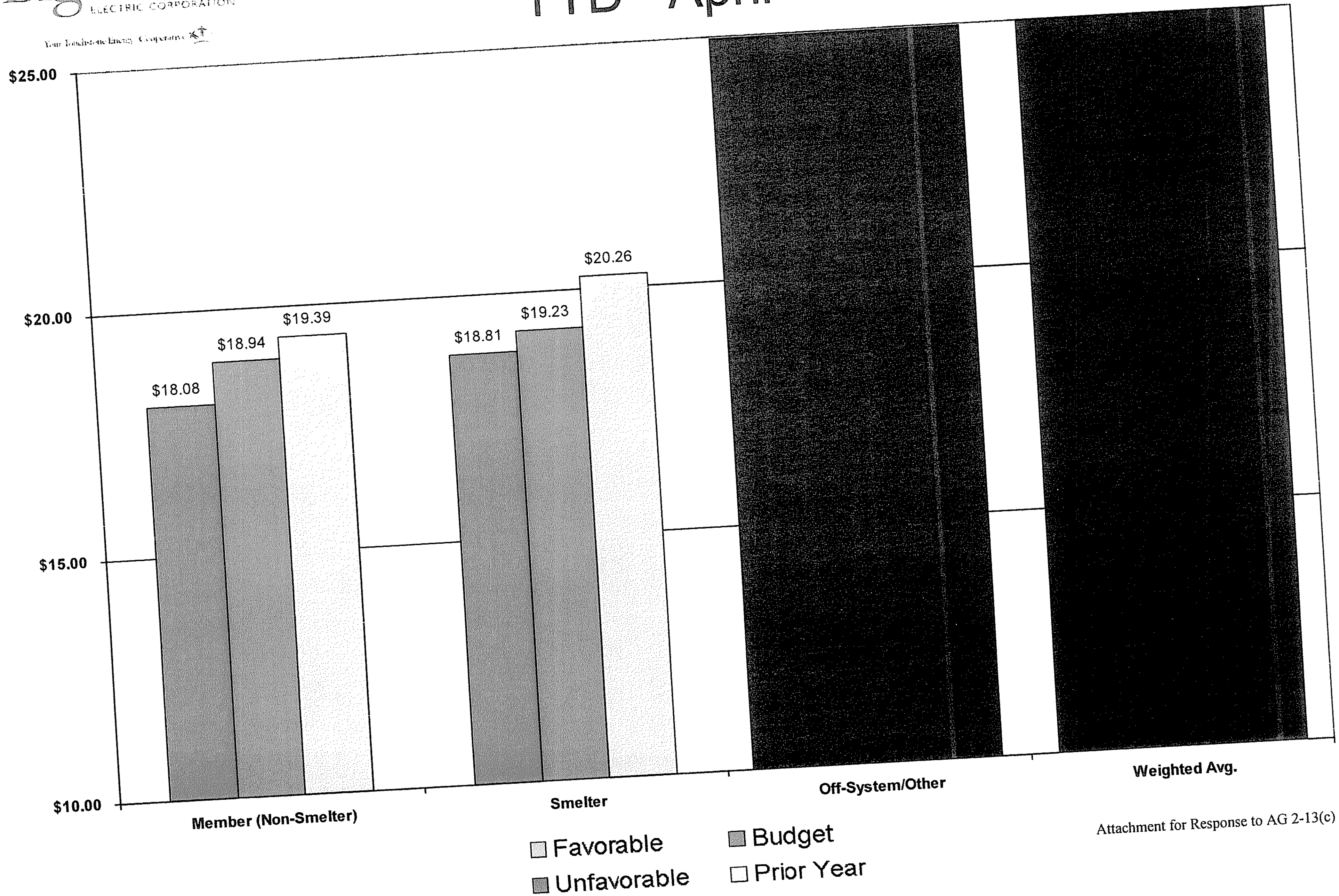
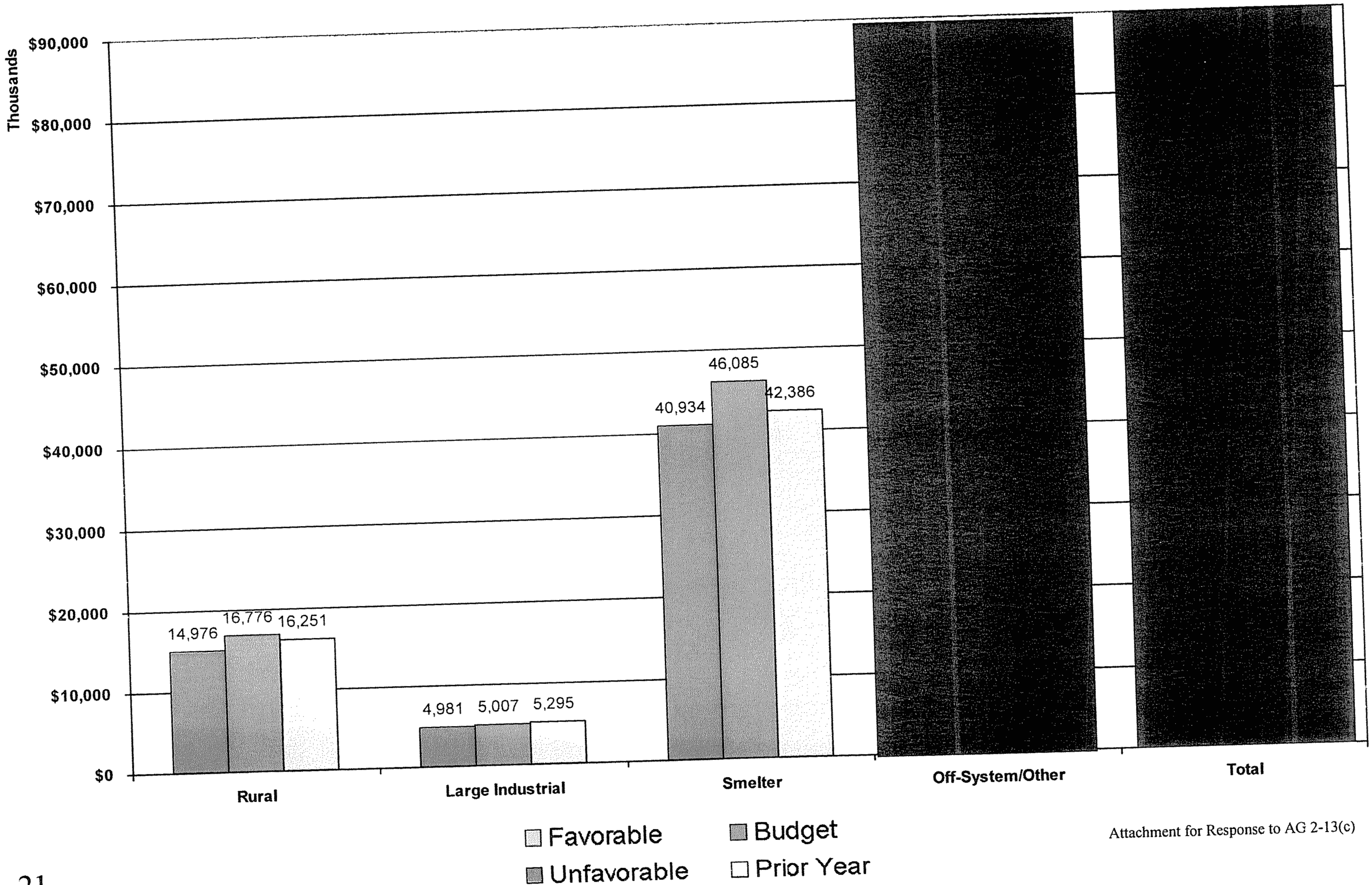
Your Touchstone Energy Cooperative



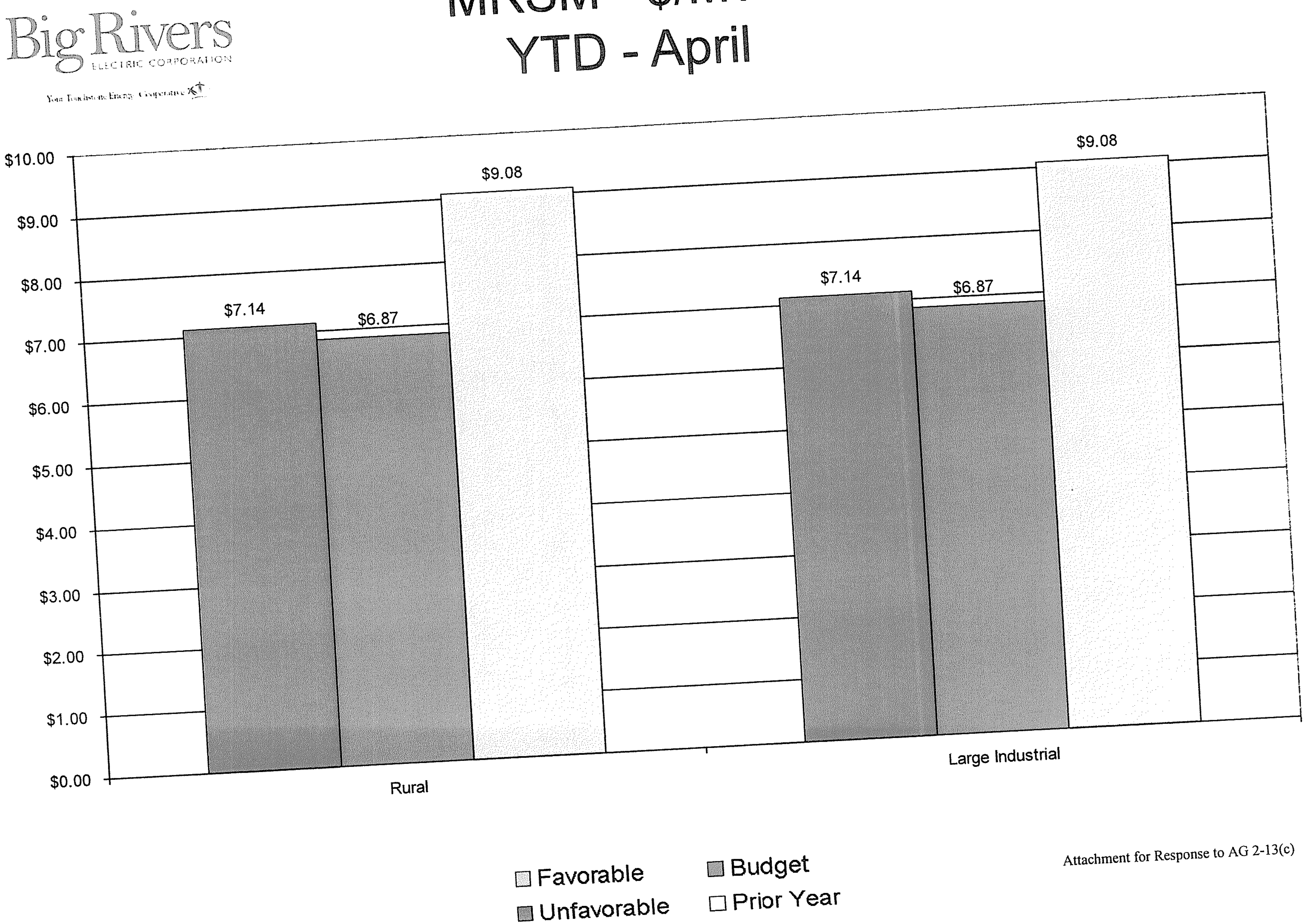
Attachment for Response to AG 2-13(c)

Sales Margin
YTD - April



Attachment for Response to AG 2-13(c)

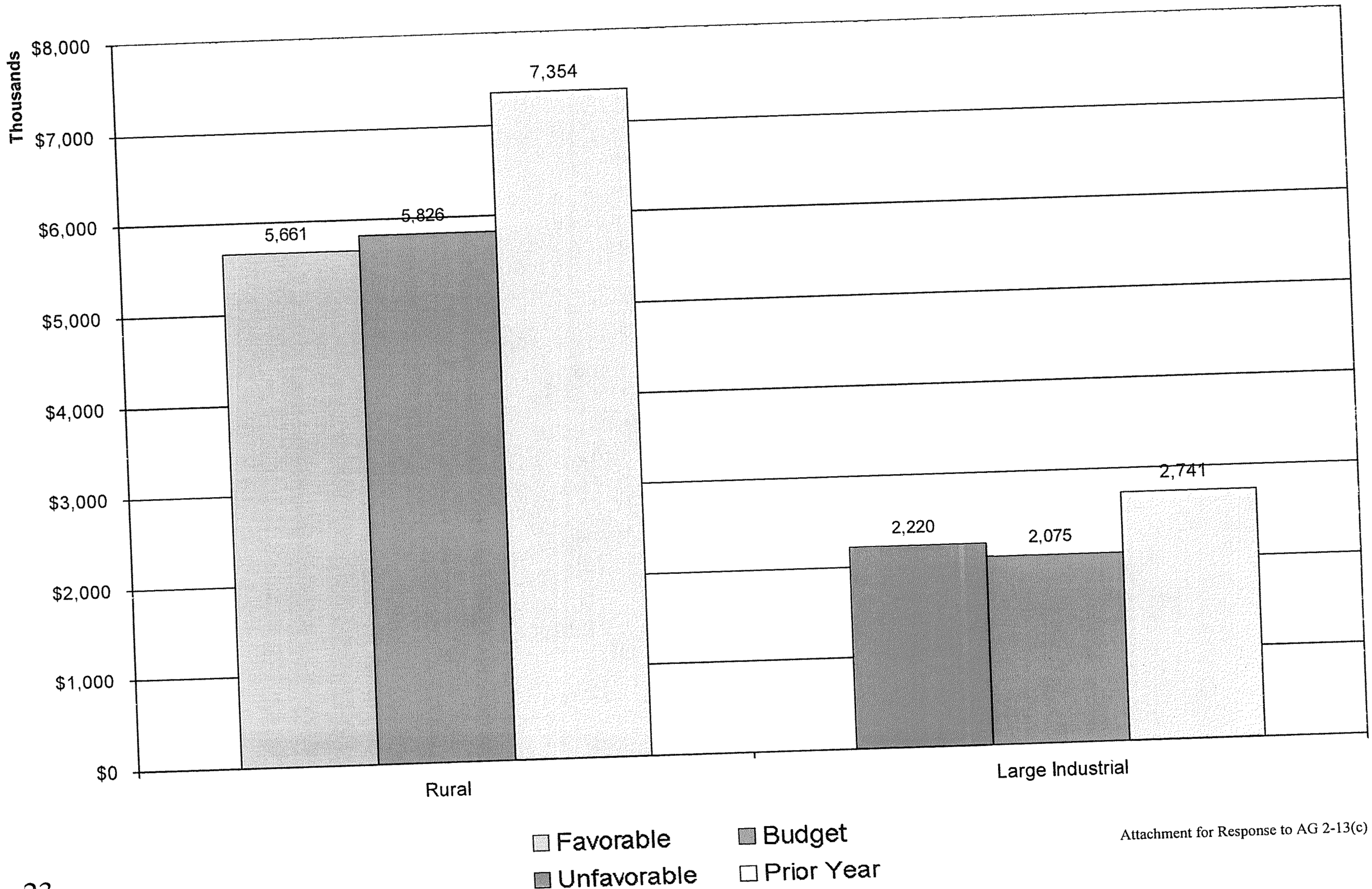
MRSM - $/MWh
YTD - April



Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION

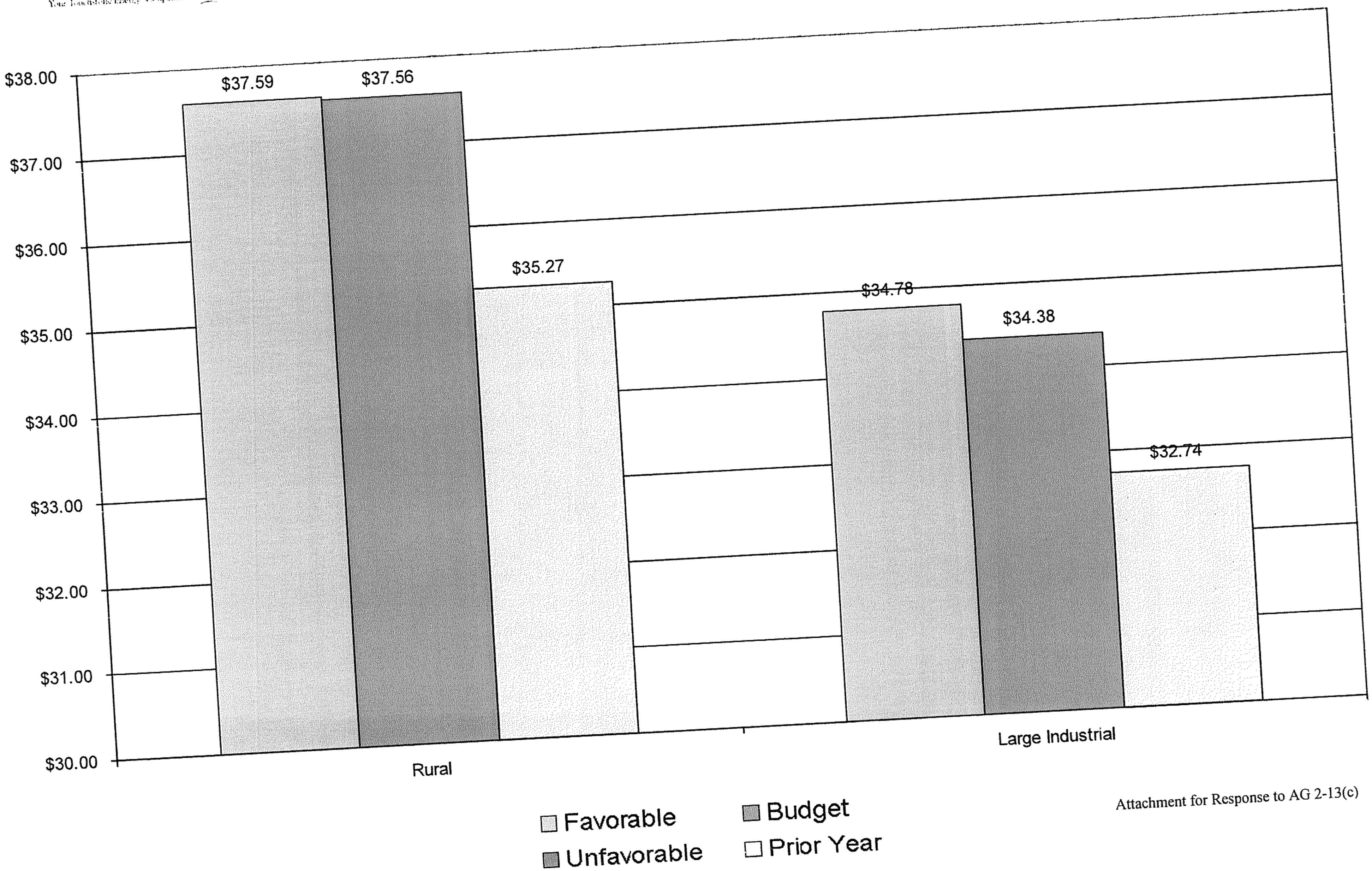
MRSM
YTD - April



Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Net Revenue (Excl. MRSM) - $/MWh
YTD - April

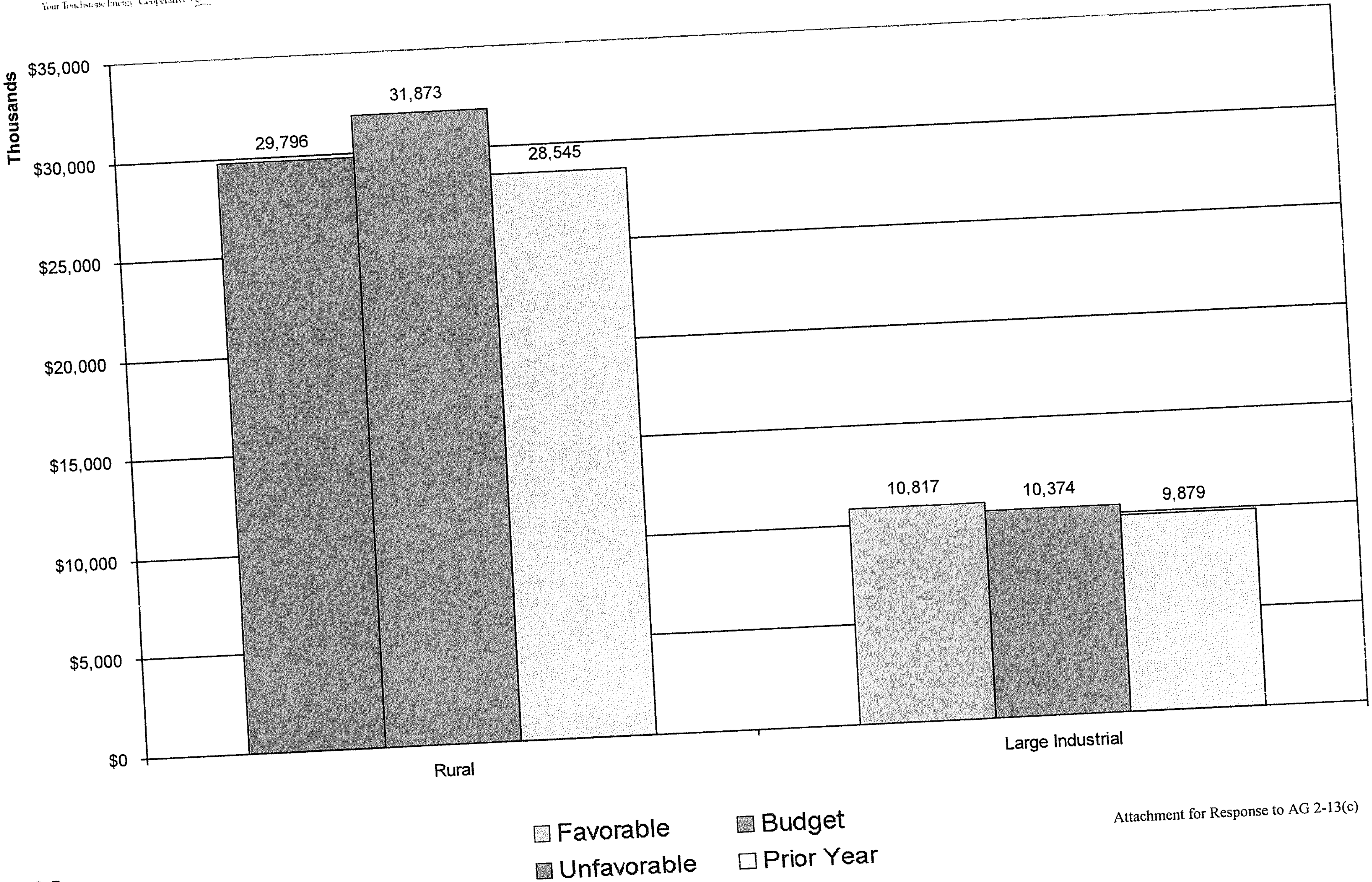


Attachment for Response to AG 2-13(c)

Net Revenue (Excl. MRSM)
YTD - April

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy Cooperative



Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Other Operating Revenue and Income

	2011			2010	
	Actual	Budget	Variance Fav/(Unfav)	2010 Actual	Variance Fav/(Unfav)
April YTD	994	8	986	4,508	(3,514)

Favorable to Budget due to (intentional) omission of the power supply transmission reservation for off-system sales.

Unfavorable to prior year due to a lower power supply transmission reservation.

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Non-Variable Production and Other Power Supply – Operations

	2011		
	Actual	Budget	Variance Fav/(Unfav)
April YTD	20,625	21,889	1,264

	Fav/(UnFav)
Power Supply transmission reservation for off-system sales	(1,828)
HMPL 1 Outage scope reduction	1,445
Timing of HMPL 1 outage and O&M expenses at Station Two	1,416
Other	231
Non-Variable Production and Other Power Supply - Operations	1,264

Attachment for Response to AG 2-13(c)

Big Rivers ELECTRIC CORPORATION

Your Touchstone Energy Cooperative

Operation Expense – Transmission

	2011			2010	
	Actual	Budget	Variance Fav/(Unfav)	2010 Actual	Variance Fav/(Unfav)
April YTD	4,016	5,439	1,423	2,575	(1,441)

Favorable to budget primarily due to 1) lower than anticipated MISO related expenses $679, 2) unfilled positions and more labor capitalized than budgeted $499, and 3) various stations and lines fixed departmental expenses $245.

Unfavorable to prior year due to MISO membership.

Attachment for Response to AG 2-13(c)

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

Maintenance Expense – Production

	2011			2010	
	Actual	Budget	Variance Fav/(Unfav)	2010 Actual	Variance Fav/(Unfav)
April YTD	12,143	14,130	1,987	9,541	(2,602)

Favorable to budget due to projects at Green that have been delayed $907. These included mill overhauls, fire water lines and plant controls. The Coleman facility is favorable $401 due to a timing of maintenance activities such as mill and pump overhauls and bar screen repairs. The planned outage was reduced on the Reid combustion turbine $354.

Unfavorable to prior year due to higher planned maintenance activities this year, the planned outage at Wilson and higher unplanned outages at Green and Coleman.

Attachment for Response to AG 2-13(c)

All AG 2-13(d) attachments have been omitted from the public filing. They have been provided under a petition for confidential treatment.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2012-00535

Response to the Office of the Attorney General's Supplemental Set of Data Requests Dated March 14, 2013

March 28, 2013

Item 14) *Referencing Big Rivers' response to AG 1-46 related to RUS Forms: Explain if BREC is required to provide RUS with CAPEX budgets and provide these related forms/reports provided to RUS showing CAPEX budgets for 2012, 2013, 2014, and 2015.*

Response) Big Rivers is not required to provide RUS with CAPEX budgets.

Witness) Billie J. Richert

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2012-00535

Response to the Office of the Attorney General's Supplemental Set of Data Requests Dated March 14, 2013

March 28, 2013

Item 15) *Please reference Big Rivers' response to AG 1-48 which refers to PSC 2-13 and 2-36 regarding issues and amounts that could change BREC's revenue requirements. BREC has provided two potential adjustments to its revenue requirements, in particular: (i) the response to PSC 2-13 states that amending its application in Case No. 2012-00492 (if approved by the Commission) would lower BREC's test period revenue requirement by $4.4 million related to interest expense on LT Debt for paying off $58.8 m pollution control bonds (as also addressed in AG 1-63 and 64); and (ii) BRECs' response to PSC 2-36 cites other miscellaneous corrections (with revised Exhibits) that could reduce the revenue requirement another $1,507,989.*

a. Explain when BREC would update its filing in the rate case to reflect the impact of all changes to the revenue requirement.

Response)

a. 807 KAR 5:001 requires that 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. Big Rivers will continue to provide updated information in the record in this proceeding, to the extent permitted by and consistent with that regulation, as required by the Commission, or as otherwise appropriate.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

Response to the Office of the Attorney General's
Supplemental Set of Data Requests
Dated March 14, 2013

March 28, 2013

Witness) John Wolfram

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

Response to the Office of the Attorney General's
Supplemental Set of Data Requests
Dated March 14, 2013

March 28, 2013

Item 16) *Referencing Big Rivers' response to AG 1-50 regarding cost cutting measures: BREC states that its new self-insured health insurance plan effective January 1, 2012 is estimated to produce savings of $3.1 million in 2012, cost savings of $266,000 in 2013 related to changes in plan design, cost savings in 2012 of $1.9 million and 2013 of $.6 million related to reducing the cost of post-retirement medical coverage, and 2013 cost savings of $.2 million related to moving to a new provider of LT disability insurance. Address the following:*

a. For each of the previously identified cost savings, show the previous expense (by account) before changes for each year, the new expense (by account) after the change for each year, and reconcile these to the cost savings (by account) for each year.

b. Explain, show, and cite to the field and account number in the financial model where such costs and savings are included in the revenue requirement for the appropriate year.

Response)

a. See the response to AG 1-50, page 3 of 6, beginning at line number 14, for an explanation as to why the "by account number and cost category and by year" information requested is not available. The previous expense and new expense amounts at the time they were estimated are shown in the attachment to AG 1-50, pages 1, 2, and 4. The savings beyond the time of those estimates are unknown since we cannot know what the former plans' costs would have been in future periods had we not made the changes.

b. Labor and labor-related costs by account are in the financial model on the "O&M" tab, rows 137 through 167. The savings were considered during budget development and are included in the budget.

Witnesses) James V. Haner (a)
DeAnna M. Speed (b)

BIG RIVERS ELECTRIC CORPORATION

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Dated March 14, 2013

March 28, 2013

Item 17) *Referencing Big Rivers' response to AG 1-51 regarding the impact of Century smelter, address the following:*

a. If BREC can provide a "forecast" of the impact of removing Century, explain why BREC cannot use this same approach to remove an amount that is closer to "actual" amounts for Century for the historical periods 2011 and 2012;

b. Provide the "actual" impact of removing Century from the 2011 and 2012 calendar years (and provide supporting calculations and assumptions);

c. If removing the actual impact of Century cannot be determined for 2011 and 2012, then provide the "forecasted" impact of removing Century from calendar year 2011 and 2012 operations and provide all supporting calculations, and explain the reasons for changes in forecasted assumptions and calculations when removing Century from 2011 and 2012, versus the forecasted assumptions and calculations used to remove the impact of Century in BREC's rate filing.

Response)

a. Item AG 1-51 makes no reference to the historical periods of 2011 or 2012.

b. The requested information is not available.

c. It appears that the question seeks to compare the fully forecasted test period in the instant filing with an historical test period adjusted to remove all of the effects of the Century contract termination. Consistent with KRS 278.192, Big Rivers elected to use a fully forecasted test period in this filing because of the complexity associated with "removing Century" to a known and measurable degree from actual revenues and expenses from 2011 or 2012. The statute provides a choice between the historic and fully forecasted test periods. The fully forecasted test period is far better suited in this instance than the historic test period for capturing the significant changes to Big Rivers' operations and financial performance that will result from the Century contract termination. A great number of assumptions related to fundamental elements of Big Rivers' operations – e.g. power plant operations, outages, fuel costs, off system sales volumes, load variations – would be necessary to develop pro forma adjustments to the historic results. For this reason, Big Rivers did not develop for this rate filing an analysis of the effects of the Century contract termination using an historical test period.

Witness) John Wolfram

BIG RIVERS ELECTRIC CORPORATION

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March 28, 2013

Item 18) *Referencing the credit ratings attachments to Big Rivers' response to AG 1-54, please provide copies of:*

a. Standard and Poor's "Applying Key Ratings Factors to U.S. Cooperative Utilities" (page 6 of Attachment);
b. Fitch Ratings' "U.S. Public Power Rating Criteria" (page 11 of Attachment);
c. Fitch Ratings' "Revenue Supported Rating Criteria" (page 11 of Attachment); and,
d. Moody's "U.S. Electric Generation & Transmission Cooperatives Rating Methodology" (page 21 of Attachment).

Response) Please see attached.

Witness) Billie J. Richert

Criteria | Governments | U.S. Public Finance: Applying Key Rating Factors To U.S. Cooperative Utilities

Publication date: 21-Nov-2007 12:57:33 EST

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(**Editor's Note:** This criteria article originally was published Nov. 21, 2007 We're republishing this article following our periodic review completed on Nov. 20, 2012.)

Qualitative and quantitative rating factors have translated into solid credit ratings for cooperative utilities. Yet, the positive attributes and structural protections that are common to many of these utilities are not prevalent in all utilities in the sector. Moreover, because bondholder and lender protections are closely linked to the revenue stream's capacity to cover amortizing debt service, modest erosion of financial protections can impair credit ratings of cooperatives exhibiting narrow financial margins.

The Role Of Cooperative Utilities

gy providers in these major groups meet U.S. electric needs:

- Cooperative utilities;
- Public power utilities that include federal projects that produce and sell wholesale power, and state agencies and municipal utilities engaged in wholesale and/or retail operations;
- Vertically integrated investor-owned utilities that produce and distribute electricity; and
- Investor-owned distribution companies that convey electricity procured from or distributed on behalf of competitive energy suppliers;

Investor-owned utilities serve nearly three-quarters of America's electric needs. Public power utilities and cooperative utilities serve the balance, with public power utilities exhibiting a modest lead over cooperatives in annual energy sales.

Generation and transmission (G&T) cooperative utilities are not-for-profit corporations that generate or procure bulk power for sale to cooperative electric distribution utilities under wholesale power supply contracts. G&T utilities are owned by their distribution cooperative members. Distribution cooperatives are owned by their retail customers

Electric distribution cooperatives were formed in the 1930s and beyond to build the infrastructure needed to meet the electric needs of sparsely populated rural America. The New Deal's Rural Electrification Administration (REA) was an important vehicle in forming distribution cooperatives, and its low-cost, long-term loans removed barriers to financing utility investments in rural areas. REA is now the U.S. Department of Agriculture's Rural Utilities Service (RUS), which still makes low cost loans to rural utilities.

In the decades since their creation, portions of some cooperatives' rural service territories have evolved into prosperous suburbs of major metropolitan areas. Nevertheless, electric cooperative utilities mostly serve far-flung, sparsely populated areas that exhibit income levels below national averages. G&T cooperatives were created by distribution cooperatives that banded together to achieve economies of scale in constructing generation and transmission assets to meet customers' needs

Show

Business Risk As A Credit Quality Determinant

Business Risk As A Credit Quality Determinant

Evaluating all utilities' financial performance begins with assessing business risk exposure. Greater business risk requires stronger financial metrics to achieve a given rating. The factors underlying our business risk assessments are similar for all utilities, whether cooperative, public power or investor-owned. In each case, the review focuses on a common set of qualitative elements representing six areas of inquiry:

- The regulatory environment in which the utility operates, including the resulting financial and ratemaking flexibility available to the utility;
- The markets served by the utility;
- The management team's strengths and the risks presented by management's business strategies;
- The utility's operational profile;
- The utility's competitive posture, and
- A review of legal documents that define the strength of bondholder or lender protections.

The emphasis on each factor may vary for different utilities. The components of the business risk profile are scored on a 10-point scale and a weighted average is calculated to measure business risk compared to that of other utilities. The strongest score on the scale is 1, and the weakest is 10. The elements of the business risk profile are discussed below.

The credit ratings that we assigned to cooperative utilities are founded on the qualitative attributes, financial performance and the structural protections commonly found among this group of utilities.

Self-Regulation Can Bolster Credit Quality

Most G&T cooperatives set their own wholesale electric rates without oversight from state or federal regulators. G&T cooperatives that borrow from RUS are exempt from FERC jurisdiction. While RUS borrowers must file rate schedules with RUS, oversight is limited to ensuring that rates are sufficient to recover costs, including repayment of RUS debt.

The latitude most cooperatives possess to set their own rates in response to changing costs is a key driver of credit quality. Autonomous ratemaking authority sets these utilities apart from rate-regulated utilities and enables cooperative utilities to respond quickly to changing circumstances and preserve sound financial margins without exposure to the regulatory delays or disallowances that can negatively influence the financial performance of regulated utilities.

Credit quality cannot benefit if the latitude to exercise autonomous ratemaking authority does not translate into meaningful financial flexibility that can be deployed as costs increase. For credit quality to benefit, management and governing boards must demonstrate a willingness to overcome political obstacles to rate increases.

The presence of power and fuel cost pass-through adjustment mechanisms can address credit uncertainties associated with either regulatory oversight or questions of political will. Yet, to support credit quality, these tools should have well-defined triggers that can provide timely realignment of revenues and expenses as costs rise.

There is strong evidence that rate regulation can erode credit quality for cooperative utilities. That is not to say that all regulation is inconsistent with sound credit quality. Some regulators have demonstrated a commitment to sound credit quality. However, there are also instances where the financial performance of regulated cooperatives degraded after a regulator barred the utility from recovering investments in generation or other assets or precluded the full recovery of operating costs as they were incurred. In the most severe cases, regulatory impediments to cost recovery resulted in insolvency proceedings. Therefore, where cooperatives are subject to rate regulation, we examine whether the regulator is supportive of full and timely cost recovery and deferential to covenants protecting lenders.

Even where G&T utilities possess the financial flexibility of an absence of regulation, we must further examine whether their distribution members are subject to rate regulation. G&T cooperatives' credit quality depends on the quality of the cash flowing up from member cooperatives. A G&T can recover rising costs only if member systems can follow suit and adjust their retail rates. Therefore, we explore whether member distribution cooperatives have the ability to respond to changing costs embedded in revised G&T rates and are able to adjust retail rates in lockstep with the G&T.

Utility Markets Are Important To Credit Quality

The markets served by a utility determine the integrity and stability of the revenue stream A diverse market with a sound economy usually bodes well for credit quality. As noted, G&T credit ratings depend on the quality of revenues derived from member distribution cooperatives. We assess members' contributions by examining their legal obligations to fund G&T debt service and operating expenses as well as the financial wherewithal to support those obligations Consequently, a lot of emphasis is placed on the long-term, wholesale, power supply contracts between G&T cooperatives and their member distribution systems. Optimally, wholesale power supply contracts extend throughout the life of G&T debt to provide predictable debt service recovery Shorter contracts remove predictability and could leave a G&T exposed to competitive wholesale power markets An absence of captive customers presents questions as to whether electric commodity can be sold to fund the recovery of capital investments and the price at which it might be sold

Wholesale power contracts typically require the G&T to reallocate financial obligations of a defaulting member among non-defaulting members through intra-year rebudgeting that translates into an unlimited step-up For G&Ts with few member distribution cooperatives, the capacity of each distribution cooperative to meet obligations is an important determinant of credit quality However, most G&T cooperatives have large pools of distribution cooperative members.

The combination of large pools of member distribution cooperatives and unlimited financial step-up obligations imposed on non-defaulting members of G&T cooperative utilities allows us to examine the credit quality of G&T cooperatives as a system without tying the rating to the credit quality of a member representing a weak link. We view the risk of multiple simultaneous defaults among a diverse pool of distribution cooperatives as slim. Even for large pools of distributions cooperatives, it is important to understand the composition of the customer base supporting the revenue stream. One component is members' financial performance, which is ascertained through audited financial statements and financial reports filed with RUS Another element is the retail customers' economic capacity to service G&T obligations. We examine service area wealth and income indicators using our proprietary economic databases. These databases help predict volatility or stability of revenues by identifying economic means and service territory demographic trends We also look at the ·mposition of the retail customer base. We expect cooperatives with concentrations of residential customers to provide more revenue ,m stability than cooperatives with industrial customer concentrations since industrial customers' operations could be susceptible to cnanging economic conditions.

Concerns that industrial customers might be attractive targets for cherry picking by competitive energy providers have been tempered by the reduced interest in establishing competitive retail electric markets In addition, the sparsely populated cooperative service territories are not particularly attractive to competitive retail energy providers since a high percentage of the cost of serving cooperative retail load is embedded in stringing distribution lines over vast distances. High distribution costs erode the benefits of reduced commodity prices. Thin customer density is borne out by low meter per line-mile ratios

Management's Key Role

G&T cooperatives are governed by boards of directors comprised of distribution cooperative representatives, including elected distribution cooperative board members and chief executives responsible for distribution cooperatives' operations

Board members' policies and strategic philosophies are important financial performance and credit quality determinants. Ratemaking tools that can yield strong, stable cash flows may be in conflict with an interest to give customers the lowest possible cost of service. Management's reconciliation of this dichotomy influences our analysis

A willingness to place capital at risk to diversify into competitive, non-electric businesses can erode positive credit attributes typically associated with the stability and predictability of a revenue stream derived from a captive customer base tethered to a G&T by wholesale power contracts

Cohesiveness among board members is crucial to the successful adoption and implementation of strategic plans that are supportive of credit quality Cohesiveness does not mean unanimity on all issues Yet, fractious boards can become hamstrung and unable to respond to changing circumstances to protect credit quality. Divisiveness is sometimes a product of federal tax code provisions governing the allocation of cooperative voting rights. To preserve their tax-exempt status, G&T cooperatives must grant each distribution member an equal vote irrespective of relative contributions to the G&T revenue stream

Show

equal vote, irrespective of relative contributions to the G&T revenue stream.

Members with different load profiles or growth rates have varying resource needs and priorities. Slow growth members could wield voting rights to frustrate a growing member's bid to add resources whose costs must be borne by all members under postage stamp rates that spread costs proportionally over all members. Alternatively, members with different load profiles may advance rate structures that allocate demand and energy charges that best suit their retail customers. In some extreme cases, those advancing a particular strategy have cast negative votes on business matters before the board in a bid to coerce an outcome on unrelated matters. Credit quality can suffer if the board becomes deadlocked on a wide range of matters that frustrate important financial or strategic objectives.

Analyzing Operations To Identify Business Risks

Our analysis of a cooperative's operational profile identifies business risks associated with the cooperative's owned generation and transmissions assets or supply arrangements with third parties. Our operational profile analysis considers these major factors:

- Performance of owned and contracted plant;
- Diversity within the supply portfolio;
- Market exposure;
- Hedging policies and risk-management strategies; and
- Capital needs and third-party resource-procurement processes.

Performance of owned capacity is assessed with reference to the level and stability of production costs, capacity factors, and availability factors. We similarly analyze power purchase agreements. The metrics are compared with industry norms.

Utilities can benefit from power purchase agreements that shift operating risk to the supplier through targeted heat rates, availability factors and capacity factors as conditions for payment. Contracts with a large supplier for system energy can provide asset diversity that a small utility might not otherwise be able to achieve were it to build generation to meet customers' needs. There are also risks inherent in power ase agreements. The G&T, as offtaker, may be exposed to the supplier's ability to perform and the agreement might place demands ... the cooperative's liquidity in the form of collateral posting requirements.

We view power purchase agreements' capacity payments as fixed obligations that are substitutes for debt financing. It is as though the offtaker has contracted with a third party to issue debt on its behalf. Because capacity payments fund a supplier's recovery of capital invested in generation assets, we treat capacity payments as fixed charges and calculate a fixed-charge coverage, as discussed more fully in the section on financial analysis that follows.

It is important to understand how a G&T manages its exposures to fuel and electricity price volatility as well as additional operational issues such as transportation bottlenecks that may impede the flow of these commodities. We review hedging and risk-management policies and evaluate in-house and outsourced expertise available to a cooperative to tackle these issues. Several cooperatives have outsourced risk management functions. A lack of management understanding of risk management issues can present credit concerns. We place value on management teams that can identify limitations of in-house capabilities and recognize the financial and practical barriers to handling the risk management function internally. Just as distribution cooperatives banded together to achieve economies of scale in developing generation and transmission assets, G&T cooperatives, and even some distribution cooperatives, are banding together to invest in the physical and intellectual capital necessary to interact with the wholesale electric and fuel marketplaces.

Whether owned or contracted, high concentration levels in a single generation asset or fuel can create operational and financial exposures for lenders and creditors. Concentration can erode financial performance if lengthy unplanned generation outages or sharp fuel price increases occur.

Many G&Ts exhibit asset and fuel concentration. Most G&Ts are highly dependent on coal and a number are highly dependent on natural gas. Concentration in these fuels can have operational and financial implications. Gas is subject to price volatility. Reliance on coal assets has taken on new significance because costs may rise as regulation of carbon and other emissions progresses.

We evaluate the increasing resistance to and scrutiny of coal plants and the resulting operational and financial implications for existing and

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proposed coal-fired units The high probability of stricter emissions mandates dictates that we consider uncertain costs of carbon controls and renewable directives. As we examine the burdens of emissions controls, we explore the following issues:

- How large is a utility's carbon footprint?
- How does the utility plan to respond to carbon constraints from an operational and a financial perspective?
- What would be the cost of addressing carbon emissions through emissions controls, fuel switching, energy efficiency programs, or conservation?

In cases where utilities plan to dodge coal's difficulties by migrating to natural gas, we need to understand whether management has a strategy for responding to spikes that may occur in natural gas prices as demand increases In some regions, questions may also arise about the sufficiency of natural gas supply and transportation as demand rises Natural gas will not fully shield utilities from carbon emission mandates because it is not carbon-free Its carbon footprint is about half of coal's. We also consider how utilities that are subject to renewable mandates will address reliability issues associated with generation resources that can't be dispatched to follow load

Distribution cooperatives engaged in a "wires" business face fewer direct operational challenges than do G&T utilities. Nevertheless, distribution cooperatives' dependence on a G&T translates into an exposure to the supplier's operational and financial issues.

Competitive Business Pursuits Can Be Risky

Despite the absence of a profit motive, some G&T and distribution cooperatives have pursued competitive businesses. Pursuits beyond the core business of providing customers with attractively priced, reliable electricity have had varying degrees of success. Affiliate or subsidiary companies are often created for conducting these businesses. Some cooperatives have electric marketing arms whose proceeds subsidize member rates. Some sell surplus power in wholesale markets while others purchase power for resale to take advantage of regional price differentials.

` financial risks related to these activities include exposure to potentially volatile wholesale markets. Unless commitments to supply :ricity can be suspended, they can present financial and operational challenges if internal or third party power supply is disrupted or native load responsibilities increase due to spikes in customer demand. Moreover, such arrangements can present contingent liquidity requirements, such as exposure to collateral calls Of greater concern are cooperatives that pursue competitive businesses requiring skills beyond management's day-to-day expertise. These ventures include businesses tangential to electric supply as well as speculative businesses that are unrelated to the metered customer

As noted, the wholesale power contract serves as a vehicle for recovering funds invested in a cooperative's electric operations By comparison, investments in competitive businesses lack the protections captive customers provide If meaningful capital is placed at risk through investments in competitive businesses, a cooperative will need to demonstrate a robust financial cushion capable of absorbing the financial impact of a degraded investment if the outstanding rating assigned prior to the investment is to be preserved. Electric utility subsidization of competitive businesses during start-up or to offset operating losses can negatively influence a credit rating.

In evaluating the credit implications of competitive businesses, we analyze standalone and consolidated financial statements of the cooperative and its ancillary businesses to determine:

- The size of competitive operations relative to the core electric business;
- Expansion plans for the competitive business;
- The amount of debt attributable to the competitive business;
- The electric business' commitments to support affiliate or subsidiary operations, either though explicit guarantees or board policies to infuse equity and liquidity;
- Historical profitability and projected performance of the competitive business, and
- The level of competition facing the product or service provided

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Examining Rate Competitiveness

The specter of pervasive competition for retail loads anticipated in the 1990s and early 2000s has not materialized More recently, some states have moved to once again regulate investor-owned utilities and eliminate new opportunities for customer choice Although the threat that retail competition might have presented to a utility's revenue stream has abated, competitiveness of rates remains an important component of our analysis

Even in the absence of direct access to competitive suppliers, customers need to be satisfied that their retail rates are reasonable. Today's customers are more mindful of how their rates compare to those of other utilities Competitiveness, like the affordability of rates we examine as part of our analysis of markets served by a utility, is an important indicator of ratemaking flexibility and the attendant financial flexibility to respond to changing circumstances

As not-for-profit membership organizations, cooperatives employ cost-based rates that cover operating costs and debt service, fund a portion of capital costs, and provide a small measure of financial cushion to meet lender and/or creditor requirements or expectations. Profits are not built into the equation. Even so, retail cooperative rates can be high because of the increased costs of distributing electricity in sparsely populated service territories. Resulting high distribution rates, combined with generally limited income levels, can erode financial flexibility.

Lender And Creditor Legal Protections

The wholesale power contract bond

Wholesale power supply contracts bind distribution cooperatives to G&Ts and contribute to a secure revenue stream. The contracts' legal protections benefit cooperative utilities' lenders and trade creditors by enhancing prospects for the recovery of investments in these utilities and the receipt of trade receivables.

Wholesale power contracts are take-and-pay requirements contracts. They dictate that all electricity needed by distribution cooperatives must be procured through the G&T. They also provide for intra-year G&T budget adjustments in the event of shortfalls whether due to rising costs or defaulted member obligations The rebudgeting tool imposes an unlimited step-up requirement on members to keep the G&T 'e. Consequently, a G&T can count on its member distribution cooperatives to support its debt and trade obligations.

Wholesale power contracts extending through the life of outstanding debt obligations provide a secure revenue stream from dedicated energy off-takers. It is common for G&T cooperatives to ask members to extend contracts as the G&T embarks on large capital projects with useful lives and debt extending beyond the outstanding contracts' expiration. In many cases, members have extended contracts without any qualms. However, in recent years some members have used the contract extension request as leverage to advance a particular agenda or strategy. Such tactics can frustrate the ability of cooperatives to carry out strategic objectives or achieve financial targets, which could negatively influence credit quality.

The combination of the breadth of the cooperative service territories, as reflected in the large average number of member distribution cooperatives in each G&T, the sizable retail customer bases and the unlimited step-up obligations imposed on non-defaulting members of a G&T, allows us to examine a G&T's credit quality as a system without tying the rating to the credit quality of a member that represents a weak link We view the risk of multiple simultaneous defaults among a diverse pool of distribution cooperatives as slim. This approach parallels the analytical methodology for the evaluation of municipal joint action agencies.

There are limited exceptions to the all-requirements paradigm Members of a handful of G&T cooperatives can procure prescribed portions of their energy needs outside the cooperative structure. All energy needs beyond the permitted exception must be procured from the G&T, ensuring that it has a vehicle for recovering fixed and variable costs.

Indenture covenants provide limited cash flow protection

Cooperative utilities largely rely on RUS and two cooperative lending institutions, CoBank and National Rural Utilities Cooperative Finance Corporation (CFC), to finance capital needs. Mortgage indentures executed between utilities and RUS govern RUS, CFC and CoBank financings. The RUS indentures' principal measures of financial performance are "margins-for-interest" (MFI) and "times-interest-earned" (TIER) ratios. Neither test requires that rates cover total annual amortizing debt service requirements. Only a limited number of indentures contain debt service coverage requirements. In some cases, mortgage indentures require that MFI and TIER targets only be satisfied in two of three years Because the TIER and MFI ratios do not adequately represent a utility's financial capacity to cover

Show

amortizing principal and interest payments and do not paint a full picture of financial capacity or protections, we employ a debt service coverage analysis irrespective of whether a utility is legally bound to meet an all-in debt-service coverage test.

We look to the income statement and the statement of cash flows to ascertain the strength of the financial cushion available to shield lenders and creditors from changing circumstances. The MFI and TIER tests and most indenture-based debt service coverage tests are calculated solely with reference to the income statement. Cash flows analysis sheds light on elements of financial performance that may not be apparent from the income statement since revenue and expense deferrals are common among cooperative utilities, and the marking of power supply arrangements to market can have income statement implications.

Historically, RUS borrowers' mortgages proscribed parity borrowing unless approved through a lien accommodation. In recent years, RUS permitted a number of cooperatives to restate indentures to allow parity borrowing without a lien accommodation. However, certain financial thresholds must be met. Permitted parity lenders include CFC, CoBank and capital markets. Prerequisites financial benchmarks for parity borrowing are not uniform among the revised indentures, so we review each indenture's unique provisions. RUS is working to establish a master indenture to provide consistency as cooperatives restate their indentures in the future.

RUS' new indentures are corporate-style in many respects and do not provide high levels of lender protection. While a few contain debt service coverage tests, most focus exclusively on net revenues coverage of debt interest, as did predecessor indentures. The indentures also govern permitted additional indebtedness. Like corporate indentures, additional debt is generally allowed if elements of "bondable additions" tests are met. Such tests are not based on the strength of net revenues or cash flows to support additional debt service. Rather, they focus on maintaining a baseline equity investment. Additional debt may be issued so long as a positive equity ratio is preserved. For most cooperatives, a weak 10% equity investment is targeted in keeping with the leverage commonly exhibited by cooperatives. This threshold is low as compared to corporate utility indentures that require higher equity contributions when debt-financing asset additions.

A handful of cooperative utilities have elected to forego RUS borrowing, despite the low interest rates. These cooperatives rely on capital markets to achieve greater flexibility in their financing activities. The RUS loan approval process can be protracted and can impose financial operational limitations on a utility. In addition, there are questions as to whether RUS funds will be available to finance baseload generation capacity in coming years. Cooperative utilities' capital market financings use corporate-style indentures with liberal provisions that are similar to the modern RUS indentures and are analyzed accordingly.

Financial Analysis

Lender and creditor protections derived from financial performance are evaluated through debt service coverage ratios, liquidity, leverage analysis and external financing needs. Financial analysis of cooperative utilities closely tracks our municipal utilities' and public power joint-action agencies' rating methodology. Like public power utilities, G&T cooperatives' highly leveraged capital structures reflect an inability to access capital markets to fund a perpetual equity cushion. Low, but sound debt service coverage ratios reflect the use of amortizing debt and an absence of profit-related revenues. Cooperative utilities with high leverage and sufficient debt service coverage ratios can achieve sound credit ratings upon a demonstration of strong qualitative attributes.

Debt service coverage ratios

Cash available from current operating revenues to pay debt service is the principal focus. We use the income statement to calculate net revenues available for debt service. (See Table 1) Non-cash accruals are eliminated from revenues and expenses. We also look to cash flow statements to identify deferrals of revenues and expenses, mismatches between depreciation expenses and amortizing principal that might erode cash available to service debt, and the income statement effects of marking power supply arrangements to market. Even deferrals of revenues can present issues because ultimate income statement revenue recognition may lack corresponding cash available to service debt during the period of accrued income recognition.

Table 1

Show

Key Cash Flow Metrics

Debt Service Coverage (DSC): Net revenues available for debt service divided by scheduled cash principal and interest payments. Net revenues are defined as operating revenues plus investment income less operating expenses net of depreciation and amortization items.

Cash from operations divided by scheduled cash principal and interest payments. Funds from operations divided by scheduled cash principal and interest payments. Funds from operations are defined as net income from continuing operations plus depreciation, amortization, deferred and interest payments. Funds from operations are defined as net income from continuing operations plus depreciation, amortization, deferred income taxes, and other non-cash items.

Fixed Charge Coverage (FCC): Similar to debt service coverage, but adds to both the numerator and denominator an adjustment for fixed charges attributable to leases and power purchase agreements' capacity payments.

Internal Funding Ratio: Net cash flow (FFO less dividends such as repatriation of cooperative patronage capital), divided by capital expenditures

Free Cash Flow: Net cash flow less capital expenditures

Amortizing debt and high leverage lead to narrow cash flow coverage of debt service. Yet, in the cooperative sector, debt service coverage in the range of 1.1x can support investment grade ratings because of protections provided by a secure, captive revenue stream, ratemaking flexibility, and a generally narrow strategic focus. We do not publish medians aligning the preceding ratios with specific ratings for cooperative utilities because our ratings are an amalgamation of qualitative and quantitative factors.

Our analysis is both a historical and forward looking analysis. We examine the strength and consistency of historical financial performance and evaluate prospects for future financial performance. Actual performance is benchmarked against the utility's prior projections of future performance to identify deviations and understand their rationale. In examining financial projections, we evaluate the reasonableness of key assumptions and apply stress tests to determine cash flow impacts of changes in fuel prices, capital costs and demand. We also consider the level of retail rate adjustments that may be needed to meet financial covenants and preserve metrics upon increases in debt or operating expenses.

In calculating debt-service coverage, consideration is given to some fixed obligations that are not reflected on the balance sheet, particularly those related to power purchase agreements' capacity payments and long-term lease payments. We view power supply agreements as creating fixed, debt-like, financial obligations that represent substitutes for direct, debt-financed investments in generation capacity. In a sense, a utility that has entered into a power purchase agreement has contracted with a supplier to make the financial investment on its behalf. A "fixed charge coverage ratio" is used to assess the adequacy of cash flows to service the fixed financial obligations. (See table 2).

Table 2

d-Charge Ratio Calculation

Cash flow available for debt service or income statement net revenues available for debt service + fixed obligations recorded as operating expenses.

Divided by:

Principal repayment + interest expense + fixed obligations recorded as operating expenses.

Fixed obligations' adjustments to financial metrics are a tool for comparing utilities that finance and build generation capacity with those that purchase capacity and incur off balance sheet obligations to satisfy customer needs. That said, utilities could benefit from contracting for supply because these agreements typically shift various risks to suppliers, such as construction risk and operating risks. Power purchase agreements can also provide utilities with asset diversity that might not have been achievable through self-build.

Evaluating debt service coverage ratios for the limited group of cooperatives that rely heavily on non-amortizing debt with bullet maturities requires a hybrid analysis that incorporates elements derived from the rating methodology for both public power and investor-owned utilities. In such cases, non-amortizing debt creates considerably stronger annual debt service coverage than would be expected of a utility whose debt amortizes like a mortgage and the coverage must be discounted unless bullet maturities are staggered to create level debt service. Refinancing risk and capital market access are also factored into the analysis of utilities that use non-amortizing debt.

Evaluating debt leverage

Cooperatives' capital structures vary according to the type of service they offer. G&T cooperatives are heavily leveraged reflecting the capital-intensive nature of their business and their indentures' permissive debt leverage covenants. By comparison, less-capital intensive distribution cooperatives exhibit more favorable leverage ratios. Yet, because the distribution cooperatives have authorized and committed to pay G&T debt issued on their behalf, we analyze distribution cooperatives by evaluating fixed charge coverage ratios that measure the capacity of the distribution cooperatives to service direct debt and G&T debt. We measure the financial burdens created by leverage in the several ways. (See Table 3)

Show

Table 3

Table 6

Financial Burden Calculation

Debt to total capitalization (This debt leverage ratio divides total on-balance sheet debt by the sum of equity and total debt)

Debt to net plant: Calculates total debt as a percentage of depreciated net plant, property and equipment

Debt per kW of installed capacity, kW of peak demand, and customer meters: These debt measures provide a basis for comparing utility systems to assess the value derived from and the efficiency of their capital expenditures

Net variable debt to total debt: Measures the degree of floating interest rate exposure in a cooperative's debt structure, adjusting for floating rate debt that is hedged. Includes short-term debt, adjusted for seasonal balances

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U.S. Public Power Rating Criteria

Sector-Specific Criteria

Inside This Report

This criteria report replaces the prior version of the same title, dated Jan. 11, 2012. There have been no substantial changes to the criterion.

Related Research

2013 Outlook: U.S. Public Power and Electric Cooperative Sector — Nothing Shocking (December 2012)

U.S. Public Power Peer Study — June 2012 (June 2012)

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Scope

This criteria report details Fitch Ratings' approach to rating U.S. public power systems. It is a sector-specific extension of Fitch's global master criteria report, "Revenue-Supported Rating Criteria." More specifically, the report elaborates on five key areas of operational and financial importance to the credit quality of municipal and cooperative power entities: governance and management strategy; assets and operations; cost structure; financial performance and legal provisions; and customer profile and service area.

These key elements of Fitch's public power rating criteria remain largely consistent with its prior criteria reports. However, the weighting of individual credit factors changes as the industry evolves, particularly in response to new regulatory initiatives or as new market dynamics emerge. In addition, not all rating factors outlined in this report apply to each individual rating or rating action. Each specific rating action commentary or rating report discusses those factors most relevant to the individual rating decisions.

Key Rating Drivers

Rate Sufficiency and Flexibility: A public power utility's ability and willingness to maintain rates sufficient to meet all of its financial obligations is of paramount importance. Fitch considers how a utility's rate structure affects its capacity for the full and timely recovery of costs, as well as its flexibility to raise additional revenue. Ratemaking autonomy and the process for adjusting rates factor into this analysis.

Comprehensive Strategic Planning and Risk Management: The extent of strategic planning and risk management performed by a utility is a key indicator of management's preparedness and sophistication, and an important rating factor. Fitch typically reviews prior strategic and financial plans versus actual outcomes, as well as newly adopted strategies, to gauge management effectiveness.

Resource Adequacy and Performance: Ensuring the adequacy of power supply resources to meet current and projected demand is a fundamental planning requirement of public power utilities. Together with demonstrated operating efficiency, it is an important factor in providing a low-cost, reliable energy supply. Fitch measures resource adequacy and performance against industry standards for cost and reliability.

Financial Strength and Forecasting: The strength and stability of a utility's financial metrics reveal its ability to meet all financial obligations, and detailed financial forecasting provides an indication of future performance. Fitch reviews a broad array of historical and projected financial metrics in an assessment of a utility's financial strength, as well as a utility's adherence to adopted financial policies. Financial metrics focus principally on three core areas: cash flow, liquidity, and capital structure.

Service Area Composition and Depth: Service area characteristics demonstrate the breadth, depth, and stability of a utility's constituents, as well as their financial wherewithal. Fitch considers customer composition and concentration; income levels; and employment, population, and sales growth trends in this assessment.

Public Power Ratings in Context

U.S. public power utilities are effectively owned by their customers and operate with a mission to provide essential, reliable, and relatively low-cost electric service. Fitch's average rating for retail systems in the sector is 'A+', compared with an Issuer Default Rating of 'BBB+' for investor-owned utilities.

Key credit characteristics supporting higher ratings for public power utilities include their self-regulating authority, predominantly residential customer bases, and lower consolidated enterprise risk. Self-regulating authority allows for the more timely recovery of costs through electric rates, while higher proportions of residential customers provide for more stable energy sales and, in turn, more predictable financial operations. Efforts to diversify operations in the public power sector are extremely rare.

Governance and Management Strategy

The strength of a utility's senior management and governing body — usually an independent board of directors or elected city council — is a key credit consideration in Fitch's analytical process. Management's experience and ability to design and implement a comprehensive strategic plan is important to an issuer's rating, as is its ability to respond to unforeseen circumstances. A high degree of board or city council understanding and support of a utility's business strategy and the issues facing the utility is also important.

Achieving Strategic Goals

Fitch typically reviews prior strategic and financial plans versus actual outcomes in an assessment of management and governance effectiveness. A stronger management team consistently meets or exceeds financial projections, and deals well with unexpected developments. Moreover, Fitch takes into account the reasonableness of key financial and operational planning assumptions in its assessment.

Major Components of a Comprehensive Strategic Plan

Forecasts of customer and load growth.
New generation, transmission, or distribution requirements.
Plans to meet capital needs, including financing schedules.
Plans for rate increases.
Financial projections, including stress scenarios.
Risk-management procedures and analysis.

Comprehensive Resource Planning

Fitch analyzes a utility's integrated resource plan and its long-term strategies to provide reliable, high-quality, and low-cost service to its customers to determine if they are adequate and reasonable. Fitch monitors the implementation of those strategies and a utility's financial flexibility for responding to changing market conditions.

Fitch discusses with management the purpose, amount, and structure of planned debt issuances, and any debt-management policies in assessing a utility's capital needs and their effect on its future debt profile and financial performance. Fitch assesses the willingness and

Related Criteria

Criteria for Rating Prepaid Energy Transactions (August 2012)

Criteria for Assigning Short-Term Ratings Based on Internal Liquidity (June 2012)

venue-Supported Rating Criteria ɹne 2012)

Attributes: Governance and Management

Stronger

Management and board of directors with extensive experience.

An objective, engaged board of directors.

Transparency and strong communication between management, the board of directors, and customers.

In the case of wholesale power systems, coordinated efforts among member utility systems and the governing body.

Frequent analysis and updating of financial forecasts and resource management plans.

Well-developed and documented risk-management policies and procedures.

Documented succession planning.

Midrange

Generally stable management team and board of directors with modest turnover.

Comprehensive strategic and resource plans, forecasts of demand, and risk-management policies that generally reflect current economic, system, and political conditions

Weaker

A detached, politically-appointed board of directors.

Lack of experience or frequent turnover of management.

Significant political pressure in the underlying municipality or in the members' service area.

Failure to maintain open communication between the utility and the board of directors, which may reveal itself in unexpected, significant rate increases.

Limited financial forecasting and rate planning.

Lack of adequate risk-management policies and procedures.

ability of an issuer's management and governing body to increase rates to ensure the measured, timely, and adequate recovery of total costs. Fitch also evaluates the likely effect of rate increases on a utility's financial performance relative to its peer group.

Preparing for Uncertainties

The extent of risk management performed by a utility is a key indicator of management's sophistication. Fitch believes that the ability to manage unforeseen circumstances without causing material changes to the utility's financial or operating position is a good indication of management planning and preparedness. Fitch views favorably a management team that is able to recognize and discuss risks (and mitigating factors) that could affect a system, and in turn, bondholder security. Such risks include participation in the fuel and energy commodity markets; plans for managing a large generation unit or transmission outage; reliance on off-system counterparty credit quality; and the effect of regulatory or legislative changes.

Assets and Operations

Fitch analyzes the generation, transmission, and distribution assets of wholesale and retail power systems to determine if a utility's power supply mix and asset operating performance adequately meet existing and future demand requirements. Fitch also analyzes how a utility's power supply mix and performance compare to similar systems.

Generation Benchmarking

Fitch benchmarks a utility's generation mix to that of industry standards, the regional market in which the utility operates, and other utilities in the rating category. This allows for a comparative analysis of a utility's relative strengths and weaknesses. Fitch considers the following areas in its assessment of generation:

- Fuel mix;
- Plant availability and capacity factors;
- Load factor;

- Heat rate; and
- Environmental mandates or goals.

Fitch looks through the wholesale provider and performs a similar assessment for distribution systems that purchase power under bilateral contractual agreements from a joint-action agency or cooperative.

New Power Resources

Fitch analyzes how a utility's customer or load growth, expiring purchase power contracts, aging generation fleet, and renewable mandates influence the demand for future power resources. Fitch considers the following areas in its assessment of a utility's integrated resource plan:

- The type of generation chosen and alternatives considered;
- The size and cost of the unit;
- The effect of the unit on the utility's existing portfolio resource mix (baseload, intermediate, or peaking);
- The availability of transmission and distribution resources; and
- Environmental factors.

Building and owning assets provides many benefits, such as:

- Control of asset operation;
- Limited counterparty risk and collateral-posting (requirements associated with power purchases); and
- Equity associated with owning a long-term asset.

However, there are also benefits to being a power purchaser in periods when market power supply is ample and electric transmission access is available. Some small- to medium-sized systems can benefit from avoiding large, costly capital programs and operating obligations that come with owned generation.

Attributes: Assets and Operations

Stronger

A stable, diverse, and regionally cost-effective power resource mix.
Adequate fuel supply contracts and a well-constructed fuel-hedging strategy.
Sound operating performance that is in line with or better than industry standards.
Adequate reliability and redundancy.
A power supply plan to maintain load balance.
Sufficient transmission access.

Midrange

A power supply mix in line with the region.
Fuel-hedging strategy that strives to minimize fuel price volatility at competitive prices.
Sound asset operations, comparable to industry standards.
Limited outages that cause resources to perform below industry standards.
Evolving power supply plan that might have an open position.

Weaker

A generation portfolio that is uneconomic or might ultimately pose unusual environmental concerns.
Dependency on a single fuel or generation site.
Below-average reliability levels stemming from frequent outages, high line losses, theft, or customer dissatisfaction.
Excessive dependence on the open market for either spot power purchases or sales of surplus power.
Lack of a comprehensive power supply plan.

Fitch does not typically evaluate the merits of owning generation versus purchasing power. On the contrary, Fitch's analysis considers the costs and benefits to individual utilities of both scenarios.

Renewable Resources

Fitch reviews a utility's strategy for developing renewable or alternative power generation to gauge how a utility's generation mix will change, particularly when it must comply with a state renewable portfolio standard. Fitch also evaluates the capital and operational costs of the projects, and how they will ultimately affect customer rates.

Renewable energy projects are expected to have long-term environmental benefits. However, the intermittent nature of their generation and higher operating costs relative to traditional generating resources can pressure a utility's financial operations without adequate cost recovery. The availability and types of these resources and the transmission capability vary by region.

Environmental Considerations

Fitch conducts a review of a utility's compliance with current and proposed environmental standards to fully understand a system's future capital needs and operating expenses. Environmental retrofits can be costly on a capital basis and from an operating perspective, as increased captive consumption often results in lower plant output. The cost to retrofit may be high for older, coal-fired generating facilities, rendering the generating facility uneconomic and subject to retirement. As such, the effect of more restrictive federal and state environmental policies can have significant operating and financial repercussions for a utility.

Fuel-Supply Management

Fitch reviews a utility's hedging techniques as part of its risk-management assessment. The ability to manage fuel costs is a key credit factor, because fuel is often a utility's largest budgetary expense. Hedging can be critical to the financial stability of, for example, a retail distribution system that purchases a portion of its power in the spot market.

The use of financial markets and power derivatives can help mitigate the risk of price volatility or a longer term trend of increasing prices. However, these instruments can leave a utility exposed to a drop in fuel prices, which can render certain hedges uneconomic, or "out of the money." This might require a collateral posting by the utility that, if coupled with declines in operating performance, could tighten liquidity and result in negative credit pressures.

Other factors of the fuel supply that Fitch considers include:

- Diversity of fuel mix;
- Flexibility of fuel agreements;
- Fuel transportation arrangements; and
- Alternative fuels, if primary sources are not available.

The optimal fuel-supply strategy varies by utility. It is driven by the diversity of generating resources, sufficiency of fuel sources, and the ability to mitigate associated risks.

Off-System Sales and Purchases

Heavy reliance on off-system sales is viewed as a negative credit factor as revenues tend to be more volatile, reflecting inherently variable power market prices. However, a power generator's off-system sales to non-native load can reduce existing customers' costs or provide surplus funds for reinvestment in system facilities, depending on market conditions.

Conversely, spot purchases can increase overall cost efficiency if power generators can purchase power in the open market when the cost is beneficial (the market cost of power is lower than the cost of a system's own generation). However, short-term purchases will also expose issuers to greater cost volatility.

Distribution and Transmission

Fitch's review of a distribution system includes an assessment of its reliability, as measured by the frequency of outages, line losses, etc., and the extent and timeliness of necessary capital improvements for its traditionally "wires only" infrastructure. Fitch views the distribution function largely as a monopoly-type, stable business with limited business risk.

Fitch evaluates the level of historical and planned system investment to determine if customer growth will affect the operations of the existing system relative to a peer group. Fitch also reviews a utility's business strategy regarding its transmission connection with a regional operator or other transmission system that can provide it with reliable access to market power, if needed.

Cost Structure

Fitch analyzes a utility's cost structure and methods of adjusting rates to determine its rate-raising flexibility for the timely funding of financial operations and capital needs. The analysis is conducted "bottom up," by looking at the costs to generate (or purchase) and supply electricity to customers, and "top down," by examining the structure of retail rates charged to different customer classes. A utility with overall rates that are below neighboring systems or systems with similar fuel mixes is generally viewed as having greater flexibility to use rates as a tool for funding, and strong service territory income measures typically enhance this flexibility.

Local Rate-Setting Authority

Fitch views the flexibility most municipal systems and electric cooperatives have to independently adjust rates as a positive credit factor and distinguishing characteristic from comparable investor-owned utilities. Most public power systems are not subject to regulation by state public service commissions. Instead, public power systems typically maintain local authority to adjust rates as needed, which contributes to the timely recovery of costs. This provides management with the ability to raise rates to maintain financial stability, build liquidity, or pay for portions of a capital improvement plan.

Fitch also considers the use of automatic or interim rate adjustments, which further ensure timely cost recovery, in its assessment of a utility's rate structure. Interim adjustments that may be implemented by a utility's management team — without the involvement of a governing board — can help ensure the overall stability of financial operations.

Attributes: Cost Structure

Stronger
Sole authority to set appropriate customer or member rates and a demonstrated willingness to do so.
Retail/wholesale rates are typically below those of neighboring utilities and frequently more competitive nationally.
Competitive "all-in" production costs.
Use of an automatic monthly fuel or purchased power adjustment surcharge for timely recovery of variable energy and fuel costs.
Timely and measured rate increases in anticipation of multiyear capital spending.

Midrange
Authority to set customer or member rates, subject to the approval of an elected city council.
Comparable rates to neighboring utilities, and within range of regional averages.
Use of a fuel or purchased power adjustment surcharge typically adjusted less frequently than monthly.
Well documented rate strategy for servicing capital spending and related debt obligations.

Weaker
Outside regulatory approval required for rate increases.
Political pressure that might limit or postpone needed rate increases, which could ultimately affect a utility's financial metrics.
Above-average rates relative to a peer group, which reduces flexibility for managing unforeseen operating or other capital expenses.
Lack of any fuel or purchased power adjustment factor.

The rates of wholesale power suppliers, including joint-action agencies and generation and transmission cooperatives, and their distribution members are compared at the wholesale and retail levels, respectively.

Rate Competitiveness and Affordability

Fitch analyzes rate affordability with a mixture of qualitative and quantitative factors. While this area typically does not have a significant impact on rating outcomes, Fitch's perception of high or volatile rates, lack of future rate flexibility, or difficulty in obtaining timely rate relief may influence a utility's rating. Fitch believes credit is due to those systems that consistently raise rates to preserve financial strength. However, Fitch believes these activities will be more sustainable when rate affordability is a focus of policymakers and cost containment is regularly employed. Fitch reviews a utility's rates relative to neighboring systems and against service area income levels to gauge rate competitiveness and affordability.

Financial Performance and Legal Provisions

The assessment of a utility's financial performance and policies, and the legal provisions underpinning specific debt issuances, are important considerations in Fitch's rating process. Fitch reviews five years of audited financial statements for an established utility to understand its historical trends and competitive position relative to a peer group. A utility's operating results, liquidity levels, and capital structure are evaluated. Financial projections, including planning assumptions for load growth, rate increases, and expenses, are likewise critical to the rating process. Fitch also examines the financial profiles of a wholesale power provider's members as necessary, to the extent that information is available.

Financial Performance

Fitch's analysis of financial metrics focuses principally on three core areas: cash flow, liquidity, and capital structure. No single financial ratio stands apart from the rest. On the contrary, the ratios are examined together, providing a context for a utility's financial position that informs a complete analysis.

Cash Flow

Cash flow indicators, particularly as they pertain to debt service coverage, provide a measure of financial cushion to meet obligations to bondholders. Fitch primarily considers two measures of debt service coverage to compare utilities that own generation versus purchase power. The standard debt service coverage ratio measuring funds available for debt service to total debt service applies to all utilities. An adjusted measure of debt service coverage, primarily for retail systems that own little or no generation, treats a percentage (30%) of purchased power costs as a debt-like obligation. Thirty percent is an approximation based on historical experience for that portion of off-balance sheet obligations that might otherwise be a fixed expense. The ratio provides a more conservative estimate of financial margin and facilitates comparison with systems that own generation.

Key Financial Ratios

Ratio	Calculation	Significance
Cash Flow		
FADS ($)	Operating Revenues–Operating Expenses+Depreciation+Interest Income[a]	Provides a measure of cash flow from operations.
Debt Service Coverage (x)	FADS/Total Annual Debt Service	Indicates the margin available to meet current debt service requirements.
Coverage of Full Obligations (x)	(FADS+Fixed Charge–General Fund Transfer and/or PILOT)/ (Total Annual Debt Service+Fixed Charge)[b]	Indicates the margin available to meet all debt service and other fixed obligations.
Debt/FADS (x)	Total Debt/FADS	Indicates the size of debt compared to the margin available for debt service.
Liquidity		
Days Cash on Hand	Unrestricted Cash and Cash Equivalents/ (Operating Expenses–Depreciation)x365	Indicates financial flexibility, specifically cash and cash equivalents, relative to expenses.
Days Liquidity on Hand	(Unrestricted Cash and Cash Equivalents+Available Lines of Credit and Commercial Paper Capacity)/(Operating Expenses-Depreciation)x365	Indicates financial flexibility, including all available sources of cash and liquidity, relative to expenses.
Capital Structure		
Equity/Capitalization (%)	Total Equity/Capitalization	Provides a measure of cost recovery, leverage, and additional debt capacity.
Debt Service/Cash Operating Expenses (%)	Total Annual Debt Service/(Operating Expenses+Total Annual Debt Service–Depreciation)	Provides an indication of debt burden relative to cash operating expenses.
Debt/Customer ($)	Total Debt/Total Customers	Provides a measure for relative comparison of leverage.
Variable-Rate Debt/Total Debt (%)	Variable-Rate Debt/Total Debt	Provides context for an issuer's short-term obligations.
Other		
Operating Margin (%)	Operating Margin/Operating Revenues	Provides a measure of operating stability and capacity to manage an increase in debt levels.
Capex/Depreciation and Amortization (%)	Capex/(Depreciation+Amortization)	Indicates whether annual capital spending keeps pace with depreciation.
Free Cash Flow/Capex ($)	(FADS–Total Annual Debt Service–General Fund Transfer and/or PILOT)/Capex	Indicates a utility's ability to internally fund capex.
Net Debt/Net Capital Assets (x)	(Total Debt–Cash and Reserve Funds)/Net Utility Plant	Provides a measure of leverage relative to the book value of physical assets.
General Fund Transfer/ Operating Revenues (%)	(General Fund Transfer+PILOT)/Operating Revenues	Indicates the degree to which a utility provides city or county general fund support.

[a]Operating revenues exclude deferrals to and transfers from a rate stabilization fund. [b]Fixed charge – 30% of purchased power expense, which is an approximation of the associated fixed expense. FADS – Funds available for debt service. PILOT – Payment in lieu of taxes.

Wholesale power suppliers often have lower coverage levels than retail systems, as total wholesale costs are passed through to their members on a monthly basis. Fitch reviews a wholesale system's cost structure, rate adjustment, and billing processes to assess the timeliness of cost recovery, given their lower financial coverage metrics.

Liquidity

Liquidity measures, such as days cash on hand and days liquidity on hand, provide an estimate of an issuer's ability to meet uncertain operating or other capital expenses. Public power entities typically carry less cash on the balance sheet than water and wastewater utilities. As such, days liquidity on hand, reflecting any undrawn bank facilities, is an important measure of financial flexibility.

Certain utilities, typically cooperatives, rely heavily on third-party liquidity providers for bank revolvers or lines of credit. Fitch assesses the diversity and credit quality of the liquidity providers, the ability to extend and replace such agreements, and the adequacy and terms of the liquidity support when reviewing these utilities.

Fitch reviews transfers by a utility to the corresponding municipality's general fund to determine if they are formulaic or subject to limitation. Subjective, open-ended transfer policies that allow a local government to affect the liquidity levels of a utility generally increase credit risk. For electric cooperatives, the amount of patronage capital repatriated has similar importance.

Capital Structure

A utility's capital structure, which encompasses the strength of its balance sheet, presents another indication of financial flexibility. More specifically, the equity-to-capitalization ratio measures a utility's ability to grow equity over time.

A rising equity ratio is favorable, as it suggests adequate cost recovery in rates or load growth. A high level of system equity indicates capacity for issuing additional debt to fund future capital needs. Wholesale power providers with equity levels below 10% are likely to be considered financially disadvantaged.

Attributes: Select Financial Metrics (Retail Systems)

Debt Service Coverage (x)	Debt/FADS (x)	Days Cash on Hand	Equity/Capitalization (%)
Stronger			
Coverage of consistently more than 2.0x provides solid cash flow and bondholder protection.	Less than 6x debt to FADS indicates a favorable level of leverage relative to cash flow.	More than 120 days cash on hand indicates solid financial flexibility to meet unforeseen spending needs.	Strong equity levels of more than 40% indicate adequate cost recovery and ample debt capacity for future capital needs.
Midrange			
Many utilities target coverage in the 1.5x–2.0x range.	Ratios in the 6x–9x range indicate a generally balanced level of debt relative to cash flow.	Many utilities target approximately 60–90 days operating cash.	Many utilities maintain 20%–40% equity levels.
Weaker			
Consistently less than 1.5x coverage provides limited cushion for unexpected revenue shortfalls.	Greater than 9x debt without a suitable rationale can indicate a deficient rate structure.	Less than 60 days cash indicates less financial flexibility, but can be adequate if a utility is subject to less cash flow volatility.	Less than 15% and 10% equity is relatively low for retail electric and wholesale systems, respectively.

FADS – Funds available for debt service. Note: The debt and equity ratios above do not reflect off-balance sheet obligations, which apply to retail systems that are participants in joint-action agencies or are part-owners of generation facilities. Fitch reviews adjusted financial ratios to take into account such obligations.

Debt Profile

Fitch's assessment of a utility's debt profile considers the purpose, amount, and structure of its existing debt. Fitch also considers any off-balance sheet obligations such as take-or-pay contracts or interest rate swap agreements for a complete assessment of fixed expense obligations. Future financing plans, including the funding of a long-term capital program, and the renewal and replacement of any bank liquidity facilities, are also important considerations, particularly as they will affect financial metrics.

The amount of hedged or unhedged variable-rate debt an issuer can manage is a function of its operating risk profile; the strength, predictability, and amount of its cash flows; the level of available funds; and its management of interest rate exposure and maturities. Fitch will assess the resiliency of an issuer's financial metrics relative to a peer group when evaluating its ability to manage variable-rate and short-term debt exposure. Higher rated issuers are typically better able to take on a greater percentage of variable-rate debt, as compared with lower rated issuers.

Legal Provisions

Aspects of the Bond Indenture

The legal provisions of a bond indenture or resolution provide a framework for the establishment of funds and, ultimately, the repayment of a debt obligation. Consequently, Fitch analyzes indenture provisions, such as the pledge of revenues, rate covenant, additional bonds test, debt service reserve fund, and flow of funds to determine the relative strength of the security.

Bond covenants are important to overall bondholder protection, though the degree to which they influence a rating varies. The legal provisions take on greater importance the weaker the credit quality, as they are more likely to be tested.

Pledge of Revenues

Fitch does not distinguish between a pledge of gross and net revenues for public power systems, as all systems must fully cover annual operating expenses and debt service from total revenues. A weaker revenue pledge may allow for the inclusion of other available funds as revenues.

Separately, a mortgage interest provides bondholder support via a lien on physical assets, as is typical of cooperatives.

Rate Covenant

The rate covenant provides a minimum level of protection and ensures that a system reliably covers debt service by a certain margin. Fitch views it as an element of financial cushion. Rate covenants with only a 1.0x (sum sufficient) debt service coverage requirement, or those that allow inclusion of other funds in the calculation, are viewed as being weaker.

Additional Bonds Test

The terms of the additional bonds test often mimic the rate covenant. The strongest tests include both a historical and projected debt service coverage test and limit the period for calculating net revenues to the 12 months immediately preceding the issuance of additional debt.

Debt Service Reserve Fund

The incidence of relying on a debt service reserve fund to pay debt obligations is low, given the limited number of public power entities that Fitch rates below investment grade. However, maintaining additional legally restricted, cash-funded reserves is looked upon favorably, particularly for weaker credits. Fitch evaluates those instances where reserve funds have been funded with a surety from a financial guarantor on a case-by-case basis.

Flow of Funds

The flow of funds is fairly standardized, providing for regular deposits to the debt service fund after the payment of operations and maintenance. As such, the flow of funds has little bearing on the rating, except in the uncommon instances when it deviates from the typical arrangement.

Attributes: Select Indenture Provisions

Rate Covenant	Additional Bonds Test
Stronger	
Greater than 1.25x coverage of ADS by net revenues alone.	More than 1.25x coverage of MADS from net revenues. Typically, the test includes both a historical and projected revenue period; the test will have to be met over a consecutive number of months.
Midrange	
Coverage of ADS between 1.10x and 1.25x by net revenues alone.	Coverage of MADS from net revenues of between 1.10x and 1.25x. Might only include a historical or projected net revenue coverage test; might allow inclusion of other available fund balances to meet the test.
Weaker	
Less than 1.10x coverage of ADS by net revenues plus available funds.	Less than 1.10x coverage of ADS from net revenues. Typically, a historical or projected test, with a looser interpretation of the revenue period (i.e. 12 consecutive months of the 24 months preceding the issuance of additional bonds).

ADS – Annual debt service. MADS – Maximum annual debt service.

Wholesale Power Contracts

The power sales contracts between a wholesale power supplier and its distribution customers are among the most important factors supporting the credit rating of a wholesale power system (joint-action agency or cooperative), as the credit strength of a wholesale provider is intrinsically linked to that of its purchasers. A wholesale power supplier would be unlikely to obtain an investment-grade rating absent these long-term agreements, many of which are court validated to provide assurances that they are enforceable.

In particular, Fitch evaluates the nature of the contractual obligation (take-or-pay, take-and-pay, all requirements, etc.) and the expiration and renewal terms of these contracts relative to the final maturity of an issuer's outstanding bonds. Debt maturities beyond the terms of the agreements are considered a negative rating factor, as issuers could be forced to sell power in the open market on a merchant basis to support debt service.

Take-Or-Pay Contracts

Strengths

Long-term commitment of participants to purchase 100% of project output.

Participants are required to make payments regardless of unit operation; many such contracts have been deemed by the state courts as legally binding to the participants.

Contracts can mitigate price volatility risk (for the power purchaser) inherent in short-term purchase power contracts, as the contracts are often for a fixed price plus a modest escalator.

Step-up requirements can mitigate the default risk of the weakest and smallest participants (e.g. with a 25% step up, a default by 25% of participants [by participation] would be borne by the other participants rather than by bondholders).

Weaknesses

Depending on the transaction's structure, the step-up provision can be insufficient to mitigate a default of the weakest participants.

Take-And-Pay Contracts

Strengths

Long-term commitment of participants to purchase 100% of agency output.

Participants are obligated to pay for power that is delivered, whether generated or purchased.

The risk of an individual participant defaulting is, in effect, borne by membership rather than bondholders in the form of higher average wholesale rates set by the agency (e.g. an unlimited step-up provision when "take-and-pay" is coupled with an "all-requirements" power supply contract).

Weaknesses

Participants are only obligated to pay for power that is available. Hence, an agency would lose revenues if it did not deliver power.

Effects of Litigation

Fitch considers any litigation that might result in financial payments in its review of an issuer's legal framework. Any such payments that materially affect an issuer's balance sheet could result in a negative rating action.

Customer Profile and Service Area

Service area characteristics provide an indication of the stability of a constituency's load, and ultimately its ability to pay electric bills. Stronger electric systems typically serve growing, well-

Key Service Area Metrics

Indicator	Source	Significance
Economic Factors	U.S. Bureau of Labor Statistics and U.S. Bureau of Economic Analysis.	A diversified economy is typically better positioned to absorb cyclical changes than an economy concentrated in a certain sector, providing for greater stability of revenues.
Customer Profile (breakdown of residential, commercial, and industrial customers)	Utility or consultant	A higher percentage of residential energy sales (more than 40%) typically provides for greater financial stability. Residential customers each account for very small percentages of total sales. As such, the loss of any single customer does not disrupt a utility's revenue stream.
Top 10 Customers	Utility or consultant.	As a percentage of the total, 5% of sales to the largest customer or 25% of sales to the 10 largest customers reveals concentration in the revenue base, which can be disruptive if a large customer(s) leaves the area.
Population	U.S. Census.	A growing service area typically leads to additional energy sales, in support of revenues.
kWh Sales (breakdown of residential, commercial, and industrial sales)	Utility or consultant.	The trend of kWh sales provides an indication of the health of the local economy, with steady annual increases demonstrating sound economic and population growth.
Unemployment Rate	U.S. Bureau of Labor Statistics.	Provides an indication of the relative depth of a local employment base.
Income Levels	U.S. Census and U.S. Bureau of Economic Analysis.	Provides an indication of the relative ability to pay.

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diversified areas. However, the essential nature of electric service and the remedies available to most public power providers (e.g. shutoffs and liens) make payment delinquencies in the sector extremely low, regardless of wealth and other economic indicators.

Service Area Considerations

A utility's ability to maintain a sound operating position, despite changing service area characteristics, is an important rating consideration. Some of the factors Fitch considers in its assessment of a service area are shown in the Key Service Area Metrics table on page 12.

Fitch performs a more detailed analysis of an electric system's customer base to further evaluate the stability of the revenue source when there is industry or customer concentration. The latter is defined as one or a few large customers accounting for a material proportion of revenues (e.g. an individual customer accounting for more than 5%, or the top 10 accounting for more than 25% of the system's operating revenues). Fitch also conducts an analysis of all relevant member information when reviewing joint-action agencies and cooperatives as necessary, to the extent that information is available.

Key Rating Considerations

Governance and Management Strategy

- Type of governing body
- Management's relationship with governing body
- Management's experience and depth of industry knowledge
- Business strategy and planning
- Management's track record at achieving financial and strategic goals
- The relationship among the members, for joint-action agencies and cooperatives

Assets and Operations

- Review of generation mix and comparison to the region
- Historical operating performance of generation facilities
- Relative load balance or shortfall, and plans for meeting additional power needs
- Environmental concerns and compliance
- Fuel supply and hedging contracts
- Off-system power sales/purchases
- Distribution and transmission issues

Cost Structure

- State or federal regulatory oversight
- Rate-raising flexibility and competitiveness
- Process of adjusting rates to ensure timely and adequate cost recovery
- Structure and use of fuel or purchased power adjustment mechanism
- Generating plant production costs relative to similar plants in the region
- Average total power supply cost relative to a peer group
- Average wholesale cost of power, for joint-action agencies and cooperatives
- Average retail rates by customer classification and comparison to peers

Financial Performance and Legal Provisions

- Management's financial policies
- Historical five-year analysis of key cash flow, liquidity, and leverage ratios
- Financial projections and reasonableness of key assumptions
- Existing debt characteristics and future financing needs
- Financial analyses of the largest member distribution systems, for joint-action agencies and cooperatives
- Review of indenture provisions and bond security features
- Type, length, and renewal terms of wholesale power contracts
- Any material pending litigation

Customer Profile and Service Area

- Economic and demographic makeup and trends
- Customer composition, including a breakout of kWh sales and revenues
- Customer revenue or business sector concentration
- Service area profiles of member systems, for joint-action agencies and cooperatives

Revenue-Supported Rating Criteria

Master Criteria

This report replaces the previous report of the same title dated June 20, 2011.

Master Criteria: This report presents Fitch Ratings' master criteria for assigning credit ratings to revenue-supported obligations and entities in the public finance sector. The report discusses the key qualitative and quantitative factors that influence a borrower's expected ability to meet financial obligations in full and on schedule.

Four Categories of Focus: The criteria are organized into four broad categories of analytical focus: governance and management; operational profile; debt profile; and financial profile. While the report describes Fitch's general approach for assigning revenue-supported ratings, not all the credit factors discussed may pertain to every rating situation.

Extremely Diverse Borrowers: Public finance borrowers that issue revenue-supported debt represent an extremely diverse set of organizations that include municipal enterprises, educational and cultural institutions, nonprofit hospitals, and cooperative utilities. Even among entities of similar size, scope, and purpose, these businesses are predominantly localized enterprises, each of whose creditworthiness is tightly linked to local demographic, economic, political, and/or competitive characteristics.

Credit Factors Will Vary: As a result of the diversity among borrowers, the degree to which certain credit factors are emphasized — especially nonfinancial factors — will vary depending on the levels of credit stability and competitiveness observed within the sector and for individual borrowers. Each specific rating action commentary or rating report will discuss those factors most relevant to the individual rating action. This report highlights the credit factors reviewed by Fitch that are most common across revenue-supported borrowers.

Sector-Specific Criteria Available: For more guidance on the application of the rating factors discussed in this report, refer to Fitch's sector-specific rating criteria.

Related Criteria

Rating U.S. Municipal Short-Term Debt, Dec. 8, 2011

Criteria for Assigning Short-Term Ratings Based on Internal Liquidity, June 20, 2011

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Governance and Management

The effectiveness of governance and management is an important factor in assessing an organization's creditworthiness, as management's decisions and initiatives — subject to the oversight and strategic direction of the governing body (such as a board of trustees or city council) — can ultimately determine an entity's long-term financial viability. Fitch generally focuses its commentary on management and governance practices where their effectiveness materially influences the rating decision.

Governance

With a level of analysis tailored to the structural characteristics of the sector, Fitch reviews the effectiveness of the governing body in establishing and implementing the organization's policies and principles. Fitch's assessment may involve developing an understanding of the governing body's mission and strategy, structure, composition, interaction with and oversight of management, knowledge of industry issues, and performance standards.

Management

Fitch also examines the track record of senior administration in implementing the governing body's policies and providing capable day-to-day management. Fitch's analysis is qualitative in nature and will assess management's history of successfully meeting the goals defined in a strategic plan and its ability and willingness to adjust to a changing operating environment. While a failure to meet specific goals may not be viewed negatively in all cases, Fitch expects management to explain significant deviations from planned, expected, or budgeted results and to articulate its contingency plans.

Management effectiveness may also be judged through a review of planning processes. Leadership teams that possess a strong understanding of their markets and capabilities, effectively articulate goals and objectives, and are organized to operate consistent with industry best practices are viewed more favorably.

Operating Profile

Fitch's rating methodology includes a review of the operating characteristics of a borrower. Measured in a variety of ways depending on the borrower's sector, Fitch's operations review may include investigations of business strategy, operational effectiveness, competitive position and environment, and capital planning and management processes. An examination of internal processes and procedures designed to maximize asset productivity and a review of an organization's ability to maintain operating strength in a variety of economic and business conditions are core to this analysis. Fitch views favorably those organizations that demonstrate stability in their performance level over time.

Business Strategy

To assess business strategy, Fitch examines an organization's position within the markets served and ability to meet the needs of its constituents. While Fitch reviews historical market position trends in the context of current industry characteristics, close attention is paid to the flexibility an organization retains to deal with potential changes in its competitive or operating landscape.

Fitch looks to overall trends in demand and financial metrics to judge the effectiveness of an organization's business strategy. As part of the analysis, Fitch reviews the institutionalized processes that facilitate effective strategic planning, with an emphasis on aspects that provide operating flexibility to adjust for variations in demand. Even within the same industry, Fitch recognizes that no single business strategy is appropriate for all organizations. The plan should fit the mission of the borrower, the needs of its customers and other constituents, and its specific marketplace. The ability of management to articulate a business strategy that demonstrates a thorough understanding of its operating environment is an important factor in achieving and maintaining an investment-grade rating.

Operational Effectiveness

The efficient employment of capital assets to generate surplus funds to cover debt service requirements and ongoing repair and replacement of assets is a key credit consideration for all revenue-supported sectors. Fitch examines the productivity or utilization levels of existing physical plant assets in the context of a borrower's industry. Borrowers with elevated excess capacity and limited means to recoup their fixed costs are viewed negatively. While growth prospects and assumptions are carefully considered as part of a proposed expansion, Fitch may negatively view such plans when excess capacity or organizational inefficiencies have historically plagued a borrower's operation.

An organization's ability to generate cash flow from its operations sufficient to fund capital renewal and expansion and service debt obligations is evaluated through an analysis of revenue and expense trends. Changes in revenue are analyzed by reviewing an organization's pricing strategies; regulatory, political, or market limitations on its ability to influence price levels; and volume or demand patterns. An organization's expense structure is similarly reviewed, with additional consideration given to cost containment efforts and industry-specific factors that may affect the cost and availability of inputs, whether raw materials, supplies, or labor, going forward.

Competitive Profile

In sectors where marketplace competition is a potential rating concern, an organization's position relative to its peers is a major area of analytical focus. In such cases, Fitch's analysis may include reviews of market share trends, rate competitiveness, industry reputation, geographic coverage or footprint, and product differentiation. Aspirations to achieve higher industry standing or ranking, support service area economic development, or significantly change market share concentration are evaluated in conjunction with the practical realities of the organization's current competencies and ability to secure additional resources to fund such initiatives.

Regulatory Issues

For sectors subject to external regulation, Fitch combines a review of the current and expected regulatory climate with an assessment of the organization's ability to maintain stable operations in the face of regulatory change. Fitch may review responses to prior regulatory mandates, identifying financial and operational effects. Fitch examines the potential for future regulatory initiatives and assesses whether the organization, through its systems, practices, and resources, will have the ability to manage potential downside risks. In sectors where external regulation is prevalent and has a bearing on creditworthiness, an organization's proactive response to regulatory developments and effective participation in the regulatory and legislative processes help support solid investment-grade ratings.

Capital Planning and Management

Fitch assesses the feasibility of significant investment in physical plant capacity by reviewing the borrower's master facilities plan (MFP) or capital improvement plan (CIP). Plans that are dynamic, address facilities needs over multiple time spans, and specify funding sources are viewed more credibly in the rating process. In general, modular MFPs are viewed more favorably by Fitch because they provide an organization the flexibility to modify its planned capital investment should business or market conditions prove unfavorable.

Fitch's review focuses on current capacity constraints and limitations, the assumptions that underlie volume projections, and the capital budgeting process. In addition, funding sources, which may include a combination of debt proceeds, cash on hand, governmental appropriation, and other sources, are reviewed for reasonableness. For sectors that have large CIPs, Fitch may also evaluate the overall terms and provisions of construction contracts (such as liquidated damages, early completion incentives, and labor contracts and cost adjustments), as well as the experience of the development team, to assess the mitigation of construction and development risk.

Fitch reviews an organization's process for and financial ability to make annual routine investment in asset maintenance and equipment acquisition. The amount of deferred maintenance an organization has will be assessed in the context of its physical plant size and the plan for addressing the most critical needs.

Rating Relationship to Host Government

For certain public finance credits that are an enterprise or component unit of a general government, the rating of the revenue-backed security may be tied to or influenced by the credit quality of the general government. In addition to sharing common management and service area characteristics, there are situations where significant legal or operational connections may exist between the two (for example where credit agreements cross-default or if one fund is drawing upon the cash of the other). In these cases the revenue-supported rating may be closely tied to the host government's general obligation rating. Fitch details any direct relationship between the general government's credit quality and related revenue-supported securities within the appropriate rating action commentary.

Debt Profile

The level and structure of a borrower's debt strongly affect Fitch's overall assessment of creditworthiness. The purpose of a planned financing, the total amount of debt outstanding, and various characteristics of a borrower's debt structure are all components of Fitch's review. Fitch's approach may also consider the realization of low likelihood but high consequence debt market dislocations and a borrower's ability to meet obligations under such stressed conditions.

Purpose

Fitch's debt profile analysis begins with a review of the rationale to issue debt. For new money issues, Fitch seeks to determine if planned capital investments are justified by capacity constraints, projected market growth, or competitive opportunities. In addition to Fitch's own research and analysis, Fitch considers a borrower's methods for monitoring industry growth patterns and their relative market position, if appropriate. Fitch looks favorably on organizations that soundly demonstrate a need for their CIP by employing a variety of techniques to assess service area dynamics, such as econometric analysis and consultations with regional economic development and planning agencies and local businesses, as well as timely economic research and valid surveys. Fitch is specifically interested in the most significant variables that affect increases and decreases in demand for an organization's goods and/or services.

A borrower's ability to service planned debt from existing operations is viewed favorably. Alternatively, if debt repayment depends on the incremental revenue to be generated by new capital assets, the evaluation of project completion risk and feasibility becomes an important aspect of Fitch's analysis. For debt issued to refinance or restructure existing obligations, Fitch's analysis focuses on the rationale for the issuance and the options available to the borrower for that purpose.

Magnitude

Fitch evaluates the actual and expected amount of debt outstanding by comparing debt and debt service levels to a comparable group of borrowers and examining future debt service requirements in relation to historical and expected revenue streams and the borrower's overall cost structure. Ratios relevant to the sector capture the financial flexibility afforded by an organization's assets and operations relative to outstanding and expected long-term debt.

The inability to meet periodic debt service requirements with operating cash flows is viewed negatively. However, in certain cases, these concerns may be mitigated when a borrower's non-operating revenues (or those of an affiliate or other related entity that support the borrower) show a long and stable history or its liquid assets are several times greater than debt obligations (particularly for the higher education and healthcare sectors).

Investment-grade ratings generally require coverage of debt service by earnings before capital costs, with higher ratings correlating strongly with higher coverage ratios. However, the presence of extraordinary pricing flexibility or available liquidity can mitigate occasional deficiencies in coverage.

Structure

The characteristics of a borrower's debt instruments and capital structure have a strong bearing on Fitch's assessment of creditworthiness. The establishment and composition of the obligated entity or entities, the nature of the security pledge, interest rate mechanisms, demand features, performance covenants, and principal amortization are all components of Fitch's review.

A high proportion of fixed-rate debt is viewed positively by Fitch. Moreover, fixed-rate bonds with amortizing principal within the expected life of the assets financed provide the most stable debt configuration.

Fitch examines the ability of borrowers that use variable-rate debt to manage interest rate and liquidity risk. Factors that can mitigate the risks involved, such as large cash reserves or interest rate hedges, are also considered. Generally, variable-rate borrowers that cannot absorb dramatic interest rate increases or address any failure to remarket variable-rate demand obligations (VRDOs), without materially damaging their overall financial profile, are viewed negatively.

While most VRDOs issued by U.S. public finance borrowers are supported by dedicated liquidity facilities provided by financial institutions, highly rated borrowers sometimes act as their own liquidity providers, allowing them to avoid bank liquidity fees and potentially restrictive legal covenants. In such instances, Fitch's analysis considers the availability and stability of a borrower's liquid resources, as well as the policies and procedures that would be followed, should a failed VRDO remarketing and/or rollover of CP notes occur *(for a more detailed description of Fitch's analysis, see "Criteria for Assigning Short-Term Ratings Based on Internal Liquidity," dated June 20, 2011, available on Fitch's Web site at www.fitchratings.com).*

The amount of variable-rate debt a borrower can manage (hedged or not) is a function of its operating risk profile, quality of cash flows, amount of available funds, and ability to manage interest rate exposure and financial hedges. To determine if an borrower can manage its variable-rate and short-term debt exposure at its given rating level, Fitch may perform stress tests to determine the resilience of a borrower's financial metrics (e.g. cash flow and liquidity adequacy), compared with its peer group. Typically, borrowers rated 'A' or higher have greater financial flexibility, including market access, to manage the various risks associated with variable-rate debt than their lower rated counterparts.

Fitch's analysis also includes a review of the borrower's use of financial derivatives, or swaps. Where exposure to interest-rate swaps is significant, credit concerns can be tempered in the rating process by an effective oversight function, counterparty diversification, and demonstration of a clear understanding by management and governance of the benefits and risks involved.

Legal Provisions

Fitch analyzes several legal factors, which may include indenture provisions such as security pledges, rate covenants, events of default, additional bonds tests, and reserve requirements. While Fitch believes bond covenants are clearly important to overall investor security, the degree to which they influence ratings varies. Operating performance will have a greater effect on the rating than legal provisions for most highly rated borrowers. However, legal provisions become increasingly important as a borrower moves down the rating scale.

Fitch also seeks to review provisional terms for VRDOs or direct lending arrangements, including related third-party credit support agreements, whether or not the obligations are rated by Fitch. If asked to assign a hypothetical long-term rating to VRDOs that assumes the debt has been tendered, not remarketed, and purchased by the liquidity provider in accordance with the liquidity support agreement (i.e. bank bonds), Fitch bases the bank bond rating on its analysis of the borrower's underlying credit strength and a review of related third-party credit agreements. Fitch considers the potential negative effects of these obligations on a borrower's financial profile, which may include higher interest rates and an accelerated repayment of principal, as part of this analysis.

Since these factors are considered in Fitch's analysis of the underlying rating of all parity debt, bank bonds whose security is on parity with their corresponding VRDOs carry the same underlying long-term rating as those VRDOs. Similarly, an obligation arising from commercial paper being purchased by a liquidity provider would be assigned the same rating as the borrower's parity obligations.

Financial Profile

A borrower's overall financial profile contributes materially to the rating determination. Fitch's analysis includes quantitative assessments of operating performance, liquidity, and debt load, as well as the historical trends in such measures. Comparisons with the borrower's sector-specific rated peers are often a component of the analysis.

Fitch believes the financial profile is a product of the qualitative and strategic factors discussed herein and that the credit rating should be supported by well-founded expectations for such factors. Additionally, qualitative factors can often modulate the risk level that may be indicated by a narrow review of financial metrics, contributing to additional credit strength or weakness. Finally, absent the development of a clear trend, a certain amount of variability in financial performance should not affect the rating on the bonds, as long as a borrower's underlying strategic position remains stable.

Performance Metrics

Both historical and projected financial results are considered. The best indicator of future financial performance is the recent track record of the borrower, its management team, and its market. If future performance is expected to track differently from historical results due to major project plans, environmental changes, or management initiatives, Fitch examines the assumptions that drive projected results. Forecasts that rely on aggressive volume growth, market share capture, price increases, or expense reductions are viewed with analytical conservatism in the rating process. Fitch may request sensitivity analyses stressing major forecast assumptions to gauge their importance in achieving projected results.

Using audited and interim financial information and statistics, Fitch assesses the organization's financial profile, reviewing trends in operating performance and non-operating results, absolute and relative levels of balance sheet assets and liabilities, and statistical information relevant to the sector. Financial forecasts, if available, are included in Fitch's review.

An organization's ability to generate resources from its operations sufficient to fund capital renewal and comfortably meet expected debt service obligations is a key rating consideration. Demonstrated stability or consistent improvement is viewed positively. Where variability is observed, Fitch's analysis seeks to identify the reasons for such changes and management's response to internal and external factors that may have resulted in negative movements. Although Fitch's approach considers non-operating revenues, performance analysis emphasizes core operating results.

For sectors such as healthcare and education, whose credit characteristics call for relatively large cash reserves to support investment-grade ratings, the level of balance sheet assets held as cash, or that can be expeditiously converted to cash, is a key credit factor. Unrestricted cash and investments are measured absolutely and relative to operating performance and debt levels, whether such assets are used to quickly pursue market opportunities, counter market threats, absorb unexpected declines in operating performance, generate income to support operations, or simply serve as a backup reserve to meet debt service requirements. In such sectors, higher allocations of investments to alternative asset classes, including private equity and hedge funds, could be viewed less favorably due to their potential for price volatility, lack of price transparency, and illiquidity.

The actual and expected debt a borrower carries — its amount, amortization, and servicing requirements — is a key component of the financial profile. While specific metrics vary depending on the sector, Fitch's analysis includes the computation of several ratios that describe the relative amount of debt used to capitalize the enterprise, the magnitude of debt service requirements in relation to the scope of the entity's operations, and the ability of operations to generate funds to meet debt service requirements.

Peer Comparisons

Fitch's analysis also considers how a borrower's financial profile matches up with the profiles of other entities with similar market, operational, financial, and credit characteristics. Depending on the sector, one or more analytical tools may be used to compare a borrower's actual or pro forma financial performance with peer group benchmarks or rating-specific median financial ratios.

Note on Sources

Fitch's analysis and rating decisions are based on relevant information available to its analysts. The sources of this information include the borrower and/or the obligor, the public domain, and, in the case of U.S. public finance, the financial advisor if a financial advisor has been engaged. This includes relevant, publicly available information on the borrower, such as financial statements and regulatory filings. The rating process may also incorporate information provided by other third-party sources. If this other third-party information is material to the rating, the specific rating action will disclose the relevant source.

Rating Methodology

Moody's Global
Corporate Finance

December 2009

U.S. Electric Generation & Transmission Cooperatives

Table of Contents:

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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). It replaces the U.S. Electric Generation & Transmission Cooperatives rating methodology that was published in May 2006. While based on the same core principles as the May 2006 methodology, this updated framework incorporates refinements that better reflect the more recent challenges facing G&T co-ops and the way Moody's applies its industry methodologies.

The goal of this report is to help issuers, investors and other interested market participants understand how Moody's assesses credit risk for companies in the U.S. G&T cooperative industry, and to explain how key quantitative and qualitative risk factors map to specific rating outcomes. Cooperative structures in other global industrial sectors may be subject to a number of other considerations and are not intended to be covered by this rating methodology. Our objective 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.

Moody's analysis of U.S. Electric G&T co-ops focuses on five key rating factors that are considered central to assigning ratings in this sector. The five rating factors encompass 14 elements (or sub-factors), each of which maps to specific letter ratings (see Appendix A). The number of sub-factors is reduced from 22 previously, largely reflecting a combination of several factors that were determined to be somewhat duplicative and to further simplify the rating methodology. The five key factors, which will be detailed in this report, are as follows:

1) Long-Term Wholesale Power Supply Contracts/Regulatory Status

2) Rate Flexibility

3) Member Profile

4) Financial Metrics

5) Size

In appendix B we have included a detailed rating grid for the 17 G&T co-ops included in this methodology. For each G&T co-op, the grid maps the key rating factors and sub-factors and shows the indicated alpha-numeric rating that is calculated from the overall combination of factors. We also include in appendix C discussions of "outliers" – G&T co-ops whose rating for a specific sub-factor differs by two or more broad rating categories from the actual rating, as G&T co-ops will not always map consistently to their overall rating on every sub-factor.

The purpose of the rating grid is to provide a reference tool that can be used to approximate credit profiles within the U.S. G&T co-op sector. The grid provides summarized guidance on the factors that Moody's believes are most important in assigning ratings to G&T co-ops. The grid is a summary rather than an exhaustive representation of every rating consideration and does not fit every business model equally well. In addition, many of our sub-factor mappings utilize historical financial or statistical data to illustrate the grid; however, our ratings also consider future expectations. Accordingly, the grid indicated rating is not expected to always match the actual rating of each G&T co-op. The text of the rating methodology provides insights on the key rating considerations that are not represented in the grid, as well as the circumstances in which the rating effect for a factor might be significantly different from the weight indicated in the grid.

Readers should also note that this rating methodology does not attempt to provide an exhaustive list of every factor that can be relevant to G&T co-op ratings. For example, our analysis covers factors that are common across all industries (such as debt leverage, liquidity, ownership, and legal structure) as well as factors that can be meaningful on a company specific basis (such as litigation, environmental or carbon exposure, capital expenditure needs, and customer and generation supply diversity).

This publication includes the following sections:

- **About the Rated Universe**: overview of the rated G&T co-op universe
- **About this Rating Methodology**: description of our rating methodology, including a detailed explanation of each of the key factors that drive ratings
- **Assumptions and Limitations**: Comments on the rating methodology's assumptions and limitations, including a discussion of other rating considerations that are not included in the grid

In addition to appendices A, B, and C, we also provide a brief industry overview (Appendix D) and a discussion of key rating issues for the G&T co-op sector over the intermediate term (Appendix E).

About The Rated Universe

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 small G&T co-ops. Each distribution cooperative sells power on a retail basis to its customers, who are the members that own the distribution co-op.

Moody's currently rates 17 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 17 has approximately $22.1 billion of debt outstanding and collectively owns/controls or purchases approximately 41,000 megawatts of electric generation capacity. All of these issuers are currently rated investment grade and all except one pending review for possible downgrade and three negative rating outlooks currently carry a stable rating outlook. The G&T cooperatives currently occupy the investment-grade, single-A to high-Baa range.

The credit profile of G&T co-ops on the whole has been stable. Over the past three years, we have added six G&T cooperatives to our rated universe, including Great River Energy, Golden Spread Electric Cooperative, Minnkota Power Cooperative, South Mississippi Power, Big Rivers Electric Corp., and PowerSouth Energy Cooperative, bringing the total to 17 in all. In addition to the six new ratings assigned, three issuers were downgraded, none were upgraded, and three rating outlooks were changed to negative from stable. We also assigned three new commercial paper program ratings for Basin Electric Power Cooperative (Prime-1), Arkansas Electric Cooperative (Prime-1) and Chugach Electric Association (Prime-2). Chugach Electric Association's senior unsecured long-term rating was downgraded in December 2008 to A3 from A2 in conjunction with assigning a Prime-2 short-term rating to its commercial paper program. The downgrade

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reflected concerns about potential loss of wholesale revenue, re-financing risk, external financing of higher capital expenditures, and the potential need for higher rates, which are subject to Alaska regulatory jurisdiction. In April 2009, Hoosier Energy's senior secured rating was downgraded to Baa1 from A3 and kept on review for possible further downgrade, primarily due to concerns about ongoing litigation with John Hancock Life Insurance Company related to an existing leveraged lease transaction and the potential effects on its liquidity. In September 2009, Oglethorpe Power's rating outlook was changed to negative from stable, primarily reflecting concerns about the costs associated with its plans to partner with others in constructing a new nuclear plant, among other factors. In October 2009, Dairyland Power's A2 Issuer Rating was downgraded to A3 and its rating outlook is negative. The downgrade primarily reflected concerns about weak metrics compared to its prior rating level and the negative outlook captures ongoing concerns that soft market power rates in the Midwest may delay potential opportunities for Dairyland to take advantage of its strong baseload capacity profile by engaging in third party sales. On November 11, 2009, Buckeye Power's rating outlook was changed to negative from stable primarily reflecting the recent weakening of its credit metrics but also our concern as to how long it may take for improvement in the metrics to materialize given the softness in the economy of the region and lower than expected power prices for excess energy sales.

Meanwhile, we note that G&T co-ops have conservatively managed their businesses during the past three years by:

- using long term supply planning to meet increasing demands for power from their member co-ops,
- tightly controlling operating costs,
- increasing rates when necessary, and
- carefully attending to liquidity.

The following table illustrates the distribution of ratings in the U.S. G&T cooperative sector.

Rated Issuers

Company	Current Rating [1]	Commercial Paper/ Short-term Rating	Outlook	Total Debt ($ Millions) (d)
Arkansas Electric Cooperative	A2 (a)	P-1	Stable	644 (e)
Associated Electric Cooperative	A1		Stable	1,478
Basin Electric Power Cooperative	A1	P-1	Stable	2,287
Big Rivers Electric Corp.	(P) Baa1		Stable	1,039 (f)
Buckeye Power Inc.	A1		Negative	1,318
Chugach Electric Association	A3 (b)	P-2	Stable	346
Dairyland Power Cooperative	A3 (c)		Negative	973
Georgia Transmission	A3	P-2	Stable	1,560
Golden Spread Electric Cooperative	A3 (c)		Stable	161
Great River Energy	A3		Stable	2,362
Hoosier Electric Power	Baa1		RUR ↓	1,138
Minnkota Power Cooperative	Baa1 (c)		Stable	258
Oglethorpe Power Corp.	A3	P-2	Negative	4,127
Old Dominion Electric Cooperative	A3		Stable	783
PowerSouth	Baa1 (c)		Stable	1,411
South Mississippi Electric Power Association	A3		Stable	758
Tri-State G&T Association	Baa1		Stable	1,880
Total Unadjusted Debt of Rated G&T Co-ops				**22,524**

Notes:
[1] Ratings are senior secured unless otherwise noted
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating
(d) As of June 30, 2009, unless otherwise indicated
(e) As of July 31, 2009
(f) As of December 31, 2008

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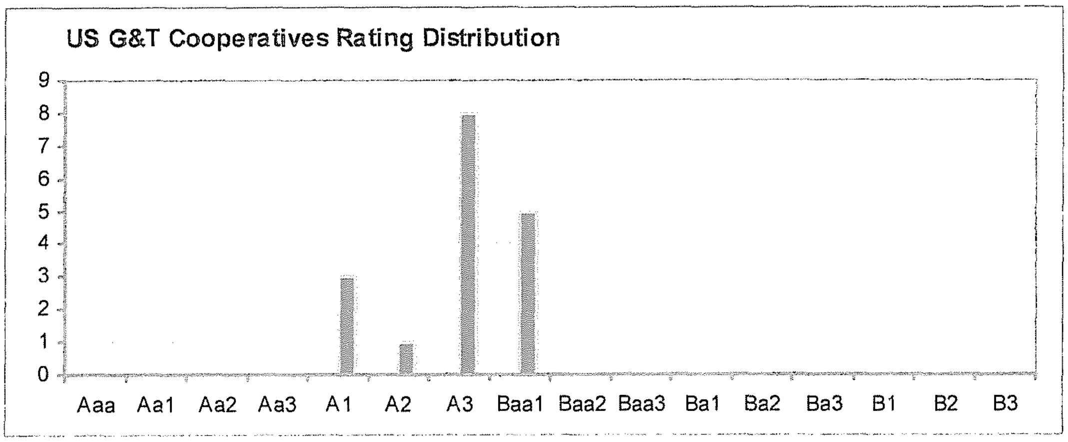

About This Rating Methodology

Moody's U.S. electric G&T cooperative rating methodology consists of the six sections listed below.

1) Identification 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.

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 of 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.

This rating methodology uses historical data in most instances based on information as of the latest fiscal year end; 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.

3) Mapping Factors to Rating Categories

After identifying the measurement criteria for each rating sub-factor, we provide a chart that maps the rating sub-factors to specific alpha rating categories (Aaa, Aa, A, Baa, Ba, or B). In this report, we provide a range or description for each of the measurement criteria. For example, we specify what level of FFO/Interest is generally acceptable for an A credit versus a Baa credit, etc.

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 indicated rating for each broad factor. We also highlight companies (Appendix C) whose grid indicated performance on a specific factor or sub-factor is higher or lower by two or more broad rating categories from the actual rating. A company whose performance is two or more broad rating categories higher than its actual rating is deemed a positive outlier for that factor. A company whose performance is two or more broad rating categories below is deemed a negative outlier. We also discuss the general reasons for such outliers within a given factor or sub-factor.

5) Discussion of Assumptions, Limitations and Other Rating Considerations

This section discusses limitations in the use of the grid to map against actual ratings as well as limitations and key assumptions that pertain to the overall rating methodology.

6) Determining the Overall Grid-Indicated Rating

To determine the overall grid-indicated rating, the indicated rating category for each sub-factor is converted into a numeric value based upon the scale below.

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-average factor score is then mapped back to an alpha-numeric rating based on the ranges in the grid below.

Composite Rating

Indicated Rating	Aggregate Weighted Factor Score
Aaa	$0.0 \le x < 1.5$
Aa1	$1.5 \le x < 2.5$
Aa2	$2.5 \le x < 3.5$
Aa3	$3.5 \le x < 4.5$
A1	$4.5 \le x < 5.5$
A2	$5.5 \le x < 6.5$
A3	$6.5 \le x < 7.5$
Baa1	$7.5 \le x < 8.5$
Baa2	$8.5 \le x < 9.5$
Baa3	$9.5 \le x < 10.5$
Ba1	$10.5 \le x < 11.5$
Ba2	$11.5 \le x < 12.5$
Ba3	$12.5 \le x < 13.5$
B1	$13.5 \le x < 14.5$
B2	$14.5 \le x \le 15.0$

For example, an issuer with a composite weighted factor score of 8.2 would have a Baa1 grid-indicated rating. We use a similar procedure to derive the grid-indicated ratings in the tables embedded in the discussion of each of the five broad rating factors.

The Key Rating 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 Profile
- Financial Metrics
- Size

Factor 1: Long-Term Wholesale Power Supply Contracts/Regulatory Status

Why it Matters

Against a backdrop of significant spending for capital projects, volatile fuel costs and looming carbon legislation and related costs, the strength of the wholesale power contracts and the predictable revenue stream they provide for G&T co-ops remains 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 have combined regulatory status of the G&T and its distribution member/owners, previously considered in Factors 2 and 3, respectively, into Factor 1. In doing so, we also increased the weighting for Factor 1 to 20% from 15% previously.

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.

How We Measure 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.

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	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 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 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 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 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 Relationships

Factor 2: Rate Flexibility

Why it Matters

Prices for fuels used to generate electricity are unregulated in the U.S. and have been subject to dramatic fluctuation over the last couple of years. 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 forthcoming related to carbon emissions along with any capital investment associated with construction of new plants (especially nuclear powered), among other factors.

We note that the number of sub-factors in Factor 2 have been reduced to four from six previously, as regulatory status was combined into Factor 1 and rate competitiveness was combined into Rate Shock Exposure. In doing so, each of the remaining four sub-factors in Factor 2 have been assigned a 5% weighting.

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 coop'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 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 coops. 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 may face increased 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.

Potential for Rate Shock Exposure: In many respects, the potential for rate shock exposure is linked to rate competitiveness, so we have combined our consideration of rate competitiveness into this sub-factor as part of this updated methodology. 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, member unrest could lead to contract challenges or possible withdrawal from the co-op.

How We Measure 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 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 periods obviously 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.

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. In addition, we have expanded our measurement criteria for this sub-factor to also consider the G&T's reliance on coal and other carbon emitting generating resources. Those G&Ts with a high reliance on such resources will be scored lower on this sub-factor due to their vulnerability to potential carbon legislation 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&Ts 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.

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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 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 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 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 ex as % Net 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 10% reliance on purchased power and less than 10% 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 Profile

Why it Matters

Assessing the member 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 are concerned about the overall creditworthiness of the members. Although we still seek information about the members' expected consolidated demand growth and their consolidated

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assets, to further simplify this methodology, these two sub-factors previously included in the May 2006 methodology are not specifically incorporated into this update. The following two sub-factors, which are weighted at 5% each, continue to 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.

How We Measure 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 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' debt 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. Most of the G&T co-ops that are covered by the methodology fall into the Baa or A category with consolidated member equity to capitalization in the range of 25% to 50%.

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

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. In the interest of reducing the number of sub-factors and simplifying this methodology, we dropped the net operating margin metric from

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Factor 4 as part of the update of this methodology since the net margin component of the coverage calculations already captures the operating profit. In doing so, we also adjusted the weighting of the remaining five sub-factors in Factor 4 to retain the overall 40% weighting for financial metrics. Nevertheless, we continue to highlight that while 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 still 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.

How We Measure It for the Grid

See Moody's Ratings Methodology: Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations - Part 1, July 2005. The ratios used as a basis for this methodology are three year averages of calculations using the latest three fiscal year end statements, including 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)

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

Why it Matters

Size, together with Factor 3, Member Profile, has the lowest weighting of the five key factors because it tends to be less important for entities, such as G&T coops, that are subject to limited competition. As part of the update to this methodology, we have eliminated two sub-factors from Factor 5 (i.e. megawatts owned/purchased and revenues) because we found that they were somewhat duplicative and wanted to further simplify the methodology. Nevertheless, 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.

How We Measure 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.

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	2 ≤ x < 5	1 ≤ x < 2	0.4 ≤ x < 1	0.3 ≤ x < 0.4	x < 0.3	5%

Rating Methodology Assumptions and Limitations, and Other Rating Considerations

The rating methodology grid incorporates a trade-off between simplicity that enhances transparency and greater complexity that would enable the grid to map more closely to actual ratings. The five rating factors in the grid do not constitute an exhaustive treatment of all the considerations that are important for ratings of

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G&T co-ops. 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. In other cases, we estimate future results based upon past performance, industry trends, demand and price outlook, peer actions and other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

In choosing the metrics for this rating methodology grid, we did not include certain important factors that are common to all companies in any industry, such as the quality and experience of management, assessments of corporate governance and quality of financial reporting and information disclosure. The assessment of these factors can be highly subjective and ranking them by rating category in a grid would, in some cases, suggest too much precision in the relative ranking of particular issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that only have a meaningful effect in differentiating credit quality in some cases. Such factors include environmental obligations, nuclear decommissioning trust obligations, industrial customer concentrations, financial controls, and the political and economic environment, including possible government interference.

As an example, industrial exposure can vary considerably across the rated universe and this customer class can sometimes be subjected to more cyclicality in terms of energy consumption, which cannot be consistently represented in a simple grid format.

Actual ratings assigned may also reflect circumstances in which the weighting of a particular factor will be different from the weighting suggested by the grid. For example, Factors 1 and 2 address long term wholesale power contracts/regulatory status and rate flexibility, respectively; however, there may be instances where the effects of a G&T cooperative's financial metrics will be given greater consideration in an assigned rating than what is indicated by the weighting in the grid.

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. For consistency in drawing our conclusions, we rely upon an implied senior secured rating (i.e. the implied senior most rating) for the six G&T cooperatives who have senior secured debt in their respective capital structures but whose current ratings are either senior unsecured Issuer Ratings or whose current ratings apply to a class of debt junior to the senior secured debt. The methodology grid-indicated ratings map to Moody's current assigned or implied senior most ratings as follows (See Appendix B for the details):

Eight cooperatives or 47% have indicated ratings that match the Moody's actual (or implied) senior most rating,

six cooperatives or 35% have indicated ratings within one-notch of Moody's actual (or implied) senior most rating, and

three cooperatives or 18% have an indicated rating within two-notches of Moody's actual (or implied) senior most rating.

APPENDIX A: U. S. Electric G&T Cooperative 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	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 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 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 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 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 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 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 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 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 10% reliance on purchased power and less than 10% 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%

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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	2 ≤ x < 5	1 ≤ x < 2	0.4 ≤ x < 1	0.3 ≤ x < 0.4	x < 0.3	5%

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APPENDIX B: Methodology Grid-Indicated Ratings

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	
	Current Rating [1]	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	A2 (a)	Stable	A3	Baa	A	Aa	Ba	Ba	A	Baa	A	Baa	A	Aa	Aa	A	Baa
Associated Electric	A1	Stable	A2	Aa	Aa	Aa	Baa	Ba	A	A	A	A	A	A	Baa	Aa	A
Basin Electric Power	A1	Stable	A1	Aa	Aa	Aa	B	Ba	Ba	Baa	Aaa	Aa	Aa	Aa	A	A	Aa
Big Rivers Electric Corp.	(P) Baa1	Stable	Baa2	Aa	Baa	B	A	B	B	Baa	Aa	Aa	Baa	Baa	B	Baa	Baa
Buckeye Power	A1	Negative	A1	Aa	Aa	Aa	A	B	A	A	A	A	A	Aa	A	Baa	A
Chugach Electric Assoc.	A3 (b)	Stable	A3	Baa	A	Aa	Ba	B	A	Baa	A	Aa	Aa	Aa	A	B	Baa
Dairyland Power	A3 (c)	Negative	Baa1	Aa	Aa	Aa	A	B	A	Baa	Ba	Ba	Baa	Baa	Baa	Baa	Baa
Georgia Transmission	A3	Stable	A2	Aa	Aa	Aa	Baa	Aa	A	Baa	Baa	Ba	Baa	Baa	Baa	Aa	A
Golden Spread Electric	A3 (c)	Stable	A2	A	Aa	B	Ba	B	A	Baa	Aaa	Aaa	Aaa	Aaa	Aaa	Baa	B
Great River Energy	A3	Stable	A3	A	Aa	Baa	Ba	B	A	Baa	A	Baa	A	A	Baa	A	Aa
Hoosier Electric Power	Baa1	RUR ↓	A2	Aa	Baa	A	Baa	B	A	Aa	A	A	A	Aa	Baa	Baa	Baa
Minnkota Power	Baa1 (c)	Stable	A3	Aa	Aa	A	Ba	B	A	Baa	Baa	Baa	Baa	A	Aa	Ba	B
Oglethorpe Power Corp.	A3	Negative	Baa1	A	A	Aa	Ba	Baa	A	Baa	Ba	Ba	Baa	Baa	Baa	Aa	Aa
Old Dominion Electric	A3	Stable	A2	Aa	A	Ba	A	Baa	A	Baa	A	Aa	A	A	A	Baa	A
PowerSouth	Baa1 (c)	Stable	A3	Aa	Aa	Baa	A	B	A	Baa	A	A	Baa	A	Baa	Baa	A
South Mississippi	A3	Stable	A3	Aa	Aa	B	Ba	Ba	A	A	A	Baa	A	A	Baa	Baa	Baa
Tri-State G&T Assoc.	Baa1	Stable	A3	Aa	A	Baa	Ba	B	Ba	Baa	Aaa	Baa	A	Aa	Baa	A	Aa

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APPENDIX C: Observations and Outliers for Grid Mapping

Factor 1: Ratings Mapping

The following table details the mapping for the Nature of Long-Term Wholesale Power Supply Contracts/Regulatory Status factor:

FACTOR 1 (20%)
Nature of Long-Term Wholesale Power Supply Contracts and Regulatory Status

Negative Outlier
Positive Outlier

G&T Co-op	Current Rating [1]	Outlook	% of Member Load Served	Indicated Rating
Arkansas Electric	A2 (a)	Stable	91%	Baa
Associated Electric	A1	Stable	100%	Aa
Basin Electric Power	A1	Stable	100%	Aa
Big Rivers Electric Corp.	(P) Baa1	Stable	100%	Aa
Buckeye Power	A1	Negative	100%	Aa
Chugach Electric Assoc.	A3 (b)	Stable	94%	Baa
Dairyland Power	A3 (c)	Negative	100%	Aa
Georgia Transmission	A3	Stable	100%	Aa
Golden Spread Electric	A3 (c)	Stable	90%	A
Great River Energy	A3	Stable	98%	A
Hoosier Electric Power	Baa1	RUR ↓	100%	Aa
Minnkota Power	Baa1 (c)	Stable	100%	Aa
Oglethorpe Power Corp.	A3	Negative	65%	A
Old Dominion Electric	A3	Stable	100%	Aa
PowerSouth	Baa1 (c)	Stable	100%	Aa
South Mississippi	A3	Stable	100%	Aa
Tri-State G&T Assoc.	Baa1	Stable	100%	Aa

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

Factor 1: Observations and Outliers

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. All of the rated G&T co-ops score quite well with indicated ratings of Aa , A, or Baa. Two of the five positive outliers are directly attributable to comparison of the indicated rating for the sub-factor against an actual senior unsecured Issuer Rating and would not be outliers if compared to an implied senior secured rating one notch higher than the Issuer Rating. 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 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 Ba indicated rating for Factor 1. This strict interpretation results from the fact that OPC's owned resources are currently providing only about 65% of its members' power requirements. 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 are not unduly concerned 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 A more appropriately 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 94% of its sales made to customers includes not only the 39% of energy sales made under wholesale power contracts, but also the 55% of energy sales made directly to retail customers under the tariff and certificated service territory in the state of Alaska. Moody's views direct retail revenues to commercial and residential customers to be of equal, if not somewhat better quality, than wholesale revenues derived from sales to member co-ops.

Factor 2: Ratings Mapping

The following table details the mapping for the Rate Flexibility factor:

Factor 2 (20%)
Rate Flexibility

Negative Outlier
Positive Outlier

G&T Co-op	Current Rating [1]	Outlook	Bd. Involve/ Adj. Mech.	Purchased Power/Total MWh Sales	Indicated Rating	New Build Exposure	Indicated Rating	Carbon Exposure	Rate Shock Exposure Indicated Rating
Arkansas Electric	A2 (a)	Stable	A	15%	Aa	107%	Ba	76%	Ba
Associated Electric	A1	Stable	Aa	12%	Aa	59%	Baa	80%	Ba
Basin Electric Power	A1	Stable	Aa	17%	Aa	152%	B	82%	Ba
Big Rivers Electric Corp.	(P) Baa1	Stable	Baa	101%	B	33%	A	89%	B
Buckeye Power	A1	Negative	Aa	8%	Aa	44%	A	90%	B
Chugach Electric Assoc.	A3 (b)	Stable	A	17%	Aa	78%	Ba	90%	B
Dairyland Power	A3 (c)	Negative	Aa	8%	Aa	42%	A	90%	B
Georgia Transmission	A3	Stable	Aa	N/A	N/A	51%	Baa	N/A	Aa
Golden Spread Electric	A3 (c)	Stable	Aa	85%	B	84%	Ba	100%	B
Great River Energy	A3	Stable	Aa	31%	Baa	76%	Ba	98%	B
Hoosier Electric Power	Baa1	RUR ↓	Baa	27%	A	64%	Baa	100%	B
Minnkota Power	Baa1 (c)	Stable	Aa	27%	A	106%	Ba	100%	B
Oglethorpe Power Corp	A3	Negative	A	8%	Aa	115%	Ba	55%	Baa
Old Dominion Electric	A3	Stable	A	54%	Ba	29%	A	67%	Baa
PowerSouth	Baa1 (c)	Stable	Aa	38%	Baa	29%	A	100%	B
South Mississippi	A3	Stable	Aa	63%	B	76%	Ba	81%	Ba
Tri-State G&T Assoc.	Baa1	Stable	A	32%	Baa	83%	Ba	91%	B

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

Factor 2: Observations and Outliers

Factor 2 contains the most outliers of any of the five key Factors, the substantial majority of which are negative outliers. In particular, over 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 seven negative outliers for the New Build Exposure sub-factor, reflecting the growing need for generating capacity and transmission infrastructure for those G&Ts as they have either grown into

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what excess capacity they previously had or are projecting growth in demand that exceeds current capabilities. In particular, Oglethorpe's New Build Exposure relates to its plans to participate in construction of a new nuclear plant, which contributed to the recent change in its rating outlook to negative from stable.

Big Rivers, Old Dominion, Golden Spread, and South Mississippi are all negative outliers for the sub-factor measuring Purchased Power as a Percentage of Sales. We anticipate that Big Rivers' outlier status will improve prospectively following the recently completed unwind transaction which re-establishes its direct rights to power produced from its generation assets previously leased to LG&E. 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.

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 low rates for so many of the G&Ts make it more likely that the members will accept what in many instances will be the continuation of significant expected rate increases over the next several years even after a series of rate increases already implemented over the past few years.

The two positive outliers for the sub-factor relating to Board Involvement/Rate Adjustment Mechanisms are directly attributable to comparison of the indicated rating for the sub-factor against an actual senior unsecured Issuer Rating and would not be outliers if compared to an implied senior secured rating one notch higher than the Issuer Rating.

Factor 3: Ratings Mapping

The following table details the mapping for the Member Profile factor:

Factor 3 (10%) Member / Owner Profile — Negative Outlier / Positive Outlier

G&T Co-op	Current Rating [1]	Outlook	Res. Sales/ Total Sales (%)	Indicated Rating	Mbrs. Equity / Capitalization (%)	Indicated Rating
Arkansas Electric	A2 (a)	Stable	50%	A	39%	Baa
Associated Electric	A1	Stable	71%	A	50%	A
Basin Electric Power	A1	Stable	36%	Ba	35%	Baa
Big Rivers Electric Corp.	(P) Baa1	Stable	18%	B	34%	Baa
Buckeye Power	A1	Negative	60%	A	50%	A
Chugach Electric Assoc.	A3 (b)	Stable	51%	A	43%	Baa
Dairyland Power	A3 (c)	Negative	70%	A	46%	Baa
Georgia Transmission	A3	Stable	70%	A	43%	Baa
Golden Spread Electric	A3 (c)	Stable	58%	A	45%	Baa
Great River Energy	A3	Stable	57%	A	45%	Baa
Hoosier Electric Power	Baa1	RUR ↓	65%	A	61%	Aa
Minnkota Power	Baa1 (c)	Stable	62%	A	45%	Baa
Oglethorpe Power Corp.	A3	Negative	68%	A	43%	Baa
Old Dominion Electric	A3	Stable	63%	A	36%	Baa
PowerSouth	Baa1 (c)	Stable	69%	A	47%	Baa
South Mississippi	A3	Stable	65%	A	53%	A
Tri-State G&T Assoc.	Baa1	Stable	33%	Ba	49%	Baa

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

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Factor 3: Observations and Outliers

Indicated ratings for Factor 3 map reasonably well to the actual ratings for each of the 17 rated G&T co-ops in this methodology, with just one positive outlier and two negative outliers.

Basin Electric Power Cooperative and Big Rivers are negative outliers for residential sales as a percentage of total sales to retail customers. In Basin Electric's case this is primarily because of the relatively high percentage of sales that Basin makes to non-members due to excess generation capacity. Importantly, off-system sales to non-members have served Basin well through the years and has enabled Basin to avoid member rate increases that otherwise would have been needed to meet financial covenants. Basin's demand growth from its members in recent years has enabled it to grow into some of its excess capacity. As Basin's sales to members continue to increase and off-system sales decline, the percentage of residential sales should continue to increase as it has over the past few years, albeit remaining an outlier. Big Rivers' negative outlier status is directly attributable to the high concentration of sales that its largest member/owner, Kenergy, makes to two aluminum smelters.

The lone positive outlier for Factor 3 relates to Hoosier Electric's members' consolidated equity as a percentage of equity. This status is more a function of the recent downgrade of Hoosier's rating than any noteworthy strengthening of the equity portion of total capitalization.

Factor 4: Ratings Mapping

The following table details the mapping for the Financial Metrics factor:

Factor 4 (40%)
3-Year Average G&T Financial Metrics

Negative Outlier
Positive Outlier

G&T Co-op	Current Rating [1]	Outlook	TIER	Indicated Rating	DSC	Indicated Rating	FFO / Debt	Indicated Rating	FFO / Interest	Indicated Rating	Equity/ Total Cap.	Indicated Rating
Arkansas Electric	A2 (a)	Stable	1.31x	A	1.19x	Baa	9%	A	2.6x	Aa	40%	Aa
Associated Electric	A1	Stable	1.29x	A	1.27x	A	6%	A	2.1x	A	20%	Baa
Basin Electric Power	A1	Stable	2.23x	Aaa	1.50x	Aa	10%	Aa	3.0x	Aa	30%	A
Big Rivers Electric Corp.	(P) Baa1	Stable	1.51x	Aa	1.54x	Aa	6%	Baa	1.9x	Baa	-18%	B
Buckeye Power	A1	Negative	1.36x	A	1.36x	A	7%	A	2.6x	Aa	26%	A
Chugach Electric Assoc.	A3 (b)	Stable	1.25x	A	1.84x	Aa	11%	Aa	2.6x	Aa	29%	A
Dairyland Power	A3 (c)	Negative	1.00x	Ba	1.04x	Ba	3%	Baa	1.6x	Baa	12%	Baa
Georgia Transmission	A3	Stable	1.19x	Baa	1.09x	Ba	4%	Baa	1.9x	Baa	10%	Baa
Golden Spread Electric	A3 (c)	Stable	5.02x	Aaa	3.93x	Aaa	31%	Aaa	5.7x	Aaa	51%	Aaa
Great River Energy	A3	Stable	1.34x	A	1.12x	Baa	7%	A	2.4x	A	13%	Baa
Hoosier Electric Power	Baa1	RUR ↓	1.40x	A	1.37x	A	8%	A	2.5x	Aa	13%	Baa
Minnkota Power	Baa1 (c)	Stable	1.17x	Baa	1.11x	Baa	5%	Baa	2.0x	A	36%	Aa
Oglethorpe Power Corp.	A3	Negative	1.07x	Ba	1.09x	Ba	6%	Baa	1.9x	Baa	11%	Baa
Old Dominion Electric	A3	Stable	1.28x	A	1.46x	Aa	7%	A	2.2x	A	24%	A
PowerSouth	Baa1 (c)	Stable	1.34x	A	1.20x	A	5%	Baa	2.1x	A	10%	Baa
South Mississippi	A3	Stable	1.36x	A	1.18x	Baa	7%	A	2.3x	A	14%	Baa
Tri-State G&T Assoc.	Baa1	Stable	1.72x	Aaa	1.13x	Baa	8%	A	2.8x	Aa	15%	Baa

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

Factor 4: Observations and Outliers

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

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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 positive outlier status is evident. Most notably, Golden Spread is a positive outlier for all its key metrics, reflecting conservative financing strategies through the years. We expect that this situation will begin to change over the next several years as Golden Spread begins to rely on debt financing to fund its investment in new generation capacity. Other positive outliers for various metrics include Basin Electric, Big Rivers, Hoosier Energy, Minnkota Power, and Tri-State G&T Association. The strength of these scores helps balance the weaker scores these G&Ts have in Factor 2, especially as it relates to Rate Shock Exposure and New Build Exposure.

Georgia Transmission Corporation, Oglethorpe Power Corporation, and Dairyland Power are negative outliers on TIER and/or DSC, reflecting greater acceptance by their respective management and boards to manage results close to the minimum required levels contained in their debt indentures. Big Rivers is a negative outlier for equity as a percentage of Total Capitalization, reflecting its negative net worth that has prevailed for many years following approval of its plan of reorganization when it emerged from bankruptcy proceedings. The negative outlier status will eventually become a moot point as the G&T's net worth turns substantially positive following completion of the company's unwind transaction.

Factor 5: Ratings Mapping

The following table details the mapping for the Size factor:

Factor 5 (10%)
G&T Size

Negative Outlier
Positive Outlier

G&T Co-op	Current Rating [1]	Outlook	Megawatt Hour Sales (Millions)	Indicated Rating	Net PP&E ($ Billions)	Indicated Rating
Arkansas Electric	A2 (a)	Stable	13.2	A	$0.80	Baa
Associated Electric	A1	Stable	23.4	Aa	$1.69	A
Basin Electric Power	A1	Stable	19.5	A	$2.41	Aa
Big Rivers Electric Corp.	(P) Baa1	Stable	5.2	Baa	$0.91	Baa
Buckeye Power	A1	Negative	9.1	Baa	$1.22	A
Chugach Electric Assoc.	A3 (b)	Stable	2.8	B	$0.46	Baa
Dairyland Power	A3 (c)	Negative	6.7	Baa	$0.97	Baa
Georgia Transmission	A3	Stable	N/A	N/A	$1.49	A
Golden Spread Electric	A3 (c)	Stable	7.6	Baa	$0.20	B
Great River Energy	A3	Stable	15.0	A	$2.08	Aa
Hoosier Electric Power	Baa1	RUR ↓	10.9	Baa	$0.80	Baa
Minnkota Power	Baa1 (c)	Stable	4.9	Ba	$0.24	B
Oglethorpe Power Corp.	A3	Negative	23.3	Aa	$3.64	Aa
Old Dominion Electric	A3	Stable	10.0	Baa	$1.02	A
PowerSouth	Baa1 (c)	Stable	9.0	Baa	$1.23	A
South Mississippi	A3	Stable	9.9	Baa	$0.79	Baa
Tri-State G&T Assoc.	Baa1	Stable	19.0	A	$2.57	Aa

[1] Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating; No secured debt in capital structure
(c) Issuer Rating

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Factor 5: Observations and Outliers

Even the largest G&T co-op, Oglethorpe Power Corporation, is considered to be relatively small by investor-owned electric utility standards, so it is not surprising that there is only one positive outlier in Key Factor 5. The three negative outliers are Chugach Electric, Golden Spread, and Minnkota, reflecting smaller than average size for the rated universe.

There are offsetting considerations in these three cases that merit comment. 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 concern about its small size. In the case of Golden Spread and Minnkota, there are large capital programs under way, which over time may mitigate their respective negative outlier status for net property, plant and equipment.

APPENDIX D: 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 A2 average (senior most) rating assigned for G&T co-ops equals the average rating for municipal or public power entities, and is two notches higher than the Baa1 average rating for (IOUs). 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.

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	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	Defaults have been extremely rare
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 Power Agencies

Moody's rates approximately $35 billion of bonds issued by Joint Power Agencies (JPAs), which have 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 JPAs serve small rural communities in the U.S. A significant difference between the two is the greater ability of JPAs to issue low cost tax-exempt debt, although cooperatives may borrow at below market rates through the federal Rural Utilities Service.

Since the 1970's, groups of city-owned electric utilities have established JPAs to pool resources to finance the construction of new generation facilities or to jointly purchase electric power supply. Participating members of

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JPAs 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 JPAs. The power sales agreements are structured to have the same term as the debt issue.

JPAs have unregulated rate-setting authority and their municipal utility participants can recover costs by independently raising retail rates. The current median municipal scale rating of JPAs is A2. After a period of low debt issuance, JPAs have accelerated the pace of borrowing 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 key rating factors Moody's considers for JPA ratings include municipal utility participant credit quality, pricing power and market position, as well as governance structure and management abilities of these public sector organizations. Financial position, capital spending, and structural features of borrowing instruments are also important. Key questions embedded in our analysis of these factors are:

- How economic are power sales contracts relative to competitors?
- How are the power supply contracts structured, and what are the bond security provisions?
- 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 do JPAs manage their balance sheet and plan for capital spending in order to position the JPA to meet future demand growth and competition?

The price of power the JPA supplies, and the reliability of the power supply, are among the most significant drivers of JPA credit ratings given the importance of these factors to their municipal utility participants. JPAs with the highest cost power are generally rated lower than those with more competitive price structures.

APPENDIX - E

Key Rating Issues over the Intermediate Term

Global Climate Change and Environmental Awareness

There have been significant increases in environmental expenditure estimates among G&T co-ops with significant coal fired generation in recent years as policymakers have mandated pollution control measures and emissions limitations in response to public concerns over carbon. These expenditures are likely to continue to increase with the imposition of new and sometimes uncertain requirements with respect to carbon emissions. G&T co-ops may have to implement substantial additional reductions in power plant emissions and could experience progressively higher capital expenditures over the next decade. In the U.S., the planned construction of several new coal plants have been cancelled or at least delayed as a result of opposition from regulators, political leaders, and the public or because cheaper alternatives appeared more compelling due to the significant increase in coal plant construction costs.

Large Capital Expenditures and Rising Costs for New Generation and Transmission

In order to meet rising electricity demand as the U.S. slowly emerges from a recession, many G&T co-ops intend to purchase generating plants or plan to build additional peaking and base load generating capacity, while correspondingly taking steps to upgrade and/or add to transmission infrastructure. As of end of 2008, the aggregate net property plant and equipment for rated G&T co-ops was approximately $12 billion with about an additional $8 billion of capital expenditures planned over the next five years. For those G&Ts that elect to participate in the construction of large, highly capital intensive 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.

Larger Rate Increases May Test Members' Willingness To Raise Rates

After a period of rate stability or rate decline throughout the 1980's and 1990's, G&T co-ops are increasing the wholesale rates that they charge their members. The impact of higher prices for fuel and purchased power has not been fully experienced by member co-ops because some purchase contracts have not yet been reset to new market levels.

G&Ts will likely impose large rate increases on co-op members when the G&T's power purchase contracts expire if that coincides with a period of rising market prices or when a large new generating plant is being constructed. Very large increases could test the willingness of members to pay higher rates.

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, most G&T co-ops try to pursue 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 commodity cost volatility and capital spending requirements, as well as more expensive insurance and pension benefits, we do not expect that the rates that G&T co-ops charge their members will be less competitive than those charged by other power providers.

Reliance on Low-Cost Loans from U.S. Government Sponsored Agencies

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.

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 (CFC; A1 senior secured; stable outlook) and CoBank, and local commercial banking institutions.

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. However, the RUS requires that some of its borrowers obtain at least 30% of their financing from other sources. Larger G&T co-ops, such as those in Moody's rated universe, have sought to increase financial flexibility by accessing the capital markets. We anticipate that more G&T co-ops will do likewise in the future given the RUS decision not to lend for the construction of base load coal and nuclear plants.

Moody's Related Research

Industry Outlooks:

- U.S Regulated Electric Utilities, Six-Month Update, July 2009 (118776)
- U. S. Investor-Owned Electric Utility Sector, January 2009 (113690)
- EMEA Electric and Gas Utilities, November 2008 (112344)
- North American Natural Gas Transmission & Distribution, March 2009 (115150)

Rating Methodologies:

- Regulated Electric and Gas Utilities (118481)
- Unregulated Utilities and Power Companies, August 2009 (118508)
- Regulated Electric and Gas Networks, August 2009 (118786)
- Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations - Part I, July 2005 (93570)

Special Comments:

- Credit Roadmap for Energy Utilities and Power Companies in the Americas, March 2009 (115514)
- Carbon Risks Becoming More Imminent for U.S. Electric Utility Sector (115175)
- New Nuclear Generation: Ratings Pressure Increasing (117883)

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.

U.S. Electric Generation & Transmission Cooperatives

Report Number: 121189

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Item 19) ***Referencing Big Rivers' response to AG 1-58: State the basis for the belief "the power market will steadily increase" and that it will "reasonably rebound."***

Response) Big Rivers believes coal generating units that are not currently in compliance with the proposed MATS standards, and those that do not have plans to come into compliance, will likely be coming offline by April 2015. While some regulated utilities have chosen to build combined cycle gas generation to replace those generating units, most merchant companies will decommission their coal plants and not replace that supply. This decline in supply should have a positive impact on wholesale market prices, but the extent to which it may have this effect is unknown at this time. Likewise, an improvement in the national economy and/or an increase in natural gas pricing will also have positive impacts on the wholesale price of power, if they occur. Big Rivers believes a combination of these factors will likely occur to cause a steady increase in the wholesale market over the next few years.

Witness) Robert W. Berry

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Item 20) ***Referencing Big Rivers' response to AG 1-67(a), provide a copy of the cited "generally accepted depreciation study procedures" used by the utility industry and used by Burns & McDonnell in their depreciation study.***

Response) There is no single book, document, or manual that incorporates all the generally accepted depreciation study procedures widely used by the utility industry. Different (yet reasonable) methods and procedures can be approved by different state commissions and the Rural Utilities Service. Burns & McDonnell's study was performed in accordance with Rural Utilities Service Bulletin 1767B-1 and utilized the same methodology as the prior depreciation study that was approved by the Kentucky Public Service Commission in Big Rivers' last rate case, Case No. 2011-00036. Individual requirements and procedures will vary based on each cooperative's specific depreciation situation and what the Rural Utilities Service and different state regulatory commissions require and approve.

Witness) Ted J. Kelly

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Item 21) ***Referencing Big Rivers' response to AG 1-68: Please provide specific references to documents in Case No. 2011-00036 which identify these "process issues" and their resolution.***

Response) See Main Brief of KIUC filed August 11, 2011, pp. 18-19, and Post-Hearing Brief of Big Rivers Electric Corporation filed August 11, 2011, pp. 33.

Witness) John Wolfram

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Item 22) *Referencing Big Rivers' response to AG 1-72: The response to AG 1-72 and the related attachment appears to show $198,000 of legal rate case costs ($174,000 for Sullivan, Mountjoy and $24,000 for Orrick, Herrington) have been included in the forecasted test period August 31, 2014, and the response to AG 1-73 shows a different amount of legal rate case costs of $975,700 ($454,620 for Sullivan, Mountjoy and $521,080 for Dinsmore&Shohl) included in total rate case costs of $1,585,977 (which appears to agree to the response to PSC 1-54). And the 36-month total of rate case expense of $1,585,977 is addressed at Ms. Speed's testimony at Tab 68, page 19. Address the following:*

a. *Please reconcile the response to AG 1-72 legal expense of $198,000 versus AG1-73 and PSC1-54 legal expense of $975,700 (as well as reconciling the different amounts shown for attorneys Sullivan, Mountjoy), and identify which amount is included in the forecasted test period August 31, 2014 as rate case expense (or explain and identify the portion of these legal expenses that are not included in rate case expense, but are included in the forecasted test period as other professional fees that are not amortized).*
b. *Explain if these amounts above represent the 3-year amortized portion, or the total amount before amortization over 3 years.*
c. *Explain how "rate case legal fees" versus "other legal fees" are identified and reflected in the forecasted test period and provide supporting documentation.*
d. *In regards to (a) above, Ms. Speed's testimony at Tab 68, page 19, line 10 identifies total rate case costs of $1,585,980 (to be amortized over 36*

months), although the response to PSC 1-54 and Ms. Speed's testimony is susceptible to the interpretation that the entire amount of $1,585,980 is included in the forecasted test period August 31, 2014 (instead of just one-third of the 36 month amortization). Please clarify and provide the total and amortized portion of costs included in the forecasted test period, for all legal fees and other professional costs.

e. AG1-72(a) requested an explanation of the services for each attorney which was not provided with the response (although BREC objected to providing copies of legal invoices at AG1-72(b), it does not appear to have objected to explaining the services provided by attorneys). Regarding forecasted test period legal fees of $198,000 at AG 1-72 and $975,700 at AG 1-73 and PSC 1-54, explain the purpose of these legal costs and provide supporting documentation. For example, provide: (i) the amount of these legal fees related to litigating the rate case; (ii) legal costs for other issues related to the rate case but not for litigating the rate case; (iii) legal fees related to other Kentucky regulatory issues and not this rate case (identify by case number); legal costs related to the status of the smelters; and (v) other legal costs for corporate matters unrelated to the rate case.

Response)

a. As stated in the title of the attachment to AG 1-72, the $198,000 represents forecasted payments to outside attorneys and legal representation during the forecasted test period, excluding expenses associated with this rate case proceeding. The $454,620 and $521,080 ($975,700 total) included in the attachments to PSC 1-54(b) and AG 1-73(a) for Sullivan, Mountjoy, Stainback & Miller, P.S.C. and Dinsmore & Shohl LLP, respectively, represent the total projected expenses for services performed by each of these firms in connection with this rate case proceeding.

   The amount provided in PSC 1-54(b), for projected costs associated with Sullivan, Mountjoy, Stainback& Miller P.S.C. related to this rate case proceeding, agrees to the amount provided in AG 1-73(a) ($454,620). Details regarding the amount of rate case expenses included in the forecasted test period ending August 31, 2014 are provided in Big Rivers' Application at Tab 52.

b. The $198,000 included in the attachment to AG 1-72 represents projected expenses for outside attorneys and legal representation during the forecasted test period, excluding expenses associated with this rate case proceeding. This amount represents the amount expected to be incurred during the forecasted test period for legal expenses not related to rate case proceedings; it does not represent the amortization of any deferred legal expenses.

   The $1,585,977 included in the attachments to PSC 1-54(b) and AG 1-73(a) represents the total estimated cost associated with this rate case for third-party service providers (e.g. legal, engineering, and consulting). This amount represents the total estimated amount (i.e. not the annual amortization of these expenses during a specific period).

c. Anticipated costs for "rate case legal fees" were developed based on a variety of factors including, but not limited to: (i) Big Rivers' experience in previous rate case proceedings; (ii) analysis of the various filing requirements and anticipated work loads; (iii) additional complexities associated with a rate case using a fully forecasted test period; and (iv) hourly rate information provided by external service providers.

   Rate case fees are deferred and amortized over a 36 month period beginning September 1, 2013. Please reference Ms. Speed's testimony at Application Tab 68, page 15, lines 16-22 and page 16, lines 1-10.

   The "other legal fees" are identified and reflected in the forecasted test period as expensed when anticipated to be incurred.

d. As stated in Ms. Speed's testimony at Application Tab 68, page 19, line 10: "The total estimated amount of these [rate case] costs is $1,585,980, or $44,055 per month when amortized over thirty-six months, beginning in September 2013." As illustrated in the attachment to Tab 52 of Big Rivers' Application, the total amortized portion of these costs included in the forecasted test period is approximately $528,660 (i.e. $44,055 per month x 12 months in forecasted test period = $528,660).

e. Big Rivers' objection also applied to the request to provide explanations for all services performed by each attorney during 2010, 2011, 2012, 2013 YTD and all forecasted periods. Notwithstanding this objection, and without waiving it, Big Rivers responds as follows.

As indicated in the title of the attachment to AG 1-72, the $198,000 of legal fees included in the forecasted test period represents estimated payments to outside attorneys and legal representation for general corporate matters, excluding expenses associated with this rate proceeding. Big Rivers' forecast in this case is based on its past experience (i.e., historical trends for annual costs) with corporate counsel.

The $454,620 and $521,080 ($975,700 total) included in the attachments to PSC 1-54(b) and AG 1-73(a) for Sullivan, Mountjoy, Stainback & Miller, P.S.C. and Dinsmore & Shohl LLP, respectively, represent the total projected costs for services to be performed by each of these firms in connection with this rate case proceeding. These services include, but are not limited to, the planning and preparation of the application and testimony for this case, preparation and review of responses to the Commission's first set of data requests, preparation and review of responses to the Commission's second and Intervenors' first sets of data requests, preparation and review of the Commission's third and Intervenors' second sets of data requests, preparation for the hearing, the hearing itself, rebuttal testimony, post hearing briefs, and other assistance directly related to the current rate case.

Witness) DeAnna M. Speed

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Item 23) ***Referencing Big Rivers' response to AG 1-73 (d): Please clarify if rate case expense or any expense is included in the forecasted test period August 31, 2014 related to BREC's prior rate case Case No. 2011-00036, and provide these amounts by consultant and show the related amortization of these costs by account number.***

Response) The forecasted test period ending August 31, 2014 includes a pro forma adjustment to reflect the amortization of rate case costs for Case No. 2011-00036. See Exhibit Wolfram-2.2, Reference Schedule 1.09, provided in response to PSC 2-36. The annual amount is $203,352, which reflects the amortization of the uncollected balance of rate case costs approved by the Commission in its Order on Rehearing dated January 29, 2013. This is an adjustment for ratemaking purposes only; there are no Case No. 2011-00036 rate case expenses included from an accounting standpoint in the forecasted test period.

Witnesses) John Wolfram

Item 24) *Referencing Big Rivers' response to AG 1-107 (e): Please provide the calculated net savings for idling the Wilson Station for the 2014-2016 timeframe and all workpapers and spreadsheets associated with this calculation.*

a. This calculation should include an itemization of the fixed costs saved, the variable costs saved, the additional costs due to running more expensive units to replace Wilson generation, the layup costs incurred and all other inputs and analysis used to derive these net savings.

b. Does this calculation include savings from depreciation or interest expenses? If yes, identify such with specificity.

Response)

a. Please see response to PSC 3-16 for the fixed cost savings breakdown for idling Wilson Station during the 2014-2016 timeframe. Please see the following table displaying the variance in expenses between Wilson Station running and idled. Variable expenses were obtained from the PCM run – Sens. 4 (please see response and CD attachment of PCM model runs to AG 1-236). The additional costs due to running more expensive units to replace Wilson generation have not been quantified.

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b. No, the calculation above does not include any savings from depreciation or interest expense.

Witness) Robert W. Berry

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Item 25) ***Referencing Big Rivers' response to AG 1-113 regarding the efforts to idle the Wilson Station:***

a. Is it Big Rivers' position that this layup process will preserve the plant and save its useful life for the future?

b. Is it Big Rivers' position that this layup will extend the plant such that the 33.5 years of useful life will be "suspended" until operation is once again commenced? If not, why not?

c. Would Big Rivers agree that depreciation expenses related to the 33.5 years of useful life should also be suspended while the plant is idled? If not, why not?

Response)

a. The remaining useful life of fossil fired steam generating assets is typically estimated based on expected hours of operation and anticipated number of thermal cycles. Big Rivers believes that these types of assets, when idled using appropriate layup techniques and approved best practice preservation methods, will deteriorate less rapidly than similar assets that operate routinely. That being said, Big Rivers also understands that all deterioration and depreciation of these assets will not cease, and that appropriate maintenance activities must be sustained during the layup period in order to minimize the effects of oxidation, pitting, and corrosion fatigue. Big Rivers intends to apply utility best practice procedures and innovative methods for protecting boiler and turbine equipment to its idled assets; the extent to which doing so affects the useful life of the assets will become known when future depreciation studies are performed.

b. No. The determination of the useful life of the plant following any layup will be made in future depreciation and/or engineering studies. Please see the response to part (a) above, PSC 2-21(c), and AG 1-113.

c. No. Big Rivers expects that Wilson Station will remain in service and available to operate as needed to cover outages at other stations and to maintain its environmental permits. As such, Big Rivers will continue to incur depreciation expenses while the plant is idled, in a manner consistent with the RUS System of Accounts and accounting practices. Also please see the response to PSC 2-21 and AG 1-113.

Witnesses) Robert W. Berry; Billie J. Richert

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Item 26) ***Referencing Big Rivers' response to AG 1-132, please provide a detailed analysis which shows how Big Rivers determined the expenses recorded in the FERC accounts in question are "predominately demand related" and not related to variable use of the facilities. Response should include a detailed discussion of expenses in each account. For example, why are steam expenses (account 502) not related to production of steam (variable use related) and instead treated as fixed or demand related expenses?***

a. Provide references related to FERC rulings regarding the accounts in question.

Response) Big Rivers did not make the determination described in the question but instead adhered to FERC precedent. See attached. FERC's Staff for a number of years has used the predominance method for classifying production O&M accounts.

a. *See, e .g., Arizona Public Service Co.*, 4 FERC ¶61,101, pp. 61,209-10 (1978); *Illinois Power Co.*, 11 FERC ¶63,040, pp. 65,255-56 (1980), *aff'd*, 15 FERC ¶61,050, p. 61,093 (1981); *Kansas City Power & Light Co.*, 21 FERC ¶63,003, p. 65,037 (1982), *aff'd*, 22 FERC ¶61,262 (1983); *Minnesota Power & Light Co.*, Opinion No. 86, 11 FERC ¶61,312, pp. 61,648-49 (1980).

Witness) John Wolfram

BIG RIVERS ELECTRIC CORPORATION

FERC Predominance Method
Classification of Production Expenses

USoA Acct #	Description		Classification Demand	Energy
	Steam Power Generation Operation			
500		Operations Supervision and Engineering	X	
501		Fuel		X
502		Steam Expenses	X	
503		Steam From Other Sources		X
504		Steam Transferred - Cr.		X
505		Electric Expenses	X	
506		Miscellaneous Steam Power Expenses	X	
507		Rents	X	
	Maintenance			
510		Supervision and Engineering		X
511		Structures	X	
512		Boiler Plant		X
513		Electric Plant		X
514		Miscellaneous Steam Plant	X	
	Nuclear Power Generation Operation			
517		Operations Supervision and Engineering	X	
518		Fuel		X
519		Coolants and Water	X	
520		Steam Expenses	X	
523		Electric Expenses	X	
524		Miscellaneous Nuclear Power Expenses	X	
525		Rents	X	
	Maintenance			
528		Supervision and Engineering		X
529		Structures	X	
530		Reactor Plant Equipment		X
531		Electric Plant		X
532		Miscellaneous Nuclear Plant	X	

FERC Predominance Method
Classification of Production Expenses

USoA Acct #		Description	Classification: Demand	Classification: Energy
	Hydraulic Power Generation Operation			
535		Operations Supervision and Engineering	X	
536		Water for Power	X	
537		Hydraulic Expenses	X	
538		Electric Expenses	X	
539		Miscellaneous Hydraulic Power Expenses	X	
540		Rents	X	
	Maintenance			
541		Supervision and Engineering	X	
542		Structures	X	
543		Reservoirs, Dams and Waterways	X	
544		Electric Plant		X
545		Miscellaneous Hydraulic Plant	X	
	Other Power Generation Operation			
546		Operations Supervision and Engineering	X	
547		Fuel		X
548		Generation Expenses	X	
549		Miscellaneous Other Power Generation	X	
550		Rents	X	
	Maintenance			
551		Supervision and Engineering	X	
552		Structures	X	
553		Generating and Electric Equipment	X	
554		Miscellaneous Other Power Generation Plant	X	
555		Purchased Power		As Billed
556		System Control and Load Dispatching	X	
557		Other Expenses	X	

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

**Response to the Office of the Attorney General's
Supplemental Set of Data Requests
Dated March 14, 2013**

March 28, 2013

Item 27) ***Referencing Big Rivers' response to AG 1-180: Please explain why Big Rivers does not know the coincident demand for Kenergy, Jackson Purchase, Meade County load and each smelter and why Big Rivers as a transmission owner in MISO is not otherwise able to provide this information or data. To the extent that Big Rivers does have this information, please provide it for each month since Big Rivers has been taking service under the MISO OATT.***

Response) Big Rivers understood that AG 1-180 pertained to the coincident demand for the member cooperatives and smelters shown on the monthly statement from MISO for Network Integrated Transmission Service. As indicated in that response, those values are not included on the MISO statement, because the load and revenue credits offset one another. Also please see the responses to AG 2-28 and AG 2-29.

Big Rivers does have the coincident demand for the member cooperatives and the smelters that is used by Big Rivers for wholesale billing purposes. See attached.

Witness) Lindsay N. Barron

Big Rivers Coincident Peaks (at System Peak)

Year	Month	Meade	JP	Kenergy	Smelters	Date	Time
2011	January	109	128	373	741	1/12/2011	HE19
2011	February	121	137	369	748	2/10/2011	HE07
2011	March	82	106	312	744	3/1/2011	HE07
2011	April	75	83	279	797	4/1/2011	HE07
2011	May	88	130	357	798	5/31/2011	HE17
2011	June	91	140	387	795	6/8/2011	HE17
2011	July	101	160	401	780	7/11/2011	HE18
2011	August	98	165	395	778	8/3/2011	HE18
2011	September	99	145	390	794	9/2/2011	HE17
2011	October	66	83	276	812	10/21/2011	HE07
2011	November	78	104	296	845	11/29/2011	HE18
2011	December	93	110	313	827	12/12/2011	HE07
2012	January	101	127	347	847	1/12/2012	HE20
2012	February	100	112	321	851	2/13/2012	HE07
2012	March	84	92	294	867	3/5/2012	HE07
2012	April	52	104	295	869	4/2/2012	HE18
2012	May	81	130	346	866	5/25/2012	HE17
2012	June	103	163	381	846	6/29/2012	HE17
2012	July	106	160	395	853	7/7/2012	HE16
2012	August	94	153	385	856	8/2/2012	HE15
2012	September	83	137	354	845	9/6/2012	HE17
2012	October	70	88	275	853	10/31/2012	HE07
2012	November	91	111	309	867	11/28/2012	HE07
2012	December	91	117	321	854	12/26/2012	HE18

Item 28) *Referencing Big Rivers Response to AG 1-230 (a), please respond to the following questions:*

a. Is it Big Rivers' position that Kenergy Corp, Jackson Purchase Energy Corporation, and Meade County RECC would not be allowed to purchase transmission service under the MISO tariff? If the answer is yes, please describe and reference specific sections of the MISO OATT that would prohibit such a transaction.

b. It appears that MISO has stated that the only MISO requirement for Kenergy Corp, Jackson Purchase Energy Corporation, and Meade County RECC to purchase MISO NITS under the MISO OATT would be to change reservation 76856899 to normal network contract service and this could be done with a mere 30-days' notice (see response to KIUC 1-5 p. 7). Please explain why Big Rivers responded to AG 1-230 (a) that this is not permissible under the MISO tariff, and yet it appears MISO has stated that it would be relatively simple for these entities to obtain NITS under the MISO OATT.

i. Referencing MISO's opinion that reservation 76856889 can be easily updated to normal network contract service: Provide an update of Wolfram Exhibit 3 that removes all costs that would be recovered under the Big Rivers MISO Attachment O spreadsheet if reservation 76856899 were converted to normal network contract service as contemplated by MISO.

ii. Indicate where each cost under the current Wolfram Exhibit 3 would be recovered in the Big Rivers MISO Attachment O spreadsheet assuming reservation 76856899 was converted to "normal network contract service."

c. Given that Big Rivers has said in its response to AG 1-224 that the smelter would be allowed to purchase firm transmission service from MISO, please explain why Kenergy Corp, Jackson Purchase Energy Corporation and Meade County RECC would not be allowed to purchase firm transmission from MISO regardless of power supply. Explanation should describe specific sections of the MISO OATT.

d. Please explain why Big Rivers could not simply charge the monthly Network service charge listed in the Attachment O spreadsheet to Kenergy Corp, Jackson Purchase Energy Corporation, and Meade County RECC (for example $1.424/kW/Mo as shown in the 2011 spreadsheet line 17 page 1 provided in response to AG 1-181) and fully recover Big Rivers' cost related to transmission service to these entities. Explanation should include a quantitative value and fully reference the Attachment O spreadsheets.

Response)

a. Big Rivers has all-requirements wholesale power contracts with Kenergy Corp., Jackson Purchase Energy Corporation, and Meade County RECC ("Members") through December 31, 2043. The all-requirements contracts require Big Rivers to supply and deliver electricity to the Members; this includes the provision of the transmission service needed to supply that electricity. It is Big Rivers' understanding that, under the MISO Tariff, the Members are treated as native load with bundled service under Network Integration Transmission Service ("NITS"), which is provided by Big Rivers, who is both the Transmission Owner and the Market Participant under the MISO Tariff.

Furthermore, it is Big Rivers' understanding that, in order for a party to purchase transmission service from MISO and receive Financial Transmission Rights ("FTRs") to manage congestion risk, the party must be a Market Participant under the MISO Tariff. The Members are not Market Participants and thus, even if the Members were not considered native load customers of Big Rivers, the Members would not be allowed to purchase transmission service at present under the MISO Tariff. See Modules A and B of the MISO Tariff available on the MISO website at https://www.midwestiso.org/Library/Tariff/Pages/Tariff.aspx

b. Big Rivers does not agree with the interpretation of the response to KIUC 1-5, p. 7. In the email referenced on that page, MISO is not referring to a possible transfer of transmission reservations from Big Rivers to the Members. MISO does not state that the only MISO requirement for *the Members to purchase MISO NITS under the MISO Tariff* (emphasis added) would be to "change reservation 76856899 to normal network contract service and this could be done with a mere 30-days' notice" as cited in this question. Reservation

76856899 does not pertain at all to the transmission service for the Members' native load noted in this question. Instead, the email from MISO refers to the option that Big Rivers has, as the Transmission Owner with bundled network load, either (i) to include certain schedules on the settlement statements as both a charge to network load and an equivalent, fully-offsetting credit to the Transmission Owner, or (ii) to not include these offsetting schedules at all since they net to zero. Changing from the latter to the former requires a 30-day notice to MISO. In either case, the Transmission Owner is Big Rivers, not the Members. The email from MISO makes no reference whatsoever to the possibility of the Members purchasing transmission service directly from MISO.

i. The premise of this question is flawed. The referenced conversion would not change Big Rivers' transmission costs or the recovery of such costs under Attachment O in any way.

ii. See the response to parts (a) and (b)(i).

c. Big Rivers did not state in response to AG 1-224 that the smelter would be allowed to purchase firm transmission service from MISO. Notwithstanding this fact, please see the response to part (a).

d. In theory, Big Rivers could seek Commission approval to recover its transmission costs from the Members via an unbundled rate structure, as opposed to the bundled wholesale rate proposed in the instant filing. The potential change from a bundled rate structure to an unbundled rate structure would necessitate a change to Big Rivers' base rates, to remove the transmission demand cost component. However, Big Rivers did not propose to do so in this case. Big Rivers is not aware of any unbundled transmission rate structures that have been approved by the Commission for electric utilities in the Commonwealth. Furthermore, Big Rivers has not attempted to identify any other requirements or approvals necessary for Big Rivers to seek to implement an unbundled transmission rate.

Witness) John Wolfram

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

Response to the Office of the Attorney General's
Supplemental Set of Data Requests
Dated March 14, 2013

March 28, 2013

Item 29) *Referencing Big Rivers' response to AG 1-230 (e), please respond to the following questions:*

a. Provide all workpapers, input and calculations used in arriving at the 12 coincident system peak values used to develop "divisors" in the spreadsheets provided in response to AG 1-181 (for example those values listed as lines 8 through 14 on page 1 of the 2011 Attachment O spreadsheet).

b. For each of these values provide the 12 coincident peak allocation among Kenergy Corp, Jackson Purchase Energy Corporation and Meade County RECC.

c. For each of these values provide the 12 coincident peak allocation among the "Rurals", "Large Industrials" and "Smelter" customers.

Response)

a. The source for the 12 CP system peak values used in the Attachment O spreadsheets provided in AG 1-181 is the Big Rivers Energy Management System ("EMS"). The load values are the total Big Rivers system load, which is calculated from the gross metered total system generation less auxiliary/startup load, less metered interchange, less HMP&L's share of Station Two generation. The EMS uses real-time hourly data and there are no spreadsheets or workpapers available.

b. The data in the EMS that is used to develop the Attachment O divisors is collected on a system-wide basis and is not compiled by summing the load data of the individual members.

c. The data in the EMS that is used to develop the Attachment O divisors is collected on a system-wide basis and is not compiled by rate class.

Witness) John Wolfram

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2012-00535

Response to the Office of the Attorney General's Supplemental Set of Data Requests Dated March 14, 2013

March 28, 2013

Item 30) *Referencing Big Rivers' response to AG 1-236: Please explain in complete detail why Big Rivers did not ask ACES to perform a sensitivity run with "Green 1 and Green 2 idled and Century not operating."*

Response) Big Rivers did not request ACES to perform a sensitivity run with Green 1 and Green 2 idled due to [redacted]

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

**Response to the Office of the Attorney General's
Supplemental Set of Data Requests
Dated March 14, 2013**

March 28, 2013

Item 31) *Referencing Big Rivers' response to AG 1-250 regarding the 2011 audited financial statements, page 4 shows that income for the defined benefit plan has decreased from $2.6 m in 2008 to ($2.4 m):*

a. Explain why income on the defined benefit plan has declined over this period and provide all related supporting documentation.

b. Explain if BREC has had to increase funding for the defined benefit plan and explain this impact on funding and cash flow for 2011, 2012 and 2013 (although it appears that the defined benefit plans were closed to new salaried entrants effective January 1, 2008 and to new bargaining employees effective November 1, 2008, with a defined contribution plan established for new entrants).

c. Page 24 of the audited financials states that BREC's expense under the defined contribution plan for 2011 and 2010 was $4.5 m and $4.4 m, respectively, and 2012 expected contribution to pension plan is $.1 million. Identify the amount of pension expense included in the rate case forecasted test period (by account) and compare to these amounts above, and explain the reasons for all differences.

Response)

a. On December 31, 2007, Big Rivers adopted SFAS No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans (now

FAS ASC 715, Compensation – Retirement Benefits). Please see page 19 of the 2011 financial statements attached to the response to AG 1-250. FAS 158 (ASC 715) requires recognition of the funded status of pension and other postretirement plans as an asset or liability in the statement of financial position, and recognition of the changes in funded status through comprehensive income (Accumulated Other Comprehensive Income or "AOCI"). AOCI is a balance sheet account that includes the gains or losses, prior service costs or credits, and the transition asset or obligation remaining from the initial application of FAS 87, Employers' Accounting for Pensions, and FAS 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, that have yet to be recognized as components of net periodic benefit cost pursuant to FAS 87 or FAS 106. The defined benefit plans referred to on page 4 of the 2011 financial statements referred to above include the defined benefit retirement plans and the postretirement medical benefits. The $2.6 m and ($2.4 m) comprehensive income figures are the sum totals of the respective annual changes in the prior service cost, unamortized actuarial gains and losses, and transition obligation components of AOCI. The $2.6 m indicates a net decrease (credit to AOCI) in these unrecognized components (net deferred expense), whereas the ($2.4 m) indicates a net increase. These annual changes are actuarially determined and dependent on the numerous factors entering into the respective actuarial valuations.

b. See the response to subpart (a) above. The change in AOCI is not a factor in the funding of the defined benefit retirement plans.

RECEIVED

MAR 28 2013

PUBLIC SERVICE
COMMISSION

Big Rivers Electric Corporation

Kentucky Public Service Commission Financial and Statistical Report (Annual Report)

For Year Ended December 31, 2011

RECEIVED

MAR 2 8 2013

PUBLIC SERVICE COMMISSION

OATH

Commonwealth of Kentucky)
) ss:
County of Henderson)

Mark A. Hite makes oath and says
(Name of Officer)

that he/she is Vice President Accounting & Interim CFO of
(Official title of officer)

Big Rivers Electric Corporation
(Exact legal title or name of respondent)

that it is his/her duty to have supervision over the books of account of the respondent and to control the manner in which such books are kept; that he/she knows that such books have, during the period covered by the foregoing report, been kept in good faith in accordance with the accounting and other orders of the Public Service Commission of Kentucky, effective during the said period; that he/she has carefully examined the said report and to have the best of his/her knowledge and belief the entries contained in the said report have, so far as they relate to matters of account, been accurately taken from the said books of account and are in exact accordance therewith; that he/she believes that all other statements of fact contained in the said report are true; and that the said report is a correct and complete statement of the business and affairs of the above-named respondent during the period of time from and including

January 1, 20 11, to and including December 31, 20 11

Mark A Hite
(Signature of Officer)

subscribed and sworn to before me, a Notary Public, in and for the State and County named in the above this 27th day of April, 20 12

(Apply Seal Here)

My Commission expires 1-12-13

Paula Mitchell
(Signature of officer authorized to administer oath)

[Persons making willful false statements in this report may be punished by fi...

KENTUCKY PUBLIC SERVICE COMMISSION
REPORT OF GROSS OPERATING REVENUES DERIVED FROM INTRA-KENTUCKY BUSINESS FOR THE YEAR ENDING DECEMBER 31, 2011

Name of Utility Reporting: Big Rivers Electric Corporation

FEIN # (Federal Employer Identification Number) 6 1 - 0 5 9 7 2 8 7

Address of Utility: 201 Third Street Phone: 270-827-2561

City: Henderson State: KY Zip: 42420 Fax: 270-844-6408

E-Mail: Albert.Yockey@bigrivers.com Web Site: www.bigrivers.com

Primary Regulatory Contact: Albert Yockey (Name) VP Governmental Relations & Enterprise Risk Management (Title)

(1) Gross Revenues of Electric Utility $461,586,621
(2) Gross Revenues of Gas Utility $
(3) Gross Revenues of Water Utility $
(4) Gross Revenues of Sewer Utility $
(5) Other Operating Revenues $
*** TOTAL GROSS REVENUES $461,586,621

OATH

State of)
) ss.
County of)

Mark A. Hite (Officer) being duly sworn, states that he/she is VP Accounting & Interim CFO (Official Title) of the Big Rivers Electric Corporation (Utility Reporting) that the above report of gross revenues is in exact accordance with Big Rivers Electric Corporation (Utility Reporting) and that such books accurately show the gross revenues of Big Rivers Electric Corporation (Utility Reporting) derived from Intra-Kentucky business for the calendar year ending December 31, 2011

Mark A. Hite (Officer) VP Accounting & Interim CFO (Title)

This the 12th day of March, 2012

Paula Mitchell (Notary Public) Henderson (County) 1-12-13 (Commission Expires)

Case No. 2012-00535
Attachment for Response to AG 2-53(e)
Witness: James V Haner
Page 3 of 178

NOTE: ANY DIFFERENCE BETWEEN THE AMOUNT OF THE GROSS REVENUES SHOWN IN THE ANNUAL REPORT AND THE AMOUNT APPEARING ON THIS STATEMENT MUST BE RECONCILED ON THE REVERSE OF THIS REPORT

Big Rivers Electric Corporation
FEIN: 61-0597287

2011 GROSS OPERATING REVENUES -- INTRA-KENTUCKY BUSINESS:

Gross Operating Revenue **$ 561,989,232**

Revenues from Out-of-State Business:

American Electric Power Service Corporation
Cargill Power Markets, LLC
Constellation Energy Commodities Group, Inc.
EDF Trading North America, LLC
Midwest Independent Transmission System Operator, Inc.
PJM Interconnection, LLC
PowerSouth Energy Cooperative
Southern Company Services, Inc,

Total Revenues from Out-of-State Business

Total Gross Operating Revenues -- Intra-Kentucky Business

[redacted]

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

April 27, 2011

Jeff D. Cline
Public Service Commission
P.O. Box 615
Frankfort, KY 40602-0615

Dear Mr. Cline:

Enclosed is an original notarized copy of Big Rivers Electric Corporation's 2011 Financial and Statistical Report (Annual Report) pursuant to Public Service Commission (PSC) Regulation 807 KAR 5:006, Section 3(1), and Kentucky Revised Statute KRS 278.230(3). This report has also been submitted electronically via the PSC's internet-based data collection system. A copy of Big Rivers' 2011 Audit Report is being provided in conjunction with this filing.

If you have any questions, please feel free to contact either Donna Windhaus or me.

Sincerely,

BIG RIVERS ELECTRIC CORPORATION

Mark A. Hite

Mark A. Hite, CPA
Vice President of Accounting & Interim CFO

/msb
Enclosure

cc: Mark Bailey
Albert Yockey
Ralph Ashworth
Donna Windhaus

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Principal Payment and Interest Information

Amount of Principal Payment During Calendar Year	$45,879,127.00
Is Principal Current?	Y
Is Interest Current?	Y

Case No 2012-00535
Attachment for Response to AG 2-53(e)
Witness: James V. Haner
Page 6 of 178

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Services Performed by Independent CPA

Are your financial statements examined by a Certified Public Accountant?		
Enter Y for Yes or N for No	Y	
If yes, which service is performed?		
Enter an X on each appropriate line		
Audit		X
Compilation		
Review		

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Additional Information - Part 1

Please furnish the following Information, for Kentucky Operations only	
Number of Rural Customers (other than farms)	
Number of Farms Served (A farm is any agricultural operating unit consisting of 3 acres or more)	
Number of KWH sold to all Rural Customers	
Total Revenue from all Rural Customers	
LINE DATA	
Total Number of Miles of Wire Energized (located in Kentucky)	1,266
Total number of Miles of Pole Line (Located in Kentucky)	1,266

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Additional Information - Counties

Ballard, Breckinridge, Caldwell, Carlisle, Crittenden, Daviess, Graves, Grayson, Hancock, Hardin, Henderson, Hopkins, Livingston, Lyon, McCracken, McLean, Marshall, Meade, Muhlenberg, Ohio, Union, Webster

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Supplemental Electric Information

Residential (440)			
Commercial and Industrial Sales			
Small (or Comercial)			
Large (or Industrial)			
Public St and Hwy Lighting (444)			
Other Sales to Public Authorities (445)			
Sales to Railroads and Railways (446)			
Interdepartmental Sales (448)			
Total Sales to Ultimate Customers			
Sales For Resale (447)	$558,372,354.00	13,255,124,574	3
Total Sales of Electricity	$558,372,354.00	13,255,124,574	3

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Identification (Ref Page: 1)

	Name	Address	Address2	City	State	Zip	Phone
Exact Legal Name of Respondent							
	Big Rivers Electric Corporation						
Previous Name and Date of change (if name changed during the year)							
	N/A						
Name Address and Phone number of the contact person							
	Donna M. Windhaus Manager General Accounting	201 Third Street		Henderson	KY	42420	2708446167
Note File: Attestation and signature via Electronic Filing							

General Information - (1) (Ref Page: 101)

Provide name and title of the Officer having custody of the general corporate books of account	C. William Blackburn Senior Vice President & CFO	201 Third Street	Henderson	KY	42420
Provide Address of Office where the general Corporate books are kept	Same as above				
Provide the Address of any other offices where other coprorate books are kept if different from where the general corporate books are kept					

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

General Information (2,3,4) (Ref Page: 101)

Provide the name of the State under the laws which respondent is incorporated and date

If incorporated under a special law give reference to such law

If not incorporated state that fact and give the type of organization and the date organized

Kentucky, June 14, 1961

If at any time during the year the property of respondent was held by a receiver or trustee

give (a) the name of receiver or trustee

(b) date such receiver or trustee took possession

(c) the authority by which the receivership or trusteeship was created and

(d) date when possession by receiver or trustee ceased.

N/A

State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Class "A" Utility - Generation and Transmission Cooperative - Wholesale Supplier of Electrical Energy - Transmission of Electrical Energy

General Information - (5) (Ref Page: 101)

Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal account for the previous years certified financial statements?	
Enter Y for Yes or N for No	N
If yes, Enter the date when such independent accountant was initially engaged	

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Control Over Respondent (Ref Page: 102)

If any corporation, business trust or similar organization or combination of such organizations jointly held control over respondent at end of year

state name of controlling corporation or organization

manner in which control was held and extent of control.

If control was in a holding company organization , show the chain of ownership or control to the main parent company or organization.

If control was held by a trustee(s), state name of trustee(s), name of beneficiary or benficiaries for whom trust was maintained and purpose of the trust.

Big Rivers Electric Corporation is a generation and transmission cooperative owned by its three member distribution cooperatives. Each member distribution cooperative has two representatives on the Big Rivers' Board. Big Rivers members are: Jackson Purchase Energy Corporation, Kenergy Corp., and Meade County RECC.

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Corporations Controlled by Respondent (Ref Page: 103)

Name of Company	Business	[illegible]

NOT APPLICABLE

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Officers (Ref Page: 104)

Report name,title and salary for each executive officer whose salary is $50,000 or more				
	President & CEO	Bailey	Mark	$0.00
	Sr Vice President & CFO	Blackburn	C. William	$0.00

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Directors (Ref Page: 105)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Dr. James Sills, Chair	362 Tuels Creek Rd.	Hardinsburg	KY	40143
Wayne Elliott, Vice Chair	6725 New Hope Church Road	Paducah	KY	42001
Larry Elder, Secretary-Treasurer	2245 Hayden Bridge Road	Owensboro	KY	42301
Lee Bearden	211 Green Oaks Ln	Benton	KY	42025
Paul Edd Butler	183 Davison Lane	Falls of Rough	KY	40119
Bill Denton	12633 Hwy 351	Henderson	KY	42420

Case No. 2012-00535
Attachment for Response to AG 2-53(e)
Witness: James V. Haner
Page 18 of 178

Important Changes During the Year (Ref Page: 108)

Give particulars concerning the matters indicated below.

1. Changes in and important additions to franchise rights:	NONE
2. Acquisition of ownership in other companies by reorganization, merger or consolidation with other companies:	NONE
3. Purchase or sale of an operating unit or system:	NONE
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given assigned or surrendered:	See Note 2 to Financial Statements, Pages 123.4-123.6 in Hard Copy of Annual Report.
5. Important extension or reduction of transmission or distribution system:	NONE
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees.	NONE
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.	NONE
8. State the estimated annual effect and nature of any important wage scale changes during the year.	NONE
9. State briefly the status of any materially important legal proceedings pending at the end of the year and the results.	See Note 13 to Financial Statements, Page 123.24 in Hard Copy of Annual Report.
10. Describe briefly any materially important transactions not disclosed elsewhere in this report in which an officer, director, or associated company was a party or had a material interest.	NONE
(Reserved)	
12. If the important changes appear in the annual report to stockholders are applicable and furnish data required by instructions 1 - 11 such notes may be included.	See Notes to Financial Statements, Pages 123-123.24 in Hard Copy of Annual Report.

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Balance Sheet - Assets and Other Debits (Ref Page: 110)

1. UTILITY PLANT		
2. Utility Plant (101-106,114)	$1,946,193,027.00	$1,979,267,724.00
3. Construction Work in Progress (107)	$54,874,458.00	$49,150,583.00
4. TOTAL UTILITY PLANT	$2,001,067,485.00	$2,028,418,307.00
5. (Less) Accum. Prov. for Depr. Amort. Depl. (108,111,115)	$909,501,402.00	$936,354,953.00
6. Net Utility Plant	$1,091,566,083.00	$1,092,063,354.00
7. Nuclear Fuel (120.1-120.4,120.6)		
8. (Less) Accum. Prov. for Amort. of Nucl. Assemblies (120.5)		
9. Net Nuclear Fuel		
10. Net Utility Plant (Enter Total of Line 6 and Line 9)	$1,091,566,083.00	$1,092,063,354.00
11. Utility Plant Adjustments (116)		
12. Gas Stored Underground - Non Current (117)		
13. OTHER PROPERTY AND INVESTMENTS		
14. Nonutility Property (121)		
15. (Less) Accum. Prov. for Depr and Amort. (122)		
16. Investment in Associated Companies (123)	$4,280,307.00	$4,333,296.00
17. Investments in Subsidiary Companies (123.1)		
18		
19. Noncurrent Portion of Allowances		
20. Other Investments (124)	$15,334.00	$15,334.00
21. Special Funds (125-128)	$218,166,328.00	$164,151,431.00
22. TOTAL Other Property and Investments	$222,461,969.00	$168,500,061.00
23. CURRENT AND ACCRUED ASSETS		
24. Cash (131)	$2,152.00	$1,973.00
25. Special Deposits (132-134)	$572,263.00	$572,679.00
26. Working Fund (135)	$3,725.00	$3,725.00
27. Temporary Cash Investments (136)	$44,774,114.00	$44,843,791.00

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Balance Sheet - Assets and Other Debits (Ref Page: 110)

	Balance Beginning of Year	[illegible]
28. Notes Receivable (141)		
29. Customer Accounts Receivable (142)	$43,733,010.00	$43,114,276.00
30. Other Accounts Receivable (143)	$778,278.00	$232,280.00
31. (Less) Accum. Prov. for Uncollectible Acct. Credit (144)		
32. Notes Receivable from Associated Companies (145)		
33. Accounts Receivable from Assoc. Companies (146)		
34. Fuel Stock (151)	$36,750,058.00	$33,553,927.00
35. Fuel Stock Expenses Undistributed (152)		
36. Residuals (Elec) and Extracted Products (153)		
37. Plant Materials and Operating Supplies (154)	$23,164,775.00	$24,585,465.00
38. Merchandise (155)		
39. Other Materials and Supplies (156)		
40. Nuclear Materials Held for Sale (157)		
41. Allowances (158.1 and 158.2)	$578,382.00	$340,087.00
42. (Less) Noncurrent Portion of Allowances		
43. Stores Expense Undistributed (163)	$52,877.00	$709,799.00
44. Gas Stored Underground - Current (164.1)		
45. Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		
46. Prepayments (165)	$3,000,688.00	$4,507,736.00
47. Advances for Gas (166-167)		
48. Interest and Dividends Receivable (171)	$1,394,037.00	$940,212.00
49. Rents Receivable (172)		
50. Accrued Utility Revenues (173)		
51. Miscellaneous Current and Accrued Assets (174)	$3,472.00	$3,472.00
52. Derivative Instrument Assets (175)		
53. Derivative Instrument Assets - Hedges (176)		

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Balance Sheet - Assets and Other Debits (Ref Page: 110)

54. TOTAL Current and Accrued Assets	$154,807,831.00	$153,409,422.00
55. DEFERRED DEBITS		
56. Unamortized Debt Expenses (181)	$2,185,564.00	$2,079,214.00
57. Extraordinary Property Losses (181.1)		
58. Unrecovered Plant and Regulatory Study Costs (182.2)		
59. Other Regulatory Assets (182.3)		
60. Prelim. Survey and Investigation Charges (Electric) (183)	$33,774.00	$892,873.00
61. Prelim. Sur. and Invest. Charges (Gas) (183.1,183.2)		
62. Clearing Accounts (184)	$7,210.00	($277.00)
63. Temporary Facilities (185)		
64. Miscellaneous Deferred Debits (186)	$481,307.00	$367,451.00
65. Def. Losses from Disposition of Utility Plt. (187)		
66. Research, Devel. and Demonstration Expend. (188)		
67. Unamortized Loss on Reaquired Debt (189)	$641,388.00	$610,178.00
68. Accumulated Deferred Income Taxes (190)		
69. Unrecovered Purchased Gas Costs (191)		
70. TOTAL Deferred Debits	$3,349,243.00	$3,949,439.00
71. Total Assets and other Debits (Total Lines 10,11,12,22,54,70)	$1,472,185,126.00	$1,417,922,276.00

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Balance Sheet - Liabilities and Other Credits (Ref Page: 112)

	[illegible]	[illegible]
1. PROPRIETARY CAPITAL		
2. Common Stock Issued (201)	$75.00	$75.00
3. Preferred Stock Issued (204)		
4. Capital Stock Subscribed (202,205)		
5. Stock Liability for Conversion (203,206)		
6. Premium on Capital Stock (207)		
7. Other Paid-In Capital Stock (208-211)	$4,444,502.00	$4,444,502.00
8. Installments Received on Capital stock (212)		
9. (Less) Discount on Capital Stock (213)		
10. (Less) Capital Stock Expense (214)		
11. Retained Earnings (215,215.1,216)	$391,498,804.00	$397,099,185.00
12. Unappropriated Undistributed Subsidiary Earnings (216.1)		
13. (Less) Reacquired Capital Stock (217)		
14. Accumulated Other Comprehensive Income (219)	($9,367,986.00)	($11,723,247.00)
15. TOTAL Proprietary Capital	$386,575,395.00	$389,820,515.00
16. LONG TERM DEBT		
17. Bonds (221)		
18. (Less) Reacquired Bonds (222)		
19. Advances from Associated Companies (223)		
20. Other Long-Term Debt (224)	$816,995,916.00	$786,398,429.00
21. Unamortized Premium on Long-Term Debt (225)		
22. (Less) Unamortized Discount on LongTerm Debt (226)		
23. TOTAL Long Term Debt	$816,995,916.00	$786,398,429.00
24. OTHER NONCURRENT LIABILITIES		
25. Obligations Under Capital Leases-NonCurrent (227)		
26. Accumulated Provision for Property Insurance (228.1)		
27. Accumulated Provision for Injuries and Damages (228.2)		

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Balance Sheet - Liabilities and Other Credits (Ref Page: 112)

[illegible]	[illegible]	[illegible]
28. Accumulated Provision for Pensions and Benefits (228.3)	$19,661,867.00	$22,098,788.00
29. Accumulated Miscellaneous Operating Provisions (228.4)		
30. Accumulated Provision for Rate Refunds (229)		
31. Asset Retirement Obligations (230)		
32. TOTAL OTHER Noncurrent Liabilities	$19,661,867.00	$22,098,788.00
33. CURRENT AND ACCRUED LIABILITIES		
34. Notes Payable (231)	$10,000,000.00	$0.00
35. Accounts Payable (232)	$31,298,484.00	$30,324,950.00
36. Notes Payable to Associated Companies (233)		
37. Account Payable to Associated Companies (234)		
38. Customer Deposits (235)	$400,902.00	$201,134.00
39. Taxes Accrued (236)	$659,009.00	$956,559.00
40. Interest Accrued (237)	$11,133,555.00	$9,898,751.00
41. Dividends Declared (238)		
42. Matured Long-Term Debt (239)		
43. Matured Interests (240)		
44. Tax Collections Payable (241)	$164,930.00	$515,569.00
45 Miscellaneous current and Accrued Liabilities (242)	$9,401,938.00	$8,706,564.00
46. Obligations Under Capital Leases - Current (243)		
47. Derivative Instrument Liabilities (244)		
48. Derivative Instrument Liabilities - Hedges (245)		
49. TOTAL Current and Accrued Liabilities	$63,058,818.00	$50,603,527.00
50. DEFERRED CREDITS		
51. Customer Advances for Construction (252)		
52. Accumulated Deferred Investment Tax Credits (255)		
53. Deferred Gains from Disposition of Utility Plant (256)		
54. Other Deferred Credits (253)		$0.00

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Balance Sheet - Liabilities and Other Credits (Ref Page: 112)

	[illegible]	[illegible]
55. Other Regulatory Liabilities (254)	$185,893,130.00	$169,001,017.00
56. Unamortized gain on Reacquired Debt (257)		
57. Accmulated Deferred Income Taxes (281-283)		
58. TOTAL Deferred Credits	$185,893,130.00	$169,001,017.00
59. TOTAL Liabilities and Other Credits (Total Lines 14,22,30,48 and 57)	$1,472,185,126.00	$1,417,922,276.00

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Statement of Income for the Year (Ref Page: 114)

1..UTILITY OPERATING INCOME					
2. Operating Revenues (400)	$561,989,232.00	$527,324,453.00	$561,989,232.00	$0.00	$0.00
3. Operating Expenses					
4. Operation Expenses (401)	$427,987,798.00	$394,946,355.00	$427,987,798.00	$0.00	$0.00
5. Maintenance Expenses (402)	$47,717,577.00	$46,880,348.00	$47,717,577.00	$0.00	$0.00
6. Depreciation Expense (403)	$35,247,017.00	$33,828,638.00	$35,247,017.00	$0.00	$0.00
7. Depreciation Expense for Asset Retirement Costs (403.1)					
8. Amort and Depl of Utility Plant (404-405)	$159,789.00	$413,554.00	$159,789.00	$0.00	$0.00
9. Amort of Utility Plant Acq. Adj (406)					
10. Amort of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)					
11. Amort. of Conversion Expenses (407)					
12. Regulatory Debits (407.3)					
13. (Less) Regulatory Credits (407.4)					
14. Taxes Other than Income Taxes (408.1)					
15. Income Taxes - Federal (409.1)	$100,000.00	$259,571.00	$100,000.00	$0.00	$0.00
16. Income Taxes - Other (409.1)	($1,611.00)	$3,227.00	($1,611.00)	$0.00	$0.00
17. Provision for Deferred Income Taxes (410.1)					

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Statement of Income for the Year (Ref Page: 114)

18. (Less) Provision for Deferred Income Taxes (411.1)					
19. Investment Tax Credit Adj. - Net (411.4)					
20. (Less) Gains from Disp. of Utility Plant (411.6)					
21. Losses from Disp. of Utility Plant (411.7)	($2,065.00)	($27,702.00)	($2,065.00)	$0.00	$0.00
22. (Less) Gains from Disposition of Allowances (411.8)					
23. Losses from Disposition of Allowances (411.9)					
24. Accretion Expense (411.10)					
25. Total Utility Operating Expenses (Enter Total of Lines 4 - 24)	$511,208,505.00	$476,303,991.00	$511,208,505.00	$0.00	$0.00
26. Net Utility Operating Income (Line 2 less line 25 - Carry forward to pg 117 line 25)	$50,780,727.00	$51,020,462.00	$50,780,727.00	$0.00	$0.00

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Statement of Income (continued) (Ref Page: 117)

27. Net Utility Operating Income (Carried from pg 114)	$50,780,727.00	$51,020,462.00
28. Other Income and Deductions		
29. Other Income		
30. Nonutility Operating Income		
31. Revenues From Merchandising, Jobbing and Contract Work (415)		
32. (Less) Costs and Exp. of Merchandising,Job. and Contract Work (416)		
33. Revenues From Nonutility Operations (417)		
34. (Less) Expenses of Nonutility Operations (417.1)		
35. Nonoperating Rental Income (418)	$9,288.00	$28,146.00
36. Equity in Earnings of Subsidiary Companies (418.1)	$150,516.00	
37. Interest and Dividend Income (419)		$391,494.00
38. Allowance for Other Funds Used During Construction (419.1)		
39. Miscellaneous Nonoperating Income (421)	$108,536.00	$2,145,385.00
40. Gain on Disposition of Property (421.1)	$0.00	$169,374.00
41. TOTAL Other Income	$268,340.00	$2,734,399.00
42. Other Income Deductions		
43. Loss on Disposition of Property (421.2)		
44. Miscellaneous Amortization (425)		
45. Miscellaneous Income Deductions (426.1 - 426.5)	$84,939.00	$91,490.00
46. TOTAL Other Income Deductions	$84,939.00	$91,490.00
47. Taxes Applic. to Other Income and Deductions		
48. Taxes Other Than Income Taxes (408.2)		
49. Income Taxes - Federal (409.2)		
50. Income Taxes - Other (409.2)		
51. Provision for Deferred Inc. Taxes (410.2)		

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Statement of Income (continued) (Ref Page: 117)

52. (Less) Provision for Deferred Income Taxes CR (411.2)		
53. Investment Tax Credit Adj. Net (411.5)		
54. (Less) Investment Tax Credits (420)		
55. TOTAL Taxes on Other Income and Deduct.		
56. Net Other Income and Deductions (Lines 41,46,55)	$183,401.00	$2,642,909.00
57. Interest Charges		
58. Interest on Long Term Debt (427)	$45,166,938.00	$46,380,691.00
59. Amort of Debt Disc. and Expense (428)	$106,350.00	$84,305.00
60. Amortization of Loss on Reacquired Debt (428.1)	$31,210.00	$18,299.00
61. (Less) Amort. of Premium on Debt - CR (429)		
62. (Less) Amortization of Gain on Reacquired Debt - CR (429.1)		
63. Interest on Debt to Assoc. Companies (430)		
64. Other Interest Expense (431)	$59,249.00	$189,161.00
65. (Less) Allowance for Borrowed Funds Used During Construction CR (432)		
66. Net Interest Charges	$45,363,747.00	$46,672,456.00
67. Income Before Extraordinary Items (Lines 25,54 and 64)	$5,600,381.00	$6,990,915.00
68. Extraordinary Items		
69. Extraordinary Income (434)		
70. (Less) Extraordinary Deductions (435)		
71. Net Extraordinary Items (Lines 67 less 68)		
72. Income Taxes - Federal and Other (409.3)		
73. Extraordinary Items After Taxes (Lines 69 less 70)		
74. Net Income (Lines 67 and 73)	$5,600,381.00	$6,990,915.00

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Statement of Retained Earnings for the Year (Ref Page: 118)

UNAPPROPRIATED RETAINED EARNINGS (216)	
State balance and purpose of each appropriated retained earnings amount at end of year	
Balance - Beginning of the Year	$391,498,804.00
Changes (Identify by prescribed retained earnings accounts)	
give accounting entries for any applications of appropriated retained earnings during the year.	
Adjustments to Retained Earnings (439)	
Credit:	
TOTAL Credits to Retained Earnings (439)	
Debit:	
TOTAL Debits to Retained Earnings (439)	
Balance Transferred from Income (433 less 418.1)	$5,600,381.00
Appropriations of Retained Earnings (436)	
TOTAL appropriations of Retained Earnings (436)	
Dividents Declared - Preferred stock (437)	
TOTAL Dividends Declared - Preferred Stock (437)	
Dividends Declared - Common Stock (438)	
TOTAL Dividends Declared - Common Stock (438)	
Transfers from Acct 216.1, Unappropriated Undistributed Subsidary Earnings	

Statement of Retained Earnings for the Year (Ref Page: 118)

Balance End of Year (Total Lines 01, 09,15,16,22,29,36,37)	$397,099,185.00
APPROPRIATED RETAINED EARNINGS (215)	
(215)	
TOTAL Appropriated Retained Earnings (215)	
APPROPRIATED RETAINED EARNINGS - AMORTIZATION RESERVE, FEDERAL	
TOTAL Appropriated Retained Earnings - Amortization Reserve, Federal (215.1)	
TOTAL Appropriated Retained Earnings (total lines 45 and 46) (214,215.1)	
TOTAL Retained Earnings (215, 215.1, 216)	$397,099,185.00
UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (216.1)	
Balance - Beginning of Year (Debit or Credit)	
Equity in Earnings for Year (Credit) (418.1)	
(Less) Dividends Received (Debit)	
Other Charges (explain)	
Balance - End of Year	

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Statement of Cash Flows (Ref Page: 120)

Net Cash Flow From Operating Activities:		
Net Income (Line 72 c on page 117)		$5,600,381.00
Noncash Charges (Credits) to Income:		
Depreciation and Depletion		$37,807,713.00
Amortization of (Specify)		
	Increase in RUS Series A Note	$8,397,778.00
	Increase in RUS Series B Note	$6,883,863.00
	Noncash Member Rate Mitigation Revenue	($18,946,530.00)
Deferred Income Taxes (Net)		
Investment Tax Credit Adjustment (Net)		
Net (Increase) Decrease in Receivables		$1,618,556.00
Net (Increase) Decrease in Inventory		$1,356,815.00
Net (Increase) Decrease in Allowances Inventory		
Net Increase (Decrease) in Payables and Accrued Expenses		($2,455,291.00)
Net (Increase) Decrease in Other Regulatory Assets		
Net Increase (Decrease) in Other Regulatory Liabilities		
(Less) Allowance for Other Funds Used During Construction		
(Less) Undistributed Earnings from Subsidiary Companies		
Other:		
	Net (Increase) Decrease in Prepaid Expenses	($1,714,843.00)
	(Net (Increase) Decrease in Deferred Charges	$121,343.00
	Net (Increase) in Other, Net	($70,375.00)
Net Cash Provided by (Used in) Operating Activities (Total lines 2 thru 21)		$38,599,410.00
Cash Flows from Investment Activities:		
Construction and Acquisition of Plant (Including Land):		
Gross Additions to Utility Plant (Less nuclear fuel)		($38,745,820.00)

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Statement of Cash Flows (Ref Page: 120)

Gross Additions to Nuclear Fuel		
Gross Additions to Common Utility Plant		
Gross Additions to Nonutility Plant		
(Less) Allowance for Other Funds Used During Construction		
Other		
Cash Outflows for Plant (Total lines 26-33)		($38,745,820.00)
Acquisition of Other Noncurrent Assets (d)		
Proceeds from Disposal of Noncurrent Assets (d)		
Investments in and Advances to Assoc. and Subsidiary Companies		
Contributions and Advances from Assoc. and Subsidiary Companies		
Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
Associated and Subsidiary Companies		
Purchase of Investment Securities (a)		
Proceeds from Sales of Investment Securities (a)		
Loans Made or Purchased		
Collections on Loans		
Net (Increase) Decrease in Receivables		
Net (Increase) Decrease in Inventory		
Net (Increase) Decrease in Allowances Held for Speculation		
Net Increase (Decrease) in Payables and Accrued Expenses		
Other:		
	Proceeds from Restricted Investments and Other Dep	$56,095,034.00
Net Cash Provided by (used in) Investing Activities (Lines 34-55)		$17,349,214.00

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Statement of Cash Flows (Ref Page: 120)

Cash Flows from Financing Activities:	
Proceeds from Issuance of:	
Long - Term Debt (b)	$0.00
Preferred Stock	
Common Stock	
Other	
Net Increase in Short-Term Debt (c)	
Other	
Cash Provided by Outside Sources (Total lines 61 thru 69)	$0.00
Payments for Retirement of	
Long-Term Debt (b)	($45,879,126.00)
Preferred Stock	
Common Stock	
Other	
Net Decrease in Short-Term Debt (c)	($10,000,000.00)
Dividends on Preferred Stock	
Dividends on Common Stock	
Net Cash Provided by (used in) Financing Activities (Lines 70 - 81)	($55,879,126.00)
Net Increase (Decrease) in Cash and Cash Equivalents (Total Lines 22, 57, 83)	$69,498.00
Cash and Cash Equivalents at Beginning of Year	$44,779,991.00
Cash and Cash Equivalents at End of Year	$44,849,489.00

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Statement Accumulated Comprehensive Income, Comprehensive Income and Hedging Activities (Ref Page: 122)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Comprehensive Income Current Year:	$0.00	$0.00	$0.00	$0.00
Net Margin	$0.00	$0.00	$0.00	$0.00
FAS 158 Funded Status Adj	$0.00	$0.00	$0.00	$2,355,261.00
Total Comprehensive Income-Current Year	$0.00	$0.00	$0.00	$2,355,261.00

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Statement Accumulated Comprehensive Income, Comprehensive Income and Hedging Activities (Ref Page: 122) (Part Two)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Comprehensive Income Current Year:	$0.00	$0.00	$0.00	$0.00	$0.00
Net Margin	$0.00	$0.00	$0.00	$5,600,381.00	$5,600,381.00
FAS 158 Funded Status Adj	$0.00	$0.00	$2,355,261.00	$0.00	$2,355,261.00
Total Comprehensive Income-Current Year	$0.00	$0.00	$2,355,261.00	$5,600,381.00	$7,955,642.00

Note:
Ref. Page: 122 - Column h

RUS has established Account 209, Accumulated Other Comprehensive Income and modified its Accounting Requirements for RUS Electric Borrowers accordingl\ This is a deviation from FERC accounting requirements under FERC Order 627, which established Account 219 for Accumulated Other Comprehensive Income. Therefore, the FAS 158 adjustments shown on this page are reflected on Big Rivers' books in Account 209 instead of Account 219 as shown in the description of column (h).

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COMPUTATION OF TAX

	Patronage Income	Non-Patronge Income	Total Income
Taxable Income (Loss)	(28,574,836)	10,321,554	(18,253,282)
LESS: NOL Deduction		9,289,399	
Income Subject to AMT		1,032,155	
AMT Rate - 20%		X .20	
AMT Liability		206,431	

(1) Organization and Summary of Significant Accounting Policies

(a) General Information

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

Management evaluated subsequent events up to and including March 26, 2012, the date the financial statements were available to be issued.

(b) Principles of Consolidation

The financial statements of Big Rivers include the accounts of Big Rivers and its wholly owned subsidiary, Big Rivers Leasing Corporation (BRLC). All significant intercompany transactions have been eliminated. BRLC was dissolved July 7, 2009.

(c) Estimates

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

(d) System of Accounts

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

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(Dollars in thousands)

(e) ***Revenue Recognition***

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

(f) ***Utility Plant and Depreciation***

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

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

Depreciation of utility plant in service is recorded using the straight-line method over the estimated remaining service lives, as approved by the RUS and KPSC. During 2010, the Company commissioned a depreciation study to evaluate the remaining economic lives of its assets. In 2011, the study was completed and approved by the RUS and KPSC. The annual composite depreciation rates used to compute depreciation expense were as follows:

	Jan-Nov 2011	Dec 2011
Electric plant	1.60 – 2.47%	0.50 – 20.22%
Transmission plant	1.76 – 3.24	1.42 – 2.23
General plant	1.11 – 5.62	2.84 – 17.12

For 2011, 2010, and 2009, the average composite depreciation rates were 1.91%, 1.86%, and 1.85%, respectively. At the time plant is disposed of, the original cost plus cost of removal less salvage value of such plant is charged to accumulated depreciation, as required by the RUS.

(g) ***Impairment Review of Long-Lived Assets***

Long-lived assets are reviewed as facts and circumstances indicate that the carrying amount may be impaired. FASB ASC 360, *Property, Plant, and Equipment*, requires the evaluation of impairment by comparing an asset's carrying value to the estimated future cash flows the asset is expected to generate over its remaining life. If this evaluation were to conclude that the future cash flows were not sufficient to recover the carrying value of the asset, an impairment charge would be recorded based on the difference between the asset's carrying amount and its fair value (less costs to sell for assets to be disposed of by sale) as a charge to net margin.

(h) ***Inventory***

Inventories are carried at average cost and include coal, petroleum coke, lime, limestone, oil and gas used for electric generation, and materials and supplies used for utility operations. Emission allowances are carried in inventory at a weighted average cost by each vintage year. Issuances of allowances are accounted for on a vintage basis using a monthly weighted average cost.

(i) ***Restricted Investments***

Investments are restricted under KPSC order to establish certain reserve funds for member rate mitigation in conjunction with the Unwind Transaction. These investments have been classified as held-to-maturity and are carried at amortized cost (see note 9).

(j) ***Cash and Cash Equivalents***

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

(k) ***Income Taxes***

Big Rivers was formed as a tax-exempt cooperative organization as described in Internal Revenue Code Section 501(c)(12). To retain tax-exempt status under this section, at least 85% of the Big Rivers' receipts must be generated from transactions with the Company's members. In 1983, sales to nonmembers resulted in Big Rivers failing to meet the 85% requirement. Until Big Rivers can meet the 85% member income requirement, the Company will not be eligible for tax-exempt status and will be treated as a taxable cooperative.

As a taxable cooperative, Big Rivers is entitled to exclude the amount of patronage allocations to members from taxable income. Income and expenses related to non-patronage sourced operations are taxable to Big Rivers. Big Rivers files a federal income tax return and certain state income tax returns.

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

(l) ***Patronage Capital***

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

(m) ***Derivatives***

Management has reviewed the requirements of FASB ASC 815, *Derivatives and Hedging*, and has determined that certain contracts the Company is party to may meet the definition of a derivative under FASB ASC 815. The Company has elected the Normal Purchase and Normal Sale exception for these contracts and, therefore, the contracts are not required to be recognized at fair value in the financial statements.

(n) ***Fair Value Measurements***

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

- Level 1 – quoted prices in active markets for identical assets or liabilities;
- Level 2 – observable inputs other than quoted prices included in Level 1, such as quoted prices for similar assets and liabilities in active markets; quoted prices for identical or similar assets and liabilities in markets that are not active; or other inputs that are observable or can be corroborated by observable market data; and
- Level 3 – unobservable inputs that are supported by little or no market activity and that are significant to the fair values of the assets or liabilities, including certain pricing models, discounted cash flow methodologies, and similar techniques that use significant unobservable inputs.

(Dollars in thousands)

(2) LG&E Lease Agreement

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(Dollars in thousands)

(3) Utility Plant

At December 31, 2011 and 2010, utility plant is summarized as follows:

	2011	2010
Classified plant in service:		
Production plant	$ 1,706,243	$ 1,689,024
Transmission plant	238,738	237,689
General plant	33,744	18,937
Other	543	543
	1,979,268	1,946,193
Less accumulated depreciation	936,355	909,501
	1,042,913	1,036,692
Construction in progress	49,150	54,874
Utility plant – net	$ 1,092,063	$ 1,091,566

Interest capitalized for the years ended December 31, 2011, 2010, and 2009, was $548, $684, and $133, respectively.

The Company has not identified any material legal asset retirement obligations, as defined in FASB ASC 410, *Asset Retirement and Environmental Obligations*. In accordance with regulatory treatment, the Company records an estimated net cost of removal of its utility plant through normal depreciation. As of December 31, 2011 and 2010, the Company had approximately $41,449 and $38,000, respectively, related to nonlegal removal costs included in accumulated depreciation.

(Dollars in thousands)

(4) Debt and Other Long-Term Obligations

A detail of long-term debt at December 31, 2011 and 2010 is as follows:

		2011		2010
RUS Series A Promissory Note, stated amount of $523,192, stated interest rate of 5.75%, with an imputed interest rate of 5.84% maturing July 2021	$	521,250	$	558,731
RUS Series B Promissory Note, stated amount of $245,530, no stated interest rate, with interest imputed at 5.80%, maturing December 2023		123,049		116,165
County of Ohio, Kentucky, promissory note, fixed interest rate of 6.00%, maturing in July 2031		83,300		83,300
County of Ohio, Kentucky, promissory note, variable interest rate (average interest rate of 3.30% and 3.27% in 2011 and 2010, respectively), maturing in June 2013		58,800		58,800
Total long-term debt		786,399		816,996
Current maturities		72,145		7,373
Total long-term debt – net of current maturities	$	714,254	$	809,623

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

		Amount
Year:		
2012	$	72,145
2013		79,260
2014		21,661
2015		22,955
2016		231,882
Thereafter		358,496
Total	$	786,399

(a) *RUS Notes*

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

(b) Pollution Control Bonds

In June 2010, the County of Ohio, Kentucky, issued $83,300 of Pollution Control Refunding Revenue Bonds, Series 2010A (Series 2010A Bonds), the proceeds of which are supported by a promissory note from Big Rivers, which bears the same interest rate. These bonds bear interest at a fixed rate of 6.00% and mature in July 2031.

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

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

The Series 1983 Bonds are subject to a maximum interest rate of 13.00%. The December 31, 2011 interest rate on the Series 1983 Pollution Control Bonds was 3.25%.

(c) Notes Payable

Notes payable represent the Company's borrowing on its line of credit with the National Rural Utilities Cooperative Finance Corporation (CFC) and CoBank, ACB (CoBank). The maximum borrowing capacity on the lines of credit is $100,000 consisting of $50,000 each for CFC and CoBank. In March 2011, Big Rivers paid down the $10,000 of borrowings outstanding on the CoBank line of credit at December 31, 2010. The Company had no borrowings outstanding on the lines of credit at December 31, 2011. Letters of credit issued under an associated Letter of Credit Facility with CFC reduced the borrowing capacity on the CFC line of credit by $5,375 and $5,928 at December 31, 2011 and 2010, respectively. Advances on the CFC line of credit bear interest at a variable rate and outstanding balances are payable in full by the maturity date of July 16, 2014. The CFC variable rate is equal to the CFC Line of Credit Rate, which is defined as "the rate published by CFC from time to time, by electronic or other means, for similarly classified lines of credit, but if not published, then the rate determined for such lines of credit by CFC from time to time." Advances on the CoBank line of credit bear interest at a variable rate and outstanding balances are payable in full by the maturity date of July 16, 2012. The CoBank variable rate is a fixed rate per annum (for interest periods of 1, 2, 3, and 6 months) equal to LIBOR plus the Applicable Margin as determined by the Company's credit rating. On February 25, 2011, a $2,500 CFC line of credit, available to the Company to finance storm emergency repairs and expenses related to electric utility operations, matured.

(d) ***Covenants***

Big Rivers is in compliance with all debt covenants associated with both long-term and short-term debt. The Company's Indenture and its line of credit with CFC require that a Margins for Interest Ratio (MFIR) of at least 1.10 be maintained for each fiscal year. The CoBank line of credit agreement requires that at the end of each fiscal year the Company have a Debt Service Coverage Ratio (DSCR) of not less than 1.20. Big Rivers' lines of credit with CFC and CoBank require Equity to Asset ratios of 12% and 15%, respectively. Big Rivers' 2011 MFIR was 1.12, its DSCR was 1.47 and the Asset to Equity Ratio was 27%.

(5) Rate Matters

The rates charged to Big Rivers' members consist of a demand charge per kilowatt (kW) and an energy charge per kilowatt hour (kWh) consumed as approved by the KPSC. The rates include specific demand and energy charges for its members' two classes of customers, the large industrial customers and the rural customers under its jurisdiction. For the large industrial customers, the demand charge is generally based on each customer's maximum demand during the current month. Effective September 1, 2011, the Company received approval from the KPSC to base the member rural demand charge on its Maximum Adjusted Net Local Load (as defined in Big Rivers tariff).

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

The net impact of the tariff riders to members rates is currently mitigated by a Member Rate Stability Mechanism (MRSM) that was funded by certain cash amounts received from the E.ON Entities in connection with the Unwind Transaction (the Economic and Rural Economic Reserves) and held by Big Rivers as restricted investments. An offsetting regulatory liability – member rate mitigation was established with the funding of these accounts.

In its order approving the Unwind Transaction, the KPSC stipulated that Big Rivers file a rate case within three years of the Unwind Closing Date or by July 2012. On March 1, 2011, the Company filed an application with the KPSC requesting, among other things, authority to adjust its rates for wholesale electric service. The KPSC entered an order on November 17, 2011, granting Big Rivers an annual revenue increase of $26,745. One of the intervenors in the case has filed an appeal seeking, among other things, an approximate $6,200 reduction in the revenue relief granted in the order, and will presumably ask that any relief obtained be retroactive to the effective date of the rates approved in the order (September 1, 2011). Big Rivers has also sought rehearing on certain matters raised in the order that could increase Big Rivers' annual revenue by $2,735.

The wholesale rates established for the members nonsmelter large direct-served industrial customers (the Large Industrial Rate) provide the basis for pricing the energy consumed by the Aluminum Smelters.

(Dollars in thousands)

The primary component of the pricing used for the Aluminum Smelters is an energy charge in dollars per megawatt hour (MWh) determined by applying the Large Industrial Rate to a load with a 98% load factor, and adding an additional charge of $0.25 per MWh. The other components reflected in the pricing of the Aluminum Smelters' energy usage are certain charges and credits as provided for under the terms of the Aluminum Smelters' wholesale electric service agreements between Big Rivers and Kenergy Corp. (Kenergy Corp. is the retail provider for the Aluminum Smelters load).

(6) Income Taxes

At December 31, 2011, Big Rivers had a Nonpatron Net Operating Loss Carryforward of approximately $32,434 expiring at various times between 2011 and 2031, and an Alternative Minimum Tax Credit Carryforward of approximately $7,138, which carries forward indefinitely.

The Company has not recorded any regular income tax expense for the years ended December 31, 2011, 2010, and 2009, as the Company has utilized federal net operating losses to offset any regular taxable income during those years. Had the Company not had the benefit of a net operating loss carryforward, the Company would have recorded $3,613, $3,846, and $19,619 in current regular tax expense for the years ended December 31, 2011, 2010 and 2009, respectively.

The components of the net deferred tax assets as of December 31, 2011 and 2010 were as follows:

	2011	2010
Deferred tax assets:		
Net operating loss carryforward	$ 12,812	$ 16,730
Alternative minimum tax credit carryforwards	7,138	6,038
Member rate mitigation	10,326	10,326
Fixed asset basis difference	3,980	10,752
RUS Series B Note	19,689	14,767
Total deferred tax assets	53,945	58,613
Deferred tax liabilities:		
RUS Series B Note	—	—
Bond refunding costs	(9)	(8)
Total deferred tax liabilities	(9)	(8)
Net deferred tax asset (prevaluation allowance)	53,936	58,605
Valuation allowance	(53,936)	(58,605)
Net deferred tax asset	$ —	$ —

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Attachment for Response to AG 2-53(e)
Witness: James V. Haner

(Dollars in thousands)

A reconciliation of the Company's effective tax rate for 2011, 2010, and 2009 follows:

	2011	2010	2009
Federal rate	35.0%	35.0%	35.0%
State rate – net of federal benefit	4.5	4.5	4.5
Permanent differences	0.9	0.5	—
Patronage allocation to members	(40.8)	(38.8)	(35.4)
Tax benefit of operating loss carryforwards and other	0.4	(1.2)	(4.1)
Alternative minimum tax	3.5	3.0	0.2
Effective tax rate	3.5%	3.0%	0.2%

The Company files a federal income tax return, as well as certain state income tax returns. The years currently open for federal tax examination are 2007 through 2011 and 1996 through 1997, due to unused net operating loss carryforwards. The major state tax jurisdiction currently open for tax examination is Kentucky for years 2004 through 2011 and years 2001 through 2003, also due to unused net operating loss carryforwards. The Company has not recorded any unrecognized tax benefits or liabilities related to federal or state income taxes.

The Company classifies interest and penalties as an operating expense on the income statement and accrued expense in the balance sheet. No material interest or penalties have been recorded during 2011, 2010, or 2009.

(7) Power Purchased

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

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

(8) Pension Plans

(a) *Defined Benefit Plans*

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

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

The Company has adopted FASB ASC 715, *Compensation – Retirement Benefits*, including the requirement to recognize the funded status of its pension plans and other postretirement plans (see note 11 – Postretirement Benefits Other Than Pensions). FASB ASC 715 defines the funded status of a defined benefit pension plan as the fair value of its assets less its projected benefit obligation, which includes projected salary increases, and defines the funded status of any other postretirement plan as the fair value of its assets less its accumulated postretirement benefit obligation.

FASB ASC 715 also requires an employer to measure the funded status of a plan as of the date of its year-end balance sheet and requires disclosure in the notes to the financial statements certain additional information related to net periodic benefit costs for the next fiscal year. The Company's pension and other postretirement benefit plans are measured as of December 31, 2011 and 2010.

(Dollars in thousands)

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

A reconciliation of the Company's benefit obligations of its noncontributory defined benefit pension plans at December 31, 2011 and 2010 follows:

		2011		2010
Benefit obligation – beginning of period	$	28,804	$	25,493
Service cost – benefits earned during the period		1,279		1,289
Interest cost on projected benefit obligation		1,296		1,368
Benefits paid		(481)		(806)
Actuarial loss		845		1,460
Benefit obligation – end of period	$	31,743	$	28,804

The accumulated benefit obligation for all defined benefit pension plans was $25,482 and $21,977 at December 31, 2011 and 2010, respectively.

A reconciliation of the Company's pension plan assets at December 31, 2011 and 2010 follows:

		2011		2010
Fair value of plan assets – beginning of period	$	25,267	$	22,270
Actual return on plan assets		324		2,707
Employer contributions		2,890		1,096
Benefits paid		(481)		(806)
Fair value of plan assets – end of period	$	28,000	$	25,267

The funded status of the Company's pension plans at December 31, 2011 and 2010 follows:

		2011		2010
Benefit obligation – end of period	$	(31,743)	$	(28,804)
Fair value of plan assets – end of period		28,000		25,267
Funded status	$	(3,743)	$	(3,537)

(Dollars in thousands)

Components of net periodic pension costs for the years ended December 31, 2011, 2010, and 2009 were as follows:

	2011	2010	2009
Service cost	$ 1,279	$ 1,289	$ 1,241
Interest cost	1,296	1,368	1,466
Expected return on plan assets	(1,737)	(1,533)	(1,332)
Amortization of prior service cost	14	19	19
Amortization of actuarial loss	461	584	834
Settlement loss	—	—	1,690
Net periodic benefit cost	$ 1,313	$ 1,727	$ 3,918

A reconciliation of the pension plan amounts in accumulated other comprehensive income at December 31, 2011 and 2010 follows:

	2011	2010
Prior service cost	$ (26)	$ (40)
Unamortized actuarial loss	(11,151)	(9,354)
Accumulated other comprehensive income	$ (11,177)	$ (9,394)

In 2012, $14 of prior service cost and $696 of actuarial loss is expected to be amortized to periodic benefit cost.

The recognized adjustments to other comprehensive income (loss) at December 31, 2011 and 2010 follows:

	2011	2010
Prior service cost	$ 14	$ 19
Unamortized actuarial gain (loss)	(1,797)	297
Other comprehensive income (loss)	$ (1,783)	$ 316

At December 31, 2011 and 2010, amounts recognized in the balance sheets were as follows:

	2011	2010
Deferred credits and other	$ (3,743)	$ (3,537)

(Dollars in thousands)

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

	2011	2010	2009
Discount rate – projected benefit obligation	4.26%	4.95%	5.59%
Discount rate – net periodic benefit cost	4.95	5.59	6.38
Rates of increase in compensation levels	4.00	4.00	4.00
Expected long-term rate of return on assets	7.25	7.25	7.25

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

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

Big Rivers utilizes a third party investment manager for the plan assets, and has communicated thereto the Company's Retirement Plan Investment Policy, including a target asset allocation mix of 50% U.S. Equities (an acceptable range of 45%-55%), 15% International Equities (an acceptable range of 10%-20%), and 35% fixed income (an acceptable range of 30%-40%). As of December 31, 2011 and 2010, the investment allocation was 56% and 58%, respectively, in U.S. Equities, 8% and 9%, respectively, in International Equities, and 36% and 33%, respectively, in fixed income. The objective of the investment program seeks to (a) maximize return on investment, (b) minimize volatility, (c) minimize company contributions, and (d) provide the employee benefit in accordance with the plans. The portfolio is well diversified and of high quality. The average quality of the fixed income investments must be "A" or better. The equity portfolio must also be of investment grade quality. The performance of the investment manager is reviewed semi-annually.

(Dollars in thousands)

At December 31, 2011 and 2010, the fair value of Big Rivers' defined benefit pension plan assets by asset category are as follows:

	Level 1	Level 2	December 31, 2011
Cash and money market	$ 2,129	$ —	$ 2,129
Equity securities:			
U.S. large-cap stocks	10,178	—	10,178
U.S. mid-cap stock mutual funds	3,365	—	3,365
U.S. small-cap stock mutual funds	1,666	—	1,666
International stock mutual funds	2,168	—	2,168
Preferred stock	493	—	493
Fixed:			
TIPS bond fund	723	—	723
U.S. government agency bonds	—	1,085	1,085
Taxable U.S. municipal bonds	—	3,258	3,258
U.S. corporate bonds	—	2,630	2,630
Global bond fund	—	305	305
	$ 20,722	$ 7,278	$ 28,000

	Level 1	Level 2	December 31, 2010
Cash and money market	$ 1,517	$ —	$ 1,517
Equity securities:			
U.S. large-cap stocks	9,731	—	9,731
U.S. mid-cap stock mutual funds	2,926	—	2,926
U.S. small-cap stock mutual funds	1,448	—	1,448
International stock mutual funds	2,194	—	2,194
Preferred stock	490	—	490
Fixed:			
TIPS bond fund	161	—	161
U.S. government agency bonds	—	1,843	1,843
Taxable U.S. municipal bonds	—	2,635	2,635
U.S. corporate bonds	—	2,322	2,322
	$ 18,467	$ 6,800	$ 25,267

(Dollars in thousands)

Expected retiree pension benefit payments projected to be required during the years following 2011 are as follows:

		Amount
Years ending December 31:		
2012	$	2,330
2013		4,386
2014		1,799
2015		3,196
2016		3,265
2017 – 2020		10,986
Total	$	25,962

In 2012, the Company expects to contribute $970 to its pension plan trusts.

(b) *Defined Contribution Plans*

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

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

The Company's expense under these plans was $4,464 and $4,389 for the years ended December 31, 2011 and 2010, respectively.

(c) *Deferred Compensation Plan*

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

The nonqualified deferred compensation plan is unfunded, but the Company has chosen to finance its obligations under the plan, including any employee deferrals, through a rabbi trust. The trust assets remain a part of the Company's general assets, subject to the claims of its creditors. The 2011 employer contribution was $58 and deferred compensation expense was $81. As of December 31, 2011, the trust asset was $283 and the deferred liability was $202.

(Dollars in thousands)

(9) Restricted Investments

The amortized costs and fair values of Big Rivers restricted investments held for member rate mitigation at December 31, 2011 and 2010 are as follows:

	2011		2010	
	Amortized costs	Fair values	Amortized costs	Fair values
Cash and money market	$ 12,765	$ 12,764	$ 12,812	$ 12,812
Debt securities:				
U.S. Treasuries	62,073	63,917	60,941	62,582
U.S. government agency	88,324	88,485	143,809	143,922
Total	$ 163,162	$ 165,166	$ 217,562	$ 219,316

Gross unrealized gains and losses on restricted investments at December 31, 2011 and 2010 were as follows:

	2011		2010	
	Gains	Losses	Gains	Losses
Cash and money market	$ —	$ —	$ —	$ —
Debt securities:				
U.S. Treasuries	1,843	—	1,641	—
U.S. government agency	161	—	331	217
Total	$ 2,004	$ —	$ 1,972	$ 217

Debt securities at December 31, 2011 and 2010 mature, according to their contractual terms, as follows (actual maturities may differ due to call or prepayment rights):

	2011		2010	
	Amortized costs	Fair values	Amortized costs	Fair values
In one year or less	$ 43,021	$ 43,092	$ 71,111	$ 71,193
After one year through five years	120,141	122,074	146,451	148,123
Total	$ 163,162	$ 165,166	$ 217,562	$ 219,316

(Dollars in thousands)

Gross unrealized losses on investments and the fair values of the related securities, aggregated by investment category and length of time that individual securities have been in a continuous unrealized loss position at December 31, 2011 and 2010 were as follows:

	2011		2010	
	Less than 12 months		Less than 12 months	
	Losses	Fair values	Losses	Fair values
Debt securities:				
U.S. Treasuries	$ —	$ —	$ —	$ —
U.S. government agency	—	—	217	15,783
Total	$ —	$ —	$ 217	$ 15,783

The unrealized loss positions were primarily caused by interest rate fluctuations. The number of investments in an unrealized loss position as of December 31, 2011 and 2010 was zero and one, respectively. Since the Company does not intend to sell and will more likely than not maintain each debt security until its anticipated recovery, and no significant credit risk is deemed to exist, these investments are not considered other-than-temporarily impaired.

(10) Fair Value of Other Financial Instruments

FASB ASC 820 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measures. It applies under other accounting standards that require or permit fair value measurements and does not require any new fair value measurements.

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

	2011	2010
Institutional money market government portfolio	$ 44,844	$ 44,774

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

Big Rivers' long-term debt at December 31, 2011 consists of RUS notes totaling $644,299, variable rate pollution control bonds in the amount of $58,800, and fixed rate pollution control bonds in the amount of $83,300 (see note 4). The RUS debt cannot be traded in the market and, therefore, a value other than its outstanding principal amount cannot be determined. The fair value of the Company's variable rate pollution control debt is par value, as each variable rate reset effectively prices such debt to the current market. At December 31, 2011, the fair value of Big Rivers' fixed rate pollution control debt was determined based on quoted prices in active markets of identical liabilities (Level 1 measure) and totaled $86,399.

(Dollars in thousands)

(11) Postretirement Benefits Other than Pensions

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

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

	2011	2010	2009
Discount rate – projected benefit obligation	4.29%	4.96%	5.78%
Discount rate – net periodic benefit cost	4.96	5.78	6.32

The health care cost trend rate assumptions as of December 31, 2011 and 2010 were as follows:

	2011	2010
Initial trend rate	7.40%	7.60%
Ultimate trend rate	4.50	4.50
Year ultimate trend is reached	2028	2028

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

	2011	2010
One-percentage-point decrease:		
Effect on total service and interest cost components	$ (211)	$ (201)
Effect on year end benefit obligation	(1,056)	(1,131)
One-percentage-point increase:		
Effect on total service and interest cost components	254	236
Effect on year end benefit obligation	1,226	1,306

BIG RIVERS ELECTRIC CORPORATION

Notes to Financial Statements

December 31, 2011 and 2010

(Dollars in thousands)

A reconciliation of the Company's benefit obligations of its postretirement plan at December 31, 2011 and 2010 follows:

		2011		2010
Benefit obligation – beginning of period	$	15,864	$	13,864
Service cost – benefits earned during the period		1,253		1,313
Interest cost on projected benefit obligation		754		743
Participant contributions		160		85
Benefits paid		(611)		(313)
Actuarial loss		620		172
Benefit obligation – end of period	$	18,040	$	15,864

A reconciliation of the Company's postretirement plan assets at December 31, 2011 and 2010 follows:

		2011		2010
Fair value of plan assets – beginning of period	$	—	$	—
Employer contributions		451		228
Participant contributions		160		85
Benefits paid		(611)		(313)
Fair value of plan assets – end of period	$	—	$	—

The funded status of the Company's postretirement plan at December 31, 2011 and 2010 follows:

		2011		2010
Benefit obligation – end of period	$	(18,040)	$	(15,864)
Fair value of plan assets – end of period		—		—
Funded status	$	(18,040)	$	(15,864)

The components of net periodic postretirement benefit costs for the years ended December 31, 2011, 2010, and 2009 were as follows:

		2011		2010		2009
Service cost	$	1,253	$	1,313	$	878
Interest cost		754		743		464
Amortization of prior service cost		17		17		17
Amortization of actuarial (gain)		—		—		(17)
Amortization of transition obligation		31		31		31
Net periodic benefit cost	$	2,055	$	2,104	$	1,373

(Dollars in thousands)

A reconciliation of the postretirement plan amounts in accumulated other comprehensive income (loss) at December 31, 2011 and 2010 follows:

		2011		2010
Prior service cost	$	(130)	$	(147)
Unamortized actuarial gain (loss)		(385)		235
Transition obligation		(31)		(62)
Accumulated other comprehensive income (loss)	$	(546)	$	26

In 2012, $18 of prior service cost, $0 of actuarial gain, and $31 of the transition obligation is expected to be amortized to periodic benefit cost.

The recognized adjustments to other comprehensive loss at December 31, 2011 and 2010 follows:

		2011		2010
Prior service cost	$	17	$	18
Unamortized actuarial loss		(620)		(172)
Transition obligation		31		30
Other comprehensive loss	$	(572)	$	(124)

At December 31, 2011 and 2010, amounts recognized in the balance sheets were as follows:

		2011		2010
Accounts payable	$	(762)	$	(600)
Deferred credits and other		(17,278)		(15,264)
Net amount recognized	$	(18,040)	$	(15,864)

Expected retiree benefit payments projected to be required during the years following 2011 are as follows:

		Amount
Year:		
2012	$	761
2013		963
2014		1,148
2015		1,277
2016		1,383
2017 – 2021		8,754
Total	$	14,286

In addition to the postretirement plan discussed above, in 1992 Big Rivers began a postretirement benefit plan, which vests a portion of accrued sick leave benefits to salaried employees upon retirement or death. To the extent an employee's sick leave hour balance exceeds 480 hours such excess hours are paid at 20% of the employee's base hourly rate at the time of retirement or death. The accumulated obligation recorded for the postretirement sick leave benefit is $579 and $391 at December 31, 2011 and 2010, respectively. The postretirement expense recorded was $191, $21, and $45 for 2011, 2010, and 2009, respectively, and the benefits paid were $3, $5, and $78 for 2011, 2010, and 2009, respectively.

(12) Related Parties

For the years ended December 31, 2011, 2010, and 2009, Big Rivers had tariff sales to its members of $151,472, $151,001, and $125,826, respectively. In addition, for the years ended December 31, 2011, 2010, and 2009, Big Rivers had certain sales to Kenergy for the Aluminum Smelters and Domtar Paper loads of $306,420, $281,473, and $167,885, respectively.

At December 31, 2011 and 2010, Big Rivers had accounts receivable from its members of $40,314 and $36,636, respectively.

(13) Commitments and Contingencies

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

Big Rivers plans to seek KPSC approval for its 2012 environmental compliance plan (ECP) in an April 2012 filing. This ECP will consist of $283,490 of capital projects, primarily for a new scrubber at the D.B. Wilson station and a new selective catalytic reduction facility at the R.D. Green station, and certain additional operations and maintenance costs. The purpose of the ECP is to allow Big Rivers to comply, in the most cost-effective manner, with the U.S. Environmental Protection Agency Cross-State Air Pollution Rule, and Mercury and Other Air Toxics Standards. Among other things, the ECP filing will seek to recover the costs of the ECP through an amendment to Big Rivers' existing environmental surcharge tariff rider, an automatic cost-recovery mechanism that is similar in function to the fuel adjustment clause. The regulatory process is expected to last six months after the filing date.

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Summary of Utility Plant and Accumulated Provisions for Depreciation Amortization and Depletion (Ref Page: 200)

Utility Plant					
In Service					
3. Plant in Service (Classified)	$1,978,791,756.00	$1,978,791,756.00	$0.00	$0.00	$0.00
4. Property under Capital Leases					
5. Plant Purchased or Sold					
6. Completed Construction not Classified					
7. Experimental Plant Unclassifed					
8. Total - In Service	$1,978,791,756.00	$1,978,791,756.00	$0.00	$0.00	$0.00
9. Leased to Others					
10. Held for Future Use	$475,968.00	$475,968.00	$0.00	$0.00	$0.00
11. Construction Work in Progress	$49,150,583.00	$49,150,583.00	$0.00	$0.00	$0.00
12. Acquisition Adjustments					
13. Total Utility Plant (Lines 8 - 12)	$2,028,418,307.00	$2,028,418,307.00	$0.00	$0.00	$0.00
14. Accum. Prov. for Depr. Amort. And Depl.	$936,354,953.00	$936,354,953.00	$0.00	$0.00	$0.00
15. Net Utility Plant (Line 13 less 14)	$1,092,063,354.00	$1,092,063,354.00	$0.00	$0.00	$0.00
16. Detail of Accumulated Provisions for Depreciation Amortization and Depletion					
17. In Service					
18. Depreciation	$913,869,436.00	$913,869,436.00	$0.00	$0.00	$0.00
19. Amort. and Depl. of Production Natural Gas Land and Land Rights					

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Summary of Utility Plant and Accumulated Provisions for Depreciation Amortization and Depletion (Ref Page: 200)

	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
20. Amort of Underground Storage Land and Land Rights					
21. Amort of Other Utility Plant	$22,485,517.00	$22,485,517.00	$0.00	$0.00	$0.00
22. Total In Service (Lines 18-21)	$936,354,953.00	$936,354,953.00	$0.00	$0.00	$0.00
23. Leased to Others					
24. Depreciation					
25. Amortization and Depletion					
26. Total Leased to Others (Lines 24 and 25)					
27. Held for Future Use					
28. Depreciation					
29. Amortization					
30. Total Held for Future Use (Lines 28 and 29)					
31. Abandonment of Leases (Natural Gas)					
32. Amort. Of Plant Aquision Adj.					
33. Total Accumulated Provisions (Should agree with Line 14, Total 22,26,30,31 and 32)	$936,354,953.00	$936,354,953.00	$0.00	$0.00	$0.00

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Nuclear Fuel Materials (Ref Page: 202)

	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1. Nuclear Fuel in process of Refinement, Conv, Enrichment + Fab (120.1)						
2. Fabrication						
3. Nuclear Materials						
4. Allowance for Funds Used during Construction						
5. (Other Overhead Construction Cost, details in notes)						
6. Subtotal (Lines 2-5)						
7. Nuclear Fuel Materials and Assemblies						
8. In Stock (120.2)						
9. In Reactor (120.3)						
10. Subtotal (lines 8 and 9)						
11. Spent Nuclear Fuel (120.4)						
12. Nuclear Fuel Under Capital Leases (120.6)						
13. (Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)						
Total Nuclear Fuel Stock (Lines 6,10,11,12 less 13)						
15. Estimated net Salvage Value of Nuclear Materials in line 9						

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Nuclear Fuel Materials (Ref Page: 202)

	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
16. Estimated net Salvage Value of Nuclear Materials in Line 11						
17. Est Net Salvage Value of Nuclear Materials in Chemical Processing						
18. Nuclear Materials held for Sale (157)						
19. Uranium						
20. Plutonium						
21. Other (provide details in note)						
22 Total Nuclear Materials held for Sale (Total 19, 20, 21)						

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Nuclear Fuel Materials (Ref Page: 202)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Estimated net Salvage e of Nuclear Materials ne 11						
Est Net Salvage Value uclear Materials in nical Processing						
Nuclear Materials held ale (157)						
Uranium						
Plutonium						
Other (provide details te)						
otal Nuclear Materials for Sale (Total 19, 20,						

NOT APPLICABLE

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900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Electric Plant in Service - Intangible and Production Plant (Ref Page: 204)

	Beginning (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance (g)
1. Intangible Plant						
Organization (301)	$420.00	$0.00	$0.00	$0.00	$0.00	$420.00
Franchises and Consents (302)	$66,476.00	$0.00	$0.00	$0.00	$0.00	$66,476.00
Miscellaneous Intangible Plant (303)						
5. Total Intangible Plant	$66,896.00	$0.00	$0.00	$0.00	$0.00	$66,896.00
2. Production Plant						
A. Steam Production Plant						
Land and Land Rights (310)	$4,537,577.00	$0.00	$0.00	$0.00	$0.00	$4,537,577.00
Structures and Improvements (311)	$124,654,006.00	$1,026,685.00	$206,474.00	$0.00	$0.00	$125,474,217.00
Boiler Plant Equipment (312)	$1,258,560,635.00	$17,976,052.00	$4,882,212.00	$0.00	$0.00	$1,271,654,475.00
Engines and Engine Driven Generators (313)						
Turbogenerator Units (314)	$228,280,409.00	$3,837,567.00	$1,758,893.00	$0.00	$0.00	$230,359,083.00
Accessory Electric Equipment (315)	$61,423,950.00	$362,044.00	$145,755.00	$0.00	$0.00	$61,640,239.00
Misc. Power Plant Equipment (316)	$3,573,552.00	$1,147,645.00	$143,214.00	$0.00	$0.00	$4,577,983.00
Asset Retirement Costs for Steam Production (317)						
16. Total Steam Production Plant	$1,681,030,129.00	$24,349,993.00	$7,136,548.00	$0.00	$0.00	$1,698,243,574.00
B. Nuclear Production Plant						
Land and Land Rights (320)						

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Electric Plant in Service - Intangible and Production Plant (Ref Page: 204)

Structures and Improvements (321)	
Reactor Plant Equipment (322)	
Turbo generator Units (323)	
Accessory Electric Equipment (324)	
Misc. Power Plant Equipment (325)	
Asset Retirement Costs for Nuclear Production (326)	
25. Total Nuclear Production Plant	
C. Hydraulic Production Plant	
Land and Land Rights (330)	
Structures and Improvements (331)	
Reservoirs, Dams and Waterways (332)	
Water Wheels, Turbines, and Generators (333)	
Accessory Electric Equipment (334)	
Misc. Power Plant equipments (335)	
Roads, Railroads and Bridges (336)	
Asset Retirement Costs for Hydraulic Production (337)	

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Electric Plant in Service - Intangible and Production Plant (Ref Page: 204)

	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
35. Total Hydraulic Production Plant						
D. Other Production Plant						
Land and Land Rights (340)						
Structures and Improvements (341)	$154,233.00	$0.00	$0.00	$0.00	$0.00	$154,233.00
Fuel Holders, Products and Accessories (342)	$1,436,911.00	$49,200.00	$43,724.00	$0.00	$0.00	$1,442,387.00
Prime Movers (343)	$4,915,885.00	$0.00	$0.00	$0.00	$0.00	$4,915,885.00
Generators (344)	$1,102,964.00	$0.00	$0.00	$0.00	$0.00	$1,102,964.00
Accessory Electric Equipment (345)	$383,520.00	$0.00	$0.00	$0.00	$0.00	$383,520.00
Misc. Power Plant Equipment (346)						
Asset Retirement Costs for Other Production (347)						
45. Total Other Production Plant	$7,993,513.00	$49,200.00	$43,724.00	$0.00	$0.00	$7,998,989.00
46. Total Production Plant (Lines 16,25,35 and 45)	$1,689,023,642.00	$24,399,193.00	$7,180,272.00	$0.00	$0.00	$1,706,242,563.00

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Electric Plant in Service - Transmission, Distribution and General Plant (Ref Page: 206)

	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3. Transmission Plant						
Land and Land Rights (350)	$13,856,815.00	$2,087.00	$0.00	$0.00	$0.00	$13,858,902.00
Structures and Improvements (352)	$6,859,817.00	$12,489.00	$0.00	$0.00	$0.00	$6,872,306.00
Station Equipments (353)	$122,103,112.00	$1,095,091.00	$192,774.00	$0.00	$0.00	$123,005,429.00
Towers and Fixtures (354)	$8,593,544.00	$0.00	$0.00	$0.00	$0.00	$8,593,544.00
Poles and Fixtures (355)	$42,410,905.00	$126,451.00	$6,348.00	$0.00	$0.00	$42,531,008.00
Overhead Conductors and Devices (356)	$43,864,755.00	$12,954.00	$621.00	$0.00	$0.00	$43,877,088.00
Underground Conduit (357)						
Underground Conductors and Devices (358)						
Roads and Trails (359)						
Asset Retirement Costs for Transmission Plant (359.1)						
58. Total Transmission Plant	$237,688,948.00	$1,249,072.00	$199,743.00	$0.00	$0.00	$238,738,277.00
4. Distribution Plant						
Land and Land Rights (360)						
Structures and Improvements (361)						
Station equipments (362)						
Storage Battery Equipments (363)						
Poles, Towers and Fixtures (364)						
Overhead Conductors and Devices (365)						

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Electric Plant in Service - Transmission, Distribution and General Plant (Ref Page: 206)

	[illegible]	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	[illegible]
Underground Conduit (366)						
Underground Conductors and Devices (367)						
Lines Transformers (368)						
Services (369)						
Meters (370)						
Installations on Customer Premises (371)						
Leased Property on Customer Premises (372)						
Street Lighting and Signal Systems (373)						
Asset Retirement Costs for Distribution Plant (374)						
75. Total Distribution Plant						
5. General Plant						
Land and Land Rights (389)	$407,251.00	$0.00	$0.00	$0.00	$0.00	$407,251.00
Structures and Improvements (390)	$3,948,934.00	$1,560,508.00	$258,221.00	$0.00	$0.00	$5,251,221.00
Office Furniture and Equipment (391)	$8,072,629.00	$13,185,716.00	$22,733.00	$0.00	$0.00	$21,235,612.00
Transportation Equipment (392)	$3,093,119.00	$217,911.00	$0.00	$0.00	$0.00	$3,311,030.00
Stores Equipment (393)	$98,766.00	$0.00	$0.00	$0.00	$0.00	$98,766.00
Tools, shop and Garage Equipments (394)	$722,077.00	$4,679.00	$0.00	$2,425.00	$0.00	$729,181.00
Laboratory Equipment (395)	$221,279.00	$0.00	$0.00	$0.00	$0.00	$221,279.00

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Electric Plant in Service - Transmission, Distribution and General Plant (Ref Page: 206)

	[illegible]	Additions	Retirements	Adjustments	Transfers	[illegible]
Power Operated Equipment (396)	$564,573.00	$3,302.00	$0.00	$0.00	$0.00	$567,875.00
Communication Equipment (397)	$1,640,119.00	$245,695.00	$215,263.00	$0.00	$0.00	$1,670,551.00
Miscellaneous Equipment (398)	$168,826.00	$82,429.00	$0.00	$0.00	$0.00	$251,255.00
Subtotal General Plant (Lines 71 thru 80)	$18,937,573.00	$15,300,240.00	$496,217.00	$2,425.00	$0.00	$33,744,021.00
Other Tangible Property (399)						
Asset Retirement Costs for General Plant (399.1)						
90. Total General Plant	$18,937,573.00	$15,300,240.00	$496,217.00	$2,425.00	$0.00	$33,744,021.00
Total (Accts 101 and 106) (Lines 5,16,25,35,45,58,75,90)	$1,945,717,059.00	$40,948,505.00	$7,876,232.00	$2,425.00	$0.00	$1,978,791,757.00
Electric Plant Purchased (See Instr. 8) (102)						
(Less Electric Plant Sold (See Instr. 8) (102)						
Experimental Plant Unclassified (103)						
Total Electric Plant in Service	$1,945,717,059.00	$40,948,505.00	$7,876,232.00	$2,425.00	$0.00	$1,978,791,757.00

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900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Electric Plant Leased to Others (104) (Ref Page: 213)

NOT APPLICABLE

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Electric Plant Held for Future Use (Acct 105) (Ref Page: 214)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
and Rights:				
	Land, Combustion Turbine	01/09/2008		$475,968.00
r Property				
				$475,968.00
AL				

Construction Work in Progress - Electric (107) (Ref Page: 216)

Two Way Radio System	$4,903,915.00
Wilson 19F Line	$3,362,278.00
GN - Boiler Painting	$2,905,116.00
GN - FGD Restoration	$2,642,888.00
OC-3 Ring	$2,073,717.00
White Oak Substation	$1,925,291.00
WL Secondary Air Heater	$1,807,115.00
Falls of Rough-McDaniels	$1,497,272.00
WL Finishing Superheater	$1,300,417.00
Wilson 19F Terminal	$1,096,803.00
Paradise - 7B Tap 161kV Line	$703,956.00
Operator Training Simulator	$667,281.00
GN Barge Unloader Dust Collector	$662,885.00
2010 Poles	$622,482.00
G1 - C/T Decks & Support	$604,514.00
WL Dust Collectors Phase 2	$575,244.00
WL FGD Modification	$568,340.00
Wilson/Centertown 69kV Line	$566,878.00
Skillman Transformer Rewind	$554,360.00
CL 3-4 Startup to 69kV	$548,013.00
H1 - Cooling Tower MCC	$495,169.00
GN - Replace #6N Mooring Cell	$475,874.00
Hyperion Software System	$463,983.00
G1 - Air Heater Baskets	$423,330.00
Livingston Autotransformer	$386,725.00
GN - IUCS Control	$358,971.00
CL Auxiliary Transformer	$344,148.00

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Construction Work in Progress - Electric (107) (Ref Page: 216)

IT Network Interface - ACES/MISO	$322,697.00
C3 Excitation System	$321,289.00
Armstrong Lewis Creek Mine	$316,906.00
GN - Lime Silo Dust Collector	$308,282.00
G1 - Generator Volt Regulator	$295,544.00
WL 8-1 Conveyor Belt	$275,174.00
CL Server & Client Replacement	$244,791.00
Paradise 161kV Terminal Upgrade	$240,629.00
GN - Replace Lime Silo Screws	$234,819.00
GN - Emergency Diesel Generator	$234,523.00
Armstrong Dock	$231,220.00
Ops Training Simulator - GN & CL	$224,617.00
Equality Mine	$224,613.00
WL Barge Unloader Controls	$224,000.00
WL Grounding Lightning Arrest	$218,673.00
GN - Precipitator AVC's	$216,495.00
2011 Poles	$212,528.00
GN - B Trans Twr Dust Collector	$211,969.00
H1 - Wet Btm Ash Rmval Hopper	$210,679.00
Coleman EHV Reconductor	$201,548.00
G2 - Remote Racking and Relays	$197,434.00
Comm Tower Corrosion Prot	$192,544.00
R1 & R2 161kV Lns Teleprotect	$191,569.00
C1B Circ Water Pump OH	$187,583.00
C3 Heater #5 Replacement	$187,132.00
G1 - Precip Repair	$184,987.00
G1 - Precip A Inlet Diffuser	$184,042.00

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Construction Work in Progress - Electric (107) (Ref Page: 216)

GN - Landfill Expansion	$183,802.00
G2 - Upgrd SOE Migrate to DCS	$183,484.00
H1 - A&B AH Cold End Baskets	$178,253.00
Switches-Const 938	$178,220.00
Tower-Engineering	$174,127.00
CMS - Shop Expansion	$170,982.00
C1B Circ Water Pump Column	$170,471.00
G1 - Generator Rectifier Rpl	$165,089.00
Ops Training Simulator - Henderson	$163,664.00
WL Remote Racking - ARC	$163,061.00
H2 - Cooling Tower MCC	$151,903.00
G2-B River Water Make Up Pump	$144,788.00
H1 - Burner Repl Study	$144,121.00
G1 - # 3 LP Heater Retube	$138,805.00
GN - FGD Rehabilitation	$138,752.00
2010 Tier C Replacements	$136,023.00
WL Dust Collection Tripper Twr	$136,000.00
H1 - Insulation & Lagging	$135,368.00
G2 - ABB DCS Infi90 MPSII Power	$128,276.00
WL Drainage Ditch Landfill	$122,246.00
GN - IU Bldg Component Rplce	$120,417.00
WL Turbine Emergency Trip	$120,267.00
GN - Bleed Pump (2) 7 & 8 of 8	$120,013.00
G2 - OFA Beck Drives	$119,898.00
C3 DCS Contr & Comm Mod	$119,320.00
WL WWClarifier	$115,767.00
R1 - "B" Mill Bearing Housing	$115,602.00

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Construction Work in Progress - Electric (107) (Ref Page: 216)

[redacted]

H0 - Updgrade CEMs Equipment	$115,198.00
G1 - B Boiler Feed Pump Motor	$114,658.00
EMS Hardware Software Upgrade	$112,295.00
C1 DCS Contr & Comm Mod	$112,173.00
G1 - O2 Probe Additions	$111,491.00
G2 - DCS Bridge Controller Upg	$108,753.00
CL - 2011 Remote Racking & Relay	$101,856.00
Other - Minor Projects	$5,602,188.00
Total	$49,150,583.00

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Accumulated Provision for Depreciation of Electric Utility Plant (108) (Ref Page: 219)

[redacted]

SECTION A BALANCES AND CHARGES DURING THE YEAR					
Balance Beginning of Year		$888,597,139.00	$888,597,139.00	$0.00	$0.00
Depreciation Provisions for Year Charged to					
Depreciation Expense (403)		$35,247,017.00	$35,247,017.00	$0.00	
Depreciation Expense for Asset Retirement Costs (403.1)					
Exp of Elec Plant Leased to Others (413)					
Transportation Expenses - Clearing					
Other Clearing Accounts					
Other Accounts (Specify)					
	Shared Asset Accumulated Provision	$106,702.00	$106,702.00	$0.00	$0.00
Total Depreciation Prov for Year		$35,353,719.00	$35,353,719.00	$0.00	$0.00
Net Charges for Plant Retired					
Book Cost of Plant Retired		($7,411,207.00)	($7,411,207.00)	$0.00	$0.00
Cost of Removal		($2,757,790.00)	($2,757,790.00)	$0.00	$0.00
Salvage (Credit)		($87,366.00)	($87,366.00)	$0.00	$0.00
Total Net Charges for Plant Retired		($10,081,631.00)	($10,081,631.00)	$0.00	$0.00
Other Debit or Credit Items					
	Freight-Returned Item	$209.00	$209.00	$0.00	$0.00
Balance End of Year		$913,869,436.00	$913,869,436.00	$0.00	$0.00

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Accumulated Provision for Depreciation of Electric Utility Plant (108) (Ref Page: 219)

SECTION B BALANCES AT END OF YEAR ACCORDING TO FUNCTIONAL CLASSIFICATION				
Steam Production	$788,358,540.00	$788,358,540.00	$0.00	$0.00
Nuclear Production				
Hydraulic Production - Conventional				
Hydraulic Production - Pumped Storage				
Other Production	$5,746,582.00	$5,746,582.00	$0.00	$0.00
Transmission	$112,985,524.00	$112,985,524.00	$0.00	$0.00
Distribution				
General	$6,778,790.00	$6,778,790.00	$0.00	$0.00
Total	$913,869,436.00	$913,869,436.00	$0.00	$0.00

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900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Investments in Subsidiary Companies (123.1) (Ref Page: 224)

Description	Date Acquired (b)	Date Maturity (c)	Investment Beg of Yr (d)	Equity in Subsidiary (e)	Revenues (f)	[illegible]	[illegible]
'OTAL							

NOT APPLICABLE

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900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Materials and Supplies (Ref Page: 227)

Fuel Stock (151)		$36,750,058.00	$33,553,927.00	0
Fuel stock Expenses Undistributed (152)				
Residuals and Extracted Products (153)				
Plant Materials and Operating Supplies (154)				
Assigned to - Construction (Estimated)				
Assigned to - Operations and Maintenance				
Production Plant (Estimated)		$22,495,130.00	$23,824,466.00	0
Transmission Plant (Estimated)		$669,645.00	$760,999.00	0
Distribution Plant				
Assigned to Other				
Total Plant Materials and Operating Supplies (154)		$23,164,775.00	$24,585,465.00	
Merchandise (155)				
Other Materials and Supplies (156)				
Nuclear Materials Held for Sale (Not applicable to Gas Utilities) (157)				
Stores Expense Undistributed (163)		$52,877.00	$709,799.00	0
	0			
Total Materials and Supplies		$59,967,710.00	$58,849,191.00	

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900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Allowances (158.1 and 158.2) (Ref Page: 228)

[redacted]

Balance-Beginning of Year		26,790	$578,382.00	0	$0.00	0	$0.00
Acquired During Year							
Issued (Less Withheld Allow)		54,239	$0.00	54,239	$0.00	54,239	$0.00
Returned by EPA		0	$0.00	0	$0.00	0	$0.00
Purchases/Transfers							
	Element Markets, LLC	400	$4,000.00	0	$0.00	0	$0.00
	American Electric Pwr Srvc Corp	2,225	$293,500.00	0	$0.00	0	$0.00
	HMP&L - Station Two	3,276	$0.00	0	$0.00	0	$0.00
		0	$0.00	0	$0.00	0	$0.00
Total		5,901	$297,500.00	0	$0.00	0	$0.00
Relinquished During Year							
Charges to Account 509		31,243	$535,795.00	0	$0.00	0	$0.00
Other:							
	Adj for 2:1 Allowances	0	$0.00	0	$0.00	0	$0.00
	EPA True-Up	0	$0.00	0	$0.00	0	$0.00
Cost of Sales/Transfers							
Transfers							
Adjustments							
Total							
Balance at End of Year		55,687	$340,087.00	54,239	$0.00	54,239	$0.00
Sales							

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Allowances (158.1 and 158.2) (Ref Page: 228)

Net sales Proceeds (Assoc. Co)						
Net Sales Proceeds (Other)						
Gains						
Losses						
Allowances Withheld (158.2)						
Balance Beginning of Year						
Add: Withheld by EPA	1,382	$0.00	1,382	$0.00	1,382	$0.00
Deduct: Returned by the EPA						
Cost of Sales	1,382	$0.00	691	$0.00	691	$0.00
Balance - End of Year	0	$0.00	691	$0.00	691	$0.00
Sales						
Net Sales Proceeds (Assoc. Co.)	1,382	$2,065.00	0	$0.00	0	$0.00
Net Sales Proceeds (Other)	0	$0.00	0	$0.00	0	$0.00
Gains	0	$2,065.00	0	$0.00	0	$0.00
Losses	0	$0.00	0	$0.00	0	$0.00

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900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Allowances (158.1 and 158.2) (Ref Page: 228) (Part Two)

Balance-Beginning of Year		0	$0.00	0	$0.00	26,790	$578,382.00
Acquired During Year							
Issued (Less Withheld Allow)		54,239	$0.00	1,062,166	$0.00	1,279,122	$0.00
Returned by EPA		0	$0.00	0	$0.00	0	$0.00
Purchases/Transfers							
	Element Markets, LLC	0	$0.00	0	$0.00	400	$4,000.00
	American Electric Pwr Srvc Corp	0	$0.00	0	$0.00	2,225	$293,500.00
	HMP&L - Station Two	0	$0.00	0	$0.00	3,276	$0.00
		0	$0.00	0	$0.00	0	$0.00
Total		0	$0.00	0	$0.00	5,901	$297,500.00
Relinquished During Year							
Charges to Account 509		0	$0.00	0	$0.00	40,206	$535,795.00
Other:							
	Adj for 2:1 Allowances	0	$0.00	0	$0.00	-8,973	$0.00
	EPA True-Up	0	$0.00	0	$0.00	10	$0.00
Cost of Sales/Transfers							
Transfers							
Adjustments							
Total							
Balance at End of Year		54,239	$0.00	1,062,166	$0.00	1,280,570	$340,087.00
Sales							

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Allowances (158.1 and 158.2) (Ref Page: 228) (Part Two)

[redacted]

Net sales Proceeds (Assoc. Co)						
Net Sales Proceeds (Other)						
Gains						
Losses						
Allowances Withheld (158.2)						
Balance Beginning of Year						
Add: Withheld by EPA	1,382	$0.00	35,932	$0.00	41,460	$0.00
Deduct: Returned by the EPA						
Cost of Sales	691	$0.00	2,764	$0.00	6,219	$0.00
Balance - End of Year	691	$0.00	33,168	$0.00	35,241	$0.00
Sales						
Net Sales Proceeds (Assoc. Co.)	0	$0.00	0	$0.00	1,382	$2,065.00
Net Sales Proceeds (Other)	0	$0.00	0	$0.00	0	$0.00
Gains	0	$0.00	0	$0.00	0	$2,065.00
Losses	0	$0.00	0	$0.00	0	$0.00

Note:

1) EPA SO2 allotted through 2040. EPA Nox allotted through 2014.

2) All SO2 and Nox forward are reflective of EPA vintage year allocation excluding HMP&L Station Two. HMP&L Station Two is a 312 MW generating facility owned by Henderson Municipal Power and Light (HMP&L) that Big Rivers operates under an agreement with HMP&L. Big Rivers receives certain capacity rights to the Station Two facility under its operating agreement with HMP&L.

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Extraordinary Property Losses (182.10) (Ref Page: 230)

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Other Regulatory Assets (182.3) (Ref Page: 232)

[redacted]

Total

Miscellaneous Deferred Debits (186) (Ref Page: 233)

	Deferred Cost - CoBank Line of Credit	$128,585.00	$0.00	930	$83,333.00	$45,252.00
	Deferred Cost - NRUCFC Line of Credit	$88,575.00	$0:00	930	$25,000.00	$63,575.00
	Deferred Cost - Hanson Site Lease	$190,502.00	$0.00	567/931	$5,523.00	$184,979.00
	Deferred Cost - Ice Storm Repair	$73,645.00	$0.00	562/570/571	$0.00	$73,645.00
Misc Work in Progress						
Deferred Regulatory Commission Expenses						
TOTAL		$481,307.00				$367,451.00

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Accumulated Taxes (Ref Page: 234)

Electric

Other

Total Electric

Gas

Other

Total Gas

Other

Total (Acct 190)

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Capital Stock (Accounts 201 and 204) (Ref Page: 250)

Common Stock

Total Common Stock

Preferred Stock

Total Preferred Stock

Other

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Capital Stock (Accounts 201 and 204) (Ref Page: 250) (Part Two)

Common Stock

Total Common Stock

Preferred Stock

Total Preferred Stock

Other

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Other Paid-In Capital (Ref Page: 253)

[redacted]

	Kenergy Corp.	$163,564.00
	Meade County RECC	$81,782.00
	Jackson Purchase Energy Corporation	$82,810.00
	Consumers Donated Capital	$435,819.00
	Consumers Cont. for Debt Service Account 211	$3,680,527.00
Total		$4,444,502.00

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Capital Stock Expense (214) (Ref Page: 254)

Total

Long Term Debt (221,222,223,224) (Ref Page: 256)

Acct 221					
Total Acct 221					
Acct 222					
Total Acct 222					
Acct 223					
Total Acct 223					
Acct 224					
	RUS Series A Note	$602,573,536.00	$0.00	07/16/2009	07/01/2021
	RUS Series B Note	$245,530,257.00	$0.00	07/16/2009	12/31/2023
	Ohio County of Kentucky Note, Series 1983	$58,800,000.00	$444,843.00	06/30/1983	06/01/2013
	Ohio County of Kentucky Note, Series 2010A	$83,300,000.00	$2,247,917.00	06/01/2010	07/15/2031
Total Acct 224		$990,203,793.00	$2,692,760.00		

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Long Term Debt (221,222,223,224) (Ref Page: 256) (Part Two)

[redacted]

Acct 221					
Total Acct 221					
Acct 222					
Total Acct 222					
Acct 223					
Total Acct 223					
Acct 224					
	RUS Series A Note			$521,249,857.00	$31,629,145.00
	RUS Series B Note			$123,048,572.00	$6,883,863.00
	Ohio County of Kentucky Note, Series 1983	07/10/1983	09/30/1987	$58,800,000.00	$2,204,136.00
	Ohio County of Kentucky Note, Series 2010A	06/01/2010	07/15/2031	$83,300,000.00	$4,998,000.00
Total Acct 224				$786,398,429.00	$45,715,144.00

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900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Reconciliation of Reported Net Income with Taxable for Federal Income (Ref Page: 261)

Net Income for the Year		$5,700,381.00
Taxable Income Not Reported on Books		
	RUS Series B Note Int. Exp. 481(a) Adj.	$18,975,009.00
	Interest Income - Economic Reserve	$898,779.00
	Interest Income - Rural Economic Reserve	$1,155,638.00
Deductions Recorded on Books not Deducted for Return		
	NonSmelter Non-FAC PPA	$1,859,758.00
	Dues and Penalties	$48,486.00
	Meals & Entertainment	$48,891.00
	Lobbying	$25,754.00
Income Recorded on Books not Included in Return		
	Economic Reserve Usage	$20,806,289.00
	0	$0.00
	0	$0.00
	0	$0.00
Deductions on Return Not Charged Against Book Income		
	Reverse PC Bond Refunding Cost (Amort. for Books)	$3,155.00
	Interest Expense - RUS Series B Note	$4,150,994.00
	Loss on Disposal of Property	$6,646,134.00
	Depreciation	$15,359,406.00
Federal Tax net Income		($18,253,282.00)
Show Computation of Tax		
	See Hard Copy For Detail of Tax Computation	$0.00

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Taxes Accrued, Prepaid and Charged During Year (Ref Page: 262)

	FEDERAL TAXES	$0.00	$0.00	$0.00	$0.00	$0.00
	Unemployment	$309.00	$0.00	$50,758.00	$36,166.00	$0.00
	FICA	$210,430.00	$0.00	$3,566,002.00	$3,573,933.00	$0.00
	Income	$0.00	$0.00	$100,000.00	$130,000.00	($30,000.00)
	STATE and LOCAL TAXES	$0.00	$0.00	$0.00	$0.00	$0.00
	Unemployment	$475.00	$0.00	$73,795.00	$54,164.00	$0.00
	Sales and Use	$85,739.00	$0.00	$2,058,588.00	$1,919,837.00	$0.00
	Income	$0.00	$0.00	($1,611.00)	($1,611.00)	$0.00
	Property-Ad Valorum/Franchise	$362,056.00	$0.00	$3,536,096.00	$3,403,589.00	$0.00
Total Taxes		$659,009.00	$0.00	$9,383,628.00	$9,116,078.00	($30,000.00)

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900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Taxes Accrued, Prepaid and Charged During Year (Ref Page: 262) (Part Two)

	FEDERAL TAXES	$0.00	$0.00	$0.00	$0.00	$0.00	$50,758.00
	Unemployment	$14,901.00	$0.00	$0.00	$0.00	$0.00	$3,566,002.00
	FICA	$202,499.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Income	$0.00	$30,000.00.	$100,000.00	$0.00	$0.00	$0.00
	STATE and LOCAL TAXES	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Unemployment	$20,106.00	$0.00	$0.00	$0.00	$0.00	$73,795.00
	Sales and Use	$224,490.00	$0.00	$0.00	$0.00	$0.00	$2,058,588.00
	Income	$0.00	$0.00	($1,611.00)	$0.00	$0.00	$0.00
	Property-Ad Valorum/Franchise	$494,563.00	$0.00	$0.00	$0.00	$0.00	$3,536,096.00
Total Taxes		$956,559.00	$30,000.00	$98,389.00	$0.00	$0.00	$9,285,239.00

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Accumulated Deferred Investment Tax Credit (255) (Ref Page: 266)

[redacted]

Electric Utility	
3 percent	
4 percent	
7 percent	
10 percent	
TOTAL	
Other (List seperately and show 3, 4, 7 and 10 Percent and TOTAL)	
Total Other	
Total	

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Other Deferred Credits (253) (Ref Page: 269)

TOTAL

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Accumulated Deferred Income Taxes - Accelerated Amortization Property (281) (Ref Page: 272)

Accelerated Amortization (281)

Electric

Defense Facilities

Pollution Control Facilities

Other

Total Electric

Gas

Defense Facilities

Pollution Control Facilities

Other

TOTAL Gas

TOTAL (281)

Classification of Total

Federal Income Tax

State Income Tax

Local Income tax

Other Specify

Accumulated Deferred Income Taxes - Accelerated Amortization Property (281) (Ref Page: 272) (Part Two)

Accelerated Amortization (281)
Electric
Defense Facilities
Pollution Control Facilities
Other
Total Electric
Gas
Defense Facilities
Pollution Control Facilities
Other
TOTAL Gas
TOTAL (281)
Classification of Total
Federal Income Tax
State Income Tax
Local Income tax
Other Specify

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Accumulated Deferred Income Taxes - Other Property (282) (Ref Page: 274)

[redacted]

Account 282

Electric

Gas

Other (Define)

Total

Other (specify)

TOTAL Acct 282

Classification of Total

Federal Income Tax

State Income Tax

Local Income tax

Accumulated Deferred Income Taxes - Other Property (282) (Ref Page: 274) (Part Two)

[redacted]

Account 282

Electric

Gas

Other (Define)

Total

Other (specify)

TOTAL Acct 282

Classification of Total

Federal Income Tax

State Income Tax

Local Income tax

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Accumulated Deferred Income Taxes - Other (283) (Ref Page: 276)

[redacted]

Account 283

Electric

Other

Total Electric

Gas

Other

TOTAL Gas

Other (Specify)

TOTAL (Acct 283)

Classification of Total

Federal Income Tax

State Income Tax

Local Income tax

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Accumulated Deferred Income Taxes - Other (283) (Ref Page: 276) (Part Two)

Account 283

Electric

Other

Total Electric

Gas

Other

TOTAL Gas

Other (Specify)

TOTAL (Acct 283)

Classification of Total

Federal Income Tax

State Income Tax

Local Income tax

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Other Regulatory Liabilities (254) (Ref Page: 278)

Other Reg. Liab-Economic Reserve-Member Rate Stability	447	$26,704,850.00	$6,797,340.00	$98,859,793.00
Other Reg Liab-Rural Economic Reserve-Member Rate Stability	447	$95,216.00	$1,250,854.00	$63,500,830.00
Other Reg Liab-Non Smelter Non-FAC PPA-Member Rate Stability	557	$7,787,460.00	$3,635,702.00	$628,877.00
Other Reg Liab - Non Smelter Non-FAC PPA - Amort. Member Rate Stability	557	$1,069,060.00	$7,080,577.00	$6,011,517.00
		$35,656,586.00	$18,764,473.00	$169,001,017.00

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Electric Operating Revenues (Ref Page: 300)

Sales of Electricity						
Residential Sales (440).						
Commercial and Industrial Sales (442)						
Small (or comm.) (See Instr. 4)						
Large (or Ind) (See Instr 4)						
Public Street and Highway Lighting (444)						
Other Sales to Public Authorities (445)						
Sales to Railroads and Railways (446)						
Interdepartmental Sales (448)						
Total Sales to Ultimate Consumers						
Sales for Resale (447)	$558,372,354.00	$514,490,437.00	13,255,125	11,969,420	3	3
Total Sales of Electricity	$558,372,354.00	$514,490,437.00	13,255,125	11,969,420	3	3
(Less) Provision for Rate Refunds (449.1)						
Total Revenues Net of Prov. for Refunds	$558,372,354.00	$514,490,437.00	13,255,125	11,969,420	3	3
Other Operating Revenues						
Forfeited Discounts (450)						
Miscellaneous Service Revenues (451)						

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Electric Operating Revenues (Ref Page: 300)

Sales of Water and Water Power (453)						
Rent from Electric Property (454)	$39,000.00	$26,250.00	0	0	0	0
Interdepartmental Rents (455)						
Other Electric Revenues (456)	$3,577,878.00	$12,807,766.00	0	0	0	0
Total Other Operating Revenues	$3,616,878.00	$12,834,016.00	0	0	0	0
Total Electric Operating Revenues	$561,989,232.00	$527,324,453.00	13,255,125	11,969,420	3	3
*NOTE Line 12 Column b includes Total of unbilled Revenues						
**Note Line 12 Column d includes Total MWH relating to unbilled revenues						

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Sales of Electricity by Rate Schedules (Ref Page: 304)

	ALL SALES OF ELECTRICITY ARE FOR RESALE	0	$0.00	0	0	0.0000
Total Billed						0
Total Unbilled Rev (see Instr 6)						0
TOTAL						0

[redacted]

Requirements Service				
KENERGY CORP	RQ	367	366	337
JACKSON PURCHASE ENERGY CORP	RQ	126	126	126
MEADE COUNTY RURAL ECC	RQ	92	92	89
KENERGY - ALCAN	RQ	0	0	0
KENERGY - CENTURY	RQ	0	0	0
	RQ	0	0	0
	RQ	0	0	0
	RQ	0	0	0
	RQ	0	0	0
	RQ	0	0	0
	RQ	0	0	0
	RQ	0	0	0
Total RQ		585	584	552
Non Requirements Service				
KENERGY - DOMTAR COGEN	LF	0	0	0
KENERGY - DOMTAR - ARS	LF	0	0	0
AMERICAN ELECTRIC POWER SERVICE CORP	OS	0	0	0
CARGILL - ALLIANT LLC	OS	0	0	0
CONSTELLATION ENERGY COMMODITIES	OS	0	0	0
EDF TRADING NORTH AMERICA, LLC	OS	0	0	0

Sales for Resale (447) (Ref Page: 310)

	HENDERSON MUNICIPAL POWER & LIGHT	OS	0	0	0
	KENTUCKY UTILITIES COMPANY	OS	0	0	0
	MIDWEST ISO	OS	0	0	0
	PJM INTERCONNECTION	OS	0	0	0
	POWERSOUTH ENERGY COOPERATIVE	OS	0	0	0
	SOUTHERN COMPANY SERVICES	OS	0	0	0
Total Non RQ			0	0	0
Total			585	584	552
EXPORT					
INTRASTATE					
TOTAL					

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Sales for Resale (447) (Ref Page: 310) (Part Two)

[redacted]

Requirements Service						
	KENERGY CORP	2,180,184	$39,374,026.00	$51,168,551.00	$6,188,165.00	$96,730,742.00
	JACKSON PURCHASE ENERGY CORP	683,764	$12,183,246.00	$17,926,721.00	$1,885,337.00	$31,995,304.00
	MEADE COUNTY RURAL ECC	480,251	$8,815,839.00	$12,490,373.00	$1,439,848.00	$22,746,060.00
	KENERGY - ALCAN	3,083,275	$0.00	$135,972,842.00	$0.00	$135,972,842.00
	KENERGY - CENTURY	3,771,545	$0.00	$168,906,623.00	$0.00	$168,906,623.00
		0	$0.00	$0.00	$0.00	$0.00
		0	$0.00	$0.00	$0.00	$0.00
		0	$0.00	$0.00	$0.00	$0.00
		0	$0.00	$0.00	$0.00	$0.00
		0	$0.00	$0.00	$0.00	$0.00
		0	$0.00	$0.00	$0.00	$0.00
		0	$0.00	$0.00	$0.00	$0.00
Total RQ		10,199,019	$60,373,111.00	$386,465,110.00	$9,513,350.00	$456,351,571.00
Non Requirements Service						
	KENERGY - DOMTAR COGEN	41,321	$0.00	$1,535,953.00	$0.00	$1,535,953.00
	KENERGY - DOMTAR - ARS	0	$0.00	$4,092.00	$0.00	$4,092.00

[redacted]

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Sales for Resale (447) (Ref Page: 310) (Part Two)

[redacted]

Total Non RQ	[redacted]
Total	
EXPORT	
INTRASTATE	
TOTAL	

Note:
Ref Page 310

Column (i) - Energy Charge - credit amount represents prior year true-ups.

Column (j) - Other Charges represents Member Rate Stability Mechanism (MRSM).

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Electric Operation and Maintenance Expenses - 1. Power Production (Ref Page: 320)

POWER PRODUCTION EXPENSES		
A. Steam Power Generation		
Operation		
Operation Supervision and Engineering (500)	$5,180,360.00	$4,624,985.00
Fuel (501)	$225,295,221.00	$207,087,919.00
Steam Expenses (502)	$29,760,153.00	$34,236,992.00
Steam from Other Sources (503)		
(Less) Steam Transferred CR (504)		
Electric Expenses (505)	$6,684,248.00	$5,878,526.00
Miscellaneous steam Power Expenses (506)	$8,216,012.00	$7,331,014.00
Rents (507)		
Allowance (509)	$535,795.00	$401,618.00
Total Operation	$275,671,789.00	$259,561,054.00
Maintenance		
Maintenance Supervision and Engineering (510)	$4,734,044.00	$3,945,686.00
Maintenance of Structures (511)	$3,648,594.00	$3,727,682.00
Maintenance of Boiler Plant (512)	$26,279,855.00	$26,814,441.00
Maintenance of Electric Plant (513)	$4,799,647.00	$4,098,834.00
Maintenance of Miscellaneous Steam Plant (514)	$3,283,553.00	$2,778,045.00
Total Maintenance	$42,745,693.00	$41,364,688.00
21. Total Power Production Expenses --Steam Power	$318,417,482.00	$300,925,742.00
B. Nuclear Power Generation		
Operations		
Operation Supervision and Engineering (517)		
Fuel (518)		
Coolants and water (519)		
Steam Expenses (520)		

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Electric Operation and Maintenance Expenses - 1. Power Production (Ref Page: 320)

Steam from Other Sources (521)

(Less) Steam Transferred -- CR (522)

Electric Expenses (523)

Miscellaneous Nuclear Power Expenses (524)

Rents (525)

Total Operation

Maintenance

Maintenance Supervision and Engineering (528)

Maintenance of Structures (529)

Maintenance of Reactor Plant Equipment (530)

Maintenance of Electric Plant (531)

Maintenance of Miscellaneous Nuclear Plant (532)

Total Maintenance

41. Total Power Production Expenses - Nuclear Power

C. Hydraulic Power Generation

Operation

Operation Supervision and Engineering (535)

Water for Power (536)

Hydraulic Expenses (537)

Electric Expenses (538)

Miscellaneous Hydraulic Power Genration Expenses (539)

Rents (540)

Total Operation

Maintenance

Maintenance of Supervision and Engineering (541)

Maintenance of Structures (542)

Maintenance of Reservoirs, Dams and Waterways (543)

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Electric Operation and Maintenance Expenses - 1. Power Production (Ref Page: 320)

Maintenance of Electric Plant (544)		
Maintenance of Miscellaneous Hydraulic Plant (545)		
Total Maintenance		
59. Total Power Production Expenses - Hydraulic Power		
D. Other Power Generation		
Operation		
Operation Supervision and Engineering (546)		
Fuel (547)	$933,829.00	$660,601.00
Generation Expenses (548)	$33,917.00	$33,807.00
Miscellaneous Other Power Generation Expenses (549)		
Rents (550)		
Total Operation	$967,746.00	$694,408.00
Maintenance		
Maintenance Supervision and Engineering (551)		
Maintenance of Structures (552)		
Maintenance of Generating and Electric Plant (553)	$150,725.00	$792,175.00
Maintenance of Miscellaneous Other Power Generation Plant (554)		
Total Maintenance	$150,725.00	$792,175.00
Total Power Production Expenses – Other Power	$1,118,471.00	$1,486,583.00
E. Other Power Supply Expenses		
Purchased Power (555)	$104,779,045.00	$80,327,589.00
System Control and Load Dispatching (556)	$45,850.00	$689,793.00
Other Expenses (557)	$7,436,997.00	$18,403,884.00
79. Total Other Power Supply Expenses	$112,261,892.00	$99,421,266.00
80. Total Power Production Expenses (Lines 21,41,59,74,79)	$431,797,845.00	$401,833,591.00

c. See the attached schedule of defined contribution and defined benefit pension costs by account for the forecasted test period. The $3.5 m defined contribution amount on the attached schedule is less than the $4.5 m and $4.4 m amounts referred to above because of the anticipated reduction in the number of employees. The $2.3 m defined benefit amount on the attached schedule is the anticipated net periodic pension cost, whereas the $.1 m referenced above is an expected contribution amount. The two are not related.

Witness) James V. Haner

Big Rivers Electric Corporation
Case No. 2012-00535
Attachment for Response to AG 2-31(c)

Defined Contribution and Defined Benefit Pension Costs
Forecasted Test Period Budget

Account	Defined Benefit	Defined Contribution	Total
10700000	17,849	27,354	45,203
50010000	185,808	284,762	470,570
50120000	116,702	178,853	295,555
50210000	216,928	332,456	549,384
50211000	48,969	75,048	124,017
50510000	219,445	336,314	555,759
50610000	56,749	86,972	143,721
51010000	169,103	259,161	428,264
51110000	27,688	42,434	70,122
51210000	233,632	358,057	591,689
51211000	105,489	161,669	267,158
51212000	8,009	12,274	20,283
51214000	458	701	1,159
51310000	53,774	82,413	136,187
51410000	49,655	76,100	125,755
56010000	13,958	21,392	35,350
56020000	18,077	27,705	45,782
56110000	39,587	60,670	100,257
56210000	13,043	19,989	33,032
56310000	2,517	3,858	6,375
56610000	6,178	9,469	15,647
56620000	8,695	13,326	22,021
56810000	11,441	17,535	28,976
56820000	11,441	17,535	28,976
57010000	32,036	49,097	81,133
57110000	40,731	62,423	103,154
57310000	3,890	5,962	9,852
57320000	5,263	8,066	13,329
90810000	7,780	11,924	19,704
92010000	416,923	638,961	1,055,884
92010300	142,330	218,130	360,460
93510000	4,119	6,312	10,431
Total	**2,288,267**	**3,506,922**	**5,795,189**

BIG RIVERS ELECTRIC CORPORATION

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March 28, 2013

Item 32) ***Referencing Big Rivers' responses to KIUC 1-8, page 12, which is an email dated November 13, 2012 that includes the statement "Mark Hite had a few comments for this presentation," and AG 1-134 which states Mark Hite retired July 14, 2012, please explain:***

a. Why Mark Hite would be commenting on presentations to the Board of Directors following his retirement;

b. What are Mark Hite's ongoing tasks and responsibilities at Big Rivers; and,

c. On what basis is Mark Hite working for Big Rivers, and for what compensation?

Response:

a. The statement "Mark Hite had a few comments for this presentation" is referring to the prior year's presentation made to the Board on the depreciation study completed for Big Rivers' 2011 rate case, and does not refer to the presentation made by Ms. Richert to the Board on November 16, 2012.

b. None.

c. Not applicable.

Witness) Billie J. Richert

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Item 33) *Referring to page 8 of Big Rivers' response to PSC 2-18: [BEGIN CONFIDENTIAL]*

a. [redacted]

b. [redacted]

c. [redacted] *[END CONFIDENTIAL]*

Response)

[redacted]

[redacted]

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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Item 34) *Regarding the MISO Attachment O spreadsheets provided in response to AG 1-181, please provide the following:*

a. All Big Rivers Attachment O spreadsheets subsequent to the 2011 spreadsheet as they become available

Response)

a. No subsequent Attachment O spreadsheet is currently available. Big Rivers will update its responses as required by law, as ordered by the Commission, or as it otherwise deems appropriate.

Witness) Chris Warren

BIG RIVERS ELECTRIC CORPORATION

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Item 35) ***If Big Rivers is able to sell any one or more generation facilities, would there be stranded costs for those facilities even after the sale? If so, how would Big Rivers recover those costs?***

Response) Big Rivers objects that the use of the term "stranded costs" is inappropriate in this context. This question cannot be answered without knowing the sale price(s) of any such transaction(s).

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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Item 36) ***Does Big Rivers intend to offer an incentive pay plan during the future test year? If so, provide complete details, and explain why the ratepayers should finance such a pay plan given the "precarious" financial position of the company, as Mr. Bailey testified.***

Response) Incentive pay is not included in the test period.

Witness) DeAnna M. Speed

BIG RIVERS ELECTRIC CORPORATION

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Item 37) ***Reference Big Rivers' responses to AG 1-213, AG 1-214, AG 1-215; KIUC 1-25, KIUC 1-26; and Alcan 1-1. Please confirm that Big Rivers submitted to RUS a "Corrective Plan to Achieve Two Credit Ratings of Investment Grade" on or about March 7, 2013.***

a. Please confirm that this Corrective Plan is responsive to the requests for information referenced above.

b. Please supply a copy of this Corrective Plan, together with any confidential version thereof.

Response: Confirmed.

a. Confirmed.

b. A copy of this Corrective Plan is provided as an attachment to Commission Staff's Third Request for Information dated March 14, 2013, PSC 3-9.

Witness) Billie J. Richert

Item 38) *Reference Big Rivers' responses to PSC 2-6 and 2-15. Do Big Rivers' responses reflect and take into account the additional changes to its application in Case No. 2012-00492, which were made via the testimony of Billie Richert during the hearing on February 28, 2013?*

a. If not, please provide amended answers in light of the above-referenced testimony.

b. What anticipated maintenance may be deferred as a result of this reduced level of funding for ordinary capital expenditures?

Response) The amended application and the testimony of Billie J. Richert in Case No. 2012-00492 are not expected to result in any revisions to the answers to PSC 2-6 or PSC 2-15.

a. Not applicable.

b. Big Rivers does not anticipate deferring additional maintenance as a result of the amended application in Case No. 2012-00492.

Witnesses) Billie J. Richert; Robert W. Berry

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Item 39) *Reference Big Rivers' response to PSC 2-11. Provide the audited statement of operating (income statement) when it becomes available.*

Response) Please see the response to KIUC 2-49.

Witness) Billie J. Richert

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2012-00535

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Item 40) *Reference Big Rivers' response to KIUC 1-63. Please provide a final version of the KPMG memo referenced during the February 28, 2013 hearing in Case No. 2012-00492.*

Response) Please see the KPMG memo that was provided to the Commission and intervenors, including the Attorney General, in the response to request number 1 of the March 4, 2013 Responses to Data Requests from Hearing on February 28, 2013 in Case No. 2012-00492.

Witness) Billie J. Richert

BIG RIVERS ELECTRIC CORPORATION

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CASE NO. 2012-00535

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Item 41) ***Reference Big Rivers' response to PSC 2-13. Does Big Rivers response reflect and take into account the additional changes to its application in Case No. 2012-00492, which were made via the testimony of Billie Richert during the hearing on February 28, 2013? If not, please provide an amended answer in light of the above-referenced testimony.***

Response) The amended application and the testimony of Billie J. Richert in Case No. 2012-00492 are not expected to result in any revisions to the answer to PSC 2-13.

Witness) Billie J. Richert

BIG RIVERS ELECTRIC CORPORATION

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March 28, 2013

Item 42) ***Reference Big Rivers' response to PSC 2-18. Regarding the negotiations detailed in its response, would Big Rivers characterize itself as competitively advantaged or disadvantaged in these negotiations with the counterparties referenced? Please explain in detail.***

Response) Big Rivers would characterize itself as well-positioned in the negotiations with the counterparties referenced in response to PSC 2-18. However, whether Big Rivers is competitively advantaged or disadvantaged is largely dependent upon the views, priorities, and risk tolerances of the counterparties. Those views may vary by counterparty.

Big Rivers recognizes that there are advantages and disadvantages to its current position. One advantage is that Big Rivers is a low-cost provider of electricity, not only in the state of Kentucky, but in the nation. If Big Rivers is able to acquire load equivalent to current levels, Big Rivers' costs are competitive or significantly better than most providers in the U.S. Please see the response to KIUC 2-45(b). Another advantage is the close proximity of Big Rivers to many of the potential counterparties; this reduces the delivery cost and risk to those counterparties. One disadvantage, at least in the short term, is that current MISO market prices are less than most providers' all-in fixed and variable costs.

Regardless of whether or not Big Rivers is competitively advantaged in its negotiations, Big Rivers remains committed to the implementation of the Load Concentration Analysis & Mitigation Plan, with the goal of alleviating the adverse impacts of the Century contract termination on Big Rivers' remaining members.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

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Item 43) ***Referencing Big Rivers' response to AG 1-166, which requested all correspondence, emails, etc. between Big Rivers and the smelters regarding provision of draft annual capital and operating budgets under Sections 3.4 (a) and 3.4 (e) of the Coordination Agreement:***

a. It appears no correspondence is provided beyond the brief cover letters that accompany each budget. Please provide all correspondence, emails, etc. between Big Rivers and the smelters, or their respective representatives, during the period between provision of the draft and final annual budgets.

b. Please provide a communications log of all communications between Big Rivers and the smelters or their respective representatives during the periods between the provision of the draft budget, and the final budget to the smelters.

Response) Big Rivers objects to this request on the grounds that it is overly broad and unduly burdensome. Notwithstanding this objection, but without waiving it, Big Rivers states as follows.

a. AG 1-166 asked Big Rivers to *"provide a copy of each draft budget provided to the smelters under the terms of the smelter agreements since 2010 and to provide copies of all correspondence, emails, etc. between Big Rivers and the smelters regarding those draft budgets."* The only known communication provided to the smelters regarding the draft budgets was given in response to AG 1-166, in the form of cover letters to the budget packages.

b. All known communication regarding the draft budgets has been provided previously in response to AG 1-166.

Witness) DeAnna M. Speed

BIG RIVERS ELECTRIC CORPORATION

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Item 44) *Referencing Big Rivers' response to AG 1-166, comparing the "Budget Assumptions" for the draft and final budgets provided to the smelters for fiscal year 2013 provide documents which show the basis for:*

a. [BEGIN CONFIDENTIAL] [redacted]

b. [redacted]

c. [redacted]

d. [redacted]

e. [redacted]

f. [redacted]

g. [redacted]

h. [redacted]

i. [redacted]

j. [redacted]

BIG RIVERS ELECTRIC CORPORATION

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FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

Response to the Office of the Attorney General's
Supplemental Set of Requests
Dated March 14, 2013

March 28, 2013

k. [redacted]

l. [redacted]

m. [redacted] *[END CONFIDENTIAL].*

Response) Section 3.4 of the Coordination Agreements states that Big Rivers shall provide to each smelter for its review and evaluation (i) on or prior to the date 90 days prior to the end of each fiscal year (which Big Rivers interprets to mean by October 1st of each year), a copy of Big Rivers' then-current draft proposed annual capital and operating budget (the "Proposed Budget") for the following fiscal year, and (ii) any reasonably-requested supporting information with respect to the Proposed Budget or expenditures in excess of the budget. Big Rivers' budget development process typically calls for the Board of Directors to review and approve the budget in the November/December timeframe. Thus, it is expected that the Proposed Budget provided to the smelters is a draft and that advancement of that draft into a final budget ready for Board approval will continue after October 1st each year. With this in mind, Big Rivers does not log or document the specific changes in assumptions, values, or other budgetary inputs between the provision of the draft budget to the smelters and the provision of the near-final budget to the Board for its review and approval. All of the changes listed in the question generally result from the on-going revision, correction, and/or refinement of budgetary information that takes place in that timeframe, as data becomes available and through the normal course of business.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

Response to the Office of the Attorney General's
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Dated March 14, 2013

March 28, 2013

Witness) John Wolfram

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

Response to the Office of the Attorney General's
Supplemental Set of Data Requests
Dated March 14, 2013

March 28, 2013

Item 45) *Referencing Big Rivers' response to AG 1-166, comparing the "Budget Assumptions" for the draft and final budgets provided to the smelters for fiscal year 2012 provide documents which show the basis for:*

a. [BEGIN CONFIDENTIAL] [redacted]

b. [redacted]

c. [redacted]

d. [redacted]

e. [redacted]

f. [redacted]

g. [redacted]

h. [redacted]

i. [redacted]

[END CONFIDENTIAL]

Response) Please see the response to AG 2-44.

Witness) John Wolfram

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2012-00535

Response to the Office of the Attorney General's Supplemental Set of Data Requests Dated March 14, 2013

March 28, 2013

Item 46) ***Referencing Big Rivers' Board of Director Minutes provided in response to AG 1-38 (page 855): [BEGIN CONFIDENTIAL]*** [redacted] ***[END CONFIDENTIAL]***

Response) [redacted]

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

Response to the Office of the Attorney General's
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Dated March 14, 2013

March 28, 2013

Item 47) ***Provide all Board of Director Minutes, for both regular sessions and Executive Sessions, regardless of the nature of the meeting, for January and February 2013.***

Response) Attached under a petition for confidential treatment are the regular session minutes of the January and February 2013 board meetings. There were no Executive Session minutes.

Witness) Mark A. Bailey

All AG 2-47 attachments have been omitted from the public filing. They have been provided under a petition for confidential treatment.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

**Response to the Office of the Attorney General's
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Dated March 14, 2013**

March 28, 2013

Item 48) *Referencing Big Rivers' Board of Direct Minutes at AG 1-38 (page 869): [BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL]*

Response) Page 869 of AG 1-38 does not reference the subject identified in this request.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

**Response to the Office of the Attorney General's
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Dated March 14, 2013**

March 28, 2013

Item 49) ***Referencing the "Executive Session Minutes" provided in response to AG 1-38, please explain how many of the minutes consist of approving the prior session's minutes but there are no prior session minutes provided. See, e.g., pages 4-11.***

a. Provide all <u>Executive Session</u> Minutes from January 1, 2010 to present.

Response) There is only one set of executive session minutes (the January 2010 minutes) where the prior session's minutes were approved but not provided. The January 2010 minutes noted the approval of the minutes of the December 2009 executive session. The December 2009 executive session minutes were not provided because the question asked for minutes beginning in 2010.

a. All such minutes were provided on the CONFIDENTIAL CD in response to AG 1-38.

Witness) Mark A. Bailey

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

Response to the Office of the Attorney General's
Supplemental Sets of Data Requests
Dated March 14, 2013

March 28, 2013

Item 50) *Referencing Big Rivers' Board of Direct Minutes provided in response to AG 1-38*

a. *At Page 3: [BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL]*

b. *At page 400: [BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL]*

c. *At page 400: [BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL*

d. *At page 417: [BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL]*

e. *At page 444: [BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL*

f. *At page 483:[BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL]* *g. At page 504: [BEGIN CONFIDENTIAL]* [redacted] *[END CONFIDENTIAL]*

h. At page 532: [BEGIN CONFIDENTIAL] [redacted] *[END CONFIDENTAL]*

i. At page 532: [BEGIN CONFIDENTIAL] [redacted] *[END CONFIDENTIAL]*

j. At page 838: [BEGIN CONFIDENTIAL] [redacted] *[END CONFIDENTIAL]*

k. At page 864: [BEGIN CONFIDENTIAL] [redacted] *[END CONFIDENTIAL]*

Response) Big Rivers objects to this request on the grounds that it does not provide information sufficient for Big Rivers to identify much of the requested material. Many of the requests seek detailed explanations of oral discussions from more than a year ago, or documents related to those specific oral discussions. These discussions were not recorded. The minutes provided in response to AG 1-38 are the best documentation of these discussions. Due to the limited amount of available information and the passage of time, it is often impossible to determine with any certainty the content of those oral discussions. Notwithstanding this objection, but without waiving it, Big Rivers states as follows.

a. Big Rivers objects to this request on the grounds that [redacted]

b. Big Rivers objects to this request on the grounds that it does not provide information sufficient for Big Rivers to identify [redacted]

c. Big Rivers objects to this request on the grounds that it does not provide information sufficient for Big Rivers to identify [redacted]

d. Please see the attached document submitted under a petition for confidential treatment.

e. Please see the attached document submitted under a petition for confidential treatment.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
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f. Please see the attached document submitted under a petition for confidential treatment.

g. [redacted]

h. Big Rivers objects to this request on the grounds that it does not provide information sufficient for Big Rivers to identify [redacted]

i. Big Rivers objects to this request on the grounds that it does not provide information sufficient for Big Rivers to identify [redacted]

j. Big Rivers objects to this request on the grounds that it does not provide information sufficient for Big Rivers to identify [redacted]

k. Big Rivers cannot provide the requested information because [redacted]

Witnesses) Mark A. Bailey; Counsel

All AG 2-50 attachments have been omitted from the public filing. They have been provided under a petition for confidential treatment.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2012-00535

Response to the Office of the Attorney General's Supplemental Set of Data Requests Dated March 14, 2013

March 28, 2013

Item 51) *Referencing AG1-17 related to Financial Model "sensitivity" runs performed by BREC since August 2012, address the following:*

a. Explain if BREC has run a Financial Model or sensitivity run with actual 2012 calendar year amounts in the calculation of the revenue requirement and provide this sensitivity run with all related documentation, adjustments, and assumptions.

b. If BREC has not run the sensitivity analysis in (a), please provide this sensitivity run.

c. Regarding the sensitivity runs in (a) and (b) above, provide a sensitivity run with all adjustments used for the forecasted test period in this filing (such as those shown at Tab 50 Attachment (page 7 of 7) and Mr. Wolfram's testimony (Exhibit Wolfram-2, Schedules 1.01 through 1.12), except reflect these adjustments on an actual calendar year 2012 basis and provide supporting documentation.

d. Regarding (a) and (b) above, identify, explain and provide calculations supporting all other adjustments that BREC made to the actual calendar year 2012 sensitivity run to reflect this on a revenue requirements/rate case basis.

Response)

a. No. Big Rivers has not run a Financial Model or sensitivity run with actual 2012 calendar year amounts as inputs. The Big Rivers Financial Model is a tool that uses certain input data to project Big Rivers' overall financial values and metrics for future periods. The model is not designed to use actual data as inputs to the forecast model and simply recreate the past results. The model accepts input from the production cost model and from Big Rivers' budgeting system Hyperion – data which differs from that reflected as actuals on the company's books and records. The model is incompatible with the input of actual data in certain respects; for example, the model assumes perfect rate treatment (i.e. ignores regulatory lag associated with FAC, ES, and Non-FAC PPA). The model calculates member revenues, FAC, ES, Surcharge, and Non-FAC PPA; it does not accept these terms as inputs. In order to accept 2012 actual data as an input, the very structure of the model would have to be altered (i.e. calculations would have to be over-written, links would have to be broken, etc.). The modifications to the model required in order to accept actual data as inputs to the model would render meaningless any comparison of model outputs to the information provided in the instant filing.

Even if the use of 2012 actuals was limited to the determination of the revenue requirement (and did not apply to all model inputs), this would inappropriately combine historical and forecast values in the Big Rivers Financial Model. The revenue requirement based on 2012 actuals would be inconsistent with the production cost model output, payroll costs, and other assumptions in the model that correspond to the forecast. This would essentially invalidate the model.

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

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

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

Witness) John Wolfram

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

**Response to the Office of the Attorney General's
Supplemental Set of Data Requests
Dated March 14, 2013**

March 28, 2013

Item 52) *Referencing AG 1-39 related to Management Business Plans and budgeted CAPEX for 2013 and 2014, this response shows CAPEX budgets for 2013 and 2014 that are less than CAPEX amounts for 2013 and 2014 included in BREC's filing at Tab 25 Attachment (Berry and Crockett). Address the following:*

a. Explain which CAPEX budgets cited above should be relied upon for this rate case and the forecasted test period.

b. Explain if BREC's financial model and adjustments for the forecasted test period use the CAPEX plant amounts in (a) above (and explain which CAPEX amounts or budgets are used) to adjust expenses (i.e., depreciation expense, property taxes, and others), accumulated depreciation, deferred income taxes, and other amounts and costs in the forecasted test period. If the answer is "yes", then show how all expenses and other costs in the forecasted test period are calculated based on the related CAPEX plant amounts that are assumed for the forecasted test period and provide all supporting calculations and workpapers.

Response)

a. The budget is the same for AG 1-39 and Tab 25 except that AG 1-39 is just referencing Production projects and excludes Administration, Information Technology and Transmission. The total of all Big Rivers Electric

Corporation CAPEX is attached in Tab 25 and should be relied upon for this rate case and the forecasted test period.

b. For depreciation, accumulated depreciation, etc. please refer to AG 1-239.

Witness) **Robert W. Berry**

Item 53) ***Referencing Big Rivers' response to AG 1-75 related to payroll costs, address the following:***

a. ***Per the attached spreadsheet AG 1-75(a), please reconcile and show where the expensed and capitalized payroll amounts for the base period ($49.9 m expenses, $.9 m capitalized), forecasted test period ($45.4 expensed and $.4 m capitalized), and 2015 budget ($45.1 m expensed and $.4 m capitalized) are included in the Company's financial model and rate case filing (provide specific references to rows and fields in spreadsheets), and explain the reasons for all differences.***
b. ***Regarding the amounts in (a) above for the forecasted test period, explain if these amounts are before or after BREC's adjustment at Schedule 1.10 to remove "non-recurring labor related to Wilson Layup", and provide a reconciliation of these amounts, showing amounts before and after the Wilson Layup adjustment and all other adjustments to payroll costs.***
c. ***Confirm if the "YTD 2011" payroll expense of $48.1 m and capitalized of $.7 m are actual 2011 calendar year payroll amount, or explain what these amounts represent because they do not agree with 2011 payroll costs of $47,854,574 at AG 1-245 (a). Provide an explanation and reconciliation between these amounts.***
d. ***Provide actual 2011 calendar year payroll amounts expensed and capitalized for AG 1-75(a), (b),(c),(d) and (e).***

e. Provide copies of RUS forms or forms filed with regulatory agencies or other entities that show 2011 and 2012 payroll costs, and explain and reconcile the differences between the 2011 and 2012 payroll amounts provided in response to AG 1-75(a) and AG 1-76(a).

Response)

a. The numbers shown in Big Rivers' response to AG 1-75(a) are for wages and salaries only, and do not include burdens, whereas the budgeted numbers (i.e., in the financial model) do include burdens. Additionally, the wages and salaries shown in response to AG 1-75(a) are gross of the City of Henderson share. For total labor costs in the forecasted test period, 2013 portion of the base period, and 2015, please see the financial model, O&M tab, rows 137-169. Capitalized labor is not shown independently of capital projects within the Big Rivers' capital budget.

b. Per the original response to AG 1-75(a), budget labor is unadjusted for the Wilson labor pro forma. The wages and salaries portion of the $2,595,458 for the Wilson labor pro forma, shown in the direct testimony of John Wolfram, Exhibit Wolfram-2, Schedule 1.10, is $1,558,742. Please refer to Big Rivers' response to AG 2-60(a) for a breakdown of the $2,595,458 Wilson labor pro forma. The reconciliation of the labor expense shown in the response to AG 1-75(a) before and after the Wilson labor pro forma is as follows:

Forecasted test period wages and salaries expensed:	$45,410,144
Less Wilson labor pro forma:	<u>$1,558,742</u>
Forecasted test period wages and salaries after adjustment:	$43,851,402

c. AG 1-245(a) reflects gross payroll, which is regular hours, overtime, double-time, off-duty hours, and shift premiums. Alternatively, AG 1-75(a) reflects payroll and burden processing, which includes incentive payments and miscellaneous credits. A reconciliation of these amounts is as follows:

Capitalized Labor	$743,369
Expensed Labor	48,095,286
Total AG 1-75(a)	48,838,655
Total Gross Payroll AG 1-245(a)	47,854,574
Difference	984,081

A breakdown of the difference is as follows:

Incentive	$993,462
Miscellaneous credits	(9,381)
Total	984,081

d. This information was provided on AG 1-75(a), (b), (c), (d), and (e). These amounts have not changed.

e. Copies of the RUS Annual Supplement for 12/31/11, and the KPSC Financial and Statistical Report (Annual Report) for 12/31/11, are attached. Reconciliation to AG 1-75(a) and AG 1-76(a) is as follows:

<u>AG 1-75(a), AG 1-76(a)</u>:

Capitalized Labor	$ 743,369
Expensed Labor	48,095,286
Total	$48,838,655

<u>RUS 2011 Report:</u>

Expensed	$46,222,175
Other	2,865,906
Incentive	(993,462)
Account 10103116,7	667
	$48,095,286
Capitalized	$ 744,036
Account 10103116,7	(667)
	$ 743,369

Accounts 10103116, 10103117, in the amount of $667, were included in the RUS capitalized amount. They were classified as expense in AG 1-75(a) and AG 1-76(a). The RUS expensed amount includes incentive payments, which are not included in AG 1-75(a) and AG 1-76(a).

Witness) James V. Haner

Big Rivers
ELECTRIC CORPORATION

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

FINAL

April 2, 2012

Mr. Victor T. Vu
Director, Power Supply Division
USDA/RUS
1400 Independence Avenue, SW, Stop 1568
Washington, DC 20250 1568

RE: RUS Form 12

Dear Mr. Vu:

Enclosed is the original signed Certification page of the electronically submitted Annual Operating Reports, Parts A, B, C, D, F, H, and I for the year ending December 31, 2011.

A copy of this Part A filing has been mailed to each of the parties listed below.

If you have any questions, please contact Donna Windhaus, Manager General Accounting at (270) 844-6167.

Sincerely,
BIG RIVERS ELECTRIC CORPORATION

Mark A. Hite

Mark A. Hite, CPA
Vice President Accounting and Interim CFO

MH/msb
Enclosures

C: Big Rivers' Board of Directors
Chairman – Kentucky Public Service Commission
Jeff Cline – Kentucky Public Service Commission
James M. Miller, Esq. – Sullivan, Mountjoy, Stainback & Miller, P.S.C.
Mr. Sandy Novick – Kenergy
Mr. Burns Mercer – Meade County R.E.C.C.
Mr. G. Kelly Nuckols – Jackson Purchase Energy Corporation
Ms. Kelli McClellan – EP-MN-WS3C – US. Bank Corporate Trust Services
Mr. Philip G. Kane Jr. – U. S. Bank National Association
Ms. Suk-Ling Ng – U. S. Bank National Association
Mr. John List - NRUCFC
Mr. Mark Glotfelty – Goldman, Sachs & Co.
Mr. Jeffrey Childs – CoBank, ACB
Mr. Fil Agusti – Steptoe & Johnson, LLP
Mr. Ryan Baynes – Midwest ISO
Mr. Jeremy Jenkins – Alcan Primary Products
Mr. Tim Martin – Century Aluminum
Mr. Doug Nelson – Wadell & Reed
Joseph P. Charles – KPMG LLP
Scott A. Heiser – KPMG LLP
Kevin Lyons – KPMG LLP
Email only: CRM.StructuredFinance@dexia-us.com
Email only: tbruckman@ambac.com
Email only: document_management@ambac.com

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0572-0032. The time required to complete this information collection is estimated to average 21 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	**BORROWER DESIGNATION** KY0062 **PERIOD ENDED** December, 2011 **BORROWER NAME** Big Rivers Electric Corporation
INSTRUCTIONS - See help in the online application.	

This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C. 552)

CERTIFICATION

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7 CFR CHAPTER XVII

(check one of the following)

☑ All of the obligations under the RUS loan documents have been fulfilled in all material respects.

☐ There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part A Section C of this report.

Mark A. Bailey

3/28/12
DATE

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

**FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART A - FINANCIAL**

BORROWER DESIGNATION
KY0062

PERIOD ENDED
December, 2011

INSTRUCTIONS - See help in the online application.

SECTION A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	YEAR-TO-DATE BUDGET (c)	THIS MONTH (d)
1. Electric Energy Revenues	514,490,437	558,372,354	544,848,212	47,411,310
2. Income From Leased Property (Net)				
3. Other Operating Revenue and Income	12,834,016	3,616,878	19,083,996	379,876
4. **Total Operation Revenues & Patronage Capital *(1 thru 3)***	527,324,453	561,989,232	563,932,208	47,791,186
5. Operating Expense -- Production - Excluding Fuel	52,506,942	50,410,485	64,788,729	4,672,988
6. Operating Expense -- Production - Fuel	207,748,520	226,229,050	206,689,669	19,074,410
7. Operating Expense -- Other Power Supply	99,421,265	112,261,892	109,893,232	9,728,939
8. Operating Expense -- Transmission	7,888,483	9,183,058	12,297,288	841,338
9. Operating Expense -- RTO/ISO	233,099	2,529,532	2,783,040	211,850
10. Operating Expense -- Distribution				
11. Operating Expense -- Customer Accounts				
12. Operating Expense -- Customer Service & Information	446,300	631,535	863,960	193,230
13. Operating Expense -- Sales	239,803	185,004	918,500	44,078
14. Operating Expense -- Administrative & General	26,461,943	26,557,242	25,728,474	2,854,518
15. **Total Operation Expense *(5 thru 14)***	394,946,355	427,987,798	423,962,892	37,621,351
16. Maintenance Expense -- Production	42,156,863	42,896,418	47,234,025	3,894,676
17. Maintenance Expense -- Transmission	4,473,124	4,680,625	3,262,807	563,893
18. Maintenance Expense -- RTO/ISO				
19. Maintenance Expense -- Distribution				
20. Maintenance Expense -- General Plant	250,361	140,534	103,595	7,010
21. **Total Maintenance Expense *(16 thru 20)***	46,880,348	47,717,577	50,600,427	4,465,579
22. Depreciation and Amortization Expense	34,242,192	35,406,806	36,227,624	3,252,184
23. Taxes	262,798	98,389	249,228	(30,000)
24. Interest on Long-Term Debt	47,064,226	45,715,144	47,366,652	3,788,739
25. Interest Charged to Construction -- Credit	(683,535)	(548,206)	(425,884)	(40,372)
26. Other Interest Expense	189,162	59,249	228,904	9
27. Asset Retirement Obligations				
28. Other Deductions	166,390	220,434	137,395	17,651
29. **Total Cost Of Electric Service *(15 + 21 thru 28)***	523,067,936	556,657,191	558,347,238	49,075,141
30. **Operating Margins *(4 less 29)***	4,256,517	5,332,041	5,584,970	(1,283,955)
31. Interest Income	391,494	150,516	385,669	6,179
32. Allowance For Funds Used During Construction				
33. Income (Loss) from Equity Investments				
34. Other Non-operating Income (Net)	2,321,612	9,288		
35. Generation & Transmission Capital Credits				
36. Other Capital Credits and Patronage Dividends	21,292	108,536	96,438	3,883
37. Extraordinary Items				
38. **Net Patronage Capital Or Margins *(30 thru 37)***	6,990,915	5,600,381	6,067,077	(1,273,893)

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART A - FINANCIAL

INSTRUCTIONS – See help in the online application.

BORROWER DESIGNATION: KY0062

PERIOD ENDED: December, 2011

SECTION B. BALANCE SHEET

ASSETS AND OTHER DEBITS		LIABILITIES AND OTHER CREDITS	
1. Total Utility Plant in Service	1,979,267,724	33. Memberships	75
2. Construction Work in Progress	49,150,583	34. Patronage Capital	
3. **Total Utility Plant (1 + 2)**	2,028,418,307	a. Assigned and Assignable	0
4. Accum. Provision for Depreciation and Amortization	936,354,953	b. Retired This year	0
		c. Retired Prior years	0
5. **Net Utility Plant (3 - 4)**	1,092,063,354	d. **Net Patronage Capital (a - b - c)**	0
6. Non-Utility Property (Net)	0	35. Operating Margins - Prior Years	(247,338,928)
7. Investments in Subsidiary Companies	0	36. Operating Margin - Current Year	5,440,576
8. Invest. in Assoc. Org. - Patronage Capital	3,648,303	37. Non-Operating Margins	638,997,537
9. Invest. in Assoc. Org. - Other - General Funds	684,993	38. Other Margins and Equities	(7,278,745)
10. Invest. in Assoc. Org. - Other - Nongeneral Funds	0	39. **Total Margins & Equities (33 + 34d thru 38)**	389,820,515
11. Investments in Economic Development Projects	10,000		
12. Other Investments	5,334	40. Long-Term Debt - RUS (Net)	572,153,789
13. Special Funds	164,151,431	41. Long-Term Debt - FFB - RUS Guaranteed	0
14. **Total Other Property And Investments (6 thru 13)**	168,500,061	42. Long-Term Debt - Other - RUS Guaranteed	0
		43. Long-Term Debt - Other (Net)	142,100,000
15. Cash - General Funds	5,698	44. Long-Term Debt - RUS - Econ. Devel. (Net)	0
16. Cash - Construction Funds - Trustee	0	45. Payments – Unapplied	0
17. Special Deposits	572,679	46. **Total Long-Term Debt (40 thru 44 - 45)**	714,253,789
18. Temporary Investments	44,843,791	47. Obligations Under Capital Leases Noncurrent	0
19. Notes Receivable (Net)	0	48. Accumulated Operating Provisions and Asset Retirement Obligations	22,098,788
20. Accounts Receivable - Sales of Energy (Net)	43,114,276	49. **Total Other NonCurrent Liabilities (47 + 48)**	22,098,788
21. Accounts Receivable - Other (Net)	232,280		
22. Fuel Stock	33,894,014	50. Notes Payable	0
23. Renewable Energy Credits	0	51. Accounts Payable	30,324,950
24. Materials and Supplies - Other	25,295,264	52. Current Maturities Long-Term Debt	72,144,640
25. Prepayments	4,507,736	53. Current Maturities Long-Term Debt - Rural Devel.	0
26. Other Current and Accrued Assets	943,684	54. Current Maturities Capital Leases	0
27. **Total Current And Accrued Assets (15 thru 26)**	153,409,422	55. Taxes Accrued	956,559
		56. Interest Accrued	9,898,751
28. Unamortized Debt Discount & Extraordinary Property Losses	2,079,214	57. Other Current and Accrued Liabilities	9,423,267
29. Regulatory Assets	0	58. **Total Current & Accrued Liabilities (50 thru 57)**	122,748,167
30. Other Deferred Debits	1,870,225	59. Deferred Credits	169,001,017
31. Accumulated Deferred Income Taxes	0	60. Accumulated Deferred Income Taxes	0
32. **Total Assets and Other Debits (5+14+27 thru 31)**	1,417,922,276	61. **Total Liabilities and Other Credits (39 + 46 + 49 + 58 thru 60)**	1,417,922,276

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2011

SECTION C. NOTES TO FINANCIAL STATEMENTS

Footnote to RUS Financial and Operating Report Electric Power Supply - Part A

Financial Ratios: 2011

Margins For Interest Ratio (MFIR) 1.12

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2011

SECTION C. CERTIFICATION LOAN DEFAULT NOTES

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2011

PART B SE - SALES OF ELECTRICITY

Sale No.	Name Of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Fuel Type (e)	Average Monthly Billing Demand (MW) (f)	Actual Average Monthly NCP Demand (g)	Actual Average Monthly CP Demand (h)
1	Ultimate Consumer(s)		AD					
2	Jackson Purchase Energy Corp	KY0020	RQ			126	138	123
3	Kenergy Corporation (KY0065)	KY0065	RQ			366	381	337
4	Kenergy Corporation (KY0065)	KY0065	IF					
5	Kenergy Corporation (KY0065)	KY0065	LF					
6	Meade County Rural E C C	KY0018	RQ			92	98	86
7	PowerSouth Energy Cooperative	AL0042	OS					
8	American Electric Power (AEP)		OS					
9	Cargill-Alliant LLC		OS					
10	Constellation Energy Commodities		OS					
11	EDF Trading North America, LLC		OS					
12	Henderson Muhic Power & Light		OS					
13	Kentucky Utilities Company		OS					
14	Midwest Independent		OS					
15	PJM Interconnection (PA)		OS					
16	Southern Company Services,		OS					
	Total for Ultimate Consumer(s)							
	Total for Distribution Borrowers					584	617	546
	Total for G&T Borrowers					0	0	0
	Total for Other					0	0	0
	Grand Total					584	617	546

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2011

PART B SE - SALES OF ELECTRICITY

Sale No	Electricity Sold (MWh) (i)	Revenue Demand Charges (j)	Revenue Energy Charges (k)	Revenue Other Charges (l)	Revenue Total (j + k + l) (m)
1					
2	683,764	12,183,246	19,812,058		31,995,304
3	2,180,184	39,374,026	57,356,716		96,730,742
4	41,321		1,540,045		1,540,045
5	6,854,820		304,879,465		304,879,465
6	480,251	8,815,839	13,930,221		22,746,060
7	[redacted]				
8	[redacted]				
9	[redacted]				
10	[redacted]				
11	[redacted]				
12	[redacted]				
13	[redacted]				
14	[redacted]				
15	[redacted]				
16	[redacted]				
	10,240,340	60,373,111	397,518,505	0	457,891,616
	1,160	0	55,208	0	55,208
	3,013,625	0	100,425,530	0	100,425,530
	[redacted]				

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY**	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2011

PART B SE - SALES OF ELECTRICITY

Sale No	Comments
1	
2	
3	
4	
5	
6	
7	
8	
9	
10	
11	
12	
13	
14	
15	
16	

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2011

PART E PP - PURCHASED POWER

Purchase No.	Name Of Company or Public Authority (a)	RUS Borrower Designation (b)	Statistical Classification (c)	Renewable Energy Program Name (d)	Primary Renewable Fuel Type (e)	Average Monthly Billing Demand (MW) (f)	Actual Average Monthly NCP Demand (g)	Actual Average Monthly CP Demand () (h)
1	Ameren Missouri (MO)		OS					
2	American Electric Power (AEP)		OS					
3	Cargill-Alliant LLC		OS					
4	EDF Trading North America, LLC (TX)		OS					
5	Henderson Munic Power & Light		RQ					
6	Midwest Independent Transmission System Operator (IN)		OS					
7	PJM Interconnection (PA)		OS					
8	RRI Energy Services (TX)		SF					
9	Southeastern Power Admin		LF					
	Total for Distribution Borrowers					0	0	0
	Total for G&T Borrowers					0	0	0
	Total for Other					0	0	0
	Grand Total					0	0	0

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2011

PART B PP - PURCHASED POWER

Purchase No	Electricity Purchased (MWh) (i)	Electricity Received (MWh) (j)	Electricity Delivered (MWh) (k)	Demand Charges (l)	Energy Charges (m)	Other Charges (n)	Total (l + m + n) (o)
1	49,776				1,407,656		1,407,656
2	126,272				3,600,672		3,600,672
3	61,332				1,742,720		1,742,720
4	38,856				1,006,349		1,006,349
5	1,565,268				64,456,947		64,456,947
6	717,898				22,966,799		22,966,799
7					4,556		4,556
8	3,030				428,969		428,969
9	435,529				9,164,377		9,164,377
	0	0	0	0	0	0	0
	0	0	0	0	0	0	0
	2,998,361	0	0	0	104,779,045	0	104,779,045
	2,998,361	0	0	0	104,779,045	0	104,779,045

Case No. 2012-00535
Attachment for Response to AG 2-53(e)
Witness: James V. Haner
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UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT *ELECTRIC POWER SUPPLY*	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2011

PART B PP - PURCHASED POWER

Purchase No	Comments
1	
2	
3	
4	
5	
6	
7	
8	
9	

reUNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART C - SOURCES AND DISTRIBUTION OF ENERGY**	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2011

SOURCES OF ENERGY *(a)*	NO. OF PLANTS *(b)*	CAPACITY (kW) *(c)*	NET ENERGY RECIEVED BY SYSTEM (MWh) *(d)*	COST ($) *(e)*
Generated in Own Plant (*Details on Parts D, E, F IC, F CC, and G*)				
1. Fossil Steam	4	1,489,000	10,277,356	385,412,876
2. Nuclear	0	0	0	0
3. Hydro	0	0	0	0
4. Combined Cycle	0	0	0	0
5. Internal Combustion	1	70,000	6,994	1,532,409
6. Other	0	0	0	0
7. **Total in Own Plant (*1 thru 6*)**	5	1,559,000	10,284,350	386,945,285
Purchased Power				
8. ***Total Purchased Power***			2,998,361	104,779,045
Interchanged Power				
9. Received Into System (Gross)			3,715,300	0
10. Delivered Out of System (Gross)			3,614,830	0
11. **Net Interchange (*9 - 10*)**			100,470	0
Transmission For or By Others - (Wheeling)				
12. Received Into System			29,536	44,304
13. Delivered Out of System			29,536	44,304
14. **Net Energy Wheeled (*12 - 13*)**			0	0
15. **Total Energy Available for Sale (*7 + 8 + 11 + 14*)**			13,383,181	
Distribution of Energy				
16. Total Sales			13,255,125	
17. Energy Furnished to Others Without Charge			0	
18. Energy Used by Borrower *(Excluding Station Use)*			0	
19. **Total Energy Accounted For (*16 thru 18*)**			13,255,125	
Losses				
20. **Energy Losses - MWh (*15 - 19*)**			128,056	
21. **Energy Losses - Percentage ((*20 / 15*) * *100*)**			.95 %	

RUS Financial and Operating Report Electric Power Supply – Part C - *Sources and Distribution of Energy* **Revision Date 2010**

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART D - STEAM PLANT**	BORROWER DESIGNATION KY0062
	PLANT Coleman
	PERIOD ENDED December, 2011

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

			FUEL CONSUMPTION					OPERATING HOURS			
NO.	UNIT NO. (a)	TIMES STARTED (b)	COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE SCHED. (j)	OUT OF SERVICE UNSCH. (k)
1.	1	9	1,059,231.60		40,398.40			8,204			556
2.	2	8	1,045,340.70		50,637.00			8,339	48		373
3.	3	15	1,078,355.60		53,123.20			8,245	31		484
4.											
5.											
6.	Total	32	3,182,928	0.00	144,158.60	0.00		24,788	79	0	1,413
7.	Average BTU		11,304		1,000.00						
8.	Total BTU (10^6)		35,978,817.00		144,159.00		36,123,976				
9.	Total Del. Cost ($)		79,757,925		808,640.00						

SECTION A. BOILERS/TURBINES (*Continued*)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	160,000	1,200,851.00	
2.	2	160,000	1,188,035.00	
3.	3	165,000	1,236,305.00	
4.				
5.				
6.	Total	485,000	3,625,191.00	9,965
7.	Station Service (MWh)		316,831.00	
8.	Net Generation (MWh)		3,308,360.00	10,919.00
9.	Station Service (%)		8.74	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1.	No. Employees Full-Time (Include Superintendent)	111
2.	No. Employees Part-Time	
3.	**Total Employee Hours Worked**	255,230
4.	Operating Plant Payroll ($)	7,604,886
5.	Maintenance Plant Payroll ($)	4,751,034
6.	Other Accts. Plant Payroll ($)	
7.	**Total Plant Payroll ($)**	12,355,920

SEC. C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	84.31%
2.	Plant Factor (%)	85.33%
3.	Running Plant Capacity Factor (%)	90.46%
4.	15 Minute Gross Max. Demand (kW)	490,820
5.	Indicated Gross Max. Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	1,661,905		
2.	Fuel, Coal	501.1	83,214,365		2.31
3.	Fuel, Oil	501.2	3,455		
4.	Fuel, Gas	501.3	808,640		5.60
5.	Fuel, Other	501.4			
6.	**Fuel SubTotal (*2 thru 5*)**	501	84,026,460	25.39	2.32
7.	Steam Expenses	502	5,469,557		
8.	Electric Expenses	505	1,979,865		
9.	Miscellaneous Steam Power Expenses	506	2,224,903		
10.	Allowances	509	194,453		
11.	Rents	507			
12.	**Non-Fuel SubTotal (*1 + 7 thru 11*)**		11,530,683	3.48	
13.	**Operation Expense (*6 + 12*)**		95,557,143	28.88	
14.	Maintenance, Supervision and Engineering	510	1,518,977		
15.	Maintenance of Structures	511	1,433,848		
16.	Maintenance of Boiler Plant	512	6,976,891		
17.	Maintenance of Electric Plant	513	1,002,864		
18.	Maintenance of Miscellaneous Plant	514	1,798,844		
19.	**Maintenance Expense (*14 thru 18*)**		12,731,424	3.84	
20.	**Total Production Expense (*13 + 19*)**		108,288,567	32.73	
21.	Depreciation	403.1,411.10	4,893,767		
22.	Interest	427	7,031,566		
23.	**Total Fixed Cost (*21 + 22*)**		11,925,333	3.60	
24.	**Power Cost (*20 + 23*)**		120,213,900	36.33	

Remarks

Case No. 2012-00535
Attachment for Response to AG 2-53(e)
Witness: James V. Haner

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART D - STEAM PLANT

BORROWER DESIGNATION KY0062

PLANT Reid

PERIOD ENDED December, 2011

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: SCHED. (j)	UNSCH. (k)
1.	1	16	115,490.80	172.88				2,458	5,833		469
2.											
3.											
4.											
5.											
6.	Total	16	115,491	172.88	0.00	0.00		2,458	5,833	0	469
7.	Average BTU		12,259	138,003.23							
8.	Total BTU (10^6)		1,415,802.00	23,858			1,439,660				
9.	Total Del. Cost ($)		3,207,070	517,523.00							

SECTION A. BOILERS/TURBINES (Continued)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	72,000	121,633.00	
2.				
3.				
4.				
5.				
6.	Total	72,000	121,633.00	11,836
7.	Station Service (MWh)		26,609.00	
8.	Net Generation (MWh)		95,024.00	15,150.49
9.	Station Service (%)		21.88	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1.	No. Employees Full-Time (Include Superintendent)	22
2.	No. Employees Part-Time	
3.	**Total Employee Hours Worked**	51,196
4.	Operating Plant Payroll ($)	1,147,828
5.	Maintenance Plant Payroll ($)	739,159
6.	Other Accts. Plant Payroll ($)	
7.	**Total Plant Payroll ($)**	1,886,987

SEC. C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	23.76%
2.	Plant Factor (%)	19.28%
3.	Running Plant Capacity Factor (%)	68.73%
4.	15 Minute Gross Max. Demand (kW)	58,435
5.	Indicated Gross Max. Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/$10^6$ BTU (c)
1.	Operation, Supervision and Engineering	500	265,083		
2.	Fuel, Coal	501.1	3,585,190		2.53
3.	Fuel, Oil	501.2	517,523		21.69
4.	Fuel, Gas	501.3			
5.	Fuel, Other	501.4			
6.	**Fuel SubTotal *(2 thru 5)***	501	4,102,713	43.17	2.84
7.	Steam Expenses	502	526,818		
8.	Electric Expenses	505	274,077		
9.	Miscellaneous Steam Power Expenses	506	284,301		
10.	Allowances	509	37,441		
11.	Rents	507			
12.	**Non-Fuel SubTotal *(1 + 7 thru 11)***		1,387,720	14.60	
13.	**Operation Expense *(6 + 12)***		5,490,433	57.77	
14.	Maintenance, Supervision and Engineering	510	246,427		
15.	Maintenance of Structures	511	99,652		
16.	Maintenance of Boiler Plant	512	1,277,048		
17.	Maintenance of Electric Plant	513	156,722		
18.	Maintenance of Miscellaneous Plant	514	180,414		
19.	**Maintenance Expense *(14 thru 18)***		1,960,263	20.62	
20.	**Total Production Expense *(13 + 19)***		7,450,696	78.40	
21.	Depreciation	403.1, 411.10	402,217		
22.	Interest	427	726,112		
23.	**Total Fixed Cost *(21 + 22)***		1,128,329	11.87	
24.	**Power Cost *(20 + 23)***		8,579,025	90.28	

Remarks

Case No. 2012-00535
Attachment for Response to AG 2-53(e)
Witness: James V. Haner

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART D - STEAM PLANT

BORROWER DESIGNATION KY0062

PLANT Green

PERIOD ENDED December, 2011

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: SCHED. (j)	UNSCH. (k)
1.	1	10	1,661,797.40	392.28				7,903	143	482	232
2.	2	6	1,723,021.00	229.38				8,367	191		202
3.											
4.											
5.											
6.	**Total**	16	3,384,818	621.66	0.00	0.00		16,270	334	482	434
7.	Average BTU		11,500	137,999.87							
8.	Total BTU (10^6)		38,925,412.00	85,789			39,011,201				
9.	Total Del. Cost ($)		69,826,963	1,936,956.00							

SECTION A. BOILERS/TURBINES *(Continued)*

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	250,000	1,882,734.00	
2.	2	242,000	1,937,441.00	
3.				
4.				
5.				
6.	**Total**	492,000	3,820,175.00	10,212
7.	Station Service (MWh)		350,009.70	
8.	Net Generation (MWh)		3,470,165.30	11,241.89
9.	Station Service (%)		9.16	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1.	No. Employees Full-Time (Include Superintendent)	114
2.	No. Employees Part-Time	
3.	**Total Employee Hours Worked**	265,411
4.	Operating Plant Payroll ($)	8,077,217
5.	Maintenance Plant Payroll ($)	5,535,355
6.	Other Accts. Plant Payroll ($)	
7.	**Total Plant Payroll ($)**	13,612,572

SEC. C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	86.37%
2.	Plant Factor (%)	88.64%
3.	Running Plant Capacity Factor (%)	95.49%
4.	15 Minute Gross Max. Demand (kW)	504,900
5.	Indicated Gross Max. Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	1,531,063		
2.	Fuel, Coal	501.1	72,500,705		1.86
3.	Fuel, Oil	501.2	1,936,956		22.57
4.	Fuel, Gas	501.3			
5.	Fuel, Other	501.4			
6.	**Fuel SubTotal** *(2 thru 5)*	501	74,437,661	21.45	1.90
7.	Steam Expenses	502	12,911,566		
8.	Electric Expenses	505	3,204,146		
9.	Miscellaneous Steam Power Expenses	506	2,130,546		
10.	Allowances	509	163,724		
11.	Rents	507			
12.	**Non-Fuel SubTotal** *(1 + 7 thru 11)*		19,941,045	5.74	
13.	**Operation Expense** *(6 + 12)*		94,378,706	27.19	
14.	Maintenance, Supervision and Engineering	510	1,564,693		
15.	Maintenance of Structures	511	962,694		
16.	Maintenance of Boiler Plant	512	9,666,586		
17.	Maintenance of Electric Plant	513	1,996,858		
18.	Maintenance of Miscellaneous Plant	514	551,867		
19.	**Maintenance Expense** *(14 thru 18)*		14,742,698	4.24	
20.	**Total Production Expense** *(13 + 19)*		109,121,404	31.44	
21.	Depreciation	403.1, 411.10	6,999,419		
22.	Interest	427	8,254,568		
23.	**Total Fixed Cost** *(21 + 22)*		15,253,987	4.39	
24.	**Power Cost** *(20 + 23)*		124,375,391	35.84	

Remarks

Case No. 2012-00535
Attachment for Response to AG 2-53(e)
Witness: James V. Haner

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART D - STEAM PLANT

BORROWER DESIGNATION KY0062

PLANT Wilson

PERIOD ENDED December, 2011

INSTRUCTIONS - See help in the online application.

SECTION A. BOILERS/TURBINES

NO.	UNIT NO. (a)	TIMES STARTED (b)	FUEL CONSUMPTION: COAL (1000 Lbs.) (c)	OIL (1000 Gals.) (d)	GAS (1000 C.F.) (e)	OTHER (f)	TOTAL (g)	OPERATING HOURS: IN SERVICE (h)	ON STANDBY (i)	OUT OF SERVICE: SCHED. (j)	UNSCH. (k)
1.	1	14	3,101,964.40	641.70				8,362		164	234
2.											
3.											
4.											
5.											
6.	Total	14	3,101,964	641.70	0.00	0.00		8,362	0	164	234
7.	Average BTU		11,785	138,000.62							
8.	Total BTU (10^6)		36,556,650.00	88,555			36,645,205				
9.	Total Del. Cost ($)		57,023,465	1,814,978.00							

SECTION A. BOILERS/TURBINES (Continued)

NO.	UNIT NO. (l)	SIZE (kW) (m)	GROSS GEN. (MWh) (n)	BTU PER kWh (o)
1.	1	440,000	3,647,700.30	
2.				
3.				
4.				
5.				
6.	Total	440,000	3,647,700.30	10,046
7.	Station Service (MWh)		243,893.60	
8.	Net Generation (MWh)		3,403,806.70	10,765.95
9.	Station Service (%)		6.69	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE
1.	No. Employees Full-Time (Include Superintendent)	110
2.	No. Employees Part-Time	
3.	**Total Employee Hours Worked**	249,878
4.	Operating Plant Payroll ($)	6,907,841
5.	Maintenance Plant Payroll ($)	4,916,290
6.	Other Accts. Plant Payroll ($)	
7.	**Total Plant Payroll ($)**	11,824,131

SEC. C. FACTORS & MAX. DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	88.36%
2.	Plant Factor (%)	94.64%
3.	Running Plant Capacity Factor (%)	99.14%
4.	15 Minute Gross Max. Demand (kW)	471,243
5.	Indicated Gross Max. Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	500	1,722,309		
2.	Fuel, Coal	501.1	60,913,409		1.66
3	Fuel, Oil	501.2	1,814,978		20.49
4.	Fuel, Gas	501.3			
5.	Fuel, Other	501.4			
6.	**Fuel SubTotal *(2 thru 5)***	501	62,728,387	18.42	1.71
7.	Steam Expenses	502	10,852,212		
8.	Electric Expenses	505	1,226,160		
9.	Miscellaneous Steam Power Expenses	506	3,576,262		
10.	Allowances	509	140,177		
11.	Rents	507			
12.	**Non-Fuel SubTotal *(1 + 7 thru 11)***		17,517,120	5.14	
13.	**Operation Expense *(6 + 12)***		80,245,507	23.57	
14.	Maintenance, Supervision and Engineering	510	1,403,947		
15.	Maintenance of Structures	511	1,152,399		
16.	Maintenance of Boiler Plant	512	8,359,331		
17.	Maintenance of Electric Plant	513	1,643,203		
18.	Maintenance of Miscellaneous Plant	514	752,428		
19.	**Maintenance Expense *(14 thru 18)***		13,311,308	3.91	
20.	**Total Production Expense *(13 + 19)***		93,556,815	27.48	
21.	Depreciation	403.1, 411.10	16,584,283		
22.	Interest	427	22,103,462		
23.	**Total Fixed Cost *(21 + 22)***		38,687,745	11.36	
24.	**Power Cost *(20 + 23)***		132,244,560	38.85	

Remarks

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART F IC - INTERNAL COMBUSTION PLANT

INSTRUCTIONS - See help in the online application.

BORROWER DESIGNATION: KY0062

PLANT: Reid

PERIOD ENDED: December, 2011

SECTION A. INTERNAL COMBUSTION GENERATING UNITS

NO.	UNIT NO. (a)	SIZE (kW) (b)	FUEL CONSUMPTION: OIL (1000 Gals.) (c)	GAS (1000 C.F.) (d)	OTHER (e)	TOTAL (f)	OPERATING HOURS: IN SERVICE (g)	ON STANDBY (h)	OUT OF SERVICE: SCHED. (i)	UNSCH. (j)	GROSS GENER. (MWh) (k)	BTU PER kWh (l)
1.	1	70,000		180,243.00			372	8,166		222	7,901	
2.												
3.												
4.												
5.												
6.	Total	70,000	0.00	180,243.00	0.00		372	8,166	0	222	7,901	
7.	Average BTU			1,000.00			Station Service (MWh)				906.70	22,813.06
8.	Total BTU (10^6)			180,243.00		180,243.00	Net Generation (MWh)				6,993.90	
9.	Total Del. Cost ($)			933,555.00			Station Service % of Gross				11.48	25,771.46

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1.	No. Employees Full Time (Include Superintendent)		5.	Maintenance Plant Payroll ($)	56,719
2.	No. Employees Part Time		6.	Other Accounts Plant Payroll ($)	
3.	**Total Employee Hours Worked**	1,096	7.	**Total Plant Payroll ($)**	59,744
4.	Operating Plant Payroll ($)	3,025			

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	1.29%
2.	Plant Factor (%)	1.29%
3.	Running Plant Capacity Factor (%)	30.34%
4.	15 Min. Gross Max. Demand (kW)	69,882
5.	Indicated Gross Max. Demand (kW)	

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET (kWh) (b)	$/10^6 BTU (c)
1.	Operation, Supervision and Engineering	546	0		
2.	Fuel, Oil	547.1	0		
3.	Fuel, Gas	547.2	933,829		
4.	Fuel, Other	547.3	0		
5.	Energy for Compressed Air	547.4	0	0.00	
6.	**Fuel SubTotal (2 thru 5)**	547	933,829	133.52	
7.	Generation Expenses	548	33,917		
8.	Miscellaneous Other Power Generation Expenses	549	0		
9.	Rents	550	0		
10.	**Non-Fuel SubTotal (1 + 7 thru 9)**		33,917	4.85	
11.	**Operation Expense (6 + 10)**		967,746	138.37	
12.	Maintenance, Supervision and Engineering	551	0		
13.	Maintenance of Structures	552	0		
14.	Maintenance of Generating and Electric Plant	553	150,725		
15.	Maintenance of Miscellaneous Other Power Generating Plant	554	0		
16.	**Maintenance Expense (12 thru 15)**		150,725	21.55	
17.	**Total Production Expense (11 + 16)**		1,118,471	159.92	
18.	Depreciation	403.4, 411.10	200,021		
19.	Interest	427	213,917		
20.	**Total Fixed Cost (18 + 19)**		413,938	59.19	
21.	**Power Cost (17 + 20)**		1,532,409	219.11	

Remarks (including Unscheduled Outages)

Case No. 2012-00535
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Witness: James V. Haner

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT**	BORROWER DESIGNATION KY0062 PERIOD ENDED December, 2011
INSTRUCTIONS - See help in the online application.	

SECTION A. UTILITY PLANT

	ITEM	BALANCE BEGINNING OF YEAR (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS AND TRANSFERS (d)	BALANCE END OF YEAR (e)
1.	Total Intangible Plant (301 thru 303)	66,895				66,895
2.	Total Steam Production Plant *(310 thru 317)*	1,681,030,128	24,349,993	7,136,548		1,698,243,573
3.	Total Nuclear Production Plant *(320 thru 326)*	0				0
4.	Total Hydro Production Plant *(330 thru 337)*	0				0
5.	Total Other Production Plant *(340 thru 347)*	7,993,514	49,200	43,725		7,998,989
6.	**Total Production Plant *(2 thru 5)***	1,689,023,642	24,399,193	7,180,273		1,706,242,562
7.	Land and Land Rights *(350)*	13,856,815	2,087			13,858,902
8.	Structures and Improvements *(352)*	6,859,818	12,489			6,872,307
9.	Station Equipment *(353)*	122,103,111	1,095,090	192,774		123,005,427
10.	Other Transmission Plant *(354 thru 359.1)*	94,869,205	139,404	6,968		95,001,641
11.	**Total Transmission Plant *(7 thru 10)***	237,688,949	1,249,070	199,742		238,738,277
12.	Land and Land Rights *(360)*	0				0
13.	Structures and Improvements *(361)*	0				0
14.	Station Equipment *(362)*	0				0
15.	Other Distribution Plant *(363 thru 374)*	0				0
16.	**Total Distribution Plant *(12 thru 15)***	0				0
17.	RTO/ISO Plant (380 thru 386)					
18.	Total General Plant *(389 thru 399.1)*	18,937,573	15,300,241	496,217	2,425	33,744,022
19.	**Electric Plant in Service *(1 + 6 + 11 + 16 thru 18)***	1,945,717,059	40,948,504	7,876,232	2,425	1,978,791,756
20.	Electric Plant Purchased or Sold *(102)*	0				0
21.	Electric Plant Leased to Others *(104)*	0				0
22.	Electric Plant Held for Future Use *(105)*	475,968				475,968
23.	Completed Construction Not Classified *(106)*	0				0
24.	Acquisition Adjustments *(114)*	0				0
25.	Other Utility Plant *(118)*	0				0
26.	Nuclear Fuel Assemblies *(120.1 thru 120.4)*	0				0
27.	**Total Utility Plant in Service *(19 thru 26)***	1,946,193,027	40,948,504	7,876,232	2,425	1,979,267,724
28.	Construction Work in Progress *(107)*	54,874,458	(5,723,875)			49,150,583
29.	**Total Utility Plant *(27 + 28)***	2,001,067,485	35,224,629	7,876,232	2,425	2,028,418,307

SECTION B. ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION - UTILITY PLANT

	ITEM	COMP. RATE (%) (a)	BALANCE BEGINNING OF YEAR (b)	ANNUAL ACCRUALS (c)	RETIREMENTS LESS NET SALVAGE (d)	ADJUSTMENTS AND TRANSFERS (e)	BALANCE END OF YEAR (f)
1.	Depr. of Steam Prod. Plant (108.1)	1.81	768,648,373	28,980,457	8,364,578		789,264,252
2.	Depr. of Nuclear Prod. Plant (108.2)		0				0
3.	Depr. of Hydraulic Prod. Plant (108.3)		0				0
4.	Depr. of Other Prod. Plant (108.4)	2.50	5,589,699	200,608	63,725		5,726,582
5.	Depr. of Transmission Plant (108.5)	2.46	108,275,958	5,269,291	181,312	209	113,364,146
6.	Depr. of Distribution Plant (108.6)		0				0
7.	Depr. of General Plant (108.7)		6,371,644	903,363	494,771		6,780,236
8.	Retirement Work in Progress (108.8)		(288,535)		977,244		(1,265,779)
9.	**Total Depr. for Elec. Plant in Serv. *(1 thru 8)***		888,597,139			209	913,869,437
10.	Depr. of Plant Leased to Others (109)		0				0
11.	Depr. of Plant Held for Future Use (110)		0				0
12.	Amort. of Elec. Plant in Service (111)		20,904,263	2,108,639	527,386		22,485,516
13.	Amort. of Leased Plant (112)		0				0
14.	Amort. of Plant Held for Future Use		0				0
15.	Amort. of Acquisition Adj. (115)		0				0
16.	Depr. & Amort. Other Plant (119)		0				0
17.	Amort. of Nuclear Fuel (120.5)		0				0
18.	**Total Prov. for Depr. & Amort. *(9 thru 17)***		909,501,402	37,462,358	10,609,016	209	936,354,953

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT**	BORROWER DESIGNATION KY0062 PERIOD ENDED December, 2011

INSTRUCTIONS - See help in the online application.

SECTION B. ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION - UTILITY PLANT (*Continued*)

19. Amount of Annual Accrual Charged to Expense $ 35,406,806	20. Amount of Annual Accrual Charged to Other Accounts $ 2,055,552	21. Book Cost of Property Retired $ 7,876,232
22. Removal Cost of Property Retired $ 2,820,150	23. Salvage Material from Property Retired $ 87,366	24. Renewal and Replacement Cost $ 14,937,824

SECTION C. NON-UTILITY PLANT

ITEM	BALANCE BEGINNING OF YEAR (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS AND TRANSFERS (d)	BALANCE END OF YEAR (e)
1. NonUtility Property (121)					
2. Provision For Depr. & Amort. (122)					

SECTION D. DEMAND AND ENERGY AT POWER SOURCES

MONTH	PEAK DEMAND (MW) (a)	MONTHLY PEAKS DATE (b)	TIME (c)	TYPE OF READING (d)	ENERGY OUTPUT (MWh) (e)
1. January	1,368	01/13/2011	8	Coincident	1,144,445
2. February	1,375	02/10/2011	6	Coincident	1,010,947
3. March	1,252	03/10/2011	19	Coincident	1,116,717
4. April	1,244	04/19/2011	20	Coincident	1,071,920
5. May	1,377	05/31/2011	17	Coincident	1,215,079
6. June	1,414	06/08/2011	16	Coincident	1,113,556
7. July	1,478	07/27/2011	16	Coincident	1,196,309
8. August	1,440	08/03/2011	17	Coincident	1,159,836
9. September	1,426	09/02/2011	16	Coincident	1,091,151
10. October	1,237	10/21/2011	6	Coincident	1,094,369
11. November	1,323	11/29/2011	17	Coincident	1,042,921
12. December	1,357	12/08/2011	6	Coincident	1,125,931
13. Annual Peak	1,478			Annual Total	13,383,181

SECTION E. DEMAND AND ENERGY AT DELIVERY POINTS

MONTH	DELIVERED TO RUS BORROWERS DEMAND (MW) (a)	ENERGY (MWh) (b)	DELIVERED TO OTHERS DEMAND (MW) (c)	ENERGY (MWh) (d)	TOTAL DELIVERED DEMAND (MW) (e)	ENERGY (MWh) (f)
1. January	587	888,166	85	243,858	672	1,132,024
2. February	661	769,390	99	233,244	760	1,002,634
3. March	480	834,019	60	267,811	540	1,101,830
4. April	430	793,666	0	282,691	430	1,076,357
5. May	650	846,697	100	357,060	750	1,203,757
6. June	593	855,344	490	244,898	1,083	1,100,242
7. July	638	921,487	199	265,398	837	1,186,885
8. August	732	895,036	251	253,666	983	1,148,702
9. September	765	839,907	148	240,589	913	1,080,496
10. October	410	844,382	98	238,133	508	1,082,515
11. November	573	839,366	194	190,807	767	1,030,173
12. December	554	914,040	0	195,470	554	1,109,510
13. Peak or Total	765	10,241,500	490	3,013,625	1,083	13,255,125

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT	BORROWER DESIGNATION KY0062 PERIOD ENDED December, 2011

INSTRUCTIONS - Reporting of investments is required by 7 CFR 1717, Subpart N. Investment categories reported on this Part correspond to Balance Sheet items in Part A Section B. Identify all investments in Rural Development with an 'X' in column (e). Both 'Included' and 'Excluded' Investments must be reported. See help in the online application.

SECTION F. INVESTMENTS, LOAN GUARANTEES AND LOANS
SUB SECTION I. INVESTMENTS

No	Description (a)	Included ($) (b)	Excluded ($) (c)	Income Or Loss ($) (d)	Rural Development (e)
2	**Investments in Associated Organizations**				
	United Utility Supply Capital Credit	31,773	0		
	Ky Assn for Electric Coops Capital Credit	15,200	0		
	Jackson Purchase Capital Credit	0	4,274		
	Kenergy Capital Credit	0	20,698		
	Meade County Capital Credit	0	1,166		
	Rural Cooperatives Credit Union Deposit	5	0		
	Touchstone Energy (NRECA) Capital Credit	1,742	0		
	CoBank Capital Credit	0	3,501,953		
	NRUCFC	0	2,039		
	Cooperative Membership Fees	2,280	0		
	ACES Power Marketing Membership Fees	678,000	0		
	Federated Rural Electric Insurance Exchange Capital Credit	4,713	60,853		
	National Renewables Cooperative Organization Capital Credit	0	8,600		
	Totals	733,713	3,599,583		
3	**Investments in Economic Development Projects**				
	Breckinridge Co. Development Corp. Stock	5,000	0		X
	Hancock Co. Industrial Foundation Stock	5,000	0		X
	Totals	10,000	0		
4	**Other Investments**				
	Southern States Coop Capital Credit	5,334	0		
	Totals	5,334	0		
5	**Special Funds**				
	Other Special Funds-Deferred Compensation	0	283,400		
	Other Special Funds-Economic Reserve	11,986,433	88,323,834		
	Other Special Funds-Rural Economic Reserve	778,664	62,073,072		
	Other Special Funds-Station Two O&M Fund	150,000	250,000		
	Other Special Funds-Liberty Mutual	0	306,028		
	Totals	12,915,097	151,236,334		
6	**Cash - General**				
	General Fund	0	973		
	Right of Way Fund	0	1,000		
	Working Fund	3,725	0		
	Totals	3,725	1,973		
7	**Special Deposits**				
	TVA Transmission Reservation	572,679	0		
	Totals	572,679	0		
8	**Temporary Investments**				
	Fidelity-U.S. Treasury Only (#057)	0	44,843,791		
	Totals	0	44,843,791		
9	**Accounts and Notes Receivable - NET**				
	Accts Receivable-Employees-Other	7,376	0		
	Accts Receivable-Employees-Computer Assist Program	21,652			
	Other Accts Receivable-Misc	461,420	0		
	Accts Receivable-HMP&L Sta Two Operation	(1,200,161)	0		

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INSTRUCTIONS - Reporting of investments is required by 7 CFR 1717, Subpart N. Investment categories reported on this Part correspond to Balance Sheet items in Part A Section B. Identify all investments in Rural Development with an 'X' in column (e). Both 'Included' and 'Excluded' Investments must be reported. See help in the online application.

SECTION F. INVESTMENTS, LOAN GUARANTEES AND LOANS
SUB SECTION I. INVESTMENTS

	Accts Receivable-HMP&L Sta Two Other	836,898	0		
	Accts Receivable-HMP&L Litigation	56,824	0		
	Accts Receivable-Westlake Chemical	48,271	0		
	Totals	232,280	0		
11	TOTAL INVESTMENTS (1 thru 10)	14,472,828	199,681,681		

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT	BORROWER DESIGNATION KY0062 PERIOD ENDED December, 2011

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SECTION F. INVESTMENTS, LOAN GUARANTEES AND LOANS
SUB SECTION II. LOAN GUARANTEES

No	Organization (a)	Maturity Date (b)	Original Amount ($) (c)	Loan Balance ($) (d)	Rural Development (e)
	TOTAL				
	TOTAL (Included Loan Guarantees Only)				

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INSTRUCTIONS - Reporting of investments is required by 7 CFR 1717, Subpart N. Investment categories reported on this Part correspond to Balance Sheet items in Part A Section B. Identify all investments in Rural Development with an "X" in column (e). Both "Included" and "Excluded" Investments must be reported. See help in the online application.

SECTION F. INVESTMENTS, LOAN GUARANTEES AND LOANS
SUB SECTION III. RATIO

RATIO OF INVESTMENTS AND LOAN GUARANTEES TO UTILITY PLANT [Total of Included Investments (Sub Section I, 11b) and Loan Guarantees - Loan Balance (Sub Section II, 5d) to Total Utility Plant (Part A, Section B, Line 3 of this report)]	0.71 %

SECTION F. INVESTMENTS, LOAN GUARANTEES AND LOANS
SUB SECTION IV. LOAN

No	Organization (a)	Maturity Date (b)	Original Amount ($) (c)	Loan Balance ($) (d)	Rural Development (e)
	TOTAL				

Case No. 2012-00535
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UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT**	BORROWER DESIGNATION KY0062 PERIOD ENDED December, 2011
INSTRUCTIONS - See help in the online application	

SECTION G. MATERIALS AND SUPPLIES INVENTORY

ITEM	BALANCE BEGINNING OF YEAR (a)	PURCHASED & SALVAGED (b)	USED & SOLD (c)	BALANCE END OF YEAR (d)
1. Coal	28,610,258	237,811,600	236,291,157	30,130,701
2. Other Fuel	8,718,183	15,000,147	19,955,018	3,763,312
3. Production Plant Parts and Supplies	20,783,578	8,618,330	7,128,463	22,273,445
4. Station Transformers and Equipment	0			0
5. Line Materials and Supplies	669,645	324,896	233,541	761,000
6. Other Materials and Supplies	1,764,429	17,244,677	16,748,286	2,260,820
7. **Total** (*1 thru 6*)	60,546,093	278,999,650	280,356,465	59,189,278

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT**	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2011

SECTION H. LONG-TERM DEBT AND DEBT SERVICE REQUIREMENTS

No	Item	Balance End Of Year (a)	Interest (Billed This Year) (b)	Principal (Billed This Year) (c)	Total (Billed This Year) (d)
1	RUS (Excludes RUS - Economic Development Loans)	644,298,429	23,931,304	45,879,127	69,810,431
2	National Rural Utilities Cooperative Finance Corporation	0	0	0	0
3	CoBank, ACB	0	0	0	0
4	Federal Financing Bank	0	0	0	0
5	RUS - Economic Development Loans	0	0	0	0
6	Payments Unapplied	0			
7	Ohio County Kentucky Bonds - Series 1983	58,800,000	1,996,342		1,996,342
8	Ohio County Kentucky Bonds - Series 2010A	83,300,000	5,511,683		5,511,683
9	LEM Settlement Promissory Note	0		0	0
10	PMCC Promissory Note	0	0	0	0
	TOTAL	786,398,429	31,439,329	45,879,127	77,318,456

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT	BORROWER DESIGNATION KY0062 PERIOD ENDED December, 2011
INSTRUCTIONS - See help in the online application.	

SECTION I. ANNUAL MEETING AND BOARD DATA			
1. Date of Last Annual Meeting 9/15/2011	2. Total Number of Members 3	3. Number of Members Present at Meeting 3	4. Was Quorum Present? Yes
5. Number of Members Voting by Proxy or Mail 0	6. Total Number of Board Members 6	7. Total Amount of Fees and Expenses for Board Members $ 189,273	8. Does Manager Have Written Contract? No

SECTION J. MAN-HOUR AND PAYROLL STATISTICS			
1. Number of Full Time Employees	628	4. Payroll Expensed	46,222,175
2. Man-Hours Worked - Regular Time	1,068,347	5. Payroll Capitalized	744,036
3. Man-Hours Worked – Overtime	145,058	6. Payroll Other	2,865,906

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT**	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2011

SECTION K. LONG-TERM LEASES

No	Name Of Lessor (a)	Type Of Property (b)	Rental This Year (c)
1	Louisville Gas & Electric	Interconnect Facilities - Cloverport Sub	21,111
	TOTAL		21,111

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART H - ANNUAL SUPPLEMENT**	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2011

SECTION L. RENEWABLE ENERGY CREDITS

ITEM	BALANCE BEGINNING OF YEAR (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS AND TRANSFER (d)	BALANCE END OF YEAR (e)
1. Renewable Energy Credits					

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY PART I - LINES AND STATIONS**	BORROWER DESIGNATION KY0062
INSTRUCTIONS - See help in the online application.	PERIOD ENDED December, 2011

SECTION A. EXPENSES AND COSTS

ITEM	ACCOUNT NUMBER	LINES (a)	STATIONS (b)
Transmission Operation			
1. Supervision and Engineering	560	285,740	381,549
2. Load Dispatching	561	3,674,737	
3. Station Expenses	562		743,341
4. Overhead Line Expenses	563	1,007,289	
5. Underground Line Expenses	564		
6. Miscellaneous Expenses	566	233,416	425,708
7. **Subtotal (*1 thru 6*)**		5,201,182	1,550,598
8. Transmission of Electricity by Others	565	2,408,336	
9. Rents	567		22,942
10. **Total Transmission Operation (*7 thru 9*)**		7,609,518	1,573,540
Transmission Maintenance			
11. Supervision and Engineering	568	273,612	253,831
12. Structures	569		16,607
13. Station Equipment	570		1,578,393
14. Overhead Lines	571	1,915,700	
15. Underground Lines	572		
16. Miscellaneous Transmission Plant	573	221,381	421,101
17. **Total Transmission Maintenance (*11 thru 16*)**		2,410,693	2,269,932
18. **Total Transmission Expense (*10 + 17*)**		10,020,211	3,843,472
19. RTO/ISO Expense – Operation	575.1-575.8	2,529,532	
20. RTO/ISO Expense – Maintenance	576.1-576.5		
21. **Total RTO/ISO Expense (*19 + 20*)**		2,529,532	
22. Distribution Expense - Operation	580-589		
23. Distribution Expense - Maintenance	590-598		
24. **Total Distribution Expense (*22 + 23*)**			
25. **Total Operation And Maintenance (*18 + 21 + 24*)**		12,549,743	3,843,472
Fixed Costs			
26. Depreciation – Transmission	403.5	2,561,778	2,707,513
27. Depreciation – Distribution	403.6		
28. Interest – Transmission	427	2,749,512	3,361,611
29. Interest – Distribution	427		
30. **Total Transmission (*18 + 26 + 28*)**		15,331,501	9,912,596
31. **Total Distribution (*24 + 27 + 29*)**			
32. **Total Lines And Stations (*21 + 30 + 31*)**		17,861,033	9,912,596

SECTION B. FACILITIES IN SERVICE

TRANSMISSION LINES		SUBSTATIONS	
VOLTAGE (kV)	**MILES**	**TYPE**	**CAPACITY(kVA)**
1. 345 KV	68.40	13. Distribution Lines	
2. 138 KV	14.40		
3. 69 KV	833.20	14. **Total (*12 + 13*)**	1,265.60
4. 161 KV	349.60		
5.		15. Stepup at Generating Plants	1,879,800
6.			
7.		16. Transmission	3,540,000
8.			
9.		17. Distribution	
10.			
11.		18. **Total (*15 thru 17*)**	5,419,800
12. **Total (*1 thru 11*)**	1,265.60		

SECTION C. LABOR AND MATERIAL SUMMARY

1. Number of Employees 55

ITEM	LINES	STATIONS
2. Oper. Labor	1,605,241	931,093
3. Maint. Labor	1,341,908	1,601,919
4. Oper. Material	8,533,809	642,447
5. Maint. Material	1,068,785	668,013

SECTION D. OUTAGES

1. Total	36,540.90
2. Avg. No. of Distribution Consumers Served	112,887.00
3. Avg. No. of Hours Out Per Consumer	.30

The public version of Attachment 2 to AG 2-53(e) is provided on the PUBLIC CD accompanying these responses.

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Electric Operation and Maintenance Expenses - Transmission and Distribution Expenses (Ref Page: 321)

2. Transmission Expenses		
Operation		
Operation Supervision and Engineering (560)	$667,289.00	$721,017.00
Load Dispatching (561)	$6,204,269.00	$1,634,089.00
Station Expenses (562)	$743,341.00	$1,043,675.00
Overhead Lines Expenses (563)	$1,007,289.00	$970,450.00
Underground Lines Expenses (564)		
Transmission of Electricity by Others (565)	$2,408,336.00	$3,051,502.00
Miscellaneous Transmission Expenses (566)	$659,124.00	$674,389.00
Rents (567)	$22,942.00	$26,460.00
Total Operation	$11,712,590.00	$8,121,582.00
Maintenance		
Maintenance Supervision and Engineering (568)	$527,443.00	$537,921.00
Maintenance of Structures (569)	$16,607.00	$20,997.00
Maintenance of Station Equipment (570)	$1,578,393.00	$1,625,828.00
Maintenance of Overhead Lines (571)	$1,915,700.00	$2,174,112.00
Maintenance of Underground Lines (572)		
Maintenance of Miscellaneous Transmission Plant (573)	$642,482.00	$114,266.00
Total Maintenance	$4,680,625.00	$4,473,124.00
100. Total Transmission Expenses	$16,393,215.00	$12,594,706.00
3. Distribution Expenses		
Operation		
Operation Supervision and Engineering (580)		
Load Dispatching (581)		
Station Expenses (582)		
Overhead Line Expenses (583)		
Underground Line Expenses (584)		

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Electric Operation and Maintenance Expenses - Transmission and Distribution Expenses (Ref Page: 321)

Street Lighting and signal System Expenses (585)

Meter Expenses (586)

Customer Installations Expenses (587)

Miscellaneous Expenses (588)

Rents (589)

Total Operation

Maintenance

Maintenance Supervision and Engineering (590)

Maintenance of Structures (591)

Maintenance of Station Equipment (592)

Maintenance of Overhead Lines (593)

Maintenance of Underground Lines (594)

Maintenance of Line Transformers (595)

Maintenance of Street Lighting and Signal Systems (596)

Maintenance of Meters (597)

Maintenance of Miscellaneous Distribution Plant (598)

Total Maintenance

126. Total Distribution Expenses

Note:
Ref Page 321

Load Dispatching (561) includes the account Market Facilitation, Monitoring & Compliance Serv (575) with the amount of $2,529,532.00

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Electric Operation and Maintenance Expenses - Customer, Sales and Administrative Expenses (Ref Page: 321)

[redacted]

4. Customer Accounts Expenses		
Operation		
Supervision (901)		
Meter Reading Expenses (902)		
Customer Records and Collection Expenses (903)		
Uncollectible Accounts (904)		
Miscellaneous Customer Accounts Expenses (905)		
134. Total Customer Accounts Expenses		
5. Customer Service and Informational Expenses		
Operation		
Supervision (907)		
Customer Assistance Expenses (908)	$589,810.00	$446,300.00
Information and Instructional Expenses (909)	$41,725.00	
Miscellaneous Customer Service and Information Expenses (910)		
141. Total Cust. Service and Informational Exp	$631,535.00	$446,300.00
6. Sales Expenses		
Operation		
Supervision (911)		
Demonstrating and selling Expenses (912)		
Advertising Expenses (913)	$185,004.00	$239,803.00
Miscellaneous Sales Expenses (916)		
148. Total Sales Expenses	$185,004.00	$239,803.00
7. Administrative and General Expenses		
Operation		
Administrative and General Salaries (920)	$14,136,342.00	$13,195,035.00
Office Supplies and Expenses (921)	$5,899,252.00	$6,809,479.00
(Less) Administrative Expenses Transferred--CR (922)		

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Electric Operation and Maintenance Expenses - Customer, Sales and Administrative Expenses (Ref Page: 321)

Outside Services Employed (923)	$1,587,501.00	$3,297,366.00
Property Insurance (924)		
Injuries and Damages (925)	$214,141.00	$169,994.00
Employee Pensions and Benefits (926)	$209,760.00	$84,244.00
Franchise requirements (927)		
Regulatory Commission Expenses (928)	$2,547,612.00	$1,452,074.00
(Less) Duplicate Charges -- CR (929)		
General Advertising Expenses (930.1)	$156,139.00	$160,540.00
Miscellaneous General Expenses (930.2)	$1,804,562.00	$1,291,277.00
Rents (931)	$1,933.00	$1,933.00
Total Operation	$26,557,242.00	$26,461,942.00
Maintenance		
Maintenance of General Plant (935)	$140,534.00	$250,361.00
168. Total Administrative and General Expenses	$26,697,776.00	$26,712,303.00
Total Electric Operation and Maintence (80,100,126,134,141,148,168)	$475,705,375.00	$441,826,703.00

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Purchased Power (555) (Ref Page: 326)

[redacted]

TOTAL [redacted]

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Purchased Power (555) (Ref Page: 326) (Part Two)

[redacted]

TOTAL [redacted]

Note:
Ref. Page 326 Henderson Municipal Power & Light
Power purchased from Henderson Municipal Power & Light is not based on non-coincident peak (NCP) or coincident peak (CP).
Big Rivers has capacity rights under an operating agreement for the Henderson Municipal Power & Light (HMP&L) Station Two facility.

Ref. Page 326 Southeastern Power Administration
The contract with Southeastern Power Administration (SEPA) shall continue in effect until terminated on June 30 of any year by Big Rivers Electric Corporation, upon written notice to SEPA of not less than 37 months in advance of the date of termination, or by SEPA upon written notice to Big Rivers Electric Corporation o not less than 36 months in advance of termination. Power purchased from Southeastern Power Administration is not based on non-coincident peak (NCP)or coincident peak (CP).

Transmission of Electricity for Others (456) (Ref Page: 328)

1	Big Rivers Power Supply		Midwest ISO	LF
2	EDF Trading North America, LLC		EDF Trading North America, LLC	LF
3	Cargill Power Markets, LLC		Cargill Power Markets, LLC	LF
4	Henderson Municipal Power & Light	SEPA	Henderson Municipal Power & Light	OS

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Transmission of Electricity for Others (456) pg 2 (Ref Page: 329)

	1	Midwest ISO Ties	Midwest ISO Ties	0	0	0
	2	Midwest ISO Ties	Southern Company Ties	0	80,160	80,160
	3	Midwest ISO Ties	Southern Company Ties	0	114,888	114,888
	4	Barkley/Paradise	HMP&L ties	0	29,536	29,536
Total				0	224,584	224,584

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Transmission of Electricity for Others (456) pg 3 (Ref Page: 330)

[redacted]

	1	$2,873,422.00	$0.00	$0.00	$2,873,422.00
	2	$127,440.00	$0.00	$0.00	$127,440.00
	3	$303,811.00	$0.00	$0.00	$303,811.00
	4	$44,304.00	$0.00	$0.00	$44,304.00
Total		$3,348,977.00	$0.00	$0.00	$3,348,977.00

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Tranmission of Electricity by Others (565) (Ref Page: 332)

	Louisville Gas & Electric Co.	25,801	25,050	$25,147.00	$0.00	$0.00	$25,147.00
	Kentucky Utilities Company	11,312	10,983	$53,269.00	$0.00	$0.00	$53,269.00
	Midwest ISO	468,400	280,032	($73.00)	$0.00	$0.00	($73.00)
	Tennessee Valley Authority	286,245	277,144	$2,329,993.00	$0.00	$0.00	$2,329,993.00
Total		791,758	593,209	$2,408,336.00	$0.00	$0.00	$2,408,336.00

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Miscellaneous General Expenses 930.2 Electric (Ref Page: 335)

Industry Association Dues			$550,930.00
Nuclear Power Research Expenses			
Other Experimental and general Research Expenses			
Publishing and Distributing Information and Reports to Stockholders; Trustee, Registrar and Transfer Agent Fees and Expenses, and Other Expenses of Servicing Outstanding securities of the Respondent			
Other Expenses (List items of $5000 or more in this column showing the Purpose, Recipient and amount of such items.			
Group amounts of less than $5000 by classes if the number of items so grouped is shown.			
	Annual Report	Commercial Printing	$5,832.00
	Debt Expense/Bank Services	NRUCFC	$208,141.00
	Debt Expense/Bank Services	CoBank	$209,146.00
	Debt Expense/Bank Services	US Bank	$24,327.00
	Debt Expense/Bank Services	Standard & Poors	$30,000.00
	Debt Expense/Bank Services	Fitch, Inc.	$30,000.00
	Directors Fees and Expenses	Directors	$189,273.00
	General Plant Property Tax	State of Ky and Local Taxing Districts	$516,100.00
	Insurance	E M Ford and Company	$21,369.00
	Insurance	Federated Rural Electric Insurance Exchange	$5,031.00
	Insurance	2 Items	$6,641.00
	Debt Expense/Bank Services	1 Item	$3,813.00
	Misc Expenses	3 Items	$3,959.00
TOTAL			$1,804,562.00

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Depreciation and Amortization of Electric Plant (Ref Page: 336)

Intangible Plant					
Steam Product Plant	$28,879,685.00	$0.00	$0.00	$0.00	$28,879,685.00
Nuclear Production Plant					
Hydraulic Production Plant -- Conventional					
Hydraulic Production Plant -- Pumped Storage					
Other Production Plant	$200,021.00	$0.00	$0.00	$0.00	$200,021.00
Transmission Plant	$5,269,291.00	$0.00	$159,789.00	$0.00	$5,429,080.00
Distribution Plant					
General Plant	$898,020.00	$0.00	$0.00	$0.00	$898,020.00
Common Plant -- Electric					
Total	$35,247,017.00	$0.00	$159,789.00	$0.00	$35,406,806.00

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Regulatory Commission Expenses (Ref Page: 350)

	KY Public Service Commission (KPSC)	$0.00	$0.00	$0.00	$0.00	Electric
	Administrative Case No. 2008-00408	$0.00	$1,984.00	$1,984.00	$0.00	Electric
	Case No. 2010-00269	$0.00	$1,875.00	$1,875.00	$0.00	Electric
	Case No. 2011-00250	$0.00	$3,750.00	$3,750.00	$0.00	Electric
	Case No. 2011-00036	$0.00	$1,855,138.00	$1,855,138.00	$0.00	Electric
	Assessment for Maintenance of KPSC KRS 278.130	$684,865.00	$0.00	$684,865.00	$0.00	Electric
Total		$684,865.00	$1,862,747.00	$2,547,612.00	$0.00	

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Regulatory Commission Expenses (Ref Page: 350) (Part Two)

	KY Public Service Commission (KPSC)	0	$0.00	$0.00	0	$0.00	$0.00
	Administrative Case No. 2008-00408	928	$1,984.00	$0.00	0	$0.00	$0.00
	Case No. 2010-00269	928	$1,875.00	$0.00	0	$0.00	$0.00
	Case No. 2011-00250	928	$3,750.00	$0.00	0	$0.00	$0.00
	Case No. 2011-00036	928	$1,855,138.00	$0.00	0	$0.00	$0.00
	Assessment for Maintenance of KPSC KRS 278.130	928	$684,865.00	$0.00	0	$0.00	$0.00
Total			$2,547,612.00	$0.00		$0.00	$0.00

Research Developement and Demonstration Activities (Ref Page: 352)

	B.External 4.Support to Others	National Renewables Coop Org	$0.00	$52,783.00	930.2	$52,783.00	$0.00
	B.External 4.Support to Others	National Rural Electric Coop - CRN	$0.00	$16,791.00	930.2	$16,791.00	$0.00
Total						$69,574.00	

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Distribution of Salaries and Wages - Electric (Ref Page: 354)

Electric	
Operation	
3. Production	$19,658,177.00
4. Transmission	$1,704,409.00
5. Distribution	
6. Customer Accounts	$207,446.00
7. Customer Service and Informational	
8. Sales	
9. Administrative and General	$9,539,352.00
10. Total Operation	$31,109,384.00
Maintenance	
12. Production	$13,069,463.00
13. Transmission	$1,975,625.00
14. Distribution	
15. Administrative and General	$67,703.00
16. Total Maint	$15,112,791.00
17. Total Operation and Maintenance	
18. Total Production (Lines 3 and 12)	$32,727,640.00
19. Total Transmission (Lines 4 and 13)	$3,680,034.00
20. Total Distribution (Lines 5 and 14)	$0.00
21. Customer Accounts (Transcribe from Line 6)	$207,446.00
22. Customer Service and Informational (Transcribe from Line 7)	$0.00
23. Sales (Transcribe from Line 8)	$0.00
24. Administrative and General(Lines 9 and 15)	$9,607,055.00

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Distribution of Salaries and Wages - Electric (Ref Page: 354)

25. Total Oper. and Maint. (Lines 18-24)	$46,222,175.00	$20,111.00	$46,242,286.00

Distribution of Salaries and Wages - Gas (Ref Page: 354)

[redacted]

Gas

Operation

28. Production -- Manufactured Gas

29. Production -- Nat. Gas (Including Expl and Dev.)

30. Other Gas Supply

31. Storage, LNG Terminaling and Processing

32. Transmission

33. Distribution

34. Customer Accounts

35. Customer Service and Informational

36. Sales

37. Administrative and General

38. Total Operation

Maintenance

40. Production -- Manufactured Gas

41. Production -- Natural Gas

42. Other Gas Supply

43. Storage, LNG Terminaling and Processing

44. Transmission

45. Distribution

46. Administrative and General

47. Total Maint

48. Total Operation and Maintenance

Distribution of Salaries and Wages - Gas (Ref Page: 354)

49. Total Production -- Manufactured Gas (Lines 28 and 40)			
50. Total Production -- Natural Gas (Lines 29 and 41)			
51. Total Other Gas Supply (Lines 30 and 42)			
52. Total Storage LNG Terminaling and Processing (Lines 31 and 43)			
53. Total Transmission (Lines 32 and 44)			
54. Total Distribution (Lines 33 and 45)			
55. Customer Accounts (Transcribe Line 34)			
56. Customer Service and Informational (Transcribe Line 35)			
57. Sales (Transcribe Line 36)			
58. Total Administrative and General (Lines 37 and 46)			
59. Total Operation and Maintenance			
60. Other Utility Departments			
61. Operation and Maintenance			
62. Total All Utility Dept (25,59,61)	$46,222,175.00	$20,111.00	$46,242,286.00

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Distribution of Salaries and Wages - Utility Plant (Ref Page: 355)

Utility Plant				
Construction (By Utility Departments)				
65. Electric Plant		$744,036.00	$0.00	$744,036.00
66. Gas Plant				
67. Other				
68. Total Construction		$744,036.00	$0.00	$744,036.00
69. Plant Removal (By Utility Departments)				
70. Electric Plant				
71. Gas Plant				
72. Other				
73. Total Plant Removal				
74. Other Accounts				
	Accounts Receivable	$2,845,795.00	$0.00	$2,845,795.00
	Clearing	$20,111.00	($20,111.00)	$0.00
95. Total Other Accounts		$2,865,906.00	($20,111.00)	$2,845,795.00
96. Total Salaries and Wages		$49,832,117.00	$0.00	$49,832,117.00

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Electric Energy Account (Ref Page: 401)

Sources of Energy	
Generation (Excluding Station Use:)	
Steam	10,277,356
Nuclear	
Hydro--Conventional	
Hydro--Pumped Storage	
Other	6,994
(Less) Energy for Pumping	
Net Generation	10,284,350
Purchases	2,998,361
Power Exchanges	
Received	3,715,300
Delivered	3,614,830
Net Exchanges (line 12 - Line 13)	100,470
Transmission for Other	
Received	29,536
Delivered	29,536
Net Transmission for Other (Line 16-17)	0
Transmission by Other Losses	
Total (Lines 9,10,14,18 and 19)	13,383,181
Disposition of Energy	
Sales to Ultimate Consumers (including Interdepartmental Sales)	
Requirements Sales for Resale (See Instruction 4 pg 311)	10,199,019
Non-Requirements Sales for Resale (See Instruction 4 pg 311)	3,056,106
Energy furnished without Charge	
Energy Used by the Company (Electric Dept Only, excluding Station Use)	
Total Energy Losses	128,056

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Electric Energy Account (Ref Page: 401)

Total (Lines 22 thru 27)	13,383,181

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Monthly Peaks and Output (Ref Page: 401)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
January	1,144,445	249,196	1,368	13	9
February	1,010,947	236,482	1,375	10	7
March	1,116,717	271,608	1,252	10	20
April	1,071,920	282,655	1,244	19	21
May	1,215,079	362,536	1,377	31	18
June	1,113,556	249,104	1,414	8	17
July	1,196,309	270,769	1,478	27	17
August	1,159,836	258,582	1,440	3	18
September	1,091,151	265,718	1,426	2	17
October	1,094,369	245,305	1,237	21	7
November	1,042,921	193,276	1,323	29	18
December	1,125,931	199,470	1,357	8	7
Total	13,383,181	3,084,701			

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Steam-Electric Generating Plant Statistics - Part One Plant Info (Ref Page: 402)

Please enter the information regarding each plant corresponding to the column intended for pg 402

Col b - Plant name	Reid
Kind of Plant (internal comb, gas turb, nuclear)	Steam
Type of Constr (conventional, outdoor, boiler, etc)	Semi-Outdoor
Col c - Plant name	Coleman
Kind of Plant (internal comb, gas turb, nuclear)	Steam
Type of Constr (conventional, outdoor, boiler, etc)	Outdoor
Col d - Plant name	Green
Kind of Plant (internal comb, gas turb, nuclear)	Steam
Type of Constr (conventional, outdoor, boiler, etc)	Semi-Outdoor
Col e - Plant name	HMP&L Station Two
Kind of Plant (internal comb, gas turb, nuclear)	Steam
Type of Constr (conventional, outdoor, boiler, etc)	Outdoor
Col f - Plant name	Wilson
Kind of Plant (internal comb, gas turb, nuclear)	Steam
Type of Constr (conventional, outdoor, boiler, etc)	Indoor

Steam-Electric Generating Plant Statistics - Part Two (Lines 3-33) (Ref Page: 402)

Year Originally Constructed	1,965	1,969	1,979	1,973	1,986
Year Last Unit was Installed	1,965	1,972	1,981	1,974	1,986
Total Installed Cap (Max Gen name Plate Ratings MW)	66	480	484	335	440
Net Peak Demand on Plant - MW (60 minutes)	53	454	470	306	443
Plant Hours Connected to Load	2,458	24,788	16,270	15,993	8,362
Net Continuous Plant Capability (MW)					
When Not Limited by Condenser Water	65	443	454	312	417
When Limited by Condenser Water					
Average Number of Employees	17	111	114	112	110
Net Generation, Exclusive of Plant Use - KWh	95,024,000	3,308,360,000	3,470,165,300	1,565,267,830	3,403,806,700
Cost of Plant:					
Land and Land Rights	83,342	1,124,665	1,110,712	0	2,218,858
Structures and Improvements	3,472,808	19,359,481	27,410,539	0	73,278,620
Equipment Costs	29,352,873	252,800,189	364,214,548	183,844,327	862,458,329
Asset Retirement Costs					
Total Cost	32,909,023	273,284,335	392,735,799	183,844,327	937,955,807
Cost per KW of Installed Capacity (line 5)	499	569	811	549	2,132
Production Expenses:					
Oper, Supv and Engr	265,083	1,661,905	1,531,063	0	1,722,309
Fuel	4,102,713	84,026,460	74,437,661	0	62,728,387
Coolants and Water (Nuclear only)					

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Steam-Electric Generating Plant Statistics - Part Two (Lines 3-33) (Ref Page: 402)

Steam Expenses	526,818	5,469,557	12,911,566	0	10,852,212
Steam from Other Sources					
Steam Transferred (Cr)					
Electric Expenses	274,077	1,979,865	3,204,146	0	1,226,160
Misc Steam (or Nuclear) Power Expenses	284,301	2,224,903	2,130,546	0	3,576,262
Rents					
Allowances	37,441	194,453	163,724	0	140,177
Maintenance Supervision and Engineering	246,427	1,518,977	1,564,693	0	1,403,947
Maintenance of Structures	99,652	1,433,848	962,694	0	1,152,399
Maintenance of Boiler (or reactor) Plant	1,277,048	6,976,891	9,666,586	0	8,359,331
Maintenance of Electric Plant	156,722	1,002,864	1,996,858	0	1,643,203
Maintenance of Misc Steam (or Nuclear) Plant	180,414	1,798,844	551,867	0	752,428
Total Production Expenses	7,450,696	108,288,567	109,121,404	0	93,556,815

Steam-Electric Generating Plant Statistics - Part Two (Line 34) (Ref Page: 402)

Expenses per Net KWh	0.0784	0.0327	0.0315	0.0000	0.0275

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Steam-Electric Generating Plant Statistics - Part Three (Lines 35-43) (Ref Page: 402)

Column b				
Nuclear Unit				
Quantity of Fuel Burned	57,745.5100	4,116.00000000	0.0000	0.0000
Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12,367.0000	138,000.00000000	0.0000	0.0000 0
Avg Cost of Fuel/unit as Delvd f.o.b. during year	58.0945	119.30300000	0.0000	0.0000
Average Cost of Fuel per Unit Burned	55.8497	119.33660000	0.0000	0.0000
Average Cost of Fuel Burned per Million BTU	2.2579	20.58840000	0.0000	0.0000
Average Cost of Fuel Burned per KWh Net Gen	0.0339	0.00520000	0.0000	0.0000
Average BTU per KWh Net Generation	15,031.0000	251.00000000	0.0000	0.0000
Column c				
Nuclear Unit				
Quantity of Fuel Burned	1,591,463.9500	0.00000000	144,158.6000	0.0000
Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11,397.0000	91,500.00000000	1,000,000.0000	0.0000 0
Avg Cost of Fuel/unit as Delvd f.o.b. during year	49.9600	0.00000000	5.5799	0.0000
Average Cost of Fuel per Unit Burned	50.1161	0.00000000	5.5799	0.0000
Average Cost of Fuel Burned per Million BTU	2.1986	0.00000000	5.5799	0.0000
Average Cost of Fuel Burned per KWh Net Gen	0.0241	0.00000000	0.4360	0.0000
Average BTU per KWh Net Generation	10,965.0000	0.00000000	44.0000	0.0000
Column d				

Steam-Electric Generating Plant Statistics - Part Three (Lines 35-43) (Ref Page: 402)

Nuclear Unit				
Quantity of Fuel Burned	1,697,668.4500	14,801.45000000	0.0000	0.0000
Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11,328.0000	138,000.00000000	0.0000	0.0000 0
Avg Cost of Fuel/unit as Delvd f.o.b. during year	42.2954	132.00180000	0.0000	0.0000
Average Cost of Fuel per Unit Burned	41.2557	130.51920000	0.0000	0.0000
Average Cost of Fuel Burned per Million BTU	1.8209	22.51900000	0.0000	0.0000
Average Cost of Fuel Burned per KWh Net Gen	0.0202	0.00060000	0.0000	0.0000
Average BTU per KWh Net Generation	11,084.0000	25.00000000	0.0000	0.0000
Column e				
Nuclear Unit				
Quantity of Fuel Burned	726,802.8100	6,913.00000000	0.0000	0.0000
Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12.1020	138,000.00000000	0.0000	0.0000 0
Avg Cost of Fuel/unit as Delvd f.o.b. during year	53.8644	131.60350000	0.0000	0.0000
Average Cost of Fuel per Unit Burned	53.6909	129.07870000	0.0000	0.0000
Average Cost of Fuel Burned per Million BTU	2.2183	22.27010000	0.0000	0.0000
Average Cost of Fuel Burned per KWh Net Gen	0.0249	0.00060000	0.0000	0.0000
Average BTU per KWh Net Generation	11,239.0000	26.00000000	0.0000	0.0000
Column f				
Nuclear Unit				

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Steam-Electric Generating Plant Statistics - Part Three (Lines 35-43) (Ref Page: 402)

[redacted]

Quantity of Fuel Burned	1,550,982.2200	14,909.61000000	0.0000	0.0000
Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11.7880	138,000.00000000	0.0000	0.0000 0
Avg Cost of Fuel/unit as Delvd f.o.b. during year	37.6597	130.62000000	0.0000	0.0000
Average Cost of Fuel per Unit Burned	36.7660	121.73280000	0.0000	0.0000
Average Cost of Fuel Burned per Million BTU	1.5595	21.00280000	0.0000	0.0000
Average Cost of Fuel Burned per KWh Net Gen	0.0168	0.00050000	0.0000	0.0000
Average BTU per KWh Net Generation	10,743.0000	25.00000000	0.0000	0.0000

Steam-Electric Generating Plant Statistics - pg two - Part One Plant Info (Ref Page: 402)

Please enter the information regarding each plant corresponding to the column intended for pg 402

Col b - Plant name	Reid
Kind of Plant (internal comb, gas turb, nuclear)	Combustion Turbine
Type of Constr (conventional, outdoor, boiler, etc)	
Col c - Plant name	
Kind of Plant (internal comb, gas turb, nuclear)	
Type of Constr (conventional, outdoor, boiler, etc)	
Col d - Plant name	
Kind of Plant (internal comb, gas turb, nuclear)	
Type of Constr (conventional, outdoor, boiler, etc)	
Col e - Plant name	
Kind of Plant (internal comb, gas turb, nuclear)	
Type of Constr (conventional, outdoor, boiler, etc)	
Col f - Plant name	
Kind of Plant (internal comb, gas turb, nuclear)	
Type of Constr (conventional, outdoor, boiler, etc)	

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Steam-Electric Generating Plant Statistics - pg two - Part Two (Lines 3-33) (Ref Page: 402)

Year Originally Constructed	1,976	0	0	0	0
Year Last Unit was Installed	1,976	0	0	0	0
Total Installed Cap (Max Gen name Plate Ratings MW)	72	0	0	0	0
Net Peak Demand on Plant - MW (60 minutes)	59	0	0	0	0
Plant Hours Connected to Load	372	0	0	0	0
Net Continuous Plant Capability (MW)					
When Not Limited by Condenser Water	65	0	0	0	0
When Limited by Condenser Water					
Average Number of Employees					
Net Generation, Exclusive of Plant Use - KWh	6,993,900	0	0	0	0
Cost of Plant:					
Land and Land Rights					
Structures and Improvements	154,233	0	0	0	0
Equipment Costs	8,029,864	0	0	0	0
Asset Retirement Costs					
Total Cost	8,184,097	0	0	0	0
Cost per KW of Installed Capacity (line 5)	114	0	0	0	0
Production Expenses:					
Oper, Supv and Engr					
Fuel	933,829	0	0	0	0
Coolants and Water (Nuclear only)					

Steam-Electric Generating Plant Statistics - pg two - Part Two (Lines 3-33) (Ref Page: 402)

[redacted]

Steam Expenses					
Steam from Other Sources					
Steam Transferred (Cr)					
Electric Expenses	33,918	0	0	0	0
Misc Steam (or Nuclear) Power Expenses					
Rents					
Allowances					
Maintenance Supervision and Engineering					
Maintenance of Structures					
Maintenance of Boiler (or reactor) Plant					
Maintenance of Electric Plant	150,725	0	0	0	0
Maintenance of Misc Steam (or Nuclear) Plant					
Total Production Expenses	1,118,472	0	0	0	0

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Steam-Electric Generating Plant Statistics - pg two - Part Two (Line 34) (Ref Page: 402)

Expenses per Net KWh	0.1599	0.0000	0.0000	0.0000	0.0000

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Steam-Electric Generating Plant Statistics - pg two - Part Three (Lines 35-43) (Ref Page: 402)

[redacted]

column b				
Nuclear Unit				
Quantity of Fuel Burned	0.0000	0.0000	164,464.0000	0.0000
Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0.0000	0.0000	1,000,000.0000	0.0000
Avg Cost of Fuel/unit as Delvd f.o.b. during year	0.0000	0.0000	5.6763	0.0000
Average Cost of Fuel per Unit Burned	0.0000	0.0000	5.6763	0.0000
Average Cost of Fuel Burned per Million BTU	0.0000	0.0000	5.6763	0.0000
Average Cost of Fuel Burned per KWh Net Gen	0.0000	0.0000	0.1335	0.0000
Average BTU per KWh Net Generation	0.0000	0.0000	23.5150	0.0000
column c				
Nuclear Unit				
Quantity of Fuel Burned	0	0	0	0
Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0
Avg Cost of Fuel/unit as Delvd f.o.b. during year	0	0	0	0
Average Cost of Fuel per Unit Burned	0	0	0	0
Average Cost of Fuel Burned per Million BTU	0	0	0	0
Average Cost of Fuel Burned per KWh Net Gen	0	0	0	0
Average BTU per KWh Net Generation	0	0	0	0
column d				

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Steam-Electric Generating Plant Statistics - pg two - Part Three (Lines 35-43) (Ref Page: 402)

Nuclear Unit				
Quantity of Fuel Burned	0	0	0	0
Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0
Avg Cost of Fuel/unit as Delvd f.o.b. during year	0	0	0	0
Average Cost of Fuel per Unit Burned	0	0	0	0
Average Cost of Fuel Burned per Million BTU	0	0	0	0
Average Cost of Fuel Burned per KWh Net Gen	0	0	0	0
Average BTU per KWh Net Generation	0	0	0	0
column e				
Nuclear Unit				
Quantity of Fuel Burned	0	0	0	0
Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0
Avg Cost of Fuel/unit as Delvd f.o.b. during year	0	0	0	0
Average Cost of Fuel per Unit Burned	0	0	0	0
Average Cost of Fuel Burned per Million BTU	0	0	0	0
Average Cost of Fuel Burned per KWh Net Gen	0	0	0	0
Average BTU per KWh Net Generation	0	0	0	0
column f				
Nuclear Unit				

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Steam-Electric Generating Plant Statistics - pg two - Part Three (Lines 35-43) (Ref Page: 402)

Quantity of Fuel Burned	0	0	0	0
Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0
Avg Cost of Fuel/unit as Delvd f.o.b. during year	0	0	0	0
Average Cost of Fuel per Unit Burned	0	0	0	0
Average Cost of Fuel Burned per Million BTU	0	0	0	0
Average Cost of Fuel Burned per KWh Net Gen	0	0	0	0
Average BTU per KWh Net Generation	0	0	0	0

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HydroElectric Generating Plant Statistics - Part One Plant Info (Ref Page: 406)

Please enter the information regarding each plant corresponding to the column intended for pg 406

Col b Ferc Licensed Project No

Plant Name

Kind of Plant (Run-of-River or Storage)

Plant Construction type (Conventional or Outdoor)

Col c Ferc Licensed Project No

Plant Name

Kind of Plant (Run-of-River or Storage)

Plant Construction type (Conventional or Outdoor)

Col d Ferc Licensed Project No

Plant Name

Kind of Plant (Run-of-River or Storage)

Plant Construction type (Conventional or Outdoor)

Col e Ferc Licensed Project No

Plant Name

Kind of Plant (Run-of-River or Storage)

Plant Construction type (Conventional or Outdoor)

Col f Ferc Licensed Project No

Plant Name

Kind of Plant (Run-of-River or Storage)

Plant Construction type (Conventional or Outdoor)

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HydroElectric Generating Plant Statistics - Part Two (Lines 3-34) (Ref Page: 406)

Year Originally Constructed
Year Last Unit was Installed
Total installed cap (Gen name plate Rating in MW)
Net Peak Demand on Plant-Megawatts (60 minutes)
Plant Hours Connect to Load
Net Plant Capability (in megawatts)
(a) Under Most Favorable Oper Conditions
(b) Under the Most Adverse Oper Conditions
Average Number of Employees
Net Generation, Exclusive of Plant Use - KWh
Cost of Plant
Land and Land Rights
Structures and Improvements
Reservoirs, Dams, and Waterways
Equipment Costs
Roads, Railroads and Bridges
Asset Retirement Costs
Total Cost
Cost per KW of Installed Capacity (line 5)
Production Expenses
Operation Supervision and Engineering

HydroElectric Generating Plant Statistics - Part Two (Lines 3-34) (Ref Page: 406)

Water for Power
Hydraulic Expenses
Electric Expenses
Misc Hydraulic Power Generation Expenses
Rents
Maintenance Supervision and Engineering
Maintenance of Structures
Maintenance of Reservoirs, Dams and Waterways
Maintenance of Electric Plant
Maintenance of Misc Hydraulic Plant
Total Production Expenses
Expenses per net KWh

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Pumped Storage Generating Plant Statistics - Part One Plant Info (Ref Page: 408)

Please enter the information regarding each plant corresponding to the column intended for pg 406

Col b Ferc Licensed Project No

Plant Name

Type of Plant Construction (Conventional or Outdoor)

Col c Ferc Licensed Project No

Plant Name

Type of Plant Construction (Conventional or Outdoor)

Col d Ferc Licensed Project No

Plant Name

Type of Plant Construction (Conventional or Outdoor)

Col e Ferc Licensed Project No

Plant Name

Type of Plant Construction (Conventional or Outdoor)

Col f Ferc Licensed Project No

Plant Name

Type of Plant Construction (Conventional or Outdoor)

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Pumped Storage Generating Plant Statistics - Part Two (Lines 3-34) (Ref Page: 408)

Year Originally Constructed
Year Last Unit was Installed
Total installed cap (Gen name plate Rating in MW)
Net Peak Demand on Plant-Megawatts (60 minutes)
Plant Hours Connect to Load
Net Plant Capability (in megawatts)
Average Number of Employees
9. Generation, Exclusive of Plant Use - KWh
10. Energy Used for Pumping
Net Output for Load (line 9 - line 10)
Land and Land Rights
Structures and Improvements
Reservoirs, Dams, and Waterways
Water Wheels, Turbines and Generators
Accessory Electric Equipment
Misc Pwerplant Equipment
Roads, Railroads and Bridges
Asset Retirement Costs
Total Cost
Cost per KW of Installed Capacity (line 5)
Production Expenses

Pumped Storage Generating Plant Statistics - Part Two (Lines 3-34) (Ref Page: 408)

Operation Supervision and Engineering
Water for Power
Pumped Storage Expenses
Electric Expenses
Misc Pumped Storage Power Generation Expenses
Rents
Maintenance Supervision and Engineering
Maintenance of Structures
Maintenance of Reservoirs, Dams and Waterways
Maintenance of Electric Plant
Maintenance of Misc Pumped Storage Plant
Production Expenses before Pumping Exp (23 thru 33)
Pumping Expenses
Total Production Expenses
Expenses per net KWh

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Generating Plant Statistics (Small Plants) (Ref Page: 410)

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0

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Generating Plant Statistics (Small Plants) (Ref Page: 410) (Part Two)

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Transmission Line Statistics (Ref Page: 422)

1	Barkley	Reid	161	161	H-W	58.8000	0.0000	1
2	Coleman	Southwire	161	161	H-W	5.0000	0.0000	1
3	Coleman	EHV Tie Lines	161	161	H-W	2.8000	0.0000	1
4	Reid	Hancock	161	161	H-W	48.2000	0.0000	1
5	Hancock	Harvey	161	161	H-W	1.3000	0.0000	1
6	Scott Paper	Daviess Co	161	161	H-W	15.7000	0.0000	1
7	Coleman	New Hardinsburg	161	161	H-W	24.8000	0.0000	1
8	Paradise	New Hardinsburg	161	161	H-W	46.3000	0.0000	1
9	Hancock	Coleman	161	161	H-W	3.7000	0.0000	1
10	Coleman	HED	161	161	H-W	2.9200	0.0000	1
11	New Hardinsburg	KU Tie	138	138	H-W	0.4000	0.0000	1
12	New Hardinsburg	Meade Co	161	161	H-W	17.9000	0.0000	1
13	Skillman-West		161	161	H-W	3.0000	0.0000	1
14	Skillman-East		161	161	H-W	3.0000	0.0000	1
15	Skillman Tap	Meade Co	161	161	H-W	17.1000	0.0000	1
16	Barkley Dam	SIPC	161	161	H-W	23.8000	0.0000	1
17	Livingston Co	McCracken Co	161	161	H-W	39.1000	0.0000	1
18	McCracken Co	TVA Line L	161	161	H-W	3.2000	0.0000	1
19	Marshall Co	TVA Tie	161	161	H-W	3.1000	0.0000	1
20	Bryan Road		161	161	H-W	0.3100	0.0000	1
21	Livingston Co	CoalTek-Calvert City	161	161	H-W	0.0000	0.0000	1
22	Reid	Alcan	161	161	H-W	4.5000	0.0000	1
23	Reid	Reid EHV	161	161	H-W	0.6000	0.0000	1
24	Reid	Henderson Co	161	161	H-W	15.3000	0.0000	1
25	Henderson Co	SIGECO	138	138	h-w	5.6000	0.0000	1

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Transmission Line Statistics (Ref Page: 422)

26	New Hardinsburg	LG&E	138	138	H-W	8.4000	0.0000	1
27	Wilson	Reid EHV	345	345	H-W	28.3000	0.0000	1
28	Wilson	Coleman EHV	345	345	H-W	39.1000	0.0000	1
29	Wilson Start-Up		161	161	H-W	0.6000	0.0000	1
30	Wilson Step-Up		161	161	H-W	0.6000	0.0000	1
31	Wilson	KU	161	161	H-W	8.0000	0.0000	1
32	Wilson	Paradise	161	161	H-W	0.0000	0.0000	1
33	Daviess Co		345	345	H-W	1.0000	0.0000	1
34	Under 32 kV		69	69	SP-W	833.1600	0.0000	2

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Transmission Line Statistics (cont) (Ref Page: 423)

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1	795 ACSR	$153,159.00	$1,566,948.00	$1,720,107.00	$0.00	$0.00	$0.00	$0.00
2	795 ACSR	$0.00	$29,381.00	$29,381.00	$0.00	$0.00	$0.00	$0.00
3	795 ACSR	$1,378.00	$15,755.00	$17,133.00	$0.00	$0.00	$0.00	$0.00
4	795 ACSR	$121,391.00	$2,411,797.00	$2,533,188.00	$0.00	$0.00	$0.00	$0.00
5	795 ACSR	$3,019.00	$30,886.00	$33,905.00	$0.00	$0.00	$0.00	$0.00
6	795 ACSR	$622,292.00	$1,575,966.00	$2,198,258.00	$0.00	$0.00	$0.00	$0.00
7	795 ACSR	$87,120.00	$576,208.00	$663,328.00	$0.00	$0.00	$0.00	$0.00
8	795 ACSR	$156,316.00	$1,071,306.00	$1,227,622.00	$0.00	$0.00	$0.00	$0.00
9	795 ACSR	$23,247.00	$54,586.00	$77,833.00	$0.00	$0.00	$0.00	$0.00
10	795 ACSR	$674.00	$211,683.00	$212,357.00	$0.00	$0.00	$0.00	$0.00
11	795 ACSR	$0.00	$17,155.00	$17,155.00	$0.00	$0.00	$0.00	$0.00
12	795 ACSR	$429,118.00	$1,691,144.00	$2,120,262.00	$0.00	$0.00	$0.00	$0.00
13	795 ACSR	$17,297.00	$335,176.00	$352,473.00	$0.00	$0.00	$0.00	$0.00
14	795 ACSR	$16,889.00	$334,763.00	$351,652.00	$0.00	$0.00	$0.00	$0.00
15	795 ACSR	$952,898.00	$4,033,062.00	$4,985,960.00	$0.00	$0.00	$0.00	$0.00
16	795 ACSR	$80,337.00	$744,435.00	$824,772.00	$0.00	$0.00	$0.00	$0.00
17	795 ACSR	$925,135.00	$4,159,779.00	$5,084,914.00	$0.00	$0.00	$0.00	$0.00
18	1590 ACSR	$61,576.00	$436,276.00	$497,852.00	$0.00	$0.00	$0.00	$0.00
19	795 ACSR	$62,138.00	$610,820.00	$672,958.00	$0.00	$0.00	$0.00	$0.00
20	795 ACSR	$0.00	$152,164.00	$152,164.00	$0.00	$0.00	$0.00	$0.00
21	795 ACSR	$2,965.00	$0.00	$2,965.00	$0.00	$0.00	$0.00	$0.00
22	795 ACSR	$1,427.00	$163,951.00	$165,378.00	$0.00	$0.00	$0.00	$0.00
23	1590 ACSR	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
24	795 ACSR	$201,433.00	$724,170.00	$925,603.00	$0.00	$0.00	$0.00	$0.00
25	795 ACSR	$76,137.00	$398,896.00	$475,033.00	$0.00	$0.00	$0.00	$0.00
26	795 ACSR	$9,395.00	$343,540.00	$352,935.00	$0.00	$0.00	$0.00	$0.00

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Transmission Line Statistics (cont) (Ref Page: 423)

			[illegible]	Cost of Line	Total of Line	[illegible]	[illegible]	[illegible]	[illegible]
	27	1590 ACSR	$632,159.00	$13,086,441.00	$13,718,600.00	$0.00	$0.00	$0.00	$0.00
	28	1590 ACSR	$876,205.00	$18,080,561.00	$18,956,766.00	$0.00	$0.00	$0.00	$0.00
	29	795 ACSR	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	30	1590 ACSR	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	31	795 ACSR	$214,753.00	$2,019,337.00	$2,234,090.00	$0.00	$0.00	$0.00	$0.00
	32	795 ACSR	$291,013.00	$0.00	$291,013.00	$0.00	$0.00	$0.00	$0.00
	33	795 ACSR	$15,056.00	$2,006,560.00	$2,021,616.00	$0.00	$0.00	$0.00	$0.00
	34	VARIOUS	$7,119,507.00	$38,118,894.00	$45,238,401.00	$0.00	$0.00	$0.00	$0.00
Total			$13,154,034.00	$95,001,640.00	$108,155,674.00	$0.00	$0.00	$0.00	$0.00

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Transmission Lines Added During Year (Ref Page: 424)

[redacted]

0

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Transmission Lines Added During Year (cont) (Ref Page: 425)

Total

900 Big Rivers Electric Corporation 01/01/2011 - 12/31/2011

Substations (Ref Page: 426)

1	BARKELY DAM	TRANSMISSION/U	69.0000	13.8000	4.1600
2	REID STATION	TRANSMISSION/U	161.0000	69.0000	4.1600
3	HANCOCK COUNTY	TRANSMISSION/U	161.0000	69.0000	4.1600
4	HARDINSBURG	TRANSMISSION/U	161.0000	138.0000	13.8000
5	HARDINSBURG	TRANSMISSION/U	161.0000	69.0000	13.8000
6	DAVIESS COUNTY	TRANSMISSION/U	161.0000	69.0000	13.8000
7	HENDERSON COUNTY	TRANSMISSION/U	161.0000	138.0000	13.8000
8	HENDERSON COUNTY	TRANSMISSION/U	161.0000	69.0000	13.8000
9	MEADE COUNTY	TRANSMISSION/U	161.0000	69.0000	13.8000
10	LIVINGSTON COUNTY	TRANSMISSION/U	161.0000	69.0000	13.8000
11	McCRACKEN COUNTY	TRANSMISSION/U	161.0000	69.0000	13.8000
12	HOPKINS COUNTY	TRANSMISSION/U	161.0000	69.0000	13.8000
13	WILSON EHV	TRANSMISSION/U	345.0000	161.0000	13.8000
14	REID EHV	TRANSMISSION/U	345.0000	161.0000	13.8000
15	COLEMAN EHV	TRANSMISSION/U	345.0000	161.0000	13.8000
16	NATIONAL ALUMINUM	TRANSMISSION/U	161.0000	13.8000	0.0000
17	BRYAN ROAD	TRANSMISSION/U	161.0000	69.0000	13.8000
18	CALDWELL	TRANSMISSION/U	161.0000	69.0000	13.8000
19	TOTALS		0.0000	0.0000	0.0000

Note:

Note:
Column A: Barkley Dam

Barkley Dam is owned by the Army Corp of Engineers. Only one (1) transformer and other related special facilities are owned by Big Rivers. Big Rivers finances the expenses on its own equipment.

Substations (continued) (Ref Page: 427)

1	35.0000	1	0	0	0
2	200.0000	2	0	0	0
3	90.0000	2	0	0	0
4	200.0000	1	0	0	0
5	95.0000	2	0	0	0
6	200.0000	2	0	0	0
7	200.0000	1	0	0	0
8	100.0000	2	1	0	0
9	100.0000	2	0	0	0
10	100.0000	2	1	0	0
11	200.0000	2	0	0	0
12	50.0000	1	0	0	0
13	600.0000	2	0	0	0
14	600.0000	2	0	0	0
15	600.0000	2	0	0	0
16	50.0000	2	0	0	0
17	100.0000	2	0	0	0
18	20.0000	1	0	0	0
19	3,540.0000	31	2	0	0

CheckList

Item	Value 1	Value 2	Agree	Explain
Balance Sheet (Assets and Other Debts) (ref pg 110)				
Line 2. Utility Plant (101-106) agrees with Sched Sum of Util Plant and Acc Prov for Depr Amort and Depletion (ref pg 200) Sum of Lines Total In Service,Leased to Others and Held for Future Use	1979267724.00	1979267724.00	OK	
Line 3. Construction Work in Progress agrees with Sched Sum of Util Plant and Acc Prov for Depr Amort and Depletion (ref pg 200) Line Construction Work in Progress Col Elec (c)	49150583.00	49150583.00	OK	
Line 4. Total Utility Plant agrees with Sched Sum of Util Plant and Acc Prov for Depr Amort and Depletion (ref pg 200) Line Total Utility Plant Col Elec (c)	2028418307.00	2028418307.00	OK	
Line 5. (Less) Accum. Prov for Dep. Amort. Depl agrees with Sched Sum of Util Plant and Acc Prov for Depr Amort and Depletion (ref pg 200) Line Accum. Prov. for Depr, Amort and Depl.	936354953.00	936354953.00	OK	
Line 6. Net Utility Plant agrees with Sched Sum of Util Plant and Acc Prov for Depr Amort and Depletion (ref pg 200) Line Net Utility Plant	1092063354.00	1092063354.00	OK	
Line 17. Investments in Subsidiary Companies agrees with Sched Investments in Subsidiary Companies (ref pg 224) Line Total	0	0	OK	
Line 34. Fuel Stock agrees with Sched Materials and Supplies (ref pg 227) Line Fuel Stock	33553927.00	33553927.00	OK	
Line 35. Fuel Stock Expenses Undistributed agrees with Sched Materials and Supplies (ref pg 227) Line Fuel Stock Expenses Undistributed	0	0	OK	
Line 36. Residuals (Elect) and Extracted Products agrees with Sched Materials and Supplies (ref pg 227) Line Residuals (Elect) and Extracted Products	0	0	OK	
Line 37. Plant Materials and Operating Supplies agrees with Sched Materials and Supplies (ref pg 227) Line Total Plant Materials and Operating Supplies	24585465.00	24585465.00	OK	

CheckList

Item	Value 1	Value 2	Agree	Explain
Line 38. Merchandise agrees with Sched Materials and Supplies (ref pg 227) Line Merchandise	0	0	OK	
Line 39. Other Materials and Supplies agrees with Sched Materials and Supplies (ref pg 227) Line Other Materials and Supplies	0	0	OK	
Line 40. Nuclear Materials Held for Sale agrees with Sched Materials and Supplies (ref pg 227) Line Nuclear Materials Held for Sale	0	0	OK	
Line 43. Stores Expense Undistributed agrees with Sched Materials and Supplies (ref pg 227) Line Store Expense Undistributed	709799.00	709799.00	OK	
Line 55. Extraordinary Property Losses agrees with Sched Extraordinary Property Losses (ref pg 230) Line Total Col Balance (f)	0	0	OK	
Line 62. Misceallaneous Deferred Debits agrees with Sched Miscellaneous Deferred Debits (ref pg 233) Line Total Col Balance (f)	367451.00	367451.00	OK	
Line 64. Research, Devel. and Demonstration Expend. agrees with Sched Research Development and Demonstration Activities (ref pg 352) Line Total Col g	0	0.0000	OK	
Line 66. Accumulated Deferred Income Taxes agrees with Sched Accumulated Taxes (ref pg 254) Line Total Acct 190	0	0	OK	
Balance Sheet - Liabilities and Other Credits (ref pg 112)				
Line 2. Common Stock Issued (201) agrees with Sched Capital Stock (Acct 201 and 204) ref pg 250 Line Total Common Stock Col f	75.00	0	NO	Amount reported on Ref. Page 112, Line 2, Account 201 is for membership fees. Big Rivers Electric Corporation is a cooperative, therefore it does not issue stock.
Line 3. Preferred Stock Issued (204) agrees with Sched Capital Stock (Acct 201 and 204) ref pg 250 Line Total Preferred Stock Col f	0	0	OK	

CheckList

Item	Value 1	Value 2	Agree	Explain
Line 11. Retained Earnings agrees with Sched Statement of Retained Earnings (ref pg 118) Line Total Retained Earnings Col Amount c	397099185.00	397099185.00	OK	
Line 12. Unappropriated Undistributed Subsidiary Earnings agrees with Sched Statement of Retained Earnings (ref pg 118) Line Balance End of Year for Unappropriated Undistrib Sub Earnings Col c	0	0	OK	
Line 13. (Less Reaquired Capital Stock) agrees with Sched Capital Stock (ref pg 250) Line Total Col h	0	0	OK	
Line 16. Bonds (221) agrees with Sched Long Term Debt (221, 222,223,224) (ref pg 256) Line Total 221 Col h	0	0	OK	
Line 18. Advances from Associated Companies (223) agrees with Sched Long Term Debt (221, 222,223,224) (ref pg 256) Line Total 223 Col h	0	0	OK	
Line 19. Other Long Term Debt (224) agrees with Sched Long Term Debt (221, 222,223,224) (ref pg 256) Line Total 224 Col h	786398429.00	786398429.00	OK	
Line 37. Taxes Accrued agrees with Sched Taxes Accrued, Prepaid and Charged (Ref pg 262) Line Total Col g	956559.00	956559.00	OK	
Line 48. Accumulated Def Investment Tax Credits agrees with Sched Accumulated Deferred Investment Tax Credit (Ref Pg 266) Line Total Col h	0	0	OK	
Line 50. Other Deferred Credits agrees with Sched Other deferred Credits (Ref Pg 269) Line Total Col h	0.0000	0	OK	
Line 53. Other Deferred Credits agrees with Sched Other deferred Credits (Ref Pg 269) Line Total Col h	0	0	OK	
Income Statement (Ref pg 114)				
Line 2. Operating Revenues agrees with Sched Electric Operating Revenues (Ref pg 300) Line Total Electric Operating Revenues Col b	561989232.00	561989232.00	OK	

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CheckList

Item	Value 1	Value 2	Agree	Explain
Sum of Lines 4. Operation Exp and 5. Maint Exp agrees with Sched Electric Operation and Maint. Expenses (Ref pg 323) Line Total Elec Operation and Maintence	475705375.00	475705375.00	OK	
Line 6. Depreciation Expense agrees with Sched Depreciation and Amort of Electric Plant (Ref pg 336) Line Total Col b	35247017.00	35247017.00	OK	
Line 7. Amort and Depl of Utility Plant agrees with Sched Depreciation and Amort of Electric Plant (Ref pg 336) The Sum of Cols d and e Line Total	159789.00	159789.0000	OK	
Sum of Lines 13,14 and 15 Col. Electric (e) agrees with Sched Taxes Accrued, Prepaid and Charged (Ref pg 262) Line Total Taxes Col i	98389.00	98389.00	OK	
Line 19. Investment Tax Credit Adj. agrees with Sched Accumulated Deferred Investment Tax Credit (Ref pg 266) Line Total Col f	0	0	OK	
Statement of Income (Continued) (Ref Pg 117)				
Line 70. Income Taxes - Federal and Other agrees with Sched Taxes Accrued Prepaid and Charged (ref pg 262) Col j	0	0.0000	OK	
Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization and Depletion				
Line Plant Purchased or Sold Col c Electric agrees with Schedule Electric Plant in Service (ref pg 207) Line Electric Plant Purchased Less Electric Plant Sold Col g	0	0	OK	
Line Experimental Plant Unclassified Col c Electric agrees with Schedule Electric Plant in Service (ref pg 206) Line Experiemental Plant Uncalssified Col g	0	0	OK	
Line Held for Future Use Col c Electric agrees with Schedule Electric Plant Held for Future Use (ref pg 214) Line Total	475968.00	475968.00	OK	
Electric Operating Revenues (Acct 400) (ref pg 300)				
Line Sales for Resale Col b agrees with Sched Sales for Resale (Ref pg 310) Line Total Col k	558372354.00	558372354.00	OK	

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CheckList

Item	Value 1	Value 2	Agree	Explain
Line Sales for Resale Col d MWH agrees with Sched Sales for Resale (Ref pg 310) Line Total Col g MWH	13255125	13255125	OK	
Electric Operation and Maintenance Expenses (Ref pg 323)				
Line Miscellaneous General Expenes Col b agrees wtih Sched Miscellaneous General Expenses (Ref pg 335) Line Total Amount	1804562.00	1804562.00	OK	
Electric Energy Account (ref pg 401)				
Line Purchases Col MWHours agrees with Sched Purchased Power (Ref pg 326) Line Total Col g MWH Purchased	2998361	2998361	OK	
Line Sales to Ultimate Consumers Col MWHours agrees with Sched Electric Operating Revenues (Ref pg 300) Line Total Sales to Ultimate Consumers Col d MWH Sold	0	0	OK	
Line Requirements Sales for Resale Col MWHours agrees with Sales for Resale (Ref pg 310) Line Total RQ Col g MWH Sold	10199019	10199019	OK	

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Oath Statement

See Beginning of Report

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION
FOR A GENERAL ADJUSTMENT IN RATES
CASE NO. 2012-00535

Response to the Office of the Attorney General's
Supplemental Set of Data Requests
Dated March 14, 2013

March 28, 2013

Item 54) *Referencing Big Rivers' response to AG 1-75(a) and AG 1-76(a): Explain and quantify the primary reasons for the reduction in total payroll costs from $49.3 m in 2012 to $45.8 m in the forecasted test period, and provide related calculations for the annualized impact of the removal of payroll costs related to the Wilson Layup and all other reasons that exceed $100,000 per year.*

Response) Please see attached.

Witness) James V. Haner

Wages & Salaries Reconciliation
$ in millions

2012 YTD Actual as of 12/31/12	$49.3
Incentive Pay	(0.7)
Wilson Difference as Annualized [1]	(4.5)
Extrapolated Estimate [2]	1.0
All Other	0.7
Forecasted Test Period (FTP) Budget*	$45.8

**Not adjusted for Wilson Layup Labor Pro Forma*

Wages and Salaries related to Wilson Layup Pro Forma:	
Pro Forma Amount (included in FTP budget)	$1.5
Annualized ($1.5 x 4)	6.0
Difference [1]	$4.5

Extrapolated Estimate of Wage & Salary Increase [2]	
($45.8-(45.8 / 1.0225))	$1.0

[1] Reflects the difference between the annualized amount for Wages & Salaries related to the Wilson Layup Pro Forma and the amount that is reflected in the FTP budget amount of $45.8.

[2] Wage and Salary annual increase in the test period is extrapolated to provide an estimate.

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2012-00535

Response to the Office of the Attorney General's Supplemental Set of Data Requests Dated March 14, 2013

March 28, 2013

Item 55) ***Referencing Big Rivers' response to AG 1-77 and AG 1-75(a): Address the following:***

a. Explain why the forecast test period shows an increase in percentage of "payroll expensed" and a reduction in the percentage of "payroll capitalized" for the first time compared to the prior base period, 2012, and YTD 2011.

b. Explain why the percentage of payroll capitalized would decrease in the forecasted test period (and other forecasted years) when the amount of CAPEX is expected to increase.

Response)

a. The numbers for 2011, 2012, and the base period all include labor costs in the capitalized category that include inventory or receivable projects, which are not capital projects. Big Rivers does not budget for these items separately since their timing is hard to predict. Also, the percentage of payroll capitalized varies from year to year, depending upon the number and amounts of more internal-labor-intensive projects. Please refer to the Direct Testimony of David G. Crockett, Tab 67, pages 5 and 6 for the derivation of capital costs included in the budget.

b. The total capital amount in the forecasted test period includes $55 million for environmental compliance projects, which will not be internal-labor-intensive. Also, please see response to subpart (a) above.

Witness) James V. Haner

BIG RIVERS ELECTRIC CORPORATION

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR A GENERAL ADJUSTMENT IN RATES CASE NO. 2012-00535

Response to the Office of the Attorney General's Supplemental Set of Data Requests Dated March 14, 2013

March 28, 2013

Item 56) *Referencing Big Rivers' response to AG 1-78, address the following regarding the "retention program":*

a. Provide a copy of BREC's retention program policy.
b. Provide the amount of retention amounts paid to each employee for each year the program was in place, and show amounts expensed for the one-year period following the Unwind transaction (and provide that year), 2009, 2010, 2011, 2012, and the forecasted test period.
c. Explain and provide the criteria used for determining payments under the retention program, and explain how this was used in regards to evaluating actual amounts paid to employees.
d. Show retention "target/criteria" and show the percent of "target/criteria" achieved for each year, and how this translated to the amount paid for retention bonuses to employees for each of the periods in (b).
e. Explain the "target/criteria" related or tied to the Unwind Transaction and explain how this was used to determine the amount of related bonuses that were paid.
f. Explain how the retention program was implemented, who proposed this policy, how was it adopted, and provide copies of Board Minutes authorizing the retention program.

Response)

a. The retention program is described in AG 1-78. There is no written policy.

b. The program provided a one-time payment in July 2010, following the one-year anniversary of the close of the unwind transaction. The retention bonus paid in 2010 is not included in Big Rivers' revenue requirement in this Case No. 2012-00535, nor was it included in the Big Rivers' revenue requirement in Case No. 2011-00036. Consequently, to the extent that this request seeks additional information, this request is unduly burdensome and is not reasonably calculated to lead to the discovery of admissible evidence because the retention amounts are not contained in the revenue requirements.

c-e. The retention "target/criteria" was to remain in the continuous full-time employment of Big Rivers during the 12-month period following the close of the unwind transaction. For those meeting that "target/criteria," the bonus was a percentage of starting base pay or cash compensation for hours worked. See response to AG 1-78.

f. Executive management proposed the program for the reasons stated in AG 1-78. It was approved by Big Rivers' Board of Directors in January 2008. A copy of the minutes authorizing the program is being provided pursuant to a petition for confidentiality.

Witness) James V. Haner

The AG 2-56(f) attachment has been omitted from the public filing. It has been provided under a petition for confidential treatment.

Item 57) *Referencing Big Rivers' response to AG 1-75(c),(d), and (e) and AG 1-76(c),(d), and (e) related to short and long-term incentive pay, SERP, and bonuses, address the following:*

a. Provide separately the amount of short and long-term incentive, SERP, and bonus paid to each officer and management for 2011, 2012, base period, forecasted test period, and 2015 budget.

b. Provide the amounts in (a) for the 12 months following the Unwind Transaction and identify that period.

c. For (a) and (b), explain why amounts paid in each category increased for each year and provide supporting documentation.

d. Provide a copy of BREC's short and long-term incentive program, SERP, and bonus policy.

e. Explain and provide the criteria used for determining payments under the short and long-term incentive program and bonus program, and explain how this was used in regards to evaluating actual amounts paid to employees.

f. Show "target/criteria" and show the percent of "target/criteria" achieved for short and long-term incentives and bonuses for each period in (a) and (b) for officers only, and how this translated to the amount paid for short and long-term incentives and bonuses for officers for each of the periods in (a) and (b). If necessary, show how the various "target/criteria" were *weighted in determining the amount paid to each officer for the periods in (a) and (b).*

g. *For each of the "target/criteria", explain how they were determined and who determined these.*

h. *For each of the "target/criteria", explain how and why they were changed each year, and how the change in targets/criteria was determined.*

i. *For each of the "target/criteria", explain those which are beneficial to customers or provide benefits to customers and identify those benefits.*

j. *For each of the "target/criteria", explain which are related to safety, service quality, Company profits or margins, the Unwind transaction, the current rate case, TIER, return on rate base, and other specific goals.*

k. *For each of the "target/criteria", explain which are considered "short" term and which are considered "long" term, and explain why.*

l. *Explain the "target/criteria" related or tied to the Unwind Transaction and explain how this was used to determine the amount of related bonuses that were paid.*

m. *Explain the "target/criteria" related to this pending rate case and explain how this was used to forecast amounts for short and long-term incentives, bonuses, retention pay, and other amounts in the forecasted test period.*

n. *Provide copies of Board Minutes authorizing the current compensation program.*

Response)

a. The attached schedule provides the data requested for the president and CEO, and the Vice Presidents.

b. The 12 months following the unwind transaction are part of the period for which actual payroll detail is unavailable due to inaccessibility of the Oracle 11i information system environment provided by E.ON pursuant to a contract that terminated January 15, 2011, at which time Big Rivers transitioned to Oracle 12.

c. Changes in incentive pay are the result of changes in compensation and the incentive payout percentage. Incentive pay can increase or decrease from year to year. Changes in deferred compensation (SERP) are the result of changes in compensation, IRS limits with regard to qualified pension plans, and the non-discrimination test results for those plans. Deferred compensation can increase or decrease from year to year. Changes in Christmas bonus expense are primarily the result of changes in the number of employees, since the amount for each employee is the gross amount that will result in a net check of $100 per employee each year.

d. See the responses to AG 1-258 and AG 1-78. There is no written Christmas bonus policy.

e. The criteria for determining payments are based on the company's performance in relation to the targets approved each year. The development of the plan is discussed in subpart (g) below. Payments are made if performance in a category falls between the minimum and maximum targets, in which case the payout percentage is extrapolated, but only if the company meets its loan covenants.

f. See the attached schedules for the incentive pay awards paid in 2011 and 2012. The award percentage is the same for all eligible employees.

g. Big Rivers' incentive plan is based upon budgeted targets/goals that are developed each year and approved by the Board of Directors. No dollars are budgeted for payouts as the plan is designed to be self-funding by producing lower expenses or higher non-member revenues. The members receive 90% of the savings, and plan participants share 10% of the savings. For the 2013 plan, maximum payout is 6% for the eligible participants. The four measurement areas relate to Financial Performance, Safety, Plant Performance, and Transmission System Reliability. For the Financial Performance target, the company's North Star calculation [(Total Expenses less Non-Member Revenues)/Member kWh)] in the Board-approved budget is the starting point for the minimum payout. The North Star measurement funds the financial measurement and any other measurement that cannot fund itself. In the current plan, the North Star comprises 50% of the total payout and funds approximately 93% of the 6% maximum payout, with the Heat Rate measurement self-funding and EAF (Equivalent Availability Factor) partially self-funding. To achieve the maximum payout for Financial Performance, higher non-member revenues or lower expenses (or a combination of both) would have to be $13.7 million, with the members receiving $12.3 million and the plan participants receiving $1.4 million. The Safety targets are developed by management. Since it is difficult to quantify the savings related to safety, this measure is funded by North Star. The Plant Performance measure is comprised of EAF and Heat Rate results. The EAF target is established by management using planned outage schedules, historical performance, and unit availability in the production model outputs which are used to develop financial results and the Board-approved annual budgets. This measure can be self-funding as increased generation from a higher EAF increases the off-system sales volumes, but with low market prices in the current plan, this target could only fund 14% of its potential payout, with the remaining 86% being funded by North Star. The Heat Rate target is established based on historical performance, projected fuel quality, and production cost model outputs. This measure is self-funding as a lower heat rate (higher unit efficiency) provides fuel savings. The Transmission System Reliability targets (SAIDI or System Average Interruption Duration Index) comprise 25% of the potential payout. The targets are developed by using a five-year average of each member system cooperative's transmission system reliability measure. To ensure conservative targets are established, if the five-year average for any individual system is higher than the system-wide average, the system-wide average is adopted for that target. In addition, major outages such as the 2009 ice storm are excluded from the five-year average. To achieve maximum payout for Transmission System Reliability, the company must achieve a 20% improvement in the five-year average.

h. The financial targets are adjusted each year based on the Board-approved budgeted North Star and labor base of the plan participants. The Safety targets are established each year by management, with full payout for two fewer recordable incidents than the target and no lost time incidents. The EAF target changes based on planned outage schedules and projected unit performance. Heat Rate targets change based on fuel quality and unit efficiency. The SAIDI targets are modified each year based on a five-year average adjusted for major outages.

i. The plan is designed to benefit the members (customers) significantly more than the plan participants. The financial performance targets are developed with the members receiving 90% of the benefit and the plan participants receiving 10%. This can be achieved by lowering expenses or increasing non-member revenues. Big Rivers personnel work to maximize revenue from off-system sales and other non-member sources to lower the revenue requirement from its members. Safety performance is difficult to quantify financially, but safety records can impact the company's insurance rates, medical expenses, and employee productivity. EAF performance has a direct relation to the amount of purchased power cost the company passes on to its members, as well as to the maximization of available power to sell in the off-system sales market in an effort to lower the revenue requirement from its members. Heat

Rate directly impacts fuel costs that are passed along to the members. SAIDI performance directly impacts customer satisfaction.

j. There are no targets related to the unwind transaction, return on rate base, or the current rate case. The financial targets are developed to drive lower member cost/kWh. Safety targets are related to employee safety results. Plant performance and system reliability targets are related to service quality.

k. Incentive award plans are developed and approved on an annual basis. The goal is to keep plan participants aware of, and in alignment with, the company's strategic goals in the "short" term, and in turn have positive "long" term impact.

l. There were no targets tied to the Unwind Transaction.

m. There are no targets related to the pending rate case.

n. A copy of the minutes approving the program is attached under a petition for confidential treatment.

Witness) James V. Haner

Incentive

Employee	2011	2012	Base Period	Test Period	2015
1	9,053	6,529	-	-	-
2	-	-	-	-	-
3	7,687	6,404	-	-	-
4	-	3,486	-	-	-
5	8,705	6,725	-	-	-
6	8,676	6,605	-	-	-
7	10,437	9,387	-	-	-
8	10,967	9,745	-	-	-

Base period incentives (see AG 1-75(c)) were not budgeted by individual, and incentives are not included in the test period or 2015 budget.

Bonus

Employee	2011	2012	Base Period	Test Period	2015
1	150	150	-	-	-
2	-	-	-	-	-
3	150	-	-	-	-
4	154	147	-	-	-
5	150	150	-	-	-
6	150	150	-	-	-
7	150	150	-	-	-
8	150	-	-	-	-

Christmas bonuses are not included in budgets or forecasts, and none were made in the actual portion of the base period.

Deferred Compensation (SERP)

Employee	2011	2012	Base Period	Test Period	2015
1	1,337	-	-	-	-
2	45,824	48,386	24,193	-	-
3	-	-	-	-	-
4	-	-	-	-	-
5	-	-	-	-	-
6	-	-	-	-	-
7	10,122	11,596	5,798	-	-
8	1,368	260	-	-	-

Deferred compensation is not identified separately from pension expense in budgets or forecasts. The base period numbers shown are for the deferred compensation booked in the actual portion of the base period.

Big Rivers
ELECTRIC CORPORATION
Your Touchstone Energy Cooperative

2011 Incentive Pay Award

Measurement	Weighting	Actual 12/31/2011	0% Minimum	8% Maximum	Maximum Possible Incentive Rate	Actual Payout Rate Based on Performance	Incentive Pay	Incremental Member Value
Financial Performance								
North Star ($/kw)	50%	0.044396	0.044766	0.043205	4.00%	0.95%	$ 195,084	$ 3,396,273
Safety								
Recordable Incidents	6.25%	12	9	7	0.50%	0.00%	$ -	
Lost Time Incidents	6.25%	2	2	0	0.50%	0.00%	$ -	
Plant Performance/Operations								
EAF*	6.25%	93.3%	92.6%	93.1%	0.50%	0.50%	$ 102,676	$ 1,571,280
Heat Rate	6.25%	[redacted]			0.50%	0.49%	$ 100,622	$ 1,332,812
Transmission System Reliability								
SAIDI Hrs/YR - Jackson Purchase	6.25%	0.040	0.778	0.622	0.50%	0.50%	$ 102,676	
SAIDI Hrs/YR - Meade County	6.25%	0.971	0.809	0.647	0.50%	0.00%	$ -	
SAIDI Hrs/YR - Kenergy	6.25%	0.127	1.578	1.262	0.50%	0.50%	$ 102,676	
SAIDI Hrs/YR - System Wide	6.25%	0.318	1.578	1.262	0.50%	0.50%	$ 102,676	
	25%							
	100%				8.00%	3.44%	$ 706,410	$ 6,300,366

Base earnings for incentive pay purposes is W-2, plus pre-tax cafeteria plan contributions and 401(k) deferrals, and excludes bonus dollars, taxable educational reimbursement, taxable vehicle, taxable group term life insurance, and accident protection insurance.
Base earnings for the eligible employees for the 12-month period ended December 31, 2010, are $20,535,171. The award for each measurement cannot exceed the maximum, and if the result is between the minimum and maximum, the award is interpolated.

* The original target of 91.0% was adjusted to 92.6% to account for the planned outage cancellations and scope reductions that occurred throughout the year.

An Incentive Award Payout will only be made to the extent the Company remains in compliance with its loan covenants.

Date: 2/13/2012

Case No. 2012-00535
Attachment for Response to AG 2-57(f)
Witness: James V. Haner

2012 Incentive Pay Award (Prepared 2/18/2013)

Measurement	Weighting	Actual 12/31/2012	0% Minimum	6% Maximum	Maximum Possible Incentive Rate	Payout Rate Based on Performance	Base Earnings $ 21,127,933 Incentive Pay	Net Incremental Member Value
Financial Performance								
North Star ($/kWh)*	50%	0.048826	0.050925	0.049724	3.00%	3.00%	$ 735,252	$ 21,371,635
Safety								
Recordable Incidents	6.25%	7	9	7	0.38%	0.38%	$ 91,907	
Lost Time Incidents	6.25%	0	1	0	0.38%	0.38%	$ 91,907	
Plant Performance/Operations								
EAF**	6.25%	92.4%	91.6%	91.9%	0.38%	0.38%	$ 91,907	$ 245,428
Heat Rate	6.25%	[redacted]			0.38%	0.38%	$ 91,907	$ 5,290,780
Transmission System Reliability								
SAIDI Hrs/YR - Jackson Purchase	6.25%	0.692	0.541	0.433	0.38%	0.00%	$ -	
SAIDI Hrs/YR - Meade County	6.25%	0.919	0.741	0.593	0.38%	0.00%	$ -	
SAIDI Hrs/YR - Kenergy	6.25%	0.271	1.013	0.810	0.38%	0.38%	$ 91,907	
SAIDI Hrs/YR - System Wide	6.25%	0.544	1.013	0.810	0.38%	0.38%	$ 91,907	
	25%							
	100%				6.00%	5.25%	$ 1,286,691	$ 26,907,843

Base earnings for incentive pay purposes is W-2, plus pre-tax cafeteria plan contributions and 401(k) deferrals, and excludes bonus dollars, taxable educational reimbursement, taxable vehicle, taxable group term life insurance, and accident protection insurance. Base earnings for the eligible employees for the 12-month period ended December 31, 2012, were $21,127,933. The award for each measurement cannot exceed the maximum, and if the result is between the minimum and maximum, the award is interpolated.

* The actual North Star ($/kWh) was adjusted upward for planned outage cancellations and scope reductions that occurred in 2012.

** The original target of 88.3% was adjusted to 91.6% to account for the planned outage cancellations and scope reductions that occurred throughout the year.

An Incentive Award Payout is only made to the extent the Company remains in compliance with its loan covenants.

Date: 2/18/2013

The AG 2-57(n) attachment has been omitted from the public filing. It has been provided under a petition for confidential treatment.

Item 58) *Referencing Big Rivers' response to AG 1-75(i) which states that the forecasted test period includes an adjustment related to the Wilson Station Layup for 92 employees and related nonrecurring payroll costs of $1,558,742 for the period September 2013 to November 2013, address the following:*

a. BREC's adjustment for nonrecurring labor related to the Wilson Layup is identified as $2,595,458 at Tab 50 Attachment, page 7 of 7. Explain the reason for the difference between the amount of $1,558,742 cited at the response to AG 1-75(i) versus the adjustment of $2,595,458 at the Company's filing and provide a reconciliation and all supporting documentation.

b. Mr. Wolfram's testimony (Exhibit Wolfram-2, Schedule 1-10) shows that 127 budget employees and 35 pro forma employees (total of 162 employees) are reflected in the Wilson Layup adjustment of $2,595,458, explain why this number of employees varies from the 92 employees cited at the response to AG 1-75(i) and provide a reconciliation and all supporting workpapers.

Response)

a. Big Rivers' adjustment for nonrecurring labor related to the Wilson Layup is $2,595,458. This includes wages and salaries of $1,558,742 as well as other payroll related costs, i.e., overheads or burdens, of $1,036,716. Information provided for AG 1-75(i) reflects only the wages and salaries portion of the nonrecurring labor in the amount of $1,558,742.

b. Exhibit Wolfram 2, Reference Schedule 1.10 shows that the Headcount – Budget Total is 127 (row 17, column 8) and the Headcount – Pro Forma Total is 16 (row 18, column 8). This means that for ratemaking purposes, the budgeted number of 127 employees should be reduced to the pro forma number of 35 employees. Thus the numbers are not additive and do not result in a total of 162 employees; instead, the pro forma headcount should be subtracted from the budgeted headcount to show a total of 127 – 35 = 92 employees reduced, which reconciles to the number of employees cited in response to AG 1-75(i).

Witnesses) DeAnna M. Speed (a)
John Wolfram (b)

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Item 59) *Referencing Big Rivers' response to AG 1-75(g) is confusing and states that no severance pay was allocated in the forecasted/budgeted periods, but severance pay of $4.6 million is deferred and amortized over 60 months in the budget beginning September 2013 and is not reflected as part of payroll costs. Address the following:*

a. Please clarify the confusion regarding this response, explain if severance costs are included, or are not included, in the forecasted test period.
b. If the answer to (a) is "yes": (i) provide the amount of severance costs included in the forecasted test period and cite to amounts in the financial model (by field/location); and (ii) provide all calculations regarding the amount of severance costs including showing total severance costs, period of amortization, and amortized expenses in the test period.
c. Explain and clarify if all severance costs are related to the Wilson Layup or identify all severance costs by related event or conditions, including the date such events or conditions will begin and end.
d. BREC's response to AG 1-112 provides a brief explanation of severance costs, but clarify per the following and the response to AG 1-75(g) by providing the components included in severance pay of $4.6 million, including payroll costs, medical and dental insurance, and other components.

Response)

a. Severance costs of \$4.6 million are deferred and amortized in the budget over 60 months beginning September 2013. The forecasted test period contains 12 months of amortization expense related to severance costs. However, the amortization thereof is not reflected as part of wages and salaries on the schedule in the response to AG 1-75(g).

b. (i) The forecasted test period contains amortization of severance costs in the amount of \$920,000. This is located in the financial model on the tab "Regulatory Charge" on row 47. (ii) Please refer to PSC 1-57 for calculations.

c. The amortization of severance costs reflected in the forecasted test period is related to the Wilson Layup.

d. Please refer to Direct Testimony of James V. Haner, Exhibit Haner-2, for components included in severance costs of \$4.6 million.

Witnesses) James V. Haner (subparts b(ii), c, and d)
DeAnna M. Speed (subparts a and b(i))

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Item 60) *Referencing Big Rivers' response to AG 1-161 which asks for supporting documentation for the Wilson Layup adjustment. BREC's response states that the forecasted test period beginning September 1, 2013, only includes budget labor for the Wilson plant for September, October, and November 2013 (and personnel reductions will not be complete until December 2013), and thus BREC's Wilson Layup adjustment removes the September to November 2013 payroll costs from the rate case, and for that reason an adjustment of $2,595,458 was removed (Exhibit Wolfram-2, Schedule 1-10). Address the following:*

a. *Allocate the amount of the adjustment of $2,595,458 between payroll, payroll overheads/benefits, severance costs, and all other costs by specific type.*
b. *Identify the payroll benefits loadings factor used to allocated payroll overheads for this adjustment, or provide what this payroll benefits loadings factor percentage would be and provide all supporting documentation.*
c. *Explain if payroll costs for specific employees were removed via the Wilson Layup adjustment, or explain if any "average" payroll cost for employees performing functions at the Wilson plant were removed, and provide supporting calculations for average costs.*

Response)

a. Please see attachment for AG-2-60(a).
b. Please see attachment for AG-2-60(b).

c. In general, average payroll costs for employees at Wilson rather than the costs for specific employees at Wilson were removed. Specifically, the payroll costs for each of the five areas shown in Exhibit Wolfram-5 Reference Schedule 1.10 – namely Plant, IT, Safety, Budget, and Supply Chain – were scaled proportionately from the total costs associated with full Headcount – Budget levels to the lower Headcount – Pro Forma levels. For Wilson-IT and Wilson-Safety staff, pro forma headcount is zero, so all of the test year costs for these employees were removed, and averaging is not an issue. For Wilson-Plant, Wilson-Budget, and Wilson-Supply Chain staff, the full budget cost is scaled by the ratio of pro-forma headcount to full headcount, by area, to determine the amount of cost to be removed. Thus for these three staff categories, costs were removed on a proportionate or "average" basis.

Witnesses) DeAnna M. Speed (a-b)
John Wolfram (c)

WILSON LAYUP ADJUSTMENT

PAYROLL	1,558,742
401K PLAN	64,042
DENTAL INSURANCE	18,108
GROUP LIFE INSURANCE	11,365
LONG TERM DISABILITY INSURANC]	17,676
MEDICAL INSURANCE	365,132
POST RETIREMENT MEDICAL (SFAS	60,414
PENSION	328,891
WORKERS COMP	27,313
PAYROLL TAXES	143,775
SEVERANCE COSTS*	-
TOTAL	2,595,458

*Severance costs are not allocated to the pro forma adjustment for the Wilson Layup. Please see AG-1-59 for information regarding severance costs.

WILSON LAYUP ADJUSTMENT - PAYROLL LOADING FACTOR

	$	Loading Factor
401K PLAN	64,042	0.0411
DENTAL INSURANCE	18,108	0.0116
GROUP LIFE INSURANCE	11,365	0.0073
LONG TERM DISABILITY INSURANC	17,676	0.0113
MEDICAL INSURANCE	365,132	0.2342
POST RETIREMENT MEDICAL (SFAS	60,414	0.0388
PENSION	328,891	0.2110
WORKERS COMP	27,313	0.0175
PAYROLL TAXES	143,775	0.0922
	1,036,716	0.6651

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Item 61) ***Referencing Big Rivers' response to AG 1-245 related to payroll costs, address the following:***

a. Per the Excel attachments to AG 1-245(a), explain if the amounts shown on those attachments reflect actual 2011 payroll costs of $47,854,573, actual 2012 payroll costs of $49,066,667, and actual January 2013 payroll costs of 6,059,045, or provide the appropriate payroll costs for these periods.

b. Please confirm that BREC's financial model does not calculate or project payroll costs on a per employee basis as provided as shown at AG1-245 on an employee basis per actual payroll records.

Response)

a. The response to AG 1-245(a) reflects actual gross unadjusted payroll costs, which are regular hours, overtime, double-time, off-duty hours, and shift premiums.

b. Confirmed.

Witness) James V. Haner

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Item 62) *Referencing Big Rivers' response to AG 1-270 related to the environmental compliance plan (ECP) adjustment and amortization which are cited to Schedule 1.02 of Exhibit Wolfram-2, address the following:*

a. Provide the monthly revenues and expenses (and all capital costs) in the same format shown at Schedule 1.02 of Exhibit Wolfram-2, except provide this information for each actual month of calendar 2012 and provide related supporting documentation and explanations as necessary.

b. Explain and show how the $21.3 million of ECP revenues and expenses at Schedule 1.02 of Wolfram-2 reconcile to the amount of ECP cost recovery allowed by the Commission in the ECP tariff rider, and cite to the amounts and other documents in relevant Commission orders and explain the reasons for any differences, and provide related calculations and supporting documentation.

c. Show the amount of ECP revenues and costs recovered under the ECP tariff rider in 2012 for each month, and reconcile this to the amount of ECP cost recovery allowed by the Commission in the ECP tariff rider, and cite to the amounts and other documents in relevant Commission orders. Explain the reasons for any differences, and provide related calculations and supporting documentation.

d. Explain the month and year which the ECP tariff rider was effective and first started collecting revenues.

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e. Regarding (b) and (c) above, identify in detail the amount of all expenses (property tax expense, property insurance, interest expense, fixed departmental expense, labor/overhead, depreciation expense, etc.) and other costs (capital plant costs, deferred income taxes, etc.) allowed for recovery per the ECP tariff rider and reconcile these amounts to specific amounts allowed for recovery in relevant Commission orders. Explain the reasons for any differences and provide related calculations and all supporting documentation.

f. Regarding (e) above, reconcile these expenses to the expense amounts identified in the response to AG 1-105(f). Explain the reasons for all differences and provide all calculations and supporting documentation.

g. Explain if the amount of ECP revenues and costs recovered from the ECP tariff rider can be allocated between environmental costs related to the Wilson plant, the R.D. Green station, and any other plants. If the answer is "yes", then provide these amounts by month for: i) actual calendar year 2012; and ii) the months September 2013 through August 2014 of the forecasted test period per Schedule 1.02 of Wolfram-2.

h. Explain if BREC's adjustment to remove ECP revenues and expenses at Schedule 1.02 of Wolfram-2 will properly match up with the removal of costs related to the Wilson Layup or explain further adjustments that are necessary.

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Response)

a. See attached. The data provided is reflected in Big Rivers' monthly Environmental Surcharge ("ES") filings with the Commission, in which all of the supporting calculations, workpapers, and documentations are provided.
b. The $21.3 million of ECP revenues and expenses reflect the amounts that Big Rivers projects will be allowed by the Commission for recovery pursuant to Big Rivers' ES Tariff. The Big Rivers Financial Model incorporates the methodology approved by the Commission in Case No. 2012-00063, with the exception of regulatory lag. (The Big Rivers Financial Model assumes perfect rate treatment of eligible ECP costs, while the actual ES tariff filings include a lag between expense month and service month.)
c. Please see the response to subpart (a). Review of these amounts, including any reconciliations, is undertaken by the Commission every six months and two years in formal proceedings, pursuant to KRS 278.183(3). The statute states in part that "At six (6) month intervals, the commission shall review past operations of the environmental surcharge of each utility, and after hearing, as ordered, shall, by temporary adjustment in the surcharge, disallow any surcharge amounts found not just and reasonable and reconcile past surcharges with actual costs recoverable pursuant to subsection (1) of this section. Every two (2) years the commission shall review and evaluate past operation of the surcharge…" A six-month review is currently underway in Case No. 2012-00534.

d. Big Rivers first received Commission approval for an ECP tariff rider in 1994. See Case No. 1994-00032 *In the Matter of Application of Big Rivers Electric Corporation to Assess a Surcharge Under KRS 278.183 to Recover Costs of Compliance with Environmental Requirements of the Clean Air Act*, final Order dated August 31, 1994. Big Rivers first billed under this mechanism in October 1995 for the July 1995 expense month. The ECP tariff rider was not in effect during the lease transaction that began in 1998. Big Rivers re-implemented its ES Tariff in conjunction with the Unwind Transaction in mid-2009 pursuant to the Commission's Order dated March 6, 2009 in Case No. 2007-00455. ES revenues were collected in August 2009 for the service month of July 2009 and the expense month of June 2009. On April 2, 2012, Big Rivers filed an application seeking approval of a new ECP and revisions to the ES Tariff in Case No. 2012-00063. The Commission approved the ES Tariff, which remains in effect at present, in its Order dated October 1, 2012.

e. The requested data is considered in the Commission's six-month and two-year reviews. See the response to subpart (c).

f. See the response to subpart (c).

g. Certain costs in the ECP can be categorized by plant. For 2012, see the monthly ES filings described in subpart (c). For the forecasted test period of September 2013 through August 2014, all of the ECP costs that can be categorized by plant (net of the City of Henderson) are found on the ECP tab (for capital costs) and PCM tab (for O&M costs) of the Big Rivers Financial

Model provided in response to PSC 1-57. Also see the files provided in response to AG 1-267(i).

h. The adjustment in Exhibit Wolfram-2.2, Reference Schedule 1.02, does reflect the idling of the Wilson plant as proposed in the instant case. Big Rivers is not aware of any further adjustments that are necessary.

Witness) John Wolfram

Big Rivers Electric Corporation
Case No. 2012-00535
Attachment for Response to AG 2-62(a)

2012 Environmental Surcharge Revenues and Expenses

Line #	Year (1)	Month (2)	Revenue (3)	Expense (4)
1	2012	Jan	$ 2,169,948	$ 1,912,876
2	2012	Feb	$ 1,650,224	$ 1,723,005
3	2012	Mar	$ 1,718,425	$ 1,864,316
4	2012	Apr	$ 1,929,404	$ 1,640,416
5	2012	May	$ 1,724,275	$ 1,918,626
6	2012	Jun	$ 1,986,609	$ 1,949,804
7	2012	Jul	$ 2,001,891	$ 2,192,644
8	2012	Aug	$ 2,093,906	$ 2,089,750
9	2012	Sep	$ 1,768,800	$ 2,045,245
10	2012	Oct	$ 2,103,181	$ 1,754,663
11	2012	Nov	$ 1,929,910	$ 2,032,618
12	2012	Dec	$ 2,089,081	$ 2,151,288
13		TOTAL	$ 23,165,654	$ 23,275,251

BIG RIVERS ELECTRIC CORPORATION

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Item 63) ***Referencing Big Rivers' response to AG 1-108 and PSC 2-18 mentioning the [BEGIN CONFIDENTIAL]*** [redacted] ***[END CONFIDENTIAL] correspondence and related documents through the most recent period and on a continuing basis.***

Response) No additions to the information provided in response to PSC 2-18 exist at this time. To the extent this request seeks continuous or ongoing updates, Big Rivers objects on the grounds that it is overbroad and unduly burdensome. Notwithstanding this objection, but without waiving it, Big Rivers states that it will only update its response as required by law, as ordered by the Commission, or as it otherwise deems appropriate.

Witness) Robert W. Berry