case file

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PSC CASE NO. 2007-00455
BIG RIVERS ELECTRIC CORPORATION'S
RESPONSES TO AG's
INITIAL DATA REQUEST
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BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
February 14, 2008

Item 60) Please reference the testimony of Mark W. Glotfelty, pages 4-6, regarding "key credit factors the rating agencies will focus."

a. State the extent to which the list of factors presented here is a complete and total list. If not, state and describe any other factors the ratings agencies will likely focus on.

b. State whether the ratings agencies will also focus on leverage ratios, e.g., net debt/EBITDA.

c. Provide any documents to which you have access which provide and describe the ratings agencies' (e.g., Moody's, S&P, Fitch) key credit ratings factors and methodologies for determining credit ratings for:

i. Utilities;
ii. Electric distribution companies; and
iii. Generation and Transmission companies.

Response) The key credit factors referenced in my testimony is a summary of the key credit factors generally reviewed by the rating agencies. For a more complete list of credit factors please refer to the attached rating criteria reports published by the rating agencies. The rating agencies will focus on leverage (total equity to total capitalization) as part of their assessment of credit quality.

Witness) Mark W. Glotfelty

Rating Methodology

May 2006

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New York	
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U.S. Electric Generation & Transmission Cooperatives

Summary

This rating methodology provides a detailed explanation of how Moody's assigns ratings to issuers and obligations in the U.S. electric generation & transmission cooperative sector. Our goal is to help the markets understand the quantitative and qualitative risk factors that we consider to be most important for this sector, and to illustrate how these map to specific rating outcomes. Our objective is for readers to be able to use this report to gauge most ratings of U.S. electric generation & transmission cooperatives (G&T co-ops) to within two notches.

Moody's analysis of G&T co-ops focuses on five key rating factors. These key factors are:

1) Nature of Long-Term Wholesale Power Supply Contracts

2) Rate Flexibility

3) Member Profile

4) Financial Metrics

5) Size

Each of these rating factors is explained in detail along with a total of 22 measurements (or sub-factors) used to measure the five factors. Important emphasis is given to how company specific results map to Moody's rating categories.

The highlights of this report include the following:

- An overview of the industry trends and market risk factors for the electric generation & transmission cooperative industry sector
- A description of our rating methodology using the five key factors and their 22 measurements
- Tables showing Moody's actual application of the rating framework to G&T co-ops
- A summary discussion of our results

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 11 U.S. electric G&T cooperatives, which have approximately $12.5 billion of debt outstanding. All of these issuers are rated investment grade and currently carry a stable outlook. The senior most ratings fall between A1 and Baa1.

Rated Issuers

Electric Generation &Transmission Cooperative	Rating	Outlook	Debt ($'s in millions)
Arkansas Electric Cooperative	A2 (a)	Stable	580
Associated Electric Cooperative	A1	Stable	895
Basin Electric Power Cooperative	A1	Stable	1,523
Buckeye Power Cooperative	A1	Stable	338
Chugach Electric Association	A2 (b)	Stable	379
Dairyland Power Cooperative	A2 (c)	Stable	424
Georgia Transmission Corp.	A3	Stable	1,058
Hoosier Energy Rural Electric Cooperative	A3	Stable	778
Oglethorpe Power Corp.	A3	Stable	3,779
Old Dominion Electric Cooperative	A3	Stable	913
Tri-State Generation & Transmission Association	Baa1	Stable	1,830
Total Adjusted Debt of Rated G&T Co-ops			12,467

Ratings are senior secured unless otherwise noted.
(a) Secured Facility Bonds ranking junior to RUS security
(b) Senior Unsecured Rating
(c) Issuer Rating

The credit profile of G&T co-ops has been stable. Over the past three years, two issuers were upgraded and none were downgraded. G&T co-ops have conservatively managed their businesses during this period by:

- using long term supply planning to meet increasing demands for power from their member distribution co-ops,
- tightly controlling operating costs, and
- avoiding the diversification trend that had an adverse credit impact for many issuers in the investor owned utility sector.

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 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 $30 billion of bonds issued by Joint Power Agencies (JPAs), which have some characteristics in common with electric generation and transmission cooperatives. Both are non-profit enterprises and are governed by their members. Cooperatives as well as many JPAs serve 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 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 predominantly tax-exempt debt issued by JPAs. The power sales agreements typically are structured to have the same term as the debt issue.

JPAs have unregulated rate-setting authority and their municipal participants can recover costs by independently raising retail rates. The current median municipal scale rating of JPAs is A2, which is one notch higher than it was in 2005. The increase in the median rating is largely due to the reduced likelihood of electric industry deregulation. After a period of low debt issuance, JPAs have now begun to accelerate their 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 municipal scale ratings include 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 any competitors?
- How are the power supply contracts structured, and what are the bond security provisions?
- 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 and competition?

The price of power, and the reliability of the power supply, are among the most significant drivers of JPA credit ratings given the importance of these two critical factors to their municipal members. JPAs with the highest cost power are generally rated lower than those with more competitive price structures.

Key Rating Issues Over The Next Decade

Need for Substantially Higher Capital Spending

In order to meet rising electricity demand, many G&T co-ops intend to purchase generating plants or plan to build additional peaking and base load generating capacity. The aggregate net property plant and equipment for rated G&T co-ops is approximately $12 billion with about an additional $8 billion of capital expenditures planned over the next five years.

Rising Fuel Costs

G&T co-ops have faced significant increases in the cost of fuel and purchased power. The majority of the electricity generation for G&T co-ops is provided by coal fired generating plants, although in some cases, there is also a significant reliance upon natural gas plants, hydro and nuclear power. The average price of delivered steam coal has increased by more than 30% over the past several years while the price of natural gas has more than doubled. Even with more rate flexibility than IOUs, G&Ts may experience member resistance if fuel cost pressures, when combined with higher capital spending, results in increases in wholesale rates that could affect the financial flexibility of their members. Continued ability to pass along higher fuel and other operating costs to member distribution co-ops is essential for credit quality in this sector.

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&T's will likely impose large rate increases on co-op members when the G&T's power purchase contracts expire in a period of rising market prices or when a large new generating plant is being constructed. Very large increases would test the willingness of members to pay higher rates.

G&T's 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 rising outlays for fuel costs and capital spending, 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.

Some cooperatives have elected to repay all RUS loans 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.

In This Rating Methodology

Moody's approach to rating G&T co-ops includes the following three steps:

1) Identification Of Key Rating Factors

Moody's rating committees focus on the following five key rating factors for G&T co-ops:

1) Long-Term Wholesale Power Supply Contracts
    a) % Member Load Served
2) Flexibility to Increase Rates As Needed
    a) Regulatory Review for Rate Increases
    b) Rate Adjustment Mechanisms
    c) Purchased Power as % of Sales
    d) New Build Exposure
    e) Competitiveness of Rates
    f) Rate Shock Exposure
3) Member Profile
    a) Demand Growth
    b) Diversity of Customer Mix
    c) Size
    d) Financial Strength
    d) Degree of Regulation
4) Financial Metrics
    a) Times Interest Earned Ratio
    b) Debt Service Coverage Ratio
    c) Funds from Operations to Adjusted Debt
    d) Funds from Operations to Interest
    e) Equity to Total Capital
    f) Net Operating Margin
5) Size
    a) Kilowatt Hour Sales
    b) Revenues
    c) Net PP&E
    d) Megawatts Owned and Purchased

Measurements of the five key rating factors are quantified and compared across the issuers in the sector.

For each of the five key rating factors, there are one or more metrics (called sub-factors) that determine the level of the key rating factor. For example, we consider six different financial metrics within Key Factor 4. In total, the rating methodology incorporates 22 metrics. Step 2 through 4, outlined below, as well as Appendices A through C to this report, provide details as to how the metrics are calculated and lists the weighting for each individual metric.

2) Measurement Of Key Rating Factors

We present a set of metrics that are used to quantify each of the five key factors. Our measurements comprise both financial statement metrics as well as other metrics that can not be derived directly from financial statement analysis but which can be approximated with additional research. For example, the metric of funds from operations (FFO) coverage of interest is quantified from financial statements. Other metrics can be derived from statistical information provided by the co-ops in their annual reports, web sites or elsewhere in the public domain.

However, for some factors qualitative judgment or empirical observation is necessary to determine the appropriate category. Of the total of 22 metrics, 17 are quantitative and 5 are qualitative.

For each of the 22 metrics, we assign a weight based on relative importance.

- Collectively, the 17 quantitative sub-factors are assigned a weight of approximately 84%.
  - The percentage of member load served under wholesale power contracts, which is the lone sub-factor in Factor 1 (Nature of Long-Term Wholesale Power Supply Contracts) carries the single largest weighting of all sub-factors (i.e. 15%).
  - Almost half of the quantitative weighting (40%) is derived from the six sub-factors embodied within Factor 4 (G&T Co-op Financial Metrics).
  - Three of the six sub-factors in Factor 4 (FFO/Debt; FFO/Interest; and Equity/Total Capitalization) are assigned weighting of 8%, 8%, and 9%, respectively, while the other three are weighted at 5% each.
  - The weightings of the four remaining quantifiable sub-factors are assigned weightings within a fairly narrow range from 2.5% to 3.33% each.
- The remaining 16% is almost evenly distributed between the five qualitative sub-factors.

This results in:

Factor 1 (Long-Term Wholesale Power Supply Contracts) accounting for 15% of the overall rating;

Factor 2 (Flexibility To Increase Rates) accounting for 20%;

Factor 3 (Member Profile) accounting for 15%;

Factor 4 (Financial Metrics) accounting for 40%; and

Factor 5 (Size) accounting for 10%

3) Applying The Rating Methodology / Outlier Discussion

The first step in determining an indicated rating is to assign factor ratings to each G&T co-op for each of the 22 sub-factors. We then explain how performance on each of the metrics maps to Moody's rating categories, before taking into account any offsetting factors. For each of the 22 metrics, we describe what we deem to be the appropriate ranges or other descriptive characteristics for the broad rating categories (i.e. Aa, A, Baa, etc.). These ranges represent our expectations for each rating category. For example, we identify the range of FFO coverage of interest and debt and the level of new build exposure appropriate for an A-rated G&T co-op versus a Baa-rated G&T co-op.

We also compare the indicated ratings for the sub-factors to the actual rating for each G&T co-op. A G&T co-op may perform higher or lower on a specific sub-factor than its actual rating level. After completing this comparison, we highlight and offer commentary on both positive and negative outliers as part of the outliers and observations section that follows each results section. We define positive and negative outliers as those where the indicated rating for a particular sub-factor is two or more rating categories higher or lower than the G&T co-op's actual rating.

4. Determining The Final Rating

To determine the overall rating, we convert each of the 22 assigned factor ratings into a numeric value based on the following scale:

Aaa	Aa	A	Baa	Ba	B	Caa
1	3	6	9	12	15	18

We multiply each metric's numeric value by an assigned weight (refer to the table below or Appendix A for weights), and then do a summation.

Factors	Sub-factors	Weighting
Wholesale Power Contracts	% Member Load Served	15.00%
Rate Flexibility	Reg. Review / Relationship with Regulators	3.33%
	Board Involvement / Rate Adj. Mechanism	3.33%
	Purchased Power / Sales (%)	3.33%
	New Build Capex (% Net PP&E)	3.33%
	Rate Competitiveness	3.33%
	Rate Shock Exposure	3.33%
Member/owner profile	Demand Growth	3.00%
	Residential Sales / Total Sales	3.00%
	Members' Consolidated Assets	3.00%
	Members' Consolidated Equity / Capitalization	3.00%
	Regulatory Status	3.00%
3-Year Average G&T Financial Metrics	TIER	5.00%
	DSC	5.00%
	FFO / Debt	8.00%
	FFO / Interest	8.00%
	Equity / Capitalization	9.00%
	Net Operating Margin	5.00%
G&T Size	MWh sales	2.50%
	Revenues	2.50%
	Net PP&E	2.50%
	MW Owned and Purchased	2.50%

The total is then mapped to the table below, and an overall alpha-numeric rating is assigned based on where the score falls in the range. The outcome provides good correlation, with indicated ratings falling at or one notch away from actual ratings.

Indicated Rating	Overall Score
Aaa	1.49 or lower
Aa	1.5 to 4.49
A	4.50 to 7.49
Baa	7.50 to 10.49
Ba	10.50 to 13.49
B	13.5 to 16.49
Caa	16.5 to 18.00

The entire array of scores and mappings for each of the G&T co-ops is shown in Appendix B.

Moody's recognizes that there are instances in which consolidated financial information may not capture the complete picture of credit risk. This can occur for many reasons, the most common of which in this sector includes:

- changes that will affect financial performance going forward (an example for a G&T co-op would be increased debt for legally mandated environmental spending that is certain to occur but has not yet been reflected in the financial performance),
- recently completed or pending acquisitions that are not yet reflected in the reported historical data, and
- benefits associated with strategic reorganization activity.

These instances are identified and explained as part of the overall rating mapping and assessment.

Five Key Rating Factors

FACTOR 1: NATURE OF LONG-TERM WHOLESALE POWER SUPPLY CONTRACTS

Why it Matters

Against a backdrop of increasing spending for capital projects and rising fuel 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. 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.

Measurement metrics for this factor are as follows:

- 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.

Factor Mapping - Factor 1

Factor 1: Nature of Long-Term Wholesale Power Supply Contracts								
Weighting:		15%						
	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Percentage of Member Load Served under Wholesale Power Contracts	100%	100%	> 80%	> 70%	< 70%	< 60%	< 50%	15.00%

Results of Mapping - Factor 1

FACTOR 1 G&T Co-op Mapping: Nature of Long-Term Wholesale Power Supply Contracts				Negative Outlier
G&T Co-op	Current Rating	Outlook	% of Member Load Served	Indicated Rating
Arkansas Electric Cooperative	A2 (a)	Stable	91%	A
Associated Electric Cooperative	A1	Stable	100%	Aa
Basin Electric Power Cooperative	A1	Stable	100%	Aa
Buckeye Power Cooperative	A1	Stable	100%	Aa
Chugach Electric Association	A2 (b)	Stable	93%	A
Dairyland Power Cooperative [1]	A2 (c)	Stable	90%	A
Georgia Transmission	A3	Stable	100%	Aa
Hoosier Energy	A3	Stable	100%	Aa
Oglethorpe Power Corp.	A3	Stable	90%	A
Old Dominion Electric Cooperative	A3	Stable	100%	Aa
Tri-State G&T Association	Baa1	Stable	100%	[redacted]

Ratings are senior secured unless otherwise noted.
[1] Moody's estimated % of member load served
(a) secured facility bonds that rank junior to RUS security
(b) senior unsecured debt rating
(c)Issuer Rating

Outliers And Observations

All of the rated G&T co-ops score quite well in Factor 1, as evidenced by indicated ratings of Aa or A. There are no negative outliers based on this measurement criteria. The lone positive outlier is Tri-State G&T, and the high rating for this metric helps to offset other metric scores that are weaker than average.

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. One of the weaker scores on this metric is the A indicated rating for Oglethorpe Power Corp. (OPC), and OPC's score is likely to further weaken going forward. OPC power purchase agreements with LG&E Energy Marketing and Morgan Stanley have been terminated. As a result, OPC's resources are expected to provide only about 70% of its members' power requirements going forward, dropping from the 90% historical number shown in the chart for Factor 1. This situation results from a conscious decision by OPC's members to enter into power supply arrangements with six third-party suppliers for their future incremental growth as permitted under the amended wholesale power supply contracts, extending through 2050. Wholesale power contracts continue to bind members to pay for OPC's fixed costs associated with its existing capacity. Nevertheless, OPC's lower score on this metric reflects a weaker position than peers that have contracts for 100% of member needs.

Chugach Electric Association (CEA) operates as a combined G&T co-op and distribution cooperative. As such, the 93% of its sales made to customers (see Factor 1 table) includes not only the 46% of energy sales made under wholesale power contracts, but also the 47% 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 better quality, as wholesale revenues derived from sales to member co-ops.

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. 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, costs associated with mandated environmental requirements, and capital investment associated with construction of new plants.

Measurement Metrics for This Factor are as Follows:

- **Regulatory Status/Relationship With Regulators**

G&T co-ops have more flexibility to increase rates in response to rising costs when regulatory approval is not required. There are currently 10 states that have full regulatory jurisdiction over the level of rates that G&T 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.

The regulatory status/relationship with regulators is an important sub-factor 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. An unsupportive regulatory jurisdiction is a credit negative and leaves G&T 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 G&T co-ops are not subject to rate regulation, and set the rates they charge customers after careful consideration of their underlying cost structure and expected members' 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 a modest cushion of member equity to protect against adverse events such as sudden increases in costs or operating difficulties with key generating plants.

- **Rate Adjustment Mechanisms**

The timing of a G&T co-op's ability to increase rates is impacted by a number of rate adjustment mechanisms.

Mechanisms include the activity of the G&T co-op's board of directors in approving rate increases, and the degree to which rates can automatically adjust to cost increases without requiring action by the Board. Each G&T co-op's board of directors has a fiduciary responsibility to approve rates at a level that ensures 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.

Variable cost adjustment mechanisms provide for more automatic changes in rates when costs change and increase the speed with which rates can be increased when costs increase. The extent to which variable cost adjustment mechanisms are available is especially important where regulatory jurisdiction applies to a G&T co-op.

The existence of variable cost adjustment mechanisms is a credit strength, especially when rate adjustments can be implemented at frequent intervals. Such mechanisms mitigate liquidity pressures that might otherwise arise when the cost of fuels exceeds rates in effect at that time.

- **Degree Of Reliance On Purchased Power**

Most of the power supply needs of G&T co-op members are met from generating plants owned by the G&T co-ops. Some G&Ts rely on market purchases of power to meet a portion of the member needs because their owned resources are insufficient or periodically unavailable. More recently, they have also been allowed to purchase power from other wholesale marketers.

Assessing the degree of reliance on purchased power to meet members' demand is important because G&Ts who purchase large amounts of power from the market to meet member demands 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.

- **Rate Competitiveness**

Assessing the rate competitiveness of the G&T co-ops is important because higher costs relative to those of alternative providers in the same region, such as other G&T co-ops or investor owned utilities, are likely to lead to member unrest and resistance to paying higher rates. G&T co-ops strive to keep their fixed costs as low as possible. Distribution co-op members will only remain comfortable with their G&T co-op supplier to the extent that the cost of power supplied under the long-term wholesale contracts is competitive to other options. 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.

Cost competitive G&T co-ops have greater flexibility to raise rates to offset cost increases or to build additional equity. 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.

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.

- **Potential For Rate Shock Exposure**

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.

Factor Mapping - Factor 2

Factor 2: Rate Flexibility								
Weighting:		20%						
	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Regulatory Review/ Relationship with Regulators	No Rate Regulation by State Commission; Legislative statute to preclude regulatory intervention in the future rate setting process	No Rate Regulation by State Commission; No legislative statute to preclude regulatory intervention in the future rate setting process	Rate Regulated by State Commission; Very Supportive Commission Practices; Very Good Regulatory Relationships	Rate Regulated by State Commission; Moderately Supportive Commission Practices; Reasonably Good Regulatory Relationships	Rate Regulated by State Commission; Unsupportive Commission Practices; Generally Difficult Regulatory Relationships	Rate Regulated by State Commission; Very Unsupportive Commission Practices; Often Contentious Regulatory Relationships	Rate Regulated by State Commission; Extremely Harsh Commission Practices; Always Contentious Regulatory Relationships	3.33%
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	Inactive board; no ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	3.33%
Purchased Power/Total MWh Sales (%)	< 5%	< 20%	< 30%	<40%	> 40%	> 60%	> 75%	3.33%
New Build Exposure (Prospective 5-yr New Build Capex as % Net PP&E)	<5%	< 25%	< 50%	< 75%	76% - 120%	> 120%	> 140%	3.33%
Rate Competitiveness versus others in region	Better than all on a consistent basis	Much better than most on a consistent basis	Better than most on a consistent basis	Better than some; Worse than some on a consistent basis	Worse than most on a consistent basis	Worse than all on a consistent basis	Worse than all on a consistent basis	3.33%
Potential for Rate Shock Exposure	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	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	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	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	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	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	Extraordinarily high (e.g. greater than 60% reliance on purchased power and greater than 85% 5-year-newbuild capex as percentage of latest year-end Net PP&E	3.33%

Results of Mapping - Factor 2

Factor 2 G&T Co-op Mapping: Rate Flexibility			Negative Outlier							
G&T Co-op	Current Rating	Outlook	Regulatory Status	Bd. Involve/ Adj. Mech.	Purch Power/ Total MWh Sales	Indicated Rating	New Build Exosure	Indicated Rating	Rate Competitiveness	Rate Shock Exposure
Arkansas Electric Cooperative	A2 (a)	Stable	Baa	A	8%	Aa	21%	Aa	Baa	Aa
Associated Electric Cooperative	A1	Stable	Aa	Aa	20%	A	112%	Ba	A	Ba
Basin Electric Power Cooperative	A1	Stable	Aa	Aa	9%	Aa	54%	Baa	A	Baa
Buckeye Power Cooperative	A1	Stable	Aa	Aa	0%	[illegible]	14%	Aa	Baa	Aa
Chugach Electric Association	A2 (b)	Stable	Baa	A	22%	A	12%	Aa	A	A
Dairyland Power Cooperative [1]	A2 (c)	Stable	Aa	Aa	8%	Aa	30%	A	Baa	Baa
Georgia Transmission	A3	Stable	Aa	Aa	N/A	N/A	48%	Baa	A	A
Hoosier Energy [2]	A3	Stable	Aa	A	24%	A	0%	[illegible]	Baa	Baa
Oglethorpe Power Corp.	A3	Stable	Aa	A	35%	Baa	0%	[illegible]	Baa	Baa
Old Dominion Electric Cooperative	A3	Stable	Aa	A	53%	Ba	0%	[illegible]	Baa	Ba
Tri-State G&T Association	Baa1	Stable	[illegible]	A	30%	Baa	133%	B	Baa	Ba

Ratings are senior secured unless otherwise noted.
[1] Moody's estimated % of purchased power, newbuild exposure, rate competitiveness and rate shock exposure
[2] Moody's estimated purchased power % total sales
(a) secured facility bonds that rank junior to RUS security
(b) senior unsecured debt rating
(c)Issuer Rating

Outliers And Observations

Tri-State is a positive outlier for regulatory status since its indicated rating for that sub-factor is substantially higher than its actual rating. However, this is balanced against an outlier that is weaker than the rating for the magnitude of new construction. Tri-state has the highest level of new build exposure among the rated universe of G&T co-ops.

Buckeye Power is another positive outlier in Factor 2, for purchased power as a percentage of megawatt hour sales. This status reflects its efficient supply planning strategy through the years, including a fairly recent acquisition of ownership rights to a 203 megawatt capacity entitlement in the Ohio Valley Electric Corporation plant.

The three other positive outliers for Factor 2 are Hoosier, Oglethorpe, and Old Dominion Electric Cooperative (ODEC) for new build exposure. This reflects the absence of significant new construction at present.

ODEC stands out as a negative outlier for two measured sub-factors: purchased power as a percentage of MWh sales and rate shock exposure. ODEC's heavy reliance on purchased power and high rate shock exposure add to the risk that its current dispute with a co-op member could result in that member resisting rate increases.

Associated Electric Cooperative, Inc. (AECI) is one of two negative outliers for new build exposure, as its anticipated capital expenditures over the next five years is 112% of its 2004 year end net property plant and equipment (second highest to Tri-State). The potential for large rate increases also results in a negative outlier status for AECI for rate shock exposure. However, AECI's relatively low rates make it more likely that members will accept significant expected rate increases over the next several years.

Tri-State is a negative outlier on new build exposure because it has the highest percentage of new construction of any rated G&T co-op. Although Tri-State is not a negative outlier for rate shock exposure, its Ba indicated rating is lower than its actual rating for that sub-factor, and reflects a need for rate increases over the next few years. These rate increases come on the heels of a series of rate increases already implemented over the past few years. However, concerns about new build exposure and rate shock exposure for Tri-State are balanced somewhat by its being a positive outlier for regulatory status.

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. We consider the level of demand growth that the members expect to experience, the diversity of their retail customer mix, their overall size and financial profile, and regulatory status. Some members are subject to rate regulation, which is important because if a member is denied approval for a large rate increase, it may not be able to comply with its contractual obligations to the G&T co-op.

The following sub-factors 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.

Measurement metrics for this factor are as follows:

- ***Member Expected Demand Growth***

Positive growth in member demand can lead to the benefits of larger scale as well as the need for increased investment, while negative growth in member demand can lead to diminished revenues.

- **Diversity Of Customer Mix**

Assessing the diversity of members' customers 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.

- **Size**

We consider the size of member co-ops important because larger resources usually provide greater ability to absorb an adverse change, such as the loss of retail customers.

- **Financial Condition**

Financial condition of the member/owners 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.

- **Regulatory Status/Relationship With Regulators**

Nine of the 11 rated G&T co-ops have at least some owner/members that are subject to rate regulation. This is important because a member that is denied approval for a large rate increase may not be able to comply with its contractual obligations to the G&T co-op, potentially causing an inability for the G&T co-op to derive the revenue it needs for increased costs or debt service.

Factor Mapping - Factor 3

Factor 3: Member/owner profile Weighting: 15%	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Demand Growth	> 6 %	4%	3%	2%	1%	0%	<0%	3.00%
Residential Sales/Total Sales (%)	> 80%	> 75%	> 50%	> 40%	< 40%	< 20%	< 10%	3.00%
Members' Consolidated Assets ($ Billions)	> $6.5 billion	> $4 billion	$3 - $4 billion	> $1 billion	< $1 billion	< $0.3 billion	< $0.2 billion	3.00%
Members' Consolidated Equity/Capitalization (%)	>65%	> 55%	> 50%	> 25%	> 20%	> 15%	>10%	3.00%
Regulatory status	None subject to rate regulation; Legislative statute to preclude regulatory intervention in the future rate setting process	None subject to rate regulation; No legislative statute to preclude regulatory intervention in the future rate setting process	Some Rate Regulated by State Commission; Very Supportive Commission Practices; Very Good Regulatory Relationships	Some Rate Regulated by State Commission; Moderately Supportive Commission Practices; Reasonably Good Regulatory Relationships	Some Rate Regulated by State Commission; Unsupportive Commission Practices; Generally Difficult Regulatory Relationships	Most Rate Regulated by State Commission; Very Unsupportive Commission Practices; Often Contentious Regulatory Relationships	All Rate Regulated by State Commission; Extremely Harsh Commission Practices; Always Contentious Regulatory Relationships	3.00%

Results of Mapping - Factor 3

Factor 3
G&T Co-op Mapping: Member/owner profile
Negative Outlier

G&T Co-op	Current Rating	Outlook	Demand Growth	Indicated Rtg.	Res. Sales/ Total Sales (%)	Indicated Rtg.	Mbrs. Cons. Assets ($Billions)	Indicated Rtg.	Mbrs. Equity / Capitalization (%)	Indicated Rtg.	Regulatory Status
Arkansas Electric Cooperative	A2 (a)	Stable	3%	A	46%	A	$1.8	Baa	45%	Baa	A
Associated Electric Cooperative	A1	Stable	2.30%	Baa	71%	A	$3.8	A	51%	A	Baa
Basin Electric Power Cooperative	A1	Stable	3.30%	A	21%	Ba	$3.0	A	27%	Baa	Baa
Buckeye Power Cooperative	A1	Stable	2.20%	Baa	59%	A	$1.5	Baa	44%	Baa	Aa
Chugach Electric Association	A2 (b)	Stable	2%	Baa	73%	A	$0.3	Ba	46%	Baa	Baa
Dairyland Power Cooperative [1]	A2 (c)	Stable	2%	Baa	46%	A	$3.1	A	28%	Baa	A
Georgia Transmission	A3	Stable	2%	Baa	66%	A	$5.1	Aa	45%	Baa	Aa
Hoosier Energy [2]	A3	Stable	3.40%	A	71%	A	$0.8	Ba	57%	Aa	Baa
Oglethorpe Power Corp.	A3	Stable	5.00%	Aa	66%	A	$4.9	Aa	46%	Baa	Aa
Old Dominion Electric Cooperative	A3	Stable	3.40%	A	64%	A	$1.9	Baa	56%	Aa	Baa
Tri-State G&T Association	Baa1	Stable	2%	Baa	33%	Ba	$2.2	Baa	49%	Baa	Baa

Ratings are senior secured unless otherwise noted.
[1] Moody's estimated for all subfactors in Factor 3
[2] Moody's estimated for Members' consolidated assets
(a) secured facility bonds that rank junior to RUS security
(b) senior unsecured debt rating
(c)Issuer Rating

Outliers And Observations

Indicated ratings for Factor 3 map reasonably well to the actual ratings for each of the 11 rated G&T co-ops, with no positive outliers noted and just three negative outliers.

Basin Electric Power Cooperative's residential sales as a percentage of total sales to retail customers is a negative outlier, 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. Like many other G&T co-ops, Basin is facing steady demand growth from its members. As Basin's sales to members increase and off-system sales decline, the percentage of residential sales is expected to increase, thereby reducing its outlier status.

Both Chugach and Hoosier are negative outliers for members consolidated assets, which primarily reflects the relatively small size of the two G&T co-ops. The relatively small size of the G&T co-ops in turn limits their ability to serve large distribution members.

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.

Among the financial ratios that Moody's considers in its quantitative analysis of G&T co-ops are the times interest earned ratio (TIER) and the debt service coverage ratio (DSC). These two ratios have governed RUS loan documentation for many years. In addition to these, Moody's also analyzes funds from operations (FFO) coverage of interest, margins for interest (MFI) as defined in certain indentures, as well as FFO as a percentage of debt. These metrics provide insight regarding the amount and quality of a G&T co-op's cash flow and its ability to service its debt. 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.

Moody's also 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, and the co-op's net operating margin as a percentage of equity to assess the G&T co-op's profitability (noting the not-for-profit status).

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. 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 viewed negatively.

Measurement metrics for this factor are as follows:

- TIER
- DSC
- FFO/Debt
- FFO/Interest
- Equity/Total Capital
- Net Operating Margin

(See Appendix C for definitions of these ratios)

Factor Mapping - Factor 4

Factor 4: 3-Year Average G&T Financial Metrics								
Weighting:			40%					
	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
TIER	> 1.6x	> 1.4x	1.2x - 1.4x	1.1x - 1.19x	1.1x	< 1.0x	< 0.5x	5.00%
DSC	>1.9x	> 1.4x	1.2x - 1.4x	1.1x - 1.19x	1.1x	< 1.0x	< 0.5x	5.00%
FFO/Debt	> 15%	10% - 15%	6% - 9%	3% - 5%	< 3%	< 2%	< 1%	8.00%
FFO/Interest	> 3.25x	2.5x - 3.25x	2.0x - 2.49x	1.5x - 1.99x	< 1.5x	< 1.2x	< 1.0x	8.00%
Equity/Total Capitalization	> 50%	35% - 50%	20% - 35%	5% - 19%	< 5%	< 3%	< 1%	9.00%
Net Operating Margin	> 40%	30% - 40%	> 10%	> 5%	< 5%	< 3%	< 1%	5.00%

Results of Mapping - Factor 4

Factor 4 G&T Co-op Mapping: 3-Year Avg. G&T Financial Metrics				Negative Outlier										
G&T Co-op	Current Rating	Outlook	TIER	Indicated Rtg.	DSC	Indicated Rtg.	FFO / Debt	Indicated Rtg.	FFO / Interest	Indicated Rtg.	Equity/ Total Cap.	Indicated Rtg.	Net Oper. Margin	Indicated Rtg.
Arkansas Electric Cooperative	A2 (a)	Stable	1.43	Aa	1.47	Aa	8%	A	2.70	Aa	42%	Aa	9.0%	A
Associated Electric Cooperative	A1	Stable	1.17	Baa	1.47	Aa	11%	Aa	2.67	Aa	22%	A	7.3%	Baa
Basin Electric Power Cooperative	A1	Stable	1.3	A	1.23	A	6%	A	2.17	A	29%	A	17.9%	A
Buckeye Power Cooperative	A1	Stable	1.9	Aa	1.23	A	12%	Aa	3.16	Aa	45%	Aa	10.1%	A
Chugach Electric Association	A2 (b)	Stable	1.17	Baa	1.80	Aa	10%	Aa	2.69	Aa	26%	A	14.1%	A
Dairyland Power Cooperative	A2 (c)	Stable	1.2	A	1.37	A	7%	A	2.29	A	18%	Baa	11.0%	A
Georgia Transmission	A3	Stable	1.2	A	1.03	Ba	4%	Baa	1.81	Baa	9%	Baa	36.3%	Aa
Hoosier Energy	A3	Stable	1.1	Baa	1.17	Baa	7%	A	2.46	A	12%	Baa	9.9%	A
Oglethorpe Power Corp.	A3	Stable	1.1	Baa	1.00	Ba	6%	A	1.98	Baa	9%	Baa	16.9%	A
Old Dominion Electric Cooperative	A3	Stable	1.3	A	1.33	A	5%	Baa	1.71	Baa	21%	A	10.7%	A
Tri-State G&T Association	Baa1	Stable	1.33	A	1.27	A	6%	A	1.77	Baa	14%	Baa	19.7%	A

Ratings are senior secured unless otherwise noted.
(a) secured facility bonds that rank junior to RUS security
(b) senior unsecured debt rating
(c)Issuer Rating

Outliers And Observations

There are no positive outliers, and just two negative outliers for Factor 4.

Both Georgia Transmission Corporation (GTC) and Oglethorpe Power Corporation (OPC) are negative outliers on the DSC, reflecting the decision by their respective boards to manage results as close as possible to the minimum required levels contained in their debt indentures.

FACTOR 5: G&T SIZE

Why it Matters

Size has the lowest weighting of the five key factors because it tends to be less important for entities, such as G&T co-ops, that are subject to limited competition. However, size still matters because larger entities usually have a greater ability to absorb unexpected shocks due to their greater diversity of generating assets, customers, and fuel sources.

Size is a relevant factor in the analysis of G&T co-ops due to the benefits in having a larger pool of assets and a more diverse source of fuels to run the generation assets. A G&T 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.

Size can also create economies of scale by enabling a G&T co-op to spread its fixed costs over a larger number of kilowatt hours of electricity thereby increasing its price competitiveness.

Measurement metrics for this factor are as follows:

- Kilowatt hour sales
- Revenues
- Net PP&E
- Megawatts owned and/or purchased

FACTOR MAPPING - FACTOR 5

Factor 5: G&T Size Weighting: 10%								
	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Megawatt hour sales (Millions of MWhs)	> 50	20 - 50	11 - 20	5 - 10	<5	< 3	< 1	2.50%
Revenues ($ Billions)	> $3.5 billion	> $2 billion	> $1 billion	$0.2 - $1.0 billion	< $0.2 billion	< $0.15 billion	< $0.10 billion	2.50%
Net PP&E ($ in Billions)	> $5 billion	$2 billion - $5billion	> $1 billion	> $0.4 billion	< $0.4 billion	< $0.3 billion	< $0.2 billion	2.50%
Megawatts owned and purchased (MWs)	> 6,000	4,000 - 6,000	> 3,000	> 2,000	500 - 2,000	300 - 499	< 300	2.50%

Results of Mapping - Factor 5

Factor 5 G&T Co-op Mapping: G&T Size			Negative Outlier							
G&T Co-op	**Current Rating**	**Outlook**	**Megawatt Hour Sales (Millions)**	**Indicated Rtg.**	**Revenues (Millions)**	**Indicated Rtg.**	**Net PP&E($ Millions)**	**Indicated Rtg.**	**MWs owned & Purchased**	**Indicated Rtg.**
Arkansas Electric Cooperative	A2 (a)	Stable	12	A	$414.7	Baa	$698.3	Baa	2,429	Baa
Associated Electric Cooperative	A1	Stable	24	Aa	$797.6	Baa	$1,066.0	A	4,933	Aa
Basin Electric Power Cooperative	A1	Stable	18	A	$915.8	Baa	$1,528.6	A	2,575	Baa
Buckeye Power Cooperative	A1	Stable	9	Baa	$331.2	Baa	$554.7	Baa	1,665	Ba
Chugach Electric Association	A2 (b)	Stable	3	Ba	$201.2	Baa	$467.8	Baa	520	Ba
Dairyland Power Cooperative	A2 (c)	Stable	6	Baa	$228.9	Baa	$464.7	Baa	1,190	Ba
Georgia Transmission	A3	Stable	N/A	N/A	$174.8	Ba	$1,104.0	A	N/A	N/A
Hoosier Energy	A3	Stable	10	A	$385.3	Baa	$649.6	Baa	1,418	Ba
Oglethorpe Power Corp.	A3	Stable	31	Aa	$1,312.8	A	$3,658.1	Aa	5,294	Aa
Old Dominion Electric Cooperative	A3	Stable	11	A	$588.5	Baa	$1,101.5	A	675	Ba
Tri-State G&T Association	Baa1	Stable	15	A	$672.7	Baa	$1,540.4	A	3,126	A

Ratings are senior secured unless otherwise noted.
(a) secured facility bonds that rank junior to RUS security
(b) senior unsecured debt rating
(c)Issuer Rating

Outliers And Observations

Even the largest G&T co-op, Oglethorpe Power Corporation, is considered to be relatively small by electric utility standards, so it is not surprising that there are no positive outliers in Key Factor 5. Negative outliers are Buckeye Power, Chugach Electric, Dairyland Power, Georgia Transmission, Hoosier Energy, and Old Dominion, reflecting smaller than average size for the rated universe.

In two cases, there are offsetting considerations that merit comment. Chugach Electric is a negative outlier for megawatt hours sold and capacity owned and purchased. Chugach Electric 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. Georgia Transmission Corporation (GTC) is a pure transmission cooperative, formed as part of the disaggregation of the former Oglethorpe Power Corporation. As such, GTC does not sell electricity and its revenues are derived solely from providing transmission service, which does not carry some of the risks that are involved in generation of electricity.

Other Rating Considerations

1) Liquidity

Liquidity is particularly important for smaller G&T co-ops that may have less ability to withstand unexpected shocks. Sharp increases in fuel costs can reduce internally generated cash flow and simultaneously create increased needs to finance working capital. Moody's considers both internal and highly reliable external sources of liquidity, which can be comprised of internally generated cash flow, cash balances available for meeting ongoing obligations, and committed bank credit facilities.

2) Corporate Governance

Our Corporate Governance research includes a review of the G&T co-op board structure, composition, and behavior. Although the large majority of the G&T co-ops are not subject to the regulations imposed on public companies by the Sarbanes-Oxley Act of 2002, we find that virtually all of the rated G&T co-ops have guided their board activities to emulate the requirements of a public company.

G&T co-ops have grown increasingly sensitive to the benefits of having more board members with strong financial expertise, particularly as it relates to the audit function, and business acumen. Much of the information about the board structure and composition is readily available in the annual reports of each G&T co-op or on their respective public web sites. Typically, there is one representative from each of the distribution members on the G&T board.

G&T co-op management teams have increased the involvement of their board members in the periodic meetings they hold with Moody's analysts. We continue to welcome the increased participation of G&T co-op board members, especially those who play an active role in setting financial policy, including decisions about capital rotation policy, which is the equivalent of the dividend policy for IOUs, and compensation arrangements for senior management.

3) Legal Structure

Generally speaking, the corporate legal structure of the G&T co-op sector is less complex than that of the investor-owned utility universe. For one thing, maintaining a cooperative structure generally precludes forming a holding company structure to house diversified operations. We have, however, observed situations whereby smaller distribution co-op members have merged together to gain more size and scope and to create more cost efficient operations.

4) Diversification

The level of diversified investment by the G&T co-ops continues to be limited in scale. Basin Electric is the only G&T co-op that has very large non-power operations. There is not any material debt due to third parties related to those operations and Basin has not provided support for the diversified businesses. As the basic business of providing power to members under contract is considered to be low risk, diversification would normally be expected to increase risk, although Moody's will evaluate any instances on a case by case basis.

Final Considerations

To illustrate this rating methodology, we have applied the standards discussed throughout this text to the 11 U. S. electric generation & transmission cooperatives that Moody's currently rates.

To determine an overall rating, we convert each of the 22 assigned sub-factor ratings into a numeric value based on the following scale:

Aaa	Aa	A	Baa	Ba	B	Caa
1	3	6	9	12	15	18

APPENDIX A - Sub-factor Criteria

Factor 1: Nature of Long-Term Wholesale Power Supply Contracts								
Weighting:		15%						
	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Percentage of Member Load Served under Wholesale Power Contracts	100%	100%	> 80%	> 70%	< 70%	< 60%	< 50%	15.00%

Factor 2: Rate Flexibility								
Weighting:			20%					
	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Regulatory Review/ Relationship with Regulators	No Rate Regulation by State Commission; Legislative statute to preclude regulatory intervention in the future rate setting process	No Rate Regulation by State Commission; No legislative statute to preclude regulatory intervention in the future rate setting process	Rate Regulated by State Commission; Very Supportive Commission Practices; Very Good Regulatory Relationships	Rate Regulated by State Commission; Moderately Supportive Commission Practices; Reasonably Good Regulatory Relationships	Rate Regulated by State Commission; Unsupportive Commission Practices; Generally Difficult Regulatory Relationships	Rate Regulated by State Commission; Very Unsupportive Commission Practices; Often Contentious Regulatory Relationships	Rate Regulated by State Commission; Extremely Harsh Commission Practices; Always Contentious Regulatory Relationships	3.33%
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	Inactive board; no ability to adjust for fuel cost variability; uncertainty surrounding recovery of deferrals	3.33%
Purchased Power/Total MWh Sales (%)	< 5%	< 20%	< 30%	<40%	> 40%	> 60%	> 75%	3.33%
New Build Exposure (Prospective 5-yr New Build Capex as % Net PP&E)	<5%	< 25%	< 50%	< 75%	76% - 120%	> 120%	> 140%	3.33%
Rate Competitiveness versus others in region	Better than all on a consistent basis	Much better than most on a consistent basis	Better than most on a consistent basis	Better than some; Worse than some on a consistent basis	Worse than most on a consistent basis	Worse than all on a consistent basis	Worse than all on a consistent basis	3.33%
Potential for Rate Shock Exposure	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	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	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	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	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	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	Extraordinarily high (e.g. greater than 60% reliance on purchased power and greater than 85% 5-year-newbuild capex as percentage of latest year-end Net PP&E	3.33%

We multiply each metric's numeric value by the assigned weight (as shown in Appendix A), and then do a summation.

Factors	Sub-factors	Weighting
Wholesale Power Contracts	% Member Load Served	15.00%
Rate Flexibility	Reg. Review / Relationship with Regulators	3.33%
	Board Involvement / Rate Adj. Mechanism	3.33%
	Purchased Power / Sales (%)	3.33%
	New Build Capex (% Net PP&E)	3.33%
	Rate Competitiveness	3.33%
	Rate Shock Exposure	3.33%
Member/owner profile	Demand Growth	3.00%
	Residential Sales / Total Sales	3.00%
	Members' Consolidated Assets	3.00%
	Members' Consolidated Equity / Capitalization	3.00%
	Regulatory Status	3.00%
3-Year Average G&T Financial Metrics	TIER	5.00%
	DSC	5.00%
	FFO / Debt	8.00%
	FFO / Interest	8.00%
	Equity / Capitalization	9.00%
	Net Operating Margin	5.00%
G&T Size	MWh sales	2.50%
	Revenues	2.50%
	Net PP&E	2.50%
	MW Owned and Purchased	2.50%

The total is then mapped to the table below, and an overall alpha-numeric rating is assigned based on where the score falls in the range. The outcome provides good correlation, with no outliers.

Indicated Rating	Overall Score
Aaa	1.49 or lower
Aa	1.5 to 4.49
A	4.50 to 7.49
Baa	7.50 to 10.49
Ba	10.50 to 13.49
B	13.5 to 16.49
Caa	16.5 to 18.00

For example, if a G&T co-op's sub-factors sum to a score of 7.00, an overall rating of A3 would be assigned. On this scale, a lower score indicates a stronger credit profile than a higher score. If the G&T co-op's sub-factors sum to a total score of 9.00, an overall rating of Baa2 would be assigned. The G&T co-op would be considered as having an average Baa2 rating profile because it falls in the middle of that category range.

In this methodology, we cover 11 U.S. electric G&T co-ops. After placing these G&T co-ops through the rating factor grid we find that:

- 5 have indicated ratings that match the actual ratings
- 3 have indicated ratings one-notch above Moody's actual rating, and
- 3 have an indicated rating one-notch below Moody's actual rating.

Based on these results, we believe our methodology proves to be a very effective way to derive ratings for the G&T co-op sector. Although there are no outliers among the indicated ratings resulting from the mapping at this time (none of the indicated ratings are two or more notches above or below Moody's actual rating), Moody's notes that there may be outliers from time to time. Such instances could result in the future. For example, this could result from a pending merger transaction or other events that would put a G&T co-op into a state of significant transition.

Ultimately, Moody's ratings for U.S. electric generation & transmission cooperatives reflect an amalgamation of all the considerations discussed in this methodology. The methodology presents a representative guide to the analytics underpinning Moody's ratings and should help facilitate constituents to better understand what drives the ratings in this sector.

Refer to Appendix B for a summary table illustrating the weightings and rating outcomes for the companies in this methodology.

Factor 3: Member/owner profile								
Weighting:		15%						
	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Demand Growth	> 6 %	4%	3%	2%	1%	0%	<0%	3.00%
Residential Sales/Total Sales (%)	> 80%	> 75%	> 50%	> 40%	< 40%	< 20%	< 10%	3.00%
Members' Consolidated Assets ($ Billions)	> $6.5 billion	> $4 billion	$3 - $4 billion	> $1 billion	< $1 billion	< $0.3 billion	< $0.2 billion	3.00%
Members' Consolidated Equity/Capitalization (%)	>65%	> 55%	> 50%	> 25%	> 20%	> 15%	>10%	3.00%
Regulatory status	None subject to rate regulation; Legislative statute to preclude regulatory intervention in the future rate setting process	None subject to rate regulation; No legislative statute to preclude regulatory intervention in the future rate setting process	Some Rate Regulated by State Commission; Very Supportive Commission Practices; Very Good Regulatory Relationships	Some Rate Regulated by State Commission; Moderately Supportive Commission Practices; Reasonably Good Regulatory Relationships	Some Rate Regulated by State Commission; Unsupportive Commission Practices; Generally Difficult Regulatory Relationships	Most Rate Regulated by State Commission; Very Unsupportive Commission Practices; Often Contentious Regulatory Relationships	All Rate Regulated by State Commission; Extremely Harsh Commission Practices; Always Contentious Regulatory Relationships	3.00%

Factor 4: 3-Year Average G&T Financial Metrics								
Weighting:			40%					
	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
TIER	> 1.6x	> 1.4x	1.2x - 1.4x	1.1x - 1.19x	1.1x	< 1.0x	< 0.5x	5.00%
DSC	>1.9x	> 1.4x	1.2x - 1.4x	1.1x - 1.19x	1.1x	< 1.0x	< 0.5x	5.00%
FFO/Debt	> 15%	10% - 15%	6% - 9%	3% - 5%	< 3%	< 2%	< 1%	8.00%
FFO/Interest	> 3.25x	2.5x - 3.25x	2.0x - 2.49x	1.5x - 1.99x	< 1.5x	< 1.2x	< 1.0x	8.00%
Equity/Total Capitalization	> 50%	35% - 50%	20% - 35%	5% - 19%	< 5%	< 3%	< 1%	9.00%
Net Operating Margin	> 40%	30% - 40%	> 10%	> 5%	< 5%	< 3%	< 1%	5.00%

Factor 5: G&T Size								
Weighting:			10%					
	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Megawatt hour sales (Millions of MWhs)	> 50	20 - 50	11 - 20	5 - 10	<5	< 3	< 1	2.50%
Revenues ($ Billions)	> $3.5 billion	> $2 billion	> $1 billion	$0.2 - $1.0 billion	< $0.2 billion	< $0.15 billion	< $0.10 billion	2.50%
Net PP&E ($ in Billions)	> $5 billion	$2 billion - $5billion	> $1 billion	> $0.4 billion	< $0.4 billion	< $0.3 billion	< $0.2 billion	2.50%
Megawatts owned and purchased (MWs)	> 6,000	4,000 - 6,000	> 3,000	> 2,000	500 - 2,000	300 - 499	< 300	2.50%

APPENDIX B - Indicated Ratings

Rating Factors				Wholesale Power Contracts	Rate Flexibility						Member/owner profile					3-Year Average G&T Financial Metrics						G&T Size			
	Current Rating [1]	Outlook	Indicated Rating	% Memb. Load Served	Reg. Rev.	Board Involve/ Rate Adj. Mech.	Purch. Pwr / Sales (%)	New Build Capex (% Net PP&E)	Rate Comp.	Rate Shock Exp.	Growth	Resid. Sales	Member Consol. Assets	Member Consol. Eq / Cap	Reg. status	TIER	DSC	FFO / Debt	FFO / Int	Eq / Cap	Net Op. Margin	MWh sales	Rev	Net PP&E	MW owned / purch.
Moody's Weights				15.00%	3.33%	3.33%	3.33%	3.33%	3.33%	3.33%	3.00%	3.00%	3.00%	3.00%	3.00%	5.00%	5.00%	8.00%	8.00%	9.00%	5.00%	2.50%	2.50%	2.50%	2.50%
Arkansas Electric	A2 (a)	Stable	A1	A	Baa	A	Aa	Aa	Baa	Aa	A	A	Baa	Baa	A	Aa	Aa	A	Aa	Aa	A	A	Baa	Baa	Baa
Associated Electric	A1	Stable	A2	Aa	Aa	Aa	A	Ba	A	Ba	Baa	A	A	A	Baa	Baa	Aa	Aa	Aa	A	Baa	Aa	Baa	A	Aa
Basin Electric Power	A1	Stable	A2	Aa	Aa	Aa	Aa	Baa	A	Baa	A	Ba	A	Baa	Baa	A	A	A	A	A	A	A	Baa	A	Baa
Buckeye Power	A1	Stable	A1	Aa	Aa	Aa		Aa	Baa	Aa	Baa	A	Baa	Baa	Aa	Aa	A	Aa	Aa	Aa	A	Baa	Baa	Baa	Ba
Chugach Electric Assoc.	A2 (b)	Stable	A2	A	Baa	A	A	Aa	A	A	Baa	A	Ba	Baa	Baa	Baa	Aa	Aa	Aa	A	A	Ba	Baa	Baa	Ba
Dairyland Power [2]	A2 (c)	Stable	A3	A	Aa	Aa	Aa	A	Baa	Baa	Baa	A	A	Baa	A	A	A	A	A	Baa	A	Baa	Baa	Baa	Ba
Georgia Transmission	A3	Stable	A2	Aa	Aa	Aa	N/A	Baa	A	A	Baa	A	Aa	Baa	Aa	A	Ba	Baa	Baa	Baa	Aa	N/A	Ba	A	N/A
Hoosier Energy	A3	Stable	A3	Aa	Aa	A	A		Baa	Baa	A	A	Ba	Aa	Baa	Baa	Baa	A	A	Baa	A	A	Baa	Baa	Ba
Oglethorpe Power Corp.	A3	Stable	A3	A	Aa	A	Baa		Baa	Baa	Aa	A	Aa	Baa	Aa	Baa	Ba	A	Baa	Baa	A	Aa	A	Aa	Aa
Old Dominion Electric	A3	Stable	A3	Aa	Aa	A	Ba		Baa	Ba	A	A	Baa	Aa	Baa	A	A	Baa	Baa	A	A	A	Baa	A	Ba
Tri-State G&T Assoc.	Baa1	Stable	A3			A	Baa	B	Baa	Ba	Baa	Ba	Baa	Baa	Baa	A	A	A	Baa	Baa	A	A	Baa	A	A

[1]Ratings are senior secured unless otherwise noted.
[2] Moody's estimated for various subfactors as noted throughout the text
(a) senior secured bonds that rank junior to RUS debt
(b) senior unsecured
(c)Issuer Rating

Negative Outlier

The summary table on page 22 shows the results for each of the 11 G&T co-ops for all 22 sub-factors. We average the collected criteria, weighting them according to the indicated weightings, and compare them to their actual ratings.

Specifically, we score the indicative letter rating in each sub-factor with a number. For example, we score the indicative ratings as follows:

Aaa	Aa	A	Baa	Ba	B	Caa
1	3	6	9	12	15	18

We multiply each metric's numeric value by an assigned weight, and then do a summation.

The total is then mapped to the table below, and an overall rating is assigned based on where the score falls in the range. The outcome provides good correlation, with no outliers.

Indicated Rating	Overall Score
Aaa	1.49 or lower
Aa	1.5 to 4.49
A	4.50 to 7.49
Baa	7.50 to 10.49
Ba	10.50 to 13.49
B	13.5 to 16.49
Caa	16.5 to 18.00

Appendix C

MOODY'S ELECTRIC G&T COOPERATIVE METRIC DEFINITIONS

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 standard adjustments.

1. *TIER (Times Interest Earned Ratio)*
   (Adjusted NIAC + Adjusted Interest + Income Tax) / Adjusted Interest

2. *DSCR (Debt Service Coverage Ratio)*
   (Adjusted NIAC + Adjusted Interest + Depreciation & Amortization) / (Adjusted Interest + Principal Payment)

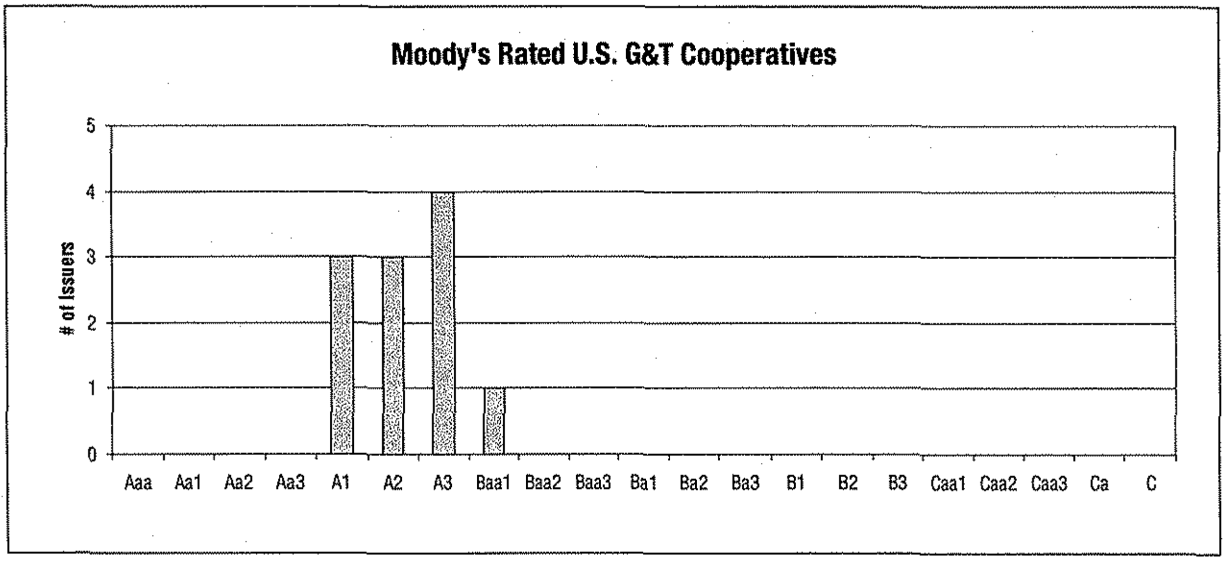
3. *FFO / Interest*
   (Funds from operations + Interest expense)/ Interest expense

4. *FFO / Debt*
   Funds from operations / (Short Term Debt + Long Term Debt, gross)

5. *Equity / Total Capitalization*
   (Deferred Taxes + Minority Interest + Book Equity) / (Short Term Debt + Long Term Debt, gross + Deferred Taxes + Minority Interest + Book Equity)

6. *Net Operating Margin*
   Operating Profit / Net Revenue

Appendix D



Moody's Rated U.S. G&T Cooperatives
# of Issuers
5
4
3
2
1
0
Aaa Aa1 Aa2 Aa3 A1 A2 A3 Baa1 Baa2 Baa3 Ba1 Ba2 Ba3 B1 B2 B3 Caa1 Caa2 Caa3 Ca C

Related Research

Rating Methodology:

Global Regulated Electric Utilities, March 2005 (91730)

Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations - Part I, July 2005 (93570)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

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Public Power/North America
Special Report

Electric Cooperatives—An Industry Outlook and Primer

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■ Overview

Electric cooperatives account for a small but rapidly growing part of the U.S. power supply system. Designed as not-for-profit utilities, they are operated for the benefit of their owner members. Composed of power supply systems (which own generation and transmission [G&T] assets) and distribution systems (which provide electricity to the end-user), the cooperative industry's primary function is to supply native-load customers with reliable and competitively priced electric service.

Distribution systems are generally viewed as having less risk than G&T power supply cooperatives. G&T's by nature are of greater risk, but the degree is materially less than power suppliers actively competing in the wholesale energy market, since cooperative power supply systems rely on long-term power sales agreements with member systems and focus on meeting the electricity needs of more predictable retail customers.

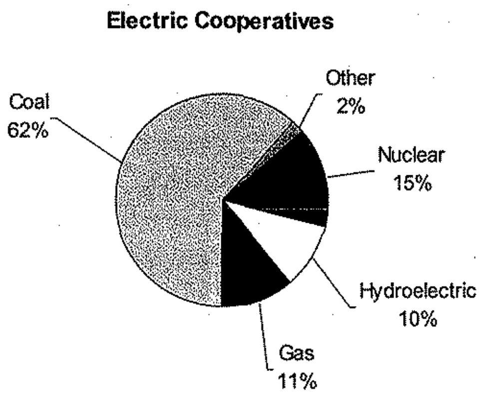
■ Outlook

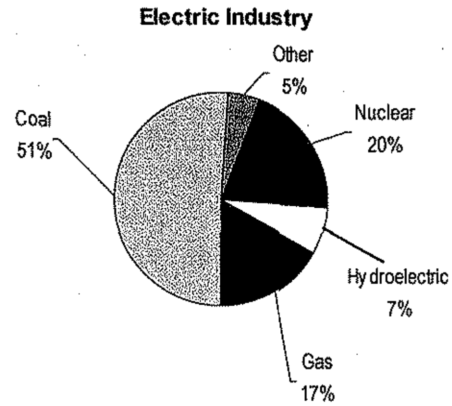
Fitch Ratings' outlook for rural electric cooperatives is stable, with cooperative ratings falling mostly in the 'A' category. Fitch presently has 18 electric cooperative ratings, most of which are power supply systems (see Fitch-Rated Electric Cooperatives table on page 10). Fitch's constructive view reflects the solid working relationship between most wholesale power suppliers and their member distribution systems, reduced concern over intense industrywide competition, the industry's current access to less expensive Rural Utilities Service (RUS) funding, an improving outlook for cooperative lender National Rural Utilities Cooperative Finance Corp. (CFC), and positive operating performance for most cooperative systems. Also incorporated in this rating assessment is the industry's need for major new base-load power plants, the need to successfully manage large, new capital and construction programs in a difficult global labor and commodity market, environmental considerations, volatile energy prices, regulatory risk in certain regions and above-average retail electric rates in more rural areas.

■ Purpose

This report is designed to provide investors, members of the financial community and industry representatives with an overview of the electric cooperative program and Fitch's current assessment of key industry rating drivers. While Fitch expects RUS to remain an important lender to cooperatives, it would not be surprising to see an increased number of cooperative systems entering the public/private capital markets to take advantage of more flexible financing strategies and quicker turnaround time, especially given their pressing need to fund new base-load generation. Therefore, a fuller understanding of the

Approximate Power Supply by Fuel Type





Source: Fitch Ratings.

electric cooperative industry and the credit factors supporting individual coop systems is an essential tool for debt holders.

■ Electric Cooperatives

Principally through the organizations of systems under the RUS program in 47 states and U.S. territories, rural electric cooperatives serve approximately 12% of the nation's consumers, compared with approximately 73% for investor-owned utilities (IOUs) and 15% for municipal and government-owned utilities. Cooperative sales of electricity amount to approximately 10% of total electric sales, and cooperatives own approximately 5% of energy generation and generating capacity.

Generation is primarily built to meet the native-load requirements of member distribution systems. G&T systems supply nearly 43% of the power purchased by distribution members, up from 41% nearly 10 years before. Other large electric suppliers to distribution cooperatives include traditional IOUs, power marketers, Tennessee Valley Authority, public government utilities and other power suppliers. The upward trend in G&T-supplied power is expected to continue, given the rising demand for power in developing rural areas and as G&T wholesale suppliers complete new generating stations.

Electric cooperative power generation by fuel type is quite diverse. Other significant credit characteristics of electric cooperatives are that distribution companies often have defined service territories and serve mostly residential and small-commercial users. Cooperatives generally have been able to opt out of electric deregulation in applicable states, and G&Ts have limited merchant or independent power producer risk.

Cooperatives now serve approximately 17 million consumers. Typically, consumer growth is higher than other segments of the electric utility industry, with many distribution cooperatives growing twice as fast as the overall electric industry. Several cooperatives operate near very high-growth metropolitan areas, such as Atlanta, Denver, Dallas and Washington, D.C. Rapid development of Western U.S. energy supplies is also having a major positive effect on cooperative electric demand. Residential electricity usage (as measured by kilowatt-hours (kwh)/month) is typically higher in cooperative areas than IOUs and municipals. This reflects a higher customer dependence on electricity versus other energy sources in the rural service area. Electric cooperative revenues total approximately $30 billion, with residential revenues accounting for approximately 65% of cooperative total revenues, and commercial and industrial contribute 20% and 15%, respectively.

Electric power costs represent approximately two-thirds of a distribution cooperative's customer bill, with distribution costs and net margins making up the remainder. Power costs generally declined during the

1990s. But beginning in 1999, they have climbed due to increased cost of fuel. Future costs are likely to see a further rise, due to the need to build new and more expensive generation, higher fuel costs, environmental factors and expanded transmission and distribution facilities.

■ History

The electric cooperative movement took hold in 1935 when the Rural Electrification Administration (REA) was established by President Franklin D. Roosevelt. At the time, only approximately 11% of the farm community had access to central station electric service, compared to the rest of consumers in more densely populated cities and towns where almost 100% of the population had access to electricity. Rural electrification became one of the great success stories of the New Deal.

The Rural Electrification Act of 1936 gave the REA the statutory authority to finance the construction and operation of electric generation, transmission and distribution facilities and provide power to consumers in rural areas. In 1949, REA's mandate was expanded to include the authorization to loan funds for telephone service in rural areas. Congress was given the power to approve annual appropriations to fund these capital programs.

By the late 1950s, the rural electric program's growing need for funds exceeded the amount Congress was willing to provide through the traditional REA loan program, which was administered by the U.S. Department of Agriculture (USDA). Under the authority of the REA Act, the USDA makes direct loans and loan guarantees to electric utilities to serve customers in rural areas. Before 1973, all direct loans were made at a 2% interest rate, which was subsequently increased to 5%. In time, the loan program grew to include larger loans, which were at the long-term Treasury rate plus one-eighth of 1%. REA also guaranteed loans made through the Federal Financing Bank or by private lenders at a similar low-cost interest rate. Under Internal Revenue Service Code, rural electric cooperatives are exempt from federal income taxes if at least 85% of their income is received from members. Cooperatives that may not meet this guideline, including a number of G&T systems, are subject to federal income taxes and have the ability to take advantage of tax benefits, similar to investor-owned companies.

■ G&T Systems Emerge

With demand for electricity in the cooperatives' service territories growing rapidly, reflecting consumers movement away from larger cities to the surrounding areas, it became clear that alternative financing sources would be needed to help meet the funding and development of new generation and distribution facilities, since it was unlikely that the federal government would be able to finance the industry's total growth requirements. In addition, hoping to lower operating costs and improve efficiency, a number of distribution systems decided to form new G&Ts to supply their longer term power needs, believing that building large power stations would be less expensive than constructing many smaller, less efficient units or continuing to rely on purchased power from for-profit IOUs.

However, forming new G&Ts would require a substantial increase in capital to finance the generating facilities. Initially, there was resistance for loans to G&Ts. But under President John F. Kennedy's administration, G&T loan policy was revised to allow for greater federal funds to be spent on power supply projects. By the-mid 1960s, the cooperative industry was growing at a rate of approximately 10% a year, almost 50% faster than investor-owned companies. Capital requirements were increasing, and funding needs were staggering. Following an extended review, a decision was made to continue the lower cost federal loan funding program, which primarily benefited distribution systems but also concluded that an intermediate financing plan be developed to offer greater flexibility in loans and a mechanism be established to provide a way to bring supplemental private capital into the program. The chosen proposal was a federal bank for rural electric systems, which would capture features of the Farm Credit System. In 1969, CFC was established as a cooperative self-help financing organization.

■ Growth of Supplemental Lenders

CFC and CoBank are the primary supplemental lenders to the electric cooperative industry. CFC was designed to provide its distribution members, as well as power suppliers, a dependable source of market-based capital and financial products and services. CFC is owned by its members, which differentiates it from most other financing companies. CFC has since taken a leadership role in helping to fund the needs of the electric and telecommunications cooperative industry, working closely with the RUS (the 1994 successor to REA). CoBank (formerly the Bank for Cooperatives) as well as the public and private capital markets constitute the other primary funding sources for the electric cooperative industry. Loans issued by supplemental lenders must typically be approved by RUS and are secured on a parity with other secured lenders, primarily RUS.

RUS is generally the cooperatives' first financing option, as it is able to offer members interest rates that are generally lower than the rates CFC, other banks and the capital markets are able to offer. Increasingly, CFC, CoBank and the other lenders compete for bridge loans in anticipation of long-term funding from RUS, the portion of a loan that RUS is not able to provide, loans to members that cannot borrow from RUS and loans to members that have elected not to use RUS.

The wholesale power contracts between the G&T and its distribution systems provide for rate adjustments to cover the costs of supplying power, although in certain cases, such adjustments may have to be approved by regulatory agencies. These agreements permit the power supply system, subject to approval by RUS and, in certain circumstances, state public service commissions or the Federal Energy Regulatory Commission (FERC), to establish rates for its members to produce revenues sufficient (with revenues from all other sources) to meet the costs of operation and maintenance, pay debt service, and establish and maintain reasonable reserves.

The board of directors of power supply systems must review their rates at least annually. Cooperatives that have power supply arrangements with IOUs and other suppliers that are not borrowers of RUS usually have rates subject to outside regulation. Examples of cooperatives that have chosen to borrow outside of RUS and from the capital markets include Chugach Electric Association, Inc., Old Dominion Electric Cooperative and most recently, Great River Energy (pending). In these cases, the cooperatives chose to use other financing options they believed provided greater flexibility and timeliness.

■ Security Features

Debt issued by the G&T cooperatives is typically secured by a pledge of the power supplier's assets and supported by joint and several all-requirements power supply contracts between the G&T and the member systems, under which the members agree to pay their pro rata share of all operating and fixed costs. In most cases, the current assets and all future assets of the entity are pledged as security for the debt. This pledge of assets is secured by a loan contract and mortgage. In making these loans, RUS takes into account the borrower's service territory, the inherent cost of providing service, the disparity in rates between the borrower and neighboring utilities, the intensity of competition and the relative amount of new capital investment required to serve existing or new loads.

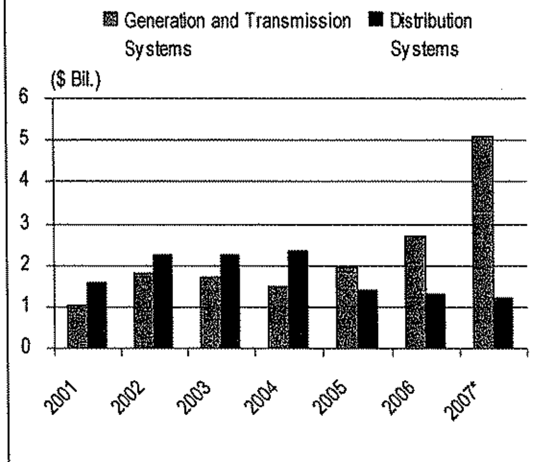
RUS may also approve the use of an indenture commonly used by utilities engaged in private market financing, in lieu of a mortgage, as the security instrument for loans to power supply borrowers. The terms of each indenture and related loan agreement are negotiated on a case-by-case basis. Given the cooperative industry's growing need for capital, it appears that more G&T's will seek indentures in the future.

■ Outstanding Debt

As of May 31, 2006, an estimated 898 electric utility cooperatives, including 829 distribution systems and 69 G&Ts had a total of $48 billion in long-term debt outstanding. RUS is the dominant lender to the electric cooperative industry and as of Sept. 30, 2006, had approximately $32.5 billion of total outstanding debt.

As of May 31, 2006, CFC had a total of $16 billion of long-term exposure to its distribution and power

Rural Utilities Service Loans



*Projected fiscal year. Source: Fitch Ratings.

supply member systems, including $15 billion of long-term loans and $1 billion of guarantees, 81.6% of which is to distribution systems. The remaining borrowings come from CoBank and other lenders.

■ Future Borrowing Needs

Over the next 10 years, G&T cooperative capital requirements are expected to total approximately $42 billion, with approximately $29 billion of this amount to fund new generation capital needs. The percentage breakdown will go for new electric generation (68%), with 22% for transmission and 10% for environmental compliance. Historically, RUS, CFC and CoBank were sufficient to meet the capital needs of the cooperative industry. In addition, capital needs of distribution systems will be substantial in the billions of dollars.

Some power supply systems were able to negotiate trust indentures with the RUS that allowed them more financing flexibility than what is usually permitted by the RUS mortgage. As financing needs grow, it is expected that G&T cooperatives will need to go beyond the traditional lenders into the public/private capital markets. While this would result in higher costs for the cooperative program, Fitch believes the increased funding flexibility is a valuable tool and should serve the industry well over the longer term.

■ Solid Operating Performance

Over the past quarter-century, the financial performance of the electric cooperative industry has generally been good. This reflects the cooperative industry's primary role as provider of electric service to retail customers, the risk-adverse nature of most cooperative boards and the overall stability of its largely residential and agrarian loads. As nonprofit organizations, cooperatives are designed by policy to keep rates as low as possible.

Despite the satisfactory record, the industry had a rocky period in the latter 1980s when several problem borrowings occurred, following a boom period of base-load power plant construction for the public power industry (municipal electric systems and rural electric cooperatives). A few G&Ts that borrowed heavily from the RUS and the public capital markets assumed overly optimistic energy growth forecasts supporting the need for major new coal and nuclear facilities. This was just as the industry was entering a period of reduced energy demand and higher inflation. This had a pronounced negative affect on the industry for some time.

At the same time, due to competitive pressures, certain state public service commissions took a harder line toward oversight of IOUs and cooperatives, and some G&T's found it difficult to raise wholesale rates and pass along these increased costs to their members. Some member systems even attempted to abrogate their power supply agreements, further undermining investors' confidence in electric cooperative credits. A few systems sought refuge in bankruptcy court or through loan forgiveness, and several others had to restructure their debt, hoping to reduce the burden of the heavy fixed charges.

While approximately one-third of G&Ts are rate regulated, nine of the 11 workouts for these troubled power suppliers occurred in rate-regulated states. With regard to lenders, RUS was the primary supplier of loans to most of these affected cooperatives, and it eventually incurred multibillion dollar write-offs. Other lenders, such as CFC, were also negatively affected, but to a much lesser degree. As a result of this experience, RUS and other lenders substantially tightened up their lending practices and major losses have since been minimized. Currently, it appears that investors once again see the cooperative industry in a more favorable light, given the positive growth characteristics of the industry, their stable financial record and the largely, straightforward business model that is employed by most electric cooperative systems.

■ Analytical Framework (Past and Present)

Past Approach

Looking back, the analytical process for G&T cooperatives focused primarily on the quality of the long-term, all-requirements contracts between a G&T and its members and the financial strength of the supporting distribution systems. A detailed review of the G&T was often believed to be less significant than assessing the creditworthiness of the members.

The original corporate structure placed most of the equity and financial strength at the membership level, while the G&T was leveraged up to hold costs down. The G&T was designed to be almost a quasi-holding company for power supply assets. It assumed the rating of the G&T would primarily reflect the financial health of the distribution systems and the members' ability and willingness to make timely payments of debt service and operating costs to the G&T, pursuant to the power supply agreements. Based on the solid equity and coverage levels of the average distribution member (typically 40% equity and approximately 2.0 times [x] debt-service coverage), the initial ratings for most G&T's tended to be in the 'A' category.

It was understood that the G&T's primary purpose was to finance power supply and meet the long-term electric requirements of its member systems, either through owned generation or power purchase arrangements. The all-requirements contracts, extending out approximately 35 years, were felt to provide sufficient bondholder protection and were central to the ratings. Initially, many of these wholesale systems had elements similar to project-style structures.

Several of these entities initially financed a single or small number of power supply projects. These generating projects were often one- or two-unit base-load coal or nuclear facilities, in some cases approximating 1,000 megawatts (mw). Fuel supply was long-term and sourced to meet the life of the project's debt (usually 30 years), with limited re-openers, thereby limiting operating flexibility. Plants were often oversized and assumed a fair amount of shorter term off-system sales, as members' loads were projected to grow into the resource.

Legal provisions were simple in design, with fixed-charge ratio (times interest earned ratio [TIER] and debt-service coverage [DSC]) generally light, set at approximately 1.00x–1.10x. Except for certain renewal and replacement and operating reserves, there was never any desire to accumulate much equity at the G&T. Almost all of the equity and credit strength was provided by the members, who typically did not upstream monies to the G&T beyond the minimum legal requirement. This had the potential to put regulated G&T cooperatives at greater risk should forecasts prove inaccurate or be affected by poor public service commissions decisions.

Since high energy prices and fuel volatility were not felt to be a major concern at the time, there was not a strong focus on the need for having extra financial liquidity at the G&T. However, high interest rates were definitely a problem, which were exacerbated by project overruns and inflation. Most systems did not rely on fuel and power purchase adjustment clauses to a great degree.

With inexpensive and secure RUS loans available and the belief that cooperatives would not get into financial difficulty given RUS oversight, it seemed to make sense to have G&Ts use higher debt leverage, minimal equity and low fixed-charge coverage. As long as a distribution system's equity/total assets was solid, members' TIER and DSC were approximately 1.75x–2.00x, and the cooperative's board structure and regulatory environment functioned properly, a low level of financial protection at the G&T level was deemed acceptable. Rating determinations for power suppliers were done mostly through comparisons to other G&T cooperatives and municipal joint-action agencies.

Problems Arise

This basic model worked well for some time. However, the surrounding economic landscape changed, and a number of G&T's found themselves getting into financial difficulty through overbuilding, a slowdown in demand, higher fixed costs and an inability to pass along these higher costs to their distribution members. Some distribution cooperatives even decided to test the legality of the RUS all-requirements power sales contract, thereby placing the entire electric cooperative industry in jeopardy. The most significant being the Shoshone case, where Shoshone River Power, Inc. tried to end its power supply contract with Tri-State Generation & Transmission Association, Inc. and use a different power supplier. Following an extended series of court reviews, the RUS contracts were upheld, and the financial integrity of the electric cooperative industry was maintained, putting an end to these serious legal concerns.

Most recently, the industry went through other challenges caused by electric industry restructuring, members' desire for increased power supply options, utilities moving into less conventional lines of business and evolving regulatory issues. These raised further potential concerns about the overall creditworthiness of the electric cooperative program.

By the mid 1990s, it became clear that the traditional analytical framework used to evaluate the electric cooperative industry needed to be modified. The historical synergistic relationship between G&T cooperatives and their distribution members was fraying and subjecting some cooperative utilities and investors to greater risk.

An example of this was with G&T cooperative Oglethorpe Power Corporation (OPC), where there was serious disagreements among cooperative members, with a few of the largest systems wanting a greater say over their future power supply options. This had the potential to place existing lenders at risk, while subjecting OPC's credit rating to a material downgrade. It also brought into a clearer focus the need for a newer, more balanced analytical approach when evaluating G&T and member distribution systems.

New Modified Approach

The conclusion was that there needed to be solid financial protection for investors at both the G&T and distribution system levels. To rely exclusively on having virtually 100% of financial protection at the membership level was deemed too risky and not good business policy. In addition, cooperative members were being asked to extend their purchase power agreements for another 20–30 years to help finance the next wave of base-load power plants, which could be problematic.

As a result, the current analytical format has been modified to incorporate a more balanced approach between supplier and member systems when assessing the key credit factors of the utility system. To maintain a healthy bond rating, it is imperative that there be a strong working relationship between the combined utility systems and solid financial ratios and liquidity at both the G&T and the distribution system levels. Power supply contracts, while offering significant credit protection, cannot mitigate all risks in the current business climate. Fitch recognizes that some member systems want increased power supply choice. In concept, Fitch supports this notion, but it must be done in a prudent way to protect existing bondholders and insure that the G&T's bond rating remains strong.

Regarding financial ratios, Fitch strives to be flexible in its analytical approach and in how it uses ratio analysis in the overall credit rating process. In other words, Fitch evaluates credits on a case-by-case basis, but it is fair to say that the trend and consistency in financial performance, desired fiscal and operating targets and other key metrics, such as management, price competitiveness and demographics, all matter. A cohesive board is also important.

End Result

In the end, the heightened fears associated with electric deregulation and market restructuring were bigger than the actual experience, and most G&Ts and their members were able to successfully resolve their internal differences, continue as combined utility systems and maintain their favorable ratings. To the industry's credit, cooperative boards successfully addressed most of these concerns, refocused their systems on their core business values and worked aggressively to bolster the financial strength of the G&Ts, in addition to maintaining strong operating distribution systems. Part of this reflects the eventual realization among member systems that low-cost alternative or non-G&T power supply choices were not as plentiful as originally believed. It is Fitch's belief that the G&T and distribution member systems have made major strides in bolstering their financial ratios and liquidity and worked through disruptive issues that could have splintered the industry, while positioning themselves for future growth requirements.

■ Financial Metrics

To achieve a solid investment-grade rating ('A' category) Fitch believes G&T cooperatives should establish reasonable financial targets, that capture the appropriate risk profile for the entity. This would include DSC, TIER and liquidity ratios. General guidelines for G&Ts might be equity of approximately 20%, TIER and DSC of 1.20x, net margins as a percentage of operating revenues of 5%–7% and 60–90 days of liquidity. Equity and interest coverage at the distribution level should approximate 40% and 2.00x, respectively.

Net margins and patronage capital are treated as equity capital and eventually must be returned to the members in proportion to their patronage or purchase of electricity. While there is no predetermined time frame or percentage for the return of patronage capital, since each cooperative sets its own policy, cooperatives that do choose to retain more of these surplus margins to help build equity are often viewed more favorably by adding to overall financial flexibility and strength. By having control over these funds, the monies can be used to help the G&T and distribution systems build equity more quickly, establish extra reserves and serve as an additional positive management tool.

For distribution systems, creditworthiness depends on credit factors, such as size, demographics, cost of power, retail rates and other relevant points. The following are ranges of member system financial

Distribution Cooperative Annual Key Ratio Trend Analysis

U.S. National Medians	2005	2004	2003	2002	2001	2000
Times Interest Earned Ratio (x)	2.20	2.33	2.28	2.30	2.11	2.03
Modified Debt-Service Coverage (x)	1.90	1.92	2.01	2.02	1.98	2.00
Annual Capital Credits Retired per Total Equity (%)	2.30	2.43	2.45	2.34	2.32	2.31
Equity/Assets (%)	42.0	43.0	43.0	43.0	44.0	43.0
Blended Interest Rate (%)	4.9	4.6	4.8	5.0	5.5	5.6
Total Operating Revenue/Kilowatt-Hour Sold ($)	83.40	78.83	76.78	74.19	74.29	72.68
Residential Operating Revenue/Kilowatt-Hour Sold ($)	88.31	83.39	81.23	78.62	78.08	76.15
Non-Residential Operating Revenue/Kilowatt-Hour Sold ($)	72.30	68.89	67.17	65.18	64.85	63.56
Non-Operating Revenue/Kilowatt-Hour Sold ($)	0.57	0.45	0.39	0.42	0.53	0.66
Total Margins Less Allocations/Kilowatt-Hour Sold ($)	3.49	3.32	3.46	3.85	3.38	3.24
Power Cost/Total Kilowatt-Hour Sold ($)	51.67	47.17	45.73	43.28	42.54	41.61
Power Cost/Revenue (%)	61.0	59.0	59.0	58.0	58.0	59.0
Total Operating Expenses/Kilowatt-Hour Sold ($)	18.12	18.27	17.92	17.23	17.12	16.41
Total Cost of Electric Service/Kilowatt-Hour Sold ($)	80.74	75.59	73.38	70.65	70.89	69.94
Annual Growth in Kilowatt-Hour Sold (%)	4.7	2.0	1.1	4.8	2.1	5.6
Annual Consumer Growth (%)	1.5	1.5	1.5	1.5	1.7	2.0
Average Consumer/Mile	5.82	5.78	5.7	5.66	5.64	5.52

Source: Fitch Ratings.

ratios that help support a high investment-grade G&T rating:

- Equity to capitalization of 40%–50%.
- Days cash/liquidity on hand of 45–75 days.
- DSC of 1.75x–2.00x (or greater).

Important Credit Drivers

Looking forward over the near term, areas of greatest importance in the rating process for cooperatives will likely include fuel price volatility, capital expenditures for base-load projects, financial management, environmental compliance, and demand and growth patterns. As previously mentioned, continued access to reasonably priced capital will remain highly important in addition to the industry's strong political support at the national and state levels.

Fuel Prices

Volatility in energy prices remains one of the biggest issues for the electric industry. With unprecedented demand for energy supplies, transportation bottlenecks and global supply risk, cooperative managements must have in place diversified power supplies, adequate hedging and risk-management programs, and sufficient liquidity. Fitch believes timely recover of fuel costs is essential to a utility's continued good credit standing.

Most electric cooperatives and municipal systems have the ability to set their own rates, which is an important strength. Nevertheless, rate-setting ability does not necessarily translate into willingness to raise rates and timely and full-cost recovery. Over the past several years, many cooperative and municipal systems have moved aggressively to deal with the effects of the volatile and rising fuel markets (e.g., hedging, increasing rates, building up cash reserves and implementing fuel and purchased power adjustment clauses). Presently, it appears that most cooperatives are sufficiently well-positioned in this area.

New Base-Load Generation

To meet growth in demand, electric cooperatives will have to develop and finance new base-load facilities for an extended period. Facing a dwindling supply of power reserves and increasing demand for electricity in well-situated service areas, the cooperative industry is exposed to a growing challenge to license, construct and finance new power projects at reasonable prices. Given material and labor shortages and the large number of competing infrastructure projects simultaneously being developed throughout the nation, there is less margin for error in the development and pricing of these plants.

On a positive side, the amount of incremental capacity being added by individual utilities is less of a concern than when these systems first added new generation approximately 20 years ago. Clearly, there was much higher risk then. Also, fuel supply options are much more diverse, and contracts are more flexible. However, should construction prices continue to escalate, the amount of risk associated with new power station development will increase and be of greater concern to investors.

Financial Management

Benefiting from a relatively conservative business model, along with reasonable financial and liquidity ratios, rural electric cooperatives have been able to maintain credit ratings in the upper tier of the electric industry. Utility management's ability to plan for system capital needs, while incorporating possible unexpected industry or global events, remains essential. Given that the not-for-profit business profile is less complex and more flexible than the for-profit part of the sector, the expectation is that most cooperatives should continue to fare well in the future.

Cooperative boards, being well-tenured, are showing an ability to deal with the changing needs of the business environment. There seems to be less friction among member systems, and financial ratios at the G&T level have improved in recent years. However, it remains less clear where funding will come from to meet the industry's future capital needs, what level of financial ratios will be appropriate as building programs ramp up, and what degree of push back, if any, from customers will be experienced as electric rates move meaningfully higher to pay for these new power plants. Despite these challenges, it would appear that many cooperative managements are preparing their systems and educating their customers for the business challenges that lie ahead.

Environmental Considerations

Greater environmental regulations are clearly an imposing issue for the electric utility industry. The financial effect of new environmental restrictions could be substantial in scope, and compliance costs for the industry could be particularly onerous for cooperatives, which are heavily coal-based. Limitations placed on greenhouse gas emissions will be important to watch. Presently, most public power systems seem to be in reasonably good shape in meeting known air emission requirements, but this could change, depending on future legislation regarding greenhouse gas emission.

Alternative generation (green power) is another area to watch. Most public power systems have been exempt from state standards up to this point. However, many cooperatives and municipals are already performing as if they will be mandated to meet future, more stringent requirements. This is a plus, with cooperatives in Minnesota being a good example of utilities leading the way in this area.

Growth in Demand

The electric industry has enjoyed steady growth in recent years, reflecting the nation's insatiable appetite for electricity-driven products and services. Cooperatives have been experiencing an even faster rate of growth, with some regions experiencing annual increases in electric demand approaching double digits. This reflects increased suburban development, which is directly benefiting cooperative service territories, and major new energy projects in the Western United States and upper Midwest. While there are benefits to the improved service area characteristics, there are also risks associated with this rapid rate of growth.

Rapid growth was one of the major problems that negatively affected public power 20 years ago. While Fitch believes the risks are different today, given utilities' broader power supply mix, the smaller increments of new generation added at any one time, better hedging practices and management's awareness of past mistakes, there remains a heightened degree of risk, particularly to systems that must meet the very rapid growth needs of large industrial and commercial loads, which could be negatively affected should energy prices fall at some future date.

■ Summary

Overall, the electric cooperative industry has done a solid job of meeting the needs of its customers, while maintaining reasonable financial parameters. Future challenges appear manageable, but volatile fuel prices will necessitate the use of more comprehensively designed risk-management and hedging strategies, while above-average growth among distribution systems will require power supply systems to add expensive, new base-load generation over the next 10 years.

Electric rates will have to rise to pay for these additional fixed assets, in some cases substantially, eroding the historical competitive price advantage that some cooperatives have enjoyed versus neighboring utilities. However, given the cooperatives' close working relationship with customers, the industry's successful extension of wholesale power contracts and their focus on providing highly reliable service, Fitch would expect that the cooperative sector would continue to perform well, maintain solid investment-grade ratings and benchmark well against most other sectors in the energy industry.

Electric Utility Comparisons Summary

Cooperative-Member-Owned Utilities	Investor-Owned Utilities (IOUs)	Government-Owned Utilities
Most not rate-regulated.	Rate-regulated.	Not rate-regulated.
Not-for-profit; Operated for the benefit of their own members.	Profit seeking; operated for the benefit of public shareholders with obligations to serve regulated rate payers.	Operated for public benefit for the region served.
Most are small relative to IOUs.	Most are larger; may have multiple entities in an issuer family.	Most are small relative to IOUs.
Little direct competition.	Subject to competition in the wholesale market, sometimes in the retail market.	Little competition.
Defaults have been rare.	Some history of defaults, usually as a result of needing rate increases that are too large to be acceptable to rate payers.	Defaults have been extremely rare.
Can file for Chapter 11 bankruptcy.	Can file for Chapter 11 bankruptcy.	More impediments to bankruptcy but may be able to file Chapter 9.
Rates tend to be comparable to IOUs.	Tend to have higher rates compared to municipal or public power.	Tend to have lower rates than cooperatives and IOUs.
Most borrow from Rural Utilities Service, National Rural Utilities Cooperative Finance Corp. and CoBank.	Rely extensively on capital markets.	Rely on public markets for financing; may have access to local government support.

Source: Fitch Ratings.

Fitch-Rated Electric Cooperatives

Rated Company	Type	Rating	Rating Outlook	Debt-Service Coverage (x)	Debt/ FADS (x)	Days Cash On Hand	Days Liquidity On Hand	Equity/ Capitalization (%)	Variable-Rate Exposure/ Total Capitalization (%)
'AA' Rated Senior Debt									
Associated Electric Cooperative Inc. (Mo.)	G&T	'AA'	Stable	1.12	6.4	53	166	25	0.0
'AA–' Rated Senior Debt									
Basin Electric Power Cooperative (N.D.)	G&T	'AA–'	Stable	1.72	5.7	216	232	34	10.0
Georgia Transmission Corp.	T	'AA–'	Stable	1.12	10	160	701	0	5.0
Pedernales Electric Cooperative, Inc. (Texas)	Retail	'AA–'	Stable	2.59	4.3	62	136	39	0.0
Median				**1.72**	**5.7**	**160**	**232**	**34**	**5.0**
'A+' Rated Senior Debt									
Arkansas Electric Cooperative Corp.	G&T	'A+'	Stable	1.08	5.7	47	126	45	0.0
Buckeye Power, Inc. (Ohio)	G&T	'A+'	Stable	1.39	5.7	24	24	35	0.0
Median				**1.24**	**5.7**	**36**	**75**	**40**	**0.0**
'A' Rated Senior Debt									
Brazos Electric Power Cooperative, Inc. (Texas)	G&T	'A'	Stable	1.49	10.0	6	319	17	16.0
National Rural Utilities Cooperative Finance Corp. (Va.) — Unsecured	Lender	'A'	Positive						
Oglethorpe Power Corp. (Ga.)	G&T	'A'	Stable	1.09	8.3	217	370	12	14.0
Old Dominion Electric Cooperative (Va.)	G&T	'A'	Stable	1.54	6.5	27	172	26	1.0
Tri-State Generation & Transmission Association, Inc. (Colo.)	G&T	'A'	Negative	1.07	8.1	66	151	17	11.0
Median				**1.29**	**8.2**	**47**	**246**	**17**	**12.5**
'A–' Rated Senior Debt									
Central Iowa Power Cooperative	G&T	'A–'	Stable	1.06	8.8	20	127	19	0.0
Chugach Electric Association, Inc. (Alaska)	G&T	'A–'	Stable	1.98	5.6	18	121	29	17
Golden Spread Electric Cooperative, Inc. (Texas)	G&T	'A–'	Stable	2.81	4.0	30	119	43	1.0
Great River Energy (Minn.)	G&T	'A–'	Stable	1.30	8.6	54	383	13	16.0
Western Farmers Electric Cooperative (Okla.)	G&T	'A–'	Stable	1.11	9.0	10	124	12	2.0
Median				**1.21**	**8.7**	**25**	**126**	**16**	**1.5**
'BBB+' Rated Senior Debt									
Alabama Electric Cooperative	G&T	'BBB+'	Stable	1.15	9.0	52	155	11	8.0
'BBB–' Rated Senior Debt									
Vermont Electric Cooperative Inc.	Retail	'BBB–'	Negative	3.73	3.2	27	27	39	0.0

FADS – Funds available for debt service. G&T – Generation and transmission, T – Transmission. Source: Fitch Ratings.

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S&P's Rating Methodology For U.S. Power Cooperatives: Key Business Risks

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S&P's Rating Methodology For U.S. Power Cooperatives: Key Business Risks

(Editor's Note: This is the second article in a three-part series that discusses the methodology used to establish credit ratings for the U.S. electric cooperative sector. This article provides an in-depth look at how we analyze cooperatives' business risks. The other articles in the series, published Nov. 2, 2006, are "S&P's Rating Methodology For U.S. Power Cooperatives: An Overview" and "S&P's Rating Methodology For U.S. Power Cooperatives: Key Financial Indicators.")

The business profile (BP) score is an important element in Standard & Poor's Ratings Services' credit analysis, and factors significantly into the rating assigned to an electric cooperative. The score is our assessment of the business risk each company faces. We assign business profile scores to utilities using a 10-point scale, where '1' represents the lowest risk and '10' the highest risk (see table 1).

Table 1

Business Profile Scores

Score	Interpretation
1-2	Excellent
3-4	Strong
5-6	Satisfactory
7-8	Weak
9-10	Vulnerable

BP scores for generation and transmission (G&T) cooperatives are between '3' and '6' and, for distribution cooperatives, are between '3' and '5'. Five, and possibly six, factors are examined when assigning a BP score:

- Regulation,
- Markets,
- Electric operations,
- Nonelectric operations (if any),
- Competitiveness, and
- Management

What is assessed in each of these categories is discussed in detail below, but it is important to note that the emphasis that is placed on each category, is not uniform. For example, one of the key credit features of cooperatives is their ability to set their own electric rates. How well a cooperative functions in this role and how much discipline it demonstrates in implementing rate changes is a critical consideration, and, for this reason, carries more weight than the analysis of the markets that cooperatives serve, for example.

Regulation

To be consistent with our utilities methodology, Standard & Poor's uses the same names for each category of the business profile score, but the label "regulation" is somewhat misleading in the context of cooperatives. While for investor-owned utilities we assess the quality and consistency of the regulatory commissions that oversee the ratemaking process, for cooperatives, credit strength often comes from the absence of state or federal ratemaking oversight. Whether cooperatives are subject to state regulation is a function of whether state regulatory law applies to electric cooperatives. In Vermont, Alaska, and Michigan, for example, cooperatives are subject to state regulation. But in most states, the state utility commission has no direct oversight over the rates charged by G&Ts or its members.

Regarding FERC regulation, as long as G&Ts borrow from the U.S. Department of Agriculture's Rural Utilities Service (RUS), they are not subject to FERC jurisdiction. Furthermore, while all electric cooperatives that are RUS borrowers must file rates plans and schedules with the RUS, the RUS's rate-setting authority is limited to insuring that the rates, as approved, are sufficient to recover costs, including the repayment of RUS debt, a level of oversight that Standard & Poor's views as benign.

We view cooperatives' ability to set their own rates and recover costs autonomously as favorable for credit quality because regulators can and have disallowed electric plant and equipment in rate base and exercise significant authority over what utility costs are collected and over what time period. Unfortunately, regulatory oversight can and has led to the deterioration of utility credit ratings (and to defaults and bankruptcy), not only in the cooperative sector but also for several investor-owned utilities. For this reason, if a cooperative does face regulation, all else being equal, its business profile can be expected to receive a weak regulatory score. While Standard & Poor's assesses the quality of regulation for those cooperatives that face state approval of rates, a positive history may not provide substantial comfort because the composition and stance of commissions can change over time.

Our analysis of regulation does not begin and end with whether a cooperative is regulated by a state or federal authority. For those cooperatives that are self-regulated, emphasis is placed on the quality of self-regulation. Relevant questions include:

- What is the process for raising rates and how much time does this take?
- Does the cooperative have a fuel and purchased power adjustor and how strong is it?
- Has the cooperative in the past allowed financial performance to lag rather than raise rates charged to members or customers?
- Has the cooperative incurred fuel and purchased-power deferrals in the past?

These questions suggest why, even in the absence of state or federal regulation, that this component of the business profile score is the most important. A cooperative's ability to be its own regulator requires discipline and is the key factor that determines financial performance. Despite the many adverse events that a cooperative can experience, its board is ultimately able to control company cash flows by acting to raise rates in a timely manner and in amounts sufficient to cover its obligations. But, as we emphasize, it is critical that cooperatives demonstrate that they can effectively use this control.

Markets

The market component of the business profile score captures the underlying strengths and weaknesses of the customers who provide the cash flows to the cooperative. For distribution cooperatives, this analysis focuses on the service territory in which the company sells retail electricity, assessing the fundamental characteristics of the underlying market.

In the case of G&Ts, this analysis is also performed, but Standard & Poor's also examines the strength of the members, who are effectively the "market" that pays the G&T's power bills, thus allowing it, in turn, to meet its financial obligations. G&T member strength is measured by reviewing RUS Form 7s for each member and evaluating the members' financial metrics, liquidity, and historic performance.

But because the strength of members is clearly linked not only to their own financial polices but also to the attributes of the local economy they serve, as with distribution cooperative market analysis, Standard & Poor's "looks through" the members to get a sense of the major features of the local retail electric market. Thus, in analyzing the underlying market for either a distribution or G&T rating, Standard and Poor's examines:

- The economic base of the communities served, including the make-up the local economy and the region's growth prospects.
- Service area demographics are also reviewed to identify what the recent population trends are and how the areas compare with the nation in terms of household income, the level of income transfers, and unemployment statistics.
- Electric sales data (energy sales, revenue, and peak demand) is also examined to determine how service territory demographics translate into electric consumption growth over time.
- The portion of energy sales and revenues that members receive from residential, commercial, and industrial accounts. We consider high levels of residential accounts to be a credit attribute because sizable out migration of residences does not usually occur, and smaller customers tend to be capable of absorbing rate increases without bringing significant political pressure to the rate-setting process.
- The top 10 industrial accounts over all members in a G&T provide information about the exposures a G&T may have if those accounts are concentrated in a single industry. In addition, how much of total sales and revenues these accounts represent provides a measure of the extent to which the G&T could be left with surplus capacity if one or more important accounts leaves the area or goes out of business.

While there is no one factor that is most important in markets analysis, generally speaking in the case of a G&T favorable markets would serve members who all have good liquidity and cash coverage of their own debt service. Service territory characteristics would exhibit steady growth, with no pattern of population decline, a fairly high level of residential accounts, and, if industrial accounts constitute a sizable component of revenue, the industries represented are not cyclical.

As a practical matter, however, although many cooperatives have seen former rural service territories transformed into prosperous bedroom communities of major metropolitan areas, for the most part electric co-ops serve remote, sparsely populated areas that often exhibit below-average demographics, have low growth, and feature some level of industrial concentration. Such attributes can often be compensated for by the member systems' financial strength.

Electric Operations

Standard & Poor's analysis of a G&T's operational profile considers four major factors:

- Diversity of the supply portfolio,
- Performance of owned and contracted plant,
- Hedging policies and risk-management strategies, and
- Resource-procurement process.

Ideal for credit quality is a G&T that has diverse sources of generation, with no overconcentration in a single asset or fuel. This can result in vulnerability if unplanned outages or price increases occur if a particular fuel cost rises. In assessing operational business risk, we examinee not only the performance of owned units (as measured in terms of annual capacity factor and equivalent availability factors relative to industry performance over time), but also the megawatt-hours (MWh) delivered under contract and the terms that exist for counterparties that fail to perform.

Also important to understand is how the G&T manages its attendant exposures to fuels, transport, and other factors. This entails a review of the G&T's hedging and risk-management policies. We also evaluate the in-house resources or external expertise that is available to a company to implement and assess the effectiveness of its policies.

Notably, many G&Ts do have some asset and fuel concentration. Most of G&T's owned generation is coal fired, and given the scale of operations, with the total capacity of a single G&T's owned plant typically under 2,000 MW, G&Ts often rely on one or two coal units to supply the majority of member requirements. It is not uncommon to see, for example, a G&T's coal units provide 50% to 70% of the total power requirements of its members. In these instances, the historic performance of these units, as well as what plans exist for backup power supply in the event of a forced outage, becomes especially important.

For a distribution cooperative, operations analysis often begins with assessing the factors outlined above for the distribution company's wholesale supplier. While the distribution company has no direct control over the supplier's operational profile, a distribution cooperative's operational profile at the distribution company can easily be influenced by problems at the wholesale supply level. When analyzing distribution operations, Standard & Poor's also examines the challenges the company faces in providing retail electric service, which could include issues such as weather risk, rapid growth, or other difficulties in executing infrastructure plans. Reliability measures for distribution cooperatives are also assessed.

Nonelectric Operations

Nonelectric businesses consist of equity interests, subsidiaries, or affiliate companies of a cooperative that are ancillary and often distinct from the cooperative's primary business of selling wholesale or retail electric power. If non-electric businesses are substantial, there may be a sixth category of the business profile that captures the risks of these businesses.

The cooperative experience with nonelectric businesses has generally not been favorable, and for this reason any sizable nonelectric operations can be expected to weaken the business profile score. While nonelectric businesses are structured differently depending on the cooperative's objectives, the cooperative usually provides performance and financial guarantees to support its nonelectric business. As a result, losses in these businesses, if they occur, are borne by the members, often in the form of higher power rates.

While exact numbers are difficult to come by, in our experience nonelectric businesses can be more common at the distribution cooperative level, with the strategy typically being to capitalize on existing relationships with retail electric customers by offering additional products and services. In evaluating the credit implication of nonelectric businesses, we analyze standalone and consolidated financial statements of the cooperative and its ancillary businesses to determine:

- The size of operations, and plans for expansion,
- How much debt the nonelectric company has,
- The level of support provided, including guarantees, equity infusions and liquidity support,4)
- Historical profitability and future projections, and
- The level of competition for the produce or service provided.

If Standard & Poor's believes that the operations pose sizable risks to the cooperative, the rating may be adversely affected even if the nonelectric operations have been profitable because often the fortunes of these riskier operations can quickly reverse. Such is the case with electricity trading and marketing businesses, which have repeatedly demonstrated their capacity for resulting in large losses over a short period of time, irrespective of how capably they were operated in the past.

This is not to suggest that nonelectric business always have adverse consequences on the BP score. If nonelectric businesses are present but are low risk and small, there may be no significant effect on the rating from these operations.

Competitiveness

Competitiveness measures the efficiency of the cooperative sector in generating and delivering electricity, as compared with other power companies, both now and in the future. Standard & Poor's assesses competitiveness by addressing three questions:

- What is the intrinsic cost competitiveness of the rated G&T or distribution cooperative?
- What are the direct or indirect competitive threats the cooperative faces that could threaten sales?
- What is the potential for "rate shock"--defined as a dramatic shift in wholesale or retail rates--over a short period of time?

The G&T cost structure

For the G&T, Standard & Poor's examines how the wholesale rates it charges members compares with the unbundled wholesale power prices of investor-owned utilities, public power, other G&Ts, and, if the state has introduced retail competition, the wholesale power prices. There are several cost advantages that cooperatives have that typically result in the power generation costs of G&Ts being competitive against neighboring wholesale providers. First, G&Ts (and distribution cooperatives) have access to low-cost borrowing through the RUS. Second, the majority of G&Ts own significant coal-fired generation, which historically has been a relatively low-cost and stable fuel source. Third, because G&Ts are member owned, management's spending decisions are approved by a board of members whose legitimate self interests to minimize the cost of the generation service they purchase from the G&T often serve a vital role in cost control.

Forces that can work against the G&T cost structure are mostly economies-of-scale issues. For example, substantial efficiencies exist between building a 500 MW versus a 250 MW supercritical pulverized coal unit, but a cooperative may not be able to build the more efficient unit without partnering with another owner to share in the output.

Because coal has shown itself to be relatively stable and low cost, before the 2005 run-up in natural gas prices and coal transport costs, it was not uncommon to see generation costs charged by G&Ts to their members in the $40 per MWh area. While recently these costs are now averaging closer to the high $40s to low $50 per MWh, generally G&Ts continue to have a favorable cost structure, although we note that public power and investor-owned utilities with low-cost, well-run nuclear and coal base load are capable of having comparable production costs. Moreover, the generally high levels of coal in the overall G&T supply mix puts these companies at somewhat greater risk with respect to increasing environmental standards, including mercury-reduction requirements, carbon capture, and any new or increased renewable fuel portfolio standards that states impose. (While many G&Ts have added renewable fuels to their power supply in the past five years, generally the overall portion of renewables to the average G&T's total supply portfolio remains modest.)

The distribution cooperative cost structure

When rating distribution cooperatives, Standard & Poor's considers the competitiveness of the power supplied by its wholesale provider (usually a G&T), but also the all-in retail rates the distribution cooperative charges to residential, commercial, and industrial customers and compares these results with state averages and to neighboring retail electric supplies and, if present, retail electric providers

It is important to note that distribution cooperatives often rely on their G&T suppliers to produce competitive generation to offset the fundamentally higher costs that exist to serve rural areas. Distribution cooperatives typically serve rural and thinly populated service territories that traditionally have 10 or fewer electric meters per line-mile. In contrast, municipal or investor-owned utilities often have double-digit meters per line mile, which lowers distribution costs. This reality can and often does produce all-in distribution rates that are higher than state averages. In this common circumstance, Standard & Poor's does require that to achieve a strong credit rating, retail rates must be on par with more densely populated systems, but we do look at by how much rates are out of line with state averages and seek to understand if there are reasons other than density that account for unfavorable pricing.

Competitive threats

Rate analysis provides Standard & Poor's with a sense of the intrinsic competitiveness of cooperative electric service. Standard & Poor's also looks for actual indications of competitive threats, which could result in load loss for the cooperative. These threats typically come in three forms:

- Wholesale and/or retail competition exists,
- State law permits competition for large loads, and
- Municipal annexation rules could result in the loss of cooperative service territory.

Most states have moved away from retail competition due to the market problems that emerged in California in early 2001. And, for the most part, cooperatives do not face sizable threats from large load competition or annexation.

Potential for rate shock

As part of competitiveness, Standard & Poor's also examines the potential for a G&T to experience a rate shock. Rate shock universally takes place at the G&T level, although members invariably feel the consequences of that shock in the form of higher rates. It is important to note that distribution systems themselves typically do not take on risks capable of producing rate shock. The potential for a G&T to experience rate shock is material to the business profile score because rate shock is a strong predictor of increased default risk. Causes of past rate shock in the cooperative sector have generally resulted from investment in nuclear plant that either was never brought on line or was put into service at costs that were multiples of original budgets.

Standard & Poor's starts by carefully examining the company's rate forecast and may perform a scenario analysis to determine how much rates could increase over the base forecast under certain conditions. Indicators that may signal the potential for rate shock include:

- The company's five- and 10-year projections for capital expenditures, which, because the majority are debt-financed, can be expected to increase rates;
- Planned new generation without an engineering, procurement, and construction contract, which exposes the cooperative to cost overruns;
- Sizable power purchases, particularly if unhedged;
- Reliance on a single generation unit for the majority of requirements, which exposes the company to the potential for large replacement power costs;
- Risky nonelectric operations that could incur large losses

Management

As a practice, Standard & Poor's does not publicly comment on its view of management, but it is a factor in a cooperative's business profile score. Issues that we consider include management's approach to sustaining credit quality, the board policies in effect that require certain financial targets be met, the veracity of an entity's forecasts, and the seriousness with which it regards its risk-management policies. Standard & Poor's also values the extent to which management is able to articulate its own credit strengths, as well as its willingness to volunteer is own perceptions of future challenges.

It is important to note that in evaluating management, we assess not only the executive team, but also the capabilities of the board, as it is the board that must vote on all major decisions. Within this context, we try to assess over time the degree of harmony between the G&T and its board. Tensions can sometimes develop between management's goals to sustain credit metrics and member desires to manage to slim margins to insure that power costs are kept low. On occasion, related conflicts can arise over the allocation of costs (most commonly in large systems that have a significant number of members), the voting rights of members of different sizes, or investment in new generation. (Similarly, for distribution cooperatives, a board of trustees typically exists that is often elected, one from each subregion of the distribution service area and similar dynamics may be at work.)

Finally, given the lack of public disclosure and scrutiny of company operations, governance can be an important consideration in the business profile score. Some cooperatives, for example, may have chief executive officers who serve as the focal point of leadership both in the company and the local community, often serving in this role for decades. In these instances, succession planning is critical, as is insuring that checks and balances are in place that minimize potential conflicts of interest or other governance concerns.

Rated Cooperatives

Table 2

Rated G&T Cooperatives

G&T Cooperative	State	Rating as of Oct. 20, 2006
Alabama Electric Cooperative	Ala.	BBB+/Stable/--
Arkansas Electric Cooperative Corp.	Ark.	AA-/Stable/--
Associated Electric Cooperative Inc.	Mo.	AA/Stable/--

Table 2

Rated G&T Cooperatives (cont.)		
Basin Electric Power Cooperative	N.D.	A+/Stable/--
Brazos Electric Power Cooperative Inc	Texas	A-/Stable/--
Buckeye Power Inc.	Ohio	A+/Stable/--
Central Electric Power Cooperative	S.C.	AA/Stable/--
Central Iowa Power Cooperative	Iowa	A/Stable/--
Chugach Electric Assoc.	Alaska	A-/Stable/--
Dairyland Power Cooperative	Wis.	A/Stable/--
Georgia Transmission Corp.	Ga.	AA-/Stable/A-1+
Great River Energy	Minn.	BBB/Stable/--
Hoosier Energy Rural Electric Co-op Inc.	Ind.	A-/Watch Neg/--
Oglethorpe Power Corp.	Ga.	A/Stable/A-1
Old Dominion Electric Cooperative	Va.	A/Stable/--
Seminole Electric Cooperative	Fla.	A-/Stable/--
Tri-State Generation & Transmission Assoc.	Col.	A/Stable/--
Wabash Valley Power Assoc.	Ind.	BBB+/Negative/--
Western Farmers' Electric Cooperative	Okla.	BBB+/Stable/--

Table 3

Rated U.S. Cooperative Distribution Systems			
Total cooperative distribution systems*	864		
Rated by Standard & Poor's	4		
System	**State**	**Rating¶**	**Date Assigned**
Brunswick Electric Membership Corp.	N.C.	A-/Stable/--	Jan. 5, 2006
Diverse Power Inc.	Ga.	A/Stable/--	Jan. 4, 2002
Guadalupe Valley Electric Cooperative Inc.	Texas	A+/Stable/--	Sept. 25, 1998, Oct. 2006
Snapping Shoals Electric Membership Corp.	Ga.	A+/Negative/--	Aug. 21, 2001
Vermont Electric Cooperative Inc.	Vt.	BBB-/Negative/--	Jul. 21, 1997

*Source: National Rural Electric Cooperative Association. ¶Ratings as of Oct. 20, 2006.

Related Articles

The other articles in this series are " S&P's Rating Methodology For U.S. Power Cooperatives: An Overview" and " S&P's Rating Methodology For U.S. Power Cooperatives: Key Financial Indicators," published Nov. 2.

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S&P's Rating Methodology For U.S. Power Cooperatives: Key Financial Indicators

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S&P's Rating Methodology For U.S. Power Cooperatives: Key Financial Indicators

(Editor's Note: This is the third article in a three-part series that discusses the methodology we use to establish credit ratings for the U.S. electric cooperative sector. The article describes how Standard & Poor's corporate rating methodology has been adapted to date for the electric cooperative sector. It is subject to change based on decisions by Standard & Poor's Analytical Policy Board, the Industrial Ratings department, or the Utilities and Project Finance practice, which is responsible for maintaining ratings on the sector.)

Financial analysis is an essential tool of credit analysis, but it is hardly the only one. In Standard & Poor's Ratings Services' view, corporate credit quality is determined by considering both the financial risk profile and the business risk profile of a company, relying on both qualitative and quantitative assessment.

This article explains how Standard & Poor's evaluates the financial profiles of U.S. electric cooperatives using a methodology similar to that of investor-owned utilities, but with some key differences. After providing an overview of the financial characteristics of cooperatives, this article describes each of the four elements of a cooperative's financial risk profile and provides examples and formulas of useful financial indicators.

Overview Of Cooperative Financial Characteristics

Electric cooperatives are membership organizations that generally set their own rates to cover their costs and to provide some financial cushion to meet creditor covenants or the expectations associated with a targeted level of credit quality. Although cooperatives may pay dividends to their members, they do not seek to maximize profits and instead, typically set their rates to be as low as possible.

Electric cooperatives are typically classified as being either a "generation and transmission" (G&T) cooperative or a "distribution" cooperative. Distribution cooperatives own and operate their own distribution systems and have a membership base that consists of individual ratepayers. In turn, distribution cooperatives make up the membership of their respective G&T cooperatives, which own and operate G&T assets.

The most salient feature of most cooperative financial profiles is the considerable financial flexibility that comes with their ability to set their own rates (see table 1). Together with having a captive membership under long-term power supply contracts, rate-setting ability greatly enhances the credit profiles of cooperatives, allowing them to achieve relatively strong investment grade ratings despite much weaker financial profiles relative to their investor-owned utility peers.

Table 1

Regulation And Rate Autonomy Among Rated Cooperatives by Type

	Regulation		
Percentage of co-ops by category (%)	**Internal**	**External**	**Rate autonomy**
G&T co-ops	84	16	95
Distribution co-ops	80	20	80
Total	83	17	92

Table 1

Regulation And Rate Autonomy Among Rated Cooperatives by Type (cont.)

*Regulation is classified being as either external (state or federal) or internal (self-regulation). ¶Rate autonomy refers to a utility's ability to effectively set its own rates, regardless of regulatory oversight.

Cash flow measures vary among cooperatives, but are generally weaker than those of investor-owned utilities. This is largely due to the fact that cooperatives set their rates to cover costs, plus a margin tied to a type of earnings-to-interest coverage target. Since there is often a wide discrepancy between earnings and actual cash flow, achievement of accrual-based targets does not necessarily assure that operating cash flows will be sufficient to cover financing charges.

Cooperatives' capital structures generally vary according to the type of service they offer. The balance sheets of G&T cooperatives are often heavily levered (see table 2), reflecting the permissive debt leverage covenants of the sector's traditional lenders, especially the Rural Utility Service (RUS). The equity layers at G&T cooperatives vary widely, from as much as 46% of capitalization to as little as 6%, but tend be low, averaging about 19% across the rated sector, especially relative to similarly rated investor-owned utilities.

Table 2

Debt Leverage Medians/Averages By Sector*

Debt leverage--total debt/total debt + equity (%)

	Rating		
	AA	**A**	**BBB**
Industrial companies (excluding utilities)*	28.3	37.5	42.5
Utility companies¶	53.8	58.1	70.6
Generation & transmission cooperatives§	72.0	81.2	87.5

*Three-year (2002 to 2004) medians, adjusted for operating leases. ¶Three-year (2002 to 2004) medians, adjusted for purchased power and operating leases. § Five-year (2001 to 2005) averages, not adjusted for purchased power or operating leases. Note: G&T averages are based on preliminary calculations and for illustration purposes only.

The capital structures of distribution cooperatives often are usually stronger than those of G&T cooperatives, although this is mainly due to the fact that most of their debt is off-balance-sheet, residing at their respective generation and transmission cooperatives of which they are members.

Capital market access is nascent among electric cooperatives because most remain dependent on the concessionary lending afforded to them by the traditional lenders to the sector--the RUS of the U.S. Department of Agriculture, National Rural Utilities Cooperative Finance Corp. (CFC), and CoBank Agricultural Credit Bank. RUS offers attractive taxable debt financing through the U.S. Federal Financing Bank, but requires that its loans be secured either through a first-mortgage agreement or a bond indenture. RUS mortgages allow the other two traditional lenders to the sector, CFC and CoBank, to make secured loans that are pari passu with RUS financing. These lenders may structure loans with terms up to 30 years or more. Long-term loans typically feature amortizing debt structures.

A small number of G&T cooperatives no longer rely on the RUS for long-term financing and instead issue secured and unsecured debt through the private placement market. A number have also been able to issue tax-exempt debt through industrial development bond cap allocation of their respective states. Outside of such offerings, cooperatives do not usually have access to the tax-exempt debt markets and must instead issue taxable bonds when accessing the capital markets.

The Financial Risk Profile: Aspects And Relevant Ratios

Electric cooperatives are unique in that they share characteristics with both investor-owned utilities, which are universally regulated in the U.S., and public power utilities, including municipal and government-owned utilities, of which nearly all set their own rates. Despite the differences between electric cooperatives and investor-owned utilities, Standard & Poor's approach to financial analysis is remarkably similar. In both cases, Standard & Poor's evaluates a utility's financial condition through the concept of a "financial risk profile" and evaluates this financial profile according to the following considerations:

- Cash flow adequacy,
- Capital structure,
- Financial flexibility and liquidity, and
- Financial policy.

Assessing each of the above factors entails both quantitative and qualitative analysis. Below is a discussion of those aspects of the financial profile in which financial analysis--including financial ratio analysis--plays an important role, as well as the financial ratios involved in their assessment.

Cash flow adequacy

Cash flow adequacy refers to a utility's ability to service financing and other obligations through the cash flow it generates through normal operations. Although margins and cash flow coverage measures are typically slim for cooperatives (especially relative to similarly rated investor-owned utilities), cash flow adequacy is still an important consideration in assessing financial strength for all cooperatives and perhaps the most important aspect of the financial profile for cooperatives that cannot set their own rates.

Standard & Poor's relies on several measures to evaluate cash flow protection for cooperatives:

- Debt service coverage: defined as net revenues, calculated on a cash basis, divided by the sum of scheduled cash principal and interest payments;
- Fixed charge coverage: similar to debt service coverage, but adding to both the numerator and denominator an adjustment for fixed financing charges and purchased power charges in addition to debt service;
- Funds from operations (FFO)/interest coverage: a commonly used ratio in corporate utility ratings that measures the coverage of net accrual interest by cash from operations, less changes in working capital, plus net cash interest payments.
- Cash from operations (CFO)/interest coverage: similar to FFO/interest coverage, except that changes in working capital are included. CFO is an entity's net operating cash flow from ongoing operations; and
- Internal funding ratio: this ratio measures the degree to which an entity funds its capital outlays through internally generated funds, as opposed to external financing. Defined as net cash flow (FFO less dividends) divided by capital expenditures.

Capital structure

Capital structure encompasses an array of considerations regarding the capital and debt structure of a rated entity. Considerations include debt leverage, off-balance-sheet obligations, refinancing risk and other types of interest rate risk. Like earnings protection, capital structure tends to be less material to intrinsic credit quality, but can be important to credit market access and financial policy; debt leverage covenants are still common among cooperative mortgage agreement and bond indentures. Debt leverage can also serve as a useful consideration in differentiating the degree of conservatism among cooperatives across the sector.

Assuming covenant compliance is not a concern, Standard & Poor's may take a flexible view toward certain aspects of capital structure, such as debt leverage, particularly for those cooperatives that exhibit the quintessential credit strengths that characterize the most highly rated in the sector:

- Demonstrated ability and willingness to adjust rates to provide sufficient cash flow coverage and liquidity;
- Strong business profiles;
- Favorable member contract provisions; and
- A large and diverse membership base that exhibits strong credit characteristics.

For cooperatives that do not meet these criteria, capital structure can become a more significant aspect of the financial profile.

In evaluating a cooperative's capital structure, Standard & Poor's considers the following ratios:

- Debt to total capitalization: This ratio divides total on-balance-sheet debt by the sum of equity and total debt. Commonly used as a measure of "debt leverage";
- Debt to net plant: Calculates total debt as a percentage of depreciated net plant, property, and equipment. A ratio of 100% or above indicates that the par value of outstanding debt exceeds the book value of physical assets;
- Debt per kilowatt (kW) peak demand, kW installed capacity or customer meter: These debt measures provide comparability with other systems with respect to operational attributes, versus financial ones;
- Net variable debt to total debt: Measures the degree of floating interest rate exposure in a cooperative's debt structure. Defined as the percentage of total debt with a floating interest rate, adjusting for floating rate debt that is hedged. Includes short-term debt, but may adjust for seasonal balances.

Financial flexibility and liquidity

Financial flexibility and liquidity together capture a utility's ability to respond to adverse events so as to protect its capacity to meet financial obligations in a timely manner.

Liquidity.

Liquidity is an entity's ability to quickly convert assets into cash. Assessing liquidity adequacy involves comparing internal and external sources of liquidity against potential uses of cash. Standard & Poor's key liquidity considerations are:

- Cash and short-term investments,
- Credit line availability (takes into account credit line expiration dates; loan covenants such as material adverse change clauses; and compliance with those covenants),
- Projected operating cash flows that are highly predictable,
- Projected changes in working capital,
- Capital market activities,
- Debt maturities, including short-term debt,
- Capital budget: maintenance and growth capital expenditures, and
- Member dividends.

Although liquidity analysis cannot be boiled down to simple ratio analysis, one traditional measure for both public power and cooperative utilities has been "days cash on hand." For electric cooperatives, we have modified this measure to include both unrestricted cash and undrawn bank line capacity, divided by operating expenses minus depreciation.

For cooperatives with significant commodity market activity (including buying for native load requirements or selling surplus generation), Standard & Poor's may request completion of a simplified version of its liquidity adequacy survey, which involves calculation of two other liquidity measures:

- Credit event liquidity adequacy: Defined as primary liquidity (cash, plus committed bank line capacity) under a severe ratings downgrade (typically 'BB'), and
- Market and credit event liquidity adequacy: Defined as primary liquidity under a severe ratings downgrade and a severe price movement (e.g., 20% in year 1, 15% in year 2).

Financial flexibility.

Financial flexibility describes the sufficiency and diversity of financial resources available, including both those that are immediately available as well as any cash flows that can be generated, reallocated, or curtailed to improve an entity's financial position.

Financial flexibility is the most important consideration in assessing the financial profile of cooperatives that establish their own rates and have relatively strong business profiles and contractual protections. For cooperatives whose rates are externally regulated or suffer from other deficiencies, financial flexibility may be superseded by other considerations.

Rate setting is the primary form of financial flexibility for most rated cooperatives, given that most set their own rates, or for those under FERC regulation, effectively enjoy rate-setting autonomy due to FERC's flexible formulary rate structure. Power and fuel cost trackers can boost financial flexibility even further by automating recovery of commodity costs. The more frequent the adjustments, the less regulatory lag. The downside is that members may be upset by rate volatility.

Rate setting flexibility is gauged in several ways:

- Demonstrated willingness to raise rates to preserve credit quality,
- What is the maximum percentage rate increase members could reasonably support?,
- The strength of the member revenue stream,
- Is the revenue stream large, such that even small rate increases could generate large amounts of incremental cash flow?,
- Competitive position relative to peers, and
- How does the cooperative's member rates compare?

Access to capital is another element to financial flexibility. Electric cooperatives, which are usually nonprofit membership organizations, cannot issue common or preferred stock, leaving debt financing as their sole source of external funding. In gauging credit market access, Standard & Poor's examines a number of qualitative factors, including:

- The flexibility of loan covenants to permit debt financing,
- The consistency of appetite among a cooperative's existing lender base as well as other prospective lenders or fixed-income investors for cooperative paper,

- Familiarity among fixed-income investors with the prospective borrower, and
- Reputation among fixed-income investors.

Access to short term credit is especially important for all electric cooperatives, including the majority that continues to rely on RUS for long-term financing. Standard & Poor's evaluates the adequacy of committed bank lines to meet a cooperative's short-term capital needs, particularly if its traditional lenders are not forthcoming with anticipated financing or if credit market conditions suddenly worsen for those already accessing external financing in the public or public placement debt markets. Only committed credit facilities are considered in assessing *financial flexibility* because there is no assurance that uncommitted facilities will be available in the event of financial distress.

Financial flexibility can also be provided through a cooperative's ability to:

- Adjust dividend payments to member to support the cooperative's financial position, although in many cases capital credit rotations are either relatively small in relation to debt service requirements,
- Alter the scale and timing of its capital program, and
- Secure alternate sources of external funding, such as contributions in aid of construction or developer fees.

Financial policy

Financial policy is an important aspect of financial profile evaluation for all cooperatives. Because cash flow measures are relatively weak as a result of rates being cost-based, electric cooperatives' financial policies provide insight into the most important and subjective aspect of cooperatives--namely, their willingness to adjust rates to support their financial position, or alternatively, "rate-setting responsiveness." Cooperatives that adjust rates in response to significant deviation of financial results from internal financial policies or loan covenant requirements will be viewed more favorably than those that either decline to enforce financial policies or to adopt them at all. Financial policy can be discussed in terms of internal financial policies and loan covenants.

Internal policies.

Internal financial policies are those that the cooperative establishes for itself, either through formal adoption by the board or through demonstrated practice by management. Standard & Poor's compares internal policies with loan covenants, and with actual financial performance to gauge both the degree of financial conservatism of management and management's responsiveness in adjusting rates to preserve the utility's financial condition and ability to meet its obligations. Financial targets can address earnings or cash flow coverage, debt leverage and member dividends. Although sizing of bank lines and cash reserves are not commonly set by formal targets, Standard & Poor's looks for managements to explain how they determine their liquidity requirements. We also evaluate financial hedging policies to gauge the degree of conservatism and discipline in hedging open positions and maintaining effective management controls.

Loan covenants.

In evaluating loan covenants, Standard & Poor's assesses the extent to which that they establish minimum thresholds for financial performance or condition, as well as provide flexibility afforded to cooperatives to cure covenant violations by adjusting member rates. Where permissive loan covenants offer little or no bondholder protection, ratings will not be necessarily affected as long as a cooperative's financial profile remains consistent with its rating. If financial deterioration occurs and management neither acts nor is required to implement some remedy, then rating actions may be more severe than if such bondholder protections had been in place and enforced. Conversely, loan covenants that are both stringent and inflexible can pose a credit concern. Inability to cure covenant violations weakens the efficacy of the credit strength most responsible for the sector's relatively strong ratings--the ability to set rates.

Earnings protection.
Standard & Poor's considers earnings protection measures for cooperatives primarily in the context as financial policy rather than as a meaningful indicator of financial performance. Earnings protection measures can provide a way to benchmark a cooperative's financial policy against actual performance as well as determine its ability to access additional credit from the traditional lenders to the sector. Nearly all of the traditional lenders to the sector--the RUS, CFC, and CoBank--use earnings protection measures in their mortgage agreements with cooperatives. They are also used in bond indentures of cooperatives that do not rely on RUS financing. Examples of such measures include: debt service coverage (accrual accounting based); the TIER ratio, and margins for interest ratio. Each ratio measures some form of adjusted earnings relative to financing charges, offering a perspective of financial performance from an accrual accounting standpoint.

Ratio Adjustments

We base our financial analysis primarily on cash-based metrics, although we also monitor the accrual-based ratios upon which a cooperative's financial covenants are based. Standard & Poor's makes analytical adjustments to the financial statements as well as certain financial ratios used in financial statement analysis. In some cases, these adjustments are consistent with those made for corporate and investor-owned utilities, but many more cases, they are unique to the cooperative sector.

Standard & Poor's adjusts its financial ratios for cooperatives to eliminate the effects of noncash adjustments. Such adjustments may include those involving regulatory accounting (such as deferral and amortization of power expenses), and capitalization of costs. Standard & Poor's adjusted financial ratios may exclude the effects of materially defeased lease obligations such as those commonly referred to as "burned-out lease transactions," or "BOLTs", although unadjusted ratios may also be considered to the extent these obligations are especially large or result in a significant mismatch of cash flows.

In contrast to its approach to corporate and investor-owned utility ratings, Standard & Poor's currently does not adjust its cooperative financial ratios to reflect the presence of off-balance-sheet obligations such as operating leases, defeased leases, asset-retirement obligations, projected benefit obligations (in excess of actual benefit obligations), or purchased-power obligations.

Instead, Standard & Poor's relies on fixed-charge coverage--a cash flow coverage metric commonly used in financial statement analysis for public power utilities--to capture the adequacy of cash flows relative to the servicing requirements of off-balance-sheet obligations.

Standard & Poor's does not impute off-balance-sheet debt or related interest with respect to purchased power obligations, as it does with corporate utilities, due to the extremely high degree of certainty concerning cost recovery for cooperatives that set their own rates. However, Standard & Poor's may track such obligations internally for purpose of comparing relative debt burdens among cooperatives. For cooperatives that are regulated, Standard & Poor's may impute a purchased power debt equivalent, which is determined by calculating the present value of future minimum purchased power payments, discounted at the utility's average cost of debt.

Key Financial Ratio Formulas For Electric Cooperatives

Table 3

Key Financial Ratio Formulas For Electric Cooperatives	
Debt Service Coverage	
Numerator	The sum of funds from operations (FFO), cash interest paid (net), capitalized interest, other FFO adjustments, and other interest adjustments
Denominator	The sum of cash interest expense (net), capitalized interest, other interest adjustments, principal payment obligations, and other principal adjustments
Fixed Charge Coverage	
Numerator	The sum of funds from operations (FFO), cash interest paid (net), capitalized interest, other FFO adjustments, other interest adjustments, property tax and transfer payments, operating lease payments, and minimum purchase power payments
Denominator	The sum of cash interest paid (net), capitalized interest, other interest adjustments, principal payment obligations, other principal adjustments, property tax and transfer payments, operating lease payments, and minimum purchase power payments
FFO Interest Coverage	
Numerator	The sum of funds from operations (FFO), cash interest paid (net), capitalized interest, other FFO adjustments and other interest adjustments
Denominator	The sum of accrual interest expense (net), capitalized interest, and other interest adjustments
Net Cash Flow (NCF)/Capital Expenditures	
Numerator	The sum of funds from operations (FFO) and other FFO adjustments; less member dividends
Denominator	Capital expenditure (net)
Total Debt/Total Capital	
Numerator	The sum of notes payable, current maturities, current capitalized lease obligations, long term debt, and capitalized lease obligations; plus other debt adjustments, if any
Denominator	The sum of notes payable, current maturities, current capitalized lease obligations, long term debt, capitalized lease obligations, minority interest, and members equity; plus other debt adjustments, if any
Debt/Net Plant Property and Equipment	
Numerator	The sum of notes payable, current maturities, current capitalized lease obligations, long term debt, and capitalized lease obligations; plus other debt adjustments, if any
Denominator	Net plant, property & equipment (PP&E)
Days Cash (incl. bank lines)	
Numerator	365 multiplied by the sum of unrestricted cash & marketable securities and undrawn capacity on committed bank lines
Denominator	Operating expense, less depreciation

Rated Cooperatives

Table 4

Rated G&T Cooperatives

G&T Cooperative	State	Rating as of Oct. 20, 2006
Alabama Electric Cooperative	Ala.	BBB+/Stable/--
Arkansas Electric Cooperative Corp.	Ark.	AA-/Stable/--
Associated Electric Cooperative Inc.	Mo.	AA/Stable/--
Basin Electric Power Cooperative	N.D.	A+/Stable/--

Table 4

Rated G&T Cooperatives (cont.)		
Brazos Electric Power Cooperative Inc	Texas	A-/Stable/--
Buckeye Power Inc.	Ohio	A+/Stable/--
Central Electric Power Cooperative	S.C.	AA/Stable/--
Central Iowa Power Cooperative	Iowa	A/Stable/--
Chugach Electric Assoc.	Alaska	A-/Stable/--
Dairyland Power Cooperative	Wis.	A/Stable/--
Georgia Transmission Corp.	Ga.	AA-/Stable/A-1+
Great River Energy	Minn.	BBB/Stable/--
Hoosier Energy Rural Electric Co-op Inc.	Ind.	A-/Watch Neg/--
Oglethorpe Power Corp.	Ga.	A/Stable/A-1
Old Dominion Electric Cooperative	Va.	A/Stable/--
Seminole Electric Cooperative	Fla.	A-/Stable/--
Tri-State Generation & Transmission Assoc.	Col.	A/Stable/--
Wabash Valley Power Assoc.	Ind.	BBB+/Negative/--
Western Farmers' Electric Cooperative	Okla.	BBB+/Stable/--

Table 5

Rated U.S. Cooperative Distribution Systems			
Total cooperative distribution systems*	864		
Rated by Standard & Poor's	4		
System	**State**	**Rating¶**	**Date Assigned**
Brunswick Electric Membership Corp.	N.C.	A-/Stable/--	Jan. 5, 2006
Diverse Power Inc.	Ga.	A/Stable/--	Jan. 4, 2002
Guadalupe Valley Electric Cooperative Inc.	Texas	A+/Stable/--	Sept. 25, 1998, Oct. 2006
Snapping Shoals Electric Membership Corp.	Ga.	A+/Negative/--	Aug. 21, 2001
Vermont Electric Cooperative Inc.	Vt.	BBB-/Negative/--	Jul. 21, 1997

*Source: National Rural Electric Cooperative Association. ¶Ratings as of Oct. 20, 2006.

Related Articles

The other articles in the series are " S&P's Rating Methodology For U.S. Power Cooperatives: An Overview" and " S&P's Rating Methodology For U.S. Power Cooperatives: Key Business Risks," published Nov. 2.

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November 2, 2006

S&P's Rating Methodology For U.S. Power Cooperatives: An Overview

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S&P's Rating Methodology For U.S. Power Cooperatives: An Overview

(Editor's Note: This is the first article in a three-part series that discusses the methodology we use to establish credit ratings for the U.S. electric cooperative sector. The article describes how Standard & Poor's corporate rating methodology has been adapted to date for the electric cooperative sector. It is subject to change based on decisions by Standard & Poor's Analytical Policy Board, the Industrial Ratings department, or the Utilities and Project Finance practice, which is responsible for maintaining ratings on the sector. The other articles in the series, published Nov. 2, 2006, are "S&P's Rating Methodology For U.S. Power Cooperatives: Key Business Risks" and "S&P's Rating Methodology For U.S. Power Cooperatives: Key Financial Indicators.")

Electric cooperatives are private, nonprofit electric utilities that are owned by its distribution members. The cooperative model was largely born out of the need to electrify rural America in the 1930s after it became apparent that investor-owned utilities could not profitably serve sparsely populated and typically agricultural areas of the U.S.

There are about 66 electric generation and transmission (G&T) cooperatives in the U.S. and 864 distribution cooperatives, according to the National Rural Electric Cooperative Association. Collectively, cooperatives serve about 13% of U.S. electric customers, provide about 11% of total electricity sales, and own about 4% of operational power plant capacity in the U.S. Standard & Poor's maintains ratings on 21 U.S. electric cooperatives, representing about $16 billion in total debt. Despite being the smallest of the three utility ownership classes in terms of aggregate customer base or capitalization, U.S. rural electric cooperatives exhibit some of the highest customer growth rates and account for a sizable proportion of base load generation projects planned or in construction.

Unlike investor-owned utilities, cooperatives' operations are not vertically integrated. The G&T function is separated from the distribution function, which is carried out by a two separate, but interrelated, companies. G&T cooperatives supply wholesale power from owned and contracted resources to their members, who are typically distribution cooperatives at cost-based rates under long-term power supply agreements.

In turn, distribution cooperatives' membership consists of their respective G&T cooperatives, taking title to the wholesale power produced by the G&T and delivering it to the retail consumers in the area that the distribution company is licensed to serve. Distribution cooperatives own and operate their own distribution systems and their membership consists of individual ratepayers, i.e., residential, commercial, and industrial customers.

Membership in G&T cooperatives is universally governed by long-term power supply contracts with the distribution cooperative members. Distribution cooperatives do not typically guarantee their contractual obligations to their respective G&T cooperatives nor do they typically guarantee G&T cooperatives' debt obligations.

As not-for-profit membership organizations, cooperatives resemble public power utilities in that their rates are cost-based and typically set to only cover operating and financing costs, to fund a portion of capital costs, and to provide a small measure of financial cushion to meet lender/creditor requirements or the expectations associated with a targeted level of credit quality. Although cooperatives may pay dividends to their members, they do not seek to maximize profits.

Despite being the smallest of the three utility ownership classes (see table 1) in terms of aggregate customer base or capitalization, U.S. rural electric cooperatives exhibit some of the highest customer growth rates and account for a sizable proportion of base load generation projects that are in the planning stage or under construction.

Table 1

Percentage Of U.S. Electricity Sales By Type Of Utility

(%)	1994	2004	Absolute change	10-year compound annual growth rate
Investor-owned	75.8	69.5	(6.3)	(0.4)
Publicly owned	14.4	17.4	3	2.4
Cooperatives	7.8	11.1	3.4	4.2
Federal power agencies	2.1	2	(0.1)	0
Total	100	100		

What Is A Credit Rating?

A credit rating is a letter grade (see table 2) that reflects Standard & Poor's opinion of the ability and willingness of an entity to meet its debt and other obligations on time and in full. Credit ratings within the cooperative sector are typically issuer credit ratings, but publicly issued debt may be assigned a separate rating.

Table 2

Standard & Poor's Rating Scale

Investment grade	
AAA	Extremely strong
AA	Very strong
A	Strong
BBB	Adequate
Speculative grade	
BB	Vulnerable to nonpayment
B	More vulnerable, but retains capacity to meet obligations
CCC	Vulnerable
CC	Highly vulnerable
D	Default

The Number Of Rated Cooperatives Is Increasing

Standard & Poor's has assigned ratings to the power cooperative sector since the 1990s. We have rated 28 cooperatives and maintain active ratings on about 19 cooperatives, of which five are distribution cooperatives. (Not all credit ratings Standard & Poor's has assigned are public.) Although the number of cooperatives we rate is still relatively small, their presence in both the electricity and fixed-income investment markets is increasing. As a result, the number of cooperatives rated by Standard & Poor's has been relatively modest but has grown in recent years.

There are a number of reasons for this. Most cooperatives do not issue public debt, relying instead on a federal loan program operated by the U.S. Department of Agriculture's Rural Utilities Service (RUS). Lines of credit and other debt financing, including construction loans, are usually provided by the National Rural Utilities Cooperative Finance Corp. (CFC), a member-owned financial institution and by CoBank, a bank that is part of the farm credit system. As a result, credit ratings have not always been critical to access debt financing.

A second reason is that G&Ts tend to own and operate the G&T assets sufficient to deliver all the energy needs of its rural distribution members, and as a result of this independence, little interaction with third parties has been required. Supplemental power or related services were often met through power purchase agreements with neighboring utilities, with long-standing relationships and knowledge of the local cooperative's business practices often replacing the need for a rating.

Circumstances changed in the late 1990s, when in many parts of the U.S. wholesale and retail competition began and regional transmission organizations (RTO) developed. These efforts have generally resulted in cooperatives being pulled into the broader energy market. For cooperatives that are RTO members, credit ratings may substitute for lower collateral requirements. The advent of independent power suppliers has given cooperatives more incentives to competitively solicit any supplemental power or related needs, and counterparties awarded contracts may request a rating, rather than relying solely on financial statements.

A small number of G&T cooperatives no longer rely on the RUS for long-term financing and instead issue secured and unsecured debt through the private placement market. About a dozen or so have flexible indentures that allow them to issue secured debt under a trust indenture, and thus can issue debt outside of RUS. And, some cooperatives have been able to issue tax-exempt debt through industrial development bond cap allocation of their respective states. Outside of such offerings, cooperatives cannot usually access the tax-exempt debt markets and must instead issue taxable bonds when accessing the capital markets

Finally, while in general the all-requirements model continues to dominate in the cooperative sector, some distribution cooperatives are seeking to diversify their power supplies by sourcing their load growth elsewhere, which can necessitate a rating for the distribution company.

Credit Ratings Of U.S. Cooperatives Are All Investment Grade

Standard & Poor's public G&T ratings range from 'AA' to 'BBB' (see table 3). We have assigned five distribution cooperative ratings (see table 4); all are in the 'A' category.

Table 3

Rated G&T Cooperatives

G&T Cooperative	State	Rating as of Oct. 20, 2006
Alabama Electric Cooperative	Ala.	BBB+/Stable/--
Arkansas Electric Cooperative Corp.	Ark.	AA-/Stable/--
Associated Electric Cooperative Inc.	Mo.	AA/Stable/--
Basin Electric Power Cooperative	N.D.	A+/Stable/--
Brazos Electric Power Cooperative Inc	Texas	A-/Stable/--
Buckeye Power Inc.	Ohio	A+/Stable/--
Central Electric Power Cooperative	S.C.	AA/Stable/--
Central Iowa Power Cooperative	Iowa	A/Stable/--
Chugach Electric Assoc.	Alaska	A-/Stable/--
Dairyland Power Cooperative	Wis.	A/Stable/--
Georgia Transmission Corp.	Ga.	AA-/Stable/A-1+
Great River Energy	Minn.	BBB/Stable/--
Hoosier Energy Rural Electric Co-op Inc.	Ind.	A-/Watch Neg/--

Table 3

Rated G&T Cooperatives (cont.)		
Oglethorpe Power Corp.	Ga.	A/Stable/A-1
Old Dominion Electric Cooperative	Va.	A/Stable/--
Seminole Electric Cooperative	Fla.	A-/Stable/--
Tri-State Generation & Transmission Assoc.	Col.	A/Stable/--
Wabash Valley Power Assoc.	Ind.	BBB+/Negative/--
Western Farmers' Electric Cooperative	Okla.	BBB+/Stable/--

Table 4

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Vermont Electric Cooperative Inc.	Vt.	BBB-/Negative/--	Jul. 21, 1997

*Source: National Rural Electric Cooperative Association. ¶Ratings as of Oct. 20, 2006.

Cooperatives often exhibit relatively weak financial profiles, reflecting slim cash coverage rations and a typically heavily levered balance sheet.(1) However, several factors provide strong credit support that allows cooperatives to achieve relatively strong investment-grade ratings despite much weaker financial profiles relative to their investor-owned utility peers. The most important factors are:

- The all-requirements contracts between a G&T and its members, which provides the G&T with a captive customer base of long-term wholesale customers who are obligated to pay its costs, including debt service. (Similarly, from a distribution cooperative's perspective, the G&T is a reliable, competitive, and long-term not-for-profit provider.);
- The generally unfettered ability of G&Ts and most distribution members to set rates that are not subject to review by either a state regulatory commission or the FERC;
- The tendency of G&Ts to build, own, and operate their own generation, which often results in self-sufficiency of power requirements, less exposure to counterparty credit risk, and the need to make substantial purchases, which expose the cooperative to sometimes volatile power prices;
- Cost advantages, such as access to government lending, which, along with other factors, typically results in competitive generation rates that assist in perpetuating sustainable business relationships between G&T cooperatives and their members;
- The tendency for most G&Ts to focus on their core operations, that of generating and transmitting power, rather than pursue multiple unrelated businesses that often carry additional business risks.

What Is The Ratings Process?

The rating process for first-time issuers is discussed in detail in the Standard & Poor's "Corporate Ratings Criteria 2006" published March 9, 2006 on RatingsDirect, under the first section, Standard & Poor's Role in the Financial

Markets.

Standard & Poor's Rating Methodology For Cooperatives

While extensive qualitative and quantitative analysis takes place to determine both the initial rating and to refresh this rating with regular surveillance, it is important to note that Standard & Poor's ratings are not based on a formula approach. As we have noted repeatedly in our published commentaries about our ratings process, the ratings process is as much an art as science.

We use the same methodology to rate all electric utilities, including cooperatives. While credit ratings are most frequently associated with financial analysis and the attendant ratios that we calculate to assess a company's financial performance, it is critical to realize that our ratings analysis starts with assessing a company's business and competitive profile. (This analysis is captured when we assign a business profile score to each rated company, including cooperatives.)

Once a cooperative's business profile is determined, we use financial analysis to determine a cooperative's financial risk profile. The combination of business and financial risk analysis forms the basis of the credit rating assigned to a cooperative.

Details on the establishment of a business profile and the financial ratios Standard & Poor's uses to rate cooperatives are discussed in "S&P's Rating Methodology For U.S. Power Cooperatives: Key Business Risks" and "S&P's Rating Methodology For U.S. Power Cooperatives: Key Financial Indicators," published Nov. 2, 2006 on RatingsDirect.

Related Articles

The other articles in the series, published Nov. 2, 2006, are " S&P's Rating Methodology For U.S. Power Cooperatives: Key Business Risks" and " S&P's Rating Methodology For U.S. Power Cooperatives: Key Financial Indicators".

Notes

(1) Cooperatives' capital structures generally vary by type. However, the balance sheets of G&T cooperatives are often heavily levered, reflecting the permissive debt leverage covenants of the sector's traditional lenders. Distribution cooperatives' capital structures often are much stronger than those of G&T cooperatives, although this is mainly due to the fact that most of their debt is off-balance-sheet, residing at their respective G&T cooperative.

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November 26, 2007

U.S. Public Finance Report Card:

Low Risk Profiles Support Sound Electric Cooperative Credit Quality

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U.S. Public Finance Report Card:

Low Risk Profiles Support Sound Electric Cooperative Credit Quality

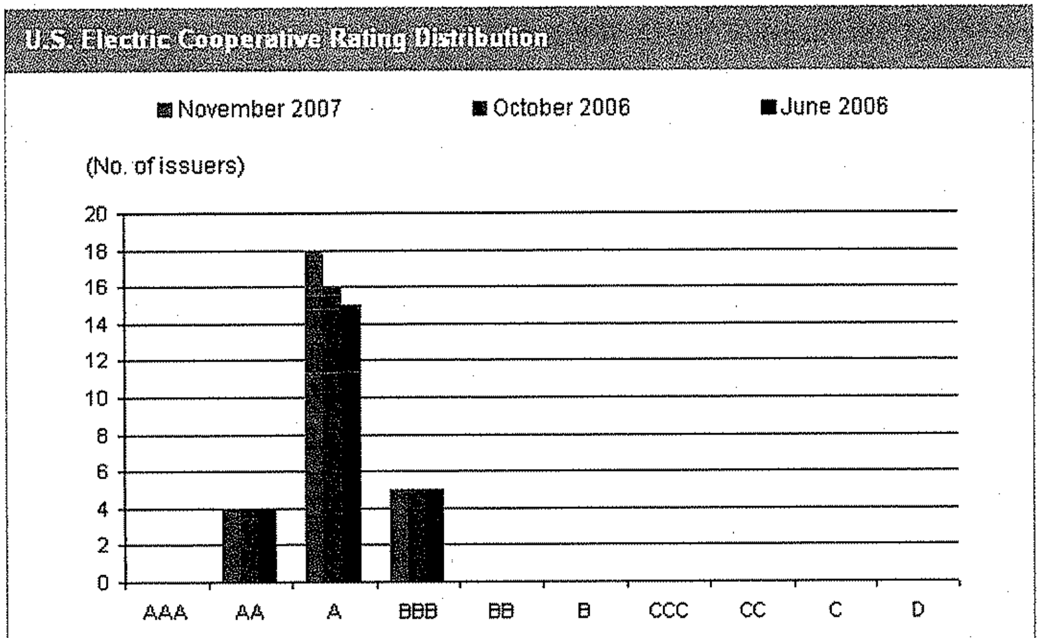
Cooperative utilities' rating stability is expected to continue because they are able to maintain a strong alignment of revenues and expenses. This latitude translated into limited rating and outlook revisions in 2007. Despite narrow cash coverage margins, high leverage and shallow service area demographics, cooperatives achieve sound credit quality because of these and other attributes:

- Autonomous rate-setting authority provides ratemaking flexibility that can shield the financial performance of cooperative utilities from the delays in rate proceedings and political vagaries that rate-regulated utilities sometimes encounter;
- Long-term energy requirements contracts between generation and transmission (G&T) cooperatives and their member distribution cooperatives contribute to stable and predictable revenue streams by generally mirroring or exceeding the life of debt obligations;
- Cooperative utilities exhibit high revenue stream integrity because they are mainly monopolists and significant regulatory and operational barriers stand in the path of potential competitors;
- Principally residential customer bases dominate cooperative utilities' revenue streams and tend to provide more stability than industrial loads;
- An absence of incentives to place capital at risk through investments in non-electric, competitive businesses; and
- Benefits derived from low-cost, amortizing loans available from the federal government and cooperative lending institutions.

Analyzing The Ratings

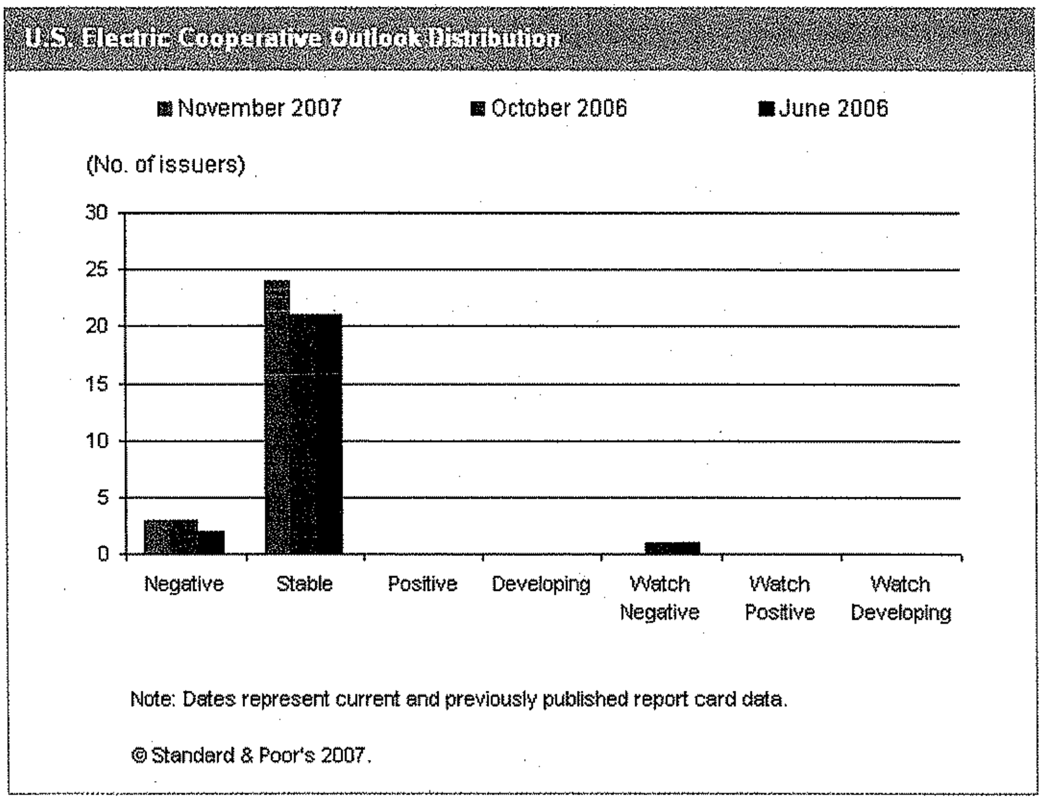
Ratings assigned to cooperative utilities are universally within the investment grade spectrum and predominantly have stable outlooks. (See Charts 1 and 2) About 75% of the G&T cooperatives are rated 'A-' or higher. Most are in the 'A' rating category, with limited ratings in the 'AA' and 'BBB' rating categories. The lowest G&T cooperative ratings are a sound 'BBB+'. Distribution cooperatives' ratings are also mainly in the 'A' category. This tight dispersal of ratings reflects operational and financial profiles and business strategies that have insulated these utilities from some of the extreme cost and market volatility that plagued investor-owned and competitive energy companies in past years.

Chart 1



Note: Dates represent current and previously published report card data.

Chart 2



Only a single cooperative had a rating change in 2007. Great River Energy (BBB+/Stable) was raised one notch in June based on management's commitment to more credit supportive financial policies and the utility's reduced exposure to competitive businesses following a discontinuation of energy trading activities. The ratings' outlooks of three cooperatives, Wabash Valley (BBB+/Stable), Associated Electric (AA/Stable) and Vermont Electric (BBB-/Stable) were revised to stable from negative in March June, and November respectively, based on rate increases adopted to counter weakening financial margins. Hoosier Energy's (A-/Stable) rating was removed from CreditWatch with negative implications and assigned a stable outlook in July based on rate increases. Two cooperatives, Seminole Electric (A-/Negative) and Arkansas Electric (AA-/Negative), were assigned negative outlooks in April and May, respectively, to reflect financial pressures associated with debt added or to be added to finance capital projects. To date, no cooperative utility's rating was lowered in 2007.

While rating stability remains the norm, the prospects for raised ratings are becoming increasingly remote. The financial challenges presented by large capital needs and the specter of tighter emissions regulation and attendant higher operating costs represent impediments to improving credit quality and are reflected in the absence of positive ratings outlooks for the cooperative utilities.

Cooperative, as well as other utilities, need substantial amounts of baseload capacity following a long hiatus since the last round of numerous baseload capacity additions. The U.S. fleet of generation is aging and the North American Electric Reliability Corporation recently reported that electricity demand is forecast to grow considerably faster than capacity additions.

Cooperative utilities are projecting multi-billion dollar capital needs over the next five years, which will place considerable upward pressures on retail rates if financial margins are to be preserved. Credit ratings of cooperatives that exhibit narrow margins can be impaired by modest erosion of financial protections as debt is added and operating costs increase. Some of the cooperatives with large capital needs include Associated Electric, which is projecting more than $2 billion of capital projects within five years; Basin Electric is forecasting capital spending exceeding $3 billion over five years; and Brazos Electric has identified nearly $2 billion of capital needs during this time. Some utilities will double and even triple debt balances as they finance and pursue capital needs.

There are additional factors that are placing downward pressure on financial margins. Increasing operating costs are expected as regulation of carbon gases and other emissions progresses. The exposure to emissions-related costs can be particularly pronounced for cooperative utilities because many are highly dependent on coal. For example, Basin Electric relies on coal for more than 90% of electric production. However, its members supplement Basin's coal production with Western Area Power Administration hydroelectric allocations, which reduces their dependence on coal. Associated Electric sources 72% of its electricity from coal-fired resources and two-thirds of Tri-State Generation and Transmission's electricity is generated with coal. These numbers stand in contrast with a national average of 49% of all electricity produced from coal.

Pressures on financial margins can also be found among utilities that are highly dependent on natural gas, a fuel with a lower carbon footprint than coal. We anticipate increased dependence on natural gas, particularly as coal-fired generation becomes more repugnant in the eyes of regulators that must approve power plant development. Increased demand can drive up natural gas prices.

Although some of the cost issues presented by these challenges are substantial, cooperative utilities are nevertheless well equipped to respond and preserve credit quality. The most important tool available to cooperative utilities is the autonomous ratemaking authority most cooperatives possess. Many cooperatives can implement a timely response to rising costs to preserve financial margins. However, this financial tool can only effectively preserve credit quality if customers have the financial capacity to absorb rate increases and management is willing to ask customers to shoulder these burdens.

Associated Electric provides a salient example of the strength of autonomous ratemaking to shore up credit quality. As noted, Associated is pursuing a sizable capital program. Growing native load necessitates capacity additions that are adding debt and eroding the utility's capacity surplus that has been used to yield power-marketing revenues.

To counter erosion of financial margins, Associated Electric's board adopted a substantial rate increase exceeding 25% to take effect in early 2008. This rate adjustment should translate into strong debt service coverage. The commitment to credit quality inherent in this board action was the catalyst for reinstating the utility's stable rating outlook. It is this ability to maintain a strong alignment of revenues and expenses that we expect to continue to serve a key driver of strong ratings among cooperative utilities.

Click on this link to see other articles in "Special Report: From Carbon To Green: What Does It Mean For Credits?"

Click on this link to go to the Special Report Archive.

Table 1

U.S. Electric Power Cooperatives

Company	Issuer Credit Rating* / Senior Secured Debt Rating*	Analyst	Comments
Alabama Electric Cooperative Inc.	BBB+ / Stable	Judith Waite	Alabama Electric Cooperative (AEC) supplies power to members under all-requirements contracts expiring in 2035. Discussions are underway to extend the contracts to 2050 to allow AEC to plan for future load growth. Management expects about a 1,500 MW generation deficit over the next 20 years. Future capacity will include peaking units, a base load plant and transmission. By mid-2008, a $300 million investment will bring the Lowman plant, which supplies about 36% of the members' current electricity needs, in compliance with current environmental regulations. Although debt service coverage continues to be thin, AEC's financial profile is stable. A rate increase in 2006 as well as a fuel clause that allows direct pass-through of fluctuating fuel costs facilitates cost recovery.
Arkansas Electric Cooperative Corp.	AA- / Negative	Judith Waite	Debt service coverage remains weak following the acquisition of the 150 MW Wrightsville generating plant, which will replace an expired purchased power contract in 2009. The plant was purchased out of bankruptcy at an extremely low cost. A $12.6 million rate increase in 2005 has helped maintain debt service coverage at just under 1.2x, and coverage is expected to be back around 2x in 2009 when the plant replaces the purchased power contract. The negative outlook, however, indicates that if the coverage level does not improve, the rating will be lowered.
Associated Electric Cooperative Inc., MO	AA / Stable	David Bodek	Associated Electric Cooperative Inc.'s board's recent adoption of a 25.3% rate increase, to take effect in the second quarter of 2008, on top of rate increases of 8% in 2006 and 4.6% in 2007, should preserve credit quality by tempering the financial impact of sizable capital needs exceeding $2 billion over 2007-2012. The capital program will largely be driven by the addition of new coal generation capacity and the installation of environmental controls at existing generation units. As a heavily coal-dependent utility, Associated is exposed to potentially higher costs as the regulation of carbon and other emissions progresses.
Basin Electric Power Cooperative, ND	A+/Stable	David Bodek	This cooperative exhibits sound financial metrics, but must stay on top of the financial pressures created by very strong growth that requires substantial generating capacity additions. Debt balances are expected to triple over about six years, placing upward pressure on revenue requirements. If growth prospects do not materialize, the utility can be left with surplus capacity that is exposed to competitive wholesale markets. Such risks are tempered by a plan to stagger generating capacity additions. Basin's Dakota Gasification Company subsidiary produces synthetic natural gas and benefits from prevailing, high natural gas prices. Dakota Gasification's financial successes help provide Basin's electric customers with favorable rates, but could also put pressure on rates were its financial performance to falter in a low natural gas price environment. As a heavily coal-dependent utility, Basin is exposed to potentially higher costs as the regulation of carbon and other emissions progresses.
Brazos Electric Power Cooperative Inc., TX	A-/Stable	Theodore Chapman	Texas' largest G&T cooperative is entering the early phases of adding significant generation capacity, in the form of a 225 MW undivided ownership interest and 150 MW purchase power agreement in the Sandy Creek coal plant near Brazos' Waco headquarters, as well as plans for additional intermediate and peaking capacity, all by 2012. Debt financing of the bulk of a $1.9 billion five-year capital program will add to outstanding debt of about $1.0 billion. Even with the addition of Sandy Creek's coal-fired capacity, Brazos remains highly dependent on owned and contracted gas-fired energy which accounts for a majority of today's energy sales. Brazos' solid financial profile, strong risk management strategies and monthly pass-through mechanism have assisted it in managing this exposure.
Brunswick Electric Membership Corp., NC	A-/Stable	Judith Waite	BEMC's primary challenge continues to be to manage strong growth in its service territory. BEMC serves the southeastern most counties of North Carolina, and has experienced 3%-4% annual customer growth over the past 10 years. BEMC has made significant investments in the distribution system and is currently in an $89 million upgrade and expansion program that will be completed in 2008. About 60% of the spending will be for new customer connections, but almost 30% will be for distribution and transmission system improvements. To maintain debt service coverage above 2x, BEMC's board voted in December 2006 to raise the base facilities charge to $17 per month from $15.50 per month, which shifted more of BEMC's cost recovery into a fixed-rate structure. While BEMC's margins remain exposed to weather and occupancy of new homes, the increase provides about $1.7 million in stable, incremental margin that supports credit quality.

Table 1

U.S. Electric Power Cooperatives(cont.)			
Buckeye Power Inc., OH	A+/Stable	Jeffrey Panger	Buckeye's power supply is dominated by coal fired generation from its ownership of two Cardinal Station units. Asset concentration concerns are mitigated by AEP's agreement to backstop these units as well as the recent purchase of entitlements to output of multiple facilities owned by Ohio Valley Electric Cooperative (OVEC). Since 2001, debt has more than doubled to $692 million, largely driven by emissions controls additions. Further emissions related projects will bring debt up to $1.1 billion by 2011. The financial profile has been preserved through rate adjustments, a movement to lower cost high-sulfur coal that can now be burned because of the addition of scrubbers, and margins earned from off-system sales. These trends should continue.
Central Electric Power Cooperative Inc.	AA/Stable	David Bodek	This cooperative is highly rated to reflect the low business risk of coordinating the power supply and transmission needs of its member distribution cooperatives. This business risk profile offsets narrow financial margins. Power is procured from South Carolina Public Service Authority doing business as Santee Cooper. Central works with Santee Cooper in planning long-term generation resource development. Saluda River Electric Cooperative will be added to Central's load by 2009. The addition should increase load by about 25%.
Central Iowa Power Cooperative	A / Stable	Peter Murphy	Central Iowa Power Cooperative (CIPCO) benefits from a diverse generation portfolio that includes coal and nuclear baseload resources, natural gas peaking capacity and renewable energy resources. CIPCO added a 9% share in the new 790 MW coal-fired Walter Scott Unit #4 (f.k.a. Council Bluffs) as scheduled in advance of 2007's summer peak season. The new unit benefits members through reduced reliance on power purchases, a reduced power cost adjustment and better than anticipated financial performance. Additional capacity needs and the cost of financing capacity additions must be managed to preserve financial margins. The utility is targeting a 100 mW interest in baseload coal by 2013, with an expected high cost of $3,000 per KW.
Chugach Electric Association, AK	A- /Stable	Peter Murphy	Chugach serves abut 64,000 retail members, and with other contract wholesale sales, is the dominant electricity provider and generator in the state of Alaska. Chugach's financial performance remains solid. Chugach expects to end the year with a margin for interest ratio slightly below expectations at 1.28, and a debt leverage ratio of about 70%. Contributing to the budget variance are increased maintenance costs and reduced surplus sales due to transmission problems that have been corrected. Chugach is faced with several unique challenges, including the authority of the Regulatory Commission of Alaska (RCA), over both retail and wholesale contract rates. However, the RCA permits Chugach to pass fuel cost increases to customers through a rate surcharge, insulating Chugach from some commodity price risk. Chugach expects to refinance two large non-amortizing principal payments maturing in 2011 and 2012 with 15 to 30 year debt. Additionally, Chugach's capital plan includes pay-as-you-go funding of transmission and distribution projects, and a possible debt-financed acquisition of natural gas-fired generation capacity, needed by 2012. Chugach has entered phase one of a public process examining various scenarios of combination or merger with Anchorage Municipal Light and Power (MLP), which serves an adjacent territory centered in the city of Anchorage. The impact on Chugach's credit qualityof any chosen course of action will be assessed when specific facts emerge.
Dairyland Power Cooperative, WI	A/Stable	Jeffrey Panger	All but one of the 25 members of Dairyland Power Cooperative (DPC) have excecuted contract extensions, but they are not uniform and expire between 2035 and 2055, which creates a measure of uncertainty as the capital program proceeds. DPC remains exposed to cost pressures related to the transportation of coal, as demonstrated by a 93% rail rate increase in 2006. The environmental retrofit of DPC's baseload coal plants, transmission projects and its 30% participation in Wisconsin Public Service's Weston 4 project are expected to add more than $585 million of debt by 2012, above today's $724 million of debt and result in increased fixed costs, placing upward pressure on member rates. Management is expected to adjust rates to preserve financial margins as debt is added. The Weston project is being built under an EPC contract, is on budget, and is expected to commence operations in June 2008. DPC continues to study adding gas-fired combustion turbines to come on line in 2011, and wind and biomass capacity that would boost its renewable portfolio to 20% by 2025 in conformity with Wisconsin's mandates.

Table 1

U.S. Electric Power Cooperatives(cont.)			
Diverse Power Inc., GA	A/Stable	Judith Waite	Diverse Power is increasingly reliant on a portfolio of contracts and power-trading activities to supplement its interest in Oglethorpe Power's generation. Contracts and market activity expose Diverse to speculative-grade power suppliers, including the risk of counterparty defaults. Market activities are conducted through the Cobb scheduling group within Oglethorpe's membership. The Cobb group employs appropriate risk-management policies to temper market exposures. Oglethorpe's members have an option to own up to 30% of two proposed nuclear units at Plant Vogtle, and a decision regarding participation in new nuclear capacity will be made within the next eight months. Residential customers account for about 80% of total energy use, are increasing electricity demand by about 4% per year, so additional supply will be needed even before the nuclear option is available.
Georgia Transmission Corp. (GTC)	AA-/Stable/A-1+	Judith Waite	GTC is facing a five-year, $949 million capital expenditure program. These large investment plans create an exposure to cost overruns due to rapid escalation in the cost of labor and materials. While we continue to view GTC as a strong company with a low risk profile because of the exclusively "wires" business, there is some risk that GTC's financial profile may weaken further, with debt service coverage slipping to less than 1.1x until rates are raised to recover the cost of expansion.
Great River Energy, MN	BBB+ / Stable	David Bodek	The ratings on this fast growing, coal-dependent cooperative were upgraded to reflect declining leverage and the recently adopted non-binding commitments to target 1.20x debt service coverage (DSC) and budget to meet net margins targets exclusive of margins derived from competitive, non-electric businesses. The principal non-electric investment is a 49% interest in the Blue Flint Ethanol plant that commenced operations in February 2007. The raised rating also reflects GRE's November 2006 exit from its energy trading and marketing business. The upward potential of the revised ratings is limited because of both sizable generation investment needs necessitated by load growth and an affinity for investments in competitive, non-electric businesses.
Guadalupe Valley Electric Power Cooperative Inc., TX	A+/Stable	Theodore Chapman	This distribution cooperative provides retail electricity services to about 61,000 customers in a 12-county area in south central Texas. An absence of on balance sheet generation translates into sound equity and debt service coverage. The LCRA contract is a take and pay requirements contract, expiring in 2016. Between 90% and 100% of power is sourced from the Lower Colorado River Authority (A/Stable/A-1+) and the balance is procured under short-term contracts. Distribution needs as the system grows are driving the capital program which will be one-third debt-financed. The utility's 56% load factor is reflective of industrial concentrations among customers, including steel mills. Residential customer growth contributes to capital needs, but should help balance the customer profile.
Hoosier Energy Rural Electric Cooperative Inc.	A-/Stable	Jeffrey Panger	In July 2007, HEREC's issuer credit rating was removed from CreditWatch with negative implications, affirmed at 'A-' and assigned a stable outlook. The rating activity resulted from Hoosier's recent action to increase member rates (10%) to cover higher operating costs as well as accelerate the recovery of the member revenue under-collections from prior years. Strong cash flow measures and improved plant operations were also considerations. Hoosier is exposed to asset concentration due to its dependence on its Merom coal station, which supplies about 63% of its power, and Ratts plant (17%). These units experienced substantial forced outages in recent years, but, as indicated by the stable outlook, we anticipate that the utility has identified and resolved operational issues.
Oglethorpe Power Corp., GA	A/Stable/A-1	Judith Waite	We continue to monitor the cost implications of increasing wholesale rates for Oglethorpe's members, as well as any changes in the risk profile of the co-op's membership that result from their power supply arrangements for a portion of load above Oglethorpe entitlements. Members continue to be responsible for fixed payments of all existing power generation facilities owned by Oglethorpe, and all members have extended their wholesale supply contracts with Oglethorpe to 2050, allowing Oglethorpe to issue debt to finance new assets with debt that matches the assets' expected lives. Targeted debt service coverage is in the range of 1.1x to 1.2x.
Old Dominion Electric Cooperative, VA	A/Stable	David Bodek	This G&T is subject to FERC rate regulation and its members are subject to state rate regulation. Regulatory uncertainties and credit concerns are mitigated by the presence of pass-through mechanisms. A high proportion of residential customers benefits the utility. Risks associated with the potential departure of the cooperative's largest member, Northern Virginia Electric Cooperative, are tempered by the ability to lay off a portion of substantial power purchases that supplement owned resources.

Table 1

U.S. Electric Power Cooperatives(cont.)			
San Miguel Electric Cooperative, TX	A-/Stable	Theodore Chapman	This single-asset cooperative owns and operates the 411 MW lignite-fired San Miguel plant for the benefit of its two G&T off takers, South Texas Electric Cooperative and Brazos Electric Cooperative. This plant is an important resource for these utilities, but is only one of several in their portfolios. STEC and Brazos share output and costs in equal shares under long-term contracts expiring in June 2020. Even with an average heat rate of nearly 12,000 BTU/kWh, all-in costs were a reasonable $34.35/MWh. The plant exhibits sound operations. About $14 million of additional pollution control improvements are anticipated by 2010, on top of the $6.6 million recently invested to help comply with CAIR and CAMR. These amounts are reasonable versus approximately $170 million of outstanding long-term debt.
Seminole Electric Cooperative, FL	A-/Negative	Jeffrey Panger	The outlook on Seminole's 'A-' rating was revised to negative in April 2007, based on expectations of weakening cash flow and increased debt levels associated with a need for substantial financing for new generation. Although additional coal capacity was contemplated, recent regulatory actions in Florida will likely preclude coal additions. Pending appeals of the Florida Department of Environmental Protection decision, Seminole is making interim arrangements for purchases of capacity and energy for 2012 and 2013, and is evaluating the potential for a 1,500 MW CCGT in Northern Florida. Further clouding Seminole's operating profile is the April 2007 catastrophic failure of the steam turbine and generator unit at the 810 MW Midulla Generating Station. Seminole's total load is about 4,100 MW. The steam unit is not expected back in service until May 2008. All but one of 10 members extended their requirements contracts through 2045. The tenth member plans to leave Seminole by 2014. Credit concerns typically associated with the loss of a large customer are tempered by substantial load growth that will absorb the departing member's capacity entitlement.
Snapping Shoals Electric Membership Corp., GA	A+/Negative/--	Judith Waite	Snapping Shoal's ability to successfully procure about 30% of its energy requirements through an affiliation with seven other Oglethorpe members continues to be a credit focus, as is the weakening of Snapping Shoal's financial profile. In 2005, several low-cost power supply contracts expired. The contracts were held by Oglethorpe Power, which supplies about 70% of Snapping Shoals' electricity requirements. At the same time, the distribution cooperative was hit with sharply higher fuel and purchased power costs. As a result, debt service coverage slipped to around 1.2x, which is weak for the current rating.
South Texas Electric Cooperative, TX	A-/Stable	Theodore Chapman	This small but growing cooperative with a peak of about 460 MW serves in southeastern Texas. Resources include an interest in San Miguel Electric Cooperative's lignite plant as well as gas-fired resources. Additional baseload resources will be required by 2012, which will necessitate additional debt. Capital expenditures are expected to total $508 million over the next five years, including the conversion by 2009 of one of its gas-fired plants to a combined cycle facility. The short tenor of some new members' contracts also presents a challenge as the utility seeks to add debt without corresponding long-term commitments from its off-takers. Current contract maturities corresponds with outstanding debt.
Square Butte Electric Cooperative	A-/Stable	Peter Murphy	Square Butte owns a single lignite-fired mine-mouth generating station. About one-third of output is sold under a long-term contract to a generation and transmission cooperative, Minnkota Power, for resale to its 11 members in Minnesota and North Dakota. The balance is sold to Minnesota Power and Light under a long-term contract. The contracts provide revenue predictability. Costs of meeting emissions controls should be moderate and only require modest rate adjustments in support of sound, but thin debt service coverage.
Tri-State Generation & Transmission Association, CO	A/Stable	David Bodek	Although Tri-State's financial metrics have eroded because of increased market power purchases needed to meet growing energy demand and replace reduced hydroelectric availability, the outlook remains stable to reflect a commitment to credit quality implicit in the series of recent rate adjustments and the plan to strengthen debt service coverage incrementally in coming years. Future credit quality will hinge on Tri-State's adhering to the debt service coverage milestones established by its board. Deviations will negatively influence the ratings. The effort to achieve financial targets may be more difficult because Kansas' recent denial of permits for planned coal capacity could force migration to costlier natural gas. Whether electricity is dervied from self-built generation or market purchases, exposure to natural gas price volatility heightens credit risk because Tri-State lacks an automatic rate adjustment mechanism for capturing changes in fuel and purchased power costs.

Table 1

U.S. Electric Power Cooperatives(cont.)			
Vermont Electric Cooperative Inc.	BBB-/Stable/--	Judith Waite	The primary credit concern associated with Vermont Electric Power's (VEC) rating is the authority of the Vermont Public Service Board (VPSB) to set rates for the cooperative's customers, and those rates do not include a fuel adjustment clause. Moreover, VEC is under a rate freeze through 2009. However, the VPSB approved a 7.15% rate increase in Jan. 2007, which was in addition to the 14.35% increase approved in December 2005. In response to the improved financial metrics, the rating outlook was revised to stable. We'll look to the next rate case filing in October 2008 for an indication of continued regulatory support. Electric utilities in Vermont are now allowed to pursue alternative regulation plans which may include a fuel cost adjustment. If implemented, this would help mitigate VEC's exposure to volatile prices associated with spot market purchases and any index-priced long-term, base load contracts.
Wabash Valley Power Association, IN	BBB+ / Stable	Peter Murphy	Wabash Valley has deferred recognition of expenses in the past three years, however, the level of deferrals is declining and deferrals have consistently been amortized in the ensuing fiscal year. In 2005 and 2006, deferrals totalled $58 million and $29 million, respectively. The current year's deferral is a modest $5 million Performance issues at Wabash's integrated coal gasification plant near Terre Haute, Ind., caused negative budget variances and power cost deferrals. Satisfactory performance of the 280 MW plant is critical to Wabash's financial standing. A recently adopted 5.5% rate increase to take effect in 2008 should help the utility avoid future deferrals. Typically, deferred balances are fully amortized in the following fiscal year. Wabash is adding one member, Citizens Electric to its existing 28 members, however, three members have given Wabash the required 10-year notice to terminate their contracts. The potential net loss is about 10% of Wabash's current load, after accounting for the newest member's addition to load. Members who have provided notice of termination may rescind such notice if a favorable power supply situation is not obtained. The loss of three members does not threaten credit quality at this time, due to the partial off-set provided by Citizens, and the long 10-year time frame before sales reductions occur.
Western Farmers Electric Cooperative, OK	BBB+ / Stable	David Bodek	This fast-growing utility's service territory and its financial performance are exposed to weather and economic volatility. In recent years, however, the utility has produced sound debt service coverage. Moreover, cash reserves provide a cushion against these exposures as well as generation asset concentration. Capital needs present operational and financial challenges. Substantial transmission and distribution investment needs as well as needs for new generation capacity will place upward pressure on rates as debt triples over five years. Two distribution members out of 20, representing about 15% of energy sales, are resisting extending their wholesale supply contracts, which could have implications for future financings. Also, there is uncertainty as to how generation resource needs will be addressed following the loss of an anticipated partner in a proposed coal-fired facility.

*Ratings are as of Nov. 26, 2007

Table 2

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Item 61) To the extent differences exist between the TIER calculations contained in the testimony, and the TIER calculations likely to be utilized by potential creditors or credit rating agencies (e.g., use of "adjustments" to earnings), identify those differences.

Response) The TIER calculations cited in my testimony are substantially the same as those calculated by the rating agencies.

Witness) Mark W. Glotfelty

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
February 14, 2008

Item 62) Please reference the testimony of Mark W. Glotfelty. Provide the formula calculation by which the TIER is calculated for purposes of this testimony.

a. State the extent to which this formula is identical to that which would be utilized by:

i. Big Rivers' potential creditors in the loan covenants; and

ii. Credit rating agencies.

Response) The formula calculations for TIER in Mr. Glotfelty's testimony is the Standard RUS Mortgage TIER Calculation. See PSC Item 13.

a. (i) Big Rivers cannot foresee what TIER calculation will be used by potential creditors;

b. (ii) Identical. See AG Item 61.

Witness) Mark W. Glotfelty
C. William Blackburn

Item 63) Please reference the testimony of David A. Spainhoward, page 6, line 4 at "Big Rivers is developing a more comprehensive and more global environmental compliance plan..."

a. List each additional environmental compliance program or issue which this "more comprehensive and more global" plan will likely address; and

b. Provide broad gauge cost estimates (capital and expense, separately) for each such program or issue in a. above, and the points in time (fiscal year) in which those costs would be estimated to occur.

Response) a. Big Rivers does not anticipate changing its environmental surcharge mechanism or the three programs therein. This more comprehensive plan does not change, add to, or contradict the environmental compliance plan filed with the Application or the three programs described to be included in the environmental surcharge mechanism. See also subpart b, below.

b. No additional programs are anticipated to be added to the environmental surcharge filed with the application.

Witness) David A. Spainhoward

Item 64) Please reference the testimony of David A. Spainhoward, page 13, line 4 at "Big Rivers projects that it will realize $14.487 million in revenues from the sale of excess 2008 SO_2 allowances, with this amount declining to $4.065 million for 2012 SO_2 allowances."

a. Provide workpapers and associated supporting documents to support these estimations.

b. Please state the extent to which the estimated declining revenues can be characterized by Big Rivers as "best case", "worst case" or "base case.

Response) a. The reference above is to testimony filed as Exhibit 2 in PSC Case No. 2007-00460. Please see attached work papers and supporting documents regarding Big Rivers estimated revenues from SO_2 allowances.

1) The most recent SO_2 allowance price forecast by Global Insights, Inc.;

2) A summary spreadsheet of annual SO_2 allowance prices, EPA allowance allocations, BREC system SO_2 emissions, etc.;

3) See PSC Item 22(a) for Big Rivers' production cost model output report.

b. The estimated declining revenues are characterized as base case.

Witness) C. William Blackburn
David A. Spainhoward

GLOBAL INSIGHT

Price Outlook for Coal Delivered to BREC Plants

Prepared for:
Big Rivers Energy Company

Prepared by:
Global Insight, Inc.
Global Energy Services

September 2007

Table of Contents

Price Outlook for Coal Delivered to BREC Plants

This report provides a forecast of delivered coal prices to the various BREC plants and describes the rationale behind their trends. The report also contains projections of SO2 and NOx prices.

Supply

The Illinois Basin, the source of coals for BREC, is in a state of transition. After having lost over one-third of its production since 1990, registering a 52 million ton decline down to about 89 million tons, output has begun to improve. Production reached over 95 million in 2006.

There are great expectations for the Illinois Basin, as described in more depth in the "Demand" section, and much of this is based on the attractiveness of this relatively low cost, high sulfur coal that can be used by the large number of power plants adding scrubbers. Yet the transition to achieve much higher output is not occurring without problems. Even though production is about 5.6% above last year's pace through the end of September, there are some clouds on the horizon caused principally by the persistence of some very high stockpile levels that is affecting the entire US.

Another problem at present is that the Illinois Basin suppliers must demonstrate their ability to produce to potential buyers, a problem that leads them into production before the buyers are ready to commit. This, along with the weather, has led to a glut in the marketplace and contributed to the stockpile problem.

The needed expansion is occurring. For example, in spite of repeated difficulties (including two roof falls), NRP's Pond Creek mine had produced about a half million tons through the first half of this year and is scheduled to mine 7 million tons annually beginning in 2008. A delay in installing a longwall there may slow first quarter production next year, but the mine will become a major contributor to the region. Alliance Resource Partners, in acquiring some needed reserves from Consol, has been able to extend the useful life of these key mines for another decade. ARP has also just broken ground on River View, a mine designed to produce 3-.4.5 million tons per year in 2009.

Global Insight expects this new expansion to aid the productivity picture in the Illinois Basin. Just as has occurred throughout the remainder of the US, productivity declines have been in evidence since the year 2000, following two decades of very strong growth. Productivity continues to decline (falling over 3% in 2006), reflecting problems of mine startups, labor shortages, and insufficient capital investment over 1999-2003. We anticipate limited productivity improvement until 2010, when the labor workforce situation should have greatly improved and the influx of capital into new/upgraded mining equipment begins to take hold. From 2010-2025, annual average productivity gains of 1.8% are expected.

Demand

Much of the support for even keeping Illinois Basin coal production from falling worse than it did was the expansion of low-to-mid sulfur coal output in the Basin, particularly in Indiana. Nevertheless, the return of high sulfur coal demand is based heavily on the promulgation of final CAIR regulations, cutting in half the SO2 allowances of the two-thirds of the nation's coal-fired units located in the CAIR area of the East and Midwest. Supplementing this has been the emergence of state and regional laws much more stringent than that proposed by the federal government, particularly with regard to mercury. Wisconsin and Illinois have already passed such laws, as have some 20 other states. For power companies burning bituminous coal, the use of scrubbers for the kind of mercury reduction levels being contemplated (70-95%) is nearly mandatory, exclusive of their need for SO2 reduction.

The impact of this development on demand was highlighted by statements by Dayton Power and Light at a conference in late September. The new FGD at their Killen station, plus their planned FGD installations at Stuart, highlight their move away from low sulfur Central Appalachian coal and creates competition among Northern Appalachian, Illinois Basin, and mid-sulfur Central Appalachian coals. DPL ruled out PRB coal on grounds of excessive transportation rates. In depicting this situation, DPL is providing the blueprint for increased competition at scrubbed plants that will be repeated over and over again in the coming years.

A number of FGD installations have already occurred in the Illinois Basin market area, including at some of BREC's plants. Moreover, a large number of FGD installations are anticipated over the next three years in regions that are reachable by Illinois Basin producers, specifically the Midwest and South. In total, Global Insight anticipates just short of 70GW of retrofit scrubbing to occur before 2010.

Pricing

Coal prices for the Illinois Basin high sulfur coal used in most of the BREC plants are forecasted to remain in the $29-31.50/ton range over the next several years (in nominal dollars), then decline gradually from about $30/ton in 2010 (in real 2006 $/ton) to about $25/ton by 2025.

There is some softness in the Illinois Basin market now, caused in part by several of the items we have previously discussed. High stockpiles are depressing the normal volume of spot purchases, and the surge in FGD installations has not quite yet arrived, even though some of the production has. As a result, prices for a 3% sulfur/11,000 BTU coal are running in the $27-$29 area currently.

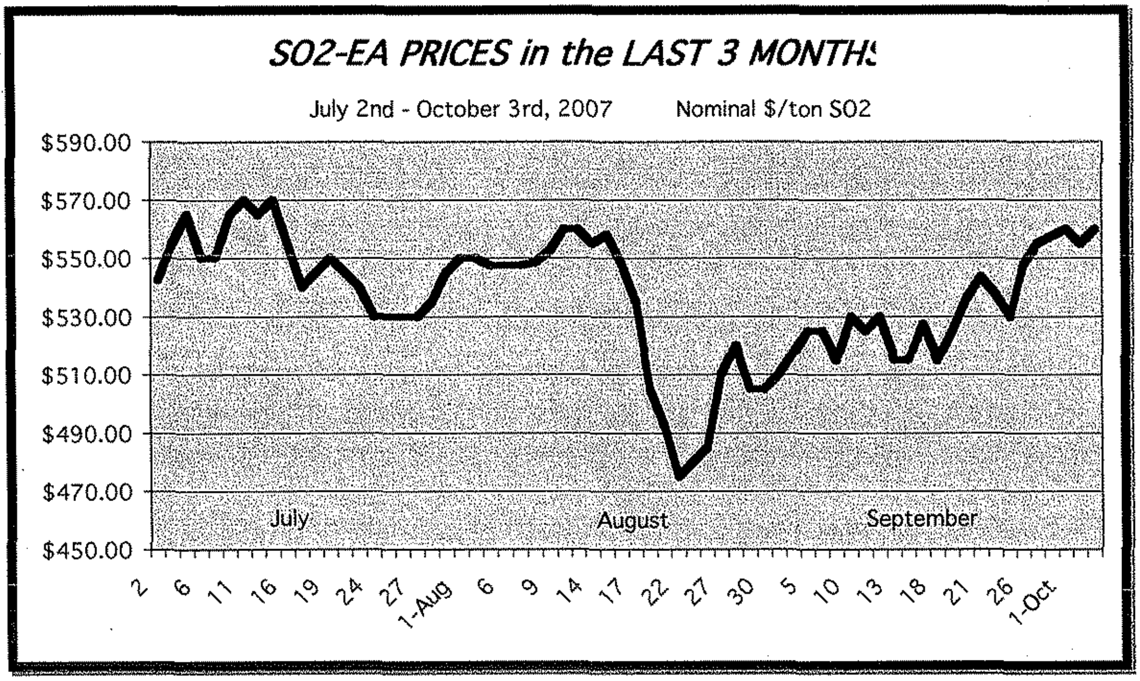
Global Insight is anticipating a moderate rise in real prices as the full impact of FGD installations is felt in terms of higher Illinois Basin coal demand. Much of this is premised on the enormous amount of investment that has had to have been made in not only new mines, but in existing mines that have needed considerable refurbishment. Over the longer term, we expect to see price modest real dollar price declines as this investment reaps productivity gains that help reduce production costs and, ultimately, prices.

Delivered Coal Prices

The tables for each of the plants are included in the Appendix.

SO2 Prices

The Short-term SO2 Outlook



After holding steady at about $550/ton for much of the summer, SO2 prices took a dive in mid-August and actually fell below $500/ton for a few days (reaching a summer low of $475 on August 22nd). Prices recovered to the $500 point before closing the month of August at $510. Allowances continued from there with a slow and steady climb through the month of September, though, returning to the $550 price point where they had held for much of the summer. Allowances officially closed the month of September at $557.50 on September 28th and finished on October 3rd at $560/ton.

Trading volume has remained relatively low, despite a late flurry of activity to end the month, similar to what we have witnessed through much of the year. The potential impact of federal CO2 regulation continues to loom over the SO2 market. Global Insight is forecasting that uncertainty leading to price paralysis will continue to dictate the SO2 market for the next year, until the American presidential election in November 2008. The outcome of that election should give much-needed guidance to the industry on the issue of CO2 regulation, based on our assumption that nothing will be signed into law in the remaining term of the Bush presidency.

Additionally, it is worth noting that SO2 vintages for 2010 and beyond (at which time the Clean Air Interstate Rule will take effect, forcing emitters to surrender two allowances for every ton of SO2 emitted) are firming up at approximately half the value of current vintages. We believe that this could be an indication that the market expects court challenges of the CAIR allowance devaluation to fail.

Holding Steady...

There remains considerable short-term downward pressure on the market due to the success of emission reductions and the resulting dampening of demand for allowances. With SO2 emissions already having fallen below the cap in 2006 and data showing the industry on pace to repeat that feat in 2007, it is unlikely that there will be a late-year surge on allowances for compliance purposes that might otherwise drive up prices. In fact, the market is finding resistance each time it goes as high as $550/ton in recent months, with sellers rushing in to sell off allowances and capitalize on any upward trend.

It is noteworthy that these lower emissions are occurring against the backdrop of coal-fired electricity generation up 1.5% and coal consumption by the power sector up 1.7%. In our view, these lower emissions are due to two factors. First, while DOE data suggests Powder River Basin production is flat on the year (versus year-to-date 2006), more of the ultra-low sulfur coal from this region appears to be going into the boilers this year instead of being used to replenish stockpiles. Secondly, the continued trend towards installation of additional FGD capacity is also removing potential compliance-buyers from the market on an on-going basis and further limiting demand.

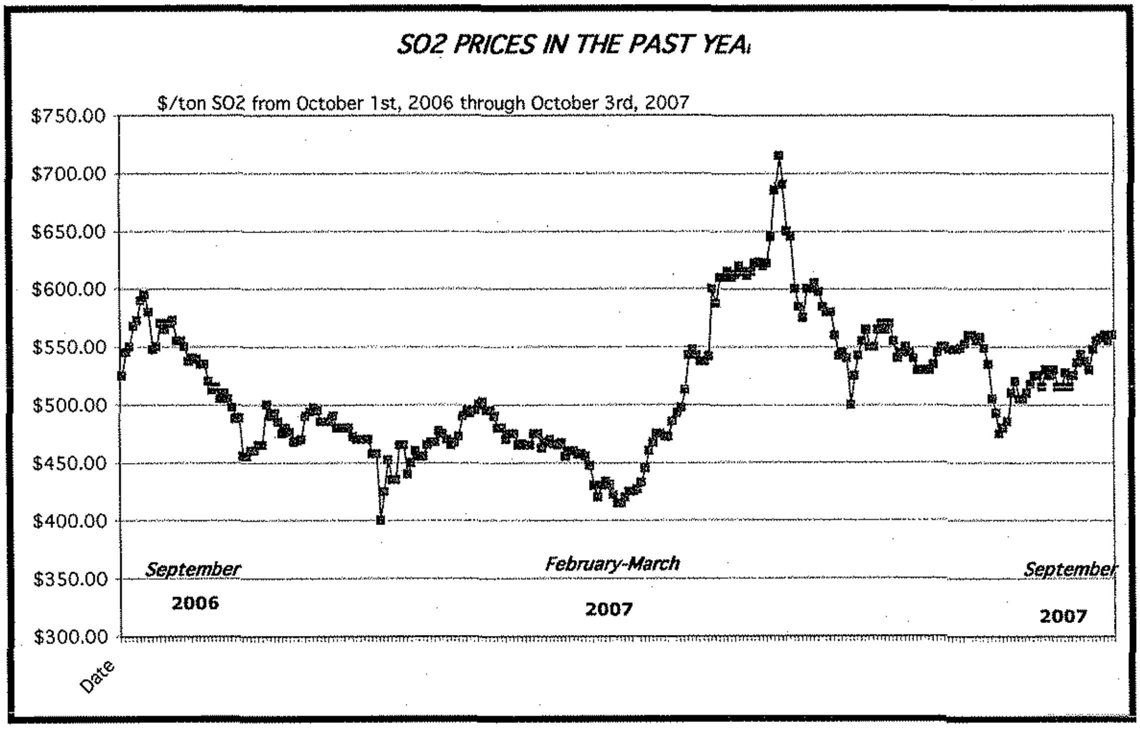
That said, Global Insight expects that the market could see a slight bump in demand for allowances during the fourth quarter as some generators may seek to build their portfolio of allowances to meet future compliance requirements. The relatively low price point, in the $500-575/ton range, should continue to prove attractive to generators already looking ahead to CAIR's 2010 requirements. Additionally, preliminary third quarter emissions figures should be released near the end of October, and could help guide the market through the remainder of the calendar year.

Implications of Breaking News...

It is also worth noting a late entry into the SO2 market, actually reported on October 1st. Emission allowance broker Evolution Markets has announced that it is auctioning nearly 250,000 vintage 2015-2036 SO2 allowances. It plans to make available for auction 11,181 allowances/year beginning with an open auction that ends at 3pm Eastern time on October 18th.

This auction tests our outlook with regard to how both naturals and speculators are viewing the market. We previously noted that the prices for future vintages for 2010 and beyond are relatively flat on a $/ton basis. Rather than being based on a more sophisticated view of the market, we suspect those prices---effectively mimicking the current SO2 price--- reflect more the indecision and lack of direction of today's market. Given the uncertainties facing the future of SO2 allowance use (e.g., the magnitude of any future CO2 requirements, the outcome of the court challenge to the CAIR SO2 program, and the environmental agenda of the next President, to name a few), purchasers of these allowances are going to have to incorporate a high risk factor into their calculations in determining a price.

But...Could Higher Prices Be Around the Corner?

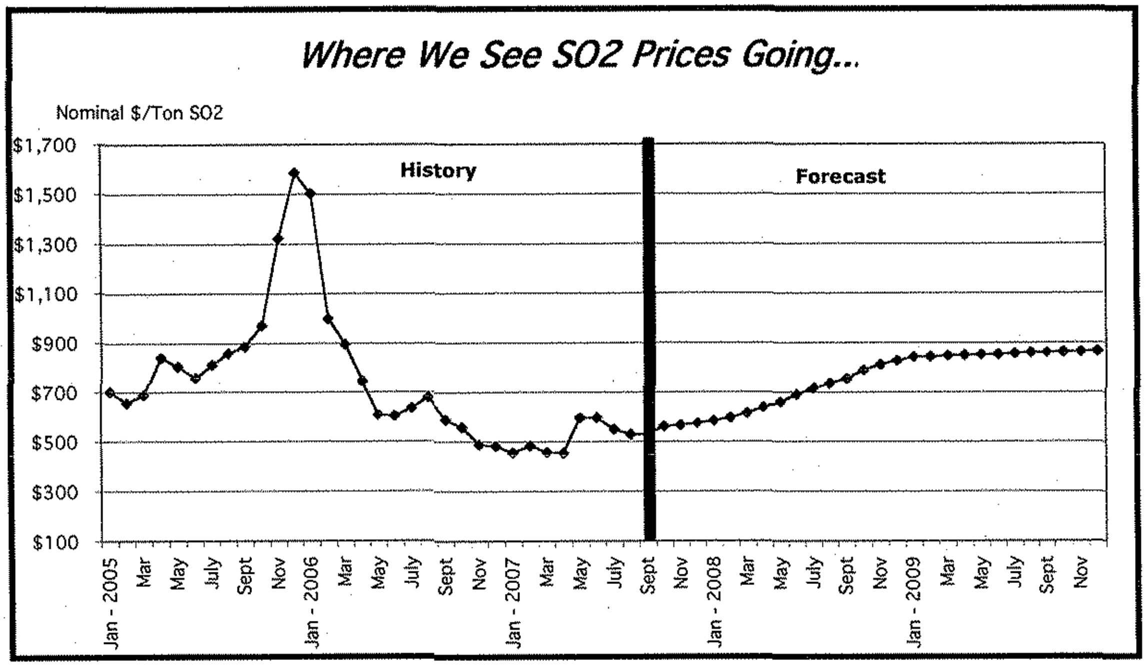


The marginal cost for scrubber installation continues to outpace the market price for SO2 allowances. As CAIR approaches, we expect that the cost of installing FGD capacity will only increase, as generators seek to remove SO2 emissions from older and smaller units. It is unlikely that emitters who are spending upwards of $800/ton for SO2 removal will continue to sell off allowances at the steep discount of $500-600/ton. Global Insight still predicts that a tipping point will ultimately be reached in the marginal cost of scrubbing that will begin to influence the SO2 allowances market, driving prices higher as we near CAIR's implementation in 2010.

Short-Term SO2 Projections

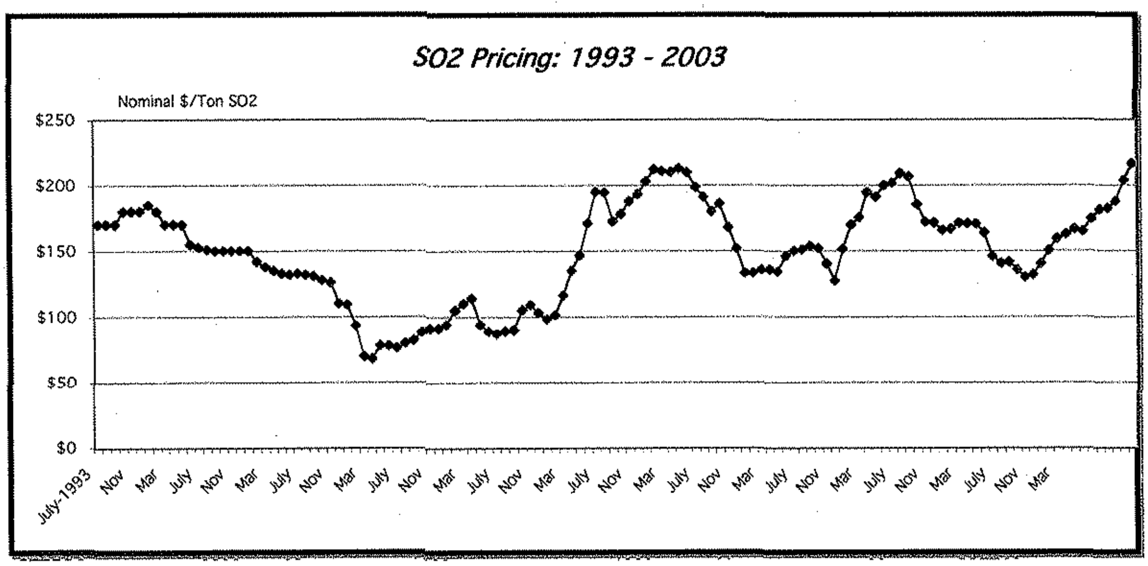
Short-term downward price pressure is likely to prevail through the remainder of 2007 for the reasons enumerated above. With natural gas prices up slightly month-to-month, we have revised downward our projection from a month ago that noticeable quantities of coal-fired capacity could be backed out in the fourth quarter by natural gas. We had been anticipating prices possibly falling below $5 in the fall, but events that have unfolded that now suggest prices remaining closer to the $6 mark, too high to bump even marginal coal units in the dispatch order.

Our long-term projections remain focused on our belief that market fundamentals will drive prices higher through 2008 and 2009 as we approach the implementation of CAIR in 2010. After CAIR is implemented, prices should begin to begin to moderate as the market shifts towards scrubbing its way to compliance once again. A challenge facing the industry early next decade will be over the issue of whether to continue retrofitting older plants at considerable cost with FGD units, or to accelerate the retirement of these plants, likely replacing them with advanced coal (or even nuclear) generating technologies.



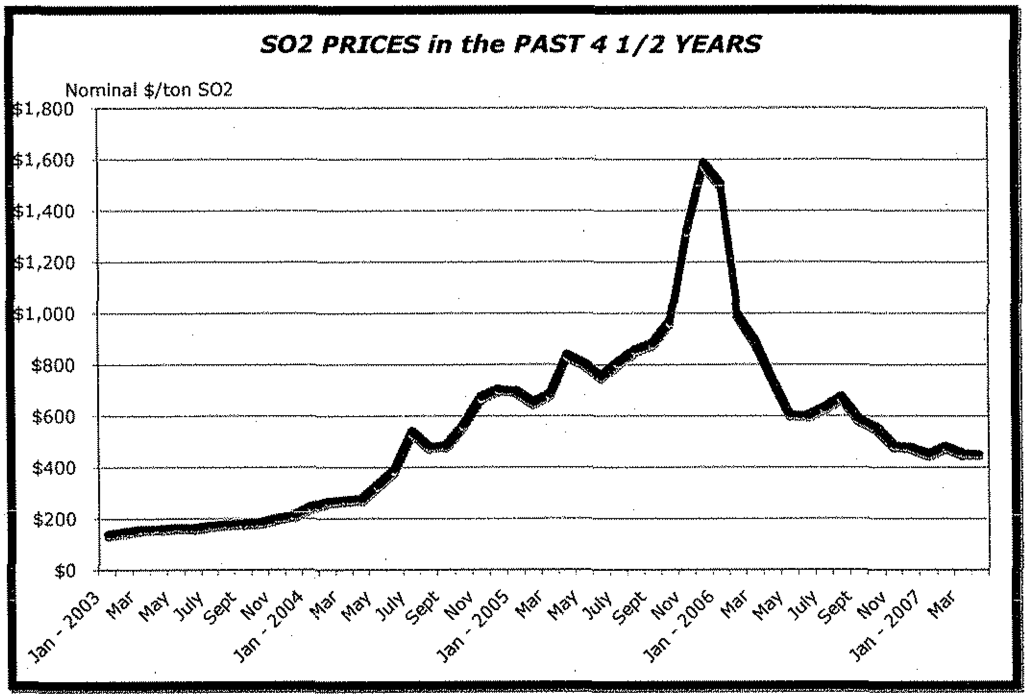
The Long-Term SO_2 Outlook

SO_2 Background



Prior to examining what lies ahead, we believe it useful to briefly describe what has occurred in the SO2 program thus far.

♦ ***The First Decade (1993-2003):*** The first decade of trading within the SO2 cap-and-trade program resulted in wild fluctuations in SO2 allowance prices. The SO2 market was thinly traded when the program began and, as such, small transactions were often able to drive the market. As the industry became familiar with the program and the new requirements of the Acid Rain Program, market participation and liquidity increased. By the late 1990s, however, the Clinton Administration's push to step up enforcement of New Source Review put downward pressure on SO2 allowance prices as the industry expected a wave of new FGD units to be installed, resulting in expected lower demand for allowances. With the election of President Bush in 2000 and his subsequent move to relax New Source Review enforcement, however, the market responded again to NSR politics and prices increased as a result.

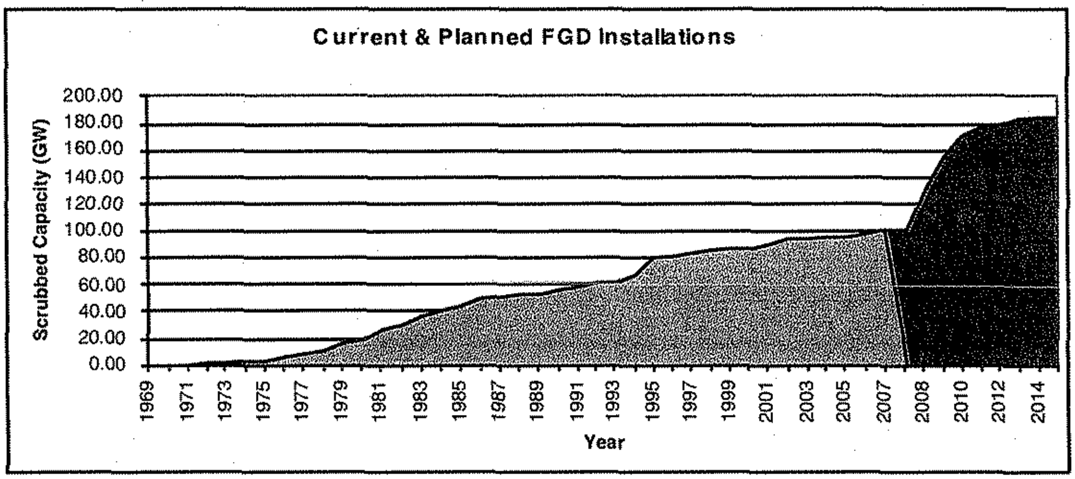


♦ ***The Surge (2004-2005):*** The SO2 market surged dramatically from 2004 into 2005, rising from approximately \$200/ton to \$1,600/ton. A number of factors drove this price surge. First, the industry took a wait and see approach after the Bush Administration announced the Clean Air Interstate Rule (CAIR). Until the specifics of CAIR were finalized, companies tended to hold onto their allowances, not knowing how stringent the newly promulgated SO2 standards would be. This led to illiquidity in the market and put upward pressure on the price of SO2 allowances. Second, the market was responding to increased coal costs. Coal prices had soared due to increased costs of production, materials, labor, and transport. Third, the marginal cost of installing FGD units was increasing for many of the same reasons that coal prices were rising. Fourth, the market saw a surge in speculative investing by 3rd party investment firms. These factors taken together drove the surge in SO2 allowance prices.

♦ ***The Plunge (2006):*** While SO2 allowances were almost certainly under-valued at \$200/ton before the surge of 2004/2005, the allowances were also significantly over-valued at \$1,600/ton by the end of 2005. As a result, prices plummeted through 2006 and industry recognition of the overvaluation of the allowances was a significant reason why. The cost of allowances at the height of the surge far surpassed the marginal cost of scrubbing per ton of SO2 removal and fell to what most believe is a more sustainable level. Liquidity also returned to the market in 2006 as industry became more comfortable with the coming requirements of the Clean Air Interstate Rule.

In terms of what comes next, the Clean Air Interstate Rule (CAIR) takes effect for SO2 in 2010 with Phase I of the program. Twenty-eight states in the central and eastern United States will be regulated by CAIR's provisions while the remaining western states will still be regulated by the Acid Rain Program's cap-and-trade program. The new requirements are designed to reduce SO2 emissions in the regulated area by 45% over 2003 levels. Phase II of CAIR will take effect for SO2 reduction in 2015 and envisions a total reduction in SO2 emissions of 57% from 2003 levels.

Of particular interest to the SO2 allowance market, CAIR contains a provision whereby SO2 vintage allowances from 2009 and years previous can be surrendered on a 1:1 ratio to meet CAIR requirements. There is a depreciation formula, however, that will take effect beginning with 2010 vintage allowances. During Phase I of CAIR (2010-2014), allowances will only be surrendered at a 2:1 ratio. During Phase II (2015-), allowances will be surrendered at a 2.85:1 ratio. It should be noted that EPA's ability to devalue these allowances has been challenged by a number of power companies and is under review by the courts.



As a result of this allowance depreciation formula, there is a surge in FGD installations coming before the end of the decade. Once CAIR was finalized in 2005, power companies began accelerating plans to install FGD units across their fleets. As a result, the total coal-fired capacity that is expected to be scrubbed is expected to rise from the approximately 100GW that is scrubbed today to 180GW or more by the start of CAIR in 2010. This strategy will allow industry sources to accumulate as many pre-CAIR vintage allowances as possible so that they will be able to surrender them at a 1:1 ratio to meet CAIR's requirements.

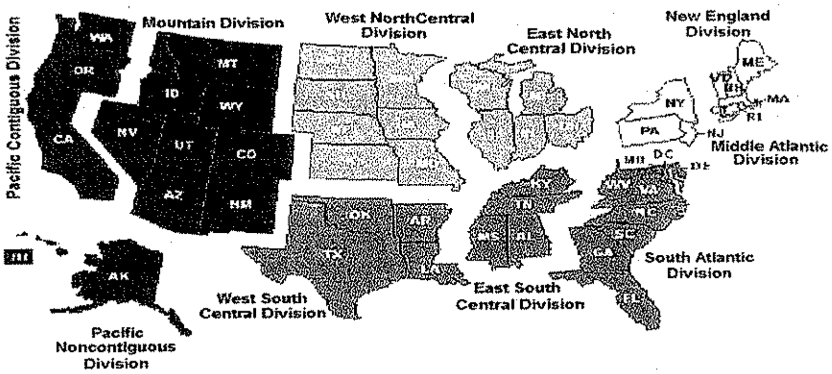
There are some other factors to consider when looking at the future of the SO2 market. First, technology is continuing to improve and FGD units capable of 99% removal efficiency are now readily available. Second, some states are taking action which may accelerate SO2 reductions beyond CAIR's requirements. The Ozone Transport Commission in the northeastern United States has been considering a proposal called CAIR+ which would accelerate reduction on a compressed schedule with Phase I coming in 2008 and Phase II in 2012. Third, the future of mercury and greenhouse gas regulations could also have a large impact on SO2 markets. Depending on the outcome of pending litigation (which could force a command and control regulation system of mercury, requiring the installation of maximum available control technology), and the degree to which states continue to pass regulations more stringent than the Clean Air Mercury Rule, efforts to control mercury could force industry to accelerate the installation of FGD units capable of removing mercury as a co-benefit. The emerging GHG markets and expected future regulation could force the otherwise premature closure of some older plants that are too costly to regulate for CO_2 emissions.

The Long-Term Outlook

The Global Insight long-term SO_2 forecast is driven by four major trends, as explained below.

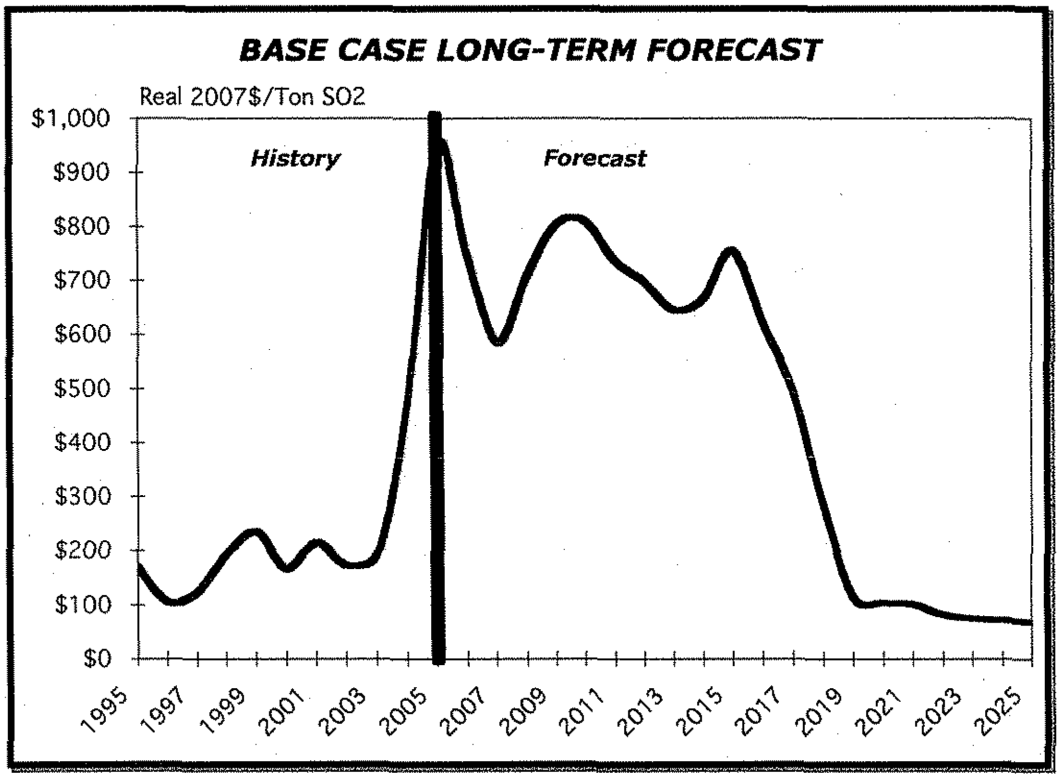
♦ ***A rebuilt bank by 2010 allows a "wait and see" approach:*** Our estimate is that the high volume of FGDs in operation prior to 2010 will create a large bank of SO_2 allowances as CAIR begins. The impact of this bank---probably reaching 10-12 million tons that can be used on a 1:1 basis for reducing emissions---will be, in our view, to create a "wait and see" approach in the marketplace over the 2010-2014 period. By this, we mean that power companies will rely on the bank and not need to take any dramatic steps at this point (such as another surge in FGD construction), preferring instead to evaluate the dynamic changes occurring across the environmental markets in NOx, mercury and GHG to see, among other things, how these developments will affect the SO_2 market.

♦ ***Yet other issues will encourage continued FGD installations at existing plants***: The pressure to scrub will not necessarily subside, for reasons outside the realm of SO_2 strategy. First, beyond the incremental 67GW we foresee placed into operation before 2010, there is still another 41GW of previously announced FGD installations that are still in the pipeline to occur between 2010-2015. These, of course, are not cast in concrete and some could be deferred, but once announced, these installations begin to develop their own momentum. Second, compliance with the significant number of state mercury programs (20) that have taken a more stringent approach (than the federal government's CAMR program) will undoubtedly convince many companies to skip the very expensive step of relying solely on activated carbon injection and decide to install a scrubber (assuming they would eventually do so anyway) sooner rather than later as a mercury control strategy. Third, in a number of instances, state regulatory authorities have required that companies planning to construct new coal-fired generation install FGDs on one or more existing plants as a quid pro quo, even when the companies had no intention or need to build scrubbers at that particular time. One examples of this is the installation of FGDs on existing units at Iatan and LaCygne as part of the agreement with Kansas City Power & Light's construction of a new unit at Iatan. There are other examples of states using their regulatory authority (e.g., Illinois, New Jersey and Georgia) to impose stringent mercury requirements and then inject flexibility into their application on the condition power companies install FGDs. Third, in the West, the CAVR program aimed at reducing regional haze will force the installation of scrubbers on units that largely burn very low sulfur coals and that otherwise would not require FGDs to comply with SO_2 mandates. The upshot of these developments is that even when there is no pronounced need emanating from the SO_2 market to install FGDs, scrubbers will continue to be constructed for other reasons, further enhancing the position of the SO_2 bank. A regional breakout of the new FGD installations is provided below.



FGD Installations 2007-2016	
Region	**Capacity (GW)**
NENG	1.17
MATL	8.44
SATL	37.24
ENC	27.97
ESC	11.95
WNC	3.90
WSC	5.12
MTN 1	1.64
MTN 2	0.00
PAC 1	0.00
PAC 2	0.00

♦ ***Technology developments will lead to greater scrubbing:*** One of the major developments foreseen by Global Insight affecting SO2 markets is the emergence of integrated pollution control systems. Specifically, we are referring to systems that combine at least SO2 and NOx removal, and now more frequently also include mercury reduction, as part of a high efficiency system that employs what are currently separate pollutant removal units to interrelate their activities so as to optimize reductions across emissions. Such a system, Powerspan, has been tested at FirstEnergy's Burger station and was selected in November 2006 by AMP-Ohio for its new unit. This is simply one example, and more integrated systems will soon be coming into the marketplace. Ideally, these units will be less expensive than their counterparts where each pollution control technology is procured separately. Their impact on the SO2 market will be felt in two ways. Due to the multi-pollutant nature of these units, companies will be reducing SO2 even though their major focus of reduction may instead be directed at NOx and/or mercury. Second, due to the high removal efficiencies that can be achieved with integrated systems (e.g., 99% for SO2), installation of these units may result in higher emission reductions than might have occurred if a company were simply targeting a general reduction in SO2.



♦ ***Do we ever reach the high cost units?*** Many observers forecast a perpetually rising cost of SO2 allowances over the long-term, for two reasons. First, the theory of the rising marginal cost of scrubbing is based on the fact that retrofits of the low cost, "low hanging fruit" have already been achieved and that each subsequent round of FGD installations will encounter more difficult and costly units to install, effectively raising the cost-per-ton of SO2 removed. Second, in this viewpoint, the retrofitting of smaller, older, more costly units occurs indefinitely because CAIR is viewed by these observers largely in a vacuum, untouched by other regulations/legislation. Global Insight's contention is that in approximately 2015, we will begin to see a transition from retrofitting these units to replacing their capacity (and then some) with new, state-of-the-art coal-fired generating units. This impetus for the retirement of these older units will be come from numerous sources, ranging from the economically imposing task of having to retrofit these aged units with controls for SO2/NOx/mercury to the need for greater energy efficiency in the coal fleet at large in light of pressures to reduce CO2. Consequently, we never reach the point of expending the capital to replace these older units that would so significantly drive up the SO2 allowance price to the $1,200/ton SO2 removed area so many have predicted.

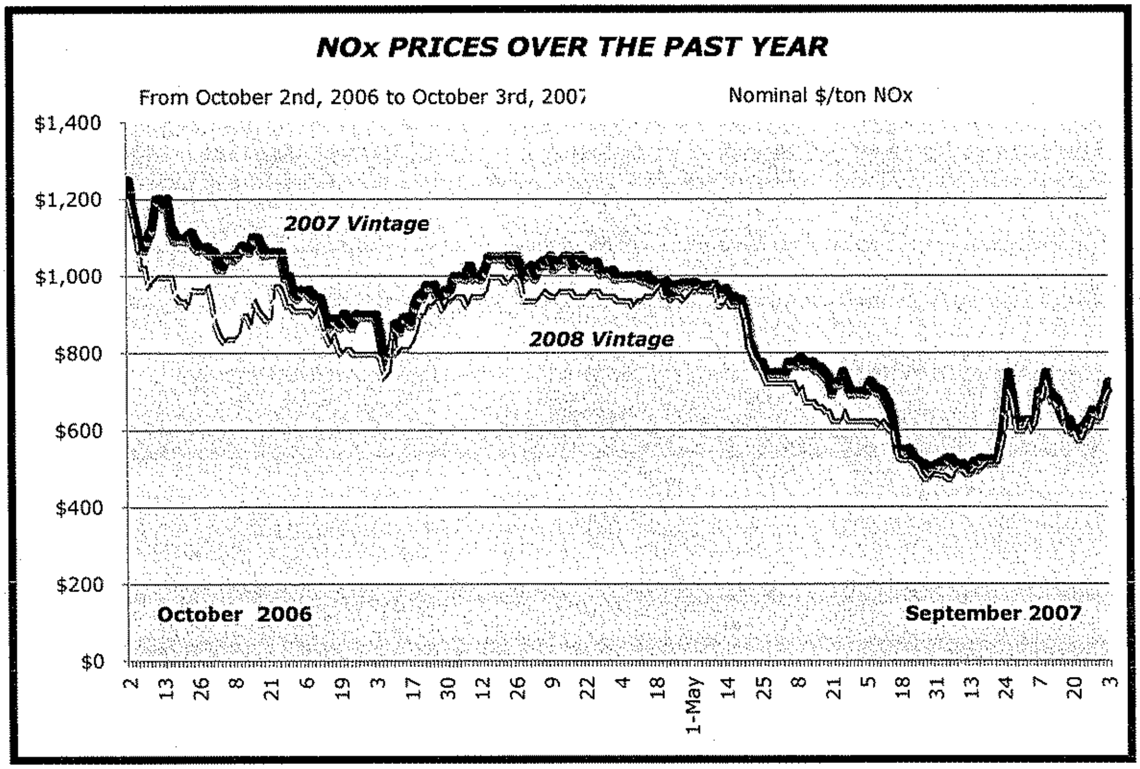
Our forecast begins Phase I of CAIR with SO2 prices of approximately $852/ton, but then stalls as the program commences with a large bank of allowances in tow. It is our perception at this point that the market will go into the "wait and see" mode described earlier and rely on the bank as power companies strategize while assessing the likely outcome of other environmental programs (CO2 and mercury) and their possible impact on the SO2 market. The price wanes during this period, driven by the downward pressure of the large bank and concern caused by the uncertainty of whether other environmental air programs might preempt the scrubbing issue, sending SO2 prices into a downward spiral.

This situation continues until about the middle of the decade (2015), when the bank is reduced to a sufficiently low level as to prompt higher SO2 prices, possibly on the back of some additional

FGD installations (and the higher marginal costs they experience). At about this time frame, however, we at Global Insight conclude that the cumulative impact of other pollution control programs will lead to the retirement of significant coal-fired capacity and its replacement by much more efficient, scrubbed (for all pollutants) generation. This will send SO2 prices into a tailspin over the 2015-2020 period, as the growing supply of allowances begins to dwarf the rapidly declining demand, driving down their value.

NOx Prices

The Short-Term NOx Outlook



After the month of August saw NOx prices flat for much of the month near $500/ton, allowances spiked late in the month on news that NOx emissions for the year were up 8% year-to-year to an August-high of $750/ton. NOx (2007 vintage) allowances entered September down some at $625/ton before spiking again to $750/ton a week into the month. Prices have calmed some since, however, and have held in the $600-650 range for the latter half of the month. It has been a fairly wild NOx market over the last six weeks, something which we believe was triggered almost exclusively by the now-known-to-be-mistaken report that appeared to indicate an increase in NOx emissions year-to-year. Prices ran up to $750 on news of the increase, before falling rapidly down to their late September levels nearer $600 and then making their way back up to $725 on October 3rd.

Last month, we discussed EPA's preliminary results for first half 2007 NOx emissions data. At the time, EPA reported that emissions had spiked 8% over the previous year, and the price for current year vintage allowances rose dramatically as a result. Global Insight was skeptical of this increase in last month's forecast and it is now acknowledged that a reporting error was at the root of the data. The Worthington Plant, a natural-gas fired peaking plant in Indiana, had reported 6,924 tons of emissions, compared with less than 1 ton emitted through the same period in 2006. The plant actually emitted 2.12 tons. This correction accounted for most of the reported increase and, afterwards, upward price pressure on the market has since been relieved.

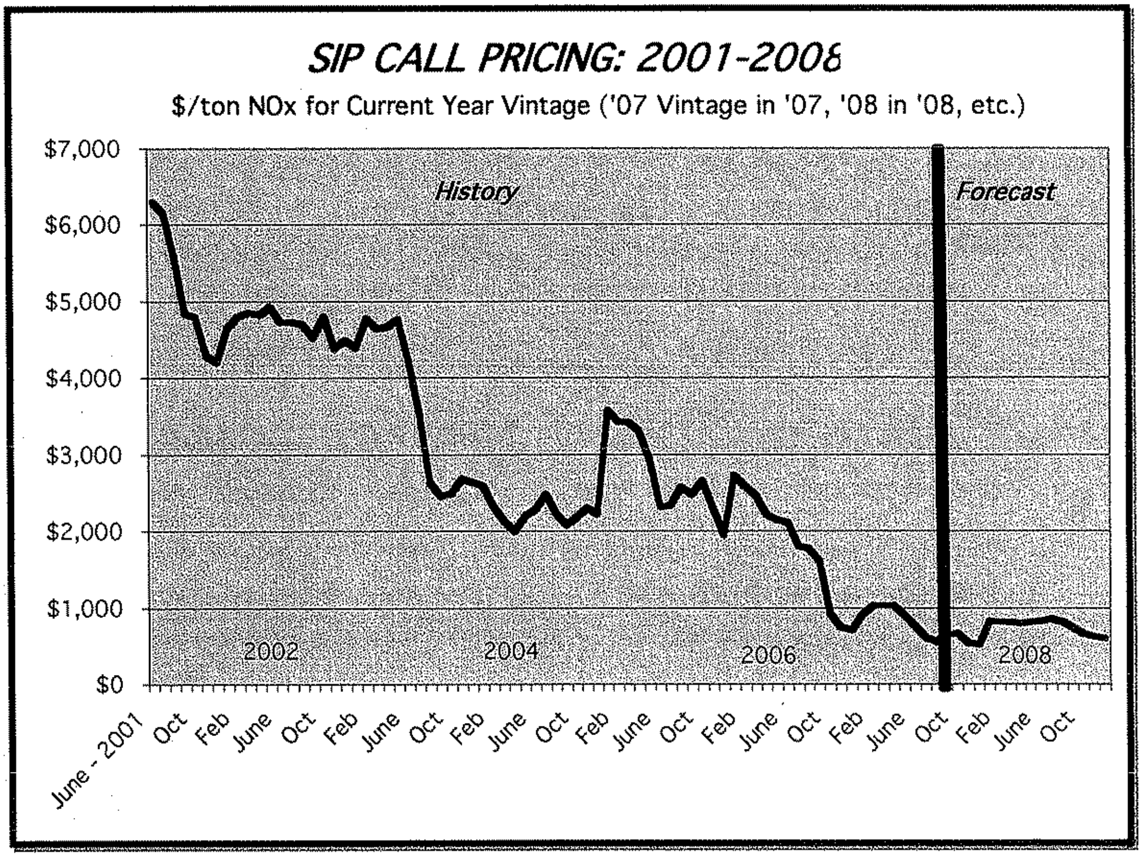
While current year vintage allowances still have not fallen back to the $500/ton price point where they held prior to EPA's reporting error, Global Insight believes that $600-$800/ton price could end up being a more sustainable price range in the seasonal market. We believe that the marginal cost of operating SCRs is in the $600-700/ton range and that, as such, allowances were significantly undervalued earlier in the summer when they traded at $500/ton and below. This false alarm on the year-to-year figures could have served as a catalyst for the small, but significant, market correction that will hold prices closer to the range we are suggesting.

Demand-side fundamentals, however, are not likely to drive prices higher in the short-term as seasonal NOx emissions are still on track to fall well below the cap for 2007. In fact, even had the 8% increase in emissions proved reliable, emissions would still have been on pace to fall below the cap. In short, the NOx market is not likely to see a significant run on allowances for compliance reasons. In addition to many naturals not needing to use their entire 2007 allocations for compliance, many generators have sizeable banks from which to draw allowances creating a significant oversupply of the market.

Once again, we also would be remiss if not making mention of the current status of potential changes to EPA's ozone rule. EPA held its final public hearing on the new rule in the month of September but will continue to take written comment until October 9th. A final rule is still on track for March 2008 with SIPs due in 2013. It is expected that EPA will tighten the ozone rule—the only real question is matter of how much—and that it will provide additional downward price pressure to the NOx market by forcing the installation of SCRs on additional units, and thus lowering demand for allowances.

Seasonal NOx: Price Forecast

A relatively tepid market was rocked for a few weeks by a false report on 2007 emissions being higher than a year ago. We expect the market to return to being relatively flat in the short-term, with significant downward pressure from the oversupply of the market keeping a lid on prices. Vintage 2009 allowance markets (the first year of CAIR for NOx) and beyond remain illiquid, but we expect activity to increase as we move through 2008. The same as with the SO2 market, we do expect that there could be a slight surge in demand for allowances as we approach CAIR if market prices remain low as generators attempt to build their portfolios ahead of the stricter standards.



The Annual CAIR Market

Global Insight continues to assess the early stages of the formation of the Annual NOx market. We have commented here in previous months on the significant overvaluation of the first annual NOx trades, with prices reaching as high as $7,100/ton earlier in the summer. September has seen some sanity enter the annual market, as prices have tempered significantly, closing today at $3,725/ton, almost half of its high a few weeks earlier.

We expect that the price will continue to fall significantly over the next 15 months, leading into the start of CAIR's annual NOx program in 2009. Our current forecast calls for annual NOx prices in 2009 in the $2,800/ton range. Given the enormous volatility of new phases in the history of the NOx market dating back to the late 1990's, it is not yet clear where exactly the market will ultimately take the price in the short-term, but we anticipate it will certainly be lower than it is today. It is worth noting, however, that a premium for the annual program does seem warranted on account of some industry concerns about the reliability of operating SCR units for twelve months on-end. That said, we expect this premium will erode over time as SCRs prove their reliability on an annual basis. A few states (Connecticut, New York, New Hampshire, and Massachusetts) currently enforce annual NOx limits and in those states, there have actually been no reliability issues reported so far.

EPA was expected to allocate 2009 annual allowances to generators by September 30th, a date which has come and gone. EPA is citing a need to spend more time reviewing and approving SIPs as the reason for the delay. Once allowances are actually populated to accounts, we expect current illiquidity issues to dissipate and market activity to increase as generators have a better handle on precisely what assets they have to work with. This should help to apply significant downward pressure to the annual market through the fourth quarter of 2007 and into 2008.

The Long-Term NOx Outlook

NOx Background

As was the case in reviewing SO2 markets, we will begin with a brief recap of NOx regulation to date.

Ozone Transport Commission (OTC): The price of NOx allowances in the OTC's trading program in the late 1990s faced volatility similar to that seen in the SO2 markets. When trading began in 1997, prices were in the $1,500-2,000/ton range but quickly spiked to over $7,000/ton in 1999 during the first year of OTC compliance. As industry adjusted to the new market, however, prices retreated and hovered around the $1,000/ton mark until 2003. NOx prices then spiked again in 2003 to nearly $7,500/ton. The reasons for this include: the new, tighter standard for NOx reduction introduced that year; uncertainty over the impact of the NOx SIP Call program which was to take effect a year later; and rising coal costs due to increases in the price of fuel, labor, and materials.

NOx SIP Call: The Northeast's OTC trading program was superseded in 2004 by the NOx SIP Call. The SIP Call expanded the number of regulated states to 22 eastern states and the District of Columbia. Like the OTC program preceding it though, the SIP Call only regulates NOx during the so-called "summer ozone season" from May-to-September.

The price of NOx allowances in the SIP Call trading program has behaved much differently than in the OTC. Allowances began trading for the SIP Call in 2001 at $6,300/ton but have fallen steadily since and now trade at approximately $1,000/ton. While the fall in prices has not been without any volatility, the decline has been steady and without any significant spikes in the market.

The reasons for this are varied but well understood:

Program Design: More so than with the SO2 trading program, the NOx SIP Call is a much more tightly designed program with more stringent standards. The 0.15#NOx/mmBtu emissions rate that the SIP Call cap requires is very closely linked with the capabilities of current NOx removal technology. That is, the cap is set at such a level to correspond to the existing technology that emitters have been installing control technologies at a rapid pace on a substantial portion of the affected units. As a result, a large bank has accumulated that industry has, for the most part, not needed to draw down in order to come into compliance. In addition, the EPA created a system called Progressive Flow Control (PFC) to further discourage an over-reliance by industry on the existing bank of allowances to meet standards. PFC restricts the value of banked allowances used for compliance if the bank exceeds 10% of the value of that year's total allocation.

Technology: The overwhelming success of NOx removal technologies has also contributed to the steady decline in NOx allowance prices since the SIP Call markets began trading in 2001. Low-NOx burners and other primary measures (such as overfire air and fuel re-burn methods) installed on boilers over the last decade have largely exceeded expectations and are now capable of removing 25-40% of NOx during the combustion process before the SCR units even attempt to remove NOx from the flue gas in the stack. Additionally, the SCR units themselves have performed incredibly well and have proved very reliable. SCRs are now capable of removal efficiencies close to 90% in most cases; however, the efficiency of some units is now being throttled back closer to 75% when used in conjunction with high-sulfur coals because of the issue of ammonia slip and formation of sulfur trioxide (SO3). The combination of low-NOx burners with SCR units is now capable of readily achieving the 0.15#NOx/mmBtu standard currently required by the SIP Call program.

The steady decline in the price of NOx allowances in the SIP Call program is a testament to how successfully the program is working. The well designed trading program coupled with reliable and efficient control technologies has driven the market this decade.

The Clean Air Interstate Rule (CAIR) takes effect for NOx in 2009 with Phase I of the program. Twenty-eight states in the central and eastern United States will be regulated by CAIR's provisions. Unlike the OTC and the SIP Call, though, CAIR will create two markets for NOx reduction – one for seasonal "summer ozone" reductions, and the other for annual reductions. The seasonal program will impose a cap of 0.58 million tons in 2009, followed by a Phase II requirement in 2015 of 0.48 million tons. The annual program will impose a cap of 1.5 million tons in 2009, followed by a Phase II requirement in 2015 of 1.3 million tons. The Phase I requirements for both programs are equivalent to a 0.15#NOx/mmBtu emission rate, while the Phase II requirements are equivalent to a 0.125#NOx/mmBtu rate.

The banked allowances from the SIP Call will carry over into CAIR's new seasonal NOx trading program. The states will be allocated allowances that are based on fuel adjusted average heat input values, using fuel adjustment factors of 1.0 for coal, 0.6 for oil, and 0.4 for gas. Additionally, there will be no progressive flow control provisions under CAIR. There will, however, be a one-time compliance supplement pool (CSP) during the first year of the program to assist states transitioning to a NOx cap-and-trade program for the first time.

There are some other factors to consider when looking at the future of the NOx market. First, technology is continuing to improve and we expect units to be capable of achieving 0.01#NOx/mmBtu by 2015. Second, some states are taking actions which may accelerate NOx reductions beyond CAIR's requirements. The Ozone Transport Commission in the northeastern United States is considering a proposal called CAIR+ which would accelerate reduction on a compressed schedule with Phase I coming in 2008 and Phase II in 2012. Third, the emerging GHG markets and expected future regulation of CO2 could force the closure of some older plants that are too costly to regulate for CO2 emissions, potentially having a big impact on the NOx market.

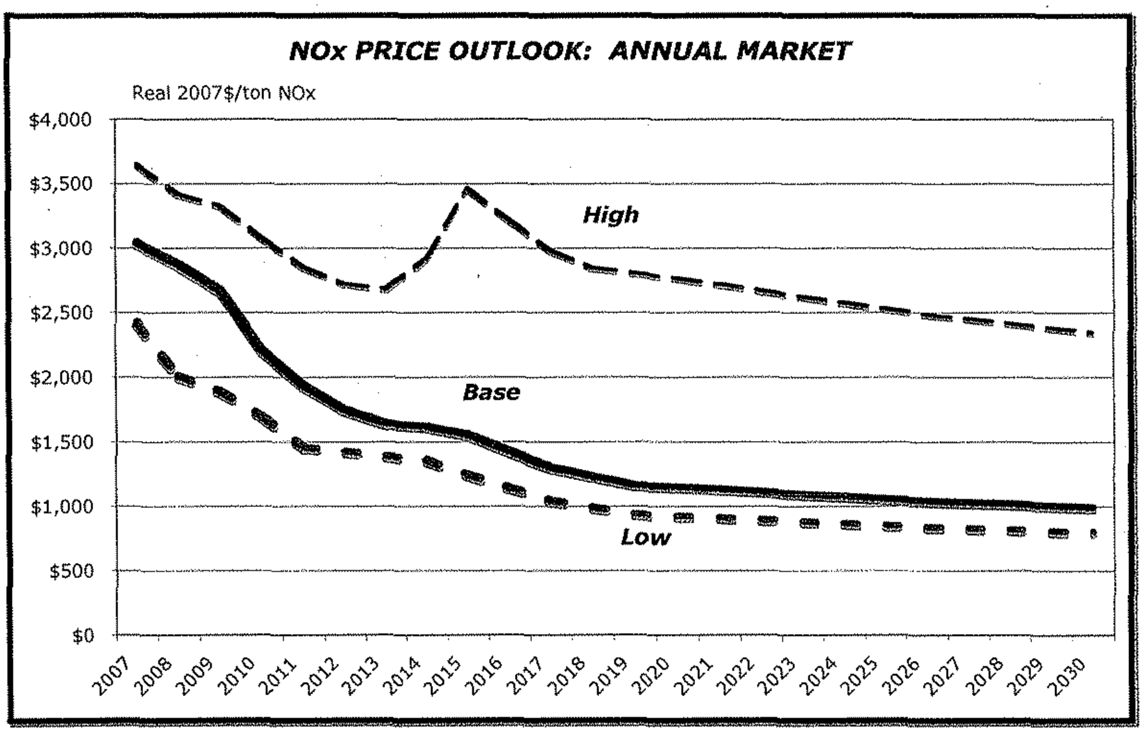
The Long-Term Outlook (CAIR)

As noted previously, one of the most dramatic features of the NOx rules under CAIR is the creation of two markets, covering annual and seasonal emissions. We expect these two markets to operate very differently, as described below.

The ***Annual Market*** should bear the heavy lifting in terms of where power companies allocate their NOx control costs. This occurs because the annual market covers the entire timeframe that must be regulated (i.e., the calendar year), rather than just the shorter May-September seasonal period.

Prices will likely begin at very high levels this year: A great deal of speculation has collected around the idea of a $3,000/ton range for the 2009 vintage, but we have been forecasting closer to $3,600. This seems to be borne out by recent quotes of $3,200 to buy that have been countered with $4,000 to sell, reinforcing our view, although no sales have been made to date. We see the price commanding this magnitude due to several factors, including (1) the arrival of a significant number of new entries into the program for the first time and (2) the absence of any bank leading into the program. As such, we anticipate most companies will first want to build their own bank for internal comfort, and only later contemplate selling allowances in any significant volumes. The CSPs (Compliance Supplement Pool) will mitigate this issue to some extent (although at least two states will likely not utilize their CSPs), but not enough to forestall the two issues we have raised.

The price will rapidly fall, however, as the program matures: In this instance, we identify three reasons why this will occur. First, the size of the bank is likely to rise quickly, due to the high price of the program at the outset (which will serve as an incentive to overcomply rather than rely on the market) and to the demonstrated success of both primary and secondary technologies in the SIP Call program. Second, the expansion of the NOx program from a seasonal to a full calendar year means, that for economic valuation, the capital costs of a company's NOx reduction program are annualized rather than spread out only over the five months of the seasonal program. In other words, the annual cost of a piece of equipment is noticeably reduced when it is divided by 12 months, rather than just 5 months. Finally, we expect substantial technology gains to be made during this period, including improved removal efficiency from units operating on high sulfur coals (that often backed off to 70-78% removal due to the SO3 problem), continued efficiency gains in the use of primary equipment, and the emergence of multi-pollutant integrated technologies that will both lower costs and raise removal efficiency.



Prices will continue to fall, in spite of the more stringent standard introduced in 2015: The 2015 adjustment to 0.125#NOx (from 0.15#NOx) is not expected to introduce any major pricing adjustments. While that may appear counterintuitive, it is in our view attributable to two inter-related factors. First, as noted above, the costs for NOx reduction will continue to fall, not only due to improving technology but also due to the increasing penetration of integrated pollution control systems. It is, very simply put, a situation where the technology will simply outrun the standard. Second, as a continuing theme in our forecasts, the accelerated retirement of the older, higher cost units will decrease demand for NOx allowances by the 2015 time frame, leading to a rising bank of annual NOx allowances that depress pricing.

The ***Seasonal Market*** poses some very interesting questions as to how prices should be established. We at Global Insight have debated three different hypothetical outcomes to how prices might ultimately be reflected. First, we theorized that since all costs were already allocated to the annual market, the cost for the seasonal market was essentially zero, so any price above that would be acceptable. Second, at the other extreme, we considered the argument that even if the full costs were already allocated to the annual market, the value of a seasonal allowance would be the fully loaded cost of creating a new allowance during the ozone season, perhaps reflected in the marginal cost of adding an SCR to a unit with only primary equipment. Finally, we settled on a middle ground where the cost would be reflected in the sum of the variable cost of operating an SCR plus a profit margin that varied based on market conditions. This floor is established because a lower price could serve as an incentive for a company to shut off its SCR for a part of the ozone season and take advantage of the lower cost allowance market.

Superimposed on our thinking regarding the seasonal market is the realization that the NOx bank will apply strong downward pressure on the price due to its enormous magnitude. With the current bank already sitting at about 200,000 tons at the end of the 2006 season and CAIR removing any semblance of constraint by eliminating the PFC (Progressive Flow Control) requirement, the bank should simply continue to expand to huge proportions in the post-2009 period.

Forecasts of Delivered Coal Prices: Coleman

COLEMAN 3-4% S, 11000 BTU	Mine-Mouth Price	Truck Transport Cost	Delivered Price	Mine-Mouth Price	Barge Transport Cost	Delivered Price
$/ton						
2007	$29.05	$9.12	$38.17	$29.05	$5.52	$34.57
2008	$31.86	$9.02	$40.88	$31.86	$5.50	$37.36
2009	$34.17	$8.69	$42.86	$34.17	$5.37	$39.54
2010	$34.72	$9.00	$43.71	$34.72	$5.54	$40.26
2011	$34.70	$9.30	$44.00	$34.70	$5.71	$40.41
2012	$34.69	$9.55	$44.25	$34.69	$5.85	$40.54
2013	$34.94	$9.77	$44.71	$34.94	$5.98	$40.92
2014	$35.28	$9.88	$45.15	$35.28	$6.06	$41.34
2015	$35.64	$10.01	$45.64	$35.64	$6.15	$41.79
2016	$36.05	$10.17	$46.23	$36.05	$6.28	$42.33
2017	$36.40	$10.23	$46.64	$36.40	$6.35	$42.75
2018	$36.81	$10.33	$47.13	$36.81	$6.44	$43.25
2019	$37.23	$10.50	$47.73	$37.23	$6.57	$43.80
2020	$37.65	$10.57	$48.21	$37.65	$6.65	$44.29
2021	$38.01	$10.68	$48.69	$38.01	$6.74	$44.75
2022	$38.43	$10.86	$49.29	$38.43	$6.86	$45.30
2023	$38.83	$10.90	$49.73	$38.83	$6.92	$45.75
2024	$39.30	$11.07	$50.37	$39.30	$7.02	$46.32
2025	$39.72	$11.27	$50.99	$39.72	$7.13	$46.85
Real 2006 $/ton						
2007	$28.35	$8.90	$37.25	$28.35	$5.39	$33.74
2008	$30.50	$8.63	$39.13	$30.50	$5.26	$35.76
2009	$32.06	$8.16	$40.22	$32.06	$5.04	$37.10
2010	$31.90	$8.27	$40.16	$31.90	$5.09	$36.99
2011	$31.21	$8.36	$39.57	$31.21	$5.13	$36.34
2012	$30.56	$8.41	$38.98	$30.56	$5.15	$35.71
2013	$30.18	$8.44	$38.62	$30.18	$5.16	$35.34
2014	$29.90	$8.37	$38.27	$29.90	$5.14	$35.03
2015	$29.64	$8.32	$37.96	$29.64	$5.12	$34.76
2016	$29.44	$8.31	$37.75	$29.44	$5.12	$34.56
2017	$29.18	$8.20	$37.38	$29.18	$5.09	$34.27
2018	$28.97	$8.13	$37.09	$28.97	$5.07	$34.04
2019	$28.77	$8.11	$36.88	$28.77	$5.07	$33.84
2020	$28.57	$8.02	$36.59	$28.57	$5.04	$33.61
2021	$28.33	$7.96	$36.28	$28.33	$5.02	$33.35
2022	$28.12	$7.94	$36.07	$28.12	$5.02	$33.15
2023	$27.90	$7.83	$35.73	$27.90	$4.98	$32.87
2024	$27.73	$7.81	$35.54	$27.73	$4.95	$32.68
2025	$27.52	$7.81	$35.33	$27.52	$4.94	$32.46

Forecasts of Delivered Coal Prices: Green

GREEN	3.3% S, 10500 BTU					
	Mine-Mouth Price	Truck Transport Cost	Delivered Price	Mine-Mouth Price	Barge Transport Cost	Delivered Price
$/ton						
2007	$27.73	$4.79	$32.52	$27.73	$3.41	$31.14
2008	$30.41	$4.74	$35.15	$30.41	$3.41	$33.82
2009	$32.61	$4.57	$37.18	$32.61	$3.35	$35.96
2010	$33.14	$4.72	$37.86	$33.14	$3.44	$36.58
2011	$33.12	$4.88	$38.01	$33.12	$3.54	$36.66
2012	$33.12	$5.02	$38.13	$33.12	$3.62	$36.74
2013	$33.35	$5.13	$38.48	$33.35	$3.70	$37.05
2014	$33.67	$5.19	$38.86	$33.67	$3.74	$37.42
2015	$34.02	$5.26	$39.27	$34.02	$3.80	$37.82
2016	$34.41	$5.34	$39.76	$34.41	$3.86	$38.28
2017	$34.75	$5.37	$40.12	$34.75	$3.90	$38.65
2018	$35.13	$5.42	$40.56	$35.13	$3.95	$39.08
2019	$35.54	$5.51	$41.05	$35.54	$4.02	$39.55
2020	$35.94	$5.55	$41.49	$35.94	$4.06	$40.00
2021	$36.28	$5.61	$41.89	$36.28	$4.11	$40.40
2022	$36.69	$5.70	$42.39	$36.69	$4.18	$40.87
2023	$37.06	$5.72	$42.79	$37.06	$4.22	$41.28
2024	$37.51	$5.81	$43.32	$37.51	$4.26	$41.77
2025	$37.91	$5.92	$43.83	$37.91	$4.31	$42.22
Real 2006 $/ton						
2007	$27.06	$4.67	$31.74	$27.06	$3.33	$30.39
2008	$29.11	$4.53	$33.64	$29.11	$3.26	$32.37
2009	$30.60	$4.28	$34.89	$30.60	$3.14	$33.74
2010	$30.45	$4.34	$34.79	$30.45	$3.16	$33.61
2011	$29.79	$4.39	$34.18	$29.79	$3.18	$32.97
2012	$29.17	$4.42	$33.59	$29.17	$3.19	$32.36
2013	$28.81	$4.43	$33.24	$28.81	$3.19	$32.00
2014	$28.54	$4.40	$32.93	$28.54	$3.17	$31.71
2015	$28.29	$4.37	$32.67	$28.29	$3.16	$31.45
2016	$28.10	$4.36	$32.46	$28.10	$3.15	$31.25
2017	$27.86	$4.31	$32.16	$27.86	$3.13	$30.98
2018	$27.65	$4.27	$31.92	$27.65	$3.11	$30.76
2019	$27.46	$4.26	$31.72	$27.46	$3.10	$30.57
2020	$27.27	$4.21	$31.48	$27.27	$3.08	$30.35
2021	$27.04	$4.18	$31.22	$27.04	$3.06	$30.10
2022	$26.85	$4.17	$31.02	$26.85	$3.06	$29.90
2023	$26.63	$4.11	$30.74	$26.63	$3.03	$29.66
2024	$26.47	$4.10	$30.57	$26.47	$3.01	$29.47
2025	$26.27	$4.10	$30.37	$26.27	$2.99	$29.25

Forecasts of Delivered Coal Prices: Henderson

HENDERSON 3-4% S, 11000 BTU

	Mine-Mouth Price	Truck Transport Cost	Delivered Price	Mine-Mouth Price	Barge Transport Cost	Delivered Price
$/ton						
2007	$29.05	$4.79	$33.84	$29.05	$3.41	$32.47
2008	$31.86	$4.74	$36.60	$31.86	$3.41	$35.27
2009	$34.17	$4.57	$38.73	$34.17	$3.35	$37.51
2010	$34.72	$4.72	$39.44	$34.72	$3.44	$38.16
2011	$34.70	$4.88	$39.59	$34.70	$3.54	$38.24
2012	$34.69	$5.02	$39.71	$34.69	$3.62	$38.32
2013	$34.94	$5.13	$40.07	$34.94	$3.70	$38.63
2014	$35.28	$5.19	$40.46	$35.28	$3.74	$39.02
2015	$35.64	$5.26	$40.89	$35.64	$3.80	$39.44
2016	$36.05	$5.34	$41.40	$36.05	$3.86	$39.91
2017	$36.40	$5.37	$41.78	$36.40	$3.90	$40.31
2018	$36.81	$5.42	$42.23	$36.81	$3.95	$40.76
2019	$37.23	$5.51	$42.74	$37.23	$4.02	$41.25
2020	$37.65	$5.55	$43.20	$37.65	$4.06	$41.71
2021	$38.01	$5.61	$43.62	$38.01	$4.11	$42.12
2022	$38.43	$5.70	$44.14	$38.43	$4.18	$42.61
2023	$38.83	$5.72	$44.55	$38.83	$4.22	$43.04
2024	$39.30	$5.81	$45.11	$39.30	$4.26	$43.56
2025	$39.72	$5.92	$45.64	$39.72	$4.31	$44.03
Real 2006 $/ton						
2007	$28.35	$4.67	$33.02	$28.35	$3.33	$31.68
2008	$30.50	$4.53	$35.03	$30.50	$3.26	$33.75
2009	$32.06	$4.28	$36.34	$32.06	$3.14	$35.20
2010	$31.90	$4.34	$36.24	$31.90	$3.16	$35.06
2011	$31.21	$4.39	$35.60	$31.21	$3.18	$34.39
2012	$30.56	$4.42	$34.98	$30.56	$3.19	$33.75
2013	$30.18	$4.43	$34.61	$30.18	$3.19	$33.37
2014	$29.90	$4.40	$34.29	$29.90	$3.17	$33.07
2015	$29.64	$4.37	$34.01	$29.64	$3.16	$32.80
2016	$29.44	$4.36	$33.80	$29.44	$3.15	$32.59
2017	$29.18	$4.31	$33.49	$29.18	$3.13	$32.31
2018	$28.97	$4.27	$33.23	$28.97	$3.11	$32.07
2019	$28.77	$4.26	$33.03	$28.77	$3.10	$31.87
2020	$28.57	$4.21	$32.78	$28.57	$3.08	$31.65
2021	$28.33	$4.18	$32.50	$28.33	$3.06	$31.39
2022	$28.12	$4.17	$32.30	$28.12	$3.06	$31.18
2023	$27.90	$4.11	$32.01	$27.90	$3.03	$30.93
2024	$27.73	$4.10	$31.83	$27.73	$3.01	$30.73
2025	$27.52	$4.10	$31.62	$27.52	$2.99	$30.50

Forecasts of Delivered Coal Prices: Reid

REID **<2.7% S, 11000 BTU**

	Mine-Mouth Price	Truck Transport Cost	Delivered Price	Mine-Mouth Price	Barge Transport Cost	Delivered Price
$/ton						
2007	$33.27	$5.35	$38.62	$33.27	$5.80	$39.07
2008	$37.60	$5.29	$42.89	$37.60	$5.77	$43.36
2009	$40.15	$5.10	$45.25	$40.15	$5.62	$45.77
2010	$40.62	$5.28	$45.90	$40.62	$5.80	$46.42
2011	$40.56	$5.46	$46.01	$40.56	$5.97	$46.53
2012	$40.50	$5.60	$46.10	$40.50	$6.12	$46.62
2013	$40.74	$5.73	$46.47	$40.74	$6.26	$47.00
2014	$41.09	$5.79	$46.88	$41.09	$6.33	$47.42
2015	$41.46	$5.87	$47.33	$41.46	$6.42	$47.88
2016	$41.90	$5.97	$47.87	$41.90	$6.53	$48.43
2017	$42.26	$6.00	$48.26	$42.26	$6.58	$48.84
2018	$42.68	$6.06	$48.74	$42.68	$6.66	$49.34
2019	$43.12	$6.16	$49.28	$43.12	$6.77	$49.89
2020	$43.56	$6.20	$49.76	$43.56	$6.83	$50.39
2021	$43.93	$6.26	$50.19	$43.93	$6.91	$50.84
2022	$44.37	$6.37	$50.74	$44.37	$7.02	$51.39
2023	$44.77	$6.39	$51.17	$44.77	$7.07	$51.84
2024	$45.26	$6.49	$51.76	$45.26	$7.16	$52.42
2025	$45.69	$6.61	$52.31	$45.69	$7.26	$52.96
Real 2006 $/ton						
2007	$32.46	$5.22	$37.68	$32.46	$5.66	$38.12
2008	$35.98	$5.06	$41.05	$35.98	$5.52	$41.50
2009	$37.67	$4.79	$42.45	$37.67	$5.28	$42.95
2010	$37.32	$4.85	$42.17	$37.32	$5.33	$42.65
2011	$36.48	$4.91	$41.38	$36.48	$5.37	$41.85
2012	$35.68	$4.94	$40.61	$35.68	$5.39	$41.07
2013	$35.19	$4.95	$40.14	$35.19	$5.40	$40.59
2014	$34.82	$4.91	$39.73	$34.82	$5.37	$40.19
2015	$34.49	$4.88	$39.37	$34.49	$5.34	$39.83
2016	$34.21	$4.87	$39.09	$34.21	$5.33	$39.54
2017	$33.88	$4.81	$38.69	$33.88	$5.28	$39.15
2018	$33.59	$4.77	$38.36	$33.59	$5.24	$38.83
2019	$33.32	$4.76	$38.08	$33.32	$5.23	$38.55
2020	$33.06	$4.70	$37.76	$33.06	$5.18	$38.24
2021	$32.74	$4.67	$37.40	$32.74	$5.15	$37.88
2022	$32.47	$4.66	$37.13	$32.47	$5.14	$37.61
2023	$32.17	$4.59	$36.76	$32.17	$5.08	$37.25
2024	$31.94	$4.58	$36.52	$31.94	$5.05	$36.99
2025	$31.66	$4.58	$36.24	$31.66	$5.03	$36.69

Forecasts of Delivered Coal Prices: Wilson

WILSON 3.3% S, 10700 BTU

	Mine-Mouth Price	Truck Transport Cost	Delivered Price	Mine-Mouth Price	Barge Transport Cost	Delivered Price
$/ton						
2007	$28.26	$6.59	$34.85	$28.26	$3.53	$31.79
2008	$30.99	$6.52	$37.51	$30.99	$3.52	$34.51
2009	$33.23	$6.28	$39.52	$33.23	$3.46	$36.69
2010	$33.77	$6.50	$40.27	$33.77	$3.56	$37.33
2011	$33.76	$6.72	$40.47	$33.76	$3.66	$37.41
2012	$33.75	$6.90	$40.65	$33.75	$3.74	$37.49
2013	$33.98	$7.06	$41.05	$33.98	$3.82	$37.81
2014	$34.32	$7.14	$41.45	$34.32	$3.87	$38.19
2015	$34.67	$7.23	$41.90	$34.67	$3.93	$38.59
2016	$35.07	$7.35	$42.42	$35.07	$4.00	$39.07
2017	$35.41	$7.39	$42.80	$35.41	$4.04	$39.45
2018	$35.80	$7.46	$43.26	$35.80	$4.09	$39.89
2019	$36.21	$7.58	$43.80	$36.21	$4.16	$40.37
2020	$36.62	$7.63	$44.26	$36.62	$4.20	$40.82
2021	$36.97	$7.72	$44.69	$36.97	$4.26	$41.23
2022	$37.39	$7.84	$45.23	$37.39	$4.33	$41.72
2023	$37.77	$7.88	$45.64	$37.77	$4.37	$42.13
2024	$38.23	$8.00	$46.22	$38.23	$4.41	$42.64
2025	$38.63	$8.14	$46.78	$38.63	$4.47	$43.10
Real 2006 $/ton						
2007	$27.58	$6.43	$34.01	$27.58	$3.44	$31.02
2008	$29.66	$6.24	$35.90	$29.66	$3.37	$33.03
2009	$31.18	$5.90	$37.08	$31.18	$3.25	$34.43
2010	$31.03	$5.97	$37.00	$31.03	$3.27	$34.30
2011	$30.36	$6.04	$36.40	$30.36	$3.29	$33.65
2012	$29.73	$6.08	$35.81	$29.73	$3.30	$33.03
2013	$29.35	$6.10	$35.45	$29.35	$3.30	$32.66
2014	$29.08	$6.05	$35.13	$29.08	$3.28	$32.36
2015	$28.83	$6.01	$34.85	$28.83	$3.27	$32.10
2016	$28.64	$6.00	$34.64	$28.64	$3.26	$31.90
2017	$28.39	$5.93	$34.31	$28.39	$3.24	$31.62
2018	$28.18	$5.87	$34.05	$28.18	$3.22	$31.39
2019	$27.99	$5.86	$33.85	$27.99	$3.21	$31.20
2020	$27.79	$5.79	$33.58	$27.79	$3.19	$30.98
2021	$27.55	$5.75	$33.30	$27.55	$3.17	$30.73
2022	$27.36	$5.74	$33.10	$27.36	$3.17	$30.52
2023	$27.14	$5.66	$32.80	$27.14	$3.14	$30.28
2024	$26.97	$5.64	$32.61	$26.97	$3.11	$30.09
2025	$26.77	$5.64	$32.41	$26.77	$3.10	$29.86

SO2 Allowance Price Forecast

SO2 ALLOWANCE PRICE FORECAST

Year	Nominal $/Ton	% Change	Real 2006 $/Ton	% Change
1992	$320		$430	
1993	$187	-41.72%	$245	-43.03%
1994	$164	-12.20%	$210	-14.02%
1995	$133	-19.08%	$167	-20.71%
1996	$84	-36.86%	$103	-38.02%
1997	$99	18.43%	$120	16.49%
1998	$157	58.90%	$189	57.15%
1999	$194	23.53%	$231	21.77%
2000	$141	-27.37%	$164	-28.92%
2001	$186	31.51%	$210	28.43%
2002	$153	-17.62%	$170	-19.04%
2003	$174	13.88%	$190	11.52%
2004	$438	151.30%	$464	144.36%
2005	$906	106.96%	$933	100.86%
2006	$731	-19.35%	$731	-21.63%
2007	$549	-24.92%	$536	-26.74%
2008	$778	41.75%	$745	39.04%
2009	$853	9.63%	$800	7.48%
2010	$881	3.30%	$809	1.15%
2011	$818	-7.12%	$736	-9.08%
2012	$792	-3.27%	$697	-5.26%
2013	$747	-5.61%	$645	-7.45%
2014	$787	5.29%	$667	3.31%
2015	$907	15.27%	$754	13.13%
2016	$759	-16.28%	$620	-17.81%
2017	$618	-18.54%	$496	-20.03%
2018	$357	-42.27%	$281	-43.33%
2019	$146	-59.04%	$113	-59.78%
2020	$137	-6.43%	$104	-8.11%
2021	$134	-1.70%	$100	-3.47%
2022	$111	-17.25%	$81	-18.75%
2023	$105	-6.00%	$75	-7.69%
2024	$102	-2.41%	$72	-4.17%
2025	$98	-4.06%	$68	-5.80%

NOTE: The price depicts the cost of reducing one ton of emissions. Under CAIR, 2 allowances generated after 2009 will be needed to reduce one ton of emissions, and in 2015 the ratio will rise to 2.86:1 As a result, reducing a ton of emissions in 2013 would take one pre-2010 allowance priced at $728 (nominal $), or two 2010-2012 allowances priced at $364 each.

NOx Allowance Price Forecast

NOx ALLOWANCE PRICE FORECAST (ANNUAL)

Year	Nominal $/Ton	% Change	Real 2006 $/Ton	% Change
2007	$6,840		$6,674	
2008	$3,482	-49.09%	$3,333	-50.07%
2009	$2,847	-18.22%	$2,672	-19.83%
2010	$2,409	-15.41%	$2,213	-17.17%
2011	$2,155	-10.54%	$1,938	-12.43%
2012	$1,985	-7.88%	$1,749	-9.77%
2013	$1,900	-4.29%	$1,641	-6.16%
2014	$1,909	0.49%	$1,618	-1.40%
2015	$1,869	-2.08%	$1,555	-3.90%
2016	$1,748	-6.47%	$1,428	-8.18%
2017	$1,625	-7.03%	$1,303	-8.73%
2018	$1,569	-3.50%	$1,234	-5.26%
2019	$1,510	-3.71%	$1,167	-5.45%
2020	$1,521	0.68%	$1,154	-1.13%
2021	$1,523	0.17%	$1,135	-1.64%
2022	$1,525	0.15%	$1,116	-1.65%
2023	$1,527	0.13%	$1,098	-1.67%
2024	$1,529	0.12%	$1,079	-1.69%
2025	$1,531	0.11%	$1,061	-1.70%

NOTE: Prices for 2007-2008 are for pre-CAIR trading; prices for 2009-2
are for the actual time period covered by CAIR

Portfolio Report
annual output - 12-15-07 (2).xls

	A	B	C	D	E	F	G	H	I	J
1	**Resource Costs**	2006	2007	2008	2009	2010	2011	2012	2013	2014
2	DBWilson			$ 61,402	$ 50,832	$ 58,455	$ 54,535	$ 65,203	$ 65,790	$ 74,156
3	HMPL1			$ 24,464	$ 23,336	$ 27,254	$ 24,334	$ 28,189	$ 26,992	$ 28,954
4	HMPL2			$ 23,253	$ 26,417	$ 26,888	$ 29,059	$ 25,343	$ 29,795	$ 28,431
5	Coleman 1			$ 20,949	$ 25,140	$ 25,681	$ 24,804	$ 26,423	$ 26,382	$ 25,887
6	Coleman 2			$ 24,651	$ 25,713	$ 24,323	$ 25,155	$ 24,730	$ 24,399	$ 24,537
7	Coleman 3			$ 25,303	$ 24,225	$ 26,365	$ 26,764	$ 22,551	$ 27,465	$ 27,445
8	Reid ST			$ 3,056	$ 2,707	$ 390	$ 7,947	$ -	$ 2,300	$ 2,478
9	Reid GT			$ 196	$ 329	$ 363	$ 552	$ 717	$ 644	$ 758
10	Green 1			$ 29,677	$ 35,767	$ 40,656	$ 44,831	$ 43,276	$ 44,488	$ 40,591
11	Green 2			$ 29,458	$ 31,819	$ 42,519	$ 36,585	$ 43,289	$ 42,340	$ 45,604
12										
13										
14	SEPA			$ 6,815	$ 6,809	$ 6,847	$ 6,849	$ 8,585	$ 7,735	$ 7,938
15	**Total Op Costs**			**$ 249,224**	**$ 253,096**	**$ 279,741**	**$ 281,415**	**$ 288,307**	**$ 298,329**	**$ 306,779**
16										
17	**Emissions Costs**									
18	SO2 Price			$ 778	$ 853	$ 441	$ 409	$ 396	$ 374	$ 393
19	SO2(ktons) - emitted			23.133	20.077	21.157	20.054	20.575	19.581	20.601
20	SO2(ktons) - REQUIRED for compliance			23.133	20.077	42.314	40.107	41.150	39.161	41.201
21	SO2 cost($000)			$ 17,997	$ 17,124	$ 18,641	$ 16,410	$ 16,286	$ 14,631	$ 16,208
22	SO2 Allowances			52.487	52.487	52.487	52.487	52.487	52.487	52.487
23	SO2 Allowance Credits			$ (40,835)	$ (44,767)	$ (23,122)	$ (21,476)	$ (20,774)	$ (19,609)	$ (20,647)
24	HMPL SO2(ktons) - emitted			4.174	4.269	4.251	4.101	4.061	4.281	4.279
25	HMPL SO2(ktons) - REQUIRED for compliance			4.174	4.269	8.502	8.201	8.123	8.562	8.558
26	HMPL Allowances			11.694	11.694	11.694	11.694	11.694	11.694	11.694
27	Excess HMPL Allowances Back to City (30% of net)			2.256	2.228	0.957	1.048	1.071	0.940	0.941
28	Allowance $ to City			$ 1,755	$ 1,900	$ 422	$ 429	$ 424	$ 351	$ 370
29										
30										
31	NOx Price			$ 763	$ 2,847	$ 2,409	$ 2,155	$ 1,985	$ 1,900	$ 1,909
32	NOx(ktons)			5.046	13.896	13.892	13.202	13.196	13.365	13.275
33	NOx Emissions Alloc to City (ktons)			0.107	0.286	0.286	0.287	0.301	0.302	0.301
34	Net NOx Emissions			4.939	13.610	13.606	12.916	12.895	13.063	12.974
35	NOx cost($000)			$ 3,768	$ 38,755	$ 32,774	$ 27,831	$ 25,597	$ 24,817	$ 24,769
36	NOx Allowances			4.799	11.398	11.398	11.398	11.398	11.398	11.398
37	NOx Allowances Alloc to City (ktons)			0.147	0.326	0.326	0.327	0.341	0.342	0.341
38	Net NOx Allowances			4.652	11.072	11.072	11.071	11.057	11.056	11.057
39	NOx Allowance Credits			$ (3,549)	$ (31,528)	$ (26,670)	$ (23,857)	$ (21,949)	$ (21,005)	$ (21,109)
40										
41	**Net Emissions Costs**			**$ (20,864)**	**$ (18,516)**	**$ 2,044**	**$ (662)**	**$ (415)**	**$ (815)**	**$ (410)**
42										
43	**Market Purchases**									
44	Purchased GWh			256	286	193	463	381	544	374
45	Price per MWh			$ 44.87	$ 53.53	$ 53.88	$ 51.18	$ 48.73	$ 43.89	$ 46.92
46	Purchases - $			$ 11,480	$ 15,303	$ 10,411	$ 23,676	$ 18,569	$ 23,857	$ 17,567
47										
48	**Smelter Sales**									
49	Smelter GWh			(7,317)	(7,297)	(7,297)	(7,297)	(7,317)	(7,297)	(7,297)
50	Price per MWh			$ 27.05	$ 27.05	$ 27.05	$ 30.25	$ 30.25	$ 30.25	$ 30.25
51	Smelter Revs			$ (197,927)	$ (197,386)	$ (197,386)	$ (220,737)	$ (221,341)	$ (220,737)	$ (220,737)
52										
53	**Henderson Sales**									
54	Henderson GWh - at Gen Bus			(634)	(632)	(632)	(632)	(666)	(666)	(666)
55	Price per MWh			$ 20.37	$ 20.83	$ 22.77	$ 23.28	$ 23.57	$ 23.71	$ 23.98
56	Contract Revs			$ (12,919)	$ (13,174)	$ (14,396)	$ (14,723)	$ (15,688)	$ (15,786)	$ (15,962)
57	Payments to HMPL (@ $1.50/MWh)			$ 312	$ 311	$ 311	$ 311	$ 331	$ 327	$ 327
58										
59	**Contract Sales**									
60	Contract GWh			-	-	-	-	-	-	-
61	Price per MWh			$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	Contract Revs			$ -	$ -	$ -	$ -	$ -	$ -	$ -
63										
64	**Market Sales**									
65	Market GWh			(1,614)	(1,493)	(1,613)	(1,319)	(1,211)	(1,199)	(1,171)
66	Price per MWh			$ 45.01	$ 48.89	$ 47.12	$ 47.83	$ 46.04	$ 49.03	$ 49.45
67	Market Revs			$ (72,633)	$ (73,011)	$ (76,015)	$ (63,109)	$ (55,762)	$ (58,797)	$ (57,921)
68										
69										
70	Total System Costs			$ (43,328)	$ (33,378)	$ 4,710	$ 6,170	$ 14,000	$ 26,378	$ 29,645
71	Native Load			3,409	3,501	3,584	3,674	3,760	3,852	3,939
72	Native Load Cost per MWh			(12.71)	(9.53)	1.31	1.68	3.72	6.85	7.53
73										
74	*Gross System Costs*			$ 239,840	$ 249,882	$ 292,196	$ 304,428	$ 306,460	$ 321,370	$ 323,936
75	Gross Source GWh			13,070	13,020	13,224	13,021	13,057	13,118	13,178
76	Average System per MWh			18.350	19.192	22.095	23.379	23.471	24.498	24.581
77										
78										
79										
80	**Sources and Uses of Energy**									
81	**Sources**									
82	System Gen			12,511	12,431	12,726	12,253	12,373	12,308	12,537
83	SEPA			304	303	305	305	303	266	267
84	Market Purchases			256	286	193	463	381	544	374
85	***Total Sources***			**13,070**	**13,020**	**13,224**	**13,021**	**13,057**	**13,118**	**13,178**
86										
87	**Uses**									
88	Native Load			3,409	3,501	3,584	3,674	3,760	3,852	3,939
89										
90	Smelter Load			7,317	7,297	7,297	7,297	7,317	7,297	7,297
91	Henderson Load			628	627	627	627	660	660	660
92	Sales Load			-	-	-	-	-	-	-
93	Mkt Sales			1,614	1,493	1,613	1,319	1,211	1,199	1,171
94	Losses			102	102	103	104	109	110	112
95	**Total Uses**			**13,070**	**13,020**	**13,224**	**13,021**	**13,057**	**13,118**	**13,178**

Portfolio Report
annual output - 12-15-07 (2).xls

	A	K	L	M	N	O	P	Q	R	S
1	**Resource Costs**	2015	2016	2017	2018	2019	2020	2021	2022	2023
2	DBWilson	$ 72,453	$ 78,026	$ 68,886	$ 79,508	$ 77,128	$ 82,026	$ 79,254	$ 84,180	$ 81,061
3	HMPL1	$ 27,728	$ 29,937	$ 28,377	$ 31,366	$ 28,051	$ 29,663	$ 31,019	$ 33,483	$ 31,034
4	HMPL2	$ 30,931	$ 29,590	$ 31,763	$ 29,867	$ 32,273	$ 28,747	$ 33,865	$ 32,846	$ 34,184
5	Coleman 1	$ 27,675	$ 27,859	$ 24,208	$ 28,209	$ 28,990	$ 27,899	$ 29,749	$ 30,210	$ 28,518
6	Coleman 2	$ 26,907	$ 22,333	$ 28,081	$ 28,542	$ 26,198	$ 28,508	$ 29,239	$ 27,606	$ 30,341
7	Coleman 3	$ 25,379	$ 28,131	$ 28,518	$ 27,112	$ 28,442	$ 29,651	$ 26,177	$ 30,932	$ 31,156
8	Reid ST	$ 1,213	$ 4,579	$ 7,098	$ 1,437	$ -	$ 2,131	$ 2,315	$ -	$ -
9	Reid GT	$ 697	$ 757	$ 993	$ 788	$ 748	$ 824	$ 835	$ 897	$ 932
10	Green 1	$ 49,101	$ 45,236	$ 49,730	$ 46,320	$ 51,067	$ 49,408	$ 52,864	$ 44,737	$ 54,343
11	Green 2	$ 42,116	$ 46,865	$ 44,381	$ 46,716	$ 42,919	$ 48,711	$ 48,773	$ 51,596	$ 50,436
12										
13										
14	SEPA	$ 7,948	$ 7,944	$ 7,971	$ 8,117	$ 8,321	$ 8,293	$ 8,373	$ 8,395	$ 8,574
15	**Total Op Costs**	**$ 312,148**	**$ 321,256**	**$ 320,006**	**$ 327,982**	**$ 324,137**	**$ 335,860**	**$342,464**	**$344,882**	**$350,578**
16										
17	**Emissions Costs**									
18	SO2 Price	$ 317	$ 265	$ 216	$ 125	$ 51	$ 48	$ 47	$ 39	$ 37
19	SO2(ktons) - emitted	20.336	20.806	19.359	20.823	19.986	20.516	20.501	20.755	20.354
20	SO2(ktons) - REQUIRED for compliance	58.161	59.504	55.367	59.552	57.161	58.675	58.631	59.358	58.212
21	SO2 cost($000)	$ 18,442	$ 15,796	$ 11,973	$ 7,434	$ 2,922	$ 2,807	$ 2,757	$ 2,310	$ 2,129
22	SO2 Allowances	52.487	52.487	52.487	52.487	52.487	52.487	52.487	52.487	52.487
23	SO2 Allowance Credits	$ (16,643)	$ (13,933)	$ (11,350)	$ (6,552)	$ (2,683)	$ (2,511)	$ (2,468)	$ (2,042)	$ (1,920)
24	HMPL SO2(ktons) - emited	4.262	4.238	4.228	4.248	4.065	3.867	4.315	4.317	4.195
25	HMPL SO2(ktons) - REQUIRED for compliance	12.189	12.122	12.093	12.148	11.627	11.060	12.342	12.347	11.998
26	HMPL Allowances	11.694	11.694	11.694	11.694	11.694	11.694	11.694	11.694	11.694
27	Excess HMPL Allowances Back to City (30% of net)	-	-	-	-	0.020	0.190	-	-	-
28	Allowance $ to City	$ -	$ -	$ -	$ -	$ 1	$ 9	$ -	$ -	$ -
29										
30										
31	NOx Price	$ 1,869	$ 1,748	$ 1,625	$ 1,569	$ 1,510	$ 1,521	$ 1,523	$ 1,525	$ 1,527
32	NOx(ktons)	13.416	13.290	13.315	13.361	13.114	13.466	13.489	13.237	13.588
33	NOx Emissions Alloc to City (ktons)	0.301	0.301	0.301	0.301	0.301	0.301	0.301	0.301	0.301
34	Net NOx Emissions	13.115	12.988	13.014	13.060	12.813	13.164	13.188	12.936	13.288
35	NOx cost($000)	$ 24,518	$ 22,708	$ 21,154	$ 20,485	$ 19,352	$ 20,017	$ 20,087	$ 19,732	$ 20,297
36	NOx Allowances	9.285	9.285	8.832	8.638	8.494	8.289	8.054	7.832	7.76
37	NOx Allowances Alloc to City (ktons)	0.341	0.341	0.341	0.341	0.341	0.341	0.341	0.341	0.341
38	Net NOx Allowances	8.944	8.944	8.491	8.297	8.153	7.948	7.713	7.491	7.419
39	NOx Allowance Credits	$ (16,721)	$ (15,637)	$ (13,802)	$ (13,014)	$ (12,313)	$ (12,085)	$ (11,748)	$ (11,427)	$ (11,333)
40										
41	**Net Emissions Costs**	**$ 9,596**	**$ 8,934**	**$ 7,974**	**$ 8,353**	**$ 7,279**	**$ 8,237**	**$ 8,628**	**$ 8,573**	**$ 9,173**
42										
43	**Market Purchases**									
44	Purchased GWh	424	419	718	471	662	530	553	624	712
45	Price per MWh	$ 48.93	$ 48.57	$ 49.27	$ 46.27	$ 48.71	$ 52.10	$ 59.38	$ 55.96	$ 59.64
46	Purchases - $	$ 20,727	$ 20,330	$ 35,360	$ 21,813	$ 32,248	$ 27,610	$ 32,822	$ 34,943	$ 42,448
47										
48	**Smelter Sales**									
49	Smelter GWh	(7,297)	(7,317)	(7,297)	(7,297)	(7,297)	(7,317)	(7,297)	(7,297)	(7,297)
50	Price per MWh	$ 30.25	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 33.00	$ 36.50	$ 36.50	$ 36.50
51	Smelter Revs	$ (220,737)	$ (241,463)	$ (240,804)	$ (240,804)	$ (240,804)	$ (241,463)	$ (266,343)	$ (266,343)	$ (266,343)
52										
53	**Henderson Sales**									
54	Henderson GWh - at Gen Bus	(666)	(666)	(666)	(666)	(666)	(666)	(666)	(666)	(666)
55	Price per MWh	$ 24.61	$ 25.11	$ 25.43	$ 25.77	$ 26.53	$ 27.00	$ 26.88	$ 27.47	$ 27.80
56	Contract Revs	$ (16,384)	$ (16,715)	$ (16,929)	$ (17,157)	$ (17,661)	$ (17,973)	$ (17,895)	$ (18,288)	$ (18,503)
57	Payments to HMPL (@ $1.50/MWh)	$ 327	$ 331	$ 327	$ 327	$ 327	$ 331	$ 327	$ 327	$ 327
58										
59	**Contract Sales**									
60	Contract GWh	-	-	-	-	-	-	-	-	-
61	Price per MWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	Contract Revs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63										
64	**Market Sales**									
65	Market GWh	(1,117)	(1,082)	(915)	(986)	(695)	(717)	(748)	(685)	(700)
66	Price per MWh	$ 51.13	$ 50.09	$ 51.19	$ 52.10	$ 54.81	$ 54.95	$ 53.44	$ 57.09	$ 56.30
67	Market Revs	$ (57,108)	$ (54,212)	$ (46,844)	$ (51,383)	$ (38,120)	$ (39,423)	$ (39,989)	$ (39,085)	$ (39,397)
68										
69										
70	Total System Costs	$ 48,569	$ 38,460	$ 59,090	$ 49,132	$ 67,407	$ 73,180	$ 60,015	$ 65,009	$ 78,282
71	Native Load	4,032	4,122	4,217	4,308	4,404	4,498	4,596	4,691	4,786
72	Native Load Cost per MWh	12.05	9.33	14.01	11.41	15.30	16.27	13.06	13.86	16.36
73										
74	Gross System Costs	$ 342,471	$ 350,520	$ 363,340	$ 358,148	$ 363,663	$ 371,708	$ 383,915	$ 388,397	$ 402,199
75	Gross Source GWh	13,217	13,296	13,203	13,367	13,173	13,312	13,420	13,452	13,562
76	Average System per MWh	25.912	26.363	27.519	26.792	27.607	27.924	28.608	28.873	29.656
77										
78										
79										
80	**Sources and Uses of Energy**									
81	**Sources**									
82	System Gen	12,526	12,611	12,218	12,630	12,244	12,516	12,599	12,559	12,582
83	SEPA	267	267	268	266	266	265	268	269	268
84	Market Purchases	424	419	718	471	662	530	553	624	712
85	**Total Sources**	**13,217**	**13,296**	**13,203**	**13,367**	**13,173**	**13,312**	**13,420**	**13,452**	**13,562**
86										
87	**Uses**									
88	Native Load	4,032	4,122	4,217	4,308	4,404	4,498	4,596	4,691	4,786
89										
90	Smelter Load	7,297	7,317	7,297	7,297	7,297	7,317	7,297	7,297	7,297
91	Henderson Load	660	660	660	660	660	660	660	660	660
92	Sales Load	-	-	-	-	-	-	-	-	-
93	Mkt Sales	1,117	1,082	915	986	695	717	748	685	700
94	Losses	111	115	114	117	116	119	118	120	119
95	**Total Uses**	**13,217**	**13,296**	**13,203**	**13,367**	**13,173**	**13,312**	**13,420**	**13,452**	**13,562**

Emissions & Allowance Summary

Nominal dollars

	2008	2009	2010	2011	2012
SO2 Price forecast	$ 778	$ 853	$ 441	$ 409	$ 396
year beginning SO2 allowance inventory	0.000	0.000	14.000	14.000	14.000
Total SO2 tons emitted x1000	14.849	20.077	21.157	20.054	20.575
yearly SO2 allowances surrendered back to EPA	14.849	20.077	42.314	40.107	41.150
yearly allocation of SO2 allowances from EPA	34.991	52.487	52.487	52.487	52.487
yearly SO2 allowances x1000 excess/(short) gross of City	20.142	32.410	10.173	12.380	11.337
Excess H-1&2 Allowances Back to City (capacity take)	1.522	2.228	0.957	1.048	1.071
yearly SO2 allowances x1000 sold/(purchased) net of City	18.620	30.182	9.216	11.332	10.266
year ending SO2 allowance inventory	0.000	14.000	14.000	14.000	14.000
SO2 allowances Sales/(purchases) net of City	$14,486,360	$25,745,246	$4,064,256	$4,634,788	$4,065,336

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Forecasts of Delivered Coal Prices: Coleman

COLEMAN 3-4% S, 11000 BTU

	Mine-Mouth Price	Truck Transport Cost	Delivered Price	Mine-Mouth Price	Barge Transport Cost	Delivered Price
$/ton						
2007	$29.05	$9.12	$38.17	$29.05	$5.52	$34.57
2008	$31.86	$9.02	$40.88	$31.86	$5.50	$37.36
2009	$34.17	$8.69	$42.86	$34.17	$5.37	$39.54
2010	$34.72	$9.00	$43.71	$34.72	$5.54	$40.26
2011	$34.70	$9.30	$44.00	$34.70	$5.71	$40.41
2012	$34.69	$9.55	$44.25	$34.69	$5.85	$40.54
2013	$34.94	$9.77	$44.71	$34.94	$5.98	$40.92
2014	$35.28	$9.88	$45.15	$35.28	$6.06	$41.34
2015	$35.64	$10.01	$45.64	$35.64	$6.15	$41.79
2016	$36.05	$10.17	$46.23	$36.05	$6.28	$42.33
2017	$36.40	$10.23	$46.64	$36.40	$6.35	$42.75
2018	$36.81	$10.33	$47.13	$36.81	$6.44	$43.25
2019	$37.23	$10.50	$47.73	$37.23	$6.57	$43.80
2020	$37.65	$10.57	$48.21	$37.65	$6.65	$44.29
2021	$38.01	$10.68	$48.69	$38.01	$6.74	$44.75
2022	$38.43	$10.86	$49.29	$38.43	$6.86	$45.30
2023	$38.83	$10.90	$49.73	$38.83	$6.92	$45.75
2024	$39.30	$11.07	$50.37	$39.30	$7.02	$46.32
2025	$39.72	$11.27	$50.99	$39.72	$7.13	$46.85
Real 2006 $/ton						
2007	$28.35	$8.90	$37.25	$28.35	$5.39	$33.74
2008	$30.50	$8.63	$39.13	$30.50	$5.26	$35.76
2009	$32.06	$8.16	$40.22	$32.06	$5.04	$37.10
2010	$31.90	$8.27	$40.16	$31.90	$5.09	$36.99
2011	$31.21	$8.36	$39.57	$31.21	$5.13	$36.34
2012	$30.56	$8.41	$38.98	$30.56	$5.15	$35.71
2013	$30.18	$8.44	$38.62	$30.18	$5.16	$35.34
2014	$29.90	$8.37	$38.27	$29.90	$5.14	$35.03
2015	$29.64	$8.32	$37.96	$29.64	$5.12	$34.76
2016	$29.44	$8.31	$37.75	$29.44	$5.12	$34.56
2017	$29.18	$8.20	$37.38	$29.18	$5.09	$34.27
2018	$28.97	$8.13	$37.09	$28.97	$5.07	$34.04
2019	$28.77	$8.11	$36.88	$28.77	$5.07	$33.84
2020	$28.57	$8.02	$36.59	$28.57	$5.04	$33.61
2021	$28.33	$7.96	$36.28	$28.33	$5.02	$33.35
2022	$28.12	$7.94	$36.07	$28.12	$5.02	$33.15
2023	$27.90	$7.83	$35.73	$27.90	$4.98	$32.87
2024	$27.73	$7.81	$35.54	$27.73	$4.95	$32.68
2025	$27.52	$7.81	$35.33	$27.52	$4.94	$32.46

Forecasts of Delivered Coal Prices: Green

GREEN	3.3% S, 10500 BTU					
	Mine-Mouth Price	Truck Transport Cost	Delivered Price	Mine-Mouth Price	Barge Transport Cost	Delivered Price
$/ton						
2007	$27.73	$4.79	$32.52	$27.73	$3.41	$31.14
2008	$30.41	$4.74	$35.15	$30.41	$3.41	$33.82
2009	$32.61	$4.57	$37.18	$32.61	$3.35	$35.96
2010	$33.14	$4.72	$37.86	$33.14	$3.44	$36.58
2011	$33.12	$4.88	$38.01	$33.12	$3.54	$36.66
2012	$33.12	$5.02	$38.13	$33.12	$3.62	$36.74
2013	$33.35	$5.13	$38.48	$33.35	$3.70	$37.05
2014	$33.67	$5.19	$38.86	$33.67	$3.74	$37.42
2015	$34.02	$5.26	$39.27	$34.02	$3.80	$37.82
2016	$34.41	$5.34	$39.76	$34.41	$3.86	$38.28
2017	$34.75	$5.37	$40.12	$34.75	$3.90	$38.65
2018	$35.13	$5.42	$40.56	$35.13	$3.95	$39.08
2019	$35.54	$5.51	$41.05	$35.54	$4.02	$39.55
2020	$35.94	$5.55	$41.49	$35.94	$4.06	$40.00
2021	$36.28	$5.61	$41.89	$36.28	$4.11	$40.40
2022	$36.69	$5.70	$42.39	$36.69	$4.18	$40.87
2023	$37.06	$5.72	$42.79	$37.06	$4.22	$41.28
2024	$37.51	$5.81	$43.32	$37.51	$4.26	$41.77
2025	$37.91	$5.92	$43.83	$37.91	$4.31	$42.22
Real 2006 $/ton						
2007	$27.06	$4.67	$31.74	$27.06	$3.33	$30.39
2008	$29.11	$4.53	$33.64	$29.11	$3.26	$32.37
2009	$30.60	$4.28	$34.89	$30.60	$3.14	$33.74
2010	$30.45	$4.34	$34.79	$30.45	$3.16	$33.61
2011	$29.79	$4.39	$34.18	$29.79	$3.18	$32.97
2012	$29.17	$4.42	$33.59	$29.17	$3.19	$32.36
2013	$28.81	$4.43	$33.24	$28.81	$3.19	$32.00
2014	$28.54	$4.40	$32.93	$28.54	$3.17	$31.71
2015	$28.29	$4.37	$32.67	$28.29	$3.16	$31.45
2016	$28.10	$4.36	$32.46	$28.10	$3.15	$31.25
2017	$27.86	$4.31	$32.16	$27.86	$3.13	$30.98
2018	$27.65	$4.27	$31.92	$27.65	$3.11	$30.76
2019	$27.46	$4.26	$31.72	$27.46	$3.10	$30.57
2020	$27.27	$4.21	$31.48	$27.27	$3.08	$30.35
2021	$27.04	$4.18	$31.22	$27.04	$3.06	$30.10
2022	$26.85	$4.17	$31.02	$26.85	$3.06	$29.90
2023	$26.63	$4.11	$30.74	$26.63	$3.03	$29.66
2024	$26.47	$4.10	$30.57	$26.47	$3.01	$29.47
2025	$26.27	$4.10	$30.37	$26.27	$2.99	$29.25

Forecasts of Delivered Coal Prices: Henderson

HENDERSON 3-4% S, 11000 BTU

	Mine-Mouth Price	Truck Transport Cost	Delivered Price	Mine-Mouth Price	Barge Transport Cost	Delivered Price
$/ton						
2007	$29.05	$4.79	$33.84	$29.05	$3.41	$32.47
2008	$31.86	$4.74	$36.60	$31.86	$3.41	$35.27
2009	$34.17	$4.57	$38.73	$34.17	$3.35	$37.51
2010	$34.72	$4.72	$39.44	$34.72	$3.44	$38.16
2011	$34.70	$4.88	$39.59	$34.70	$3.54	$38.24
2012	$34.69	$5.02	$39.71	$34.69	$3.62	$38.32
2013	$34.94	$5.13	$40.07	$34.94	$3.70	$38.63
2014	$35.28	$5.19	$40.46	$35.28	$3.74	$39.02
2015	$35.64	$5.26	$40.89	$35.64	$3.80	$39.44
2016	$36.05	$5.34	$41.40	$36.05	$3.86	$39.91
2017	$36.40	$5.37	$41.78	$36.40	$3.90	$40.31
2018	$36.81	$5.42	$42.23	$36.81	$3.95	$40.76
2019	$37.23	$5.51	$42.74	$37.23	$4.02	$41.25
2020	$37.65	$5.55	$43.20	$37.65	$4.06	$41.71
2021	$38.01	$5.61	$43.62	$38.01	$4.11	$42.12
2022	$38.43	$5.70	$44.14	$38.43	$4.18	$42.61
2023	$38.83	$5.72	$44.55	$38.83	$4.22	$43.04
2024	$39.30	$5.81	$45.11	$39.30	$4.26	$43.56
2025	$39.72	$5.92	$45.64	$39.72	$4.31	$44.03
Real 2006 $/ton						
2007	$28.35	$4.67	$33.02	$28.35	$3.33	$31.68
2008	$30.50	$4.53	$35.03	$30.50	$3.26	$33.75
2009	$32.06	$4.28	$36.34	$32.06	$3.14	$35.20
2010	$31.90	$4.34	$36.24	$31.90	$3.16	$35.06
2011	$31.21	$4.39	$35.60	$31.21	$3.18	$34.39
2012	$30.56	$4.42	$34.98	$30.56	$3.19	$33.75
2013	$30.18	$4.43	$34.61	$30.18	$3.19	$33.37
2014	$29.90	$4.40	$34.29	$29.90	$3.17	$33.07
2015	$29.64	$4.37	$34.01	$29.64	$3.16	$32.80
2016	$29.44	$4.36	$33.80	$29.44	$3.15	$32.59
2017	$29.18	$4.31	$33.49	$29.18	$3.13	$32.31
2018	$28.97	$4.27	$33.23	$28.97	$3.11	$32.07
2019	$28.77	$4.26	$33.03	$28.77	$3.10	$31.87
2020	$28.57	$4.21	$32.78	$28.57	$3.08	$31.65
2021	$28.33	$4.18	$32.50	$28.33	$3.06	$31.39
2022	$28.12	$4.17	$32.30	$28.12	$3.06	$31.18
2023	$27.90	$4.11	$32.01	$27.90	$3.03	$30.93
2024	$27.73	$4.10	$31.83	$27.73	$3.01	$30.73
2025	$27.52	$4.10	$31.62	$27.52	$2.99	$30.50

Forecasts of Delivered Coal Prices: Reid

REID **<2.7% S, 11000 BTU**

	Mine-Mouth Price	Truck Transport Cost	Delivered Price	Mine-Mouth Price	Barge Transport Cost	Delivered Price
$/ton						
2007	$33.27	$5.35	$38.62	$33.27	$5.80	$39.07
2008	$37.60	$5.29	$42.89	$37.60	$5.77	$43.36
2009	$40.15	$5.10	$45.25	$40.15	$5.62	$45.77
2010	$40.62	$5.28	$45.90	$40.62	$5.80	$46.42
2011	$40.56	$5.46	$46.01	$40.56	$5.97	$46.53
2012	$40.50	$5.60	$46.10	$40.50	$6.12	$46.62
2013	$40.74	$5.73	$46.47	$40.74	$6.26	$47.00
2014	$41.09	$5.79	$46.88	$41.09	$6.33	$47.42
2015	$41.46	$5.87	$47.33	$41.46	$6.42	$47.88
2016	$41.90	$5.97	$47.87	$41.90	$6.53	$48.43
2017	$42.26	$6.00	$48.26	$42.26	$6.58	$48.84
2018	$42.68	$6.06	$48.74	$42.68	$6.66	$49.34
2019	$43.12	$6.16	$49.28	$43.12	$6.77	$49.89
2020	$43.56	$6.20	$49.76	$43.56	$6.83	$50.39
2021	$43.93	$6.26	$50.19	$43.93	$6.91	$50.84
2022	$44.37	$6.37	$50.74	$44.37	$7.02	$51.39
2023	$44.77	$6.39	$51.17	$44.77	$7.07	$51.84
2024	$45.26	$6.49	$51.76	$45.26	$7.16	$52.42
2025	$45.69	$6.61	$52.31	$45.69	$7.26	$52.96
Real 2006 $/ton						
2007	$32.46	$5.22	$37.68	$32.46	$5.66	$38.12
2008	$35.98	$5.06	$41.05	$35.98	$5.52	$41.50
2009	$37.67	$4.79	$42.45	$37.67	$5.28	$42.95
2010	$37.32	$4.85	$42.17	$37.32	$5.33	$42.65
2011	$36.48	$4.91	$41.38	$36.48	$5.37	$41.85
2012	$35.68	$4.94	$40.61	$35.68	$5.39	$41.07
2013	$35.19	$4.95	$40.14	$35.19	$5.40	$40.59
2014	$34.82	$4.91	$39.73	$34.82	$5.37	$40.19
2015	$34.49	$4.88	$39.37	$34.49	$5.34	$39.83
2016	$34.21	$4.87	$39.09	$34.21	$5.33	$39.54
2017	$33.88	$4.81	$38.69	$33.88	$5.28	$39.15
2018	$33.59	$4.77	$38.36	$33.59	$5.24	$38.83
2019	$33.32	$4.76	$38.08	$33.32	$5.23	$38.55
2020	$33.06	$4.70	$37.76	$33.06	$5.18	$38.24
2021	$32.74	$4.67	$37.40	$32.74	$5.15	$37.88
2022	$32.47	$4.66	$37.13	$32.47	$5.14	$37.61
2023	$32.17	$4.59	$36.76	$32.17	$5.08	$37.25
2024	$31.94	$4.58	$36.52	$31.94	$5.05	$36.99
2025	$31.66	$4.58	$36.24	$31.66	$5.03	$36.69

Forecasts of Delivered Coal Prices: Wilson

WILSON 3.3% S, 10700 BTU

	Mine-Mouth Price	Truck Transport Cost	Delivered Price	Mine-Mouth Price	Barge Transport Cost	Delivered Price
$/ton						
2007	$28.26	$6.59	$34.85	$28.26	$3.53	$31.79
2008	$30.99	$6.52	$37.51	$30.99	$3.52	$34.51
2009	$33.23	$6.28	$39.52	$33.23	$3.46	$36.69
2010	$33.77	$6.50	$40.27	$33.77	$3.56	$37.33
2011	$33.76	$6.72	$40.47	$33.76	$3.66	$37.41
2012	$33.75	$6.90	$40.65	$33.75	$3.74	$37.49
2013	$33.98	$7.06	$41.05	$33.98	$3.82	$37.81
2014	$34.32	$7.14	$41.45	$34.32	$3.87	$38.19
2015	$34.67	$7.23	$41.90	$34.67	$3.93	$38.59
2016	$35.07	$7.35	$42.42	$35.07	$4.00	$39.07
2017	$35.41	$7.39	$42.80	$35.41	$4.04	$39.45
2018	$35.80	$7.46	$43.26	$35.80	$4.09	$39.89
2019	$36.21	$7.58	$43.80	$36.21	$4.16	$40.37
2020	$36.62	$7.63	$44.26	$36.62	$4.20	$40.82
2021	$36.97	$7.72	$44.69	$36.97	$4.26	$41.23
2022	$37.39	$7.84	$45.23	$37.39	$4.33	$41.72
2023	$37.77	$7.88	$45.64	$37.77	$4.37	$42.13
2024	$38.23	$8.00	$46.22	$38.23	$4.41	$42.64
2025	$38.63	$8.14	$46.78	$38.63	$4.47	$43.10
Real 2006 $/ton						
2007	$27.58	$6.43	$34.01	$27.58	$3.44	$31.02
2008	$29.66	$6.24	$35.90	$29.66	$3.37	$33.03
2009	$31.18	$5.90	$37.08	$31.18	$3.25	$34.43
2010	$31.03	$5.97	$37.00	$31.03	$3.27	$34.30
2011	$30.36	$6.04	$36.40	$30.36	$3.29	$33.65
2012	$29.73	$6.08	$35.81	$29.73	$3.30	$33.03
2013	$29.35	$6.10	$35.45	$29.35	$3.30	$32.66
2014	$29.08	$6.05	$35.13	$29.08	$3.28	$32.36
2015	$28.83	$6.01	$34.85	$28.83	$3.27	$32.10
2016	$28.64	$6.00	$34.64	$28.64	$3.26	$31.90
2017	$28.39	$5.93	$34.31	$28.39	$3.24	$31.62
2018	$28.18	$5.87	$34.05	$28.18	$3.22	$31.39
2019	$27.99	$5.86	$33.85	$27.99	$3.21	$31.20
2020	$27.79	$5.79	$33.58	$27.79	$3.19	$30.98
2021	$27.55	$5.75	$33.30	$27.55	$3.17	$30.73
2022	$27.36	$5.74	$33.10	$27.36	$3.17	$30.52
2023	$27.14	$5.66	$32.80	$27.14	$3.14	$30.28
2024	$26.97	$5.64	$32.61	$26.97	$3.11	$30.09
2025	$26.77	$5.64	$32.41	$26.77	$3.10	$29.86

SO2 Allowance Price Forecast

SO2 ALLOWANCE PRICE FORECAST

Year	Nominal $/Ton	% Change	Real 2006 $/Ton	% Change
1992	$320		$430	
1993	$187	-41.72%	$245	-43.03%
1994	$164	-12.20%	$210	-14.02%
1995	$133	-19.08%	$167	-20.71%
1996	$84	-36.86%	$103	-38.02%
1997	$99	18.43%	$120	16.49%
1998	$157	58.90%	$189	57.15%
1999	$194	23.53%	$231	21.77%
2000	$141	-27.37%	$164	-28.92%
2001	$186	31.51%	$210	28.43%
2002	$153	-17.62%	$170	-19.04%
2003	$174	13.88%	$190	11.52%
2004	$438	151.30%	$464	144.36%
2005	$906	106.96%	$933	100.86%
2006	$731	-19.35%	$731	-21.63%
2007	$549	-24.92%	$536	-26.74%
2008	$778	41.75%	$745	39.04%
2009	$853	9.63%	$800	7.48%
2010	$881	3.30%	$809	1.15%
2011	$818	-7.12%	$736	-9.08%
2012	$792	-3.27%	$697	-5.26%
2013	$747	-5.61%	$645	-7.45%
2014	$787	5.29%	$667	3.31%
2015	$907	15.27%	$754	13.13%
2016	$759	-16.28%	$620	-17.81%
2017	$618	-18.54%	$496	-20.03%
2018	$357	-42.27%	$281	-43.33%
2019	$146	-59.04%	$113	-59.78%
2020	$137	-6.43%	$104	-8.11%
2021	$134	-1.70%	$100	-3.47%
2022	$111	-17.25%	$81	-18.75%
2023	$105	-6.00%	$75	-7.69%
2024	$102	-2.41%	$72	-4.17%
2025	$98	-4.06%	$68	-5.80%

NOTE: The price depicts the cost of reducing one ton of emissions. Under CAIR, 2 allowances generated after 2009 will be needed to reduce one ton of emissions, and in 2015 the ratio will rise to 2.86:1 As a result, reducing a ton of emissions in 2013 would take one pre-2010 allowance priced at $728 (nominal $), or two 2010-2012 allowances priced at $364 each.

NOx Allowance Price Forecast

NOx ALLOWANCE PRICE FORECAST (ANNUAL)

Year	Nominal $/Ton	% Change	Real 2006 $/Ton	% Change
2007	$6,840		$6,674	
2008	$3,482	-49.09%	$3,333	-50.07%
2009	$2,847	-18.22%	$2,672	-19.83%
2010	$2,409	-15.41%	$2,213	-17.17%
2011	$2,155	-10.54%	$1,938	-12.43%
2012	$1,985	-7.88%	$1,749	-9.77%
2013	$1,900	-4.29%	$1,641	-6.16%
2014	$1,909	0.49%	$1,618	-1.40%
2015	$1,869	-2.08%	$1,555	-3.90%
2016	$1,748	-6.47%	$1,428	-8.18%
2017	$1,625	-7.03%	$1,303	-8.73%
2018	$1,569	-3.50%	$1,234	-5.26%
2019	$1,510	-3.71%	$1,167	-5.45%
2020	$1,521	0.68%	$1,154	-1.13%
2021	$1,523	0.17%	$1,135	-1.64%
2022	$1,525	0.15%	$1,116	-1.65%
2023	$1,527	0.13%	$1,098	-1.67%
2024	$1,529	0.12%	$1,079	-1.69%
2025	$1,531	0.11%	$1,061	-1.70%

NOTE: Prices for 2007-2008 are for pre-CAIR trading; prices for 2009-2
are for the actual time period covered by CAIR

Emissions & Allowance Summary
Nominal dollars

	2008	2009	2010	2011	2012
SO2 Price forecast	$ 778	$ 853	$ 441	$ 409	$ 396
year beginning SO2 allowance inventory	0.000	0.000	14.000	14.000	14.000
Total SO2 tons emitted x1000	14.849	20.077	21.157	20.054	20.575
yearly SO2 allowances surrendered back to EPA	14.849	20.077	42.314	40.107	41.150
yearly allocation of SO2 allowances from EPA	34.991	52.487	52.487	52.487	52.487
yearly SO2 allowances x1000 excess/(short) gross of City	20.142	32.410	10.173	12.380	11.337
Excess H-1&2 Allowances Back to City (capacity take)	1.522	2.228	0.957	1.048	1.071
yearly SO2 allowances x1000 sold/(purchased) net of City	18.620	30.182	9.216	11.332	10.266
year ending SO2 allowance inventory	0.000	14.000	14.000	14.000	14.000
SO2 allowances Sales/(purchases) net of City	$14,486,360	$25,745,246	$4,064,256	$4,634,788	$4,065,336

Item 65) Please reference the testimony of David A. Spainhoward, page 16, lines 7-12, regarding purchase of NO_x allowances. Provide work papers and associated supporting documents to support these estimates net costs.

Response) Please see Big Rivers' response to the Attorney General's Initial Request Item 64. *The work papers and supporting documents for the NOx allowances are* attached hereto.

Witness) David A. Spainhoward

Emissions & Allowance Summary

Nominal dollars

	2008	2009	2010	2011	2012
NOx Price forecast	$ 763	$ 2,847	$ 2,409	$ 2,155	$ 1,985
Yearly beginning NOx allowance inventory x1000	0.000	0.000	0.000	0.000	0.000
Total system NOx tons emitted x1000	5.046	13.896	13.892	13.202	13.196
System NOx Emissions allocation to City x1000	0.114	0.286	0.286	0.287	0.301
BREC NOx tons emitted net City x1000	**4.932**	**13.610**	**13.606**	**12.915**	**12.895**
yearly allocation of NOx allowances from EPA x1000	4.799	11.398	11.398	11.398	11.398
EPA NOx allowances allocation to City x1000	0.148	0.326	0.326	0.327	0.341
BREC allocation of NOx allowances net of City x1000	**4.651**	**11.072**	**11.072**	**11.071**	**11.057**
yearly BREC NOx allowances sold/(purchased) net City x1000	(0.281)	(2.538)	(2.534)	(1.844)	(1.838)
Yearly ending NOx allowance inventory x1000	0.000	0.000	0.000	0.000	0.000
BREC NOx allowances Sales/(purchases)	($214,403)	($7,225,686)	($6,104,406)	($3,973,820)	($3,648,430)

Item 66) Please reference the testimony of William Steven Seelye, page 4, line 22. Provide each purchase power rate charged by E.ON to Big Rivers or any of its members, by year, since 1998.

Response) The purchased power rates charged to Big Rivers under the current transaction are as follows:

Year	Amount
1998	18.917
1999	18.917
2000	18.917
2001	18.917
2002	19.117
2003	19.217
2004	19.317
2005	19.417
2006	19.517
2007	19.717
2008	20.017

Witness) C. William Blackburn
William Steven Seelye

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
February 14, 2008

Item 67) Please reference the testimony of Michael H. Core, page 7, where it states the higher rates paid by the Smelters under the new agreement "will add approximately $327 million in present value..." Provide documents and detailed supporting workpapers (in electronic spreadsheet format with formulas intact) that show the derivation and calculations to reach this $327 million figure.

Response) The number is arrived at by calculating the amount of payments from the Smelters that exceed what would be collected from Big Rivers' large industrial tariff at a 98% load factor. In the attached spread sheet, the Smelters pay at least 25 cents over the large industrial tariff, the cost of the 1.24 TIER and surcharges that flow back to the Members to offset some of their fuel costs.

Witness) Michael H. Core

	Contract Reference (Smelter Retail Agreements)	Total	PV	Weighted Avg.	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
$/ MWh																				
Large Industrial Rate @ 98% LF+FAC+PPA+ES-Rebate				42.13	32.67	33.28	35.55	38.62	38.81	39.71	40.04	41.73	42.09	46.23	45.61	46.36	46.60	47.43	47.70	48.51
Increment:																				
Margin	1.1.20 (Alcan)/ 1.1.19 (Century)			0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
TIER Adjustment Charge	4.7			2.13	-	-	0.00	1.81	2.64	2.40	2.26	3.16	2.88	3.14	0.15	3.17	2.16	3.46	2.50	3.69
Surcharges	4.11			2.28	1.90	1.42	1.90	1.90	2.20	2.20	2.20	2.20	2.20	2.60	2.60	2.60	2.59	2.60	2.60	2.60
Total				4.66	2.15	1.67	2.15	3.96	5.09	4.85	4.71	5.61	5.33	5.99	3.00	6.01	5.00	6.30	5.35	6.54
Effective Smelter Rate				46.79	34.82	34.94	37.70	42.58	43.90	44.56	44.75	47.34	47.42	52.22	48.61	52.37	51.61	53.73	53.05	55.05
Smelter TWh					4.90	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30
$M																				
Increment:																				
Margin		28.6	18.7		1.2	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
TIER Adjustment		244.1	143.9		-	-	0.0	13.2	19.3	17.5	16.5	23.1	21.1	22.9	1.1	23.1	15.8	25.2	18.3	27.0
Surcharges		260.3	164.4		9.3	10.3	13.9	13.9	16.1	16.1	16.1	16.1	16.1	18.9	18.9	18.9	19.0	18.9	18.9	18.9
Total		533.0	327.0		10.5	12.2	15.7	28.9	37.2	35.4	34.3	40.9	39.0	43.7	21.9	43.9	36.6	46.0	39.0	47.7

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
February 14, 2008

Item 68) Please reference the testimony of Michael H. Core, page 11, where it states "At closing, Big Rivers will become one of the financially strongest generation and transmission cooperatives in the United States." Please provide documents which support this statement.

Response) Please see the response of C. William Blackburn to question AG Item 20.

Witness) Michael H. Core

Item 69) Please reference the testimony of Michael H. Core, page 14, where it references "a number of indemnities." To the extent not previously provided, please list each of these indemnities.

Response) Please see Big Rivers' response to the Commission Staff, Item 1.o.

Witness) Michael H. Core

Item 70) Please reference the testimony of Mark A. Bailey, page 11, regarding support services agreements with WEKC. Are the prices to Big Rivers for services under these agreements entirely fixed for the 18 month duration?

a. If not, identify the services for which prices are not fixed, and the materiality of those non-fixed prices to the cost of services for a fiscal year in their entirety under the support agreements.

b. To the extent not previously provided, provide a table showing services under the service agreements, cost/price of each service, and whether or not the pricing of those services to Big Rivers is fixed in nature.

c. Provide documents which show estimated costs to Big Rivers from:

i. The Generation Dispatch Support Services Agreement; and
ii. The IT Support Services Agreement.

d. Provide documents which show where these costs are included and addressed in the financial model (Exhibit 8).

Response) (a - c) Article IV of the Generation Dispatch Services Agreement addresses Compensation. As such, there are no fixed fees, but rather "actual costs incurred by LEM". Those fees may include out-of-pocket expenses, labor costs and benefit costs for 6 employees to perform the services required under the agreement. As part of its evaluation of a permanent Generation Dispatch solution, APM has made a proposal to Big Rivers to perform the services for approximately $270,000 per year. Big Rivers has modeled for the first full year $211,193. Big Rivers will incur costs under the Generation Dispatch Services agreement for a maximum of 18 months, but may terminate the agreement earlier once it is ready to implement the permanent solution.

Big Rivers will pay a fixed fee not to exceed $1,500,000 for the Information Technology Support Services Agreement (section 1.2 (a)). In addition, Big Rivers will pay a monthly fee for services it utilizes according to the attached Exhibit A of the Agreement (specified in section 1.2(b)). Section 1.3 of the Agreement calls for payment of additional fees if royalties or other payments are paid to third parties by WKEC to obtain consents. Should Big Rivers request other data services not listed or anticipated, Big Rivers has agreed to pay actual labor rates of the WKEC personnel performing the work as specified in section 4.3.

(d) The Generation Dispatch Services costs are included in the Income Statement of the Financial Model, Exhibit 8. More specifically, they are included in the Proforma Tab, line 188, "Fixed Production O&M". The IT Support Services costs are included on line 191, "A&G".

Witness) Mark A. Bailey

EXHIBIT A -- PROCESSES AND SERVICES

Process / Service	Application or Supplier	Transition Support Duration	Comments	Monthly Fee
Payroll:				$ 8,844.17
Time Entry	VOLTS	18 Months	System provided by WKEC; business process performed by Big Rivers	
Payroll Processing	PeopleSoft Payroll	18 Months	System provided by WKEC; business process performed by Big Rivers	
Employee Payments	PeopleSoft Payroll	18 Months	System provided by WKEC; business process performed by Big Rivers	
Tax/Deduction Payments	PeopleSoft Payroll	18 Months	System provided by WKEC; business process performed by Big Rivers	
Human Resource Management				$ 4,250.26
Maintain Employee Records	PeopleSoft HR	18 Months	System provided by WKEC; business process performed by Big Rivers	
Employee Benefits				$ 1,521.96
Maintain Employee Benefits	PeopleSoft Benefits	18 Months	System provided by WKEC; business process performed by Big Rivers	
Supply Chain / Procurement				$ 10,616.11
Requisitions	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers	
Purchase Order Generation	Oracle Applications, Optio	18 Months	System provided by WKEC; business process performed by Big Rivers	

Receiving	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers	
Warehouse reorders	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers	
A/P Processing (excluding 1099s)	Oracle Applications, Filenet	18 Months	System provided by WKEC; business process performed by Big Rivers	
A/P Payments	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers	
A/P Weekly and Monthly Reporting	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers	
Financials Capital Expenditures - Financials				$ 9,687.78
Budgeting	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers	
Authorization	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers	
CWIP	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers	
Forecasting	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers	
Monthly closing of projects	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers	

Monthly reporting	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers
O&M Expense - Financials			
Budgeting	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers
Project creation	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers
Project monitoring	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers
Forecasting	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers
Reporting/Variance Analysis	Oracle Applications, Discoverer, Noetix Views	18 Months	System provided by WKEC; business process performed by Big Rivers
Month-end Closing			
Burdens	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers
Mass Allocations	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers
Interfaces with Sub ledgers	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers
Journal Entries	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers

Financial Statement Preparation	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers	
Management Report Preparation	Oracle Applications, Discoverer	18 Months	System provided by WKEC; business process performed by Big Rivers	
Reconciliations	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers	
Tax Returns				
Monthly Sales and Use Tax	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers	
Quarterly Fuel Tax Returns	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers	
New & Expanded Industry Certificates on Capital	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers	
Petty Cash Funds				
Plant Custodians	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers	
Periodic Audits of Funds	Oracle Applications	18 Months	System provided by WKEC; business process performed by Big Rivers	
Power Plant Work Management				$ 6,633.13
Planning and tracking of equipment maintenance	Computerized Maintenenance Management System (MRO)	18 Months	System provided by WKEC; business process performed by Big Rivers	
Scheduling work activities including planned maint.	Computerized Maintenenance Management System (MRO)	18 Months	System provided by WKEC; business process performed by Big Rivers	

I&E Calibrations	Custom application integrated with Maximo	18 Months	System provided by WKEC; business process performed by Big Rivers	
Help Desk (IT)				$ 2,435.97
Work management for IT incidents/requests	WKEC	18 Months	WKEC Help Desk will work with Big Rivers Help Desk to facilitate incident reporting.	
Telecommunications				$ 15,565.00
Fiber Connectivity – Network Transport to Louisville	WKEC	18 Months	WKEC will provide network transport for connectivity to the hosted Systems via Citrix.	
Network Administration Support				$ 13,799.63
Network Administration Support	Cisco	18 Months	Service includes support fees for routers and switches. BREC will not have administrative access to routers and switches.	
Network Management	WKEC	18 Months	Management of router, switches, and network infrastructure. Can be transitioned to BREC during 18 months.	
Standard Network Access				$0
File and Print Management	Windows Server 2003	30 days	BREC will take over file and print management upon closing.	
Standard Network Access (30 days service)				$0

Network Authentication	WKEC	30 days	Personal Computers will be configured to access BREC's network within thirty days after close date. Personal Computers will not authenticate to WKEC after this period. WKEC Personal user-ID domain accounts will be disabled upon closing.	
Internet Access	Peak10 Internet Service Provider	30 days	Personal Computers will be configured to access BREC's internet service within thirty days after close date. Intranet and Internet access through WKEC network will cease on closing date.	
Intranet	WKEC	30 days	Personal Computers will need to be rebuilt by BREC within thirty days after the close date. Intranet and Internet access through WKEC will cease on closing date.	
Office Productivity - Windows Environment				$23,010
Windows Environment & Office Automation Tools	Microsoft Windows, Office Professional	30 days	Personal Computers to be rebuilt by BREC within thirty days after the close date. MS Licensing rights will be transferred.	
Secure Environment				$161

Anti-Virus Protection	Trend Micro	30 days	Anti-Virus software will need to be procured and installed on personal computers. Personal Computers will need to be rebuilt by BREC within thirty days after the close date.	
Personal Firewall Protection (Laptops Only)	ISS Desktop Protector	30 days	Personal firewall software should be procured and installed for Laptop computers. PC workstations will need to be rebuilt by BREC within thirty days after the close date.	
Windows Updates	Microsoft SUS	30 days	Security updates from WKEC to PC workstations will end on closing date.	
Safety Tagging				$ 1,456.00
Track equipment isolated for repair or replacement	Hold Card System	30 days	System provided by WKEC; business process performed by Big Rivers	
OSHA compliance for lock out/tag out	Hold Card System	30 days	System provided by WKEC; business process performed by Big Rivers	
Telecommunications (30 days service)				$22,309
Cellular Phone Management Services	Cingular, Verizon, Nextel	30 days	BREC will convert cellular services to BREC agreement within 30 days of close.	
Corporate Voice Service	WKEC	30 days	Phone service to facilities via WKEC network will be terminated 30 days after the close date.	

Long Distance, Calling Cards, 800 Service	AT&T	30 days	BREC will select a long-distance service provider within 30 days after close date.	
Local Telephone Access	Bell South	30 days	BREC will select a local telephone carrier within 30 days after close date.	
Voice Mail	Communite'	30 days	BREC will assume voice mail support within 30 days of close.	
Telecommunications Relocation(30 days service)				$26,000
WKE SOAPER Building Close and Equipment Relocations	Joint WKEC and BREC Telecomm	30 days	Telecommunication equipment will move to BREC headquarters	
Total First Month				**$ 146,290**
Total Months 2 thru 18				**$ 73,354**

Legend

Process Category	
Services-Category	
Services	

Example #1

Process	Payroll
Service	Time Entry
Service	Payroll Processing
Service	Employee Payments
Service	Tax/Deduction Payments

Example #2

Process	Financials
Services Category	Capital Expenditures - Financials
Service	Budgeting
Service	Authorization
Service	CWIP
Service	Forecasting
Service	Monthly closing of projects
Service	Monthly reporting
Services Category	O&M Expense - Financials

Service	Budgeting
Service	Project creation
Service	Project monitoring
Service	Forecasting
Service	Reporting/Variance Analysis
Services Category	Month-end Closing
Service	Burdens
Service	Mass Allocations
Service	Interfaces with Sub ledgers
Service	Journal Entries
Service	Financial Statement Preparation
Service	Management Report Preparation
Service	Reconciliations
Services Category	Tax Returns
Service	Monthly Sales and Use Tax
Service	Quarterly Fuel Tax Returns
Service	New & Expanded Industry Certificates on Capital
Services Category	Petty Cash Funds
Service	Plant Custodians
Service	Periodic Audits of Funds

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
February 14, 2008

Item 71) Please identify each and every non-recurring expenditure for Big Rivers associated with this transaction in excess of $250,000 to a single vendor, e.g., Black and Veatch, Hill & Associates, etc., by purpose and amount.

a. Provide documents which show where these costs are included and addressed in the financial model (Exhibit 8).

Response) The Financial Model does not contain any non-recurring expenses related to closing this transaction, with the exception of expenses related to debt refinancing. The Financial Model, page 7 of 37, line 195, shows the interest expense and financing fees. The reimbursement agreements between Big Rivers and E.ON, and Big Rivers, E.ON and the Smelters have previously been filed in the case.

Under the most recent agreement with E.ON, Big Rivers is responsible for 25% of expenditures up to $22,000,000. At Closing, E.ON will reimburse Big Rivers for its 25% share of these non-recurring expenditures. Big Rivers is currently expensing into its income statement its 25% share of non-recurring expenditures and will credit into its income statement the reimbursement from E.ON at closing. All non-recurring expenditures related to this Unwind Transaction will be considered expenses prior to closing. Therefore, Big Rivers did not include any of these related expenses in the Financial Model.

Witness) C. William Blackburn

Item 72) Regarding Fuel Procurement Policies and Procedures, describe how these policies and procedures impacted financial model inputs and assumptions.

Response) The Financial Model inputs and assumptions for fuel are built around the individual characteristics of each generation station. The model is driven by the current WKEC fuel contracts and the fuel cost projections provided to Big Rivers by Global Insight.

The Fuel Procurement Policies and Procedures are designed to establish the principles that govern the procurement of fuel, reagent, and associated transportation. The policy and procedures outline the organization, responsibility, methods of solicitation, internal controls, award recommendation, records management, projections, supplier qualifications, and general agreement enforcement. After the Unwind Transaction is completed, Big Rivers will be operating under these policies and procedures.

Witness) Mark A. Bailey
C. William Blackburn

Item 73) Regarding Smelters' review of Big Rivers' annual capital and operating budgets, explain why it is necessary for the Smelters to conduct an annual review of Big Rivers' budgets.

Response) Big Rivers, its Members and the Smelters agreed to a coordination working group because it is important that good communications continue among Big Rivers, its Members and the Smelters for the successful operation of Big Rivers after the Unwind. Given that the Smelters purchase approximately 60% of the MWh used by Big Rivers' Members, and given the fact that the Smelters take the risk of the first dollars to maintain a 1.24 TIER in the bandwidth, it is reasonable for the Smelters to have an opportunity to review and comment on Big Rivers' budget, as a supplement to the input Big Rivers' management traditionally gets from its Board of Directors and Members.

Witness) Mark A. Bailey

Item 74) Provide documents which show the extent to which the Smelters concur in Big Rivers financial projections provided in this Application as Exhibit 8.

Response) The Smelters have not provided Big Rivers any documents which show the extent to which the Smelters concur or have differing views on Big Rivers' financial projections provided in this Application as Exhibit 8. Because the Smelters are willing to move forward with the transaction, it is assumed the Smelter management and consultants believe the financial projections in Exhibit 8 are reasonable and acceptable.

Witness) C. William Blackburn

Item 75) Provide documents which show the extent to which the Smelters have differing views on Big Rivers financial projections provided in this Application as Exhibit 8.

Response) See response to AG Item question 74.

Witness) C. William Blackburn

Item 76) Regarding Base Monthly Energy Charges to the smelters, provide a detailed pro forma calculation of a monthly bill to a smelter, assuming the new agreements, for a) December 2007 and b) June 2007, to demonstrate the "complexity" of the calculation of these charges. Also, provide actual billed amounts for these months based on the existing agreements. Finally, indicate the extent to which the smelter concurs in the pro forma calculations.

Response) Attached are the actual billed amounts to the Smelters for the months of June 2007 and December 2007 based on the existing agreements between the Smelters and Kenergy.

See the January 30, 2008 Errata Filing that shows a detailed pro forma calculation of a monthly bill to a Smelter, assuming the new agreements for 2009. It is not possible to provide actual billed amounts for these months based on the existing agreements.

Witness) C. William Blackburn
Robert S. Mudge

INVOICE
KENERGY CORP., P.O. BOX 18, HENDERSON, KY 42420

Month Ending 6/30/07

To: Alcan

Substation: Alcan Aluminum — Service from 6/1/07 thru 6/30/07

TIME	DAY	METER	Mult	KW Demand
12:30	06/12/07	356.659	1000	356,659

TOTAL KWH USED - JUNE 249,614,820

A. ELECTRIC POWER SUPPLIED BY KENERGY PURCHASED FROM LG&E ENERGY MARKETING INC.

	USAGE (KWH)	RATE	TOTAL	
Tier 1 Energy				
Energy	34,221,600	$ 0.031245	$ 1,069,253.89	
Take or Pay	-	$ -	$ -	
			$ 1,069,253.89	Subtotal
Tier 2 Energy				
Base Energy	130,183,200	$ 0.023165	$ 3,015,693.83	
Adjustment	-	$ 0.023165	$ -	
Supplemental	-	$ 0.016185	$ -	
Adjustment	777,227	$ 0.016185	$ 12,579.42	
			$ 3,028,273.25	Subtotal
Tier 3 Energy & Demand				
Interruptible	-	$ -	$ -	
Backup	1,789,307	$0.07661587	$ 137,089.30	
Transmission Credit for TIER 3 Backup Priced @ Minimum			$ (556.18)	
Ancillary Service Credit for TIER 3 Backup Priced @ Minimum			$ (471.46)	
Adjustment - Prior Month Billing			$ -	
			$ 136,061.66	Subtotal
TOTAL KWH - JUNE	166,971,334			
Customer Charge			$ 2,614.00	
Purchased from LG&E Energy Marketing Inc - June			$ 4,236,202.80	Total

Pay to: The Bank of New York
ABA: 021000018
For Credit to GLA: 211065 — $ 4,236,202.80
For Final Credit to: 417508
Account Name: LEM & Henderson & Alcan
Details of Payment: Teresa Law, telephone (502)566-6907, 417508
Bank Cut-Off is 3:30 p.m.

B. ELECTRIC POWER SUPPLIED BY KENERGY PURCHASED FROM BIG RIVERS ELECTRIC (see attached)

	USAGE (KWH)	RATE	TOTAL
Block A Power 72 MW - (BREC)	26,808,319	$ 0.052355	$ 1,403,549.54
Block A Power - Buy-Thru Price	24,480,000	$0.06324878	$ 1,548,330.14
Block A Power BREC Cost - June	*241,682*	$ 0.100045	$ 24,179.08
Block B Power 34 MW (SIPC)	22,726,000	$ 0.049645	$ 1,128,232.27
Block C Power 12 MW (FORTIS)	8,640,000	$ 0.067045	$ 579,268.80
Administrative Fees	-		$ 3,136.60
MISO - Pass-Through Charges			$ (22,212.84)
Tier 3 Transmission			$ 89,645.16
Ancillary Services Charges			$ 43,987.22
Letter of Credit Fees			$ 1,555.83
	82,896,001		$ 4,799,671.80

Pay to:	Bank Name:	Old National Bank			
	Account Name:	Kenergy Lockbox	Due 7/20/07	$	1,107,222.83
	Account Number:	103089518	Due 7/25/07	$	3,688,718.65
	Routing Number:	86300012		$	4,795,941.48

Pay to:	Bank Name:	U.S. Bank Henderson, KY		
	Account Name:	Kenergy	$	3,730.32
	Account Number:	145803863326		
	Routing Number:	042100175		

C. ADJUSTMENT FOR LINE LOSSES

	USAGE (KWH)	RATE	TOTAL
Metered KWH	249,614,820		
KWH in A & B	249,867,335		
	(252,515)	0.000045	$ (11.36)

Pay to:	Bank Name:	U.S. Bank Henderson, KY		
	Account Name:	Kenergy	$	(11.36)
	Account Number:	145803863326		
	Routing Number:	042100175		

D. SUMMARY OF WIRE TRANSFERS DUE:

Bank of New York - LG&E	$	4,236,202.80
Old National Bank	$	4,795,941.48
U.S. Bank	$	3,718.96
	$	9,035,863.24
Amount Due 7/20/07	$	1,107,222.83
Amount Due 7/25/07	$	7,928,640.41
Total Electric Power Costs	$	9,035,863.24

INVOICE
KENERGY CORP., P.O. BOX 18, HENDERSON, KY 42420

Month Ending 6/30/07

To: Century Aluminum

Substation: National Southwire Aluminum — Service from 6/1/07 thru 6/30/07

	TIME	DAY	Meter	Mult	KW Demand
	10:00	06/07/07	493.056	1000	493,056
TOTAL KWH USED - JUNE					347,738,410

A. ELECTRIC POWER SUPPLIED BY KENERGY PURCHASED FROM LG&E ENERGY MARKETING INC.

	USAGE (KWH)	RATE	TOTAL	
Tier 1 Energy				
Energy	26,107,200	$ 0.031245	$ 815,719.46	
Take or Pay	-	$ -	$ -	
			$ 815,719.46	Subtotal
Tier 2 Energy				
Base Energy	213,091,200	$ 0.023165	$ 4,936,257.65	
Adjustment	-	$ 0.023165	$ -	
Supplemental	3,718,964	$ 0.016185	$ 60,191.43	
Adjustment	-		$ -	
			$ 4,996,449.08	Subtotal
Tier 3 Energy & Demand				
Base Energy - 60 MWH Energy Sales	-	$ -	$ -	
Energy - 25 MWH Energy Sales	-	$ -	$ -	
Interruptible	-	$ -	$ -	
Backup	3,108,347	$ 0.07410435	$ 230,342.04	
Tier 3 Transmission Demand			$ -	
Transmission Credit for Tier 3 Backup Priced at Minimum			$ (900.84)	
Ancillary Service Credit for Tier 3 Backup Priced at Minimum			$ (776.82)	
			$ 228,664.38	Subtotal
TOTAL KWH - JUNE	246,025,711			
Customer Charge			$ 2,614.00	
Purchased from LG&E Energy Marketing Inc - June			$ 6,043,446.92	Total

Pay to: The Bank of New York
ABA: 021000018
For Credit to GLA: 211065
For Final Credit to: 417509
Account Name: LEM & Green River & Southwire LB — **$ 6,043,446.92**
Details of Payment: Teresa Law, telephone (502)566-6907, 417509
Bank Cut-Off is 3:30 p.m.

B. ELECTRIC POWER SUPPLIED BY KENERGY PURCHASED FROM BIG RIVERS ELECTRIC (see attached)

	USAGE (KWH)	RATE	TOTAL
Block A Power 85 MW (BREC)	31,046,682	$ 0.052355	$ 1,625,449.04
Block A Power Buy-Thru Price - June	29,520,000	$ 0.06308733	$ 1,862,337.90
Block A Power BREC Cost - June	285,319	$ 0.100045	$ 28,544.74
Block B Power 41 MW (SIPC)	27,413,000	$ 0.049645	$ 1,360,918.39
Block C Power 13 MW (BREC)	9,360,000	$ 0.067045	$ 627,541.20
Block D Power 15 MW	4,385,000	$ 0.044046	$ 193,137.33
Administrative Fees			$ 3,677.30
TIER 3 Transmission			$ 109,401.46
Ancillary Service Charges			$ 58,716.32
MISO Pass-Through Charges			$ (26,760.26)
Letter of Credit Fees			$ 1,841.98
	102,010,001		$ 5,844,805.40

Pay to:	Bank Name	Old National Bank	Due 7/20/07	$1,335,615.44
	Account Name:	Kenergy Lockbox	Due 7/25/07	$4,504,599.51
	Account Number:	103089540		$5,840,214.95
	Routing Number:	86300012		

Pay to:	Bank Name	U.S. Bank Henderson, KY	
	Account Name:	Kenergy	$ 4,590.45
	Account Number:	145803863326	
	Routing Number:	042100175	

C. ADJUSTMENT FOR LINE LOSSES

	USAGE (KWH)	RATE	TOTAL
Metered KWH	347,738,410		
KWH in A & B	348,035,712		
	(297,302)	$ 0.000045	$ (13.38)

Pay to:	Bank Name:	U.S. Bank Henderson, KY	
	Account Name:	Kenergy	$ (13.38)
	Account Number:	145803863326	
	Routing Number:	042100175	

D. INVOICE SUMMARY

SUMMARY OF WIRE TRANSFERS DUE:	
The Bank of New York	$ 6,043,446.92
Old National Bank	$ 5,840,214.95
U.S. Bank	$ 4,577.07
	$ 11,888,238.94
Amount Due 7/20/07	$ 1,335,615.44
Amount Due 7/25/07	$ 10,552,623.50
Total Electric Power Costs	$ 11,888,238.94

INVOICE
KENERGY CORP., P. O. BOX 18, HENDERSON, KY 42420

Month Ending 12/31/07

To: Alcan

Substation: Alcan Aluminum | Service from 12/1/07 thru 12/31/07

TIME	DAY	METER	Mult	KW Demand
17:00	12/18/07	356.054	1000	356,054

TOTAL KWH USED - DECEMBER 259,380,630

A. ELECTRIC POWER SUPPLIED BY KENERGY PURCHASED FROM LG&E ENERGY MARKETING INC.

	USAGE (KWH)	RATE	TOTAL	
Tier 1 Energy				
Energy	35,362,320	$ 0.031245	$ 1,104,895.69	
Adjustment - November	47,530	$ 0.031245	$ 1,485.07	
			$ 1,106,380.76	Subtotal
Tier 2 Energy				
Base Energy	134,522,640	$ 0.023165	$ 3,116,216.96	
Adjustment - November	180,810	$ 0.023165	$ 4,188.46	
Supplemental	1,962,585	$ 0.016185	$ 31,764.44	
Adjustment - November	(228,340)	$ 0.016185	$ (3,695.66)	
			$ 3,148,474.20	Subtotal
Tier 3 Energy & Demand				
Interruptible	-	$ -	$ -	
Backup	2,443,175	$0.07749377	$ 189,330.84	
Transmission Credit for TIER 3 Backup Priced @ Minimum			$ (326.68)	
Ancillary Service Credit for TIER 3 Backup Priced @ Minimum			$ (297.14)	
			$ 188,707.02	Subtotal
TOTAL KWH - DECEMBER	174,290,720			
Customer Charge			$ 2,614.00	
Purchased from LG&E Energy Marketing Inc - December			$ 4,446,175.98	Total

Pay to: The Bank of New York
ABA: 021000018
For Credit to GLA: 211065 — $ **4,446,175.98**
For Final Credit to: 417508
Account Name: LEM & Henderson & Alcan
Details of Payment: Teresa Law, telephone (502)566-6907, 417508
Bank Cut-Off is 3:30 p.m.

B. ELECTRIC POWER SUPPLIED BY KENERGY PURCHASED FROM BIG RIVERS ELECTRIC (see attached)

	USAGE (KWH)	RATE	TOTAL
Block A Power 72 MW - (BREC)	50,941,108	$ 0.052355	$ 2,667,021.71
Block A Power BREC Cost - December	244,892	$ 0.105739	$ 25,894.71
Block B Power 34 MW (SIPC)	25,330,000	$ 0.049645	$ 1,257,507.85
Block C Power 12 MW (FORTIS)	8,940,000	$0.05499714	$ 491,674.46
Power Factor Correction			$ 898.20
Administrative Fees	-		$ 3,427.00
MISO - Pass-Through Charges			$ 65,126.81
Tier 3 Transmission			$ 86,623.47
Ancillary Services Charges			$ 55,906.11
Letter of Credit Fees			$ 383.89
	85,456,000		$ 4,654,464.21

Pay to:	Bank Name:	Old National Bank			
	Account Name:	Kenergy Lockbox	Due 1/21/08	$	1,324,027.81
	Account Number:	103089518	Due 1/25/08	$	3,326,590.88
	Routing Number:	86300012		$	4,650,618.69

Pay to:	Bank Name:	U.S. Bank		
		Henderson, KY		
	Account Name:	Kenergy	$	3,845.52
	Account Number:	145803863326		
	Routing Number:	042100175		

C. ADJUSTMENT FOR LINE LOSSES

	USAGE (KWH)	RATE		TOTAL
Metered KWH	259,380,630			
KWH in A & B	259,746,720			
	(366,090)	0.000045	$	(16.47)

Pay to:	Bank Name:	U.S. Bank		
		Henderson, KY		
	Account Name:	Kenergy	$	(16.47)
	Account Number:	145803863326		
	Routing Number:	042100175		

D. SUMMARY OF WIRE TRANSFERS DUE:

Bank of New York - LG&E	$	4,446,175.98
Old National Bank	$	4,650,618.69
U.S. Bank	$	3,829.05
	$	9,100,623.72
Amount Due 1/21/08	$	1,324,027.81
Amount Due 1/25/08	$	7,776,595.91
Total Electric Power Costs	$	9,100,623.72

INVOICE
KENERGY CORP., P. O. BOX 18, HENDERSON, KY 42420

Month Ending 12/31/07

To: Century Aluminum

Substation: National Southwire Aluminum — Service from 12/1/07 thru 12/31/07

	TIME	DAY	Meter	Mult	KW Demand
	5:30	12/06/07	491.558	1000	491,558
TOTAL KWH USED - DECEMBER					359,638,820

A. ELECTRIC POWER SUPPLIED BY KENERGY PURCHASED FROM LG&E ENERGY MARKETING INC.

	USAGE (KWH)	RATE	TOTAL	
Tier 1 Energy				
Energy	26,977,440	$ 0.031245	$ 842,910.12	
Adjustment - November	36,260	$ 0.031245	$ 1,132.94	
			$ 844,043.06	Subtotal
Tier 2 Energy				
Base Energy	220,194,240	$ 0.023165	$ 5,100,799.56	
Adjustment - November	295,960	$ 0.023165	$ 6,855.91	
Supplemental	4,129,182	$ 0.016185	$ 66,830.81	
Adjustment - November	(332,220)	$ 0.016185	$ (5,376.98)	
			$ 5,169,109.32	Subtotal
Tier 3 Energy & Demand				
Base Energy - 60 MWH Energy Sales	-	$ -	$ -	
Energy - 25 MWH Energy Sales	-	$ -	$ -	
Interruptible	-	$ -	$ -	
Backup	3,946,170	$ 0.0754914	$ 297,901.82	
Transmission Credit for Tier 3 Backup Priced at Minimum			$ (555.59)	
Ancillary Service Credit for Tier 3 Backup Priced at Minimum			$ (498.30)	
			$ 296,847.93	Subtotal
TOTAL KWH - DECEMBER	255,247,032			
Customer Charge			$ 2,614.00	
Purchased from LG&E Energy Marketing Inc - December			$ 6,312,614.31	Total

Pay to: The Bank of New York
ABA: 021000018
For Credit to GLA: 211065
For Final Credit to: 417509
Account Name: LEM & Green River & Southwire LB — **$ 6,312,614.31**
Details of Payment: Teresa Law, telephone (502)566-6907, 417509
Bank Cut-Off is 3:30 p.m.

B. ELECTRIC POWER SUPPLIED BY KENERGY PURCHASED FROM BIG RIVERS ELECTRIC (see attached)

	USAGE (KWH)	RATE	TOTAL
Block A Power 85 MW (BREC)	60,137,892	$ 0.052355	$ 3,148,519.34
Block A Power BREC Cost - December	289,108	$ 0.10573952	$ 30,570.14
Block B Power 41 MW (SIPC)	30,504,000	$ 0.049645	$ 1,514,371.08
Block C Power 13 MW (BREC)	9,672,000	$ 0.055071	$ 532,646.72
Block D Power 15 MW	4,151,000	$ 0.044045	$ 182,830.80
Administrative Fees			$ 4,017.60
TIER 3 Transmission			$ 108,716.00
Ancillary Service Charges			$ 73,082.00
MISO Pass-Through Charges			$ 78,538.29
Letter of Credit Fees			$ 444.19
	104,754,000		$ 5,673,736.16

Pay to:	Bank Name	Old National Bank	Due 1/21/08	$1,594,587.09
	Account Name:	Kenergy Lockbox	Due 1/25/08	$4,074,435.14
	Account Number:	103089540		$5,669,022.23
	Routing Number:	86300012		

Pay to:	Bank Name	U.S. Bank Henderson, KY		
	Account Name:	Kenergy	$	4,713.93
	Account Number:	145803863326		
	Routing Number:	042100175		

C. ADJUSTMENT FOR LINE LOSSES

	USAGE (KWH)	RATE	TOTAL
Metered KWH	359,638,820		
KWH in A & B	360,001,032		
	(362,212)	$ 0.000045	$ (16.30)

Pay to:	Bank Name:	U.S. Bank Henderson, KY		
	Account Name:	Kenergy	$	(16.30)
	Account Number:	145803863326		
	Routing Number:	042100175		

D. INVOICE SUMMARY

SUMMARY OF WIRE TRANSFERS DUE:		
The Bank of New York	$	6,312,614.31
Old National Bank	$	5,669,022.23
U.S. Bank	$	4,697.63
	$	11,986,334.17
Amount Due 1/21/08	$	1,594,587.09
Amount Due 1/25/08	$	10,391,747.08
Total Electric Power Costs	$	11,986,334.17

Item 77) Provide an analysis which shows the proportion of cost necessary to ensure achievement of 1.24 TIER that is borne by the Smelters if TIER in 2010 prior to imposition of TIER adjustment charges is:

a. 1.20,
b. 1.10, and
c. 1.0.

Response) Please see below the scenarios requested, plus cost borne by the Smelters in the filed Financial Model, for which TIER in 2012 prior to imposition of TIER adjustment charges would be 0.94x. (Please note that in each of these cases, the Smelters would bear 100% of the incremental cost.)

a. 1.20x – Smelters pay $4.2m

		Before Adjust.	TIER Adjust./ (Rebate)	After Adjust.
1	**TWh**			
2	Members		3.76	
3	Smelters		7.32	
4	**Revenues/ MWh**		0.57	
5	**Revenues**			
6	Members	131.9	-	131.9
7	Smelters	301.9	4.2	306.0
8	Other	78.2	-	78.2
9	Total	512.0	4.2	516.1
10	**Expenses**	524.4	-	524.4
11	**Economic Res./ MRSM**	24.2	-	24.2
12	**Net Income**	11.8	4.2	15.9
13	**Adjustment** *	-	(1.7)	(1.7)
14	**Total**	11.8	2.4	14.2
15				
16	**Interest & Related**	58.9	-	58.9
17	**TIER**	1.20	0.04	1.24

* Per Smelter Agreements

b. 1.10x – Smelters pay $10.1m

		Before Adjust.	TIER Adjust./ (Rebate)	After Adjust.
1	**TWh**			
2	Members		3.76	
3	Smelters		7.32	
4	**Revenues/ MWh**		1.37	
5	**Revenues**			
6	Members	131.9	-	131.9
7	Smelters	301.9	10.1	311.9
8	Other	72.3	-	72.3
9	Total	506.1	10.1	516.1
10	***Expenses***	524.4	-	524.4
11	**Economic Res./ MRSM**	24.2	-	24.2
12	**Net Income**	5.9	10.1	15.9
13	**Adjustment ***	-	(1.7)	(1.7)
14	**Total**	5.9	8.3	14.2
15				
16	**Interest & Related**	58.9	-	58.9
17	***TIER***	1.10	0.14	1.24

*** Per Smelter Agreements**

c. 1.0x – Smelters pay $15.9m

		Before Adjust.	TIER Adjust./ (Rebate)	After Adjust.
1	**TWh**			
2	Members		3.76	
3	Smelters		7.32	
4	**Revenues/ MWh**		2.18	
5	**Revenues**			
6	Members	131.9	-	131.9
7	Smelters	301.9	15.9	317.8
8	Other	66.4	-	66.4
9	Total	500.2	15.9	516.1
10	**Expenses**	524.4	-	524.4
11	**Economic Res./ MRSM**	24.2	-	24.2
12	**Net Income**	0.0	15.9	15.9
13	**Adjustment ***	-	(1.7)	(1.7)
14	**Total**	0.0	14.2	14.2
15				
16	**Interest & Related**	58.9	-	58.9
17	**TIER**	1.00	0.24	1.24

* Per Smelter Agreements

d. 0.94x (Filed Case) – Smelters pay $19.3m

		Before Adjust.	TIER Adjust./ (Rebate)	After Adjust.
1	**TWh**			
2	Members		3.76	
3	Smelters		7.32	
4	**Revenues/ MWh**		2.64	
5	**Revenues**			
6	Members	131.9	-	131.9
7	Smelters	301.9	19.3	321.2
8	Other	63.0	-	63.0
9	Total	496.8	19.3	516.1
10	**Expenses**	524.4	-	524.4
11	**Economic Res./ MRSM**	24.2	-	24.2
12	**Net Income**	(3.4)	19.3	15.9
13	**Adjustment ***	-	(1.7)	(1.7)
14	**Total**	(3.4)	17.6	14.2
15				
16	**Interest & Related**	58.9	-	58.9
17	**TIER**	0.94	0.30	1.24

*** Per Smelter Agreements**

Witness) Robert S. Mudge

Item 77) Provide an analysis which shows the proportion of cost necessary to ensure achievement of 1.24 TIER that is borne by the Smelters if TIER in 2010 prior to imposition of TIER adjustment charges is:

a. 1.20,
b. 1.10, and
c. 1.0.

Response) Please see below the scenarios requested, plus cost borne by the Smelters in the filed Financial Model, for which TIER in 2012 prior to imposition of TIER adjustment charges would be 0.94x. (Please note that in each of these cases, the Smelters would bear 100% of the incremental cost.)

a. 1.20x – Smelters pay $4.2m

		Before Adjust.	TIER Adjust./ (Rebate)	After Adjust.
1	**TWh**			
2	Members		3.76	
3	Smelters		7.32	
4	**Revenues/ MWh**		0.57	
5	**Revenues**			
6	Members	131.9	-	131.9
7	Smelters	301.9	4.2	306.0
8	Other	78.2	-	78.2
9	Total	512.0	4.2	516.1
10	**Expenses**	524.4	-	524.4
11	**Economic Res./ MRSM**	24.2	-	24.2
12	**Net Income**	11.8	4.2	15.9
13	**Adjustment ***	-	(1.7)	(1.7)
14	**Total**	11.8	2.4	14.2
15				
16	**Interest & Related**	58.9	-	58.9
17	**TIER**	1.20	0.04	1.24

* Per Smelter Agreements

b. 1.10x – Smelters pay $10.1m

		Before Adjust.	TIER Adjust./ (Rebate)	After Adjust.
1	**TWh**			
2	Members		3.76	
3	Smelters		7.32	
4	**Revenues/ MWh**		1.37	
5	**Revenues**			
6	Members	131.9	-	131.9
7	Smelters	301.9	10.1	311.9
8	Other	72.3	-	72.3
9	Total	506.1	10.1	516.1
10	**Expenses**	524.4	-	524.4
11	**Economic Res./ MRSM**	24.2	-	24.2
12	**Net Income**	5.9	10.1	15.9
13	**Adjustment ***	-	(1.7)	(1.7)
14	**Total**	5.9	8.3	14.2
15				
16	**Interest & Related**	58.9	-	58.9
17	**TIER**	1.10	0.14	1.24

*** Per Smelter Agreements**

c. 1.0x – Smelters pay $15.9m

		Before Adjust.	TIER Adjust./ (Rebate)	After Adjust.
1	**TWh**			
2	Members		3.76	
3	Smelters		7.32	
4	**Revenues/ MWh**		2.18	
5	**Revenues**			
6	Members	131.9	-	131.9
7	Smelters	301.9	15.9	317.8
8	Other	66.4	-	66.4
9	Total	500.2	15.9	516.1
10	**Expenses**	524.4	-	524.4
11	**Economic Res./ MRSM**	24.2	-	24.2
12	**Net Income**	0.0	15.9	15.9
13	**Adjustment ***	-	(1.7)	(1.7)
14	**Total**	0.0	14.2	14.2
15				
16	**Interest & Related**	58.9	-	58.9
17	**TIER**	1.00	0.24	1.24

*** Per Smelter Agreements**

d. 0.94x (Filed Case) – Smelters pay $19.3m

		Before Adjust.	TIER Adjust./ (Rebate)	After Adjust.
1	**TWh**			
2	Members		3.76	
3	Smelters		7.32	
4	**Revenues/ MWh**		2.64	
5	**Revenues**			
6	Members	131.9	-	131.9
7	Smelters	301.9	19.3	321.2
8	Other	63.0	-	63.0
9	Total	496.8	19.3	516.1
10	**Expenses**	524.4	-	524.4
11	**Economic Res./ MRSM**	24.2	-	24.2
12	**Net Income**	(3.4)	19.3	15.9
13	**Adjustment ***	-	(1.7)	(1.7)
14	**Total**	(3.4)	17.6	14.2
15				
16	**Interest & Related**	58.9	-	58.9
17	**TIER**	0.94	0.30	1.24

*** Per Smelter Agreements**

Witness) Robert S. Mudge

Item 78) Clearly state all application terms, conditions and circumstances under which a Smelter would be allowed to terminate its retail agreement with Kenergy after the agreement becomes effective, but prior to the scheduled termination date of December 31, 2023.

Response) A Smelter is permitted to terminate its retail agreement following the commencement of service thereunder in two circumstances: (1) the termination and cessation of all aluminum smelting operations at its smelting facilities, and (2) following the occurrence of an event of default by Kenergy (or, derivatively, Big Rivers) in the performance of its obligations under that agreement.

Cessation of Smelting Activities. Several conditions exist to a Smelter's ability to terminate its retail agreement as a result of the termination and cessation of all aluminum smelting operations at its smelting facilities. These conditions are (1) at least one year's prior notice must be given; (2) no termination may be effective prior to December 31, 2010; (3) no termination may be effective prior to December 31, 2011 if the Transmission Upgrade (as defined in the wholesale agreement) is not completed and the other Smelter has issued a notice of termination; and (4) the president of the parent of the Smelter must deliver a certificate including a representation and warranty that it has made a business judgment in good faith to terminate and cease all aluminum smelting at the smelting facilities and has no current intention of re-commencing smelting operations at such facilities.

Event of Default. Each Smelter also may terminate its retail agreement upon the occurrence of an event of default by Kenergy, or, derivatively, by Big Rivers (an "Event of Default"). Events of Default may occur as a result of (1) the failure by a party to make any payment in accordance with the agreement within three business days following the non-performing party's receipt of written notice of the non-performing party's default in its payment obligation; (2) the failure of a party to perform any other material duty imposed on it by the agreement within 30 days following the non-performing party's receipt of written notice of the non-performing party's breach of its duty hereunder; (3) any attempt by a party to transfer an interest in the agreement other than as permitted thereunder; (4) the occurrence and continuance of an Event of Default or the failure, inability or refusal of Kenergy to cure a breach or default by Kenergy under the related wholesale agreement which gives rise to a termination of such wholesale agreement, or any termination by Kenergy of such wholesale agreement in breach or default thereof; and (5) insolvency events relating to a party (See Sections 7.3.2 and 14.1 of the retail agreements).

Witness) C. William Blackburn

Item 79) Clearly state all applicable terms, conditions and circumstances under which a Smelter would be allowed to terminate its retail agreement with Kenergy prior to KPSC action on the Application in this matter.

Response) There are three relevant time periods that must be examined: (1) the current period, (2) the period after execution but prior to the issuance of an order by the Commission, and (3) the period following such an order but prior to the "Effective Date," i.e., the commencement of service under the agreements.

Current Status. As described in the application, the smelter agreements have not yet been executed and therefore are not yet binding on them. While Big Rivers believes they are in substantially final form and the Smelters have advised Big Rivers that management has recommended approval of the agreements, the Smelters are seeking corporate parent approvals to enter into the agreements.

Post-Execution and Pre-Order Period. Following the execution of the smelter agreements and prior to an order of the Commission, the Smelters have additional rights to terminate the retail agreements. First, a Smelter may terminate its retail agreement upon receipt of notice from E.On or Big Rivers that either party does not intend to consummate the Unwind Transaction (See Section 7.2.2 of the retail agreements). Second, a Smelter may terminate its retail agreement if it determines in good faith, that Big Rivers' operations cannot produce during the first five years of service under the agreements the charges projected in Big Rivers' financial model and filed with the Commission in the application (See Section 7.2.4(a) of the retail agreements). Third, a Smelter may terminate its retail agreement if it determines in good faith, that there has been a material adverse change in its production facilities or a material change in economic or business factors external to the terms of the proposed transaction, that would have a material adverse financial effect on it if the transaction is consummated (See Section 7.2.4(b) of the retail agreements). Fourth, a Smelter may terminate its retail agreement if Big Rivers terminates the related wholesale agreement with Kenergy (See Section 7.2.5 of the retail agreements).

A Smelter's right to terminate its retail agreement pursuant to the Second and Third methods described above may be exercised until 24 hours after receipt of documentation and supporting calculations setting forth the estimated interest cost and terms and conditions of the final financing plan arranged by Big Rivers in connection with the Unwind, such that it can determine whether such financing plan could materially affect the calculation of the TIER Adjustment included in the Commission filing. If the actual interest cost would be more than 15 basis points in excess of such estimate or other terms or conditions are materially different than those estimated, however, Kenergy shall notify the Smelter or cause the Smelter to be notified of such changes in the interest cost or other terms and conditions, and the Smelter would have an additional right to terminate the smelter agreements for 24 hours after notice of the new estimated interest cost or terms or conditions. The deadline for the exercise of any right to terminate the retail agreements in the Second and Third methods is extended, if applicable, to the expiration of the right of the Smelters to terminate the agreements as a result of an order of the Commission (described below).

Post-Order and Pre-Effective Date Period. Following an order of the Commission but prior to the Effective Date, the Smelters have further rights to terminate the agreements. First, the Smelter Agreements will contain a date by which the parties must satisfy or waive the conditions to closing and consummate the transaction or the agreements may be terminated. Because the agreements have not yet been executed, this date has not yet been determined. Second, if the Commission issues an order on any of the filings by Big Rivers or others seeking necessary approvals for the Unwind Transaction and the New Transaction that disapproves or changes the pricing or other material terms of the Smelter Agreements or Big Rivers' ability to recover costs from the Smelters or the members' other ratepayers (Other than as contemplated), the smelter agreements may be terminated no later than three business days after the first to occur of: (1) the last date on which a petition for re-hearing may be filed if such a petition has not been filed, (2) the date on which the Commission issues an order denying the request for re-hearing for any petition for re-hearing that may have been filed during the allowed period, and (3) if a rehearing occurs, following the date on which an order on rehearing is issued (See Section 7.2.3 of the retail agreements).

In addition, the Smelter Agreements may be terminated if the wholesale agreements are terminated (as described above) or following the closing of the smelting facilities or the occurrence of an Event of Default as described in the response to AG Item 78.

Witness) C. William Blackburn

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
February 14, 2008

Item 80) Please reference the testimony of Paul W. Thompson, page. 3. Provide all documents which relate to, analyze data, and support "LEC's lease and power purchase and sale bid proposal" to the Bankruptcy Court in February 1997, including documents prepared internally by E.ON or any of its subsidiaries or affiliates, or prepared by outside consultants, investment bankers, etc.

Response) See E.ON response.

Witness) E.ON .S.

Item 81) Please reference the testimony of Paul W. Thompson, page. 3. Provide "LEC's lease and power purchase and sale bid proposal."

Response) See E.ON response.

Witness) E.ON U.S.

Item 82) Please reference the testimony of Paul W. Thompson, page. 7. To the extent not previously provided, provide the "November 2005 Letter of Intent."

Response) See E.ON response.

Witness) E.ON U.S.

Item 83) Please reference the testimony of Paul W. Thompson, page. 13, regarding "WKEC has agreed to pay to the smelter customers, collectively, at the closing a sum of money in immediately available funds." State the amount of that sum of money.

Response) See E.ON response.

Witness) E.ON U.S.

Item 84) Please state when E.ON anticipates it will receive the requested tax rulings from IRS and Kentucky Revenue Cabinet.

Response) See E.ON response.

Witness) E.ON U.S.

Item 85) Provide the complete joint application and supporting documentation for the parties' waiver from the Federal Trade Commission under the Hart-Scott-Rodino Antitrust Improvements Act ("HSR Filing"). If the filing has not yet been made, please state when it is anticipated the HSR filing will be made.

a. If the HSR filing has not yet been made, provide each document that is being considered for inclusion when the filing is made.

Response) Please refer to the PSC item 1.c.(3) and (4). See also E.ON response.

Witness) C. William Blackburn
E.ON

Item 86) Identify and provide the filings before the Federal Energy Regulatory Commission necessitated by this proposed transaction.

Response) Please refer to PSC item 1.c.(2). See E.ON's response.

Witness) David A. Spainhoward
E.ON U.S.

Item 87) Please reference the testimony of Paul W. Thompson, page 18, regarding "By terminating its commitments now, E. ON-U.S. will bring financial certainty to what would otherwise be an uneconomic set of contracts that could expose the Company to uncertain and unfavorable financial results through 2023."

a. Provide the estimated present value of these unfavorable financial results through 2023 (or any shorter period evaluated by the Company).

b. State specifically each and every fact or circumstance that makes the "set of contracts" "uneconomic."

c. For each and every fact or circumstance that makes the set of contracts uneconomic, quantify its contribution to "unfavorable financial results."

Response) See E.ON's response.

Witness) E.ON U.S.

Item 88) Provide any and all internal E.ON documents which address the subject of the existing agreements which are the subject of the "Unwind Transaction" and "Termination Transaction", including any financial analyses and strategic analyses.

Response) See E.ON's response.

Witness) E.ON U.S.

Item 89) Provide any and all documents created for E.ON, or at its direction, which address the subject of the existing agreements which are the subject of the "Unwind Transaction" and "Termination Transaction", including any financial analyses and strategic analyses.

Response) See E.ON's response.

Witness) E.ON U.S.

Item 90) Provide E.ON's strategic plan for generation assts and operations in Kentucky, or at any necessary higher level (geographic or business) if such a plan does not exist for Kentucky.

Response) See E.ON's response.

Witness) E.ON U.S.

Item 91) Provide any and all documents and materials considered by E.ON senior management and Board of Directors (or its equivalent) in acting to:

a. Initiate discussions with Big Rivers on the subjects of the Unwind and Lease Agreement Termination transactions; and,

b. Approve and authorize the proposed transactions before the Commission in this matter.

Response) See E.ON's response.

Witness) E.ON U.S.

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
February 14, 2008

Item 92) Please reference Exhibit 8, the Unwind Financial Model dated as of December 22, 2007, regarding the 10% rate increase projected for 2017. Does the company believe this increase is a reasonable assumption based on past Commission decisions? If so, why?

Response) While the Financial Model is a projection into the future, the PSC certainly is not bound by any future rate projections. The 10 percent projected rate increase in 2017 is based upon increasing cost. Big Rivers believes that any utility that has prudently monitored its business, and incurred only expenses that are justifiable, is entitled to rates that are fair, just and reasonable. Big Rivers does not believe that it is the magnitude of the rate adjustments but the justification for the increase that will determine the outcome of any future rate adjustment request.

Witness) C. William Blackburn

Item 93) Please reference Exhibit 8, the Unwind Financial Model dated as of December 22, 2007, regarding the "Inputs" tab worksheet.

a. Column C is labeled "source", and contains reference to various things including .xls spreadsheet files.

i. To the extent not previously provided, provide copies of each indicated "source" item; and,

ii. Provide machine readable working electronic file copies of each referenced .xls file, with working formulas.

b. Columns D, E, and F contain numeric inputs that in some cases (e.g., rows 146-199, 308-324, etc) do not have referenced sources. Provide documents which support these inputs.

Response) Please see PSC Item 22(a) and (b).

Witness) Robert S. Mudge

Item 94) State each material fact which prevents E.ON from electing to continue its present mode of operation, including provision of power to Big Rivers under the existing Lease Agreement and Purchase Power Agreement.

Response) See E.ON's response.

Witness) E.ON U.S.

Item 95) State each material fact and purpose which incents or otherwise motivates E.ON to seek the Unwind Transaction and Lease Agreement termination which is the subject of this proceeding. Discuss each such listed material fact and purpose.

Response) Please see E.ON's response.

Witness) E.ON U.S.

Item 96) Provide any available and current market and industry research on aluminum commodity markets and aluminum smelting that have been reviewed and considered by E.ON.

Response) Please see E.ON's response.

Witness) E.ON U.S.

Item 97) Identify and provide any filings before the Securities & Exchange Commission (SEC) which reference this proposed transaction.

Response) Please see E.ON's response.

Witness) E.ON U.S.

Item 98) Please provide the most recent 10-K filings with the SEC, to the extent they exist for:

a. E.ON
b. LG&E
c. LEC
d. WKEC
e. LEM, and
f. Any other subsidiaries or affiliates involved in the Lease Agreement or Power Purchase Agreement.

Response) See E.ON's response.

Witness) E.ON U.S.

Item 99) Provide the amount and date of any asset book value write downs or other valuation write downs since 1997, which exceed $500k, and pertain to Lease Agreement facilities.

Response) See E.ON's response.

Witness) E.ON U.S.

Item 100) Provide E.ON/LEM current view of operating budgets (cost and revenues, multi year forward looking) for facilities operated under the Lease Agreement.

a. Calculate and state the extent to which unit costs of power produced by the leased facilities are projected increase or decrease under this operating budget view.

Response) See E.ON's response.

Witness) E.ON U.S.

Item 101) Provide E.ON/LEM current capital budget (multi year, forward looking) for facilities operated under the Lease Agreement.

a. Calculate and state the extent to which unit costs of power produced by the leased facilities are projected increase or decrease under this capital budget view.

Response) See E.ON's response.

Witness) E.ON U.S.

Item 102) Provide documents which show the prices of power provided to Big Rivers by E.ON under the relevant purchase power agreements versus the cost of producing that power, for the years 2005 to current.

Response) See E.ON's response.

Witness) E.ON U.S.

BIG RIVERS ELECTRIC CORPORATION'S
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Item 103) Provide all reports or presentations prepared by investment banking advisors for E.ON pertaining to the Unwind Transaction/Lease Agreement termination.

Response) See E.ON's response.

Witness) E.ON U.S.

Item 104) Provide all E.ON management reports and analyses prepared internally pertaining to the Unwind Transaction/Lease Agreement termination which is the subject of this application.

Response) See E.ON's response.

Witness) E.ON U.S.

Item 105) Please reference the application at page 11, paragraph 21. Explain in detail why the transactions with Big Rivers "had not proven to be advantageous to E.ON U.S."

Response) See E.ON's response.

Witness) E.ON U.S.

Item 106) Explain in detail why the Joint Applicants chose not to include the Attorney General, who represents consumers in matters before the Commission, in the unwind transaction presently filed.

Response) The Attorney General was not included in the Unwind Transaction negotiations because he is not a party to any agreement being terminated, is not a party to any agreement proposed to be entered into as part of the Unwind Transaction and is not otherwise assuming or being relieved of any rights or duties in connection with the Unwind Transaction. Big Rivers viewed the role and interest of the Attorney General to be participation in the review of transactions presented to the Commission by a utility, as described in KRS 367.150, not participation in negotiating the transaction itself. Big Rivers and E.ON did promptly meet with the Attorney General when the Unwind Transaction was made public to describe the transaction to him. See also E.ON's response.

Witness) Michael H. Core

BIG RIVERS ELECTRIC CORPORATION'S
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Item 107) Please reference the Application at page 17, paragraph 33. Describe the negotiations to date with Henderson. In the description include dates, people involved, and all matters discussed.

Response) Please see attached schedule. Big Rivers anticipates that the negotiations with Henderson will be concluded and the consent will be filed with the Commission promptly after completion.

Witness) David A. Spainhoward

SCHEDULE OF MEETINGS
WITH HENDERSON MUNICIPAL POWER & LIGHT

Date	Attendees	Matters Discussed
1/31/06	Mike Core, David Spainhoward, Mike Thompson, C.B. West, Gary Quick, Wayne Thompson, Jim Miller	HMP&L's issues regarding unwind
4/10/06	David Spainhoward, Mike Thompson, Gary Quick, Wayne Thompson, C.B. West, Jim Miller	HMP&L's issues regarding unwind
6/14/06	C.B. West, Jim Miller, David Spainhoward, [City Manager], [HMP&L Board Member], Tim Dowdy, David Sinclair, Ralph Bowling, Rob Toerne, Robert Michel, Pat Northam, Wayne Thompson	HMP&L's issues regarding unwind
1/12/07	Mike Thompson, David Spainhoward, Gary Quick, Wayne Thompson, C.B. West, John Meinders, Jim Miller	HMP&L's issues regarding unwind
2/21/07	Mike Thompson, David Spainhoward, Gary Quick, Wayne Thompson, C.B. West, John Meinders	HMP&L's issues regarding unwind
4/16/07	C.B. West, Gary Quick, Wayne Thompson, David Sinclair, Tim Dowdy, Bob Berry, Jeff Vandiver, Rob Toerne, Ralph Bowling, Joe Ternes, Mike Thompson, Jim Miller	HMP&L's issues regarding unwind
4/20/07	David Spainhoward and Gary Quick	HMP&L's issues regarding unwind
4/27/07	Mike Thompson, Jeff Meadow, David Crockett	HMP&L's NERC Compliance
5/17/07	C. B. West, Wayne Thompson, Gary Quick, Jim Miller, Mike Thompson, David Spainhoward, David Sinclair, Rob Toerne, Tim Dowdy, Bob Berry	Outstanding WKE Issue List
6/18/07	No recall of who was present	HMP&L's issues regarding unwind

Date	Attendees	Matters Discussed
7/13/07	Chairman Bill Smith, Gary Quick, Wayne Thompson, Mike Thompson, Jim Miller, David Spainhoward	Post-Closing Fuel Quality Discussions
10/24/07	C.B. West, Pat Northam, Gary Quick, Jim Miller, Tim Dowdy, Wayne Thompson, David Spainhoward, Mike Thompson; Robert Michel	HMP&L's issues regarding unwind
11/6/07	Gary Quick, Wayne Thompson, C.B. West, Bill Blackburn, David Spainhoward, David Crockett, Mike Thompson, Jim Miller	HMP&L's issues regarding unwind
11/20/07	Bill Blackburn, David Crockett, Wayne Thompson, Mike Thompson, C.B. West, Gary Quick, David Spainhoward, Jim Miller	HMP&L's issues regarding unwind
12/5/07	Robert Ferdon, C.B. West, Patrick Northam, David Sinclair, Tim Dowdy, David Spainhoward, Jim Miller	Conference call regarding terms of the proposed release
12/06/07	Mike Core , Gary Quick	HMP&L's issues regarding unwind
12/06/07 +/-	Gary Quick, Wayne Thompson, Mike Core, Mark Bailey, David Spainhoward, Bill Blackburn	HMP&L's issues regarding unwind
12/11/07	Mark Bailey, Mike Core, Gary Quick, Chairman Bill Smith, Board Member Scott Miller	HMP&L's issues regarding unwind
12/14/07	Mike Thompson, Wayne Thompson	Model Inputs

Item 108) Please reference the Application at page 17, paragraph 33e. Explain what the Joint Applicants mean when they state that the negotiations are "on-going".

Response) Big Rivers assumes the Attorney General refers to page 20, paragraph 37e. The term "on-going" as it relates to negotiations with Henderson means the negotiations have not been completed. Big Rivers anticipates that the negotiations with Henderson will be concluded and the consent will be filed with the Commission promptly after completion.

Witness) C. William Blackburn

Item 109) Please reference the Application at page 20, paragraph 37d. Explain why Big Rivers believes it is prudent to continue with the transaction when it has yet to complete the due diligence of the generating facilities?

Response) Big Rivers' due diligence of the generating facilities has been and will continue to be performed up until the time of Transaction Closing due to the fact that there are a number of provisions in the Termination Agreement that must be satisfied before the Closing can occur. For example, please see page 67 of 622 (ff) – No Forced Outage at Generating Plants. Big Rivers is not required to Close should a unit be out of service due to a scheduled outage unless it is satisfied the unit will meet the criteria set forth in that section. Another example is listed in Section (dd) on page 66 of 622 – Condition of Generating Plants. Big Rivers is not required to Close unless, in its sole reasonable judgment, the units are in good condition and state of repair, ordinary wear and tear excepted, consistent with Prudent Utility Practice.

See also response to Commission Staff Question 51.

Witness) Mark A. Bailey

Item 110) Does Big Rivers agree that the heart of the ability for an electric company to exist is to have reliable generation?

a. If so, then why would Big Rivers agree to resume control over the generators unless due diligence has been completed to clearly show that the generators are reliable?

Response) Reliable generation will be important to Big Rivers in order to meet its load requirements and serve its Members.

a. Please see Big Rivers' response to Attorney General's initial request, Item 109 and Staff Request Item 51. Big Rivers believes there are sufficient closing conditions contained in the Termination Agreement to enable it to refuse to close should it find the generating units are not in reliable condition at that time. The Termination Agreement does not require Big Rivers to close the Unwind Transaction unless Big Rivers has completed its due diligence with satisfactory results as provided in the Termination Agreement. Satisfaction of other conditions to closing, while pursuing an acquiror's due diligence on the assets to be acquired, is common in arrangements for the transfer of control of assets such as the generating facilities.

Witness) Mark A. Bailey

BIG RIVERS ELECTRIC CORPORATION'S
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Item 111) Why is the agreement so time sensitive with the financing that additional time for regulatory review will presumably jeopardize the transaction?

Response) The effort to negotiate and implement the Unwind Transaction has been ongoing for more than four years. Both financing and regulatory approvals are sensitive because the parties need to proceed on parallel paths to effect a timely closing. The need to obtain multiple approvals makes a "one step at a time" approach impractical. The financing is being scheduled to meet the closing date requirements.

Witness) Michael H. Core

Item 112) The 2005 Annual Report to Members (Exhibit 4) states at page 2 "The signing of the [Letter of Intent] begins a process to seek all the necessary approvals for an unwind by early 2007". Explain why despite this goal Joint Applicants filed an arguably incomplete filing between Christmas and New Years Eve, 2007.

Response) The 2005 Annual Report was prepared in early 2006, and the quoted statement represents Big Rivers' best estimate of the schedule for the Unwind. What was unknown at that time was the delay that would be caused by negotiations with a Big Rivers creditor in the 2000 defeased sale leaseback. This delay along with the complexity of the transaction and other matters caused the change in the timing to file with the PSC. The Big Rivers filing in this matter was and is, complete.

Witness) Michael H. Core

Item 113) Please reference the Application at page 21, paragraph 39. Has the "outstanding issue with Kenergy been resolved"?

a. Regardless of the answer, please describe the issue.
b. If it has been resolved, please describe the resolution.
c. If it has not been resolved, explain why.
d. If it has not been resolved, please explain why it is prudent for the transaction to be considered by the Commission.

Response) No.

a. The issue involves questions about patronage capital at the retail level.

b. NA

c. The parties have not yet reached agreement, but are meeting within the next week in an attempt to do so.

d. The parties expect to have a timely resolution of the issue, with little or no change to the Smelter Agreements that have been filed.

Witness) C. William Blackburn

Item 114) Please reference the Application at page 31, paragraph 57. Describe in detail what financial, technical, and managerial capabilities Big Rivers will have that are materially different than when it went into bankruptcy.

Response) Big Rivers will be materially different than when it was in bankruptcy. Financially Big Rivers will be in significantly better shape than at the time of its bankruptcy. First, it will have much lower debt as a result of debt being paid down post bankruptcy and of the further debt reduction resulting from the Unwind Transaction. The Unwind Transaction will result in equity moving from a negative 13.6% to a positive 24.4% with cash of $125 million and lines of credit totaling another $100 million. This provides $225 million in liquidity and a cushion for unanticipated costs. Big Rivers will also have an indenture that will facilitate access to more lenders providing flexibility to achieve the best interest rates.

Second, the financial, technical, and managerial capabilities of Big Rivers were not the reason for the bankruptcy. Rather, at the time of the bankruptcy, Big Rivers had burdensome coal contracts, and the wholesale power market had not yet fully developed. Big Rivers will not assume long-term, burdensome coal contracts, whose prices are out of line with market prices, like those it had when it filed for reorganization. Technically, Big Rivers and the entire utility industry have undergone significant changes over the past ten years resulting in and from RTOs, structured wholesale power markets and efficiency improvements.

Big Rivers is also a member of ACES Power Marketing, a joint effort by 15 G&Ts and one distribution cooperative, and that has broadened Big Rivers' knowledge and access to other technologies regarding risk management, wholesale power markets, fuels, power production models and other pertinent types of information. Big Rivers has determined its organizational structure will have a total of 632 positions. This number is nearly 200 less than when it entered bankruptcy. Big Rivers' managerial capabilities will be in good hands after the closing of the Unwind Transaction. The description of Mark Bailey and his senior staff is included in his testimony, Exhibit 5, as Exhibit MAB-1. All permanent senior staff positions following the Unwind closing will be filled by individuals that were not senior staff at Big Rivers at the time of the filing of bankruptcy. In addition, the Board and management of Big Rivers have established a new department of Enterprise Risk Management that will focus risk identification, evaluation and mitigation of risks. This department will provide on-going reports to the Board and Members with regard to enterprise risk management. We believe these efforts will facilitate the health of the company and allow it to maintain its financial viability.

Witness) Michael H. Core

Item 115) In regard to each materially different difference, explain in detail why Big Rivers believes it will allow the company to remain viable on an on-going basis.

Response) See response to AG initial request, Item 114.

Witness) Michael H. Core

BIG RIVERS ELECTRIC CORPORATION'S
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Item 116) For each year 2008-2013, please provide the computed rate of return on rate base inherent in the financial model projections (Exhibit 8).

Response) As an electric cooperative, Big Rivers has not historically prepared a calculation of return on rate base for submission to the Kentucky Public Service Commission or other purposes.

For reference, we have prepared an indicative calculation of return on rate base inherent in the financial model projections, defined as follows:

1. Net margins + financing related expense

   divided by

2. Net plant in service (approximate Rate Base)

The calculation for the years 2008 through 2023 is provided on the attached table.

Witness) Robert S. Mudge
C. William Blackburn

ATTACHMENT TO AG ITEM 116

	2008	2009	2010	2011	2012	2013
Approximate Rate Base ($M, Beginning of Period)						
Total Utility Plant in Service	1,878	1,924	2,001	2,060	2,117	2,172
Accumulated Depreciation & Amortization	870	894	931	970	1,015	1,061
Net Plant	1,008	1,030	1,069	1,090	1,102	1,110
Return on Rate Base ($M, unless otherwise indicated)						
Net Margin	11	16	13	16	16	16
Plus Finance Related Expense:						
Interest Expense (Incl. Financing Fees and Restructuring Costs)	31	46	46	45	44	43
Net Sale-Leaseback	(2)	(2)	(2)	(2)	(2)	(2)
Total	40	60	56	58	58	57
%	6.0%	5.8%	5.3%	5.3%	5.2%	5.1%

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Section 3

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
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Item 117) Assuming the 2008 capital structure projected in the financial model (Exhibit 8), please provide Big Rivers' current weighted average cost of capital, showing computations and the cost attributed to each source of capital.

Response) The attached schedule shows the cost of capital computation for the 12 months ended December 31, 2008 based on the Financial Model (Exhibit 8). The Financial Model does not provide the detail needed to calculate cost of capital by source (generation, transmission and general plant).

Witness) C. William Blackburn

Big Rivers Electric Corporation
PSC Case 2007-00455

Cost of Capital is calculated as follows:

$$\frac{\text{Interest on Long Term Debt}}{\text{Average Principal Balance}} + \frac{\text{Depreciation \& Amortization + Property Taxes + Property Insurance}}{\text{Average Gross Plant in Service}}$$

YTD 2008

$46.1/$1,106.30	=	**4.17%**
($34.7+$2.53+$2.77)/$1,875.87	=	**2.13%**
		6.30%

12 MONTHS ENDED 12/31/08 (M$):

Interest on Long-Term Debt	$46.10
Depreciation & Amortization	$34.70
Property Taxes	$2.53
Property Insurance	$2.77
12 Month Average Principal Balance @ 12/31/08 *	$1,106.30
12 Month Average Gross Plant in Service @ 12/31 **	$1,875.87

* calculation of average principal balance:

balance @ 4/30/08 $1,237.3 x 4 months	=	$4,949.20
+ balance @ 12/31/08 $1,040.8 x 8 months	=	$8,326.40
total		$13,275.60
total divided by 12 months	=	$1,106.30

** calculation of average gross plant in service

balance @ 4/30/08 $1,780.2 x 4 months	=	$7,120.80
+ balance @ 12/31/08 $1,923.7 x 8 months	=	$15,389.60
total		$22,510.40
total divided by 12 months	=	$1,875.87

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
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Item 118) Please reference the testimony of Burns E. Mercer, page 4, regarding "absent the rate path offered by Big Rivers through the capacity restored to it by the Unwind Transaction there would be a higher chance that the Smelters could discontinue operations". Please explain in detail why E.ON/LEM would not be able to offer the smelters the same or similar "rate path" under the current status and structure, including the Lease Transaction and Purchase Power Agreements.

Response) See E.ON response.

Witness) E.ON U.S.

Item 119) Provide all correspondence to and from Jack Gaines/JDG Consulting pertaining to the negotiations surrounding the Unwind Transaction.

Response) In all negotiations surrounding the Unwind Transaction, Jack Gaines/JDG Consulting represents the interests of Big Rivers' distribution cooperative members, whose interests are independent of Big Rivers' interests. Communications between Big Rivers and Jack Gaines/JDG Consulting pertaining to the negotiations between Big Rivers and its Members are privileged, and as such, Big Rivers objects to this request. Big Rivers further objects on the grounds that the request is overly broad, unduly burdensome, and irrelevant. Notwithstanding the foregoing objection, attached are documents provided by Jack Gaines in response to this request.

Witness) Burns E. Mercer
Counsel

Barbara Harwood

From: Burns Mercer [bmercer@mcrecc.com]
Sent: Tuesday, September 11, 2007 1:32 PM
To: Jack D. Gaines
Subject: RE: Billing Load Factors

Got it!

From: Jack D. Gaines [mailto:jgaines@jdg-llc.com]
Sent: Tuesday, September 11, 2007 2:25 PM
To: Burns Mercer
Subject: FW: Billing Load Factors

Please confirm receipt.

From: Jack D. Gaines [mailto:jgaines@jdg-llc.com]
Sent: Tuesday, September 11, 2007 2:01 PM
To: 'Burnie Mercer'; 'Sandy Novick'; 'Kelly Nuckols'
Subject: Billing Load Factors

The attached shows the rolling twelve month "billing" load factors for each member and BREC (rural systems). Billing load factor measures the relationship between annual kWh and the sum of the billing demands for the same year. Billing load factor is meaningful when evaluating your average cost of power per kWh.

The file also has a comparison of billing and annual load factors by each member. The calculations are rolling twelve months beginning 12/31/98 and ending 8/31/07. The BREC rural system weighted average over the entire period is 62.73%. The averages over the entire period by member are:

JP	62.82%
Kenergy	63.29%
Meade	61.16%

The history shows that the billing load factors fluctuate over time. It is primarily weather driven. The billing load factors were off in 2006 and the effect was exaggerated because 2006 followed two good years. Billing load factor is moving back up in 2007.

The newly approved load forecast is being used for the unwind production cost and financial models. For reference, it projects a 60.17% rural billing load factor. The history would indicate that 60.17% is low. In fact, 61.25% was the lowest over the 10 year period for the combined rural system.

Although I think the billing load factor from the new forecast is on the low side, the important thing for now is that both the status quo and the unwind reflect the same load factor and they do. Nevertheless, I have asked Bob for a revenue sensitivity using the historic average of 62.73% and I will let you know what the effect is when I get it from him.

Jack D. Gaines
President
JDG Consulting, LLC
770-392-9971
770-392-9971 (fax)
770-335-3299 (cell)
jgaines@jdg-llc.com

Barbara Harwood

From: Sandy Novick [snovick@kenergycorp.com]
Sent: Friday, December 14, 2007 12:20 PM
To: Jack D. Gaines
Cc: Burns Mercer
Subject: RE: Call

Jack: Here all day. Name a time. Sandy

From: Jack D. Gaines [mailto:jgaines@jdg-llc.com]
Sent: Friday, December 14, 2007 12:09 PM
To: 'Burns Mercer'; 'Sandy Novick'; 'Kelly Nuckols'
Subject: Call

Are you available for a call this afternoon? I know Kelly has some conflict but we need to get together even if it is not at the same times.

Jack D. Gaines
President
JDG Consulting, LLC
770-392-9971
770-392-9971 (fax)
770-335-3299 (cell)
jgaines@jdg-llc.com

Barbara Harwood

From: Sandy Novick [snovick@kenergycorp.com]

Sent: Friday, August 24, 2007 7:01 AM

To: Jack D. Gaines; Burns Mercer; Kelly Nuckols

Subject: RE: Call

Jack: I am tied up with an employee meeting until 10:30 EDT. Sandy

---

From: Jack D. Gaines [mailto:jgaines@jdg-llc.com]
Sent: Thursday, August 23, 2007 4:30 PM
To: 'Burnie Mercer'; snovick@kenergycorp.com; 'Kelly Nuckols'
Subject: Call

I'm available for a conference call tomorrow if you want to talk any time before 10:30 EDT. I'll be out next Monday and Tuesday.

Jack D. Gaines
President
JDG Consulting, LLC
770-392-9971
770-392-9971 (fax)
770-335-3299 (cell)
jgaines@jdg-llc.com

Barbara Harwood

From: Kelly Nuckols [Kelly.Nuckols@jpenergy.com]
Sent: Thursday, August 23, 2007 6:27 PM
To: Jack D. Gaines; Burns Mercer; snovick@kenergycorp.com
Subject: RE: Call

I have call scheduled with CFC on rate case 9:00 CDT

From: Jack D. Gaines [mailto:jgaines@jdg-llc.com]
Sent: Thursday, August 23, 2007 4:30 PM
To: 'Burnie Mercer'; snovick@kenergycorp.com; Kelly Nuckols
Subject: Call

I'm available for a conference call tomorrow if you want to talk any time before 10:30 EDT. I'll be out next Monday and Tuesday.

Jack D. Gaines
President
JDG Consulting, LLC
770-392-9971
770-392-9971 (fax)
770-335-3299 (cell)
jgaines@jdg-llc.com

Barbara Harwood

From: Burns Mercer [bmercer@mcrecc.com]
Sent: Friday, August 24, 2007 10:07 AM
To: Jack D. Gaines; Sandy Novick; Kelly Nuckols
Subject: RE: Call

OK.

From: Jack D. Gaines [mailto:jgaines@jdg-llc.com]
Sent: Friday, August 24, 2007 10:40 AM
To: 'Sandy Novick'; Burns Mercer; 'Kelly Nuckols'
Subject: RE: Call

I am tied up on another conference call until noon and then have to attend a meeting. I will have some time Monday morning and will try to call each of you but we may not be able to do it as a conference call.

Jack

From: Sandy Novick [mailto:snovick@kenergycorp.com]
Sent: Friday, August 24, 2007 8:01 AM
To: 'Jack D. Gaines'; 'Burnie Mercer'; 'Kelly Nuckols'
Subject: RE: Call

Jack: I am tied up with an employee meeting until 10:30 EDT. Sandy

---

From: Jack D. Gaines [mailto:jgaines@jdg-llc.com]
Sent: Thursday, August 23, 2007 4:30 PM
To: 'Burnie Mercer'; snovick@kenergycorp.com; 'Kelly Nuckols'
Subject: Call

I'm available for a conference call tomorrow if you want to talk any time before 10:30 EDT. I'll be out next Monday and Tuesday.

Jack D. Gaines
President
JDG Consulting, LLC
770-392-9971
770-392-9971 (fax)
770-335-3299 (cell)
jgaines@jdg-llc.com

Barbara Harwood

From: Sandy Novick [snovick@kenergycorp.com]
Sent: Tuesday, December 04, 2007 7:14 AM
To: Jack D. Gaines
Cc: Debbie Hayden; Burns Mercer; kelly.nuckols@JPEnergy.com
Subject: RE: Latest Financial Run

Jack: I am available until 9:30am or from 11:00am until 2:00pm. Sandy

---

From: Jack D. Gaines [mailto:jgaines@jdg-llc.com]
Sent: Monday, December 03, 2007 6:25 PM
To: 'Burns Mercer'; 'Sandy Novick'; 'Kelly Nuckols'
Subject: RE: Latest Financial Run

All,

I began to question myself about the conclusion that the Economic Reserve would last 5 years including base rate increases given the higher costs of the new model. So, I went back and rechecked the pro forma and found that I had miscalculated. Based on the new model with higher costs the Reserve would only be sufficient to keep rates at the current level through the first part of 2012, or about four years.

We can discuss this more when we talk. Please let us know your availability for Wednesday.

Jack

All,

Mark Bailey suggested I contact you to discuss the use of the Economic Reserve. There has been no change in how we plan to use it since we last discussed it. However, as a modeling tactic it is longer being applied to offset to future base rate increases, the first of which is modeled for 2011. That is because the tariffs to be filed will only attach it to offset the FAC and ES as a matter of practicality and regulatory constraint. Its use against base rate increases is and has been something that would be addressed as part of the first rate case. Nevertheless, the last model I saw continued to show that there is sufficient reserve to keep the rates at their current level through 2012 and a few months of 2013 if we ask the PSC to let us use it to offset base rates as well. Again, that is something that we would review in three years when the rate case is filed. In the meantime, it will be used to keep rates at current levels through 2010 by offsetting FAC and ES net of the credits for the smelter surcharges and the rebate if any.

I spoke to Nib today about the various tariff filings you will need to make. Perhaps we can arrange a call later this week to discuss the tariffs and the new financial model in more detail. Tomorrow is bad for me. Wednesday morning works.

Thanks

Jack

Barbara Harwood

From: Burns Mercer [bmercer@mcrecc.com]
Sent: Tuesday, December 04, 2007 8:04 AM
To: Jack D. Gaines; Sandy Novick; Kelly Nuckols
Subject: RE: Latest Financial Run

I'm available Wednesday morning.

From: Jack D. Gaines [mailto:jgaines@jdg-llc.com]
Sent: Monday, December 03, 2007 7:25 PM
To: Burns Mercer; 'Sandy Novick'; 'Kelly Nuckols'
Subject: RE: Latest Financial Run

All,

I began to question myself about the conclusion that the Economic Reserve would last 5 years including base rate increases given the higher costs of the new model. So, I went back and rechecked the pro forma and found that I had miscalculated. Based on the new model with higher costs the Reserve would only be sufficient to keep rates at the current level through the first part of 2012, or about four years.

We can discuss this more when we talk. Please let us know your availability for Wednesday.

Jack

All,

Mark Bailey suggested I contact you to discuss the use of the Economic Reserve. There has been no change in how we plan to use it since we last discussed it. However, as a modeling tactic it is longer being applied to offset to future base rate increases, the first of which is modeled for 2011. That is because the tariffs to be filed will only attach it to offset the FAC and ES as a matter of practicality and regulatory constraint. Its use against base rate increases is and has been something that would be addressed as part of the first rate case. Nevertheless, the last model I saw continued to show that there is sufficient reserve to keep the rates at their current level through 2012 and a few months of 2013 if we ask the PSC to let us use it to offset base rates as well. Again, that is something that we would review in three years when the rate case is filed. In the meantime, it will be used to keep rates at current levels through 2010 by offsetting FAC and ES net of the credits for the smelter surcharges and the rebate if any.

I spoke to Nib today about the various tariff filings you will need to make. Perhaps we can arrange a call later this week to discuss the tariffs and the new financial model in more detail. Tomorrow is bad for me. Wednesday morning works.

Thanks

Jack

Barbara Harwood

From: Burns Mercer [bmercer@mcrecc.com]
Sent: Wednesday, August 15, 2007 7:36 AM
To: Jack D. Gaines; Kelly Nuckols
Cc: sthompson@kenergycorp.com
Subject: RE: Meeting

I need to start the conference call @ 8:00 c.t. if that's OK.

From: Jack D. Gaines [mailto:jgaines@jdg-llc.com]
Sent: Tuesday, August 14, 2007 5:41 PM
To: Burns Mercer; 'Kelly Nuckols'
Cc: sthompson@kenergycorp.com
Subject: Meeting

All,

I had plans to be in Henderson next Wednesday but that meeting was cancelled. Burnie and I thought that since I already had it planned I could come on up and we could get together in Henderson to discuss the status of the unwind now that new numbers are available for review. We thought 9:00 a.m. would be a good time but I am flexible. Steve, would you forward to Sandy since I don't have his e-mail address.

Also, I understand that you will be getting the board presentation tomorrow. Would we have time for a conference call Thursday morning in advance of the Board meeting? Please let me know.

Thanks

Jack D. Gaines
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jgaines@jdg-llc.com

Barbara Harwood

From: Kelly Nuckols [Kelly.Nuckols@jpenergy.com]
Sent: Wednesday, August 15, 2007 9:41 AM
To: Jack D. Gaines; Burns Mercer
Cc: sthompson@kenergycorp.com
Subject: RE: Meeting

Wednesday 22, I have meeting with vendors on our AMI project. What was purpose of meeting?

On telephone conference Thursday 16th, anytime before 10:30. I have meeting with industrial prospects. And then need to drive to Henderson.

From: Jack D. Gaines [mailto:jgaines@jdg-llc.com]
Sent: Tuesday, August 14, 2007 4:41 PM
To: 'Burnie Mercer'; Kelly Nuckols
Cc: sthompson@kenergycorp.com
Subject: Meeting

All,

I had plans to be in Henderson next Wednesday but that meeting was cancelled. Burnie and I thought that since I already had it planned I could come on up and we could get together in Henderson to discuss the status of the unwind now that new numbers are available for review. We thought 9:00 a.m. would be a good time but I am flexible. Steve, would you forward to Sandy since I don't have his e-mail address.

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Barbara Harwood

From: Jack D. Gaines [jgaines@jdg-llc.com]

Sent: Friday, August 27, 2004 9:58 AM

To: Burns Mercer; Kelly Nuckols (Nuckols, Kelly); Mark Bailey

Subject: FW: The Core Project

I slight editorial change is found in the second item 1. below.

From: Jack D. Gaines [mailto:jgaines@jdg-llc.com]
Sent: Friday, August 27, 2004 9:54 AM
To: Burns Mercer; Kelly Nuckols (Nuckols, Kelly); Mark Bailey
Subject: The Core Project

Gentlemen:

As you know, Burns and I participated in the strategy meetings in Louisville that began on Tuesday and end today. However, we both had to leave the yesterday. I would to report that the meetings were very productive and helped tremendously to bring me up to date. Many issues were discussed and several variations of the financial models and production models were run based on input provided by everyone including Burns and me. We were especially concerned with producing results that will be meaningful to your directors. To that end, the presentations are expected to be based on the following:

1. A "Status Quo" forecast that produces a base line cash flow that is realistic from a planning standpoint. The "Status Quo" will necessarily include rate increases.
2. A set of "Unwind" cases that are based on the "Status Quo" rate forecast that will produce present values of Unwind versus Status Quo at different LG&E Payment levels beginning with the $180 million offer. These will tell us the economic value of the deal.
3. A set of "Unwind" cases that are based on reduced rate forecasts that will produce minimum Unwind financial criteria (i.e. TIER, DSC, cash balances) at different LG&E Payment levels beginning with the $180 million offer. These will tell us the expected effect on rates of the deal.
4. For each of the above, a 2023 balance sheet to provide an indication of on-going financial stability and rate trends.

The presentation is expected to be simplified to show:

1. The net after financing, after tax PV differences for each item 2 case. That would be the Unwind Cases PV minus the Status Quo PV. If the value is positive then that Unwind deal is financially better than the Status Quo.
2. Comparative rate forecasts both in the aggregate and year by year. I envision a graph for the latter.
3. An itemized list of all maintenance and capital improvements planned and built into the Unwind assumptions as well as those that would be part of the Status Quo. This list would be to show that BREC has contemplated the cost of addressing plant reliability.
4. Finally, a comparative list of tangible and intangible risks/rewards of Unwind versus Status Quo that are not readily quantifiable. I believe that this list may well be the ultimate driver behind the decision if the financials are close as opposed to definitively pro or con. It may even be that this list comes down in favor of the deal even if the financials are negative. Or the reverse may be true. We will have to see.

The Working Group will reconvene in Louisville next Tuesday through Thursday. However, I will be at Kenergy on Wednesday, Therefore, I will join the group on Thursday.
Burns has also asked that I be present at the meeting with the boards on the 16th. I plan to have Mike Leverett visit BREC on the 15th to go over the production cost model and stay through the 16th so that everyone can meet him as well.

That covers it for now. If you have any questions, please call me.

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Barbara Harwood

From: Burns Mercer [bmercer@mcrecc.com]
Sent: Friday, August 31, 2007 8:38 AM
To: Jack D. Gaines; Kelly Nuckols; Sandy Novick
Subject: RE: Unwind

I agree time is getting critical. I'll plan to be there.

From: Jack D. Gaines [mailto:jgaines@jdg-llc.com]
Sent: Friday, August 31, 2007 9:34 AM
To: Burns Mercer; 'Kelly Nuckols'; 'Sandy Novick'
Subject: Unwind

All,

Negotiations with the Smelters to try to improve the economics of the deal will be held next Wednesday and Thursday (if necessary) in Louisville at the Marriott. Time is now critical. I suggest we plan to meet in Louisville Thursday morning at 10:00 a.m. at which time I hope we will have as close to a final set of numbers needed to evaluate the deal and agree on a member position. We will meet at the Marriott or the Hyatt across the street from the Marriott.

Thanks

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Barbara Harwood

From: Jack D. Gaines [jgaines@jdg-llc.com]
Sent: Wednesday, December 12, 2007 6:54 AM
To: Burns Mercer
Subject: FW: 12/11 (Tuesday) Board Call material
Attachments: Unwind Summary Data 12 10 07.xls

-----Original Message-----
From: Mike Core [mailto:mcore@bigrivers.com]
Sent: Monday, December 10, 2007 4:38 PM
To: jgaines@jdg-llc.com; 'Lyon, Carl'; 'Jim Miller'; Bill Denton; James Sills; Larry Elder; Lee Bearden; Paul Edd Butler; Wayne Elliott; Bill Blackburn; David Crockett; David Spainhoward; jhaner@bigrivers.coop; 'Mark Bailey'; 'Mark Hite'; Travis Housley; 'Burns Mercer'; 'Kelly Nuckols'; Sandy Novick
Subject: 12/11 (Tuesday) Board Call material

To All:

Attached is a spread sheet that shows the changes in the financial model to be filed with the commission. We will review this with the board on Tuesday evening at 6:30 p.m. (central time). Please use the BREC call in number.

Mike

Barbara Harwood

From: Jack D. Gaines [jgaines@jdg-llc.com]

Sent: Wednesday, August 29, 2007 7:56 PM

To: Burns Mercer; Sandy Novick; Kelly Nuckols

Subject: Call

I finally caught up with Russell. There isn't much to report. It was a civilized discussion. He began by saying that the "negotiations" had taken a bad turn. I said it wasn't the negotiations but the economics that had turned bad. He agreed.

As expected he wanted to be sure that the members consider the possibility that the Smelters are able to get BREC's output above its other native load at a rate at or near the large industrial rate. My impression is that he does not consider them getting 850 MW at average cost as being any more likely than we consider it. He emphasized the 2023 concern whereas we would get the plants back to find them of in bad shape and of little value. He wanted to be sure that possibility was being considered.

He wanted to know what is driving the members' thinking. Is it rates, risk, or something else? He wanted to know if Meade and JP considered saving the Smelters of high importance relative to other factors. I did not volunteer much other than to affirm that we are aware of and considering all of the issues he mentioned. I did remind him that when approving the deal the forecasts showed rates in the unwind expected to be comparable or a little less than the current deal. Now, the economics have caused the forecasted rates to be higher which is a tough sale. I said the members would be considering the most recent model and will be interested in seeing the effects of the smelters contract reduced to 600 MW. Russell seemed to thing the change to 600 MW could be beneficial to both parties.

He also wanted to know if the CEO's would be making the final decisions or if it was the local boards. I told him that you were doing your jobs and the boards would do theirs (not in those words).

Regarding the new model, it is improved and reducing smelter demand to 600 MW has a lot of appeal.. We need to discuss it ASAP but it would be better to do so after we find out how the Smelters react. We have a call with them tomorrow.

I'll contact you after that call.

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Barbara Harwood

From: Mark Bailey [mbailey@bigrivers.com]
Sent: Monday, December 03, 2007 4:29 PM
To: Jack D. Gaines
Cc: mcore@bigrivers.com; Burns Mercer
Subject: Latest Financial Run

Hi Jack,

While on a member CEO call earlier this afternoon to discuss a variety of matters, the CEO's inquired whether/when they would get to see the latest Financial model output. I indicated the lastest one was sent to the smelters last Wednesday and that our representatives met with them Thursday and Friday to discuss. I told them you had the latest information. You may want to consider sharing that information with them and perhaps scheduling a call or meeting to discuss.

During that call, we told the CEO's you would be getting with them to discuss how they wanted to use the Economic Reserve.

Thanks, Mark

Barbara Harwood

From: Jack D. Gaines [jgaines@jdg-llc.com]
Sent: Friday, October 26, 2007 1:24 PM
To: Burns Mercer
Subject: Presentation
Attachments: Meade Presentation 10_11_07 JG.ppt

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Barbara Harwood

From: Jack D. Gaines [jgaines@jdg-llc.com]
Sent: Saturday, January 19, 2008 9:44 AM
To: Burns Mercer; Kelly Nuckols; Sandy Novick
Cc: Frank King; Steve Thompson
Subject: Public Notice
Attachments: *Exhibit CWB-8 Revenue Comparision.xls; Retail Factors for Public Notice.xls*

All,

The attached "Retail Factors for Public Notice" file provides the annualized retail factors based on the wholesale factors used by Bill Blackburn (Exhibit CWB-8) for the BREC Public Notice. Per Steve's observation and Nib's suggestion we should calculate the individual effects of the Riders by class and show the combined sum. A suggested template is shown on the Retail Factors for Public Notice file.

I do not have the data necessary to make the calculations. To be consistent you may want to use the 12 months ending October 2007 as BREC did but I don't think it would matter if you used another 12 months. It may be easier for JP to use the data from their rate case.

I suggest using the BREC table as shown for the direct served industrials. Each is shown separately.

There is one minor technicality to mention. The BREC calculations show a 2008 Rebate. That is accurate from an accrual standpoint but not from a rate application standpoint. In any case the swing is absorbed by the MRSM so the result is still a zero but in application there won't be a Rebate billing effect until the second year assuming the first year produces a Rebate.

You can complete the calculations or send the data to me.

Thanks
Jack

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Barbara Harwood

From: *Jack D. Gaines [jgaines@jdg-llc.com]*

Sent: Friday, January 18, 2008 1:49 PM

To: Kelly Nuckols; Burns Mercer; Sandy Novick

Subject: Public Notice

FYI,
Steve Thompson pointed out that a strict interpretation of the regulations means that the effect of each new tariff *must be shown individually. Hence, we would show by class for example,*

FAC +$16
US -$ 4
ES + $2
Rebate -$ 1
MRSM -$13

USCF $-0-

Nib has suggested we proceed this way. I'll be working on a format to keep it as simple as possible.

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Barbara Harwood

From: Jack D. Gaines [jgaines@jdg-llc.com]
Sent: Sunday, January 27, 2008 9:39 AM
To: Karen Brown
Cc: Burns Mercer
Subject: Public Notice
Attachments: Meade US_draft_1_08_08.doc; Meade ES_draft_1_08_08.doc; Meade FAC_draft_1_08_08.doc; Meade MRSM_draft_1_08_08.doc; Meade Rebate_draft_1_08_08.doc; Meade URCF_draft_1_15_08.doc; Public_Notice-1 Meade.xls; Kenergy Proposed Rate - No. 45.doc; Kenergy Proposed Rate - No. 43.doc; Kenergy Proposed Rate - No. 44.doc

Karen,

Please see the attached Public Notice-1 spreadsheet. In compiling the data did you use the RUS "classes" from the Form 7? If so, what I really need is the data by tariff and I should have used that terminology to be clearer. Can you send the kWh and the revenue (I need revenue to calculate the percent increase of each rider) broken out as follows?

Rate 1
Rate 2
Rate 3
Rate 3A
Rate 5
Rate 6

Also, didn't Meade change rates in 2007? If so, we would technically need to adjust the revenue for each class to reflect the annualized revenue under current rates. Please call me if you have any questions.

I am attaching the 6 riders and the 3 Small Power Production and QF Tariffs. I have intentionally not specifically identified Rate 13 in the riders but it is captured by the broader description of Section 2 applicability. No 43 and 44 will replace your 8 TRF and 9 TRF, respectively. No. 45 is new to Meade and I suppose would become 10 TRF but that is for you to decide.

Thanks
Jack

Barbara Harwood

From: Jack D. Gaines [jgaines@jdg-llc.com]
Sent: Friday, December 14, 2007 10:03 AM
To: Sandy Novick; Kelly Nuckols
Cc: Burns Mercer; mbailey@bigrivers.com
Subject: Rate Comparison
Attachments: Rate Comparison.ppt

Sandy and Kelly,

The attached may be helpful to your board. It shows how the "big jump" moves forward one year and is a little higher. But, it also shows how the Status compares with its own "big jump" and how the use of reserve is now modeled to "feather" in the big jump. The only thing missing is an update of the status quo rate comparison that would correspond to the current unwind.

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Barbara Harwood

From: Jack D. Gaines [jgaines@jdg-llc.com]
Sent: Monday, January 07, 2008 2:54 PM
To: Sandy Novick; Burns Mercer; Kelly Nuckols
Cc: sthompson@kenergycorp.com; Nib King; fking@dkgnlaw.com
Subject: Rebate

All,

Steve has suggested and I agree that the Rebate should be a straight per kWh rate like the Member Discount Adjustment. I'll redraft it and send it as well as the other riders with some editing to you shortly.

The base rate revenue allocation approach originated with BREC where they are using revenue to allocate the rebate between the three rural systems and the large industrials similar to how they allocate the Member Discount Adjustment. However, as Steve pointed out, the Members are applying the Member Discount Adjustment as a per kWh credit across all non-dedicated delivery point classes. Hence, we should apply the Rebate in the same manner.

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Barbara Harwood

From: Jack D. Gaines [jgaines@jdg-llc.com]
Sent: Monday, January 07, 2008 4:27 PM
To: Burns Mercer; Kelly Nuckols; Sandy Novick
Cc: sthompson@kenergycorp.com; Nib King; fking@dkgnlaw.com
Subject: Revisions
Attachments: Meade Riders.ZIP; JPE Riders.ZIP; Kenergy Riders.ZIP

Per discussions with Steve I've changed the formats of each rider primarily to make clear that the wholesale dollars and over and under dollars are from the second preceding month. Note, however, that the Environmental Surcharge over and under is a six month amortization. I believe this to be a statutory requirement.

The rebate is now a per kWh rate calculation as previously mentioned.

Please look these over carefully as I could have missed something with so many.

Thanks

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jgaines@jdg-llc.com

Barbara Harwood

From: Jack D. Gaines [jgaines@jdg-llc.com]
Sent: Friday, January 11, 2008 12:57 PM
To: Burns Mercer; Kelly Nuckols; Sandy Novick
Cc: sthompson@kenergycorp.com; Nib King; fking@dkgnlaw.com
Subject: Riders

All,

We would like to have a conference call Monday at 12:00 CST, 10:00 a.m. PST. We want to reach agreement regarding the "Composite" rider and how to reflect the riders on the customers' bills. We can also discuss the plan for filing and public notice.

Steve is reviewing a 24 month sample calculation schedule that I just completed. As hoped, it shows that by basing all five riders on the same month of data the retail factor will net out to zero. If this proves accurate it would make the Composite Factor less meaningful.

I'll forward the calculations to you after Steve I hear from Steve.

We'll use the BREC call in number. 877-287-0283 (Access Code 609834)

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jgaines@jdg-llc.com

Barbara Harwood

From: Jack D. Gaines [jgaines@jdg-llc.com]
Sent: Tuesday, January 08, 2008 1:40 PM
To: Burns Mercer; Kelly Nuckols; Sandy Novick
Cc: sthompson@kenergycorp.com; Nib King; fking@dkgnlaw.com
Subject: Riders
Attachments: Meade Riders.ZIP; JPE Riders.ZIP; Kenergy Riders.ZIP

All,

I have tried to incorporate many of the suggested changes. More importantly, I checked to see if we could request a one month over and under for the ES as opposed to the six month method. The short answer is yes and the ES has been modified accordingly.

I've added some language to the Rebate Adjustment that is intended to be explanatory but could be confusing. Please review it and comment. There is one open issue with the Rebate Adjustment. As you know, BREC will pay the rebate in lump sum including the amounts paid for individual industrial accounts. The rural load rebates will be credited over 12 months per the formula. The industrial rebates could be passed through in lump sum immediately which would be the simplest. Right now the tariff says 1 month, or lump sum. Let me know if this is not what you want. One problem would be what to do with a rebate that exceeds the amount of the bill. For example, an industrial customer who is going out of business may have a very small or no bill to which the rebate would apply. How would you want to handle that situation?

One last point is that titles and some of the terminology are intended to match Big Rivers' tariffs. That is why, for example, the Environmental Surcharge has an "ES" in the title but "ES" is not used in the formula.

Again, please review carefully.

Thanks

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jgaines@jdg-llc.com

Barbara Harwood

From: Paula Mitchell [pmitchell@bigrivers.com]
Sent: Friday, September 07, 2007 10:55 AM
To: Bill Denton; Jim Sills; John Myers; Larry Elder; Lee Bearden; Paul Edd Butler; Burns Mercer; Kelly Nuckols; Sandy Novick
Cc: cflyon@orrick.com; rmudge@crai.com; Jack D. Gaines; Jim Miller; Bill Blackburn; David Crockett; David Spainhoward; James Haner; Mark Bailey; Mark Hite; Travis Housley
Subject: Special Board of Directors Meeting

Due to a scheduling conflict, the special board meeting will have to be held on Thursday morning, September 20, probably around 10 a.m., CDT.
Mike has talked with Bill Denton and it was determined that we do need to move the meeting to Thursday.

An official notice will be sent early next week.

Paula Mitchell
Executive Assistant
Big Rivers Electric Corp.
phone: 270/827-2561
e-mail: pmitchell@bigrivers.com

Barbara Harwood

From: Jack D. Gaines [jgaines@jdg-llc.com]

Sent: Friday, August 27, 2004 9:54 AM

To: Burns Mercer; Kelly Nuckols (Nuckols, Kelly); Mark Bailey

Subject: The Core Project

Gentlemen:

As you know, Burns and I participated in the strategy meetings in Louisville that began on Tuesday and end today. However, we both had to leave the yesterday. I would to report that the meetings were very productive and helped tremendously to bring me up to date. Many issues were discussed and several variations of the financial models and production models were run based on input provided by everyone including Burns and me. We were especially concerned with producing results that will be meaningful to your directors. To that end, the presentations are expected to be based on the following:

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4. For each of the above, a 2023 balance sheet to provide an indication of on-going financial stability and rate trends.

The presentation is expected to be simplified to show:

1. The net after financing, after tax PV differences for each item 2 case. That would be the Unwind Cases PV minus the Status Quo PV. If the value is positive then that deal is financially better.
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That covers it for now. If you have any questions, please call me.

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Barbara Harwood

From: Jack D. Gaines [jgaines@jdg-llc.com]
Sent: Friday, December 21, 2007 2:19 PM
To: Burns Mercer; Kelly Nuckols; Sandy Novick
Cc: Nib King; sthompson@kenergycorp.com
Subject: Unwind
Attachments: US_draft_12_10_07.doc; ES_draft_12_10_07.doc; FAC_draft_12_10_07.doc; MRSM_draft_12_10_07.doc; Rebate_draft_12_10_07.doc; Unwind Riders_draft_12_11_07.doc

I just received word that the Smelters are on board with the latest model update. Sandy, Steve and Nib may not be aware that BREC agreed to go back to the depreciation methodology reflected in the September model for the years 2011 – 2016. They also are using the current rates for 2008 -2010 which result in slightly less depreciation expense in those years. The net effect is lower rates for all but less recovery the plant value from the Smelters within the finite period of the deal. In fact, the change in depreciation gets back the previously lost year of the Economic Reserve and rates through 2016 that are essentially the same as they were in the September model. Overall, I consider this a positive change to the model but caution that the ultimate determination of the depreciation rates will be made in conjunction with the 2010 rate case for rates effective in 2011.

Attached are the tariff riders that I have drafted. Note that there are six instead of five. The additional rider, Unwind Rider (US), is intended to supersede the other five so long as the BERC net bill is zero for the five wholesale riders. In other words, while the Economic Reserve is fully offsetting the FAC, ES, and US (net of the rebate) then UR would kick in and supersede the retail FAC, ES, US, and MRSM by setting the whole thing to zero. We have a few accounting questions to clear up regarding the rebate but otherwise feel good about this approach. The riders are written for Kenergy and I will be making changes as needed for JP and Meade. We'll stay consistent with the Section 1 for non-direct serves and Section 2 for Direct Serves even though Meade does not currently have any. I have the JP rates (proposed and existing) and the Meade rates.

BREC is attempting to file by the 28th. We can probably delay a little. In any event, I'll send a draft of my testimony next Wednesday. Also, has everyone filed their respective notices of intent?

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Barbara Harwood

From: Jack D. Gaines [jgaines@jdg-llc.com]
Sent: Thursday, August 30, 2007 2:11 PM
To: Burns Mercer; Sandy Novick; Kelly Nuckols
Subject: Unwind

All,

The call with the Smelters today was uneventful. There is a meeting in Louisville with them next Tuesday and Wednesday. We should try to get together if possible. I'll call each of you tomorrow morning to discuss alternatives. I'm on my way out at the moment.

Jack D. Gaines
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Barbara Harwood

From: Jack D. Gaines [jgaines@jdg-llc.com]
Sent: Friday, August 31, 2007 8:34 AM
To: Burns Mercer; Kelly Nuckols; Sandy Novick
Subject: Unwind

All,

Negotiations with the Smelters to try to improve the economics of the deal will be held next Wednesday and Thursday (if necessary) in Louisville at the Marriott. Time is now critical. I suggest we plan to meet in Louisville Thursday morning at 10:00 a.m. at which time I hope we will have as close to a final set of numbers needed to evaluate the deal and agree on a member position. We will meet at the Marriott or the Hyatt across the street from the Marriott.

Thanks

Jack D. Gaines
President
JDG Consulting, LLC
770-392-9971
770-392-9971 (fax)
770-335-3299 (cell)
jgaines@jdg-llc.com

Item 120) Please reference the testimony of Burns E. Mercer, page 7. Provide the financial analysis which demonstrates "in return for a greater potential risk of fuel and environmental cost increases, the members believe they have helped Big Rivers secure a financially stable future that ultimately will be of a greater value to the Members".

Response) No quantitative financial analyses other than those run by Big Rivers have been made by the Members. The analyses made by Big Rivers were received by the Members, and the Members had input into the assumptions and methodologies used by the analyses either directly or through their consultant, Jack Gaines. The financial analyses prepared by Big Rivers set forth the risks and expected costs of the Unwind, and those were considered in comparison with the risks and expected costs of the existing deal. The conclusion reached by the Members was that the Unwind, in spite of the fuel and environmental costs risks, has a greater potential value as compared to the existing arrangement.

Witness) Burns E. Mercer

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
February 14, 2008

Item 121) Please reference the testimony of Burns E. Mercer, page 7, regarding "Big Rivers is entitled to strictly limited amounts of energy..."

a. State this "strictly limited amount of energy" to Big Rivers, and quantify its downstream impact of "strictly limited amounts of energy? For each of the retail cooperatives;

b. Provide projected energy needs of the retail cooperatives for the next five years;

c. Show the difference between the "strictly limited amount of energy" and the projected energy needs of the retail cooperatives.

Response)

Year	LEM Demand Available MW	LEM Energy Available MWH	Cooperative Energy MWH	LEM Energy Less Needs
2008	597	5,244,048	3,375,398	1,868,650
2009	597	5,229,720	3,430,733	1,798,987
2010	597	5,229,720	3,477,341	1,752,379
2011	717	6,280,920	3,530,346	2,750,574
2012	800	7,027,200	3,579,072	3,448,128

As can be seen above, strictly from an energy analysis, there is more than enough energy to supply all of the member cooperatives needs. Please note that the term "strictly limited amounts of energy" in the original response was limited to the LEM contract only. Big Rivers has another contract from which energy is available, and energy is also available from the market.

Witness) Burns E. Mercer

Item 122) Please reference the testimony of Burns E. Mercer, page 9, regarding "fuel and environmental costs will fluctuate up or down depending on actual costs".

a. Provide documents which show the variation in fuel costs, by type of fuel, that has been experienced by E.ON since the inception of the Lease Transaction; and,

b. Provide documents which show the extent to which environmental costs are expected to fluctuate downward.

Response) a. See E.ON response.

b. The statement was made only to demonstrate that the environmental costs will fluctuate based on actual costs. Should environmental costs go down (e.g., the price of allowances is higher than forecasted when sold) those costs will be reflected in the environmental surcharge.

Witness) E.ON U.S.
Burns E. Mercer

Item 123) Please reference the testimony of Burns E. Mercer, page 10, regarding "[Big Rivers' Members] still will be enjoying lower rates than other suppliers make available to their customers". Provide documents which demonstrate the truth of this contention.

Response) See the attached table. For additional support, see the January 8, 2008 issue of Kentucky Energy Watch published by the Governor's Office of Energy Policy. It can be found at www.energy.ky.gov.

Witness) Michael H. Core

COMPARISON OF RESIDENTIAL ELECTRIC BILLS AS OF 01/01/07

COMPANY	Util I.D.	PURSUANT TO CASE NO.	MIMIMUM BILL	kWh INCL.	Base Bill	FAC Charge	Environ Surcharge	Mo. Bill for 1,000 kWh
INVESTOR OWNED								
AMERICAN ELEC PWR	300	2005-00341	5.86	0	$65.88	$3.54	$0.26	$69.68
KENTUCKY UTILITIES	400	2004-00465	5.00	0	$52.20	$7.81	$2.18	$62.19
L G & E	500	2004-00466	5.00	0	$64.55	$1.53	$0.92	$67.00
DUKE KENTUCKY	800	1995-00312	4.50	0	$77.74	*	*	$77.74
RURAL ELECTRIC								
Small - Less than 20,000 Customers								
BIG SANDY	1000	2005-00125	7.00	0	$68.63	$2.24	$4.12	$74.99
GRAYSON	1800	2004-00474	7.98	0	$78.55	$2.15	$4.29	$84.99
SHELBY ENERGY	3000	2004-00481	7.18	0	$74.06	$8.85	$4.50	$87.41
Medium - 20,000-30,000 Customers								
CLARK ENERGY	1200	2004-00470	5.35	0	$73.18	$1.49	$3.97	$78.64
CUMBERLAND ELECTRIC	1300	2005-00187	5.00	0	$69.47	$1.97	$4.25	$75.69
FARMERS	1500	2004-00472	6.96	50	$65.10	$5.47	$4.02	$74.59
FLEMING-MASON ENERGY	1600	2004-00473	6.26	0	$67.22	$4.90	$4.63	$76.75
INTER-COUNTY ENERGY	2200	2004-00475	5.55	0	$71.88	$2.33	$4.17	$78.38
JACKSON PURCHASE	2400	1997-00224	7.00	0	$64.29	*	*	$64.29
LICKING VALLEY	2500	2004-00477	7.00	0	$72.44	$7.40	$3.70	$83.54
MEADE COUNTY	2600	2002-00391	8.00	0	$64.19	*	*	$64.19
NOLIN	2700	2004-00478	5.00	0	$67.71	$8.20	$4.26	$80.17
TAYLOR COUNTY	3200	2004-00483	6.92	0	$68.31	$2.59	$4.20	$75.10
Large - 30,000 Customers and above								
BLUE GRASS ENERGY	2000200	2004-00469	5.30	0	$65.58	$4.35	$4.03	$73.96
BGE-Fox Creek District		2004-00469	5.39	30	$68.12	$4.35	$4.18	$76.65
HARRISON Elec customers	2000	2004-00469	8.86	0	$75.14	$4.35	$4.61	$84.10
JACKSON ENERGY	2300	2004-00476	8.25	0	$77.81	$8.11	$4.19	$90.11
KENERGY	2000100	2004-00446	7.91	0	$64.68	*	*	$64.68
OWEN ELECTRIC	2800	2004-00479	5.50	0	$72.75	$3.14	$4.74	$80.63
SALT RIVER ELECTRIC	2900	2004-00480	7.70	0	$66.85	$9.30	$4.10	$80.26
SOUTH KENTUCKY	3100	2005-00450	8.00	0	$72.45	$1.56	$4.40	$78.41

This schedule includes only the major components of a monthly residential electric bill as of January 1, 2007. Additional credits and/or charges may apply.

* Does not participate in fuel adjustment clause or environmental surcharge mechanism.

Item 124) Provide the current credit ratings for the three Distribution Cooperatives that are Big Rivers' Members.

Response) None of Big Rivers' three Member distribution cooperatives have sought or received an investment credit rating. These cooperatives are borrowers from the RUS, along with CoBank and the National Rural Utilities Cooperative Finance Corporation (CFC). The cooperatives do not require credit rating for distribution cooperatives as part of their loan approval process.

Witness) Burns E. Mercer

Item 125) Provide the current credit ratings for E.ON U.S. Parties.

Response) See E.ON response.

Witness) E.ON U.S.

Item 126) Provide the most current SFAS No. 144 impairment review pertaining to the Big Rivers generation facilities.

Response) See Big Rivers' Application, Tab 41, 2006 Annual Report, page 27. See E.ON's response.

Witness) C. William Blackburn
E.ON U.S.

Item 127) Provide reference Exhibit 37/Independent Auditors' Annual Opinion states at page 10, paragraph VII that "WKEC will make required capital improvements to the facilities to comply with a new law or change to existing law ("Incremental Capital Costs")..." Provide the current view and estimation of such "Incremental Capital Costs" for:

a. The next five years; and

b. The next ten years, by type/function of capital cost.

Response) a. Over the next five years (2008-2012) the following "Incremental Capital Costs" are anticipated:

1. Catalyst replacement for the selective reduction (SCR) systems at the Wilson and HMP&L Station Two stations (approx. $5.9 million);

2. Stack monitors for mercury emissions for Wilson, Coleman, Green, Reid, and HMP&L Station Two stations (approx. $3.2 million);

3. SO_3-abatement equipment at Wilson Station (approx. $0.5 million);

4. Boilers' tube corrosion protection installed on Coleman Station units resulting from NO_x reduction equipment installed in response to SIP Call (approx. $6.45 million).

b. Over the succeeding five years (2013-2017) Big Rivers presently has no "Incremental Capital Costs" planned. However, Big Rivers will be monitoring changes in environmental regulations and will modify its environmental compliance plan accordingly.

Witness) David A. Spainhoward

Item 128) Provide a document which extends the "Statement of Cash Flows" contained on page 5 of Exhibit 37 to include 2007 and 2008 on a pro forma basis as necessary, assuming current operations continue per current structure of agreements.

Response) See response to AG Item 3.

Witness) Robert S. Mudge

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
February 14, 2008

Item 129) Provide copies of the three Distribution Cooperatives financial annual reports for 2005 to present.

Response) See attached. Jackson Purchase's 2007 Annual Report is not yet final.

Witness) Burns E. Mercer

Kentucky 20

Jackson Purchase Energy

Paducah, Kentucky

Report on Audit of Financial Statements

for the year ended December 31, 2006

CONTENTS

ALAN M. ZUMSTEIN
CERTIFIED PUBLIC ACCOUNTANT

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MEMBER
- AMERICAN INSTITUTE OF CPA S
- INDIANA SOCIETY OF CPA'S
- KENTUCKY SOCIETY OF CPA'S
- AICPA DIVISION FOR FIRMS
- TENNESSEE STATE BOARD OF ACCOUNTANCY

Independent Auditor's Report

To the Board of Directors
Jackson Purchase Energy Corporation

I have audited the balance sheet of Jackson Purchase Energy Corporation, as of December 31, 2006, and the related statements income and patronage capital and cash flows for the year then ended These financial statements are the responsibility of Jackson Purchase's management My responsibility is to express an opinion on these financial statements based on my audit The financial statements of Jackson Purchase as of December 31, 2005, were audited by other auditors whose report dated February 2, 2006, expressed an unqualified opinion on those statements

I conducted my audit in accordance with auditing standards generally accepted in the United States of America, the standards applicable to financial audits contained in Government Auditing Standards issued by the Comptroller General of the United States and 7 CFR Part 1773, Policy on Audits of Rural Utilities Service (RUS) Borrowers Those standards require that I plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement An audit includes examining on a test basis, evidence supporting the amounts and disclosures in the financial statements An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation I believe that my audit provides a reasonable basis for my opinion

In my opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Jackson Purchase as of December 31, 2006, and the results of operations and cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America

In accordance with Government Auditing Standards, I have also issued a report dated February 1, 2007, on my consideration of Jackson Purchase's internal control over financial reporting and my tests of its compliance with certain provisions of laws, regulations, contracts and grant agreements and other matters The purpose of that report is to describe the scope of my testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance That report is an integral part of an audit performed in accordance with Government Auditing Standards and should be considered in assessing the results of my audit

Alan Zumstein

Alan M Zumstein
February 1, 2007

ALAN M. ZUMSTEIN
CERTIFIED PUBLIC ACCOUNTANT

1032 CHETFORD DRIVE
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(859) 264-7147

MEMBER
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- AICPA DIVISION FOR FIRMS
- TENNESSEE STATE BOARD OF ACCOUNTANCY

To the Board of Directors
Jackson Purchase Energy Corporation

I have audited the financial statements of Jackson Purchase Energy Corporation as of and for the year ended December 31, 2006, and have issued my report thereon dated February 1, 2007 I conducted my audit in accordance with generally accepted auditing standards and the standards applicable to financial audits contained in Government Auditing Standards, issued by the Comptroller General of the United States

Compliance

As part of obtaining reasonable assurance about whether Jackson Purchase's financial statements are free of material misstatement, I performed tests of its compliance with certain provisions of laws, regulations, contracts and grants, noncompliance with which could have a direct and material effect on the determination of financial statement amounts However, providing an opinion on compliance with those provisions was not an objective of my audit and, accordingly, I do not express such an opinion The results of my tests disclosed no instances of noncompliance or other matters that are required to be reported under Government Auditing Standards

Internal Control Over Financial Reporting

In planning and performing my audit, I considered Jackson Purchase's internal control over financial reporting in order to determine my auditing procedures for the purpose of expressing my opinion on the financial statements and not to provide an opinion on the internal control over financial reporting My consideration of the internal control over financial reporting would not necessarily disclose all matters in the internal control over financial reporting that might be material weaknesses A material weakness is a condition in which the design or operation of one or more of the internal control components does not reduce to a relatively low level the risk that misstatements caused by error or fraud in amounts that would be material in relation to the financial statements being audited may occur and not be detected within a timely period by employees in the normal course of performing their assigned functions I noted no matters involving the internal control over financial reporting and its operation that I consider to be material weaknesses

This report is intended solely for the information and use of the audit committee, management, the Rural Utilities Service and supplemental lenders, and is not intended to be and should not be used by anyone other than those specified parties

Alan M Zumstein

Alan M Zumstein
February 1, 2007

Jackson Purchase Energy

Balance Sheets, December 31, 2006 and 2005

Assets	2006	2005
Electric Plant, at original cost		
In service	$105,262,626	$98,969,450
Under construction	3,204,054	2,858,480
	108,466,680	101,827,930
Less accumulated depreciation	31,714,276	29,579,797
	76,752,404	72,248,133
Investments in Associated Organizations	2,037,879	2,001,351
Current Assets		
Cash and cash equivalents	3,665,763	988,618
Accounts receivable, less allowance for 2006 of $157,214 and 2005 of $147,4485	2,301,010	2,122,726
Accrued unbilled revenue	1,668,277	2,064,940
Material and supplies, at average cost	1,183,096	2,191,946
Other current assets	466,211	497,023
	9,284,357	7,865,253
Deferred charges	1,291,215	1,489,863
Total	$89,365,855	$83,604,600

Members' Equities and Liabilities	2006	2005
Members' Equities		
Memberships	$208,695	$225,625
Patronage capital	34,235,714	34,343,254
	34,444,409	34,568,879
Long Term Debt	46,718 372	41 726,917
Accumulated Postretirement Benefits	861,127	781,235
Current Liabilities		
Current portion of long term debt	2,000,000	1,815,545
Accounts payable	3,140,559	2,854,620
Consumer deposits	1,251,047	987,371
Accrued expenses	756,807	713,464
	7,148,413	6,371,000
Consumer Advances for Construction	193,534	156,569
Total	$89,365,855	$83,604,600

The accompanying notes are an integral part of the financial statements

Statements of Revenue and Patronage Capital

for the years ended December 31, 2006 and 2005

	2006	2005
Operating Revenues	$37,396,373	$37,928,066
Operating Expenses		
Cost of power	23,655,944	23,854,261
Distribution - operations	1,761,777	1,358,619
Distribution - maintenance	3,413,939	3,003,616
Consumer accounts	1,088,682	1,114,604
Consumer service and information	277,667	284,078
Administrative and general	1,992,235	1,786,632
Depreciation, excluding $325,332 in 2006 and $395,452 in 2005 charged to clearing accounts	3,235,100	3,131,797
Taxes	41,657	40,996
Other deductions	15,995	20,236
	35,482,996	34,594,839
Operating Margins before Interest Charges	1,913,377	3,333,227
Interest Charges		
Long-term debt	2,660,517	2,211,585
Other interest	66,911	75,330
	2,727,428	2,286,915
Operating Margins after Interest Charges	(814,051)	1,046,312
Patronage Capital from Associated Organizations	113,228	107,996
Nonoperating Margins, principally interest	593,283	433,143
Net Margins	(107,540)	1,587,451
Patronage Capital - beginning of year	34,343,254	32,755,803
Patronage Capital - end of year	$34,235,714	$34,343,254

The accompanying notes are an integral part of the financial statements

Statements of Cash Flows

for the years ended December 31, 2006 and 2005

	2006	2005
Cash Flows from Operating Activities		
Net margins	($107,540)	$1,587,451
Adjustments to reconcile to net cash provided by operating activities		
Depreciation		
Charged to expense	3,235,100	3,131,797
Charged to clearing	325,332	395,452
Capital credits allocated	(113,228)	(107,996)
Accumulated postretirement benefits	79,892	42,126
Net change in current assets and liabilities		
Receivables	218,379	(141,142)
Material and supplies	1,008,850	(1,144,496)
Other current assets	30,812	(70,868)
Deferred charges	198,648	(439,262)
Accounts payable	285,939	103,411
Consumer deposits	263,676	56,229
Accrued expenses	43,343	236,261
Consumer advances for construction	36,965	29,656
	5,506,168	3,678,619
Cash Flows from Investing Activities		
Construction of plant	(8,123,614)	(7,904,152)
Salvage recovered from plant	58,911	14,384
Receipts from investments, net	76,700	79,489
	(7,988,003)	(7,810,279)
Net Cash Flows from Financing Activities		
Net decrease in memberships	(16,930)	(20,545)
Additional long-term borrowings	5,922,000	5,500,000
Advance payments	1,170,594	89,843
Payments on long-term debt	(1,916,684)	(1,561,912)
	5,158,980	4,007 386
Net increase in cash balances	2,677,145	(124,274)
Cash and cash equivalents - beginning	988,618	1,112,892
Cash and cash equivalents - ending	$3,665,763	$988 618
Supplemental disclosures of cash flow information		
Interest on long-term debt	$2,484,607	$2,139,041

The accompanying notes are an integral part of the financial statements

1 Summary of Significant Accounting Policies

Jackson Purchase maintains its records in accordance with policies prescribed or permitted by the Kentucky Public Service Commission (PSC) and the United States Department of Agriculture, Rural Utilities Service (RUS), which conform in all material respects with generally accepted accounting principles The more significant of these policies are as follows

Electric Plant

Electric plant is stated at original cost, less contributions, which is the cost when first dedicated to public service Such cost includes applicable supervisory and overhead costs There was no interest required to be capitalized on construction for the year

The cost of maintenance and repairs, including renewals of minor items of property, is charged to operating expense The cost of replacement of depreciable property units, as distinguished from minor items, is charged to electric plant The cost of units of property replaced or retired, including cost of removal net of any salvage value, is charged to accumulated depreciation

Electric plant consisted of

	2006	2005
Distribution plant	$98,386,830	$92,371,766
General plant	6,875,796	6,597,684
Total	$105,262,626	$98,969,450

Depreciation

Provision has been made for depreciation on the basis of the estimated lives of assets, using the straight-line method Depreciation rates range from 1 44% to 10 0%, with a composite rate of 3 07% for distribution plant General plant depreciation rates are as follows

Structures and improvements	2 5%
Transportation equipment	10% - 20%
Other general plant	5% - 20%

Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period Actual results could differ from those estimates used in the preparation of the financial statements

Continued

1 Summary of Significant Accounting Policies, continued

Revenue

Jackson Purchase records revenue as billed to its consumers based on monthly meter- reading cycles All consumers are required to pay a refundable deposit, however, it may be waived under certain circumstances Jackson Purchase's sales are concentrated in a six county area of western Kentucky There were no consumers whose individual account balance exceeded 10% of outstanding accounts receivable at December 31, 2006 or 2005 Consumers must pay their bill within 20 days of billing, then are subject to disconnect after another 10 days Accounts are written off when they are deemed to be uncollectible The allowance for uncollectible accounts is based on the aging of receivables

Cost of Power

Jackson Purchase is one of three (3) members of Big Rivers Electric Corporation, Inc (Big Rivers) Under a wholesale power agreement, Jackson Purchase is committed to purchase its electric power and energy requirements from Big Rivers until 2023 The rates charged by Big Rivers are subject to approval of the PSC The cost of purchased power is recorded monthly during the period in which the energy is consumed, based upon billings from Big Rivers

Fair Value of Financial Instruments

Financial instruments include cash, temporary cash investments and long-term debt Investments in associated organizations are not considered a financial instrument because they represent nontransferable interest in associated organizations

The carrying value of cash and temporary cash investments approximates fair value because of the short maturity of those instruments The fair value of long term debt approximates the fair value because of the borrowing policies of Jackson Purchase

Jackson Purchase may, and also does, invest idle funds in NRUCFC commercial paper Investments in commercial paper are classified as held-to-maturity in accordance with Statement of Financial Accounting Standards (SFAS) No 115 Held-to-maturity securities are presented at amortized cost the fair value of held-to-maturity securities approximates cost at 2006 and 2005

Income Tax Status

Jackson Purchase is exempt from federal and state income taxes under provisions of Section 501(c)(12) Accordingly, the financial statements include no provision for income taxes

Statement of Cash Flows

For purposes of the statement of cash flows, Jackson Purchase considers temporary investments having a maturity of three months or less to be cash equivalents

Continued

2 Investments in Associated Organizations

Jackson Purchase records patronage capital assigned by associated organizations in the year in which such assignments are received

The Capital Term Certificates (CTCs) of National Rural Utilities Cooperative Finance Corporation (NRUCFC) are recorded at cost The CTCs were purchased from NRUCFC as a condition of obtaining long-term financing The CTCs bear interest at 3% and 5% and are scheduled to mature at varying times from 2020 to 2080

Investments in associated organizations consisted of

	2006	2005
NRUCFC CTC's	$946,546	$947,373
NRUCFC Patronage capital assigned	40,537	41,636
CoBank, ACB	623,844	613,313
Others	426,952	399,029
Total	$2,037,879	$2,001,351

3 Patronage Capital

Under provisions of the long-term debt agreement, return to patrons of capital contributed by them is limited to amounts which would not allow the total equities and margins to be less than 30% of total assets, except that distributions may be made to estates of deceased patrons The debt agreement provides, however, that should such distributions to estates not exceed 25% of net margins for the next preceding year, Jackson Purchase may distribute the difference between 25% and the payments made to such estates The equity at December 31, 2006 was 39% of total assets

Patronage capital consisted of

	2006	2005
Assigned to date	$34,343,254	$32,755,802
Assignable	(107,540)	1,587,452
Total	$34,235,714	$34,343,254

4 Long Term Debt

All assets, except vehicles, are pledged as collateral on the long-term debt to RUS, Federal Financing Bank (FFB), CoBank, ACB and NRUCFC under a joint mortgage agreement The long term debt is due in quarterly and monthly installments of varying amounts through 2039 Jackson Purchase has loan funds available from RUS in the amount of $2,833,000 RUS assess 12 5 basis points to administer the FFB loans

Continued

4 Long Term Debt, continued

Long Term debt consisted of

	2006	2005
First mortgage notes due RUS		
2% to 5 53%	$28,791,529	$29,546,188
Advance payment	(4,929,856)	(6,100,450)
	23,861,673	23,445,738
First mortgage notes due FFB		
4 101% to 5 158%	17,720,424	12,304,721
First mortgage notes due CoBank, ACB		
4 78% to 6 62%	6,299,598	6,911,143
First mortgage notes due NRUCFC		
5 50%	836,677	880,860
	48,718,372	43,542,462
Less current portion	2,000,000	1,815,545
Long term portion	$46,718,372	$41,726,917

As of December 31, 2006, the annual current portion of long term debt outstanding for the next five years are as follows 2007 - $2,000,000, 2008 - $2,100,000, 2009 - $2,000,000, 2010 - $2,100,000, 2011 - $2,100,000

5 Short Term Borrowings

At December 31, 2006, Jackson Purchase had a short-term line of credit of $5,000,000 available from NRUCFC There were no borrowings against this line of credit during the audit period

6 Pension Plans

All eligible employees of Jackson Purchase participate in the NRECA Retirement and Security Program, a defined benefit pension plan qualified under section 401 and tax-exempt under section 501(a) of the Internal Revenue Code Eligible employees include employees hired prior to January 1, 2006 Non-eligible employees are those hired after January 1, 2006 Jackson Purchase makes annual contributions to the Program equal to the amounts accrued for pension expense Contributions to this plan were $543,867 for 2006 and $502,758 for 2005 In this multiemployer plan, which is available to all member cooperatives of NRECA, the accumulated benefits and plan assets are not determined or allocated separately by individual employer

Continued

6 Pension Plans, continued

All eligible union employees participate in the International Brotherhood of Electrical Workers (IBEW) Savings Plan Eligible employees include employees hired prior to January 1, 2006 Non-eligible employees are those hired after January 1, 2006 Jackson Purchase contributes 10% of base wages to the plan Jackson Purchase contributions to the plan totaled $157,275 in 2006 and $150,893 in 2005

7 Retirement Savings Plan

Eligible non-union employees are eligible to participate in the NRECA 401(k) Plan Jackson Energy contributes 4% of annual wages to the plan, which totaled $84,365 for 2006 and $72,720 for 2005

Non-eligible employees, as defined above, participate in the savings plan, with Jackson Purchase contributing 14% for non-union employees and 10% for union employees

8 Postretirement Benefits

Jackson Purchase sponsors a defined benefit plan that provides medical insurance coverage to retirees The premiums are paid for a maximum of ten years or until age 65, whichever comes first Postretirement benefits are not funded The study had been updated to January 1, 2006

For measurement purposes, a 8 5% annual rate of increase, decreasing by 0 5% per year until 5 5% per year, in the per capita cost of covered health care benefits was assumed The discount rate used in determining the accumulated postretirement benefit obligation was 6 75% and discount rate on expense was 7 0%

The following is a reconciliation of the postretirement benefit obligation

	2006	2005
Postretirement Benefit Obligation		
Balance, beginning of period	$781,235	$739,109
Recognition of components of net periodic postretirement benefit cost		
Service cost	45,000	52,000
Interest cost	39,000	61,100
Amortization of gains or losses	40,500	40,500
	124,500	153,600
Benefits paid to participants	(24,290)	(111,474)
Net change	100,210	42,126
Balance, end of period	$881,445	$781,235

Continued

8 **Postretirement Benefits, continued**

The funded status of the plan was as follows

	2006	2005
Accumulated postretirement benefit obligation	$635,000	$1,005,135
Plan assets at fair value	-	-
Funded status	635,000	1,005,135
Unrecognized net gain (losses) from changes in assumptions	(209,491)	(223,900)
Accrued postretirement benefit cost	$425,509	$781,235

9 **Off Balance Sheet Risk**

Jackson Purchase has off balance sheet risk in that they maintain cash deposits in financial institutions in excess of the amounts insured by the Federal Deposit Insurance Corporation (FDIC) At December 31, 2006, the financial institutions reported deposits in excess of the $100,000 FDIC insured limit on several of the accounts Deposits and repurchase agreements in excess of the FDIC limits are 100% secured with collateral from financial institutions

9 **Risk Management**

Jackson Energy is exposed to various forms of losses of assets associated with, but not limited to, fire, personal liability, theft, vehicular accidents, errors and omissions, fiduciary responsibility, workers compensation, etc Each of these areas is covered through the purchase of commercial insurance

Jackson Purchase has adopted and implemented an Emergency Response Plan, that has been filed with RUS and the Commission This plan has been tested, and in the event of a disaster, will keep the organization functioning

10 **Related Party Transactions**

Several of the Directors of Jackson Purchase, its President & CEO and another employee are on the Boards of Directors of various associated organizations

11 **Commitments**

Jackson Purchase has various other agreements outstanding with local contractors Under these agreements, the contractors will perform certain construction and maintenance work at specified hourly rates or unit cost, or on an as needed basis The duration of these contracts are one to three years

Continued

12 Advertising

Jackson Purchase expenses advertising costs as incurred

13 Environmental Contingency

Jackson Purchase from time to time is required to work with and handle PCBs, herbicides, automotive fluids, lubricants and other hazardous materials in the normal course of business As a result, there is the possibility that environmental conditions may arise which would require Jackson Purchase to incur cleanup costs The likelihood of such an event, or the amount of such costs, if any, cannot be determined at this time However, management does not believe such costs, if any, would materially affect Jackson Purchase's financial position or its future cash flows

14 New Accounting Standard

On September 29, 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans - an amendment of FASB Statements No 87, 88, 106 and 132(R) SFAS No 158 requires an employer that sponsors a defined benefit postretirement plan to report the current economic status (the overfunded or underfunded status) of the plan in its balance sheet, to measure the plan assets and plan obligations as of the balance sheet date, and to include enhanced disclosures about the plan The Cooperative will be required to adopt the recognition and disclosure provisions of SFAS No 158 for the fiscal year ending December 31, 2007, and the measurement date provision for the fiscal year ending December 31, 2008 The Cooperative does not anticipate adopting the provisions of SFAS No 158 prior to those periods

KENTUCKY 65 HENDERSON
KENERGY CORP.
HENDERSON, KENTUCKY

FINANCIAL STATEMENTS

Years Ended December 31, 2006 and 2005

Riney, Hancock & Co., PSC
Certified Public Accountants & Financial Advisors

KENTUCKY 65 HENDERSON
KENERGY CORP.
HENDERSON, KENTUCKY

FINANCIAL STATEMENTS

Years Ended December 31, 2006 and 2005

(With Independent Auditors' Report Thereon)

CONTENTS

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PKF North American Network

INDEPENDENT AUDITORS' REPORT

Board of Directors
Kenergy Corp.
Henderson, Kentucky

We have audited the accompanying balance sheets of Kenergy Corp. (Kenergy) as of December 31, 2006 and 2005, and the related statements of revenue and expenses, changes in members' equities, and cash flows for the years then ended. These financial statements are the responsibility of Kenergy's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards,* issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Kenergy as of December 31, 2006 and 2005, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

In accordance with *Government Auditing Standards,* we have also issued our report dated March 28, 2007, on our consideration of Kenergy's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be read in conjunction with this report in considering the results of our audit.

Riney, Hancock & Co., PSC

Owensboro, Kentucky
March 28, 2007

KENERGY CORP.

BALANCE SHEETS

December 31, 2006 and 2005

	2006	2005
ASSETS		
Utility plant, net	$ 169,533,638	$ 163,774,689
Investments	8,681,878	8,033,899
Current assets:		
Cash and cash equivalents	1,515,630	1,378,839
Accounts receivable, less allowance for doubtful accounts: 2006, $122,541; 2005, $158,436		
Billed	23,784,626	21,415,638
Unbilled	7,111,344	7,783,976
Materials and supplies	1,397,405	1,747,138
Other current assets	219,276	233,162
Total current assets	34,028,281	32,558,753
Other assets	17,050	51,797
Total assets	$ 212,260,847	$ 204,419,138
MEMBERS' EQUITIES AND LIABILITIES		
Members' equities:		
Memberships	$ 240,185	$ 275,480
Patronage capital	48,753,412	51,234,702
Other	3,554,886	3,407,515
	52,548,483	54,917,697
Long-term debt	117,705,836	113,756,489
Current liabilities:		
Note payable	5,000,000	1,500,000
Accounts payable	25,658,973	23,197,693
Consumer deposits	2,496,899	2,408,744
Current maturities of long-term debt	4,222,208	3,752,161
Other current and accrued liabilities	1,748,874	1,662,272
Total current liabilities	39,126,954	32,520,870
Other noncurrent liabilities	2,078,459	2,277,336
Deferred credits	801,115	946,746
Total members' equities and liabilities	$ 212,260,847	$ 204,419,138

See Notes to Financial Statements

KENERGY CORP.

STATEMENTS OF REVENUE AND EXPENSES

Years Ended December 31, 2006 and 2005

	2006	2005
Operating revenue	$ 323,837,577	$ 289,264,858
Operating expenses:		
Cost of power	295,460,224	259,986,490
Distribution operation	4,275,040	4,249,548
Distribution maintenance	8,583,298	8,113,669
Customer accounts	2,686,135	2,776,613
Consumer service and information	209,517	185,728
Sales	102,674	113,896
Administrative and general	3,245,695	3,036,362
Depreciation	6,227,515	5,752,782
Taxes	271,795	269,762
Other deductions	70,851	63,561
	321,132,744	284,548,411
Operating margin before interest expense	2,704,833	4,716,447
Interest on long-term debt	5,265,708	4,198,637
Interest charged to construction	(82,651)	(60,091)
Other interest expense	176,110	143,991
Operating margin (loss)	(2,654,334)	433,910
Nonoperating margin:		
Investment income	1,008,890	893,305
Other income (expense)	12	(31,286)
Net margin (loss) before operating margin assigned	(1,645,432)	1,295,929
Operating margin assigned by associated organizations	50,996	194,579
Net margin (loss)	$ (1,594,436)	$ 1,490,508

See Notes to Financial Statements

KENERGY CORP.

STATEMENTS OF CHANGES IN MEMBERS' EQUITIES

Years Ended December 31, 2006 and 2005

	Memberships	Patronage Capital	Other	Total
Balance, December 31, 2004	$ 275,470	$ 52,310,166	$ 2,858,224	$ 55,443,860
Net refund of membership fees	10	-	-	10
Net margin	-	1,490,508	-	1,490,508
Accumulated other comprehensive income: Decrease in additional minimum pension liability	-	-	294,929	294,929
Patronage capital retired	-	(2,565,972)	-	(2,565,972)
Retired capital credits - gain	-	-	218,290	218,290
Other changes	-	-	36,072	36,072
Balance, December 31, 2005	275,480	51,234,702	3,407,515	54,917,697
Net refund of membership fees	(35,295)	-	-	(35,295)
Net margin (loss)	-	(1,594,436)	-	(1,594,436)
Patronage capital retired	-	(886,854)	-	(886,854)
Retired capital credits - gain	-	-	120,321	120,321
Other changes	-	-	27,050	27,050
Balance, December 31, 2006	$ 240,185	$ 48,753,412	$ 3,554,886	$ 52,548,483

See Notes to Financial Statements

KENERGY CORP.

STATEMENTS OF CASH FLOWS

Years Ended December 31, 2006 and 2005

	2006	2005
Cash flows from operating activities:		
Net margin (loss)	$ (1,594,436)	$ 1,490,508
Adjustments to reconcile net margin (loss) to net cash provided by operating activities:		
Depreciation charged to operations	6,742,046	6,380,704
Noncash assigned capital credits	(77,403)	(132,844)
Decrease (increase) in accounts receivable	(2,368,988)	(1,794,267)
Decrease (increase) in materials and supplies	349,733	11,345
Decrease (increase) in other current assets	803,838	183,066
Increase (decrease) in accounts payable	2,461,280	1,574,250
Increase (decrease) in other current and accrued liabilities	(90,704)	54,335
Net cash provided by operating activities	6,225,366	7,767,097
Cash flows from investing activities:		
Capital expenditures, net	(12,643,477)	(11,659,501)
Decrease (increase) in other investments, excluding assigned capital credits	(677,869)	248,525
Net cash used in investing activities	(13,321,346)	(11,410,976)
Cash flows from financing activities:		
Additional memberships, net of refunds	52,860	136,581
Net borrowings on note payable	3,500,000	500,000
Additional long-term debt	9,000,000	10,355,000
Reduction of long-term debt	(4,580,606)	(4,506,143)
Patronage capital retired	(739,483)	(2,311,610)
Net cash provided by financing activities	7,232,771	4,173,828
Net increase in cash and cash equivalents	136,791	529,949
Cash and cash equivalents, beginning of year	1,378,839	848,890
Cash and cash equivalents, end of year	$ 1,515,630	$ 1,378,839
Supplemental disclosure of cash flow information:		
Interest paid, net of amounts capitalized	$ 5,288,979	$ 4,117,383

See Notes to Financial Statements

1. Organization and Summary of Significant Accounting Policies

Nature of Business

Kenergy is a nonprofit electric distribution cooperative association which provides electric power to approximately 54,100 residential, commercial and industrial customers located in fourteen western Kentucky counties.

Basis of Accounting

The accounting policies of Kenergy reflect those prescribed by the United States Department of Agriculture Rural Utilities Service (RUS) and the Kentucky Public Service Commission (KPSC), which conform with accounting principles generally accepted in the United States of America in all material respects.

Revenues

Revenues are accrued when services are rendered based on rates authorized by the KPSC.

Utility Plant

Utility plant is stated at original cost, net of contributions, which is the cost when first dedicated to public service. Kenergy capitalizes supervisory and overhead costs applicable to construction projects.

Maintenance and repairs of property units and renewals of minor items of property are charged to maintenance expense accounts. The costs of replacing complete property units are charged to utility plant accounts and the original cost of distribution plant property units retired and cost of removal, net of salvage value, are charged to accumulated depreciation.

Depreciation

Depreciation is provided on the basis of the estimated useful lives of assets at straight-line rates, which for 2006 and 2005, were as follows:

Distribution plant	3.10% to 6.75%
General plant	2.00% to 15.60%

1. Organization and Summary of Significant Accounting Policies, Continued

Depreciation, Continued

Kenergy uses the composite method of depreciation for distribution plant and the unit method of depreciation for general plant.

Investments

As more fully described in Note 3, Kenergy's investment in a generation and transmission corporation is recorded at zero. All other investments of Kenergy are stated at cost, which approximates fair value.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand, money market funds, and investments with an original maturity of three months or less. The carrying amount reported in the balance sheet for cash and cash equivalents approximates fair value.

Materials and Supplies

Materials and supplies inventories are stated at the lower of cost or market using the average cost method.

Use of Estimates

The preparation of 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 and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

2. Utility Plant

Utility plant at December 31 consists of the following:

2. Utility Plant, Continued

	2006	2005
Distribution plant	$ 194,082,590	$ 184,508,203
General plant	20,634,711	21,685,405
	214,717,301	206,193,608
Less accumulated depreciation	48,193,716	45,328,490
	166,523,585	160,865,118
Construction in progress	3,010,053	2,909,571
	$ 169,533,638	$ 163,774,689

Depreciation expense for the years ended December 31, 2006 and 2005, was $7,018,256 and $6,630,391, respectively.

Interest capitalized during 2006 and 2005 related to construction of utility plant was $82,651 and $60,091, respectively.

3. Investments

Generation and Transmission Corporation

As discussed in Note 7, Kenergy purchases electric power from Big Rivers, a generation and transmission cooperative association. The membership of Big Rivers is comprised of Kenergy and two other distribution cooperatives.

The following is an audited summary at December 31 of financial information pertaining to Big Rivers:

	2006	2005
	(In Thousands)	
Balance Sheet Data:		
Current assets	$ 118,310	$ 84,372
Noncurrent assets	1,136,079	1,141,608
Total assets	1,254,389	1,225,980
Current liabilities	34,339	34,053
Noncurrent liabilities	1,437,421	1,443,840
Total liabilities	1,471,760	1,477,893
Equities (deficit)	$ (217,371)	$ (251,913)

3. Investments, Continued

Generation and Transmission Corporation, Continued

		2006		2005
Income Statement Data:				
Revenues	$	258,588	$	248,955
Operating margin	$	17,958	$	11,887
Net margin	$	34,542	$	26,343

The above summary was obtained from Big Rivers audited financial statements as of and for the years ended December 31, 2006 and 2005. Big Rivers experienced significant operating losses in prior years and has a net equities deficiency of approximately $217 million at December 31, 2006. Because the equity of Big Rivers is a deficit at December 31, 2006 and 2005, Kenergy's investment in Big Rivers is carried at zero in accordance with accounting principles generally accepted in the United States of America.

Other Investments

The more significant other investments are as follows:

Capital Term Certificates (CTC's) of the National Rural Utilities Cooperative Finance Corporation are carried at cost, which approximates market. The investment at December 31, 2006 and 2005, totaled $2,528,878. The CTC's mature in varying amounts from 2020 through 2080 and bear interest at 0%, 3% and 5% per annum.

Investment in CoBank, an international cooperative bank, is a required investment which is carried at cost and totaled $1,464,748 and $1,465,084 at December 31, 2006 and 2005, respectively. Under the terms of this Loan Base Capital Plan, Kenergy's investment in CoBank (stock and notified allocated surplus from CoBank) is required to be 10% of Kenergy's average loan balance due to CoBank for the past five years accumulated through equity issued as patronage return.

Kenergy's Retirement Trust totaling $1,449,703 and $1,547,870 at December 31, 2006 and 2005, respectively, represents amounts set aside to fund Kenergy's deferred compensation agreements (Note 11) and are stated at fair value.

Economic development loans represent interest free loans made to qualifying applicants to promote rural economic development. Kenergy borrows monies from RUS (Note 4) pursuant to the Rural Electrification Act of 1936 and in turn loans these monies to

3. **Investments, Continued**

Other Investments, Continued

qualifying applicants. The loans are secured by letters of credit, thereby eliminating Kenergy's exposure to loss. Amounts outstanding at December 31, 2006 and 2005, were $2,313,388 and $1,583,305, respectively.

4. **Long-Term Debt**

Long-term debt at December 31 consists of:

	2006	2005
First mortgage notes payable to:		
RUS in quarterly and monthly installments of varying amounts through 2038:		
Interest rate term fixed to principle maturity:		
2% notes	$ 4,840	$ 63,482
5% notes	18,215,209	18,796,897
5.125% notes	2,368,648	2,410,412
Laddered interest rate terms of 1-7 years at an average rate of 3.23% at December 31, 2006	65,733,077	59,009,586
Unapplied note prepayments – 5%	(12,463,377)	(11,860,815)
	73,858,397	68,419,562
CoBank in quarterly and monthly installments of varying amounts through 2033:		
Interest rate term fixed to principle maturity:		
4.19% average rate at December 31, 2006	24,796,355	15,775,742
Seven day variable interest rate term: 6.77% at December 31, 2006	6,444	10,549,867
	24,802,799	26,325,609

4. Long-Term Debt, Continued

	2006	2005
Rural Economic Development Zero-Interest Loan payable to RUS in monthly installments of varying amounts through May 2011	2,313,388	1,583,305
Federal Financing Bank in quarterly installments of varying amounts through December 2037, with a 90 day fixed interest term of 4.2%	20,953,460	21,180,174
Total long-term debt	121,928,044	117,508,650
Less current maturities	4,222,208	3,752,161
	$ 117,705,836	$ 113,756,489

Aggregate annual maturities of long-term debt at December 31, 2006, are:

2007	$ 4,222,208
2008	4,068,211
2009	4,185,566
2010	4,295,939
2011	4,396,044
Thereafter	100,760,076
	$ 121,928,044

All assets of Kenergy are pledged as collateral on the long-term debt as previously described. Kenergy has available $19,325,000 in unadvanced loan funds from the Treasury Department at December 31, 2006.

5. Short-Term Borrowings

Kenergy has unsecured line of credit agreements with financial institutions permitting short-term borrowings for general corporate purposes totaling $35,000,000. Rates for such borrowings are variable. There was $5,000,000 and $1,500,000 outstanding under these agreements at December 31, 2006 and 2005, respectively. The rate at December 31, 2006 was 7.15%.

6. Major Customers

Operating revenue for 2006 and 2005 includes approximately $225.8 million and $189.4 million, respectively, attributable to sales of power to two aluminum smelting customers. Accounts receivable from these customers totaled $17.3 million and $15.2 million at December 31, 2006 and 2005, respectively.

Operating revenue also includes sales of power to six other large industrial customers totaling approximately 7.72% and 9.14% of Kenergy's operating revenue for 2006 and 2005, respectively.

7. Cost of Power

Kenergy presently purchases all of its power and energy requirements from Big Rivers Electric Corporation (Big Rivers) under wholesale power contracts which expire in 2023 with the exception of the power and energy requirements of its two major customers, which is supplied by LG&E Energy Marketing, Inc. and other suppliers under power purchase agreements expiring annually through December 31, 2011. Accounts payable under such contracts were $9.2 million and $14.4 million, respectively, at December 31, 2006, and $8.9 million and $12.6 million, respectively, at December 31, 2005.

8. Pension Plans

Kenergy has various pension plans covering its employees.

Noncontributory Defined Benefit Plan

Kenergy has a noncontributory defined benefit pension plan covering former Green River Electric Corporation (GREC) employees who were members of the plan on January 1, 1987. Employees with an original date of hire on or after January 1, 1987, are not eligible to join the defined benefit plan. The benefits are based on years of service and the employee's highest average monthly compensation for three consecutive years of service.

Kenergy amended the defined benefit plan effective January 1, 1987, to offset benefits accruing after January 1, 1987, by the benefits provided by the defined contribution plan discussed below. Kenergy has adopted the provisions of Statement of Financial Accounting Standards No. 87, "Employer's Accounting for Pensions," as amended by Statement of Financial Accounting Standards No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits."

8. Pension Plans, Continued

Noncontributory Defined Benefit Plan, Continued

Net pension cost (income) for 2006 and 2005 included the following components:

	2006	2005
Service cost	$ 57,000	$ 52,000
Interest cost on projected benefit obligation	107,000	143,000
Expected return on plan assets	(94,000)	(139,000)
Net amortization and deferral	87,000	92,000
Settlement	67,000	437,000
Pension cost (income)	$ 224,000	$ 585,000

The following table sets forth the plan's funded status and the amount recognized in Kenergy's balance sheet at December 31:

	2006	2005
Accumulated benefit obligation:		
Vested	$ 1,300,000	$ 1,344,000
Projected benefit obligation	$ 1,913,000	$ 2,023,000
Plan assets at fair value	1,282,000	1,307,000
Deficiency of plan assets over projected benefit obligation	(631,000)	(716,000)
Unrecognized net loss	533,000	705,000
Unrecognized prior service cost	-	16,000
Net amount recognized	$ (98,000)	$ 5,000
Amounts recognized consist of:		
Prepaid benefit cost	$ -	$ 5,000
Accrued pension liability	(98,000)	(42,000)
Intangible asset	-	16,000
Accumulated other comprehensive income	-	26,000
Net amount recognized	$ (98,000)	$ 5,000

8. Pension Plans, Continued

Noncontributory Defined Benefit Plan, Continued

In determining the actuarial present value of the projected benefit obligation, the weighted average discount rate used was 5.75% and 5.50% for the periods ended December 31, 2006 and 2005, respectively, and the rate of increase in future compensation levels was 4.00% for 2006 and 2005. The expected long-term rate of return on assets was 7.50% for the periods ended December 31, 2006 and 2005. Plan assets consist of investments in a guaranteed investment contract and pooled separate accounts. Employer contributions totaled $121,000 and $293,000 for the years ended December 31, 2006 and 2005, respectively, while there were no employee contributions. Kenergy expects to contribute $445,000 to this pension plan for the year ending December 31, 2007. Benefits paid totaled $5,000 and $47,000 for the years ended December 31, 2006 and 2005, respectively. Settlements totaled $217,000 and $1,038,000 for the years ended December 31, 2006 and 2005, respectively.

The expected long-term rate of return on plan assets for determining net periodic pension cost for each fiscal year is chosen by Kenergy 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.

The general investment objectives are to invest in a diversified portfolio, comprised of both equity and fixed income investments, which are further diversified among various asset classes. The diversification is designed to minimize the risk of large losses while maximizing total return within reasonable and prudent levels of risk. The investment objectives specify a targeted investment allocation for the pension plans of up to 47.5% equities, 47.5% bonds and 5% real estate. Objectives do not target a specific return by asset class. These investment objectives are long-term in nature. As of December 31, 2006, the investment allocation was approximately 47.5% equities, 47.7% bonds, and 4.8% real estate. Applying the year-end 2006 since inception rate of returns for each investment category to the balances in each category produced an expected rate of return of approximately 7.75%.

Estimated benefit payments for the years following 2006 are as follows:

8. Pension Plans, Continued

Noncontributory Defined Benefit Plan, Continued

2007	$	120,000
2008	$	446,000
2009	$	2,000
2010	$	2,000
2011	$	590,000
Years 2012 - 2016	$	1,071,000

Savings and Retirement Plan

Effective January 1, 1987, Kenergy adopted a defined contribution savings and retirement plan. This plan is available to all former GREC employees and all newly hired employees of Kenergy on or after July 1, 1999, excluding temporary employees, with six months of service, who work at least 1,000 hours during each twelve-month period following their date of employment. Under this plan, Kenergy contributes 6% of each employee's annual compensation. In addition, Kenergy will provide matching contributions equal to 50% of each employee's contribution; however, Kenergy's matching contribution will not exceed 5% of each employee's compensation. Employer contributions under this plan totaled $569,746 and $551,668 for the years ended December 31, 2006 and 2005, respectively.

NRECA Retirement and Security Program

All eligible employees of the former Henderson Union Cooperative Corporation (HUEC) participate in the NRECA Retirement and Security Program (Program), a defined benefit pension plan qualified under Section 401 and tax-exempt under Section 501(a) of the Internal Revenue Code. Kenergy makes annual contributions to the Program equal to the amounts accrued for pension expense. Non-SERP contributions were $428,727 and $416,590 for 2006 and 2005, respectively. In this multi-employer plan, which is available to all member cooperatives of NRECA, the accumulated benefits and plan assets are not determined or allocated separately by individual employer.

Retirement Savings Plan

The Retirement Savings Plan is available for all eligible former HUEC employees. The plan allows participants to make contributions by salary reduction, pursuant to Section 401(k) of the Internal Revenue Code. Kenergy will match the contributions of each participant, up to 3% of the participant's base compensation. Kenergy contributed $85,996 and $90,375 for 2006 and 2005, respectively. Participants vest immediately in their contributions and the contributions of Kenergy.

8. Pension Plans, Continued

Deferred Compensation Plan

The Kenergy Corp. 457(b) Deferred Compensation Plan allows designated senior management personnel the opportunity to make salary deferral contributions into a retirement plan once they reach the IRS limit on voluntary contributions into their 401(k) plan. Plan contributions were $311 and $1,390 for the years ending December 31, 2006 and 2005, respectively.

9. Deferred Compensation

Included in other investments and other noncurrent liabilities is $1,449,703 and $1,547,870 at December 31, 2006 and 2005, respectively, relating to deferred compensation agreements. The deferred compensation plan was frozen in 1999. Benefits are being paid out and the obligation is being relieved over a period of ten years through approximately 2012.

10. Postretirement Benefits

In conjunction with a Special Early Retirement Program, Kenergy is obligated to pay postretirement benefits. Six remaining individuals (out of 22) who elected early retirement December 31, 1999, are provided medical benefits for the lesser of five years or until age 65, with Kenergy paying for 100% of health care premiums up to a maximum of $600 per month per retiree. Four remaining individuals (out of 7) who retired December 31, 2002, in conjunction with a change in policy whereby payment of health insurance for disabled employees would be discontinued, will be provided medical benefits for the lessor of five years or until age 65. The funding policy is to pay the related premiums as they become due. Accrued postretirement benefit costs at December 31, 2006 and 2005, were approximately $41,414 and $104,583, respectively, and are included in other current and accrued liabilities.

No other postretirement benefits are provided to Kenergy employees or directors with the exception of allowing retirees (non-SERP) to participate in the Kenergy health care program while paying 100% of their own premiums.

11. Financial Instruments

Statement of Financial Accounting Standards No. 107, "Disclosures about Fair Value of Financial Instruments," requires Kenergy to disclose estimated fair values of its financial

11. Financial Instruments, Continued

instruments. Fair value estimates, methods, and assumptions are set forth below for Kenergy's financial instruments:

The carrying amounts of cash and cash equivalents, accounts receivable, other current assets, accounts payable, and other current liabilities approximate fair value because of the short-term maturity of those instruments.

In management's opinion, the carrying value of long-term debt also approximates fair value.

Kenergy's financial instruments that are exposed to concentrations of credit risk consist primarily of cash and trade accounts receivable. Kenergy had cash deposits in a financial institution in excess of the amount insured by the Federal Depository Insurance Corporation (FDIC) at December 31, 2006 and 2005. The risk is managed by maintaining all deposits in high quality institutions. Kenergy routinely assesses the financial strength of its customers and, as a consequence, believes that its trade accounts receivable credit risk exposure is limited.

12. Related Party Transactions

Big Rivers (Note 3) provides billing, safety training, and other services to its three distribution cooperative members for which it is not reimbursed. Big Rivers reimburses its members for economic development costs. Through March 2006, Kenergy was also reimbursed for marketing personnel who provide services for all three of Big Rivers' members. Such services requested for reimbursement from Big Rivers during the years ended December 31, 2006 and 2005, totaled $215,446 and $231,815, respectively, of which $57,737 and $50,007, respectively, was included in accounts receivable. These amounts do not include the cost of computer programming, safety training and postage provided but not quantified.

In October 2005, Kenergy received a lump sum payment of $221,000 from Big Rivers for the lease of office space in a building owned by Kenergy. In 2005, the advanced lump sum payment of rent was deferred, and in 2006, the lease was recorded as a capital lease.

13. Income Tax Status

Kenergy is exempt from federal and state income taxes under Section 501(c)(12) of the Internal Revenue Code and, accordingly, the accompanying financial statements include no provision for such taxes.

14. Limitation on Distributions

Without the prior written approval of RUS, Kenergy shall not in any calendar year make any Distributions (exclusive of any Distributions to the estates of deceased natural patrons) to its members, stockholders or consumers except as follows:

If, after giving effect to any such Distribution, the Equity of the Borrower shall be greater than or equal to 30% of its Total Assets; or

If, after giving effect to any such Distribution, the Equity of the Borrower shall be greater than or equal to 20% of its Total Assets and the aggregate of all Distributions made during the calendar year when added to such Distribution shall be less than or equal to 25% of the prior year's margins.

Provided however, that in no event shall Kenergy make any Distributions if there is unpaid, when due, any installment of principal of (premium, if any) or interest on any of its payment obligations secured by the Mortgage, if the Borrower is otherwise in default hereunder or if, after giving effect to any such Distribution, the Borrower's current and accrued assets would be less than its current and accrued liabilities.

15. Risk Management

Kenergy is exposed to various risks of loss related to torts; theft of, damage to, and destruction of assets; errors and omissions; injuries to employees; and natural disasters. Kenergy carries commercial insurance for all risks of loss, including workers' compensation, general liability and property loss insurance. As is customary in the utility industry, Utility Plant is not insured with the exception of substations. Settled claims resulting from these risks have not exceeded commercial insurance coverage in 2006 or 2005.

16. Rate Matters

Kenergy received approval on February 19, 2007, from the Kentucky Public Service Commission to increase rates effective March 1, 2007. The new rates will generate additional revenue of approximately $3,900,000 annually.

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PKF North American Network

REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AND ON COMPLIANCE AND OTHER MATTERS BASED ON AN AUDIT OF FINANCIAL STATEMENTS PERFORMED IN ACCORDANCE WITH *GOVERNMENT AUDITING STANDARDS*

Board of Directors
Kenergy Corp.
Henderson, Kentucky

We have audited the financial statements of Kenergy Corp. (Kenergy) as of and for the year ended December 31, 2006, and have issued our report thereon dated March 28, 2007. We conducted our audit in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards,* issued by the Comptroller General of the United States.

Internal Control Over Financial Reporting

In planning and performing our audit, we considered Kenergy's internal control over financial reporting as a basis for designing our auditing procedures for the purpose of expressing our opinion on the financial statements, but not for the purpose of expressing an opinion on the effectiveness of Kenergy's internal control over financial reporting. Accordingly, we do not express an opinion on the effectiveness of Kenergy's internal control over financial reporting.

A control deficiency exists when the design or operation of a control does not allow management or employees, in the normal course of performing their assigned functions, to prevent or detect misstatements on a timely basis. A significant deficiency is a control deficiency, or combination of control deficiencies, that adversely affects the entity's ability to initiate, authorize, record, process, or report financial data reliably in accordance with generally accepted accounting principles such that there is more than a remote likelihood that a misstatement of the entity's financial statements that is more than inconsequential will not be prevented or detected by the entity's internal control.

A material weakness is a significant deficiency, or combination of significant deficiencies, that results in more than a remote likelihood that a material misstatement of the financial statements will not be prevented or detected by the entity's internal control.

Our consideration of internal control over financial reporting was for the limited purpose described in the first paragraph of this section and would not necessarily identify all deficiencies

Internal Control Over Financial Reporting, Continued

in internal control that might be significant deficiencies or material weaknesses. We did not identify any deficiencies in internal control over financial reporting that we consider to be material weaknesses, as defined above.

Compliance and Other Matters

As part of obtaining reasonable assurance about whether Kenergy's financial statements are free of material misstatement, we performed tests of its compliance with certain provisions of laws, regulations, contracts and grants agreements, noncompliance with which could have a direct and material effect on the determination of financial statement amounts. However, providing an opinion on compliance with those provisions was not an objective of our audit and, accordingly, we do not express such an opinion. The results of our tests disclosed no instances of noncompliance or other matters that are required to be reported under *Government Auditing Standards*.

We noted certain matters that we have reported to the management of Kenergy in a separate letter dated March 28, 2007.

This report is intended solely for the information and use of the audit committee, management, Board of Directors, and the Rural Utilities Service and supplemental lenders and is not intended to be and should not be used by anyone other than these specified parties.

Riney, Hancock & Co., PSC

Owensboro, Kentucky
March 28, 2007

Kentucky 18

Meade County Rural Cooperative Corporation

Brandenburg, Kentucky

Report on Audits of Financial Statements

for the years ended October 31, 2006 and 2005

ALAN ZUMSTEIN

CERTIFIED PUBLIC ACCOUNTANT

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Lexington, Kentucky 40509

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ALAN M. ZUMSTEIN
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KENTUCKY SOCIETY OF CPA'S
AICPA DIVISION FOR FIRMS

Independent Auditor's Report

to the Board of Directors of
Meade County Rural Electric Cooperative Corporation

I have audited the balance sheets of Meade County Rural Electric Cooperative Corporation, as of October 31, 2006 and 2005, and the related statements of income and patronage capital and cash flows for the years then ended. These financial statements are the responsibility of Meade County Rural Electric Cooperative Corporation's management. My responsibility is to express an opinion on these financial statements based on my audits.

I conducted my audits in accordance with auditing standards generally accepted in the United States of America, the standards applicable to financial audits contained in Government Auditing Standards issued by the Comptroller General of the United States and 7 CFR Part 1773, Policy on Audits of Rural Utilities Service (RUS) Borrowers. Those standards require that I plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement. An audit includes examining on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. I believe that my audits provide a reasonable basis for my opinion.

In my opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Meade County Rural Electric Cooperative Corporation as of October 31, 2006 and 2005, and the results of operations and cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

In accordance with Government Auditing Standards, I have also issued a report dated December 7, 2006, on my consideration of Meade County Rural Electric Cooperative Corporation's internal control over financial reporting and my tests of its compliance with certain provisions of laws, regulations, contracts and grant agreements and other matters. The purpose of that report is to describe the scope of my testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with Government Auditing Standards and should be considered in assessing the results of my audit.

Alan M. Zumstein

Alan M. Zumstein
December 7, 2006

ALAN M. ZUMSTEIN
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to the Board of Directors of
Meade County Rural Electric Cooperative Corporation

I have audited the financial statements of Meade County Rural Electric Cooperative Corporation as of and for the years ended October 31, 2006 and 2005, and have issued my report thereon dated December 7, 2006. I conducted my audit in accordance with generally accepted auditing standards and the standards applicable to financial audits contained in Government Auditing Standards, issued by the Comptroller General of the United States.

Compliance

As part of obtaining reasonable assurance about whether Meade County Rural Electric Cooperative Corporation's financial statements are free of material misstatement, I performed tests of its compliance with certain provisions of laws, regulations, contracts and grants, noncompliance with which could have a direct and material effect on the determination of financial statement amounts. However, providing an opinion on compliance with those provisions was not an objective of my audit and, accordingly, I do not express such an opinion. The results of my tests disclosed no instances of noncompliance or other matters that are required to be reported under Government Auditing Standards.

Internal Control Over Financial Reporting

In planning and performing my audit, I considered Meade County Rural Electric Cooperative Corporation's internal control over financial reporting in order to determine my auditing procedures for the purpose of expressing my opinion on the financial statements and not to provide an opinion on the internal control over financial reporting. My consideration of the internal control over financial reporting would not necessarily disclose all matters in the internal control over financial reporting that might be material weaknesses. A material weakness is a condition in which the design or operation of one or more of the internal control components does not reduce to a relatively low level the risk that misstatements caused by error or fraud in amounts that would be material in relation to the financial statements being audited may occur and not be detected within a timely period by employees in the normal course of performing their assigned functions. I noted no matters involving the internal control over financial reporting and its operation that I consider to be material weaknesses.

This report is intended solely for the information and use of the audit committee, management, the Rural Utilities Service and supplemental lenders, and is not intended to be and should not be used by anyone other than those specified parties.

Alan M. Zumstein

Alan M. Zumstein
December 7, 2006

Meade County Rural Electric Cooperative Corporation

Balance Sheets, October 31, 2006 and 2005

Assets	2006	2005
Electric Plant, at original cost:		
In service	$77,441,864	$71,643,765
Under construction	1,000,337	689,883
	78,442,201	72,333,648
Less accumulated depreciation	19,058,500	17,762,536
	59,383,701	54,571,112
Investments in Associated Organizations	1,781,292	1,872,748
Current Assets:		
Cash and cash equivalents	6,045,926	5,689,238
Accounts receivable, less allowance for 2006 of $201,886 and 2005 of $178,854	2,366,189	2,373,420
Material and supplies, at average cost	379,762	272,764
Other current assets	361,215	460,427
	9,153,092	8,795,849
Total	$70,318,085	$65,239,709

Members' Equities and Liabilities	2006	2005
Members' Equities:		
Memberships	$115,940	$121,800
Patronage capital	19,942,916	19,887,770
Other equities	685,701	655,977
	20,744,557	20,665,547
Long Term Debt	43,076,326	38,797,307
Accumulated Postretirement Benefits	511,752	425,509
Current Liabilities:		
Current portion of long term debt	2,275,000	2,150,000
Accounts payable	1,501,281	1,435,362
Consumer deposits	634,055	554,211
Accrued expenses	972,071	630,525
	5,382,407	4,770,098
Consumer Advances for Construction	603,043	581,248
Total	$70,318,085	$65,239,709

The accompanying notes are an integral part of the financial statements.

Statements of Revenue and Patronage Capital

for the years ended October 31, 2006 and 2005

	2006	2005
Operating Revenues	$27,490,406	$27,214,354
Operating Expenses:		
Cost of power	15,768,944	15,722,062
Distribution - operations	1,805,050	1,728,888
Distribution - maintenance	2,504,881	2,177,825
Consumer accounts	1,192,735	1,178,182
Consumer service and information	226,791	186,878
Administrative and general	1,245,679	1,103,022
Depreciation, excluding $221,348 in 2006 and $187,782 in 2005 charged to clearing accounts	2,451,260	2,293,413
Taxes	32,695	24,939
Other deductions	105,756	87,662
	25,333,791	24,502,871
Operating Margins before Interest Charges	2,156,615	2,711,483
Interest Charges:		
Long-term debt	1,962,294	1,749,447
Operating Margins after Interest Charges	194,321	962,036
Patronage Capital from Associated Organizations	153,345	110,643
Nonoperating Margins, principally interest	269,149	170,192
Net Margins	616,815	1,242,871
Patronage Capital - beginning of year	19,887,770	19,237,322
Retirement of patronage capital	(352,071)	(430,460)
Retirements to estates of deceased members	(209,598)	(161,963)
Patronage Capital - end of year	$19,942,916	$19,887,770

The accompanying notes are an integral part of the financial statements.

Statements of Cash Flows

for the years ended October 31, 2006 and 2005

	2006	2005
Cash Flows from Operating Activities:		
Net margins	$616,815	$1,242,871
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation		
Charged to expense	2,451,260	2,293,413
Charged to clearing	221,348	187,125
Capital credits allocated	(153,345)	(110,643)
Accumulated postretirement benefits	86,243	80,382
Net change in current assets and liabilities:		
Receivables	7,231	177,624
Material and supplies	(106,998)	(6,955)
Other current assets	99,212	(61,389)
Accounts payable	65,919	169,292
Consumer deposits	79,844	55,266
Accrued expenses	341,546	6,741
Consumer advances for construction	21,795	66,119
	3,730,870	4,099,846
Cash Flows from Investing Activities:		
Construction of plant	(7,558,172)	(4,704,130)
Salvage recovered from plant	72,975	63,570
Receipts from investments, net	244,801	8,149
	(7,240,396)	(4,632,411)
Net Cash Flows from Financing Activities:		
Net decrease in memberships	(5,860)	(6,425)
Retirement of patronage capital	(561,669)	(592,423)
Increase in other equities	29,724	50,479
Additional long-term borrowings	6,000,000	4,000,000
Advance payments	563,594	(688,728)
Payments on long-term debt	(2,159,575)	(2,027,020)
	3,866,214	735,883
Net increase in cash balances	356,688	203,318
Cash and cash equivalents - beginning	5,689,238	5,485,920
Cash and cash equivalents - ending	$6,045,926	$5,689,238
Supplemental disclosures of cash flow information:		
Interest on long-term debt	$1,995,152	$1,678,311

The accompanying notes are an integral part of the financial statements.

1. Summary of Significant Accounting Policies

Meade County maintains its records in accordance with policies prescribed or permitted by the Kentucky Public Service Commission (PSC) and the United States Department of Agriculture, Rural Utilities Service (RUS), which conform in all material respects with generally accepted accounting principles. The more significant of these policies are as follows:

Electric Plant

Electric plant is stated at original cost, less contributions, which is the cost when first dedicated to public service. Such cost includes applicable supervisory and overhead costs. There was no interest required to be capitalized on construction for the year.

The cost of maintenance and repairs, including renewals of minor items of property, is charged to operating expense. The cost of replacement of depreciable property units, as distinguished from minor items, is charged to electric plant. The cost of units of property replaced or retired, including cost of removal net of any salvage value, is charged to accumulated depreciation

Electric plant in service consisted of:

	2006	2005
Distribution plant	$70,709,900	$66,374,752
General plant	6,731,964	5,269,013
Total	$77,441,864	$71,643,765

Depreciation

Provision has been made for depreciation on the basis of the estimated lives of assets, using the straight-line method. Meade County uses a composite depreciation rate of 3.36% per annum for distribution plant. General plant depreciation rates are as follows:

Structures and improvements	2.5% - 3%
Transportation equipment	12.5% - 25%
Other general plant	5% - 14.3%

Statement of Cash Flows

For purposes of the statement of cash flows, Meade County considers temporary investments having a maturity of three months or less to be cash equivalents.

Continued

1. **Summary of Significant Accounting Policies, continued**

Revenue

Meade County records revenue as billed to its consumers based on monthly meter- reading cycles. Certain consumers are required to pay a refundable deposit. Meade County's sales are concentrated in a six county area of western Kentucky. There were no consumers whose individual account balance exceeded 10% of outstanding accounts receivable at October 31, 2006 or 2005. Consumers must pay their bill within 20 days of billing, then are subject to disconnect after another 10 days. Accounts are written off when they are deemed to be uncollectible. The allowance for uncollectible accounts is based on the aging of receivables.

Cost of Power

Meade County is one of three (3) members of Big Rivers Electric Corporation, Inc. (Big Rivers). Under a wholesale power agreement, Meade County is committed to purchase its electric power and energy requirements from Big Rivers until 2023. The rates charged by Big Rivers are subject to approval of the PSC. The cost of purchased power is recorded monthly during the period in which the energy is consumed, based upon billings from Big Rivers.

Estimates

The preparation of 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 and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates used in the preparation of the financial statements.

Fair Value of Financial Instruments

Financial instruments include cash, temporary cash investments and long-term debt. Investments in associated organizations are not considered a financial instrument because they represent nontransferable interest in associated organizations.

The carrying value of cash and temporary cash investments approximates fair value because of the short maturity of those instruments. The fair value of long term debt approximates the fair value because of the borrowing policies of Meade County.

Meade County will also invest idle funds in local banks. These investments are classified as held-to-maturity in accordance with Statement of Financial Accounting Standards (SFAS) No. 115. Held-to-maturity securities are presented at amortized cost. The fair value of held-to-maturity securities approximates cost at 2006 and 2005.

Continued

1. Summary of Significant Accounting Policies, continued

Off Balance Sheet Risk

Meade County has off balance sheet risk in that they maintain cash deposits in financial institutions in excess of the amounts insured by the Federal Deposit Insurance Corporation (FDIC). At October 31, 2006 and 2005, the financial institutions reported deposits in excess of the $100,000 FDIC insured limit on several of the accounts.

Advertising

Meade County expenses advertising costs as incurred. Advertising costs were $66,060 for 2006 and $67,742 for 2005.

Income Tax Status

Meade County is exempt from federal and state income taxes under provisions of Section 501(c)(12). Accordingly, the financial statements include no provision for income taxes.

2. Investments in Associated Organizations

Meade County records patronage capital assigned by associated organizations in the year in which such assignments are received.

The Capital Term Certificates (CTCs) of National Rural Utilities Cooperative Finance Corporation (NRUCFC) are recorded at cost. The CTCs were purchased from NRUCFC as a condition of obtaining long-term financing. The CTCs bear interest at 0%, 3% and 5% and are scheduled to mature at varying times from 2020 to 2080.

Investments in associated organizations consisted of:

	2006	2005
Associated Organizations:		
National Rural Utilities Cooperative		
Finance Corporation:		
Capital Term Certificates	$1,099,255	$1,130,329
Patronage capital assigned	209,639	187,924
Other associated organizations	471,268	435,866
Others	1,130	118,629
Total	$1,781,292	$1,872,748

Continued

3. Patronage Capital

Under provisions of the long-term debt agreement, return to patrons of capital contributed by them is limited to amounts which would not allow the total equities and margins to be less than 30% of total assets, except that distributions may be made to estates of deceased patrons. The debt agreement provides, however, that should such distributions to estates not exceed 25% of net margins for the next preceding year, Meade County may distribute the difference between 25% and the payments made to such estates. The equity at October 31, 2006 was 30% of total assets.

Patronage capital consisted of:

	2006	2005
Assigned to date	$26,691,920	$25,657,811
Assignable	919,919	1,578,190
Unassigned	1,999,503	1,758,527
Retirements to date	(9,668,426)	(9,106,758)
Total	$19,942,916	$19,887,770

4. Long Term Debt

All assets, except vehicles, are pledged as collateral on the long-term debt to RUS, Federal Financing Bank (FFB) and NRUCFC under a joint mortgage agreement. Long term debt consisted of:

	2006	2005
First mortgage notes due RUS:		
2%	$12,384	$24,744
4.10% to 4.875%	$19,429,889	$13,645,608
Advance payment	(317,034)	(880,628)
	19,125,239	12,789,724
First mortgage notes due FFB:		
2.707% to 6.049%	10,187,197	10,411,293
First mortgage notes due NRU CFC:		
7%	59,432	69,711
3.05% to 6.90% fixed rate	5,699,880	4,505,535
3.60% variable rate	-	1,422,955
Refinance RUS loans 3.10 to 5.95%	10,279,578	11,748,089
	16,038,890	17,746,290
	45,351,326	40,947,307
Less current portion	2,275,000	2,150,000
Long term portion	$43,076,326	$38,797,307

Continued

4. Long Term Debt

The long term debt payable to RUS, FFB and NRUCFC is due in quarterly and monthly installments of varying amounts through 2041. Meade County has loan funds available from RUS in the amount of $17,136,000.

During 2004, Meade County refinanced $14,685,111 of RUS 5% interest loans with the 3.10% - 5.95% fixed and variable interest rate notes from NRUCFC. These notes are due in ten (10) annual installments of $1,468,511 each through 2013.

As of October 31, 2006, the annual current portion of long term debt outstanding for the next five years are as follows: 2007 - $2,275,000; 2008 - $2,300,000; 2009 - $2,350,000; 2010 - $2,400,000; 2011 - $2,450,000.

5. Short Term Borrowings

At October 31, 2006, Meade County had a short-term line of credit of $5,000,000 available from NRUCFC. There were no borrowings against this line of credit during the audit period.

6. Employee Benefits

Pension Plan

All eligible employees of Meade County participate in the NRECA Retirement and Security Program, a defined benefit pension plan qualified under section 401 and tax-exempt under section 501(a) of the Internal Revenue Code. Eligible employees include employees hired prior to August 2002. Non-eligible employees are those hired after August, 2002. Meade County makes annual contributions to the Program equal to the amounts accrued for pension expense. Contributions to this plan were $369,393 for 2006 and $338,414 for 2005. In this multiemployer plan, which is available to all member cooperatives of NRECA, the accumulated benefits and plan assets are not determined or allocated separately by individual employer.

Retirement Savings Plan

Meade County participates in the NRECA Savings Plan, a multiemployer, defined contribution master pension plan. All employees are eligible to participate in the Savings plan upon completion of one month employment. Participating employees contribute from 1% to 3% of their annual base salary and Meade County contributes 3%. Non-eligible employees, as defined above, participate in the savings plan, with Meade County contributing 12% of annual base pay, and the employee contributing from 1% to 3%. Meade County makes annual contributions to the plan equal to amounts accrued for pension expense. Contributions are vested immediately. Pension costs for the savings plan were $144,158 for 2006 and $122,685 for 2005. A portion of this cost is allocated to construction of electric plant.

Continued

6. **Employee Benefits, continued**

Postretirement Benefits

Meade County sponsors a defined benefit plan that provides medical insurance coverage to retirees. During 1996, Meade County changed its plan from contributing 50% of the projected cost of coverage to contributing 50% of the cost of a single policy. For purposes of the liability estimates, the substantive plan is assumed to be the same as the extant written plan. Postretirement benefits are not funded.

The funded status of the plan was as follows:

	2006	2005
Accumulated postretirement benefit obligation	$814,499	$635,000
Plan assets at fair value	-	-
Funded status	814,499	635,000
Unrecognized net gain (losses) from changes in assumptions	(302,747)	(209,491)
Accrued postretirement benefit cost	$511,752	$425,509

The following is a reconciliation of the postretirement benefit obligation:

	2006	2005
Postretirement Benefit Obligation:		
Balance, beginning of period	$425,509	$345,127
Recognition of components of net periodic postretirement benefit cost:		
Service cost	43,000	45,000
Interest cost	40,000	39,000
Amortization of gains or losses	21,267	20,672
	104,267	104,672
Benefits paid to participants	(18,024)	(24,290)
Net change	86,243	80,382
Balance, end of period	$511,752	$425,509

For measurement purposes, a 8.5% annual rate of increase, decreasing by 0.5% per year until 5.5% per year, in the per capita cost of covered health care benefits was assumed. The discount rate used in determining the accumulated postretirement benefit obligation was 6.50%.

Continued

7. Risk Management

Meade County is exposed to various risks of loss related to torts; theft of, damage to and destruction of assets; errors and omissions; injuries to employees; and natural disasters.

Meade County carries commercial insurance for all risks of loss, including workers' compensation, general liability and property loss insurance. As is customary in the utility industry, Electric Plant, except substations, are not insured. Settled claims resulting from these risks have not exceeded commercial insurance coverage in 2006 or 2005.

8. Related Party Transactions

Several of the Directors of Meade County, its President & CEO and another employee are on the Boards of Directors of various associated organizations. During 2006 Meade County paid $41,240 to the son of one of its Directors to pave the parking lot of the District Office.

9. Committments

Meade County has various other agreements outstanding with local contractors. Under these agreements, the contractors will perform certain construction and maintenance work at specified hourly rates or unit cost, or on an as needed basis. The duration of these contracts are one to three years.

10. Environmental Contingency

Meade County from time to time is required to work with and handle PCBs, herbicides, automotive fluids, lubricants and other hazardous materials in the normal course of business. As a result, there is the possibility that environmental conditions may arise which would require Meade County to incur cleanup costs. The likelihood of such an event, or the amount of such costs, if any, cannot be determined at this time. However, management does not believe such costs, if any, would materially affect Meade County's financial position or its future cash flows.

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Meade County Rural Electric Cooperative Corporation

Brandenburg, Kentucky

Audited Financial Statements

October 31, 2007 and 2006

ALAN ZUMSTEIN

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Independent Auditor's Report

To the Board of Directors of
Meade County Rural Electric Cooperative Corporation

I have audited the balance sheets of Meade County Rural Electric Cooperative Corporation, as of October 31, 2007 and 2006, and the related statements of income and patronage capital and cash flows for the years then ended. These financial statements are the responsibility of Meade County Rural Electric Cooperative Corporation's management. My responsibility is to express an opinion on these financial statements based on my audits.

I conducted my audits in accordance with auditing standards generally accepted in the United States of America, the standards applicable to financial audits contained in Government Auditing Standards issued by the Comptroller General of the United States and 7 CFR Part 1773, Policy on Audits of Rural Utilities Service (RUS) Borrowers. Those standards require that I plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement. An audit includes examining on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. I believe that my audits provide a reasonable basis for my opinion.

In my opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Meade County Rural Electric Cooperative Corporation as of October 31, 2007 and 2006, and the results of operations and cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

In accordance with Government Auditing Standards, I have also issued a report dated December 12, 2007, on my consideration of Meade County Rural Electric Cooperative Corporation's internal control over financial reporting and my tests of its compliance with certain provisions of laws, regulations, contracts and grant agreements and other matters. The purpose of that report is to describe the scope of my testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with Government Auditing Standards and should be considered in assessing the results of my audit.

Alan Zumstein

Alan M. Zumstein
December 12, 2007

ALAN M. ZUMSTEIN
CERTIFIED PUBLIC ACCOUNTANT

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MEMBER:
- AMERICAN INSTITUTE OF CPA'S
- INDIANA SOCIETY OF CPA'S
- KENTUCKY SOCIETY OF CPA'S
- AICPA DIVISION FOR FIRMS
- TENNESSEE STATE BOARD OF ACCOUNTANCY

To the Board of Directors of
Meade County Rural Electric Cooperative Corporation

I have audited the financial statements of Meade County Rural Electric Cooperative Corporation as of and for the years ended October 31, 2007 and 2006, and have issued my report thereon dated December 12, 2007. I conducted my audit in accordance with generally accepted auditing standards and the standards applicable to financial audits contained in Government Auditing Standards, issued by the Comptroller General of the United States.

Internal Control Over Financial Reporting

In planning and performing my audit, I considered Meade County Rural Electric's internal control over financial reporting as a basis for designing my auditing procedures for the purpose of expressing my opinion on the financial statements, but not for the purpose of expressing an opinion on the effectiveness of Meade County Rural Electric's internal control over financial reporting. Accordingly, I do not express an opinion on the effectiveness of Meade County Rural Electric's internal control over financial reporting.

A control deficiency exists when the design or operation of a control does not allow management employees, in the normal course of performing their assigned functions, to prevent or detect misstatements on a timely basis. A significant deficiency is a control deficiency, or combination of control deficiencies, that adversely affects the entity's ability to initiate, authorize, record, process, or report financial data reliably in accordance with generally accepted accounting principles such that there is more than a remote likelihood that a misstatement of the entity's financial statements that is more than inconsequential will not be prevented or detected by the entity's internal control.

A material weakness is a significant deficiency, or combination of significant deficiencies, that results in more than a remote likelihood that a material misstatement of the financial statements will not be prevented or detected by the entity's internal control.

My consideration of internal control over financial reporting was for the limited purpose described in the first paragraph of this section and would not necessarily identify all deficiencies in internal control that might be significant deficiencies or material weaknesses. I did not identify any deficiencies in internal control over financial reporting that I consider to be material weaknesses, as defined above.

Compliance and Other Matters

As part of obtaining reasonable assurance about whether Meade County Rural Electric's financial statements are free of material misstatement, I performed tests of its compliance with certain provisions of laws, regulations, contracts and grant agreements, noncompliance with which could have a direct and material effect on the determination of financial statement amounts. However, providing an opinion on compliance with those provisions was not an objective of my audit, and accordingly, I do not express such an opinion. The results of my tests disclosed no instances of noncompliance or other matters that are required to be reported under Government Auditing Standards.

This report is intended solely for the information and use of the audit committee, management, the Rural Utilities Service and supplemental lenders, and is not intended to be and should not be used by anyone other than these specified parties.

Alan M. Zumstein
December 12, 2007

Meade County Rural Electric Cooperative Corporation

Balance Sheets, October 31, 2007 and 2006

Assets	2007	2006
Electric Plant, at original cost:		
In service	$82,156,759	$77,441,864
Under construction	1,012,182	1,000,337
	83,168,941	78,442,201
Less accumulated depreciation	20,652,300	19,058,500
	62,516,641	59,383,701
Investments in Associated Organizations	1,824,950	1,781,292
Current Assets:		
Cash and cash equivalents	4,486,435	6,045,926
Accounts receivable, less allowance for 2007 of $263,129 and 2006 of $201,886	2,429,613	2,366,189
Material and supplies, at average cost	400,247	379,762
Other current assets	349,522	361,215
	7,665,817	9,153,092
Total	$72,007,408	$70,318,085

Members' Equities and Liabilities	2007	2006
Members' Equities:		
Memberships	$111,260	$115,940
Patronage capital	20,331,629	19,942,916
Other equities	763,063	685,701
Accumulated other comprehensive income	(298,332)	-
	20,907,620	20,744,557
Long Term Debt	44,131,478	43,076,326
Accumulated Postretirement Benefits	855,224	511,752
Current Liabilities:		
Current portion of long term debt	2,300,000	2,275,000
Accounts payable	1,701,323	1,501,281
Consumer deposits	633,864	634,055
Accrued expenses	607,135	972,071
	5,242,322	5,382,407
Consumer Advances for Construction	870,764	603,043
Total	$72,007,408	$70,318,085

The accompanying notes are an integral part of the financial statements.

Statements of Revenue and Patronage Capital

for the years ended October 31, 2007 and 2006

	2007	2006
Operating Revenues	$29,480,109	$27,490,406
Operating Expenses:		
Cost of power	17,015,983	15,768,944
Distribution - operations	1,868,291	1,805,050
Distribution - maintenance	2,226,819	2,504,881
Consumer accounts	1,208,174	1,192,735
Consumer service and information	238,407	226,791
Administrative and general	1,158,367	1,245,679
Depreciation, excluding $242,610 in 2007 and $221,348 in 2006 charged to clearing accounts	2,685,368	2,451,260
Taxes	33,716	32,695
Other deductions	80,983	105,756
	26,516,108	25,333,791
Operating Margins before Interest Charges	2,964,001	2,156,615
Interest Charges:		
Long-term debt	2,204,295	1,962,294
Operating Margins after Interest Charges	759,706	194,321
Patronage Capital from Associated Organizations	157,061	153,345
Nonoperating Margins, principally interest	256,623	269,149
Net Margins	1,173,390	616,815
Patronage Capital - beginning of year	19,942,916	19,887,770
Retirement of patronage capital	(601,300)	(352,071)
Retirements to estates of deceased members	(183,377)	(209,598)
Patronage Capital - end of year	$20,331,629	$19,942,916

The accompanying notes are an integral part of the financial statements.

Statements of Cash Flows

for the years ended October 31, 2007 and 2006

	2007	2006
Cash Flows from Operating Activities:		
Net margins	$1,173,390	$616,815
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation		
Charged to expense	2,685,368	2,451,260
Charged to clearing	242,610	221,348
Capital credits allocated	(157,061)	(153,345)
Accumulated postretirement benefits	45,140	86,243
Net change in current assets and liabilities:		
Receivables	(63,424)	7,231
Material and supplies	(20,485)	(106,998)
Other current assets	11,693	99,212
Accounts payable	200,042	65,919
Consumer deposits	(191)	79,844
Accrued expenses	(364,936)	341,546
Consumer advances for construction	267,721	21,795
	4,019,867	3,730,870
Cash Flows from Investing Activities:		
Construction of plant	(6,157,851)	(7,558,172)
Salvage recovered from plant	96,933	72,975
Receipts from investments, net	113,403	244,801
	(5,947,515)	(7,240,396)
Net Cash Flows from Financing Activities:		
Net decrease in memberships	(4,680)	(5,860)
Retirement of patronage capital	(784,677)	(561,669)
Increase in other equities	77,362	29,724
Additional long-term borrowings	3,000,000	6,000,000
Advance payments	317,034	563,594
Payments on long-term debt	(2,236,882)	(2,159,575)
	368,157	3,866,214
Net increase in cash balances	(1,559,491)	356,688
Cash and cash equivalents - beginning	6,045,926	5,689,238
Cash and cash equivalents - ending	$4,486,435	$6,045,926
Supplemental disclosures of cash flow information:		
Interest on long-term debt	$2,217,264	$1,995,152

The accompanying notes are an integral part of the financial statements.

1. Summary of Significant Accounting Policies

Meade County maintains its records in accordance with policies prescribed or permitted by the Kentucky Public Service Commission (PSC) and the United States Department of Agriculture, Rural Utilities Service (RUS), which conform in all material respects with generally accepted accounting principles. The more significant of these policies are as follows:

Electric Plant

Electric plant is stated at original cost, less contributions, which is the cost when first dedicated to public service. Such cost includes applicable supervisory and overhead costs. There was no interest required to be capitalized on construction for the year.

The cost of maintenance and repairs, including renewals of minor items of property, is charged to operating expense. The cost of replacement of depreciable property units, as distinguished from minor items, is charged to electric plant. The cost of units of property replaced or retired, including cost of removal net of any salvage value, is charged to accumulated depreciation

Electric plant in service consisted of:

	2007	2006
Distribution plant	$75,403,386	$70,709,900
General plant	6,753,373	6,731,964
Total	$82,156,759	$77,441,864

Depreciation

Provision has been made for depreciation on the basis of the estimated lives of assets, using the straight-line method. Meade County uses a composite depreciation rate of 3.36% per annum for distribution plant. General plant depreciation rates are as follows:

Structures and improvements	2.5% - 3%
Transportation equipment	12.5% - 25%
Other general plant	5% - 14.3%

Cash and Cash Equiavlents

Meade County considers all short-term, highly-liquid investments with original maturities of three months or less to be cash equivalents.

Advertising

Meade County expenses advertising costs as incurred.

Continued

1. Summary of Significant Accounting Policies, continued

Revenue

Meade County records revenue as billed to its consumers based on monthly meter- reading cycles. Certain consumers are required to pay a refundable deposit. Meade County's sales are concentrated in a six county area of western Kentucky. There were no consumers whose individual account balance exceeded 10% of outstanding accounts receivable at October 31, 2007 or 2006. Consumers must pay their bill within 20 days of billing, then are subject to disconnect after another 10 days. Accounts are written off when they are deemed to be uncollectible. The allowance for uncollectible accounts is based on the aging of receivables.

Cost of Power

Meade County is one of three (3) members of Big Rivers Electric Corporation, Inc. (Big Rivers). Under a wholesale power agreement, Meade County is committed to purchase its electric power and energy requirements from Big Rivers until 2023. The rates charged by Big Rivers are subject to approval of the PSC. The cost of purchased power is recorded monthly during the period in which the energy is consumed, based upon billings from Big Rivers.

Estimates

The preparation of 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 and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates used in the preparation of the financial statements.

Fair Value of Financial Instruments

The carrying value of cash and temporary cash investments approximates fair value because of the short maturity of those instruments. The fair value of long term debt approximates the fair value because of the borrowing policies of Meade County. Investments in associated organizations are not considered a financial instrument because they represent a nontransferable interest in associated organizations.

Meade County will also invest idle funds in local banks. These investments are classified as held-to-maturity in accordance with Statement of Financial Accounting Standards (SFAS) No. 115. Held-to-maturity securities are presented at amortized cost. The fair value of held-to-maturity securities approximates cost at 2007 and 2006.

Continued

1. Summary of Significant Accounting Policies, continued

Off Balance Sheet Risk

Meade County has off balance sheet risk in that they maintain cash deposits in financial institutions in excess of the amounts insured by the Federal Deposit Insurance Corporation (FDIC). At October 31, 2007 and 2006, the financial institutions reported deposits in excess of the $100,000 FDIC insured limit on several of the accounts.

Income Tax Status

Meade County is exempt from federal and state income taxes under provisions of Section 501(c)(12). Accordingly, the financial statements include no provision for income taxes.

Risk Management

Meade County is exposed to various forms of losses of assets associated with, but not limited to, fire, personal liability, theft, vehicular accidents, errors and omissions, fiduciary responsibility, workers compensation, etc. Each of these areas is covered through the purchase of commercial insurance.

2. Investments in Associated Organizations

Meade County records patronage capital assigned by associated organizations in the year in which such assignments are received.

The Capital Term Certificates (CTCs) of National Rural Utilities Cooperative Finance Corporation (NRUCFC) are recorded at cost. The CTCs were purchased from NRUCFC as a condition of obtaining long-term financing. The CTCs bear interest at 0%, 3% and 5% and are scheduled to mature at varying times from 2020 to 2080.

Investments in associated organizations consisted of:

	2007	2006
Associated Organizations:		
NRUCFC, CTC's	$1,068,396	$1,099,255
NRUCFC, patronage capital assigned	230,680	209,639
Other associated organizations	524,744	471,268
Others	1,130	1,130
Total	$1,824,950	$1,781,292

Continued

3. Patronage Capital

Under provisions of the long-term debt agreement, return to patrons of capital contributed by them is limited to amounts which would not allow the total equities and margins to be less than 30% of total assets, except that distributions may be made to estates of deceased patrons. The debt agreement provides, however, that should such distributions to estates not exceed 25% of net margins for the next preceding year, Meade County may distribute the difference between 25% and the payments made to such estates. The equity at October 31, 2007 was 30% of total assets.

Patronage capital consisted of:

	2007	2006
Assigned to date	$27,293,420	$26,691,920
Assignable	1,091,245	919,919
Unassigned	2,400,067	1,999,503
Retirements to date	(10,453,103)	(9,668,426)
Total	$20,331,629	$19,942,916

4. Accumulated Other Comprehensive Income

The changes in accumulated other comprehensive income, which includes the effects of applying the provisions of SFAS No. 158, follows.

	2007	2006
Balance, beginning of period	-	n/a
Adjustment to initially apply SFAS No. 158	(298,332)	
Balance, end of period	($298,332)	

5. Short Term Borrowings

At October 31, 2007, Meade County had a short-term line of credit of $5,000,000 available from NRUCFC. There were no borrowings against this line of credit during the audit period.

6. Long Term Debt

During 2004, Meade County refinanced $14,685,111 of RUS 5% interest loans with the 3.10% - 5.95% fixed and variable interest rate notes from NRUCFC. These notes are due in ten (10) annual installments of $1,468,511 each through 2013.

As of October 31, 2007, the annual current portion of long term debt outstanding for the next five years are as follows: 2008 - $2,300,000; 2009 - $2,350,000; 2010 - $2,400,000; 2011 - $2,450,000; 2012 - $2,500,000.

Continued

6. Long Term Debt, continued

All assets, except vehicles, are pledged as collateral on the long-term debt to RUS, Federal Financing Bank (FFB) and NRUCFC under a joint mortgage agreement. Long term debt consisted of:

	2007	2006
First mortgage notes due RUS:		
4.18 to 5.06% (2.0% to 4.875% in 2006)	$22,144,440	$19,442,273
Advance payment	-	(317,034)
	22,144,440	19,125,239
First mortgage notes due FFB:		
2.815% to 6.049% (2.707% to 6.049% in 2006)	9,953,204	10,187,197
First mortgage notes due NRU CFC:		
7%	36,154	59,432
3.05% to 6.90% fixed rate	5,486,614	5,699,880
Refinance RUS loans 3.10% to 5.95%	8,811,066	10,279,578
	14,333,834	16,038,890
	46,431,478	45,351,326
Less current portion	2,300,000	2,275,000
Long term portion	$44,131,478	$43,076,326

The long term debt payable to RUS, FFB and NRUCFC is due in quarterly and monthly installments of varying amounts through 2041. Meade County has loan funds available from RUS in the amount of $14,136,000.

7. Employee Benefits

Pension Plan

All eligible employees of Meade County participate in the NRECA Retirement and Security Program, a defined benefit pension plan qualified under section 401 and tax-exempt under section 501(a) of the Internal Revenue Code. Eligible employees include employees hired prior to August 2002. Non-eligible employees are those hired after August, 2002. Meade County makes annual contributions to the Program equal to the amounts accrued for pension expense. Contributions to this plan were $372,529 for 2007 and $369,393 for 2006. In this multiemployer plan, which is available to all member cooperatives of NRECA, the accumulated benefits and plan assets are not determined or allocated separately by individual employer.

Continued

7. Employee Benefits, continued

Retirement Savings Plan

Meade County participates in the NRECA Savings Plan, a multiemployer, defined contribution master pension plan. All employees are eligible to participate in the Savings plan upon completion of one month employment. Participating employees contribute from 1% to 3% of their annual base salary and Meade County contributes 3%. Non-eligible employees, as defined above, participate in the savings plan, with Meade County contributing 12% of annual base pay, and the employee contributing from 1% to 3%. Meade County makes annual contributions to the plan equal to amounts accrued for pension expense. Contributions are vested immediately. Pension costs for the savings plan were $156,812 for 2007 and $144,158 for 2006. A portion of this cost is allocated to construction of electric plant.

Postretirement Benefits

Meade County sponsors a defined benefit plan that provides medical insurance coverage to retirees who meet certain qualifications. During 1996, Meade County changed its plan from contributing 50% of the projected cost of coverage to contributing 50% of the cost of a single policy.

For measurement purposes, a 8.5% annual rate of increase, decreasing by 0.5% per year until 5.5% per year, in the per capita cost of covered health care benefits was assumed. The discount rate used in determining the accumulated postretirement benefit obligation was 6.50% for 2007 and 2006.

The funded status of the plan was as follows:

	2007	2006
Projected benefit obligation	($855,224)	($814,499)
Plan assets at fair value	-	-
Funded status	($855,224)	($814,499)

The components of net periodic postretirement benefit costs are as follows:

	2007	2006
Net periodic benefit cost	$72,198	$104,267
Benefits paid to participants	27,058	18,024

Projected retiree benefit payments are expected to be as follows: 2008 - $25,513; 2009 - $25,479; 2010 - $27,135; 2011 - $26,709; 2011 - $26,010.

Continued

7. **Employee Benefits, continued**

Postretirement Benefits, continued

In September 2006, the Financial Accounting Standards Board ("FASB") issued FASB Statement No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans ("SFAS NO. 158"). Meade County adopted SFAS No. 158 during the year. The incremental effect of applying SFAS No. 158 on individual line items in the Statement of Financial Position is as follows:

	Before Application of Statement 158	Adjustments	After Application of Statement 158
Accumulated postretirement benefits	$556,892	$298,332	$855,224
Accumulated other comprehensive income	-	(298,332)	(298,332)
Total members' equities	21,205,952	(298,332)	20,907,620

8. **Related Party Transactions**

Several of the Directors of Meade County, its President & CEO and another employee are on the Boards of Directors of various associated organizations. During 2006 Meade County paid $41,240 to the son of one of its Directors to pave the parking lot of the District Office.

9. **Commitments**

Meade County has various other agreements outstanding with local contractors. Under these agreements, the contractors will perform certain construction and maintenance work at specified hourly rates or unit cost, or on an as needed basis. The duration of these contracts are one to three years.

10. **Environmental Contingency**

Meade County from time to time is required to work with and handle PCBs, herbicides, automotive fluids, lubricants and other hazardous materials in the normal course of business. As a result, there is the possibility that environmental conditions may arise which would require Meade County to incur cleanup costs. The likelihood of such an event, or the amount of such costs, if any, cannot be determined at this time. However, management does not believe such costs, if any, would materially affect Meade County's financial position or its future cash flows.

11. **Rate Matters**

Meade County is anticipating an order from the PSC to allow it to increase rates in the amount of $1,900,000 or 7% of revenues.

Kentucky 18

Meade County Rural Electric Cooperative Corporation

Brandenburg, Kentucky

Report on Audits of Financial Statements

for the years ended October 31, 2005 and 2004

ALAN ZUMSTEIN

CERTIFIED PUBLIC ACCOUNTANT

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MEMBER:
AMERICAN INSTITUTE OF CPA'S
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KENTUCKY SOCIETY OF CPA'S
AICPA DIVISION FOR FIRMS

Board of Directors
Meade County Rural Electric
Cooperative Corporation
Brandenburg, Kentucky 40108

I have audited the financial statements of Meade County Rural Electric Cooperative Corporation for the year ended October 31, 2005, and have issued my report thereon dated December 14, 2005. I conducted my audit in accordance with generally accepted auditing standards, the standards applicable to financial audits contained in Government Auditing Standards issued by the Comptroller General of the United States, and 7 CFR Part 1773, Policy on Audits of the Rural Utilities Service (RUS) Borrowers. Those standards require that I plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

In planning and performing my audit of the financial statements of Meade County Electric for the year ended October 31, 2005, I considered its internal control over financial reporting in order to determine my auditing procedures for the purpose of expressing an opinion on the financial statements and not to provide assurance on the internal control over financial reporting.

My consideration of the internal control over financial reporting would not necessarily disclose all matters in the internal control over financial reporting that might be material weaknesses. A material weakness is a condition in which the design or operation of the specific internal control components does not reduce to a relatively low level the risk that misstatements in amounts that would be material in relation to the financial statements being audited may occur and not be detected within a timely period by employees in the normal course of performing their assigned functions. I noted no matters involving the internal control over financial reporting that I consider to be a material weakness.

7 CFR Part 1773.33 requires comments on specific aspects of the internal control over financial reporting, compliance with specific RUS loan and security instrument provisions and other additional matters. I have grouped my comments accordingly. In addition to obtaining reasonable assurance about whether the financial statements are free from material misstatements, at your request, I performed tests of specific aspects of the internal control over financial reporting, of compliance with specific RUS loan and security instrument provisions and of additional matters. The specific aspects of the internal control over financial reporting, compliance with specific RUS loan and security instrument provisions, and additional matters tested include, among other things, the accounting procedures and records, materials control, compliance with specific RUS loan and security instrument provisions set forth in 7 CFR 1773.33(d)(1) related transactions, depreciation rates, a schedule of deferred debits and credits and a schedule of investments, upon which I express an opinion. In addition, my audit of the financial statements also included the procedures specified in 7 CFR Part 1773.38-.45. My

objective was not to provide an opinion on these specific aspects of the internal control over financial reporting, compliance with specific RUS loan and security instrument provisions, or additional matters, and accordingly, I express no opinion thereon.

No reports, other than my independent auditor's report, and my independent auditor's report on compliance and on internal control over financial reporting, all dated December 14, 2005, or summary of recommendations related to my audit have been furnished to management.

My comments on specific aspects of the internal control over financial reporting, compliance with specific RUS loan and security instrument provisions and other additional matters as required by 7 CFR 1773.33 are presented below.

Comments on Certain Specific Aspects of the Internal Control Over Financial Reporting

I noted no matters regarding Meade County Electric's internal control over financial reporting and its operation that I consider to be a material weakness as previously defined with respect to:

- The accounting procedures and records;
- the process for accumulating and recording labor, material and overhead costs, and the distribution of these costs to construction, retirement and maintenance and other expense accounts; and,
- the materials controls.

Comments on Compliance with Specific RUS Loan and Security Instrument Provisions

At your request, I have performed the procedures enumerated below with respect to compliance with certain provisions of laws, regulations and contracts. The procedures I performed are summarized as follows:

- Procedures performed with respect to the requirement for a borrower to obtain written approval of the mortgagee to enter into any contract for the operation or maintenance of property, or for the use of mortgaged property by others for the year ended October 31, 2005, of Meade County Electric.

    1. Obtained and read a borrower prepared schedule of new written contracts entered into during the year for the operation or maintenance of its property, or for the use of its property by others as defined in 1773.33 (e)(1)(i).

    2. Reviewed Board of Director minutes to ascertain whether board-approved written contracts are included in the borrower-prepared schedule.

Comments on Compliance with Specific RUS Loan and Security Instrument Provisions, continued:

3. Noted written RUS approval was not obtained by the borrower for all the contracts listed. Meade County Electric's management informed me that RUS approval was not required as the contracts related to operation or maintenance entered into during the normal course of business.

- Procedure performed with respect to the requirement to submit RUS Form 7 to RUS:

1. Agreed amounts reported in RUS Form 7 to Meade County Electric's records as of October 31, 2005.

The results of my tests indicate that, with respect to the items tested, Meade County Electric complied in all material respects, with the specific RUS loan and security instrument provisions referred to below. With respect to items not tested, nothing came to my attention that caused me to believe that Meade County Electric had not complied, in all material respects, with those provisions. The specific provisions tested, as well as any exceptions noted, include the requirements that:

- the borrower has obtained written approval of RUS to enter into any contract for the operation and maintenance of all or any part of property, for the use of mortgaged property by others as defined in 1773.33 (d)(1)(i); and ,

- the borrower has submitted its RUS Form 7 to RUS and the Form 7, Financial and Statistical Report, as of October 31, 2005, represented by the borrower as having been submitted to RUS is in agreement with Meade County Electric's audited records in all material respects.

Comments on Other Additional Matters

In connection with my audit of the financial statements of Meade County Electric, nothing came to my attention that caused me to believe that Meade County Electric failed to comply with respect to:

- The reconciliation of continuing property records to the controlling general ledger plant accounts addressed at 7 CFR Part 1773.33(c)(1);

- the clearing of the construction accounts and the accrual of depreciation on completed construction addressed at 7 CFR Part 1773.33(c)(2);

- the retirement of plant addressed at 7 CFR Part 1773.33(c)(3) and (4);

- approval of the sale, lease or transfer of capital assets and disposition of proceeds for the sale, or lease of plant, material or scrap addressed at 7 CFR Part 1773.33(c)(5);

Comments on Other Additional Matters

- the disclosure of material related party transactions, in accordance with Statement of Financial Accounting Standards No. 57, Related Party Transactions, for the year ended October 31, 2005, in the financial statements referenced in the first paragraph of this report addressed at 7 CFR Part 1773.33(f);

- the depreciation rates addressed at 7 CFR 1773.33(g);

- the detailed schedule of deferred debits and deferred credits; and

- the detailed schedule of investments, of which there were none.

My audit was made for the purpose of forming an opinion on the basic financial statements taken as a whole. The detailed schedule of deferred debits and deferred credits required by 7 CFR 1773.33(h) and provided below is presented for purposes of additional analysis and is not a required part of the basic financial statements. This information has been subjected to the auditing procedures applied in my audit of the basic financial statements and, in my opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

The deferred credits are as follows:

Consumer advances for construction	$581,248

* * * * * *

This report is intended solely for the information and use of the Board of Directors, management, RUS and supplemental lenders and is not intended to be and should not be used by anyone other than these specified parties. However, this report is a matter of public record and its distribution is not limited.

Alan M. Zumstein
December 14, 2005

ALAN M. ZUMSTEIN
CERTIFIED PUBLIC ACCOUNTANT

1032 CHETFORD DRIVE
LEXINGTON, KENTUCKY 40509
(859) 264-7147

MEMBER:
AMERICAN INSTITUTE OF CPA'S
INDIANA SOCIETY OF CPA'S
KENTUCKY SOCIETY OF CPA'S
AICPA DIVISION FOR FIRMS

to the Board of Directors of
Meade County Rural Electric Cooperative Corporation

I have audited the financial statements of Meade County Rural Electric Cooperative Corporation for the year ended October 31, 2006, and have issued my report thereon dated December 7, 2006. I conducted my audit in accordance with generally accepted auditing standards, the standards applicable to financial audits contained in Government Auditing Standards issued by the Comptroller General of the United States, and 7 CFR Part 1773, Policy on Audits of the Rural Utilities Service (RUS) Borrowers. Those standards require that I plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

In planning and performing my audit of the financial statements of Meade County for the year ended October 31, 2006, I considered its internal control over financial reporting in order to determine my auditing procedures for the purpose of expressing an opinion on the financial statements and not to provide assurance on the internal control over financial reporting.

My consideration of the internal control over financial reporting would not necessarily disclose all matters in the internal control over financial reporting that might be material weaknesses. A material weakness is a condition in which the design or operation of the specific internal control components does not reduce to a relatively low level the risk that misstatements in amounts that would be material in relation to the financial statements being audited may occur and not be detected within a timely period by employees in the normal course of performing their assigned functions. I noted no matters involving the internal control over financial reporting that I consider to be a material weakness.

7 CFR Part 1773.33 requires comments on specific aspects of the internal control over financial reporting, compliance with specific RUS loan and security instrument provisions and other additional matters. I have grouped my comments accordingly. In addition to obtaining reasonable assurance about whether the financial statements are free from material misstatements, at your request, I performed tests of specific aspects of the internal control over financial reporting, of compliance with specific RUS loan and security instrument provisions and of additional matters. The specific aspects of the internal control over financial reporting, compliance with specific RUS loan and security instrument provisions, and additional matters tested include, among other things, the accounting procedures and records, materials control, compliance with specific RUS loan and security instrument provisions set forth in 7 CFR 1773.33(d)(1) related transactions, depreciation rates, a schedule of deferred debits and credits and a schedule of investments, upon which I express an opinion. In addition, my audit of the financial statements also included the procedures specified in 7 CFR Part 1773.38-.45. My

objective was not to provide an opinion on these specific aspects of the internal control over financial reporting, compliance with specific RUS loan and security instrument provisions, or additional matters, and accordingly, I express no opinion thereon.

No reports, other than my independent auditor's report, and my independent auditor's report on compliance and on internal control over financial reporting, all dated December 7, 2006, or summary of recommendations related to my audit have been furnished to management.

My comments on specific aspects of the internal control over financial reporting, compliance with specific RUS loan and security instrument provisions and other additional matters as required by 7 CFR 1773.33 are presented below.

Comments on Certain Specific Aspects of the Internal Control Over Financial Reporting

I noted no matters regarding Meade County's internal control over financial reporting and its operation that I consider to be a material weakness as previously defined with respect to:

- The accounting procedures and records;

- the process for accumulating and recording labor, material and overhead costs, and the distribution of these costs to construction, retirement and maintenance and other expense accounts; and,

- the materials controls.

Comments on Compliance with Specific RUS Loan and Security Instrument Provisions

At your request, I have performed the procedures enumerated below with respect to compliance with certain provisions of laws, regulations and contracts. The procedures I performed are summarized as follows:

- Procedures performed with respect to the requirement for a borrower to obtain written approval of the mortgagee to enter into any contract for the operation or maintenance of property, or for the use of mortgaged property by others for the year ended October 31, 2006, of Meade County.

  1. Obtained and read a borrower prepared schedule of new written contracts entered into during the year for the operation or maintenance of its property, or for the use of its property by others as defined in 1773.33 (e)(1)(i).

  2. Reviewed Board of Director minutes to ascertain whether board-approved written contracts are included in the borrower-prepared schedule.

Comments on Compliance with Specific RUS Loan and Security Instrument Provisions, continued:

3. Noted written RUS approval was not obtained by the borrower for all the contracts listed. Meade County's management informed me that RUS approval was not required as the contracts related to operation or maintenance entered into during the normal course of business.

- Procedure performed with respect to the requirement to submit RUS Form 7 to RUS:

1. Agreed amounts reported in RUS Form 7 to Meade County's records as of October 31, 2006.

The results of my tests indicate that, with respect to the items tested, Meade County complied in all material respects, with the specific RUS loan and security instrument provisions referred to below. With respect to items not tested, nothing came to my attention that caused me to believe that Meade County had not complied, in all material respects, with those provisions. The specific provisions tested, as well as any exceptions noted, include the requirements that:

- the borrower has obtained written approval of RUS to enter into any contract for the operation and maintenance of all or any part of property, for the use of mortgaged property by others as defined in 1773.33 (d)(1)(i); and ,

- the borrower has submitted its RUS Form 7 to RUS and the Form 7, Financial and Statistical Report, as of October 31, 2006, represented by the borrower as having been submitted to RUS is in agreement with Meade County's audited records in all material respects.

Comments on Other Additional Matters

In connection with my audit of the financial statements of Meade County, nothing came to my attention that caused me to believe that Meade County failed to comply with respect to:

- The reconciliation of continuing property records to the controlling general ledger plant accounts addressed at 7 CFR Part 1773.33(c)(1);

- the clearing of the construction accounts and the accrual of depreciation on completed construction addressed at 7 CFR Part 1773.33(c)(2);

- the retirement of plant addressed at 7 CFR Part 1773.33(c)(3) and (4);

- approval of the sale, lease or transfer of capital assets and disposition of proceeds for the sale, or lease of plant, material or scrap addressed at 7 CFR Part 1773.33(c)(5);

Comments on Other Additional Matters

- the disclosure of material related party transactions, in accordance with Statement of Financial Accounting Standards No. 57, Related Party Transactions, for the year ended October 31, 2006, in the financial statements referenced in the first paragraph of this report addressed at 7 CFR Part 1773.33(f);

- the depreciation rates addressed at 7 CFR 1773.33(g);

- the detailed schedule of deferred debits and deferred credits; and

- the detailed schedule of investments, of which there were none.

My audit was made for the purpose of forming an opinion on the basic financial statements taken as a whole. The detailed schedule of deferred debits and deferred credits required by 7 CFR 1773.33(h) and provided below is presented for purposes of additional analysis and is not a required part of the basic financial statements. This information has been subjected to the auditing procedures applied in my audit of the basic financial statements and, in my opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

The deferred credits are as follows:

Consumer advances for construction	$603,043

* * * * * *

This report is intended solely for the information and use of the Board of Directors, management, RUS and supplemental lenders and is not intended to be and should not be used by anyone other than these specified parties. However, this report is a matter of public record and its distribution is not limited.

Alan M. Zumstein
December 7, 2006

ALAN M. ZUMSTEIN
CERTIFIED PUBLIC ACCOUNTANT

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- KENTUCKY SOCIETY OF CPA'S
- AICPA DIVISION FOR FIRMS
- TENNESSEE STATE BOARD OF ACCOUNTANCY

To the Board of Directors of
Meade County Rural Electric Cooperative Corporation

I have audited the financial statements of Meade County Rural Electric Cooperative Corporation for the year ended October 31, 2007, and have issued my report thereon dated December 12, 2007. I conducted my audit in accordance with generally accepted auditing standards, the standards applicable to financial audits contained in Government Auditing Standards issued by the Comptroller General of the United States, and 7 CFR Part 1773, Policy on Audits of the Rural Utilities Service (RUS) Borrowers. Those standards require that I plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

In planning and performing my audit of the financial statements of Meade County for the year ended October 31, 2007, I considered its internal control over financial reporting in order to determine my auditing procedures for the purpose of expressing an opinion on the financial statements and not to provide assurance on the internal control over financial reporting.

My consideration of the internal control over financial reporting would not necessarily disclose all matters in the internal control over financial reporting that might be material weaknesses. A material weakness is a condition in which the design or operation of the specific internal control components does not reduce to a relatively low level the risk that misstatements in amounts that would be material in relation to the financial statements being audited may occur and not be detected within a timely period by employees in the normal course of performing their assigned functions. I noted no matters involving the internal control over financial reporting that I consider to be a material weakness.

7 CFR Part 1773.33 requires comments on specific aspects of the internal control over financial reporting, compliance with specific RUS loan and security instrument provisions and other additional matters. I have grouped my comments accordingly. In addition to obtaining reasonable assurance about whether the financial statements are free from material misstatements, at your request, I performed tests of specific aspects of the internal control over financial reporting, of compliance with specific RUS loan and security instrument provisions and of additional matters. The specific aspects of the internal control over financial reporting, compliance with specific RUS loan and security instrument provisions, and additional matters tested include, among other things, the accounting procedures and records, materials control, compliance with specific RUS loan and security instrument provisions set forth in 7 CFR 1773.33(d)(1) related transactions, depreciation rates, a schedule of deferred debits and credits and a schedule of investments, upon which I express an opinion. In addition, my audit of the financial statements also included the procedures specified in 7 CFR Part 1773.38-.45. My

objective was not to provide an opinion on these specific aspects of the internal control over financial reporting, compliance with specific RUS loan and security instrument provisions, or additional matters, and accordingly, I express no opinion thereon.

No reports, other than my independent auditor's report, and my independent auditor's report on compliance and on internal control over financial reporting, all dated December 12, 2007, or summary of recommendations related to my audit have been furnished to management.

My comments on specific aspects of the internal control over financial reporting, compliance with specific RUS loan and security instrument provisions and other additional matters as required by 7 CFR 1773.33 are presented below.

Comments on Certain Specific Aspects of the Internal Control Over Financial Reporting

I noted no matters regarding Meade County's internal control over financial reporting and its operation that I consider to be a material weakness as previously defined with respect to:

- The accounting procedures and records;
- the process for accumulating and recording labor, material and overhead costs, and the distribution of these costs to construction, retirement and maintenance and other expense accounts; and,
- the materials controls.

Comments on Compliance with Specific RUS Loan and Security Instrument Provisions

At your request, I have performed the procedures enumerated below with respect to compliance with certain provisions of laws, regulations and contracts. The procedures I performed are summarized as follows:

- Procedures performed with respect to the requirement for a borrower to obtain written approval of the mortgagee to enter into any contract for the operation or maintenance of property, or for the use of mortgaged property by others for the year ended October 31, 2007, of Meade County.

    1. Obtained and read a borrower prepared schedule of new written contracts entered into during the year for the operation or maintenance of its property, or for the use of its property by others as defined in 1773.33 (e)(1)(i).

    2. Reviewed Board of Director minutes to ascertain whether board-approved written contracts are included in the borrower-prepared schedule.

Comments on Compliance with Specific RUS Loan and Security Instrument Provisions, *continued:*

3. Noted written RUS approval was not obtained by the borrower for all the contracts listed. Meade County's management informed me that RUS approval was not required as the contracts related to operation or maintenance entered into during the normal course of business.

- Procedure performed with respect to the requirement to submit RUS Form 7 to RUS:

1. Agreed amounts reported in RUS Form 7 to Meade County's records as of October 31, 2007.

The results of my tests indicate that, with respect to the items tested, Meade County complied in all material respects, with the specific RUS loan and security instrument provisions referred to below. With respect to items not tested, nothing came to my attention that caused me to believe that Meade County had not complied, in all material respects, with those provisions. The specific provisions tested, as well as any exceptions noted, include the requirements that:

- the borrower has obtained written approval of RUS to enter into any contract for the operation and maintenance of all or any part of property, for the use of mortgaged property by others as defined in 1773.33 (d)(1)(i); and ,

- the borrower has submitted its RUS Form 7 to RUS and the Form 7, Financial and Statistical Report, as of October 31, 2007, represented by the borrower as having been submitted to RUS is in agreement with Meade County's audited records in all material respects.

Comments on Other Additional Matters

In connection with my audit of the financial statements of Meade County, nothing came to my attention that caused me to believe that Meade County failed to comply with respect to:

- The reconciliation of continuing property records to the controlling general ledger plant accounts addressed at 7 CFR Part 1773.33(c)(1);

- the clearing of the construction accounts and the accrual of depreciation on completed construction addressed at 7 CFR Part 1773.33(c)(2);

- the retirement of plant addressed at 7 CFR Part 1773.33(c)(3) and (4);

- approval of the sale, lease or transfer of capital assets and disposition of proceeds for the sale, or lease of plant, material or scrap addressed at 7 CFR Part 1773.33(c)(5);

Comments on Other Additional Matters

- the disclosure of material related party transactions, in accordance with Statement of Financial Accounting Standards No. 57, Related Party Transactions, for the year ended October 31, 2007, in the financial statements referenced in the first paragraph of this report addressed at 7 CFR Part 1773.33(f);
- the depreciation rates addressed at 7 CFR 1773.33(g);
- the detailed schedule of deferred debits and deferred credits; and
- the detailed schedule of investments, of which there were none.

However, I recommend corrective action be taken in the following area:

1. Meade County utilizes a system in which it scans all information that is not part of the software programs provided by Big River Electric Corporation. This includes all cash receipts tickets, vendor invoices, journal entries, correspondence from regulatory agencies, and all other paper information that can be scanned. There was an incidence that caused the scanning software to be hit with a surge and the information was not able to be retrieved. Upon further investigation, Meade County did not have an adequate backup system for storing information and subsequently retrieving this information in the event of an instance such as this. In effect, Meade County potentially lost two months worth of data.

   I strongly suggest that there should be proper backing up of information, storing this information off-site and periodic testing of the back-up procedures to ensure this type of loss of data does not occur in the future.

My audit was made for the purpose of forming an opinion on the basic financial statements taken as a whole. The detailed schedule of deferred debits and deferred credits required by 7 CFR 1773.33(h) and provided below is presented for purposes of additional analysis and is not a required part of the basic financial statements. This information has been subjected to the auditing procedures applied in my audit of the basic financial statements and, in my opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

The deferred credits are as follows:

Consumer advances for construction	$870,764

* * * * * *

This report is intended solely for the information and use of the Board of Directors, management, RUS and supplemental lenders and is not intended to be and should not be used by anyone other than these specified parties. However, this report is a matter of public record and its distribution is not limited.

Alan Zumstein

Alan M. Zumstein
December 12, 2007

CONTENTS

ALAN M. ZUMSTEIN
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KENTUCKY SOCIETY OF CPA'S
AICPA DIVISION FOR FIRMS

Board of Directors
Meade County Rural Electric
Cooperative Corporation
Brandenburg, Kentucky 40108

Independent Auditor's Report

I have audited the balance sheets of Meade County Rural Electric Cooperative Corporation, as of October 31, 2005 and 2004, and the related statements income and patronage capital and cash flows for the years then ended. These financial statements are the responsibility of Meade County Rural Electric Cooperative Corporation's management. My responsibility is to express an opinion on these financial statements based on my audits.

I conducted my audits in accordance with auditing standards generally accepted in the United States of America, the standards applicable to financial audits contained in Government Auditing Standards issued by the Comptroller General of the United States and 7 CFR Part 1773, Policy on Audits of Rural Utilities Service (RUS) Borrowers. Those standards require that I plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement. An audit includes examining on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. I believe that my audits provide a reasonable basis for my opinion.

In my opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Meade County Rural Electric Cooperative Corporation as of October 31, 2005 and 2004, and the results of operations and cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

In accordance with Government Auditing Standards, I have also issued a report dated December 14, 2005, on my consideration of Meade County Rural Electric Cooperative Corporation's internal control over financial reporting and my tests of its compliance with certain provisions of laws, regulations, contracts and grants. That report is an integral part of an audit performed in accordance with Government Auditing Standards and should be read in conjunction with this report in considering the results of my audit.

Alan Zumstein

Alan M. Zumstein
December 14, 2005

ALAN M. ZUMSTEIN
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MEMBER:
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KENTUCKY SOCIETY OF CPA'S
AICPA DIVISION FOR FIRMS

Board of Directors
Meade County Rural Electric
Cooperative Corporation
Brandenburg, Kentucky 40108

I have audited the financial statements of Meade County Rural Electric Cooperative Corporation as of and for the years ended October 31, 2005 and 2004, and have issued my report thereon dated December 14, 2005. I conducted my audit in accordance with generally accepted auditing standards and the standards applicable to financial audits contained in Government Auditing Standards, issued by the Comptroller General of the United States.

Compliance

As part of obtaining reasonable assurance about whether Meade County Rural Electric Cooperative Corporation's financial statements are free of material misstatement, I performed tests of its compliance with certain provisions of laws, regulations, contracts and grants, noncompliance with which could have a direct and material effect on the determination of financial statement amounts. However, providing an opinion on compliance with those provisions was not an objective of my audit and, accordingly, I do not express such an opinion. The results of my tests disclosed no instances of noncompliance that are required to be reported under Government Auditing Standards.

Internal Control Over Financial Reporting

In planning and performing my audit, I considered Meade County Rural Electric Cooperative Corporation's internal control over financial reporting in order to determine my auditing procedures for the purpose of expressing my opinion on the financial statements and not to provide assurance on the internal control over financial reporting. My consideration of the internal control over financial reporting would not necessarily disclose all matters in the internal control over financial reporting that might be material weaknesses. A material weakness is a condition in which the design or operation of one or more of the internal control components does not reduce to a relatively low level the risk that misstatement in amounts that would be material in relation to the financial statements being audited may occur and not be detected within a timely period by employees in the normal course of performing their assigned functions. I noted no matters involving the internal control over financial reporting and its operation that I consider to be material weaknesses.

This report is intended for the information of the audit committee, management, the Rural Utilities Service and supplemental lenders, and is not intended to be and should not be used by anyone other than those specified parties.

Alan Zumstein

Alan M. Zumstein
December 14, 2005

Meade County Rural Electric Cooperative Corporation

Balance Sheets, October 31, 2005 and 2004

Assets	2005	2004
Electric Plant, at original cost:		
In service	$71,643,765	$67,348,128
Under construction	689,883	1,539,244
	72,333,648	68,887,372
Less accumulated depreciation	17,762,536	16,476,282
	54,571,112	52,411,090
Investments in Associated Organizations	1,872,748	1,770,254
Current Assets:		
Cash and cash equivalents	5,689,238	5,485,920
Accounts receivable, less allowance for 2005 of $178,854 and 2004 of $143,9535	2,373,420	2,551,044
Material and supplies, at average cost	272,764	265,809
Other current assets	460,427	399,038
	8,795,849	8,701,811
Total	$65,239,709	$62,883,155
Members' Equities and Liabilities		
Members' Equities:		
Memberships	$121,800	$128,225
Patronage capital	19,887,770	19,237,322
Other equities	655,977	605,498
	20,665,547	19,971,045
Long Term Debt	38,797,307	37,613,055
Accumulated Postretirement Benefits	425,509	345,127
Current Liabilities:		
Current portion of long term debt	2,150,000	2,050,000
Accounts payable	1,435,362	1,266,070
Consumer deposits	554,211	498,945
Accrued expenses	630,525	623,784
	4,770,098	4,438,799
Consumer Advances for Construction	581,248	515,129
Total	$65,239,709	$62,883,155

The accompanying notes are an integral part of the financial statements.

Statements of Revenue and Patronage Capital

for the years ended October 31, 2005 and 2004

	2005	2004
Operating Revenues	$27,214,354	$25,988,732
Operating Expenses:		
Cost of power	15,722,062	14,718,090
Distribution - operations	1,728,888	1,448,688
Distribution - maintenance	2,177,825	2,403,413
Consumer accounts	1,178,182	1,153,006
Consumer service and information	186,878	197,062
Administrative and general	1,103,022	1,099,277
Depreciation, excluding $187,782 in 2005 and $162,926 in 2004 charged to clearing accounts	2,293,413	2,153,226
Taxes	24,939	27,674
Other deductions	87,662	36,609
	24,502,871	23,237,045
Operating Margins before Interest Charges	2,711,483	2,751,687
Interest Charges:		
Long-term debt	1,749,447	1,355,116
Operating Margins after Interest Charges	962,036	1,396,571
Patronage Capital from Associated Organizations	110,643	112,500
Nonoperating Margins, principally interest	170,192	101,669
Net Margins	1,242,871	1,610,740
Patronage Capital - beginning of year	19,237,322	18,222,686
Retirement of patrónage capital	(430,460)	(430,225)
Retirements to estates of deceased members	(161,963)	(165,879)
Patronage Capital - end of year	$19,887,770	$19,237,322

The accompanying notes are an integral part of the financial statements.

Statements of Cash Flows

for the years ended October 31, 2005 and 2004

	2005	2004
Cash Flows from Operating Activities:		
Net margins	$1,242,871	$1,610,740
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation		
Charged to expense	2,293,413	2,153,226
Charged to clearing	187,125	162,926
Capital credits allocated	(110,643)	(112,500)
Accumulated postretirement benefits	80,382	(5,864)
Net change in current assets and liabilities:		
Receivables	177,624	(542,660)
Material and supplies	(6,955)	(12,911)
Other current assets	(61,389)	114,704
Accounts payable	169,292	(180,813)
Consumer deposits	55,266	51,653
Accrued expenses	6,741	75,895
Consumer advances for construction	66,119	39,440
	4,099,846	3,353,836
Cash Flows from Investing Activities:		
Construction of plant	(4,704,130)	(6,295,475)
Salvage recovered from plant	63,570	48,276
Receipts from investments, net	8,149	(64,799)
	(4,632,411)	(6,311,998)
Net Cash Flows from Financing Activities:		
Net decrease in memberships	(6,425)	(7,445)
Retirement of patronage capital	(592,423)	(596,104)
Increase in other equities	50,479	59,089
Additional long-term borrowings	4,000,000	5,557,000
Advance payments	(688,728)	(112,843)
Payments on long-term debt	(2,027,020)	(2,015,882)
	735,883	2,883,815
Net increase in cash balances	203,318	(74,347)
Cash and cash equivalents - beginning	5,485,920	5,560,267
Cash and cash equivalents - ending	$5,689,238	$5,485,920
Supplemental disclosures of cash flow information:		
Interest on long-term debt	$1,678,311	$1,377,728

The accompanying notes are an integral part of the financial statements.

1. Summary of Significant Accounting Policies

Meade County maintains its records in accordance with policies prescribed or permitted by the Kentucky Public Service Commission (PSC) and the United States Department of Agriculture, Rural Utilities Service (RUS), which conform in all material respects with generally accepted accounting principles. The more significant of these policies are as follows:

Electric Plant

Electric plant is stated at original cost, less contributions, which is the cost when first dedicated to public service. Such cost includes applicable supervisory and overhead costs. There was no interest required to be capitalized on construction for the year.

The cost of maintenance and repairs, including renewals of minor items of property, is charged to operating expense. The cost of replacement of depreciable property units, as distinguished from minor items, is charged to electric plant. The cost of units of property replaced or retired, including cost of removal net of any salvage value, is charged to accumulated depreciation

The major classifications of electric plant in service consisted of:

	2005	2004
Distribution plant	$66,374,752	$62,260,762
General plant	5,269,013	5,087,366
Total	$71,643,765	$67,348,128

Depreciation

Provision has been made for depreciation on the basis of the estimated lives of assets, using the straight-line method. Meade County uses a composite depreciation rate of 3.36% per annum for distribution plant. General plant depreciation rates are as follows:

Structures and improvements	2.5% - 3%
Transportation equipment	12.5% - 25%
Tools and power equipment	5% - 6.7%
Office furniture and equipment	6% - 14.3%
Laboratory equipment	5%
Communication and other equipment	6%

Statement of Cash Flows

For purposes of the statement of cash flows, Meade County considers temporary investments having a maturity of three months or less to be cash equivalents.

Continued

1. Summary of Significant Accounting Policies, continued

Revenue

Meade County records revenue as billed to its consumers based on monthly meter- reading cycles. Certain consumers are required to pay a refundable deposit. Meade County's sales are concentrated in a six county area of western Kentucky. There were no consumers whose individual account balance exceeded 10% of outstanding accounts receivable at October 31, 2005 or 2004. Consumers must pay their bill within 20 days of billing, then are subject to disconnect after another 10 days. Accounts are written off when they are deemed to be uncollectible. The allowance for uncollectible accounts is based on the aging of receivables.

Cost of Power

Meade County is one of three (3) members of Big Rivers Electric Corporation, Inc. (Big Rivers). Under a wholesale power agreement, Meade County is committed to purchase its electric power and energy requirements from Big Rivers until 2023. The rates charged by Big Rivers are subject to approval of the PSC. The cost of purchased power is recorded monthly during the period in which the energy is consumed, based upon billings from Big Rivers.

Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates used in the preparation of the financial statements.

Fair Value of Financial Instruments

Financial instruments include cash, temporary cash investments and long-term debt. Investments in associated organizations are not considered a financial instrument because they represent nontransferable interest in associated organizations.

The carrying value of cash and temporary cash investments approximates fair value because of the short maturity of those instruments. It is not practicable to estimate the fair value of long-term debt.

Income Tax Status

Meade County is exempt from federal and state income taxes under provisions of Section 501(c)(12). Accordingly, the financial statements include no provision for income taxes.

Continued

2. Investments in Associated Organizations

Meade County records patronage capital assigned by associated organizations in the year in which such assignments are received.

The Capital Term Certificates (CTCs) of National Rural Utilities Cooperative Finance Corporation (NRUCFC) are recorded at cost. The CTCs were purchased from NRUCFC as a condition of obtaining long-term financing. The CTCs bear interest at 0%, 3% and 5% and are scheduled to mature at varying times from 2020 to 2080.

Investments in associated organizations consisted of:

	2005	2004
Associated Organizations:		
National Rural Utilities Cooperative		
Finance Corporation:		
Capital Term Certificates	$1,130,329	$1,023,657
Patronage capital assigned	187,924	175,117
Other associated organizations	435,866	448,760
Others	118,629	122,720
Total	$1,872,748	$1,770,254

3. Patronage Capital

Under provisions of the long-term debt agreement, return to patrons of capital contributed by them is limited to amounts which would not allow the total equities and margins to be less than 30% of total assets, except that distributions may be made to estates of deceased patrons. The debt agreement provides, however, that should such distributions to estates not exceed 25% of net margins for the next preceding year, Meade County may distribute the difference between 25% and the payments made to such estates. The equity at October 31, 2005 was 32% of total assets.

Patronage capital consisted of:

	2005	2004
Assigned to date	$25,657,811	$24,574,251
Assignable	1,578,190	1,642,193
Unassigned	1,758,527	1,535,212
Retirements to date	(9,106,758)	(8,514,334)
Total	$19,887,770	$19,237,322

Continued

4. **Long Term Debt**

All assets, except vehicles, are pledged as collateral on the long-term debt to RUS, Federal Financing Bank (FFB) and NRUCFC under a joint mortgage agreement. Long term debt consisted of:

	2005	2004
First mortgage notes due RUS:		
2%	$24,744	$44,619
4.10% to 4.875%	$13,645,608	$9,717,786
Advance payment	(880,628)	(191,901)
	12,789,724	9,570,504
First mortgage notes due FFB:		
2.707 to 6.049% (2.112 to 6.049% in 2004)	10,411,293	10,640,209
First mortgage notes due NRU CFC:		
7%	69,711	85,435
3.05% to 6.90% fixed rate	4,505,535	4,653,828
3.60% variable rate	1,422,955	1,496,479
Refinance RUS loans 3.10 to 5.95%	11,748,089	13,216,600
	17,746,290	19,452,342
	40,947,307	39,663,055
Less current portion	(2,150,000)	(2,050,000)
Long term portion	$38,797,307	$37,613,055

The long term debt payable to RUS, FFB and NRUCFC is due in quarterly and monthly installments of varying amounts through 2038. Meade County has loan funds available from RUS in the amount of $6,000,000.

During 2004, Meade County refinanced $14,685,111 of RUS 5% interest loans with the 3.10% - 5.95% fixed and variable interest rate notes from NRUCFC. These notes are due in ten (10) annual installments of $1,468,511 each through 2013.

As of October 31, 2005, the annual current portion of long term debt outstanding for the next five years are as follows: 2006 - $2,150,000; 2007 - $2,200,000; 2008 - $2,300,000; 2009 - $2,500,000; 2010 - $2,600,000.

5. **Short Term Borrowings**

At October 31, 2005, Meade County had a short-term line of credit of $5,000,000 available from NRUCFC. There were no borrowings against this line of credit during the audit period.

Continued

6. Employee Benefits

Pension Plan

All eligible employees of Meade County participate in the NRECA Retirement and Security Program, a defined benefit pension plan qualified under section 401 and tax-exempt under section 501(a) of the Internal Revenue Code. Eligible employees include employees hired prior to August 2002. Non-eligible employees are those hired after August, 2002. Meade County makes annual contributions to the Program equal to the amounts accrued for pension expense. Contributions to this plan were $338,414 for 2005 and $326,811 for 2004. In this multiemployer plan, which is available to all member cooperatives of NRECA, the accumulated benefits and plan assets are not determined or allocated separately by individual employer.

Retirement Savings Plan

Meade County participates in the NRECA Savings Plan, a multiemployer, defined contribution master pension plan. All employees are eligible to participate in the Savings plan upon completion of one month employment. Participating employees contribute 3% of their annual base salary and Meade County contributes 3%. Non-eligible employees, as defined above, participate in the savings plan, with Meade County contributing 4% of annual base pay, and the employee contributing 1%. Meade County makes annual contributions to the plan equal to amounts accrued for pension expense. Contributions are vested immediately. Pension costs for the savings plan were $122,685 and $99,237 for the years ended October 31, 2005 and 2004. A portion of this cost is allocated to construction of electric plant.

Postretirement Benefits

Meade County sponsors a defined benefit plan that provides medical insurance coverage to retirees. During 1996, Meade County changed its plan from contributing 50% of the projected cost of coverage to contributing 50% of the cost of a single policy. For purposes of the liability estimates, the substantive plan is assumed to be the same as the extant written plan. Postretirement benefits are not funded.

The funded status of the plan was as follows:

	2005	2004
Accumulated postretirement benefit obligation	$635,000	$575,000
Plan assets at fair value	-	-
Funded status	635,000	575,000
Unrecognized net gain (losses) from changes in assumptions	(209,491)	(229,873)
Accrued postretirement benefit cost	$425,509	$345,127

Continued

6. Employee Benefits, continued

Postretirement Benefits, continued

The following is a reconciliation of the postretirement benefit obligation:

	2005	2004
Postretirement Benefit Obligation:		
Balance, beginning of period	$345,127	$350,991
Recognition of components of net periodic postretirement benefit cost:		
Service cost	45,000	15,000
Interest cost	39,000	37,000
Amortization of gains or losses	20,672	(34,847)
	104,672	17,153
Benefits paid to participants	(24,290)	(23,017)
Net change	80,382	(5,864)
Balance, end of period	$425,509	$345,127

For measurement purposes, a 7% annual rate of increase, decreasing by 0.5% per year until 5.5% per year, in the per capita cost of covered health care benefits was assumed. The discount rate used in determining the accumulated postretirement benefit obligation was 7%.

7. Off Balance Sheet Risk

Meade County has off balance sheet risk in that they maintain cash deposits in financial institutions in excess of the amounts insured by the Federal Deposit Insurance Corporation (FDIC). At October 31, 2005, the financial institutions reported deposits in excess of the $100,000 FDIC insured limit on several of the accounts.

8. Risk Management

Meade County is exposed to various risks of loss related to torts; theft of, damage to and destruction of assets; errors and omissions; injuries to employees; and natural disasters.

Meade County carries commercial insurance for all risks of loss, including workers' compensation, general liability and property loss insurance. As is customary in the utility industry, Electric Plant, except substations, are not insured. Settled claims resulting from these risks have not exceeded commercial insurance coverage in 2005 or 2004.

Continued

9. Related Party Transactions

Several of the Directors of Meade County, its President & CEO and another employee are on the Boards of Directors of various associated organizations.

10. Advertising

Meade County expenses advertising costs as incurred. Advertising costs were $67,742 for 2005 and $77,926 for 2004.

11. Committments

Meade County has various other agreements outstanding with local contractors. Under these agreements, the contractors will perform certain construction and maintenance work at specified hourly rates or unit cost, or on an as needed basis. The duration of these contracts are one to three years.

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
February 14, 2008

Item 130) Regarding the "Financial Highlights", "Cost of Capital" on page 2 of the 2006 Annual Report to Members (Exhibit 41). Assuming the calculation methodology to be the same for all years, provide the calculations underlying the 7.82% "Cost of Capital" reported for 2006.

Response) The attached schedule shows the calculations underlying the 7.82% "Cost of Capital" reported on page 2 of Big Rivers' 2006 Annual Report.

Witness) C. William Blackburn

Big Rivers Electric Corporation
PSC Case 2007-00455

Cost of Capital is calculated as follows:

$$\frac{\text{Interest on Long Term Debt}}{\text{13 Month Average Principal Balance}} + \frac{\text{Depreciation \& Amortization + Property Taxes + Property Insurance}}{\text{13 Month Average Gross Plant in Service}}$$

$60,958,725/$1,046,111,878	=	**5.83%**
($31,989,986+$1,977,092+$397,541)/$1,720,007,	=	**<u>1.99%</u>**
		7.82%

<u>@ 12/31/06:</u>

Interest on Long-Term Debt	$60,958,725
Depreciation & Amortization	$31,989,986
Property Taxes	$1,977,092
Property Insurance	$397,541
13 Month Average Principal Balance	$1,046,111,878
13 Month Average Gross Plant in Service	$1,720,007,701

Item 131) Regarding the "Environmental Matters" and "significant financial impacts on the use of fossil fuels for power generation" referenced in the Big Rivers 2005 Annual Report to Members (Exhibit 41), please provide the current best estimates of costs to Big Rivers broken down by fiscal year and capital versus operating expense associated with compliance with:

a. The EPA's Clean Air Mercury Rule (CAMR);
b. The EPA's Clean Air Interstate Rule (CAIR);
c. Performance goals of the Clean Water Act Section 316(b);
d. Regulation of carbon dioxide as a pollutant under the Clean Air Act; and,
e. Any other state or federal rules likely to cause additional cost in order to meet pollution standards or otherwise comply with those rules.

Response) a. Over the next five years (2008-2012) the following costs for CAMR are anticipated:

1) Stack monitors for mercury emissions for Wilson, Coleman, Green, Reid, and HMP&L Station Two stations (approximately $3.2 million);

2) No operating expenses for CAMR are planned other than servicing the stack monitors;

3) Over the succeeding years Big Rivers presently has no other capital costs or operating expenses planned for CAMR. However, Big Rivers will be monitoring changes in environmental regulations and will modify its environmental compliance plan accordingly.

b. Over the next five years (2008-2012) the following costs for CAIR are anticipated:

1) Catalyst replacement for the selective catalyst reduction (SCR) systems at the Wilson and HMP&L Station Two stations (approximately $5.9 million);

2) Operating expenses for periodic regeneration of SCR catalyst for Wilson and HMP&L Station Two stations (approximately $9.2 million);

3) See the attached for annual variable operating expenses for CAIR;

4) Boiler tube corrosion protection installed on Coleman Station units resulting from NO_x reduction equipment installed in response to SIP Call (approximately $6.45 million);

5) Over the succeeding years Big Rivers anticipates SO_2 scrubber waste disposal variable costs to increase due to the Green/HMP&L Station Two on-site special waste landfill to reach its capacity and the waste will have to be hauled elsewhere (farther away). The financial model includes costs for the expected increase;

6) Over the succeeding years Big Rivers presently has no other capital costs planned for CAIR. However, Big Rivers will be monitoring changes in environmental regulations and will modify its environmental compliance plan accordingly.

c. Over the next five years (2008-2012), no costs for "316(b)" are anticipated:

1) No capital or operating expenses are anticipated by Big Rivers for "316(b)";

2) Over the succeeding years Big Rivers presently has no other capital costs for operating expenses planned for "316(b)". However, Big Rivers will be monitoring changes in environmental regulations and will modify its environmental compliance plan accordingly.

d. Over the next five years (2008-2012), no costs for carbon dioxide (CO_2) capture are anticipated:

1) No capital or operating expenses are anticipated by Big Rivers for CO_2;

2) Over the succeeding years Big Rivers presently has no other capital costs or operating expenses planned for CO_2 regulations. However, Big Rivers will be monitoring changes in environmental regulations and will modify its environmental compliance plan accordingly.

e. Over the next five years (2008-2012), no costs for "Ozone Attainment" or Regional Haze are anticipated:

1) No capital or operating expenses are anticipated by Big Rivers for "Ozone Attainment" or Regional Haze;

2) Over the succeeding years Big Rivers presently has no other capital costs or operating expenses planned for "Ozone Attainment" or Regional Haze regulations. However, Big Rivers will be monitoring changes in environmental regulations and will modify its environmental compliance plan accordingly.

Witness) David A. Spainhoward

Wilson Station non-fuel variable O&M
(in nominal dollars)

Year	2008-model	2008-model	2009-model	2010-model	2011-model	1st half 2012-model	2nd half 2012-model
	OTAG-Pet coke	Non-OTAG pet coke	OTAG-pet coke	OTAG-pet coke	OTAG-petcoke	OTAG-petcoke	OTAG-coal
Net Generation (MWhr)	1,390,062	855,240	2,967,000	3,331,000	3,109,000	1,648,500	1,648,500
Net Avg MW's							
verage Heat Rate (BTU/kWh)							
SO2 lb/mmBTU inlet							
Average Service Hours							
Percent SO2 removal							
Limestone							
TPY limestone	94,361	57,025	201,407	226,116	211,046	111,904	97,064
Cost per Ton of Reagent	$13.95	$13.95	$14.37	$14.80	$15.24	$15.70	$15.70
Cost of Reagent	$1,316,332	$795,499	$2,894,220	$3,346,521	$3,216,347	$1,756,895	$1,523,898
Sludge Disposal							
Tons	168,737	101,973	360,159	404,345	377,396	200,109	173,730
Cost per Ton	$1.32	$1.32	$1.36	$1.40	$1.45	$1.51	$1.51
Cost	$222,733	$134,604	$489,817	$566,083	$547,225	$302,164	$262,333
Fly Ash							
Tons of Disposal	46,207	27,924	98,626	110,726	103,346	54,798	65,430
Cost per Ton of Disposal	$1.32	$1.32	$1.36	$1.40	$1.45	$1.51	$1.51
Cost of Disposal	$60,993	$36,860	$134,131	$155,016	$149,852	$82,745	$98,800
Bottom Ash							
Tons of Disposal	11,552	6,981	24,656	27,681	25,837	13,699	16,358
Cost per Ton of Disposal	$1.32	$1.32	$1.36	$1.40	$1.45	$1.51	$1.51
Cost of Disposal	$15,248	$9,215	$33,533	$38,754	$37,463	$20,686	$24,700
Fixation Lime							
Tons of Disposal	3,009	0	6,423	7,211	6,730	3,569	3,109
Cost per Ton of Disposal	$59.33	$59.33	$61.10	$62.94	$64.83	$66.77	$66.77
Cost of Disposal	$178,537	$0	$392,445	$453,859	$436,332	$238,281	$207,594
Di-Basic Acid							
Pounds of Reagent	793,239	499,946	1,693,118	1,900,835	1,774,150	940,716	940,716
Cost per Pound of Reagent	$0.58	$0.58	$0.59	$0.61	$0.63	$0.65	$0.65
Cost of Di-Basic Acid	$460,078	$289,969	$1,005,712	$1,159,509	$1,117,715	$611,466	$611,466
SO2 and ash $/Mwhr	**$1.62**	**$1.48**	**$1.67**	**$1.72**	**$1.77**	**$1.83**	**$1.66**
Total /Year	$2,253,923	$1,266,147	$4,949,857	$5,719,742	$5,504,933	$3,012,237	$2,728,790
Sulfur							
MWhr per Gals	190.69	190.69	190.69	190.69	190.69	190.69	190.69
Gallons of Sulfur	7,290	4,485	15,559	17,468	16,304	8,645	8,645
Cost/gallon of Sulfur	$1.93	$1.93	$1.98	$2.04	$2.10	$2.17	$2.17
Cost of Sulfur	$14,069	$8,656	$30,807	$35,635	$34,238	$18,759	$18,759
Ammonia							
NH3 Lbs/ MWhr	1.8337	0.0000	1.8337	1.8337	1.8337	1.8337	1.8337
Tons of Ammonia	1,274	0	2,720	3,054	2,850	1,511	1,511
Cost / Ton of Ammonia	$506.00	$506.00	$521.18	$536.82	$552.92	$569.51	$569.51
Cost of Ammonia	$644,886	$0	$1,417,763	$1,639,463	$1,576,091	$860,773	$860,773
Lime Hydrate (for SO_3)							
TPD	25.00	0.00	25.00	25.00	25.00	25.00	25.00
Tons of Lime Hydrate	3,448	0	7,359	8,261	7,711	4,089	4,089
Cost/ton of Lime Hydrate	$122.06	$122.06	$125.72	$129.50	$133.38	$137.38	$137.38
Cost of Lime Hydrate	$420,811	$0	$925,127	$1,069,852	$1,028,468	$561,684	$561,684
NOx Sub-Total	$1,079,766	$8,656	$2,373,697	$2,744,950	$2,638,798	$1,441,216	$1,441,216
Total /Year	$3,333,689	$1,274,803	$7,323,555	$8,464,692	$8,143,731	$4,453,453	$4,170,007
Total $/Mwhr	**$2.40**	**$1.49**	**$2.47**	**$2.54**	**$2.62**	**$2.70**	**$2.53**

HMP&L Station non-fuel variable O&M
(in nominal dollars-net of City)

Year	2008-model	2008-model	2009-model	2010-model	2011-model	2012-model
	OTAG-coal	Non-OTAG coal	OTAG-coal	OTAG-coal	OTAG-coal	OTAG-coal
Net Generation (MWhr)	725,684	368,505	1,761,389	1,751,397	1,666,323	1,611,275
Net Avg MW's						
Net Average Heat Rate (BTU/kWh)						
SO2 lb/mmBTU inlet						
Average Service Hours						
Percent SO2 removal						
Lime						
TPY lime	18,644	9,292	45,253	44,997	42,811	41,397
Cost per Ton of Reagent	$66.72	$66.72	$70.29	$74.49	$87.86	$98.55
Cost of Reagent	$1,243,940	$619,980	$3,180,860	$3,351,802	$3,761,371	$4,079,641
Sludge Disposal						
Tons	74,707	37,234	181,331	180,302	171,544	165,877
Cost per Ton	$2.66	$2.66	$2.88	$3.32	$3.32	$3.32
Cost	$198,722	$99,043	$522,232	$598,603	$569,526	$550,711
Fly Ash						
Tons of Disposal	24,323	12,123	59,037	58,702	55,851	54,005
Cost per Ton of Disposal	$2.66	$2.66	$2.88	$3.32	$3.32	$3.32
Cost of Disposal	$64,699	$32,246	$170,026	$194,891	$185,424	$179,298
Bottom Ash						
Tons of Disposal	6,081	3,031	14,759	14,675	13,963	13,501
Cost per Ton of Disposal	$2.66	$2.66	$2.88	$3.32	$3.32	$3.32
Cost of Disposal	$16,175	$8,061	$42,507	$48,723	$46,356	$44,825
Fixation Lime						
Tons of Disposal	1,584	790	3,846	3,824	3,638	3,518
Cost per Ton of Disposal	$58.25	$58.25	$60.37	$65.30	$67.61	$69.47
Cost of Disposal	$92,296	$46,000	$232,176	$249,711	$245,986	$244,404
Di-Basic Acid						
Pounds of Reagent	0	0	0	0	0	0
Cost per Pound of Reagent	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cost of Di-Basic Acid	$0	$0	$0	$0	$0	$0
SO2 and ash $/Mwhr	**$2.23**	**$2.19**	**$2.35**	**$2.54**	**$2.89**	**$3.16**
Total /Year	$1,615,832	$805,330	$4,147,801	$4,443,730	$4,808,663	$5,098,878
BREC generation share from Station II	73.17%	73.17%	73.76%	73.65%	72.67%	70.95%
Sulfur						
MWhr per Gals						
Gallons of Sulfur	127	0	309	307	292	283
Cost/ton of Sulfur	$286.00	$286.00	$294.58	$303.42	$312.52	$321.11
Cost of Sulfur	$36,418	$0	$91,047	$93,247	$91,378	$90,788
Ammonia						
NH3 Lbs/ MWhr						
Tons of Ammonia	643	0	1,561	1,552	1,476	1,428
Cost / Ton of Ammonia	$515.41	$515.41	$530.87	$546.80	$563.20	$578.69
Cost of Ammonia	$331,367	$0	$828,424	$848,442	$831,440	$826,085
Lime Hydrate (for SO_3)						
TPD						
Tons of Lime Hydrate	0	0	0	0	0	0
Cost/ton of Lime Hydrate	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cost of Lime Hydrate	$0	$0	$0	$0	$0	$0
NOx Sub-Total	$367,786	$0	$919,471	$941,689	$922,819	$916,873
Total /Year	$1,983,617	$805,330	$5,067,272	$5,385,419	$5,731,482	$6,015,752
Total $/Mwhr	**$2.73**	**$2.19**	**$2.88**	**$3.07**	**$3.44**	**$3.73**

Green Station non-fuel variable O&M
(in nominal dollars)

Year	2008-model	2008-model	2009-model	2010-model	2011-model	2012-model
	OTAG-Pet coke	Non-OTAG pet coke	OTAG-pet coke	OTAG-coal	OTAG-coal	OTAG-coal
Generation (MWhr)	1,490,129	965,779	3,645,000	3,614,000	3,405,000	3,607,000
Net Avg MW's						
Net Average Heat Rate (BTU/kWh)						
SO2 lb/mmBTU inlet						
Average Service Hours						
Percent SO2 removal						
Lime						
TPY lime	49,972	32,388	122,236	119,052	112,167	118,821
Cost per Ton of Reagent	$66.72	$66.72	$70.29	$74.49	$87.86	$98.55
Cost of Reagent	$3,334,129	$2,160,908	$8,591,986	$8,868,152	$9,854,970	$11,709,808
Sludge Disposal						
Tons	198,559	128,690	485,695	473,041	445,684	472,124
Cost per Ton	$2.66	$2.66	$2.88	$3.32	$3.32	$3.32
Cost	$528,167	$342,314	$1,398,801	$1,570,495	$1,479,672	$1,567,453
Fly Ash						
Tons of Disposal	85,723	55,559	209,687	204,224	192,413	203,828
Cost per Ton of Disposal	$2.66	$2.66	$2.88	$3.32	$3.32	$3.32
Cost of Disposal	$228,023	$147,786	$603,898	$678,023	$638,813	$676,710
Bottom Ash						
Tons of Disposal	21,431	13,890	52,422	51,056	48,103	50,957
Cost per Ton of Disposal	$2.66	$2.66	$2.88	$3.32	$3.32	$3.32
Cost of Disposal	$57,006	$36,946	$150,975	$169,506	$159,703	$169,177
Fixation Lime						
Tons of Disposal	4,549	2,948	11,126	10,836	10,210	10,815
Cost per Ton of Disposal	$58.25	$58.25	$60.37	$65.30	$67.61	$67.61
Cost of Disposal	$264,951	$171,719	$671,683	$707,606	$690,269	$731,219
Di-Basic Acid						
Pounds of Reagent	0	0	0	0	0	0
Cost per Pound of Reagent	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cost of Di-Basic Acid	$0	$0	$0	$0	$0	$0
SO2 and ash $/Mwhr	**$2.96**	**$2.96**	**$3.13**	**$3.32**	**$3.77**	**$4.12**
Total /Year	$4,412,276	$2,859,674	$11,417,342	$11,993,782	$12,823,427	$14,854,367
Sulfur						
MWhr per Gals						
Gallons of Sulfur						
Cost/gallon of Sulfur						
Cost of Sulfur	$0	$0	$0	$0	$0	$0
Ammonia						
NH3 Lbs/ MWhr						
Tons of Ammonia						
Cost / Ton of Ammonia						
Cost of Ammonia	$0	$0	$0	$0	$0	$0
Lime Hydrate (for SO_3)						
TPD						
Tons of Lime Hydrate						
Cost/ton of Lime Hydrate						
Cost of Lime Hydrate	$0	$0	$0	$0	$0	$0
NOx Sub-Total	$0	$0	$0	$0	$0	$0
Total /Year	$4,412,276	$2,859,674	$11,417,342	$11,993,782	$12,823,427	$14,854,367
Total $/Mwhr	**$2.96**	**$2.96**	**$3.13**	**$3.32**	**$3.77**	**$4.12**

Coleman Station non-fuel variable O&M
(in nominal dollars)

Year	2008-model	2008-model	2009-model	2010-model	2011-model	2012-model
	OTAG-coal	Non-OTAG coal	OTAG-coal	OTAG-coal	OTAG-coal	OTAG-coal
Generation (MWhr)	1,356,812	887,713	3,405,000	3,396,000	3,372,000	3,190,000
Net Avg MW's						
Net Average Heat Rate (BTU/kWh)						
SO2 lb/mmBTU inlet						
Average Service Hours						
Percent SO2 removal						
Limestone						
TPY limestone	83,046	54,334	208,408	207,857	206,388	195,248
Cost per Ton of Reagent	$17.93	$17.93	$19.72	$21.69	$24.29	$27.20
Cost of Reagent	$1,489,007	$974,204	$4,109,802	$4,508,418	$5,013,165	$5,310,758
Gypsum sales						
Tons	109,663	71,749	275,206	274,479	272,539	257,829
Cost per Ton	($1.25)	($1.25)	($1.25)	($1.25)	($1.25)	($1.25)
Cost	($137,079)	($89,686)	($344,008)	($343,098)	($340,674)	($322,286)
Fly Ash						
Tons of Disposal	72,051	47,140	180,816	180,338	179,063	169,399
Cost per Ton of Disposal	$8.59	$8.59	$5.50	$5.69	$5.89	$6.10
Cost of Disposal	$618,917	$404,935	$994,487	$1,026,123	$1,054,684	$1,033,332
Bottom Ash						
Tons of Disposal	18,013	11,785	45,204	45,084	44,766	42,350
Cost per Ton of Disposal	$8.59	$8.59	$5.50	$5.69	$5.89	$6.10
Cost of Disposal	$154,729	$101,234	$248,622	$256,531	$263,671	$258,333
Off-Spec Gypsum disppsal						
Tons of Disposal	9,633	6,303	24,175	24,111	23,940	22,648
Cost per Ton of Disposal	$8.59	$8.59	$5.50	$5.69	$5.89	$6.10
Cost of Disposal	$82,748	$54,139	$132,961	$137,190	$141,009	$138,154
Di-Basic Acid						
Pounds of Reagent	0	0	0	0	0	0
Cost per Pound of Reagent	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cost of Di-Basic Acid	$0	$0	$0	$0	$0	$0
SO2 and ash $/Mwhr	**$1.63**	**$1.63**	**$1.51**	**$1.64**	**$1.82**	**$2.01**
Total /Year	$2,208,322	$1,444,825	$5,141,864	$5,585,163	$6,131,854	$6,418,290
Sulfur						
MWhr per Gals						
Gallons of Sulfur	0	0				
Cost/gallon of Sulfur	$0.00	$0.00				
Cost of Sulfur	$0	$0	$0	$0	$0	$0
Ammonia						
NH3 Lbs/ MWhr						
Tons of Ammonia	0	0				
Cost / Ton of Ammonia	$0.00	$0.00				
Cost of Ammonia	$0	$0	$0	$0	$0	$0
Lime Hydrate (for SO_3)						
TPD						
Tons of Lime Hydrate	0	0				
Cost/ton of Lime Hydrate	$0.00	$0.00				
Cost of Lime Hydrate	$0	$0	$0	$0	$0	$0
NOx Sub-Total	$0	$0	$0	$0	$0	$0
Total /Year	$2,208,322	$1,444,825	$5,141,864	$5,585,163	$6,131,854	$6,418,290
Total $/Mwhr	**$1.63**	**$1.63**	**$1.51**	**$1.64**	**$1.82**	**$2.01**