BEFORE THE KANSAS CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Mid-Kansas Electric Company, LLC for Approval of a Debt Service Coverage Ratemaking Pilot Plan for the Geographic Territory Served by its Member-Owner Southern Pioneer Electric Company.	)))))	Docket No. 13-MKEE-452-MIS

PREFILED DIRECT TESTIMONY OF

RICHARD J. MACKE
VICE PRESIDENT, ECONOMICS, RATES, AND BUSINESS PLANNING
POWER SYSTEM ENGINEERING, INC.

ON BEHALF OF

MID-KANSAS ELECTRIC COMPANY, LLC

January 8, 2013

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PART I - QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Richard J. Macke. My business address is 10710 Town Square Drive NE, Suite 201, Minneapolis, Minnesota 55449.

Q. What is your profession?

A. I am a Vice President and lead the Economics, Rates, and Business Planning Department at Power System Engineering, Inc. ("PSE"), which is headquartered at 1532 W. Broadway, Madison, Wisconsin 53713.

Q. Please describe the business activities of PSE.

A. Power System Engineering, Inc. is a consulting firm serving electric utilities across the country, but primarily in the Midwest. Our headquarters is in Madison, Wisconsin with regional offices in Cedar Rapids, Iowa; Indianapolis, Indiana; Minneapolis, Minnesota; Marietta, Ohio; and Sioux Falls, South Dakota. PSE is involved in: power supply, transmission and distribution system planning; distribution, substation and transmission design; construction contracting and supervision; retail and wholesale rate and cost of service ("COS") studies; economic feasibility studies; merger and acquisition feasibility analysis; load forecasting; financial and operating consultation; telecommunication and network design, mapping/GIS; and system automation including Supervisory Control and Data Acquisition ("SCADA"), Demand Side Management ("DSM"), metering, and outage management systems.

Q. Please describe your responsibilities with PSE.

A. I lead and direct staff in Indiana, Minnesota, and Wisconsin who provide economic, financial, and rate-related consulting services to electric cooperative and municipal utilities.

These services include:

- Cost of Service Studies.
- Capital Credit Allocations.
- Demand Response.
- Distributed Generation Rates.
- Energy Efficiency.
- Financial Forecasting.
- Individual Customer Profitability.
- Large Power Contract Rates/Proposals.
- Line Extension Policies/Charges.
- Load Management Analysis.
- Load Forecasting.
- Market and Load Research.
- Merger Analysis.
- Other Economic Studies.
- Pole Attachment Charges.
- Power Cost Adjustments.
- Rate Consolidation.
- Retail Rate Design and Analysis.
- Special Fees and Charges.
- Statistical Performance Measurement (Benchmarking).
- Value of Service.

Q. What is your educational background?

A. I graduated from Bethel University in St. Paul, Minnesota in 1996 with a Bachelor of Arts degree in Business, which included an emphasis in Finance and Marketing. In 2007, I received my Masters of Business Administration degree, with an emphasis in Finance and Strategic Management, from the University of Minnesota in Minneapolis, Minnesota.

Q. What is your professional background?

A. From 1996 to 1998, I was employed by PSE in its Minneapolis, Minnesota office as a Financial Analyst in the Utility Planning and Rates Department. My work responsibilities primarily were focused on retail rate studies, including revenue requirements and bundled/unbundled COS studies. I also provided analyses used to support testimony, mergers and acquisitions analysis, and financial forecasting.

From 1998 to 1999, I was employed as a Senior Analyst by Energy & Resource Consulting Group, LLC in Denver, Colorado, a financial, engineering, and management consulting firm. I performed consulting services related to electric, gas, and water rate studies. As part of the Legend Consulting Advisor Team contracted to the City Council of the City of New Orleans, Louisiana, I assisted in various electric and gas utility matters. I also provided general financial, management, and public policy support to clients.

I rejoined PSE in 1999; and from 1999 to 2002, I held the position of Rate and Financial Analyst in the Rates and Financial Planning Department. From 2002 to March 2008, I held the position of Senior Rate and Financial Analyst in the Utility Planning and Rate Division. My responsibilities have included performing complex financial analyses, such as rate studies consisting of determination of revenue requirements, bundled and unbundled COS analysis, and rate design. Other responsibilities included performing analysis of special rates and programs, key account analyses, financial forecasting, merger and acquisition analysis, activity-based costing, policy development and evaluation, and other financial analyses for various PSE clients. Additional responsibilities included strategic planning, litigation support, regulatory compliance, capital expenditure and operational assessments, and advisement. From April 2008 to June 2010, I held the position of Leader, Rates and Financial Planning. In July 2010, my title changed to Vice President, Rates and Financial Planning. Since June 2011, I have held the position of Vice President, Economics, Rates, and Business Planning. In this capacity, I continue to provide, amongst other things: 1) rate, financial, and economic consulting services to clients, 2) management and leadership to the Economics, Rates, and Business Planning Department and 3) management and leadership at the corporate level to PSE through participation on the Executive Committee and Board of Directors.

Q. Have you previously presented testimony before the Kansas Corporation Commission ("KCC" or "Commission")?

A. Yes. I submitted testimony on behalf of: Pioneer Electric Cooperative, Inc. in Docket No.

09-PNRE-563-RTS; Wheatland Electric Cooperative, Inc. in Docket No. 09-WHLE-681-RTS; and Mid-Kansas Electric Company, LLC in Docket Nos. 09-MKEE-969-RTS ("969 Docket"), 11-MKEE-439-RTS ("439 Docket"), 12-MKEE-491-RTS ("491 Docket"), and 12-MKEE-380-RTS ("380 Docket").

Q. Do you have any other relevant experience?

A. Yes. I have directed well over 100 rate and COS studies and numerous other rate and financial related projects. Many times these projects were conducted for self-regulated electric utilities. I have also performed such analysis which was filed in regulated rate cases on behalf of cooperatives in Iowa, Kansas, Michigan, Minnesota, New Hampshire, and Texas.

I have also conducted seminars and made presentations to utilities, consumers, and industry groups on a variety of topics including: COS, rate change communications, line extension policies, mergers and acquisitions, DSM, conservation and energy efficiency, industry trends, and rate design strategic planning.

PART II - INTRODUCTION

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support the request of Mid-Kansas Electric Company, LLC's ("Mid-Kansas") for a Debt Service Coverage ("DSC") Formula Based Rate ("FBR") pilot ("DSC-FBR Plan") which would be used in the future to determine the Southern Pioneer Electric Company ("Southern Pioneer" or "Company") division rates.

The DSC-FBR Plan would use a predetermined formula to calculate the DSC ratio of the Southern Pioneer division and compare it against predetermined DSC parameters. If the result is a DSC that is beneath the "floor," then a rate increase would be implemented. If the result is a DSC above the "ceiling," then a rate decrease would be implemented. If the result is between the floor and ceiling in the area referred to as the quiet zone (a.k.a. deadband), there would be no change in rates.

Q. What is the DSC ratio?

A. The DSC ratio is a financial ratio used to assess the ability of a firm to pay its debt obligations. A high ratio means that the firm is able to pay its debt obligations relatively easily, while a low ratio suggests that the firm's ability to pay its debt obligations is potentially at risk. Below is a very simple example of the calculation.

Income before Interest Expense		$100
Debt Service Payments		
Interest Expense	$25	
Principal Payments	$25	
Total Debt Service		$ 50
Debt Service Coverage Ratio		2.0

In this example, the firm has income sufficient to pay its debt service twice.

Q. Would the requested DSC-FBR Plan affect both the Southern Pioneer division retail rates and the third-party Local Access Charge ("LAC") rate?

A. No. The DSC-FBR Plan would only be used to determine the future retail rates for the Southern Pioneer division. Furthermore, it will only concern the distribution revenue requirement which means that no changes in cost for the Southern Pioneer 34.5 kV system will be passed on to either retail or third-party users of the 34.5 kV system through this FBR. Changes in the 34.5 kV revenue requirement would remain separate and subject to the current form of regulation so that the changes in costs related to this service can more directly be accounted for and collected from those using the 34.5 kV system.

Q. Did the prior Mid-Kansas rate application for the Southern Pioneer division in the 380 Docket include a request for a DSC-FBR?

A. One component of that application was a request for what was termed "DSC Ratemaking." Because that docket resulted in a unanimous Settlement Agreement without the DSC Ratemaking component, the Commission has not had an opportunity to fully consider the requested alternative ratemaking mechanism. There are similarities between the requested DSC-FBR Plan and the DSC Ratemaking approach requested in the 380 Docket; however, there have been revisions in terms of the template, calculation components, adjustments, and DSC parameters and protocols. These revisions were made in consideration of economic development and plant investment expectations in the area, which have been evolving recently, and to address discussions with parties to the 380 Docket.

Q. Is Mid-Kansas in this application requesting a rate change for the Southern Pioneer division?

A. No. The request is for approval of a DSC driven FBR on a five-year pilot basis that would be used in the future to determine the rates for the Southern Pioneer division. Any future rate change would remain subject to the review and approval of the Commission. The first filing would occur in 2014.

Q. What is Mid-Kansas requesting that the Commission approve in this application?

A. Mid-Kansas requests that the Commission approve the future use of the DSC-FBR Plan for the Southern Pioneer division in accordance with the template and protocols that have been developed and are included as exhibits to my direct testimony. The DSC-FBR template is provided both as a blank template and populated with actual 2011 year-end data with supporting information to demonstrate the workings. Also, Exhibit RJM-6 projects the results of the plan for 2013-2017 based upon the most recent budget and financial forecast information available.

Q. Will the requested DSC-FBR Plan affect the determination of the divisional rates for the other five Mid-Kansas distribution member-system owners?

A. No. The requested DSC-FBR Plan is proposed only for the Southern Pioneer division.

Q. Please briefly describe the Mid-Kansas Southern Pioneer division.

A. The Aquila, Inc., d/b/a Aquila Networks - WPK ("Aquila"), electric system in Western Kansas was acquired by Mid-Kansas and is now served in part under contracts with its six distribution member-system owners. The Southern Pioneer division refers to the area acquired by Mid-Kansas that is served at the distribution level by Southern Pioneer. Generally, this area includes rural communities in southwestern Kansas. Company witness Mr. Steve Epperson provides a more detailed discussion of the structure and operations of Southern Pioneer.

Q. What are Mid-Kansas' objectives in requesting this DSC-FBR Plan for the Southern Pioneer division?

A. The objective is to implement a cost-effective regulatory approach for the Southern Pioneer division that provides: (1) assurance of reasonable rates, (2) gradual improvement and stabilizing of Southern Pioneer's financial condition, and (3) financial flexibility needed to fund plant investments related to economic development in the area. The requested DSC-FBR Plan has been developed in response to the truly unique financial, organizational, and operational characteristics of the Southern Pioneer division. As developed, the DSC-FBR Plan provides a method for periodic adjustments to rates, as might be necessary, to achieve a predetermined and agreed-upon DSC ratio.

Q. Do you believe that the requested DSC-FBR Plan will achieve these objectives?

A. Yes, I do. Using the most current budget and forecast available, I have projected the results of the requested DSC-FBR Plan for the proposed five-year pilot period. As expected, the plan produces moderate rate adjustments while enabling the utility to improve its financial condition, meet the loan covenants of its lender, and provide electric facilities needed to support the economic development expected within the rural communities it serves.

Projected DSC-FBR Plan Results

	DSC		Equity Ratio		
Test Year	Projected CY DSC	Required Minimum	Projected EOY Equity	Required Minimum	Projected Rate Change
2013	1.32	1.35	1%	2%	5.0%
2014	1.44	1.35	3%	2%	2.8%
2015	1.57	1.35	7%	5%	2.1%
2016	1.56	1.35	10%	5%	0.0%
2017	1.50	1.35	14%	8%	2.7%

These and other projected results are more fully presented and discussed in Part V of my direct testimony.

Q. Are you sponsoring any exhibits?

A. Yes. I have included the following exhibits detailing the analysis completed:

Exhibit RJM-1 - Curriculum Vitae - Richard J. Macke
Exhibit RJM-2 - Formula-Based Rate Protocols
Exhibit RJM-3 - Formula-Based Rate Template - Blank
Exhibit RJM-4 - Formula-Based Rate Template - Populated for 2011
Exhibit RJM-5 - Southern Pioneer Annual 2011 Form 7
Exhibit RJM-6 - Projected DSC-FBR Calculations
Exhibit RJM-7 - Kansas Expedited Access Charge Filing
Exhibit RJM-8 - Michigan Public Service Commission TIER Ratemaking Orders
Exhibit RJM-9 - CFC Key Ratio Trend Analysis for 2011
Exhibit RJM-10 - Kentucky Statute, Regulation, and Pass-Through Example

Q. Have the exhibits been prepared by you or under your supervision?

A. Yes.

PART III - SUMMARY OF DIRECT TESTIMONY

Q. Please summarize the DSC-FBR Plan being requested.

A. The requested DSC-FBR Plan is an alternative approach to determining rates aimed at streamlining and improving the efficiency of the regulatory process. It has many similarities to formula-based rates that are used around the country including the formula-based rates for transmission in Kansas. The requested DSC-FBR Plan would be used for a five-year period to determine the adequacy of rates to recover the utility's revenue requirement. In particular, and on an annual basis, the DSC-FBR Plan will determine the DSC ratio for the Southern Pioneer division. If the DSC is determined to be below the "floor," or above the "ceiling," the annual filing will include a proposed rate adjustment to bring the DSC back to its targeted level. The range of results between the floor and the ceiling is referred to as the quiet zone, wherein no rate adjustments are proposed or allowed.

For example, assume a DSC floor of 1.60, ceiling of 2.00, and target of 1.80. Using year-end financials,[1] the Southern Pioneer division will make its DSC-FBR filing. If the resulting DSC was 1.50, Southern Pioneer, as part of the filing, would request an adjustment to rates that would increase the DSC up to 1.80.[2] If the result was 2.50, Southern Pioneer must include a request to adjust rates to lower the DSC to 1.80. Finally, if the result was anything in between 1.60 and 2.00 (inclusive), no rate adjustment would be proposed. In such a case, the filing would merely request a Commission finding that there is no rate adjustment for the year for the Southern Pioneer division.

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[1] Year-end financials are generally available sometime in March. We anticipate the DSC-FBR Plan filing to be made by May 1 each year.

[2] The requested FBR protocols allow for a lower increase to be requested to mitigate the potential customer impact; however, in the case of a decrease, there is no such flexibility.

Q. Please summarize the procedural schedule being requested as part of the DSC-FBR Plan request.

A. Please reference the schedule below.

May 1	Initial filing date.
Before May 31	Commission issues 90-day suspension under K.S.A. 66-117.
June 15	Within 45 days of initial filing, Staff files its report on compliance. Intervener(s), if any, file notice of any alleged deficiencies in the application.
July 1	If there are no deficiencies alleged by Staff or interveners that indicate non-compliance with the DSC-FBR Plan, the Commission issues its order approving the Application. If deficiencies are alleged, Applicant files its response.
August 1	If deficiencies were alleged, Commission issues order either approving application or further suspending under K.S.A. 66-117.

As proposed, the lag between the filing date and Commission order would be approximately 60 days unless a filing is made by Staff or other party claiming that the filing is deficient. If Staff or any other party believes the filing is deficient in some manner, it will advise the Commission within 45 days of the filing; and the Company will file its response no later than 60 days after the initial filing date. The Commission would then have until the end of the 90-day period to issue an order approving the filing or suspending the docket for an additional period of time under K.S.A. 66-117. In this situation, the Commission would set a pre-hearing conference to establish a procedural schedule for the presentation of the testimony and exhibits supporting the respective parties' position.

PART IV - DSC-FBR REGULATION

Q. Please summarize why a DSC-FBR Plan is being requested as the means for regulating the Southern Pioneer division rates in the future?

A. As has previously been discussed in my testimony and that of Southern Pioneer CEO, Mr. Steve Epperson, the current traditional regulatory approach for the Southern Pioneer division rates is deficient in that it is a high cost, timely, and resource intensive model that is inadequate to address the financial condition and plant investment needs of the Southern Pioneer division, especially given its small size.

Furthermore, Southern Pioneer is unique among electric utilities in Kansas and perhaps in the United States. While the Southern Pioneer division rates are regulated like a cooperative, Southern Pioneer is not a cooperative. It is therefore unlikely that the rates for the Southern Pioneer division could be deregulated (at least not under current statutes and regulations). DSC-FBR ratemaking is an alternative regulatory approach that can provide many benefits to the regulatory process while balancing the interests of the various stakeholders.

Q. What do you mean when you say that Southern Pioneer is unique?

A. Southern Pioneer is unique with regard to the combination of its capital structure, organizational structure, regulatory oversight, and operations. In acquiring the assets of the former Aquila electric system, Pioneer Electric Cooperative, Inc. ("Pioneer Electric Cooperative") established Southern Pioneer as a separate legal entity, whereas the rest of the Mid-Kansas member-systems acquired their share of the former Aquila electric system within their respective pre-existing cooperative organizations. As a result, Southern Pioneer is not an electric cooperative; yet it is 100 percent owned by an electric cooperative and has agreed to operate as a not-for-profit. Since it is not an electric cooperative, the Southern

Pioneer division rates will remain subject to Commission regulation.[3] I am not aware of any other electric utility operating in Kansas or elsewhere in the United States that is similar.

Q. In terms of rate regulation, is there anything unique about how the Southern Pioneer division rates are currently regulated?

A. Yes. Although it is regulated under a traditional regulatory approach, there is currently a form of alternative regulation in place for the Southern Pioneer division rates from the Aquila acquisition docket, Docket No. 06-MKEE-524-ACQ ("524 Docket"). The Commission-approved Stipulation and Agreement in the 524 Docket ("524 S&A") requires the Southern Pioneer division to file a revenue refund plan with the Commission to reduce its Times Interest Earned Ratio ("TIER") to 2.00 if its annual TIER exceeds 2.20. While the other Mid-Kansas member-systems were subject to this provision for only an initial five-year period (which has since terminated), the requirement stays in effect indefinitely for the Southern Pioneer division. This is a clear difference in how the Southern Pioneer division rates are being regulated versus the other five Mid-Kansas divisions or other regulated electric utilities in Kansas. Please reference the following from the Commission-approved 524 S&A, paragraphs 29-30:

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[3] Per Kansas Statute 66-104d, electric cooperatives, with the majority vote of the membership, may opt out of Commission rate regulation.

> 29. Southern Pioneer shall file a report by March 31st of each year supporting the TIER and DSC calculations for the preceding year's operations.
>
> 30. Southern Pioneer agrees to the following additional provisions:
>
> a. At such time as Southern Pioneer's TIER exceeds 2.2, as calculated December 31 and each calendar year-end thereafter, and Southern Pioneer meets other minimum loan covenants (*i.e.*, DSC, Equity to Asset, etc.) required by its lender(s), Southern Pioneer will initiate a Revenue Refund Plan to reduce its TIER to 2.0 and submit such Revenue Refund Plan to Commission Staff for consideration and approval.

Q. Is this provision in the 524 S&A similar to the DSC-FBR Plan Mid-Kansas is requesting in this application?

A. Yes, it is very similar. The Southern Pioneer division rates are currently being evaluated in terms of their TIER performance. Specifically, a TIER ceiling of 2.20 and a TIER target of 2.00 has been established. What is missing, and what is being requested in this application, is to add a floor and utilize a DSC ratio instead of TIER. That would complete the mechanism and would provide an appropriate and efficient model going forward for the continued regulation of the Southern Pioneer division rates.

Q. What is the difference between a TIER and DSC?

A. Both are broadly accepted coverage ratios aimed at assessing the ability of the utility to service its debt. Debt issuers often include minimum coverage ratios that must be maintained by the borrower for precisely this reason. A general definition of each is below:

<u>TIER</u> = The TIER ratio is the ratio of annual earnings before interest of a business to its annual interest expense. As such it is a measure of the long-term viability or

solvency of a business in terms of being able to pay off its debts.

DSC = The DSC ratio is the ratio of cash flows available to annual interest and principal payments on debt. Like TIER, it is a measure of the ability of the utility to pay its debt obligations.

There are a number of variations as to the numerator of these ratios; namely, the income used. For example, when using only operating income, the ratio is typically deemed an Operating TIER/DSC. When using net income, the ratio may be referred to as simply TIER/DSC or sometimes Net TIER/DSC. Somewhat of a hybrid would be the Modified TIER/DSC, in which case certain non-operating income/expense is included or excluded. Southern Pioneer's lender, CoBank, uses the term DSC, although the computation is more indicative of a Modified DSC.

Q. Is the concept of allowing an expedited rate adjustment using a preapproved formula a new concept in Kansas?

A. No I don't believe it is new. I am aware that, in Docket No. 127, 140-U, the Commission adopted a simplified filing procedure and expedited review procedure for access charge adjustments for rural telephone companies that was based on a similar concept. I have attached a copy of the process approved by the Commission in an order dated November 19, 1990 (Exhibit RJM-7). I am advised by counsel that this process was later endorsed by the Kansas Legislature in 1996 when it adopted the process as part of the 1996 Kansas Telecommunications Act in K.S.A. 66-2008(d).

Q. Are you aware of any other examples of annual formula-based rate-setting processes affecting Kansas electric rates?

A. Certainly there are formula rate processes in place at the Federal Energy Regulatory

Commission ("FERC") for setting wholesale rates charged in Kansas for transmission and generation. For example, Mid-Kansas, Kansas City Power & Light ("KCP&L"), and Westar Energy, Inc. ("Westar") each have a transmission FBR. On the generation side, Westar's Cost-Based Formula Rate Agreement for Full Requirements Electric Service was approved by FERC in Docket No. ER-07-1344 based upon a power contract entered into between Westar and Kansas Electric Power Cooperative, Inc. ("KEPCo"). Cost support for the annual adjustments to Westar's rates is based upon Westar's FERC Form 1 and is computed using an established formula. This concept was not objected to by the KCC -- which was a party to the FERC docket -- and was ultimately approved by FERC with modifications recommended by non-KCC parties to the docket. The concept underlying the request for the continued regulation of the Southern Pioneer division rates in this docket is similar.

Q. Are there any other relevant examples concerning the setting of retail rates in Kansas?

A. Yes. Automatic adjustment mechanisms that automatically flow through changes in the cost of purchased power and/or fuel expense are relevant examples of retail rate mechanisms currently in place in Kansas (and throughout most of the United States). Furthermore, the Mid-Kansas transmission FBR recently approved by this Commission is automatically passed through to retail customers in the Mid-Kansas division retail rates by way of the power cost adjustment sometimes referred to as ECA2.

Q. Are you aware of other states or electric utilities whose retail rates are subject to some form of FBR regulation?

A. Yes. Retail formula rates are available and used by Investor-Owned Utilities ("IOU") in

Alabama, Mississippi, Louisiana, and Illinois and by electric cooperatives in Michigan.

Q. Please provide and describe an example FBR being used in the regulation of retail rates for IOUs.

A. As part of the "Energy Infrastructure and Modernization Act" passed in 2011, a new distribution rate regulatory model, termed Formula Rate Plan ("FRP"), was implemented in Illinois.[4] In order to participate in the FRP, utilities must choose to invest specific amounts in their transmission, distribution, and smart grid systems with the recovery of the investments addressed in annual FRP proceedings and subject to approval by the Illinois Commerce Commission ("ICC").

Among other things, the FRP formula defines the utility's capital structure, the allowed return on equity ("ROE") formula, pension expense recovery, incentive compensation expenses, and a +/- 50 basis point quiet zone (a.k.a. deadband) around the allowed ROE. The FRP is to expire at the end of 2017 unless continued by future legislation.

A large IOU, Commonwealth Edison ("ComEd"), filed its first FRP in November of 2011. For future filings, ComEd will make its annual filing in May of each year with new rates to be effective the following January. In fact, ComEd filed its second FRP in April of 2012. Similar to what is requested in this case, it is noteworthy that the FRP includes estimated net plant additions and depreciation expense for 2012.

A second large IOU, Ameren Illinois, made its first FRP filing with the ICC in January 2012. The ICC issued its order in September for October implementation. As with ComEd, and as established by the 2011 law, new rates will take effect every January.

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[4] Public Act 097-0616. http://www.ilga.gov/legislation/publicacts/97/PDF/097-0616.pdf

ComEd has approximately 3.8 million customers in the Chicago area. Ameren Illinois serves approximately 1.2 million customers. If this type of regulatory framework can be implemented for such large IOUs, it seems reasonable that it could work for a much smaller utility that is 100 percent owned by a cooperative.

Q. Please explain the FBR mechanism that has been used by the Michigan Public Service Commission ("MPSC") to regulate the rates of Michigan electric cooperatives.

A. TIER ratemaking has been used in Michigan since 1981. TIER ratemaking started with one electric cooperative on an experimental two-year basis. Shortly after it issued its order in Case Number U-6652, the MPSC approved TIER Indexing for a second cooperative on an experimental basis. After the two-year trial period in 1983, the MPSC revisited TIER Indexing (still under Case Number U-6652); and, with some refinements, renamed the process TIER Ratemaking and made it available to all of Michigan's cooperatives as part of the ratemaking process. In November 1995, the MPSC again initiated a proceeding in Case Number U-11016 for the purpose of considering changes to the TIER ratemaking process including whether or not it should be continued. This review spawned extensive testimony and exhibits from both the cooperatives and the MPSC Staff which included a 165-page report prepared by Staff documenting its review of cooperative regulation in Michigan. Interestingly, in contrast to the conclusion in the Michigan Staff's report suggesting that TIER Ratemaking should be discontinued, the MPSC ordered that TIER Ratemaking should be continued. In fact, TIER ratemaking continues to be used by rate regulated electric cooperatives in Michigan, although the electric cooperatives there are now able to opt out of rate regulation similar to Kansas.

Q. What reasons did the MPSC give for first adopting TIER ratemaking in Case No. U-6652?

A. The reasons MPSC adopted TIER ratemaking were:

1. Lower rate case overhead (legal, consultants, staff hours, and travel to Lansing, Michigan).
2. Lower overall TIER needed due to reduced regulatory lag.
3. Lower financing costs as a result of revenue stability.
4. Reduced demand on MPSC resources.
5. Process was simple, mechanically non-controversial, and easy to understand.
6. The characteristics of cooperatives adapt themselves to this type of mechanism. Staff will monitor expenses and the reliability of the mechanism; and management will be expected to reduce, wherever possible, expenditures.

Q. In the 380 Docket, Staff testified that one of the main reasons the MPSC had initially approved TIER indexing was because the cooperative for which the process was approved was in dire need of financial assistance. Is this an accurate assessment of Michigan's approach to the issue?

A. Without question, the applicant Ontonagon County Rural Electrification Association ("Ontonagon") was in dire need of financial assistance. It had been experiencing negative operating margins even after a recent rate increase was approved by the MPSC and was faced with the need to file frequent traditional rate applications to solidify its financial performance. This is described and confirmed by the MPSC in it order in Case No. U-6652, a copy of which is attached as Exhibit RJM-8. It is important to recognize though, that while the Commission could have applied other remedies to the situation, it determined that TIER indexing was an appropriate alternative to the traditional ratemaking approach for the reasons cited above and enumerated in the order.[5]

The KCC should recognize that the Southern Pioneer division is also in need of financial assistance. Not unlike Ontonagon, Southern Pioneer has been experiencing negative operating margins even after two rate applications. The purpose for this application is precisely for reasons of improving its financial performance and developing a mechanism to achieve this purpose in the most effective and least burdensome manner.

Q. Please explain further the financial condition of Southern Pioneer.

A. With the exception of 2010, Southern Pioneer has failed to generate positive operating margins. Clearly, a utility's rates must at least cover operating expenses. Table 1 below shows the annual operating margins since the year of the acquisition.

Table 1
Summary
Annual Operating Margin

Year	Annual Operating Margin
2007	($2,463,120)
2008	($1,144,151)
2009	($1,604,626)
2010	$ 774,372
2011	($ 394,575)
2012 YTD	($ 864,598)

During this period of time, there have been two rate applications for the Southern Pioneer division. These traditional rate applications have not put the Southern Pioneer division on the path to financial stability, and another approach should be considered.

5 Reference Exhibit RJM-8.

Q. One of the claimed benefits of utilizing a non-traditional ratemaking approach, as stated above, is cost savings versus the traditional regulatory model. How much did the most recent rate application cost the Southern Pioneer division?

A. Southern Pioneer incurred costs of over $440,000 for consulting and legal fees, and KCC and Citizens' Utility Ratepayer Board ("CURB") assessed cost. It should be noted that these costs, which are ultimately borne by the customers, do not include costs for internal Mid-Kansas or Southern Pioneer utility staff time and related expenses. The cost and resource strain of making a rate application is significant for a utility the size of the Southern Pioneer division which has approximately 17,200 customers and 46 full-time employees.

Q. How would implementation of the requested DSC- FBR Plan reduce these regulatory costs and burdens?

A. Traditional rate applications have proven to be very costly and burdensome due to the complexity and process of a rate application which includes:

1. Multiple rounds of expert testimony by the applicant, interveners, and Staff.
2. Substantial analytical modeling by the applicant and its experts, along with interveners and Staff.
3. Multiple rounds of discovery involving the applicant, interveners, and Staff.
4. Substantial auditing requirements due to the adjustments typically requested.

Unfortunately, due to its financial condition and expected future facility investment requirements in its service territory, the Southern Pioneer division is likely to need to continue filing frequent rate applications; with the next application being the abbreviated case scheduled to be filed in the second quarter of 2013, and the next general rate case thereafter expected in late 2013 or early 2014.

In contrast, since the DSC-FBR template and protocols would be predetermined, the requested process should require very little consulting, legal, or even Staff and CURB costs. In addition, it should require less internal resources for the same reasons.

As is the case in Michigan, consulting and legal fees would be expected to be minimal compared to the $440,000 that the latest rate application cost Southern Pioneer and ultimately the ratepayers. I would anticipate that under the requested DSC-FBR Plan, Southern Pioneer staff would complete the formula calculation and would engage consulting and legal assistance only for review and or document/filing preparation purposes. There should not be a need for any expert testimony, let alone multiple rounds, as is currently the case. The DSC-FBR mechanism uses audited financials and includes very few adjustments so that the audit by Staff and CURB would be much less burdensome and costly. Related, the need for discovery would be reduced, something that was very costly in the last rate application. While it is difficult to put precise dollars to this, suffice it to say that one would expect substantial rate case expense savings over the course of the proposed five-year pilot term versus the traditional rate case approach.

Q. Would the requested DSC-FBR Plan lower the overall coverage ratios used to determine the revenue requirement?

A. Yes, because of reduced regulatory lag and assurance of an annual assessment, the DSC ratio can be lowered. The requested DSC target would actually start at 1.60 in 2013 and then move to 1.80 for the remaining years of the pilot. This is lower than the 2.20 or 2.00 that has been previously requested in traditional rate applications.

Q. How would implementation of the requested DSC-FBR Plan reduce regulatory lag?

A. A traditional rate application is subject to a 240-day suspension. In addition, the application is normally prepared using the audited financials from the most recent year, which are generally not available until March. Adding to that the time it takes to prepare the analysis, testimony, and application, the regulatory lag between the end of the historical test year and the date of the expected order can easily be 420 to 480 days (14 to 16 months). For example, Mid-Kansas filed the 380 Docket rate application using 2010 year-end results. The Commission order was issued June 25, 2012. From the end of the test year to the date of the order was 535 days. In contrast, and as discussed in greater detail later in my testimony, the requested DSC-FBR would be filed no later than 120 days after the end of the year with a 90-day suspension. In this case, the regulatory lag would be 210 days, or about one-half the time for a standard rate case. In addition, since the DSC-FBR Plan includes the impact of budget-year capital expenditure requirements on debt service, there is effectively even less lag.

Q. Why is regulatory lag considered such a problem for the Southern Pioneer division?

A. Regulatory lag simply refers to the time between putting infrastructure into service and when the utility may begin recovery of the costs associated with the infrastructure and its operation. While regulatory lag may be seen by some as providing a cost control incentive, Southern Pioneer's situation dictates otherwise. The Southern Pioneer division is facing increasing costs, due in large part to its need to make large plant improvements and additions to its system. Companies with a balanced capital structure can finance new capital investment with debt and equity and then seek rate adjustments to cover the increased costs. As Southern Pioneer faces increased plant investment to meet the new demands as a result of economic development related to the oil and gas industry's expansion, it must access capital from creditors or investors. This is more difficult and costly for a company like Southern Pioneer, which is already almost 100 percent debt financed. Regulatory lag impairs Southern Pioneer's ability to achieve adequate operating margins and stable coverage ratios and build equity, which makes it more difficult and costly to obtain capital needed to respond to customer demands. It also prolongs the need for Pioneer Electric Cooperative to guarantee Southern Pioneer's debt. The DSC-FBR Plan proposed in this docket is structured to allow Southern Pioneer to achieve positive operating margins and build equity to assist the Company in financing new capital investment.

Q. Are there other benefits to a DSC-FBR regulation approach for the Southern Pioneer division that the Commission should consider?

A. Yes. The DSC-FBR Plan also provides the following benefits:

1. Provides the Southern Pioneer division with more timely financial support to meet the substantial economic development related plant investment requirements in its service territory.
2. Helps avoid rate shock by resulting in smaller, more frequent rate changes.
3. Provides a level of surety to the Southern Pioneer division's banker by offering a plan to address Southern Pioneer's margin and equity performance and meet its loan covenants.

Q. Please elaborate on why the Commission should consider the impact of economic development and related plant investment requirements as part of this request.

A. Both company witnesses Mr. Epperson and Mr. Gulley provide greater specifics concerning the direct and ancillary economic development as a result of oil and gas development happening and being projected in the part of Kansas serviced by Southern Pioneer. Again, when this development and the required plant investments is coupled with the current capital structure of Southern Pioneer (i.e., 100 percent debt), clearly there is a need for a timelier means of cost recovery than a 400- to 500-day schedule would provide. This growth will require millions of dollars of upfront investment in infrastructure by Southern Pioneer, and it will take years for the development and load growth to mature and pay off these investments. In the meantime, if the Southern Pioneer division rates cannot provide cash to defray borrowing, it will be very difficult for Southern Pioneer to achieve its loan covenants concerning equity and DSC ratios. Continuing with traditional, costly, burdensome, backward-looking, and perhaps annual rate applications is not only the most expensive way of handling this but may also be inadequate given the regulatory lag previously discussed. The requested DSC-FBR Plan is a viable alternative mechanism from which the Commission, developers, and rural communities would benefit.

Q. Does the requested DSC-FBR Plan shift the "burden of proof" to Staff and interveners?

A. No. In this application, Mid-Kansas will have already met its initial burden of establishing that the DSC-FBR Plan is in the public interest as part of its approval in this docket. The Commission will have already determined that an expedited annual process is beneficial to customers of the Southern Pioneer division. In the annual filings, Mid-Kansas, or Southern Pioneer after the certification spin-down, will have the burden of presenting the data and information required by the Commission to establish the basis for any rate adjustment under the previously approved formula. If, after investigation and analysis, Staff takes the position that the Southern Pioneer division has failed to comply with the formula as approved by the Commission, the Company has the burden of establishing its compliance. If the Company's filing is in compliance with the requirements of the DSC-FBR Plan, but Staff wants to take a position that the rates resulting from the filing should not be approved (such as a recommended disallowance of an expense), then Staff would have the burden of proof as to that recommended disallowance. This is no different than the burden Staff and interveners have if they recommend a cost disallowance in a traditional rate case proceeding. Clearly, the appropriate burden stays with the appropriate party.

Similarly, if an interested party wants to ask the Commission to terminate the DSC-FBR Plan prior to the end of the five years adopted by the Commission, then that entity would have the burden of proving the DSC-FBR Plan is no longer just and reasonable and should be discontinued. This is no different than any complaint brought against a regulated utility regarding a company practice that has previously been reviewed and approved by the Commission.

Q. Should the Commission be concerned that the requested DSC-FBR Plan would result in less control and regulatory oversight?

A. No. Again, as part of this docket, the Commission will determine the appropriate structure for the DSC-FBR Plan. If the Commission agrees that there are benefits to allowing an expedited annual ratemaking process for the Southern Pioneer division, then the ultimate plan adopted will be established and approved by the Commission in this proceeding. Thus, the structure and the standards for the annual filings will have been fully reviewed and determined to be just and reasonable as a preliminary matter.

Additionally, when each annual filing is made, the Staff has a full opportunity to review and make sure the rules adopted by the Commission have been followed by the Company. Finally, although the parties would expect that the Plan would be in effect for five years if approved in this docket, the Commission always retains the power and authority to revisit a prior decision if it believes modification is necessary to protect the public interest.

Q. Does the requested DSC-FBR Plan prohibit interveners?

A. It must be remembered that one of the primary goals of the DSC-FBR Plan is to reduce regulatory expense and lag so that the Southern Pioneer division can not only meet its financial goals but so it can make the necessary investments in its plant to support economic development. This goal is forsaken if the annual filings become nothing more than standard rate cases with liberal interventions, extensive discovery, and full audits. The Company recognizes that an interested entity can request intervention in a proceeding before the Commission and that the Company has the right to object to such intervention based upon the facts and circumstances of the case. To balance competing interests, the requested DSC-FBR Plan places the responsibility upon Staff to review the filing for compliance; and if the filing is in compliance with the standards approved by the Commission in this case, then it will be expeditiously submitted to the Commission for final approval. If Staff or a party granted intervention files an objection to the application, then that objection can be presented to the Commission as part of the expedited process. Again, any interested entity can file a complaint with the Commission at any time; however, the filing of such a complaint cannot cause a delay in the annual filing unless *the Commission* takes action necessary to delay the filing.

PART V - REQUESTED DSC-FBR PLAN

A. TEMPLATE AND PROTOCOLS

Q. Please explain how the requested DSC-FBR calculation works.

A. By May 1 of each year, and for a period of five years, Southern Pioneer will complete the formula worksheet template as provided in the attached Exhibit RJM-3 and make its annual filing with the Commission. The template will be populated with financial and operating data from Southern Pioneer's year-end Form 7, Trial Balance and budget.

The major components of the calculation, which are shown in more detail in Exhibit RJM-3, are summarized as follows:

A. Statement of Operations.

B. Debt Service Payments.

C. Debt Service Margins.

D. Debt Service Coverage.

E. Debt Service Parameters.

F. Initial Operating Income Adjustment.

G. Equity Test.

H. Final Revenue Adjustment Proposed.

Q. Will any adjustments be made to the actual results or performance in completing the above steps?

A. Yes. The template pre-defines and limits the adjustments to the minimum required in order to achieve the goals of the DSC-FBR Plan. The following adjustments will be made.

<u>Operating Revenue and Patronage Capital</u>: An adjustment will be made to annualize any rate change implemented during the year being evaluated. This is necessary to avoid

pancaking rate increases. The adjustment will be made based on rate change per annual energy sales (kWh) multiplied by the actual energy sales (kWh) prior to the rate change implementation.

Tax Expense - Other: So long as Mid-Kansas holds the certificate of convenience for the Southern Pioneer division customers, an adjustment will be made to remove any Deferred Income Tax Expense reported by Southern Pioneer on its Form 7; currently on the Tax Expense - Other line. If, or when the certificate of convenience is transferred to Southern Pioneer, an adjustment will be made to remove non-cash deferred income tax expense from the test year. This adjustment is proposed in order to align with CoBank's calculation of the DSC. If CoBank's calculation changes in this regard, the DSC-FBR calculation would likewise need to change.

Debt Service: The actual debt service payments (principal and interest) in the test year will be adjusted to the budgeted amounts.

Debt Service Margins: An adjustment will be made to add back non-cash expenses related to the amortization of the Rural Utilities Service ("RUS") buyout penalty which is presently being recorded on the Other Deductions and Amortizations line of the Form 7. This will make the DSC calculation consistent with the application of the CoBank loan covenants.

Q. Why will the DSC-FBR calculation include the budgeted debt service payments for the Southern Pioneer division?

A. As previously discussed, Mid-Kansas and Southern Pioneer have been involved in discussions and meetings concerning the substantial economic development underway and expected in southwest Kansas including the rural communities served by the Southern

Pioneer division. Including the debt service payments on the budgeted plant expenditure requirements helps Southern Pioneer meet these requirements while not further degrading its financial performance.

Q. Are you recommending a true-up be made to reconcile the projected debt service payments to actual?

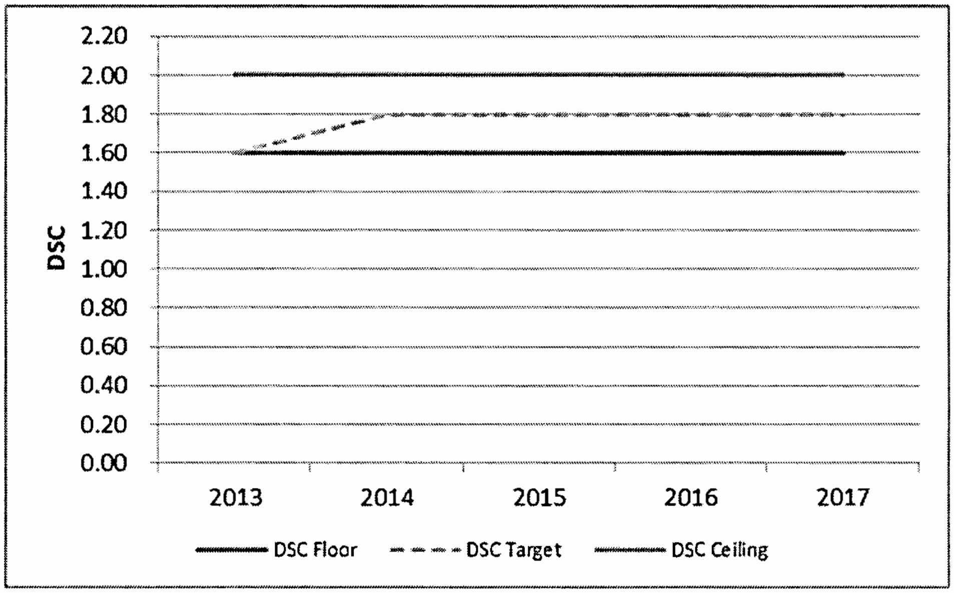
A. Yes. Each filing will include a comparison of actual annual debt service payments to what was budgeted and included in the previous filing. The difference, either positive or negative, will be multiplied by the target DSC and included in the filing.

Q. Have you included a template and protocols for the requested DSC-FBR Plan filing?

A. Yes. I have included a working template of the assessment/calculation that would be made and filed annually, beginning in 2014. This is provided as a blank template in Exhibit RJM-3 and populated with 2011 data in Exhibit RJM-4. In addition, Exhibit RJM-2 provides a description of the protocols for the DSC-FBR Plan.

Q. What DSC floor, ceiling, and target will apply to the Southern Pioneer division under the DSC-FBR Plan?

A. In the first year, the DSC floor <u>and</u> target will be set at 1.60 and the ceiling will be 2.00. Beginning in year two and for the remainder of the Plan, the floor will remain at 1.60, the ceiling will remain at 2.00, and the target will move to 1.80. Graphically, this would look as follows:



Q. Why is it appropriate to use DSC as the margin test in the FBR for the Southern Pioneer division?

A. This is appropriate for a few reasons. First, because the Southern Pioneer division operates as a not-for-profit and its sole shareholder is Pioneer Electric Cooperative, the same type of approach as is used for other Kansas cooperatives is appropriate. Second, in 2011 the Southern Pioneer division refinanced its RUS debt with CoBank. While the RUS has a TIER requirement, its current lender, CoBank, has established loan covenants and benchmarks based upon annual DSC performance. Third, and related, the DSC is an appropriate means of assessing, evaluating, and setting the Southern Pioneer division's margins because it measures the ability of Southern Pioneer to meet debt service obligations which is an indication of its financial health.

Q. For purposes of the DSC-FBR Plan, how are you recommending to define and calculate DSC?

A. Because a primary purpose for the requested DSC-FBR Plan is to provide a path for the

Southern Pioneer division to meets its loan covenants, I recommend that the DSC be defined and calculated consistent with its lender, CoBank. As evidenced in the loan contract, the Debt Service Coverage Ratio is defined as follows:

> "**Debt Service Coverage Ratio**" shall mean the ratio of: (1) the difference between (i) net income (after taxes and after eliminating any gain or loss on sale of assets or other extraordinary gain or loss), plus depreciation expense, amortization expense, and interest expense; minus (ii) non-cash patronage and non-cash income from joint ventures; to (2) all principal payments due within the period on all Long-Term Debt plus interest expense (all as calculated for the twelve month period ending with the end of the quarter in which the calculation is being made in accordance with GAAP consistently applied).

This is the same definition agreed to by the parties in the Settlement Agreement in the 380 Docket which was approved by the Commission. In applying the above formula, CoBank allows Southern Pioneer to add back non-cash deferred income tax expense to the numerator. This accommodation, which makes it easier to meet the minimum coverage requirement, has been confirmed with CoBank since the 380 Docket was completed; and so the calculation of the DSC in the template has been updated to be consistent.

Q. What is the minimum DSC that CoBank requires of Southern Pioneer?

A. Beginning third quarter 2013, CoBank's minimum DSC requirement is 1.35. Please reference the following:

> "**8.1 Debt Service Coverage Ratio**. The Company (on both a consolidated and an unconsolidated basis) will have at the end of each fiscal quarter of the Company, a Debt Service Coverage Ratio for the twelve month period ending with the end of such quarter of not less than 1.35 to 1.00."

Q. Is it necessary for the Southern Pioneer division to operate at a DSC ratio above the minimum required by its lender?

A. Yes. It is necessary to build in some "buffer" to ensure positive operation margins are produced and to deal with contingencies such as variability in sales and unexpected costs.

Ultimately, this buffer will facilitate improvement of Southern Pioneer's capital structure (i.e., equity ratio) to meet the standards of its lender, stabilize its financial condition, and allow the guarantee currently required of Pioneer Electric Cooperative to be lifted. The following Table 2 provides information on the national and state median DSC ratios in the most recent five years as available from the National Rural Utilities Cooperative Finance Corporation ("CFC") for its electric cooperative borrowers.

Table 2
Summary of Modified DSC
(2007-2011 Median Values)
Source: CFC Key Ratio Trend Analysis

Year	National	Kansas
2007	1.86	1.90
2008	1.82	1.71
2009	1.85	1.70
2010	1.96	1.86
2011	1.81	1.78
Ave.	*1.86*	*1.79*

As can be seen in the above table, the median DSC in Kansas has recently ranged from 1.70 to 1.90, with an average of 1.79. It should be noted that, similar to CoBank, CFC also requires borrowers to achieve a 1.35 DSC ratio. The lender minimums in place are to identify the point at which a utility's solvency and ability to repay its debts is at risk. Clearly, a utility should not normally operate on the edge of this minimum but should target a coverage ratio that provides an adequate cushion. Based on the above information, the cushion for electric cooperatives in Kansas is about 0.44 (1.79 - 1.35). This is the same cushion embedded in the 1.80 target for the requested DSC-FBR Plan.

Q. Is it possible for Southern Pioneer to meet its minimum DSC with CoBank while operating at negative operating margins?

A. Yes, in fact this happened in 2011. Simply achieving the minimum DSC cannot be relied upon to indicate the adequacy of rates for Southern Pioneer.

Q. You mentioned that targeting a DSC in excess of the minimum loan covenant is needed to improve the capital structure of Southern Pioneer. What is Southern Pioneer's capital structure?

A. Using 2011 year-end financial statements, I have summarized in Table 3 the Southern Pioneer division's equity ratio as a percent of total capitalization. This has been prepared using the margins and equities as stated on the balance sheet and then again excluding its investment/equity in Mid-Kansas. It is informative to look at the equity without the investment in Mid-Kansas as the remainder represents the equity generated by the distribution operations of the Southern Pioneer division. Although it accumulates an equity share in Mid-Kansas, such equity and margins are generated by Mid-Kansas' wholesale rates and are not available as cash to the Southern Pioneer division.

Table 3
Southern Pioneer Equity Position
As of 12/31/11

1. Equity Over Assets			
	Total Equity	**Total Assets**	**Equity Ratio**
	($)	($)	(%)
Southern Pioneer	329,229	103,678,095	0.3
National Median (CFC borrowers for 2011)			43.32
State Median (CFC borrowers for 2011)			43.00
2. Distribution Equity (excluding equity in associated organizations)			
	Distribution Equity	**Distribution Assets**	**Equity Ratio**
	($)	($)	(%)
Southern Pioneer	-5,094,309	98,254,557	-5.2
National Median (CFC borrowers for 2011)			35.93
State Median (CFC borrowers for 2011)			36.14

As can be seen above, the Southern Pioneer division currently has very little equity. Were it not for Southern Pioneer's equity investment in Mid-Kansas, it would actually have accumulated negative equity of over $5,000,000. Without adequate funding of operations and plant investments from rates, the capital structure of the Southern Pioneer division will continue to be substantially over-leveraged, which limits access to needed financing and increases debt costs and business risk. In fact, it is because of this that CoBank has required that Pioneer Electric Cooperative guarantee Southern Pioneer's debt. The ability for Southern Pioneer to borrow on its own merit is important to both Southern Pioneer and Pioneer Electric Cooperative and its members and should be obtained as soon as possible.

To assist in evaluating the minimum equity targets for the Southern Pioneer division, I would reference the following from the Waiver and Fifth Amendment to Amended and Restated Credit Agreement with CoBank:

3.1 Subsection 8.2 of the Credit Agreement is hereby amended and restated to read as follows:

Equity to Total Assets Ratio. The Company (on an unconsolidated basis) will have at the end of each fiscal quarter shown below, an Equity to Total Assets Ratio of not less than the ratio shown next to such quarter:

FISCAL QUARTER REQUIRED	RATIO ENDING: (Equal to or greater than)
9/30/2011 through 6/30/2013	0
9/30/2013 through 12/31/2014	2%
3/31/2015 through 12/31/2016	5%
3/31/2017 through 12/31/2018	8%
3/31/2019 through 12/31/2019	11%
Each fiscal quarter thereafter	15%

3.3 The definition of "Equity" (as contained in Exhibit A of the Credit Agreement) is hereby amended to add the following sentence at the end thereof:

> "Notwithstanding the foregoing, in calculating Equity, the other comprehensive income impact of the Company's pension payment obligation shall be excluded."

Q. What is then a reasonable DSC target ratio within the context of the requested DSC-FBR Plan?

A. Given Southern Pioneer's weak financial position and inability to fund needed capital improvement and replacement projects without a loan guarantee from Pioneer Electric Cooperative, a DSC starting at 1.60 in year one and 1.80 thereafter would be appropriate for use with the requested DSC-FBR Plan. Such would be slightly below the average national median and right at the average Kansas state median for the most recent five years. I would stress that the appropriateness of a 1.80 DSC has been established based on the specific design of the requested DSC-FBR Plan and its five-year term. If the workings of the formula were to change, the appropriate DSC target may need to be re-assessed.

Q. If a DSC target of 1.80 is sufficient to allow Southern Pioneer to meet its financial needs, why does your plan allow the Company to retain earnings from rates that generated a DSC of 1.80 - 2.00?

A. As with most FBR plans, there is a deadband or quiet zone established around the targeted return within which no rate adjustments are made. The primary purpose for having a deadband is to reduce the frequency of rate changes when possible. It can also effectively preserve an incentive for the utility to reduce costs. Without a deadband, the utility would have complete assurance that it would be able to pass along all costs and achieve its target each year. With the deadband, the utility is allowed to under-perform versus the target but only to a point at which it then needs to make an upward rate adjustment. Likewise, the utility is allowed to outperform the target but only to a point at which it then needs to make a downward adjustment. It really is a type of a risk sharing mechanism.

B. RATE DESIGN

Q. Near the beginning of your testimony you referenced that the DSC-FBR Plan will only apply to the distribution revenue requirement and not the 34.5 kV revenue requirement. Please explain.

A. The Southern Pioneer division owns, operates, and maintains 34.5 kV facilities used to provide service to its retail customers and to third parties, a.k.a. wholesale customers. The associated revenue requirement on the 34.5 kV system is currently recovered through a combination of a separate LAC to the wholesale customers and the retail rates, which embed the LAC in the base retail rates. In order to ensure the fair treatment and collection of the revenue requirement, the requested DSC-FRB Plan will focus only on the distribution system and will leave the 34.5 kV revenue requirement to be collected under existing rates and/or any adjustment requested through other available means.

Direct assignment of costs based upon the chart of accounts will be used when possible to develop the distribution system costs. The Retail and LAC Cost of Service studies from the 380 Docket will be used to allocate common costs to the distribution system. In prior Mid-Kansas rate applications, the classification of costs for the 34.5 kV system has largely been non-controversial. Since the Southern Pioneer division studies from the 380 Docket are fairly recent, I recommend utilizing the classification factors contained therein to classify the revenue requirement developed in accordance with the requested DSC-FBR Plan when direct assignments cannot easily be made. This is the purpose for the Distribution Allocation Factor column in the template (Exhibit RJM-3).

Q. Please describe how a rate adjustment would be implemented under your proposal.

A. As described in my Exhibit RJM-2, and illustrated in Exhibit RJM-4, I recommend that any rate adjustment resulting from the DSC-FBR Plan be implemented as a proportionate adjustment such that the percentage of "base revenue" by retail rate class prior to the adjustment is maintained. Base revenue is defined as retail rate schedule revenue less purchased power expense for each class as determined in the 380 Docket

Q. Are you familiar with any other regulated utilities that make rate adjustments in proportion to revenue by rate class?

A. Yes, this approach has frequently been used in Kentucky since 1999 as a means to flow through wholesale rate changes in lieu of a class cost of service study. I have attached, as Exhibit RJM-10, the Kentucky Statute KRS 278.455, Regulation 807 KAR 5:007 and an example filing for reference. With regards to this approach used in Kentucky, if a distribution cooperative wishes to make a disproportionate change, it must then file a rate application with a cost of service study. Similarly, in my proposed DSC-FBR Plan, if something other than a proportionate allocation of the increase/decrease is filed, then a class cost of service study must be filed in support.

Q. Will a proportionate allocation of a rate adjustment result in cost-based rates?

A. I believe it will, within a range of reasonableness. Because the current Southern Pioneer division rates were recently determined in the 380 Docket which included a class cost of service study, it is reasonable for an interim adjustment to simply distribute any change on a proportionate basis. There is not typically a substantial shift in cost of service over the short term (i.e., five years), and to require a class cost of service study for annual filings would be burdensome and unnecessary.

The proposed rate adjustment approach of distributing based on a pro rata basis of distribution revenue from the 380 Docket decision and cost of service study ensures that rate adjustments caused by changes in per unit distribution costs are spread in a manner that is reasonable in my opinion.

C. OTHER DSC-FBR PLAN PROVISIONS

Q. Have you developed any provisions in the DSC-FBR Plan protocols to help mitigate risk and address potential customer bill impacts?

A. In developing the template and protocols I have included a number of safeguards to ensure a proper balancing of the financial needs of the Southern Pioneer division with the rate impact to customers. These include:

1. The plan will have a five-year term.

2. A filing seeking a rate increase in excess of 10 percent would trigger a full rate case.
3. A rate increase will not be implemented that produces an equity over asset ratio greater than 35 percent unless applying such limitation would prevent Southern Pioneer from meeting its lender's minimum coverage and equity ratios.
4. The formula and protocols will be agreed upon in this case.
5. The annual filing will include support information in easily verifiable Uniform System of Accounts format.
6. Commission Staff and any party granted intervention will have adequate time, information, and opportunity to review the accuracy of the annual filing before the rates become effective; and if any unresolvable errors are identified during its review, the objecting party can submit its objection to the Commission.
7. In no way would the ability of any consumer to file a complaint with the Commission be preempted.

D. PROJECTED RESULTS OF REQUESTED DSC-FBR PLAN

Q. Have you evaluated the requested DSC-FBR Plan in terms of: 1) whether it is expected to achieve the CoBank minimum DSC covenants, 2) whether it is expected to result in equity ratios that meet or exceed the CoBank minimum equity requirements, and 3) whether the application of the DSC-FBR Plan will in fact result in more gradual, moderate rate increases?

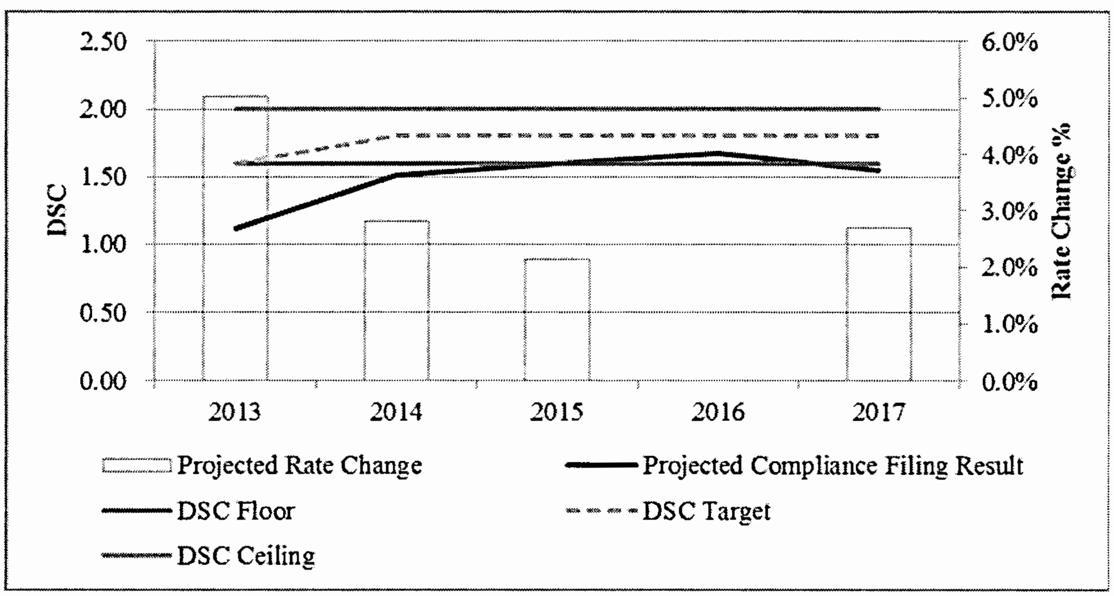
A. Yes, I have evaluated each of these. Using the best projections available from the Southern Pioneer division, I have prepared the following tables and graphs to help convey the anticipated results under the implementation of the requested DSC-FBR Plan.

The following table summarizes the projected compliance filing DSC, the DSC Floor, Target, and Ceiling along with a projection of the rate adjustment that would result from the annual filing. Keep in mind that the first annual filing would occur in 2014 and would evaluate the 2013 results and budgeted 2014 debt service levels.

Projected DSC FBR Plan Results

	DSC				
Test Year	**Projected Compliance Filing Result**	**DSC Floor**	**DSC Target**	**DSC Ceiling**	**Projected Rate Change**
2013	1.12	1.60	1.60	2.00	5.0%
2014	1.51	1.60	1.80	2.00	2.8%
2015	1.59	1.60	1.80	2.00	2.1%
2016	1.67	1.60	1.80	2.00	0.0%
2017	1.55	1.60	1.80	2.00	2.7%

This is further illustrated in the chart below.



The table below compares the projected calendar year DSC results with the CoBank minimum requirements for each year.

Projected CY DSC
Under DSC FBR Plan

Year	Projected CY DSC	CoBank Min. Req.
2013	1.32	1.35
2014	1.44	1.35
2015	1.57	1.35
2016	1.56	1.35
2017	1.50	1.35

Without any rate adjustment between now and the end of 2013, it would appear that the calendar year 2013 DSC will be slightly below the CoBank minimum. However, in the 380 Docket the Commission approved an abbreviated filing for the Southern Pioneer division that is currently expected for the first part of 2013. I have not factored that into my analysis because of the uncertainty, but I do expect it will help relieve and meet the 2013 DSC requirement.

The above table demonstrates that the FBR is projected to allow the Southern Pioneer division to meet its DSC loan covenants with CoBank. There are a couple of things that affect and lower the projected calendar year DSC from what might otherwise be expected. First, any rate adjustment resulting from the FBR Plan will not be implemented until around mid-year, so the full increase will not be realized within that calendar year. Additionally, the requested FBR is only intended to pick up changes related to the distribution revenue requirement. While there could be the need for an increase to recover the 34.5 kV revenue requirement, that would need to be achieved through other means. In a perfect world, if the rates were put into effect January 1 and included a corresponding adjustment to the 34.5 kV rate components, the calendar year DSC would get very close to hitting the target.

Finally, the table below compares the estimated ending year equity over asset ratio for the Southern Pioneer division under the DSC-FBR Plan.

Projected Year End Equity
Under DSC FBR Plan

Year	Projected EOY Equity	CoBank Min. Req.	Projected EOY Distribution Equity
2013	1%	2%	-8%
2014	3%	2%	-7%
2015	7%	5%	-5%
2016	10%	5%	-2%
2017	14%	8%	0%

In addition to showing a projection of total equity over assets, I have included a projection of the distribution equity which excludes the investment and margins from Mid-Kansas to the Southern Pioneer division. This is helpful to see to what extent equity is being generated by the Southern Pioneer division retail rates under the plan. Thus, while the total equity is projected at 14 percent at the end of the plan, the Southern Pioneer division's distribution equity is only then starting to turn positive.

Q. Please summarize your analysis of the DSC-FBR Plan.

A. In my assessment, the DSC-FBR Plan has been developed in a way that meets the objectives of: (1) assuring reasonable rates, (2) gradually improving and stabilizing Southern Pioneer's financial condition, and (3) providing the financial flexibility needed to fund plant investments in response to economic development in the area.

Q. Does this conclude your prefiled Direct Testimony?

A. Yes, it does.

VERIFICATION

STATE OF MINNESOTA)
) ss
COUNTY OF ANOKA)

The undersigned, Richard J. Macke, upon oath first duly sworn, states that he is an employee of Power System Engineering, Inc., and that he has prepared the foregoing testimony, that he is familiar with the contents thereof, and that the statements contained therein are true and correct to the best of his knowledge and belief.

Richard J. Macke

Richard J. Macke

Subscribed and sworn to before me this 4th day of January, 2013.

Shelley J. Almeida

Notary Public

SHELLEY J. ALMEIDA
NOTARY PUBLIC - MINNESOTA
My Commission Expires Jan. 31, 2015

My appointment expires: 1-31-2015

Exhibit RJM-1 - Curriculum Vitae - Richard J. Macke

RICHARD J. MACKE
VICE PRESIDENT, ECONOMICS, RATES, AND BUSINESS PLANNING

SUMMARY OF EXPERIENCE AND EXPERTISE

- Over 15 years of experience in electric utility consulting.
- Specialized expertise in financial analyses with particular emphasis on utility finance, rate and cost of service matters, financial planning, and financial modeling.
- Frequent speaker at utility board, commission, and staff meetings.
- Expert witness for utility rate cases.

PROFESSIONAL EXPERIENCE

Power System Engineering, Inc. - Minneapolis, MN (1999-present)

Vice President, Economics, Rates, and Business Planning (June 2011-present)
Vice President, Rates and Financial Planning (July 2010-May 2011)
Leader, Rates and Financial Planning (April 2008-June 2010)
Senior Rate and Financial Analyst (2002-March 2008)
Rate and Financial Analyst (1999-2002)

As Vice President of the Economics, Rates, and Business Planning Department at PSE, responsibilities include managing the firm's economic and rate practice areas and providing senior level consulting services to clients in the areas of cost of service, rate design, financial planning and forecasting, merger and acquisition analysis, and support. Additional responsibilities include strategic planning, litigation support, regulatory compliance, capital expenditure, and operational assessments and advisement.

Energy & Resource Consulting Group, LLC - Denver, CO (1998-1999)

Senior Analyst

Senior Analyst for financial, engineering and management consulting firm. Performed consulting services related to electric, gas, and water rate studies. Part of the Financial and Engineering Advisor Team contracted to the City Council of the City of New Orleans, LA to assist in various electric and gas utility matters. Provided expert testimony and participated in various regulatory proceedings involving the City Council, the Public Utilities Commission of Texas, and the Public Utilities Commission of Nevada. Provided general financial, management, and public policy support to clients.

Power System Engineering, Inc. - Blaine, MN (1996-1998)

Financial Analyst

Financial Analyst in Utility Planning and Rates Division. Emphasis on retail rate studies, including revenue requirements, and bundled/unbundled cost of service studies. Provided analysis used to support testimony, mergers and acquisitions cases, and financial forecasting.

RICHARD J. MACKE

EDUCATION

University of Minnesota, Minneapolis, MN
Masters of Business Administration (emphasis on Finance and Strategic Management), 2007

Bethel University, St. Paul, MN
Bachelor of Arts Degree in Business (emphasis on Finance and Marketing),
Minor: Economics, 1996

ADDENDUM REFERENCES - EXPERT TESTIMONY

Case or Jurisdiction	Docket No.	Description
Kansas	11-MKEE-380 -RTS	Mid-Kansas Electric Company, LLC, application for revised rates, tariffs, and rate design changes. Filed on behalf of its member-owner, Southern Pioneer Electric Company, Inc.
Kansas	11-MKEE-491 -RTS	Mid-Kansas Electric Company, LLC, application for revised rates, tariffs, and rate design changes. Filed on behalf of its member-owner, Western Cooperative Electric Assn., Inc.
Kansas	11-MKEE-439 -RTS	Mid-Kansas Electric Company, LLC, application for revised rates, tariffs, and rate design changes. Filed on behalf of its member-owner, Wheatland Electric Cooperative, Inc.
Kansas	09-MKEE-969 -RTS	Mid-Kansas Electric Company, LLC, application for approval to make certain changes in the charges for electric services. Filed on behalf of Mid-Kansas and its member-owners: Lane-Scott Electric Cooperative, Inc.; Prairie Land Electric Cooperative, Inc.; Southern Pioneer Electric Company, Inc.; Victory Electric Cooperative Association, Inc.; Western Cooperative Electric Association, Inc.; and Wheatland Electric Cooperative, Inc.
Kansas	09-PNRE-563 -RTS	Pioneer Electric Cooperative, Inc., application to increase rates. Testimony filed on behalf of Pioneer.
Kansas	09-WHLE-681 -RTS	Wheatland Electric Cooperative, Inc., application to increase rates. Testimony filed on behalf of Wheatland.
Minnesota	E-111/ GR-03-261	Dakota Electric Association, application to increase rates. Testimony filed on behalf of Dakota.
Texas	2150	North Star Steel, appropriateness of settlement rates being charged by Entergy Gulf States, Inc. Testimony filed on behalf of North Star Steel before the Public Utilities Commission of Texas.

Exhibit RJM-2 - Formula-Based Rate Protocols

Mid-Kansas: Southern Pioneer Division

DSC-FBR Plan Protocols

A. PURPOSE

The DSC-FBR Plan is an annual ratemaking mechanism used to assess and potentially adjust Mid-Kansas' Southern Pioneer Electric Company's (Southern Pioneer) divisional retail rates based on a DSC based formula. Its purpose is to allow, for a five year pilot period, timely adjustments to retail rates without the expense, risk and lag related to preparing and presenting a full rate case every year before the Kansas Corporation Commission (Commission).

B. PROCESS

No later than May 1st of each year during the Plan, Southern Pioneer shall submit is DSC-FBR Plan filing for the calendar year just ended ("Test Year").

Upon filing of the Plan by the Southern Pioneer and by May 31st the Commission will suspend the applications for a period of 90 days pursuant to K.S.A 66-117. The KCC staff will have 45 days from the date Southern Pioneer files to review the application to determine if it is in compliance with the Plan as approved by the Commission, or to obtain compliance from Southern Pioneer if Staff believes the initial filing contains errors. Within 45 days after the filing, Staff or interverners can file an objection indicating the filing is deficient if there are problems in the filing that have not been resolved informally with the Company. Any such objections shall set forth the alleged error(s) in the filing along with supporting documentation and shall relate specifically to Southern Pioneer's application of the DSC-FBR Plan process and include specific evidence that Southern Pioneer has improperly applied DSC-FBR as described herein. Other questions, concerns or complaints regarding Southern Pioneer or its parent company that are outside the scope of the DSC-FBR Plan shall not be raised in the annual adjustment dockets. However, no party is precluded from raising such issues through the normal means available before the KCC.

If Staff files a report within 45 days confirming that Southern Pioneer's filing is in compliance with the DSC-FBR Plan approved by the Commission in this docket, and no other relevant objections are submitted by interveners, then the Commission shall issue an Order allowing the rates proposed in the application to become effective no later than 60 days after the filing date.

If Staff or interveners file an objection to Southern Pioneer's DSC-FBR application indicating the filing is deficient, then Southern Pioneer shall file its response to said objection within 60 days from the filing date. Within 90 days from the filing date, the Commission will issue an order either approving the DSC-FBR application or further suspending the docket under K.S.A. 66-117 and set a prehearing conference to establish a procedural schedule for the presentation of the testimony and exhibits supporting the respective parties' position. The procedural schedule will include settlement discussions to allow the parties to attempt to resolve the objections without hearing.

The process outlined above does not prohibit interested parties from exercising any other rights they may have to bring a separate complaint before the Commission regarding Southern Pioneer, its rates or services.

C. CUSTOMER NOTIFICATION

Customers will receive notice of the filing at the time it is made with the Commission. Such notice shall be made via bill inserts and shall contain the following information:

1. The date the filing was made with the Commission and the docket number assigned.
2. The amount of the revenue adjustment presented.
3. The impact on each individual rate class as contained in the filing.
4. A statement explaining that the rate adjustment is being made pursuant to the DSC-FRB Plan, with a cite to this docket and the date of the Commission's Order approving the Plan in this docket.
5. A contact person and phone number for questions.

D. TERM

The DSC-FBR Plan, as described herein, shall be implemented for an initial period of five calendar years, inclusive of the year adopted, with the initial filing occurring in 2014 and the final filing occurring in 2018. The DSC-FBR Plan shall be a part of the Commission regulatory process as it applies to Southern Pioneer and if Southern Pioneer should become unregulated by the Commission, then DSC-FBR Plan shall be terminated.

E. CALCULATION

Each filing shall be based on actual results as presented in the *December Financial and Statistical Report* (Form 7) and trial balance utilizing the FERC Uniform System or Accounts.[1] The calculation shall follow the form and format included in Exhibit RJM-3. Specific details concerning the calculation are as follows:

1. Adjustments to actual results for the Test Year will be made as follows:
   a. If a rate adjustment was implemented during a portion of the Test Year, then the *Operating Revenue and Patronage Capital* line shall be increased or decreased for estimated revenue impact of annualizing the rate adjustment determined by multiplying the product of the average annualized kWh rate change times the kWh during the Test Year that were not subject to the rate adjustment.
   b. *Tax Expense – Other* will be adjusted to reflect the cash tax expense associated with the Test Year. As appropriate an incremental adjustment will be made to include tax obligations associated with any revenue adjustment made in accordance with B.1.a. above.
   c. *Interest on Long-Term Debt* will be adjusted to reflect the interest on long-term debt expected for the calendar year immediately following the Test Year ("Budget Year").
   d. *Interest Expense – Other* will be adjusted as necessary to reflect the amount of short-term interest expense expected for the Budget Year.
   e. *Debt Service Payments* actually made during the Test Year shall be adjusted to reflect the interest and principal payments expected for the Budget Year. Interest expense for

[1] Form 7 page number references are from the 2011 Form 7 format.

this purpose shall include both long-term and short-term interest expense. The debt service payments on said debt requirements will be calculated using a 30-year amortization schedule at the [insert rate basis]. The debt service payments will be determined within the context of the Southern Pioneer budget including the projected plant investments and cash flows needs.

2. The formula used to compute Southern Pioneer's DSC for purposes of the DSC-FBR will be made in accordance with Exhibit RJM-3, Page 2, Lines 32 through 48.

F. DEBT SERVICE COVERAGE PARAMETERS

The DSC determined in the formula will be evaluated based upon the Floor, Target and Ceiling as defined in the table below.

TABLE 1			
Test Year	**DSC Floor**	**DSC Target**	**DSC Ceiling**
2013	1.6	1.6	2.0
2014	1.6	1.8	2.0
2015	1.6	1.8	2.0
2016	1.6	1.8	2.0
2017	1.6	1.8	2.0

G. REVENUE ADJUSTMENTS

Adjustments to the Southern Pioneer division retail rates will be determined by comparing the DSC to the DSC Parameters in TABLE 1 as follows:

a) If the DSC is between the DSC Floor and DSC Ceiling, i.e., within the DSC Quiet Zone, there need be no Rate Adjustment.

b) If the DSC is greater than the DSC Ceiling, then a Rate Adjustment necessary to bring DSC back to the DSC Target will be requested.

c) If the DSC is below the DSC Floor, then a Rate Adjustment necessary to bring DSC back to the DSC Target will be requested.

d) A revenue adjustment shall not exceed 10 percent calculated on an annual system-wide basis. In the event a greater increase is requested, a standard rate case filing consistent with the modified filing requirements approved by the Commission in Docket No. 12-MKEE-380-RTS shall be required.

e) Southern Pioneer may determine to reduce or defer a revenue increase adjustment resulting from the process described herein. It may not reduce or defer a revenue decrease adjustment.

H. EQUITY TEST

A rate increase will not be implemented that would achieve or maintain an equity percent of assets in excess of 35 percent, unless such would be reasonably determined to force Southern Pioneer to violate its loan covenant(s) with its lender. For this purpose equity shall be calculated as consistent with its lender as contained in its loan documents and any amendments applicable thereto.

I. RATE DESIGN

A rate adjustment resulting from the DSC-FBR will adjust rates such that the distribution of base revenue by rate schedule or class prior to the increase remains unaffected unless Southern Pioneer provides cost of service study support to justify something different. For purposes of the Plan, base revenue by rate schedule shall be determined from rate schedule revenue by rate class shown in the 12-MKEE-380-RTS Commission Order less power supply costs as determined in the Southern Pioneer class cost of service submitted in the 380 Docket and shown in Exhibit RJM-14, Page 2, Line 32. If Southern Pioneer requests anything other than this distribution, such must be accompanied by a new class cost of service.

J. FILING EXHIBITS

In support of the annual DSC-FBR filing, Southern Pioneer shall submit the following information:

1. Application describing the revenue adjustment requested, the proposed changes in rates and how the application complies with the requirements of the DSC Ratemaking Plan approved in this docket.
2. Southern Pioneer's complete RUS Form 7 or successor document for the year in question.
3. Completed formula with adjustments as contained in Exhibit RJM-3.
4. Any supplemental schedules including trial balances as needed to audit the filing.
5. Proposed tariff sheets including the proposed rate adjustment.

Exhibit RJM-3 - Formula-Based Rate Template - Blank

SOUTHERN PIONEER ELECTRIC COMPANY
DISTRIBUTION FORMULA BASED RATE

	ITEM	UNADJUSTED HISTORICAL TEST YEAR [YEAR] ($)		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT ($)	ADJUSTED HISTORICAL TEST YEAR [YEAR] ($)	DISTRIBUTION ALLOCATION FACTOR 380 Docket	DISTRIBUTION FBR ($)
1.	**A. STATEMENT OF OPERATIONS**							
2.	Operating Revenue and Patronage Capital		F7, Pt. A, Col. B	[1]	-	-	Direct	-
3.	Power Production Expense		F7, Pt. A, Col. B			-	0.0000	-
4.	Cost of Purchased Power		F7, Pt. A, Col. B			-	1.0000	-
5.	Transmission Expense		F7, Pt. A, Col. B			-	0.0000	-
6.	Regional Market Expense		F7, Pt. A, Col. B			-	0.0000	-
7.	Distribution Expense - Operation		F7, Pt. A, Col. B			-	1.0000	-
8.	Distribution Expense - Maintenance		F7, Pt. A, Col. B			-	1.0000	-
9.	Customer Accounts Expense		F7, Pt. A, Col. B			-	1.0000	-
10.	Customer Service and Informational Expense		F7, Pt. A, Col. B			-	1.0000	-
11.	Sales Expense		F7, Pt. A, Col. B			-	1.0000	-
12.	Administrative and General Expense		F7, Pt. A, Col. B			-	0.9836	-
13.	**Total Operation & Maintenance Expense**	-	F7, Pt. A, Col. B		-	-		-
14.	Depreciation and Amortization Expense		F7, Pt. A, Col. B			-	0.7427	-
15.	Tax Expense - Property & Gross Receipts		F7, Pt. A, Col. B			-	0.7427	-
16.	Tax Expense - Other		F7, Pt. A, Col. B	[2]	-	-	Calculated	-
17.	Interest on Long-Term Debt		F7, Pt. A, Col. B	[3]	-	-	0.8068	-
18.	Interest Charged to Construction - Credit		F7, Pt. A, Col. B			-	0.8068	-
19.	Interest Expense - Other		F7, Pt. A, Col. B	[4]	-	-	0.8068	-
20.	Other Deductions		F7, Pt. A, Col. B			-	0.8068	-
21.	**Total Cost of Electric Service**	-	F7, Pt. A, Col. B		-	-		-
22.	**Patronage Capital & Operating Margins**	-	F7, Pt. A, Col. B		-	-		-
23.	Non Operating Margins - Interest		F7, Pt. A, Col. B			-	0.7427	-
24.	Allowance for Funds Used During Construction		F7, Pt. A, Col. B			-	0.7427	-
25.	Income (Loss) from Equity Investments		F7, Pt. A, Col. B			-	1.0000	-
26.	Non Operating Margins - Other		F7, Pt. A, Col. B			-	1.0000	-
27.	Generation and Transmission Capital Credits		F7, Pt. A, Col. B			-	1.0000	-
28.	Other Capital Credits and Patr. Dividends		F7, Pt. A, Col. B			-	0.8068	-
29.	Extraordinary Items		F7, Pt. A, Col. B			-	1.0000	-
30.	**Patronage Capital or Margins**	-	F7, Pt. A, Col. B		-	-		-
31.								

SOUTHERN PIONEER ELECTRIC COMPANY
DISTRIBUTION FORMULA BASED RATE

	ITEM	UNADJUSTED HISTORICAL TEST YEAR [YEAR] ($)		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT ($)	ADJUSTED HISTORICAL TEST YEAR [YEAR] ($)	DISTRIBUTION ALLOCATION FACTOR 380 Docket	DISTRIBUTION FBR ($)
32.	**B. DEBT SERVICE PAYMENTS**							
33.	Interest Expense	-	Line 17 + Line 19		-	-	0.8068	-
34.	Principal Payments		F7, Pt. O, Col. B	[5]	-	-	0.8068	-
35.	Total Debt Service Payments	-			-	-		-
36.								
37.	**C. DEBT SERVICE MARGINS**							
38.	Patronage Capital or Margins	-	Line 30			-	0.0000	-
39.	Plus: Depreciation and Amortization Expense	-	Line 14			-	0.7427	-
40.	Plus: Interest Expense	-	Line 33		-	-	0.8068	-
41.	Plus: Non-Cash Other Deductions Amortizations		Trial Balance			-	0.8068	-
42.	Plus: Cash Capital Credits Cash Received		F7, Pt. J, L6, Col. A			-	0.8068	-
43.	Plus: Non-Cash Income Tax Expense		Trial Balance		-	-	Calculated	-
44.	Less: Income (Loss) from Equity Investments	-	Line 25			-	1.0000	-
45.	Less: Other Capital Credits and Patr. Dividends	-	Line 28			-	0.8068	-
46.	Total Debt Service Margins	-				-		-
47.								
48.	**D. DEBT SERVICE COVERAGE**	-	L46/L35			-		-
49.								
50.	**E. DEBT SERVICE PARAMETERS**						Adjusted DSC Margins are:	***Below the Floor***
51.	Floor							**1.60**
52.	Target							**1.80**
53.	Ceiling							**2.00**
54.								
55.	**F. INITIAL OPERATING INCOME ADJUSTMENT**							
56.	DSC Adjustment Required to Achieve Target							-
57.	Debt Service Payments							-
58.	After-Tax Operating Income Adjustment							-
59.								

SOUTHERN PIONEER ELECTRIC COMPANY
DISTRIBUTION FORMULA BASED RATE

	ITEM	UNADJUSTED HISTORICAL TEST YEAR [YEAR]		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT	ADJUSTED HISTORICAL TEST YEAR [YEAR]	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR
		($)			($)	($)	380 Docket	($)
60.	G. EQUITY TEST (Increase will not result in > 35% equity ratio)				Plus			
61.		Pre-Adjustment			Adjustment	Post-Adjustment		
62.	Total Margins and Equities		F7, Pt. C, L35		-	-		
63.	Total Assets		F7, Pt C, L28	[6]	-	-		
64.	Equity Ratio		L62 / L63					
65.								
66.	H. FINAL REVENUE ADJUSTMENT PROPOSED							
67.	After-Tax Operating Income Adjustment							-
68.	Divided by Tax Adjustment (1 - Combined Tax Rate)							-
69.	Before-Tax Revenue Adjustment							-
70.	Rate Schedule Revenue							-
71.	Adjustment Percentage							0.00%

SOUTHERN PIONEER ELECTRIC COMPANY
DSC-FBR - ADJUSTMENTS

1.	**ADJUSTMENT [1] -- REVENUE**		
2.	***Adjustment to annualize rate adjustment implemented during test year***		
3.	Annual Rate Adjustment Authorized by Commission	-	
4.	Total kWh Sales During Test Year	-	
5.	Average per kWh	$0.00000	L3/L4
6.	kWh Sales Prior to Implementation of Rate Adjustment		Input
7.	Revenue Adjustment to Annualize Rate Adjustment	$ -	L5 x L6
8.			
9.	**ADJUSTMENT [2] -- OTHER TAXES**		
10.	***Adjustment to add back non-cash income tax expense***		
11.	Cash Test Year Other Tax Expense		
12.	Test Year Other Tax Expense	-	F7, Pt. A, Col. B
13.	Adjustment to Actual Other Tax Expense	$ -	L11 - L12
14.			
15.	**ADJUSTMENT [3] -- Long-Term Interest Expense**		
16.	***Adjustment to reflect the Budget.***		
17.	Adjustment to Long-Term Interest Expense		
18.	Actual Year Long-Term Interest Expense	$ -	F7, Pt. A, Col. B
19.	Budget Year Long-Term Interest Expense	-	Budget
20.	Adjustment to Actual Long-Term Interest Expense	$ -	L19-L18
21.			
22.	**ADJUSTMENT [4] --Other Interest Expense**		
23.	***Adjustment to reflect the Budget.***		
24.	Adjustment to Other Interest Expense		
25.	Actual Year Other Interest Expense	$ -	F7, Pt. A, Col. B
26.	Budget Year Other Interest Expense	-	Budget
27.	Adjustment to Actual Other Interest Expense	$ -	L26 - L25
28.			

SOUTHERN PIONEER ELECTRIC COMPANY
DSC-FBR - ADJUSTMENTS

29.	**<u>ADJUSTMENT [5] -- Principal Payments</u>**			
30.	***Adjustment to reflect the Budget.***			
31.	<u>Adjustment to Principal Payments</u>			
32.	Actual Year Principal Payments	$	-	F7, Pt. O, Col. B
33.	Budget Year Principal Payments		-	Budget
34.	Adjustment to Actual Principal Payments	$	-	L33- L32
35.				
36.	**<u>ADJUSTMENT [6] -- Assets</u>**			
37.	***Adjustment to reflect budgeted Assets.***			
38.	Actual Year-End Assets	$	-	F7, Pt. C, L28.
39.	Budgeted Year-End Assets		-	Budget
40.	Adjustment to Actual Assets	$	-	L39 - L38

SOUTHERN PIONEER ELECTRIC COMPANY
Proportional Allocation of DSC-FBR Rate Adjustment to Rate Classes
Based on Base Revenue by Rate Schedule

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Per Docket 380 Cost of Service and Settlement				Allocation of Rate Adjustment		
Line No.	Rate Schedule	Revenue Settlement Rates	Allocated Power Supply Cost of Service	Base Revenue	Percent	FBR Adjustment	Base Revenue	Percent
		($)	($)	($)	(%)	($)	($)	(%)
1	Residential Service (12-RS)							
2	General Use	15,466,839	8,201,386	7,265,453	42.3%	-	7,265,453	42.3%
3	Space Heating	962,557	543,365	419,192	2.4%	-	419,192	2.4%
4	General Service Small (12-GSS)	1,954,373	1,035,164	919,209	5.4%	-	919,209	5.4%
5	General Service Large (12-GSL)	14,962,201	9,086,483	5,875,718	34.2%	-	5,875,718	34.2%
6	General Service Space Heating	546,294	358,139	188,155	1.1%	-	188,155	1.1%
7	Industrial Service (12-IS)	1,984,784	1,280,249	704,535	4.1%	-	704,535	4.1%
8	Industrial Service-Primary Discount			-	0.0%	-	-	0.0%
9	Real -Time Pricing (RTP)	82,550	82,550	-	0.0%	-	-	0.0%
10	Transmission Level Service (12-STR)	24,515,362	23,809,675	705,687	4.1%	-	705,687	4.1%
11	Municipal Power Service (12-M-I)	211,942	119,821	92,121	0.5%	-	92,121	0.5%
12	Water Pumping Service (12-WP)	611,125	367,776	243,349	1.4%	-	243,349	1.4%
13	Irrigation Service (12-IP-I))	200,995	111,907	89,088	0.5%	-	89,088	0.5%
14	Temporary Service (12-CS)	8,700	3,769	4,931	0.0%	-	4,931	0.0%
15	Lighting	947,775	287,875	659,900	3.8%	-	659,900	3.8%
16	**Total Retail Rates**	62,455,499	45,288,159	17,167,339	100.0%		17,167,339	100.0%
17								
18	Third Party LAC (12-LAC)	1,059,317	-	1,059,317	100.0%		1,059,317	100.0%
19								
20	**Total All Rates**	63,514,816	45,288,159	18,226,656	100.0%	-	18,226,656	100.0%

Exhibit RJM-4 - Formula-Based Rate Template - Populated for 2011

SOUTHERN PIONEER ELECTRIC COMPANY
DISTRIBUTION FORMULA BASED RATE

	ITEM	UNADJUSTED HISTORICAL TEST YEAR 2011		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT	ADJUSTED HISTORICAL TEST YEAR 2011	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR
		($)			($)	($)	Docket 380	($)
1.	**A. STATEMENT OF OPERATIONS**							
2.	Operating Revenue and Patronage Capital	60,493,642	F7, Pt. A, Col. B	[1]	-	60,493,642	Direct	58,270,203
3.	Power Production Expense	-	F7, Pt. A, Col. B			-	0.0000	-
4.	Cost of Purchased Power	45,347,282	F7, Pt. A, Col. B			45,347,282	1.0000	45,347,282
5.	Transmission Expense	789,649	F7, Pt. A, Col. B			789,649	0.0000	-
6.	Regional Market Expense	-	F7, Pt. A, Col. B			-	0.0000	-
7.	Distribution Expense - Operation	2,998,013	F7, Pt. A, Col. B			2,998,013	1.0000	2,998,013
8.	Distribution Expense - Maintenance	1,518,929	F7, Pt. A, Col. B			1,518,929	1.0000	1,518,929
9.	Customer Accounts Expense	1,292,172	F7, Pt. A, Col. B			1,292,172	1.0000	1,292,172
10.	Customer Service and Informational Expense	68,128	F7, Pt. A, Col. B			68,128	1.0000	68,128
11.	Sales Expense	12,674	F7, Pt. A, Col. B			12,674	1.0000	12,674
12.	Administrative and General Expense	1,266,887	F7, Pt. A, Col. B			1,266,887	0.9836	1,246,064
13.	**Total Operation & Maintenance Expense**	53,293,734	F7, Pt. A, Col. B		-	53,293,734	0.9848	52,483,262
14.	Depreciation and Amortization Expense	2,444,084	F7, Pt. A, Col. B			2,444,084	0.7427	1,815,106
15.	Tax Expense - Property & Gross Receipts	-	F7, Pt. A, Col. B			-	0.7427	-
16.	Tax Expense - Other	966,129	F7, Pt. A, Col. B	[2]	(966,129)	-	1.1694	-
17.	Interest on Long-Term Debt	3,538,969	F7, Pt. A, Col. B	[3]	1,537,057	5,076,026	0.8068	4,095,529
18.	Interest Charged to Construction - Credit	-	F7, Pt. A, Col. B			-	0.8068	-
19.	Interest Expense - Other	275,477	F7, Pt. A, Col. B	[4]	(193,560)	81,917	0.8068	66,094
20.	Other Deductions	155,121	F7, Pt. A, Col. B			155,121	0.8068	125,157
21.	**Total Cost of Electric Service**	60,673,514	F7, Pt. A, Col. B		377,368	61,050,882	0.9596	58,585,148
22.	**Patronage Capital & Operating Margins**	(179,872)	F7, Pt. A, Col. B		(377,368)	(557,240)		(314,945)
23.	Non Operating Margins - Interest	869	F7, Pt. A, Col. B			869	0.7427	645
24.	Allowance for Funds Used During Construction	-	F7, Pt. A, Col. B			-	0.7427	-
25.	Income (Loss) from Equity Investments	1,415,012	F7, Pt. A, Col. B			1,415,012	1.0000	1,415,012
26.	Non Operating Margins - Other	(12,666)	F7, Pt. A, Col. B			(12,666)	1.0000	(12,666)
27.	Generation and Transmission Capital Credits	-	F7, Pt. A, Col. B			-	1.0000	-
28.	Other Capital Credits and Patr. Dividends	272,500	F7, Pt. A, Col. B			272,500	0.8068	219,863
29.	Extraordinary Items		F7, Pt. A, Col. B			-	1.0000	-
30.	**Patronage Capital or Margins**	1,495,843	F7, Pt. A, Col. B		(377,368)	1,118,475	1.1694	1,307,910
31.								

SOUTHERN PIONEER ELECTRIC COMPANY
DISTRIBUTION FORMULA BASED RATE

	ITEM	UNADJUSTED HISTORICAL TEST YEAR 2011		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT	ADJUSTED HISTORICAL TEST YEAR 2011	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR
		($)			($)	($)	Docket 380	($)
32.	**B. DEBT SERVICE PAYMENTS**							
33.	Interest Expense	3,814,446	Line 17 + Line 19		1,343,497	5,157,943	0.8068	4,161,622
34.	Principal Payments	669,847	F7, Pt. O, Col. B	[5]	749,865	1,419,712	0.8068	1,145,477
35.	Total Debt Service Payments	4,484,293			2,093,362	6,577,655	0.8068	5,307,100
36.								
37.	**C. DEBT SERVICE MARGINS**							
38.	Patronage Capital or Margins	1,495,843	Line 30			1,118,475	1.1694	1,307,910
39.	Plus: Depreciation and Amortization Expense	2,444,084	Line 14			2,444,084	0.7427	1,815,106
40.	Plus: Interest Expense	3,814,446	Line 33		1,343,497	5,157,943	0.8068	4,161,622
41.	Plus: Non-Cash Other Deductions Amortizations	53,816	Trial Balance			53,816	0.8068	43,421
42.	Plus: Cash Capital Credits Cash Received	-	F7, Pt. J, L6, Col. A			-	0.8068	-
43.	Plus: Non-Cash Income Tax Expense	966,129	Line 16		(966,129)	-	1.1694	-
44.	Less: Income (Loss) from Equity Investments	(1,415,012)	Line 25			(1,415,012)	1.0000	(1,415,012)
45.	Less: Other Capital Credits and Patr. Dividends	(272,500)	Line 28			(272,500)	0.8068	(219,863)
46.	Total Debt Service Margins	7,086,806				7,086,806		5,693,184
47.								
48.	**D. DEBT SERVICE COVERAGE**	**1.58**	L45/L35			**1.08**		**1.07**
49.								
50.	**E. DEBT SERVICE PARAMETERS**						Adjusted DSC Margins are:	***Below the Floor***
51.	Floor							**1.60**
52.	Target							**1.80**
53.	Ceiling							**2.00**
54.								
55.	**F. INITIAL OPERATING INCOME ADJUSTMENT**							
56.	DSC Adjustment Required to Achieve Target							0.73
57.	Debt Service Payments							5,307,100
58.	After-Tax Operating Income Adjustment							3,859,595
59.								

SOUTHERN PIONEER ELECTRIC COMPANY
DISTRIBUTION FORMULA BASED RATE

	ITEM	UNADJUSTED HISTORICAL TEST YEAR 2011		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT	ADJUSTED HISTORICAL TEST YEAR 2011	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR
		($)			($)	($)	Docket 380	($)
60.	**G. EQUITY TEST** (Increase will not result in > 35% equity ratio)				Plus			
61.		Pre-Adjustment			Adjustment	Post-Adjustment		
62.	Total Margins and Equities	329,229	F7, Pt. C, L36		3,859,595	4,188,824		
63.	Total Assets	103,678,095	F7, Pt C, L43	[6]	12,733,879	116,411,974		
64.	Equity Ratio	0.32%	L66 / L68			3.60%		
65.								
66.	**H. FINAL REVENUE ADJUSTMENT PROPOSED**							
67.	After-Tax Operating Income Adjustment							3,859,595
68.	Divided by Tax Adjustment (1 - Combined Tax Rate)							1.00
69.	Before-Tax Revenue Adjustment							3,859,595
70.	Rate Schedule Revenue							58,270,203
71.	Adjustment Percentage							6.62%

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE - ADJUSTMENTS

1.	**ADJUSTMENT [1] -- REVENUE**			
2.	***Adjustment to annualize rate adjustment implemented during test year***			
3.	Annual Rate Adjustment Authorized by Commission		-	
4.	Total kWh Sales During Test Year		700,682,341	
5.	Average per kWh		$0.00000	L3/L4
6.	kWh Sales Prior to Implementation of Rate Adjustment			Input
7.	Revenue Adjustment to Annualize Rate Adjustment	$	-	L5 x L6
8.				
9.	**ADJUSTMENT [2] -- OTHER TAXES**			
10.	***Adjustment to remove non-cash income tax expense***			
11.	Cash Test Year Other Tax Expense	$	-	
12.	Test Year Other Tax Expense		966,129	F7, Pt. A, Col. B
13.	Adjustment to Actual Other Tax Expense	$	(966,129)	L11 - L12
14.				
15.	**ADJUSTMENT [3] -- Long-Term Interest Expense**			
16.	***Adjustment to reflect the 2012 Budget.***			
17.	Adjustment to Long-Term Interest Expense			
18.	Actual Year Long-Term Interest Expense	$	3,538,969	F7, Pt. A, Col. B
19.	Budget Year Long-Term Interest Expense		5,076,026	Budget
20.	Adjustment to Actual Long-Term Interest Expense	$	1,537,057	L19-L18
21.				
22.	**ADJUSTMENT [4] --Other Interest Expense**			
23.	***Adjustment to reflect the 2012 Budget.***			
24.	Adjustment to Other Interest Expense			
25.	Actual Year Other Interest Expense	$	275,477	F7, Pt. A, Col. B
26.	Budget Year Other Interest Expense		81,917	Budget
27.	Adjustment to Actual Other Interest Expense	$	(193,560)	L26 - L25
28.				

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE - ADJUSTMENTS

29.	**ADJUSTMENT [5] -- Principal Payments**				
30.	***Adjustment to reflect the 2012 Budget.***				
31.	Adjustment to Principal Payments				
32.	Actual Year Principal Payments		$	669,847	F7, Pt. O, Col. B
33.	Budget Year Principal Payments			1,419,712	Budget
34.	Adjustment to Actual Principal Payments		$	749,865	L33- L32
35.					
36.	**ADJUSTMENT [6] -- Assets**				
37.	***Adjustment to reflect budgeted Assets.***				
38.	Actual Year-End Assets		$	103,678,095	F7, Pt. C, L28.
39.	Budgeted Year-End Assets			116,411,974	Budget
40.	Adjustment to Actual Assets		$	12,733,879	L39 - L38
41.					
42.	**Depreciation Expense Allocator**	Alloc.		Actual Amt.	
43.	Depreciation - Transmission	0.2573	$	391,409	
44.	Depreciation - Distribution	0.7427	$	1,129,530	
45.		1.0000	$	1,520,939	

Proportional Allocation of DSC FBR Rate Adjustment to Rate Classes
Based on Base Revenue by Rate Schedule

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Per Docket 380 Cost of Service and Settlement				Allocation of Rate Adjustment		
Line No.	Rate Schedule	Revenue Settlement Rates	Allocated Power Supply Cost of Service	Base Revenue	Percent	FBR Adjustment	Base Revenue	Percent
		($)	($)	($)	(%)	($)	($)	(%)
1	Residential Service (12-RS)							
2	General Use	15,466,839	8,201,386	7,265,453	42.3%	1,633,434	8,898,887	42.3%
3	Space Heating	962,557	543,365	419,192	2.4%	94,244	513,436	2.4%
4	General Service Small (12-GSS)	1,954,373	1,035,164	919,209	5.4%	206,658	1,125,868	5.4%
5	General Service Large (12-GSL)	14,962,201	9,086,483	5,875,718	34.2%	1,320,991	7,196,709	34.2%
6	General Service Space Heating	546,294	358,139	188,155	1.1%	42,301	230,456	1.1%
7	Industrial Service (12-IS)	1,984,784	1,280,249	704,535	4.1%	158,395	862,930	4.1%
8	Industrial Service-Primary Discount			-	0.0%	-	-	0.0%
9	Real -Time Pricing (RTP)	82,550	82,550	-	0.0%	-	-	0.0%
10	Transmission Level Service (12-STR)	24,515,362	23,809,675	705,687	4.1%	158,654	864,341	4.1%
11	Municipal Power Service (12-M-I)	211,942	119,821	92,121	0.5%	20,711	112,832	0.5%
12	Water Pumping Service (12-WP)	611,125	367,776	243,349	1.4%	54,710	298,060	1.4%
13	Irrigation Service (12-IP-I))	200,995	111,907	89,088	0.5%	20,029	109,117	0.5%
14	Temporary Service (12-CS)	8,700	3,769	4,931	0.0%	1,109	6,039	0.0%
15	Lighting	947,775	287,875	659,900	3.8%	148,360	808,260	3.8%
16	**Total Retail Rates**	62,455,499	45,288,159	17,167,339	100.0%	3,859,595	21,026,935	100.0%
17								
18	Third Party LAC (12-LAC)	1,059,317	-	1,059,317	100.0%		1,059,317	100.0%
19								
20	**Total All Rates**	63,514,816	45,288,159	18,226,656	100.0%	3,859,595	22,086,252	100.0%

Exhibit RJM-5 - Southern Pioneer Annual 2011 Form 7

NATIONAL RURAL UTILITIES COOPERATIVE FINANCE CORPORATION FINANCIAL AND STATISTICAL REPORT

Submit one electronic copy and one signed hard copy to CFC. Round all numbers to the nearest dollar.

BORROWER DESIGNATION
KS0060

BORROWER NAME
SOUTHERN PIONEER ELECTRIC COMPANY

ENDING DATE
12/31/2011

CERTIFICATION

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

Signature of Office Manager or Accountant — Date 4-26-12

Signature of Manager — Date 4-26-12

BALANCE CHECK RESULTS

Needs Attention
0 Future Review
18 Matches

AUTHORIZATION CHOICES

A. NRECA uses rural electric system data for legislative, regulatory and other purposes. May we provide this report from your system to NRECA? ◉ YES ○ NO

B. Will you authorize CFC to share your data with other cooperatives? ◉ YES ○ NO

PART A. STATEMENT OF OPERATIONS

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	YEAR-TO-DATE BUDGET (c)	THIS MONTH (d)
1. Operating Revenue and Patronage Capital	58,322,890	60,493,642	63,370,000	4,815,622
2. Power Production Expense	0	0	0	0
3. Cost of Purchased Power	45,368,418	45,347,282	49,283,000	3,346,045
4. Transmission Expense	709,170	789,649	714,000	69,066
5. Regional Market Operations Expense	0	0	0	0
6. Distribution Expense - Operation	2,401,071	2,998,013	2,605,000	259,424
7. Distribution Expense - Maintenance	1,227,652	1,518,929	1,343,000	106,054
8. Consumer Accounts Expense	1,290,700	1,292,172	1,400,000	95,359
9. Customer Service and Informational Expense	33,938	68,128	42,000	14,685
10. Sales Expense	7,615	12,674	8,000	0
11. Administrative and General Expense	1,180,208	1,266,887	1,323,000	141,324
12. Total Operation & Maintenance Expense (2 thru 11)	**52,218,772**	**53,293,732**	**56,718,000**	**4,031,957**
13. Depreciation & Amortization Expense	2,201,657	2,444,084	2,615,000	205,167
14. Tax Expense - Property & Gross Receipts	0	0	0	0
15. Tax Expense - Other	1,054,289	966,129	120,000	966,129
16. Interest on Long-Term Debt	2,438,148	3,538,969	3,640,000	425,926
17. Interest Charged to Construction (Credit)	0	0	0	0
18. Interest Expense - Other	792,193	275,477	121,000	2,091
19. Other Deductions	30,492	155,121	35,000	37,871
20. Total Cost of Electric Service (12 thru 19)	**58,735,551**	**60,673,512**	**63,249,000**	**5,669,141**
21. Patronage Capital & Operating Margins (1 minus 20)	**(412,661)**	**(179,870)**	**121,000**	**(853,519)**
22. Non Operating Margins - Interest	80	869	0	70
23. Allowance for Funds Used During Construction	0	0	0	1,415,012
24. Income (Loss) from Equity Investments	1,474,761	1,415,012	360,000	0
25. Non Operating Margins - Other	9,335	(12,666)	24,000	0
26. Generation & Transmission Capital Credits	0	0	0	0
27. Other Capital Credits & Patronage Dividends	642,263	272,500	255,000	10,904
28. Extraordinary Items	0	0	0	0
29. Patronage Capital or Margins (21 thru 28)	**1,713,778**	**1,495,845**	**760,000**	**572,467**

PART B. DATA ON TRANSMISSION AND DISTRIBUTION PLANT

ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)	ITEM	YEAR-TO-DATE LAST YEAR (a)	YEAR-TO-DATE THIS YEAR (b)
1. New Services Connected	184	156	5. Miles Transmission	302	302
2. Services Retired	0	1	6. Miles Distribution Overhead	801	801
3. Total Services In Place	18,787	18,942	7. Miles Distribution Underground	18	18
4. Idle Services (Exclude Seasonal)	1,581	1,730	**8. Total Miles Energized (5+6+7)**	**1,121**	**1,121**

CFC FINANCIAL AND STATISTICAL REPORT		BORROWER DESIGNATION	
		KS0060	
		YEAR ENDING	12/31/2011
PART C. BALANCE SHEET			
ASSETS AND OTHER DEBITS		**LIABILITIES AND OTHER CREDITS**	
1. Total Utility Plant in Service	86,612,484	29. Memberships	0
2. Construction Work in Progress	12,304,058	30. Patronage Capital	(810,838)
3. Total Utility Plant (1+2)	**98,916,542**	31. Operating Margins - Prior Years	1,713,778
4. Accum. Provision for Depreciation and Amort	23,513,700	32. Operating Margins - Current Year	(179,870)
5. Net Utility Plant (3-4)	**75,402,842**	33. Non-Operating Margins	1,675,715
6. Nonutility Property - Net	0	34. Other Margins & Equities	(2,069,556)
7. Investment in Subsidiary Companies	5,423,538	**35. Total Margins & Equities (29 thru 34)**	**329,229**
8. Invest. in Assoc. Org. - Patronage Capital	0	36. Long-Term Debt CFC (Net)	0
9. Invest. in Assoc. Org. - Other - General Funds	535,768	(Payments-Unapplied ($)	
10. Invest in Assoc. Org. - Other - Nongeneral Funds	0	37. Long-Term Debt - Other (Net)	92,230,337
11. Investments in Economic Development Projects	0	(Payments-Unapplied ($)	
12. Other Investments	1,958,690	**38. Total Long-Term Debt (36 + 37)**	**92,230,337**
13. Special Funds	0	39. Obligations Under Capital Leases - Non current	0
14. Total Other Property & Investments (6 thru 13)	**7,917,996**	40. Accumulated Operating Provisions - Asset Retirement Obligations	0
15. Cash-General Funds	1,603,276	**41. Total Other Noncurrent Liabilities (39+40)**	**0**
16. Cash-Construction Funds-Trustee	57	42. Notes Payable	2,709,095
17. Special Deposits	0	43. Accounts Payable	4,532,583
18. Temporary Investments	0	44. Consumers Deposits	727,579
19. Notes Receivable - Net	19,969	45. Current Maturities Long-Term Debt	0
20. Accounts Receivable - Net Sales of Energy	3,977,440	46. Current Maturities Long-Term Debt-Economic Dev	0
21. Accounts Receivable - Net Other	129,292	47. Current Maturities Capital Leases	0
22. Renewable Energy Credits	0	48. Other Current & Accrued Liabilities	1,799,229
23. Materials & Supplies - Electric and Other	1,216,316	**49. Total Current & Accrued Liabilities (42 thru 48)**	**9,768,486**
24. Prepayments	275,695	50. Deferred Credits	1,350,043
25. Other Current & Accrued Assets	3,351,193	**51. Total Liabilities & Other Credits (35+38+41+49+50)**	**103,678,095**
26. Total Current & Accrued Assets (15 thru 25)	**10,573,238**		
27. Deferred Debits	9,784,019		
28. Total Assets & Other Debits (5+14+26+27)	**103,678,095**		
		ESTIMATED CONTRIBUTION-IN-AID-OF-CONSTRUCTION	
		Balance Beginning of Year	10,292,848
		Amounts Received This Year (Net)	329,045
		TOTAL Contributions-In-Aid-Of-Construction	**10,621,893**

PART D. THE SPACE BELOW IS PROVIDED FOR IMPORTANT NOTES REGARDING THE FINANCIAL STATEMENT CONTAINED IN THIS REPORT.

1. Under the purchase agreement made regarding the acquisition of the Aquila assets and service territory, Southern Pioneer was restricted from implementing a rate increase until April 1, 2009. On June 15, 2009, an application to change rates was submitted to the Kansas Corporation Commission (KCC) for approval, and on January 14, 2010, an overall rate increase of 9.6% was approved by the KCC. On December 20, 2011, Southern Pioneer submitted to the KCC a rate application requesting an overall increase of 10.3% ($6,112,948) split between retail tariffs and the local access charge tariff. The KCC has 240 days from the application date to review and approve the application.
2. Based on an annual actuary study of Southern Pioneer's pension plan, Southern Pioneer recognizes Other Comprehensive Income, a Projected Pension Obligation, and Pension Plan Assets. The annual Other Comprehensive Income amount is amortized over a 20 year period.
3. During 2009 Southern Pioneer requisitioned $9,580,000 from Rural Utilities Service (RUS) approved "A8" loan. In March of 2010, after fulfilling requirements set in place by RUS, Southern Pioneer requisitioned an additional $45,057,537 from the "A8" loan. These funds paid off other short-term commitments in place as of December 31, 2009. All RUS debt is guaranteed by Pioneer Electric Cooperative, Inc. Southern Pioneer bought out of the RUS program on October 24, 2011. All existing notes were either paid in full or rescinded.
4. Southern Pioneer's electric revenue is billed on cycles throughout each month based on company's readings. As of December 31, 2011, Southern Pioneer's electric revenue includes an estimated unbilled revenue amount of $1,498,535.
5. In November 2010, Southern Pioneer leased two Sherman Reilly trailers, a puller tensioner trailer and a bull wheel tensioner trailer, from Farm Credit Leasing Services Corporation. As of December 31, 2011, the amount leased equaled $ 140,875.26.
6. As of December 31, 2011, the CoBank Line of Credit (LOC) was $7,500,000 with $6,232,137 available.
7. During 2010, Southern Pioneer completed and received board approval on a 2011-2014 Construction Work Plan in the approximate amount of $51,000,000.
8. Southern Pioneer guarantees a portion of the balance in the amount of 4.37% of two MKEC loans. As of December 31, 2011, the outstanding MKEC debt guaranteed by Southern Pioneer equaled $5,501,527.
9. Southern Pioneer advanced $21,000,000 of new CoBank debt on May 25, 2011. New CoBank funds were also advanced in October 2011 to pay off existing RUS debt of $54,001,835.53 and RUS loan premiums of $9,686,403.84. CoBank also approved a construction work plan loan of $30,000,000. At December 31, 2011, none of the $30,000,000 loan had been advanced.

CFC

FINANCIAL AND STATISTICAL REPORT

BORROWER DESIGNATION	
KS0060	
YEAR ENDING	12/31/2011

Much of Part E has been consolidated. Enter only the total of "Distribution Plant" (that includes such items as Land and Land Rights, Structures and Improvements and Station Equipment), the total of "General Plant" (items such as Office Furniture, Transportation Equipment) the total of "Transmission Plant" (items such as Land and Land Rights, Roads and Trails), Steam, Nuclear, Hydro, Other Production Plants and "All Other Utility Plant"

PART E. CHANGES IN UTILITY PLANT

	PLANT ITEM	BALANCE BEGINNING OF YEAR (a)	ADDITIONS (b)	RETIREMENTS (c)	ADJUSTMENTS AND TRANSFER (d)	BALANCE END OF YEAR (e)
1	Distribution Plant Subtotal	37,156,169	5,023,108	2,472,192	504,701	40,211,786
2	General Plant Subtotal	4,203,227	34,769	204,568	0	4,033,428
3	Headquarters Plant	1,649,617	3,000	0	0	1,652,617
4	Intangibles	0	0	0	0	0
5	Transmission Plant Subtotal	15,251,789	3,519,658	1,075,391	(539,787)	17,156,269
6	Regional Transmission and Market Operation Plant	0	0	0	0	0
7	Production Plant - Steam	0	0	0	0	0
8	Production Plant - Nuclear	0	0	0	0	0
9	Production Plant - Hydro	0	0	0	0	0
10	Production Plant - Other	0	0	0	0	0
11	All Other Utility Plant	23,558,384	0	0	0	23,558,384
12	**SUBTOTAL: (1 thru 11)**	81,819,186	8,580,535	3,752,151	(35,086)	86,612,484
13	Construction Work in Progress	13,366,556	(1,062,498)			12,304,058
14	**TOTAL UTILITY PLANT (12+13)**	95,185,742	7,518,037	3,752,151	(35,086)	98,916,542

CFC NO LONGER REQUIRES SECTIONS "F", "G", AND "N" DATA
Those sections refer to data on "Analysis of Accumulated Provision for Depreciation" (F), "Materials and Supplies" (G), "Annual Meeting and Board Data" (N), and "Conservation Data" (P).

PART H. SERVICE INTERRUPTIONS

	ITEM	Avg Minutes per Consumer by Cause: Power Supplier (a)	Avg Minutes per Consumer by Cause: Major Event (b)	Avg Minutes per Consumer by Cause: Planned (c)	Avg. Minutes per Consumer by Cause: All Other (d)	TOTAL (e)
1	Present Year	7.80	39.50	5.30	88.90	141.50
2.	Five-Year Average	52.50	93.30	10.70	114.40	270.90

PART I. EMPLOYEE - HOUR AND PAYROLL STATISTICS

1.	Number of Full Time Employees	46	4	Payroll - Expensed	2,414,712
2.	Employee - Hours Worked - Regular Time	110,871	5.	Payroll - Capitalized	735,425
3.	Employee - Hours Worked - Overtime	6,334	6.	Payroll - Other	357,926

PART J. PATRONAGE CAPITAL

	ITEM	THIS YEAR (a)	CUMULATIVE (b)
1	General Retirement	0	0
2	Special Retirements	0	0
3.	**Total Retirements (1+2)**	0	0
4.	Cash Received from Retirement of Patronage Capital by Suppliers of Electric Power	0	
5	Cash Received from Retirement of Patronage Capital by Lenders for Credit Extended to the Electric System	0	
6.	**Total Cash Received (4+5)**	0	

PART K. DUE FROM CONSUMERS FOR ELECTRIC SERVICE

1	Amount Due Over 60 Days:	400,817
2	Amount Written Off During Year:	101,342

PART L. KWH PURCHASED AND TOTAL COST

	NAME OF SUPPLIER (a)	CFC USE ONLY SUPPLIER CODE (b)	RENEWABLE ENERGY PROGRAM NAME (c)	RENEWABLE FUEL TYPE (d)	KWH PURCHASED (e)	TOTAL COST (f)	AVERAGE COST PER KWH (cents) (g)	INCLUDED IN TOTAL COST: FUEL COST ADJUSTMENT (h)	INCLUDED IN TOTAL COST: WHEELING & OTHER CHARGES (or Credits) (i)	COMMENTS (j)
1	Mid Kansas Electric Company LLC (KS)	800494		0 None	718,442,671	45,347,282	6.31	30,410,348	0	Comments
2.				0 None	0	0	0.00	0	0	Comments
3.				0 None	0	0	0.00	0	0	Comments
4				0 None	0	0	0.00	0	0	Comments
5.	TOTALS				718,441,671	45,347,282	6.31	30,410,348	0	

CFC FINANCIAL AND STATISTICAL REPORT	BORROWER DESIGNATION	
	KS0060	
	YEAR ENDING	12/31/2011

PART L. KWH PURCHASED AND TOTAL COST (Continued)

COMMENTS	
1.	
2.	
3.	
4.	

CFC FINANCIAL AND STATISTICAL REPORT	BORROWER DESIGNATION	
	KS0060	
	YEAR ENDING	12/31/2011

PART M. LONG-TERM LEASES (If additional space is needed, use separate sheet)

*LIST BELOW ALL "RESTRICTED PROPERTY" ** HELD UNDER "LONG TERM" LEASE. (If none, State "NONE")*

	NAME OF LESSOR	TYPE OF PROPERTY	RENTAL THIS YEAR
1.	NONE		$0
2.			$0
3.		TOTAL	$0

** "RESTRICTED PROPERTY" means all properties other than automobiles, trucks, tractors, other vehicles (including without limitation aircraft and ships), office and warehouse space and office equipment (including without limitation computers). "LONG TERM" means leases having unexpired terms in excess of 3 years and covering property having an intial cost in excess of $250,000).

PART O. LONG-TERM DEBT SERVICE REQUIREMENTS

	NAME OF LENDER	BALANCE END OF YEAR	BILLED THIS YEAR INTEREST (a)	BILLED THIS YEAR PRINCIPAL (b)	BILLED THIS YEAR TOTAL (c)	CFC USE ONLY (d)
1	National Rural Utilities Cooperative Finance Corporation	0	0	0	0	
2	NCSC	0	0	0	0	
3	Farmer Mac	0	0	0	0	
4	CoBank, ACB	89,022,186	1,647,741	648,238	2,295,979	
5	Federal Financing Bank	0	1,883,394	53,743,703	55,627,097	
6	CoBank Lease	119,267	7,832	21,609	29,441	
7	Retirement Plan	3,088,884	0	0	0	
8		0	0	0	0	
9		0	0	0	0	
10		0	0	0	0	
11		0	0	0	0	
12	**TOTAL (Sum of 1 thru 11)**	**$92,230,337**	**$3,538,967**	**$54,413,550**	**$57,952,517**	

CFC FINANCIAL AND STATISTICAL REPORT		BORROWER DESIGNATION			
		KS0060			
		YEAR ENDING	12/31/2011		
PART R. POWER REQUIREMENTS DATA BASE					
CLASSIFICATION	**CONSUMER, SALES, AND REVENUE DATA**	**JANUARY CONSUMERS (a)**	**DECEMBER CONSUMERS (b)**	**AVERAGE CONSUMERS (c)**	**TOTAL KWH SALES AND REVENUE (d)**
1. Residential Sales	a. No. Consumers Served	12,922	12,918	12,920	
(excluding seasonal)	b. KWH Sold				136,557,714
	c. Revenue				15,557,170
2. Residential Sales -	a. No. Consumers Served	0	0	0	
Seasonal	b. KWH Sold				0
	c. Revenue				0
3. Irrigation Sales	a. No. Consumers Served	17	16	17	
	b. KWH Sold				2,467,616
	c. Revenue				262,488
4. Comm. and Ind.	a. No. Consumers Served	4,079	4,120	4,100	
1000 KVA or Less	b. KWH Sold				146,720,396
	c. Revenue				16,118,727
5. Comm. and Ind.	a. No. Consumers Served	21	21	21	
Over 1000 KVA	b. KWH Sold				412,459,634
	c. Revenue				26,802,796
6. Public Street & Highway	a. No. Consumers Served	164	137	151	
Lighting	b. KWH Sold				2,476,981
	c. Revenue				433,810
7. Other Sales to Public	a. No. Consumers Served	0	0	0	
Authority	b. KWH Sold				0
	c. Revenue				0
8. Sales for Resales-RUS	a. No. Consumers Served	0	0	0	
Borrowers	b. KWH Sold				0
	c. Revenue				0
9. Sales for Resales-Other	a. No. Consumers Served	0	0	0	
	b. KWH Sold				0
	c. Revenue				0
10. TOTAL No. of Consumers (lines 1a thru 9a)		17,203	17,212	17,208	
11. TOTAL KWH Sold (lines 1b thru 9b)					700,682,341
12. TOTAL Revenue Received From Sales of Electric Energy (line 1c thru 9c)					59,174,991
13. Transmission Revenue					0
14. Other Electric Revenue					1,318,651
15. KWH - Own Use					752,526
16. TOTAL KWH Purchased					718,442,671
17. TOTAL KWH Generated					0
18. Cost of Purchases and Generation					46,136,931
19. Interchange - KWH - Net					0
20. Peak - Sum All KW Input (Metered)					131,981
Non-coincident ____	Coincident _X_				

Z:\Accounting\Southern Pioneer Electric\Annual Reports\Annual Form 7 (2-28)\2011 F7\SPEC 2011 cfc_form7_short_form

CFC FINANCIAL AND STATISTICAL REPORT	BORROWER DESIGNATION
	KS0060
	YEAR ENDING 12/31/2011

PART S. ENERGY EFFICIENCY PROGRAMS

Line #	Classification	Added This Year			Total To Date		
		Number of Consumers (a)	Amount Invested (b)	ESTIMATED MMBTU Savings (c)	Number of Consumers (d)	Amount Invested (e)	ESTIMATED MMBTU Savings (f)
1.	Residential Sales (excluding seasonal)	0	$0	0	0	$0	0
2.	Residential Sales - Seasonal	0	$0	0	0	$0	0
3.	Irrigation Sales	0	$0	0	0	$0	0
4.	Comm. and Ind. 1000 KVA or Less	0	$0	0	0	$0	0
5.	Comm. and Ind. Over 1000 KVA	0	$0	0	0	$0	0
6.	Public Street and Highway Lighting	0	$0	0	0	$0	0
7.	Other Sales to Public Authorities	0	$0	0	0	$0	0
8.	Sales for Resales - RUS Borrowers	0	$0	0	0	$0	0
9.	Sales for Resales - Other	0	$0	0	0	$0	0
10.	TOTAL	0	$0	0	0	$0	0

CFC INVESTMENTS, LOAN GUARANTEES AND LOANS - DISTRIBUTION (All investments refer to your most recent CFC Loan Agreement)	BORROWER DESIGNATION KS0060 BORROWER NAME SOUTHERN PIONEER ELECTRIC COMPANY		
Submit an electronic copy and a signed hard copy to CFC. Round all amounts to the nearest dollar.	MONTH ENDING 12/31/2011		

7a - PART I - INVESTMENTS

	DESCRIPTION (a)	INCLUDED ($) (b)	EXCLUDED ($) (c)	INCOME OR LOSS (d)
2. INVESTMENTS IN ASSOCIATED ORGANIZATIONS				
5	MID-KANSAS ELECTRIC COMPANY	0	5,423,538	0
6	COBANK-MEMBERSHIP	0	1,000	0
7	COBANK-PATRONAGE	0	534,768	0
8		0	0	0
	Subtotal (Line 5 thru 8)	0	5,959,306	0
3. INVESTMENTS IN ECONOMIC DEVELOPMENT PROJECTS				
9		0	0	0
10		0	0	0
11		0	0	0
12		0	0	0
	Subtotal (Line 9 thru 12)	0	0	0
4. OTHER INVESTMENTS				
13	OTHER INVESTMENTS- & PIONEER COMMUNICATIONS	33,377	0	0
14	FEDERATED RURAL INS EX	54,030	0	0
15	NISC CAPITAL CREDITS	27,032	0	0
16	RESTRICTED ASSETS-RETIREMENT PLAN	0	1,844,251	0
	Subtotal (Line 13 thru 16)	114,439	1,844,251	0
5. SPECIAL FUNDS				
17		0	0	0
18		0	0	0
19		0	0	0
20		0	0	0
	Subtotal (Line 17 thru 20)	0	0	0
6. CASH - GENERAL				
21	FNB - LIBERAL	0	242,248	0
22	WACHOVIA & CLEARING ACCOUNT & WORKING FUNDS	1,001,044	251,015	0
23	PEOPLES BANK	0	28,863	0
24	GRANT COUNTY BANK	0	80,107	0
	Subtotal (Line 21 thru 24)	1,001,044	602,233	0
7. SPECIAL DEPOSITS				
25		0	0	0
26		0	0	0
27		0	0	0
28		0	0	0
	Subtotal (Line 25 thru 28)	0	0	0
8. TEMPORARY INVESTMENTS				
29		0	0	0
30		0	0	0
31		0	0	0
32		0	0	0
	Subtotal (Line 29 thru 32)	0	0	0
9. ACCOUNT & NOTES RECEIVABLE - NET				
33	NOTES RECEIVABLE-EMPLOYEE COMPUTER CONTRACTS	8,735	0	0
34	NOTES RECEIVABLE-LINE EXTENSION	11,234	0	0
35	ACCOUNTS RECEIVABLE-NET	129,292	0	0
36		0	0	0
	Subtotal (Line 33 thru 36)	149,261	0	0
10. COMMITMENTS TO INVEST WITHIN 12 MONTHS BUT NOT ACTUALLY PURCHASED				
37		0	0	0
38		0	0	0
39		0	0	0
40		0	0	0
	Subtotal (Line 37 thru 40)	0	0	0
	Total	1,264,743	8,405,790	0

CFC INVESTMENTS, LOAN GUARANTEES AND LOANS - DISTRIBUTION	BORROWER DESIGNATION
(All investments refer to your most recent CFC Loan Agreement)	KS0060
	BORROWER NAME
	SOUTHERN PIONEER ELECTRIC COMPANY
Submit an electronic copy and a signed hard copy to CFC. Round all amounts to the nearest dollar.	MONTH ENDING
	12/31/2011

7a - PART II. LOAN GUARANTEES

Line No.	Organization & Guarantee Beneficiary (a)	Maturity Date of Guarantee Obligation (b)	Original Amount ($) (c)	Performance Guarantee Exposure or Loan Balance ($) (d)	Available Loans (Covered by Guarantees) (e)
1	MID-KANSAS ELECTRIC COMPANY	3/30/2037	5,637,300	5,501,527	0
2			0	0	0
3			0	0	0
4			0	0	0
5			0	0	0
TOTALS (Line 1 thru 5)			5,637,300	5,501,527	0

7a - PART III. LOANS

Line No.	Name of Organization (a)	Maturity Date (b)	Original Amount ($) (c)	Loan Balance ($) (d)	Available Loans (e)
1	EMPLOYEES, OFFICERS, DIRECTORS		13,813	8,735	0
2			0	0	0
3			0	0	0
4			0	0	0
5			0	0	0
TOTALS (Line 1 thru 5)			13,813	8,735	0

7a - PART IV. TOTAL INVESTMENTS AND LOANS GUARANTEES

1	TOTAL (Part I, Total - Column b + Part II, Totals - Column d + Column e + Part III, Totals - Column d + Column e)		6,775,005
2	LARGER OF (a) OR (b)		14,837,481
	a. 15 percent of Total Utility Plant (CFC Form 7, Part C, Line 3)	14,837,481	
	b. 50 percent of Total Equity (CFC Form 7, Part C, Line 35)	164,615	

Exhibit RJM-6 Projected DSC-FBR Calculations

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE

	ITEM	TEST YEAR 2013		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT	ADJUSTED HISTORICAL TEST YEAR 2013	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR
		($)			($)	($)		($)
1.	**A. STATEMENT OF OPERATIONS**							
2.	Operating Revenue and Patronage Capital	62,951,671	F7, Pt. A, Col. B	[1]	-	62,951,671	Direct	59,769,955
3.	Power Production Expense	-	F7, Pt. A, Col. B			-	0.0000	-
4.	Cost of Purchased Power	44,210,770	F7, Pt. A, Col. B			44,210,770	1.0000	44,210,770
5.	Transmission Expense	906,527	F7, Pt. A, Col. B			906,527	0.0000	-
6.	Regional Market Expense		F7, Pt. A, Col. B			-	0.0000	-
7.	Distribution Expense - Operation	3,870,838	F7, Pt. A, Col. B			3,870,838	1.0000	3,870,838
8.	Distribution Expense - Maintenance	1,641,491	F7, Pt. A, Col. B			1,641,491	1.0000	1,641,491
9.	Customer Accounts Expense	1,416,904	F7, Pt. A, Col. B			1,416,904	1.0000	1,416,904
10.	Customer Service and Informational Expense	196,868	F7, Pt. A, Col. B			196,868	1.0000	196,868
11.	Sales Expense	12,486	F7, Pt. A, Col. B			12,486	1.0000	12,486
12.	Administrative and General Expense	1,865,078	F7, Pt. A, Col. B			1,865,078	0.9836	1,834,422
13.	**Total Operation & Maintenance Expense**	54,120,962	F7, Pt. A, Col. B		-	54,120,962	0.9827	53,183,780
14.	Depreciation and Amortization Expense	2,943,957	F7, Pt. A, Col. B			2,943,957	0.8164	2,403,300
15.	Tax Expense - Property & Gross Receipts	-	F7, Pt. A, Col. B			-	0.8164	-
16.	Tax Expense - Other	1,797,804	F7, Pt. A, Col. B	[2]	(1,797,804)	-	formula	1,328,698
17.	Interest on Long-Term Debt	5,478,156	F7, Pt. A, Col. B	[3]	654,906	6,133,063	0.8068/0.7125	4,886,600
18.	Interest Charged to Construction - Credit	-	F7, Pt. A, Col. B			-	0.7968	-
19.	Interest Expense - Other	112,200	F7, Pt. A, Col. B	[4]	-	112,200	0.7968	89,397
20.	Other Deductions	447,987	F7, Pt. A, Col. B			447,987	0.7968	356,939
21.	**Total Cost of Electric Service**	64,901,066	F7, Pt. A, Col. B		(1,142,898)	63,758,168	0.9763	62,248,714
22.	**Patronage Capital & Operating Margins**	(1,949,395)	F7, Pt. A, Col. B		1,142,898	(806,497)		(2,478,759)
23.	Non Operating Margins - Interest	1,200	F7, Pt. A, Col. B			1,200	0.8164	980
24.	Allowance for Funds Used During Construction	-	F7, Pt. A, Col. B			-	0.8164	-
25.	Income (Loss) from Equity Investments	3,753,000	F7, Pt. A, Col. B			3,753,000	1.0000	3,753,000
26.	Non Operating Margins - Other	12,000	F7, Pt. A, Col. B			12,000	1.0000	12,000
27.	Generation and Transmission Capital Credits	-	F7, Pt. A, Col. B			-	1.0000	-
28.	Other Capital Credits and Patr. Dividends	962,285	F7, Pt. A, Col. B			962,285	0.7968	766,713
29.	Extraordinary Items	-	F7, Pt. A, Col. B			-	1.0000	-
30.	**Patronage Capital or Margins**	2,779,090	F7, Pt. A, Col. B		1,142,898	3,921,988		2,053,934
31.								

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE

	ITEM	TEST YEAR 2013		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT	ADJUSTED HISTORICAL TEST YEAR 2013	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR
		($)			($)	($)		($)
32.	**B. DEBT SERVICE PAYMENTS**							
33.	Interest Expense	5,590,356	Line 17 + Line 19		654,906	6,245,263	0.7968	4,975,997
34.	Principal Payments	1,502,177	F7, Pt. O, Col. B	[5]	86,557	1,588,734	0.7968	1,265,845
35.	Total Debt Service Payments	7,092,534			741,463	7,833,997	0.7968	6,241,842
36.								
37.	**C. DEBT SERVICE MARGINS**							
38.	Patronage Capital or Margins	2,779,090	Line 30		1,142,898	3,921,988	0.0000	2,053,934
39.	Plus: Depreciation and Amortization Expense	2,943,957	Line 14			2,943,957	0.8164	2,403,300
40.	Plus: Interest Expense	5,590,356	Line 33		654,906	6,245,263	0.7968	4,975,997
41.	Plus: Non-Cash Other Deductions Amortizations	332,816	trial balance			332,816	0.7968	265,176
42.	Plus: Cash Capital Credits Cash Received	612,000	F7, Pt. J, L6, Col. A			612,000	0.7968	487,619
43.	Plus: Non-Cash Income Tax Expense	1,797,804	line 16.		(1,797,804)	-	line 16	1,328,698
44.	Less: Income (Loss) from Equity Investments	(3,753,000)	Line 25			(3,753,000)	1.0000	(3,753,000)
45.	Less: Other Capital Credits and Patr. Dividends	(962,285)	Line 28			(962,285)	0.7968	(766,713)
46.	Total Debt Service Margins	9,340,739			-	9,340,739		6,995,010
47.								
48.	**D. DEBT SERVICE COVERAGE**	**1.32**	L45/L35			**1.19**		**1.12**
49.								
50.	**E. DEBT SERVICE PARAMETERS**						Adjusted DSC Margins are:	***Below the Floor***
51.	Floor							**1.60**
52.	Target							**1.60**
53.	Ceiling							**2.00**
54.								
55.	**F. INITIAL OPERATING INCOME ADJUSTMENT**							
56.	DSC Adjustment Required to Achieve Target							0.48
57.	Debt Service Payments							6,241,842
58.	After-Tax Operating Income Adjustment							2,991,937
59.								

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE

	ITEM	TEST YEAR 2013		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT	ADJUSTED HISTORICAL TEST YEAR 2013	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR
		($)			($)	($)		($)
60.	**G. EQUITY TEST** (Increase will not result in > 35% equity ratio)				Test Year	Rate		
61.		Pre-Adjustment			Adjustment	Adjustments	Post-Adjustment	
62.	Total Margins and Equities	1,938,106	F7, Pt. C, L36					
63.	Total Assets	126,987,809	Budget					
64.	Equity Ratio	1.53%	L66 / L68					
65.								
66.	**H. FINAL REVENUE ADJUSTMENT PROPOSED**							
67.	After-Tax Operating Income Adjustment							2,991,937
68.	Divided by Tax Adjustment (1 - Combined Tax Rate)							1.00
69.	Pre-tax Revenue Adjustment							2,991,937
70.	Rate Schedule Revenue							59,769,955
71.	Adjustment Percentage							5.01%

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE - ADJUSTMENTS

1.	**ADJUSTMENT [1] -- REVENUE**			
2.	***Adjustment to annualize rate adjustment implemented during historical test year***			
3.	Annual Rate Adjustment Authorized by Commission			
4.	Total kWh Sales During Test Year		762,123,302	
5.	Average per kWh		$0.00000	L2/L3
6.	kWh Sales Prior to Implementation of Rate Adjustment		867,883,011	Input
7.	Revenue Adjustment to Annualize Rate Adjustment			L5*L6
8.				
9.	**ADJUSTMENT [2] -- OTHER TAXES**			
10.	***Adjustment to remove non-cash income tax expense***			
11.	Cash Test Year Other Tax Expense	$	-	
12.	Test Year Other Tax Expense	$	1,797,804	F7, Pt. A, Col. B
13.	Adjustment to Actual Other Tax Expense	$	(1,797,804)	L11 - L12
14.				
15.	**ADJUSTMENT [3] -- Long-Term Interest Expense**			
16.	***Adjustment to reflect the Budget.***			
17.	Adjustment to Long-Term Interest Expense			
18.	Actual Year Long-Term Interest Expense	$	5,478,156	F7, Pt. A, Col. B
19.	Budget Year Long-Term Interest Expense		6,133,063	Budget
20.	Adjustment to Actual Long-Term Interest Expense	$	654,906	L26 - L25
21.				
22.	**ADJUSTMENT [4] -- Other Interest**			
23.	***Adjustment to reflect the Budget.***			
24.	Adjustment to Other Interest Expense			
25.	Actual Year Other Interest Expense		112,200	F7, Pt. A, Col. B
26.	Budget Year Other Interest Expense		112,200	Budget
27.	Adjustment to Actual Other Interest Expense	$	-	L26 - L25
28.				
29.	**ADJUSTMENT [5] -- Principal Payments**			
30.	***Adjustment to reflect the Budget.***			
31.	Adjustment to Principal Payments			
32.	Actual Year Principal Payments	$	1,502,177	
33.	Budget Year Principal Payments		1,588,734	
34.	Adjustment to Actual Principal Payments	$	86,557	

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE

	ITEM	TEST YEAR 2014 ($)		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT ($)	ADJUSTED HISTORICAL TEST YEAR 2014 ($)	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR ($)
1.	**A. STATEMENT OF OPERATIONS**							
2.	Operating Revenue and Patronage Capital	71,624,037	F7, Pt. A, Col. B	[1]	3,407,128	75,031,165	Direct	71,764,818
3.	Power Production Expense	-	F7, Pt. A, Col. B			-	0.0000	-
4.	Cost of Purchased Power	52,135,456	F7, Pt. A, Col. B			52,135,456	1.0000	52,135,456
5.	Transmission Expense	970,364	F7, Pt. A, Col. B			970,364	0.0000	-
6.	Regional Market Expense		F7, Pt. A, Col. B			-	0.0000	-
7.	Distribution Expense - Operation	4,102,220	F7, Pt. A, Col. B			4,102,220	1.0000	4,102,220
8.	Distribution Expense - Maintenance	1,723,565	F7, Pt. A, Col. B			1,723,565	1.0000	1,723,565
9.	Customer Accounts Expense	1,488,513	F7, Pt. A, Col. B			1,488,513	1.0000	1,488,513
10.	Customer Service and Informational Expense	206,717	F7, Pt. A, Col. B			206,717	1.0000	206,717
11.	Sales Expense	13,111	F7, Pt. A, Col. B			13,111	1.0000	13,111
12.	Administrative and General Expense	1,959,097	F7, Pt. A, Col. B			1,959,097	0.9836	1,926,896
13.	**Total Operation & Maintenance Expense**	62,599,043	F7, Pt. A, Col. B		-	62,599,043	0.9840	61,596,478
14.	Depreciation and Amortization Expense	3,535,055	F7, Pt. A, Col. B			3,535,055	0.8164	2,885,843
15.	Tax Expense - Property & Gross Receipts	-	F7, Pt. A, Col. B			-	0.8164	-
16.	Tax Expense - Other	1,195,681	F7, Pt. A, Col. B	[2]	(1,195,681)	-	formula	2,131,263
17.	Interest on Long-Term Debt	6,133,063	F7, Pt. A, Col. B	[3]	625,176	6,758,239	0.8068	5,452,801
18.	Interest Charged to Construction - Credit	-	F7, Pt. A, Col. B			-	0.8068	-
19.	Interest Expense - Other	112,200	F7, Pt. A, Col. B	[4]	-	112,200	0.8068	90,527
20.	Other Deductions	447,987	F7, Pt. A, Col. B			447,987	0.8068	361,453
21.	**Total Cost of Electric Service**	74,023,028	F7, Pt. A, Col. B		(570,505)	73,452,523	0.9873	72,518,366
22.	**Patronage Capital & Operating Margins**	(2,398,991)	F7, Pt. A, Col. B		3,977,632	1,578,641		(753,547)
23.	Non Operating Margins - Interest	1,200	F7, Pt. A, Col. B			1,200	0.8164	980
24.	Allowance for Funds Used During Construction	-	F7, Pt. A, Col. B			-	0.8164	-
25.	Income (Loss) from Equity Investments	3,204,000	F7, Pt. A, Col. B			3,204,000	1.0000	3,204,000
26.	Non Operating Margins - Other	12,000	F7, Pt. A, Col. B			12,000	1.0000	12,000
27.	Generation and Transmission Capital Credits	-	F7, Pt. A, Col. B			-	1.0000	-
28.	Other Capital Credits and Patr. Dividends	1,030,104	F7, Pt. A, Col. B			1,030,104	0.8068	831,127
29.	Extraordinary Items	-	F7, Pt. A, Col. B			-	1.0000	-
30.	**Patronage Capital or Margins**	1,848,313	F7, Pt. A, Col. B		3,977,632	5,825,946		3,294,560
31.								

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE

	ITEM	TEST YEAR 2014		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT	ADJUSTED HISTORICAL TEST YEAR 2014	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR
		($)			($)	($)		($)
32.	**B. DEBT SERVICE PAYMENTS**							
33.	Interest Expense	6,245,263	Line 17 + Line 19		625,176	6,870,439	0.8068	5,543,328
34.	Principal Payments	1,588,734	F7, Pt. O, Col. B	[5]	247,123	1,835,858	0.8068	1,481,239
35.	Total Debt Service Payments	7,833,997			872,299	8,706,296	0.8068	7,024,567
36.								
37.	**C. DEBT SERVICE MARGINS**							
38.	Patronage Capital or Margins	1,848,313	Line 30		3,977,632	5,825,946		3,294,560
39.	Plus: Depreciation and Amortization Expense	3,535,055	Line 14			3,535,055	0.8164	2,885,843
40.	Plus: Interest Expense	6,245,263	Line 33		625,176	6,870,439	0.8068	5,543,328
41.	Plus: Non-Cash Other Deductions Amortizations	332,816			-	332,816	0.8068	268,529
42.	Plus: Cash Capital Credits Cash Received	670,000	F7, Pt. J, L6, Col. A			670,000	0.8068	540,581
43.	Plus: Non-Cash Income Tax Expense	1,195,681			(1,195,681)	-	formula	2,131,263
44.	Less: Income (Loss) from Equity Investments	(3,204,000)	Line 25			(3,204,000)	1.0000	(3,204,000)
45.	Less: Other Capital Credits and Patr. Dividends	(1,030,104)	Line 28			(1,030,104)	0.8068	(831,127)
46.	Total Debt Service Margins	9,593,024			3,407,128	13,000,151		10,628,977
47.								
48.	**D. DEBT SERVICE COVERAGE**	**1.22**	L45/L35			**1.49**		**1.51**
49.								
50.	**E. DEBT SERVICE PARAMETERS**						Adjusted DSC Margins are:	***Below the Floor***
51.	Floor							1.60
52.	Target							1.80
53.	Ceiling							2.00
54.								
55.	**F. INITIAL OPERATING INCOME ADJUSTMENT**							
56.	DSC Adjustment Required to Achieve Target							0.29
57.	Debt Service Payments							7,024,567
58.	After-Tax Operating Income Adjustment							2,015,244
59.								

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE

	ITEM	TEST YEAR 2014	ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT	ADJUSTED HISTORICAL TEST YEAR 2014	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR
		($)		($)	($)		($)
60.	**G. EQUITY TEST (Increase will not result in > 35% equity ratio)**			Test Year	Rate		
61.		Pre-Adjustment		Adjustment	Adjustment	Post-Adjustment	
62.	Total Margins and Equities	3,786,419 F7, Pt. C, L36					
63.	Total Assets	142,327,896 F7, Pt C, L43					
64.	Equity Ratio	2.66% L66 / L68					
65.							
66.	**H. FINAL REVENUE ADJUSTMENT PROPOSED**						
67.	After-Tax Operating Income Adjustment						2,015,244
68.	Divided by Tax Adjustment (1 - Combined Tax Rate)						1.00
69.	Pre-tax Revenue Adjustment						2,015,244
70.	Rate Schedule Revenue						71,764,818
71.	Adjustment Percentage						2.81%

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE - ADJUSTMENTS

1.	**ADJUSTMENT [1] -- REVENUE**			
2.	***Adjustment to annualize rate adjustment implemented during historical test year***			
3.	Annual Rate Adjustment Authorized by Commission		2,991,937	Docket 380 Order
4.	Total kWh Sales During Test Year		762,123,302	Docket 380 Order
5.	Average per kWh		$0.00393	L2/L3
6.	kWh Sales Prior to Implementation of Rate Adjustment		867,883,011	Input
7.	Revenue Adjustment to Annualize Rate Adjustment	$	3,407,128	L5*L6
8.				
9.	**ADJUSTMENT [2] -- OTHER TAXES**			
10.	***Adjustment to remove non-cash income tax expense***			
11.	Cash Test Year Other Tax Expense	$	-	
12.	Test Year Other Tax Expense	$	1,195,681	F7, Pt. A, Col. B
13.	Adjustment to Actual Other Tax Expense	$	(1,195,681)	L11 - L12
14.				
15.	**ADJUSTMENT [3] -- Long-Term Interest Expense**			
16.	***Adjustment to reflect the Budget.***			Budget
17.	Adjustment to Long-Term Interest Expense			
18.	Actual Year Long-Term Interest Expense	$	6,133,063	
19.	Budget Year Long-Term Interest Expense		6,758,239	
20.	Adjustment to Actual Long-Term Interest Expense	$	625,176	
21.				
22.	**ADJUSTMENT [4] -- Other Interest**			
23.	***Adjustment to reflect the Budget.***			
24.	Adjustment to Other Interest Expense			
25.	Actual Year Other Interest Expense		112,200	F7, Pt. A, Col. B
26.	Budget Year Other Interest Expense		112,200	0
27.	Adjustment to Actual Other Interest Expense	$	-	L26 - L25
28.				
29.	**ADJUSTMENT [5] -- Principal Payments**			
30.	***Adjustment to reflect the Budget.***			
31.	Adjustment to Principal Payments			
32.	Actual Year Principal Payments	$	1,588,734	
33.	Budget Year Principal Payments		1,835,858	SPEC records
34.	Adjustment to Actual Principal Payments	$	247,123	

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE

	ITEM	TEST YEAR 2015		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT	ADJUSTED HISTORICAL TEST YEAR 2015	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR
		($)			($)	($)		($)
1.	**A. STATEMENT OF OPERATIONS**							
2.	Operating Revenue and Patronage Capital	73,700,382	F7, Pt. A, Col. B	[1]	5,538,206	79,238,588	Direct	75,959,593
3.	Power Production Expense	-	F7, Pt. A, Col. B			-	0.0000	-
4.	Cost of Purchased Power	54,076,845	F7, Pt. A, Col. B			54,076,845	1.0000	54,076,845
5.	Transmission Expense	1,038,874	F7, Pt. A, Col. B			1,038,874	0.0000	-
6.	Regional Market Expense		F7, Pt. A, Col. B			-	0.0000	-
7.	Distribution Expense - Operation	4,348,199	F7, Pt. A, Col. B			4,348,199	1.0000	4,348,199
8.	Distribution Expense - Maintenance	1,809,743	F7, Pt. A, Col. B			1,809,743	1.0000	1,809,743
9.	Customer Accounts Expense	1,563,763	F7, Pt. A, Col. B			1,563,763	1.0000	1,563,763
10.	Customer Service and Informational Expense	217,058	F7, Pt. A, Col. B			217,058	1.0000	217,058
11.	Sales Expense	13,766	F7, Pt. A, Col. B			13,766	1.0000	13,766
12.	Administrative and General Expense	2,057,878	F7, Pt. A, Col. B			2,057,878	0.9836	2,024,054
13.	**Total Operation & Maintenance Expense**	65,126,127	F7, Pt. A, Col. B		-	65,126,127	0.9835	64,053,429
14.	Depreciation and Amortization Expense	3,842,809	F7, Pt. A, Col. B			3,842,809	0.8164	3,137,078
15.	Tax Expense - Property & Gross Receipts	-	F7, Pt. A, Col. B			-	0.8164	-
16.	Tax Expense - Other	870,169	F7, Pt. A, Col. B	[2]	(870,169)	-	formula	2,807,169
17.	Interest on Long-Term Debt	6,758,239	F7, Pt. A, Col. B	[3]	375,613	7,133,852	0.8068	5,755,860
18.	Interest Charged to Construction - Credit	-	F7, Pt. A, Col. B			-	0.8068	-
19.	Interest Expense - Other	112,200	F7, Pt. A, Col. B	[4]	-	112,200	0.8068	90,527
20.	Other Deductions	447,987	F7, Pt. A, Col. B			447,987	0.8068	361,453
21.	**Total Cost of Electric Service**	77,157,531	F7, Pt. A, Col. B		(494,556)	76,662,975	0.9940	76,205,515
22.	**Patronage Capital & Operating Margins**	(3,457,149)	F7, Pt. A, Col. B		6,032,762	2,575,614		(245,923)
23.	Non Operating Margins - Interest	1,200	F7, Pt. A, Col. B			1,200	0.8164	980
24.	Allowance for Funds Used During Construction	-	F7, Pt. A, Col. B			-	0.8164	-
25.	Income (Loss) from Equity Investments	3,667,000	F7, Pt. A, Col. B			3,667,000	1.0000	3,667,000
26.	Non Operating Margins - Other	12,000	F7, Pt. A, Col. B			12,000	1.0000	12,000
27.	Generation and Transmission Capital Credits	-	F7, Pt. A, Col. B			-	1.0000	-
28.	Other Capital Credits and Patr. Dividends	1,122,078	F7, Pt. A, Col. B			1,122,078	0.8068	905,335
29.	Extraordinary Items	-	F7, Pt. A, Col. B			-	1.0000	-
30.	**Patronage Capital or Margins**	1,345,129	F7, Pt. A, Col. B		6,032,762	7,377,892		4,339,391
31.								

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE

	ITEM	TEST YEAR 2015 ($)		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT ($)	ADJUSTED HISTORICAL TEST YEAR 2015 ($)	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR ($)
32.	**B. DEBT SERVICE PAYMENTS**							
33.	Interest Expense	6,870,439	Line 17 + Line 19		375,613	7,246,052	0.8068	5,846,387
34.	Principal Payments	1,835,858	F7, Pt. O, Col. B	[5]	627,644	2,463,502	0.8068	1,987,646
35.	Total Debt Service Payments	8,706,296			1,003,258	9,709,554	0.8068	7,834,033
36.								
37.	**C. DEBT SERVICE MARGINS**							
38.	Patronage Capital or Margins	1,345,129	Line 30		6,032,762	7,377,892	0.0000	4,339,391
39.	Plus: Depreciation and Amortization Expense	3,842,809	Line 14			3,842,809	0.8164	3,137,078
40.	Plus: Interest Expense	6,870,439	Line 33		375,613	7,246,052	0.8164	5,915,316
41.	Plus: Non-Cash Other Deductions Amortizations	332,816			-	332,816	0.8164	271,694
42.	Plus: Cash Capital Credits Cash Received	729,000	F7, Pt. J, L6, Col. A			729,000	0.8164	595,119
43.	Plus: Non-Cash Income Tax Expense	870,169			(870,169)	-		2,807,169
44.	Less: Income (Loss) from Equity Investments	(3,667,000)	Line 25			(3,667,000)	1.0000	(3,667,000)
45.	Less: Other Capital Credits and Patr. Dividends	(1,122,078)	Line 28			(1,122,078)	0.8164	(916,009)
46.	Total Debt Service Margins	9,201,284			5,538,206	14,739,491		12,482,760
47.								
48.	**D. DEBT SERVICE COVERAGE**	**1.06**	L45/L35			**1.52**		**1.59**
49.								
50.	**E. DEBT SERVICE PARAMETERS**						Adjusted DSC Margins are:	***Below the Floor***
51.	Floor							1.60
52.	Target							1.80
53.	Ceiling							2.00
54.								
55.	**F. INITIAL OPERATING INCOME ADJUSTMENT**							
56.	DSC Adjustment Required to Achieve Target							0.21
57.	Debt Service Payments							7,834,033
58.	After-Tax Operating Income Adjustment							1,618,500
59.								

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE

	ITEM	TEST YEAR 2015	ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT	ADJUSTED HISTORICAL TEST YEAR 2015	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR
		($)		($)	($)		($)
60.	**G. EQUITY TEST (Increase will not result in > 35% equity ratio)**			Test Year	Rate		
61.		Pre-Adjustment		Adjustment	Adjustment	Post-Adjustment	
62.	Total Margins and Equities	5,131,549 F7, Pt. C, L36					
63.	Total Assets	157,012,479 F7, Pt C, L43					
64.	Equity Ratio	3.27% L66 / L68					
65.							
66.	**H. FINAL REVENUE ADJUSTMENT PROPOSED**						
67.	After-Tax Operating Income Adjustment						1,618,500
68.	Divided by Tax Adjustment (1 - Combined Tax Rate)						1.00
69.	Pre-tax Revenue Adjustment						1,618,500
70.	Rate Schedule Revenue						75,959,593
71.	Adjustment Percentage						2.13%

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE - ADJUSTMENTS

1.	**ADJUSTMENT [1] – REVENUE**		
2.	***Adjustment to annualize rate adjustment implemented during historical test year***		
3.	Annual Rate Adjustment Authorized by Commission	5,422,372	Docket 380 Order
4.	Total kWh Sales During Test Year	867,883,011	Docket 380 Order
5.	Average per kWh	$0.00625	L2/L3
6.	kWh Sales Prior to Implementation of Rate Adjustment	886,423,049	Input
7.	Revenue Adjustment to Annualize Rate Adjustment	$ 5,538,206	L5*L6
8.			
9.	**ADJUSTMENT [2] – OTHER TAXES**		
10.	***Adjustment to remove non-cash income tax expense***		
11.	Cash Test Year Other Tax Expense	-	Docket 380 Order
12.	Test Year Other Tax Expense	870,169	Docket 380 Order
13.	Adjustment to Actual Other Tax Expense	$ (870,169)	L2/L3
14.			
15.	**ADJUSTMENT [3] – Long-Term Interest Expense**		
16.	***Adjustment to reflect the Budget.***		Budget
17.	Adjustment to Long-Term Interest Expense		
18.	Actual Year Long-Term Interest Expense	$ 6,758,239	
19.	Budget Year Long-Term Interest Expense	7,133,852	
20.	Adjustment to Actual Long-Term Interest Expense	$ 375,613	
21.			
22.	**ADJUSTMENT [4] – Other Interest**		
23.	***Adjustment to reflect the Budget.***		
24.	Adjustment to Other Interest Expense		
25.	Actual Year Other Interest Expense	112,200	F7, Pt. A, Col. B
26.	Budget Year Other Interest Expense	112,200	0
27.	Adjustment to Actual Other Interest Expense	$ -	L26 - L25
28.			
29.	**ADJUSTMENT [5] – Principal Payments**		
30.	***Adjustment to reflect the Budget.***		
31.	Adjustment to Principal Payments		
32.	Actual Year Principal Payments	$ 1,835,858	
33.	Budget Year Principal Payments	2,463,502	SPEC records
34.	Adjustment to Actual Principal Payments	$ 627,644	

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE

	ITEM	TEST YEAR 2016 ($)		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT ($)	ADJUSTED HISTORICAL TEST YEAR 2016 ($)	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR ($)
1.	A. STATEMENT OF OPERATIONS							
2.	Operating Revenue and Patronage Capital	75,224,866	F7, Pt. A, Col. B	[1]	7,201,556	82,426,421	Direct	79,136,662
3.	Power Production Expense	-	F7, Pt. A, Col. B			-	0.0000	-
4.	Cost of Purchased Power	55,503,549	F7, Pt. A, Col. B			55,503,549	1.0000	55,503,549
5.	Transmission Expense	1,112,409	F7, Pt. A, Col. B			1,112,409	0.0000	-
6.	Regional Market Expense		F7, Pt. A, Col. B			-	0.0000	-
7.	Distribution Expense - Operation	4,609,745	F7, Pt. A, Col. B			4,609,745	1.0000	4,609,745
8.	Distribution Expense - Maintenance	1,900,231	F7, Pt. A, Col. B			1,900,231	1.0000	1,900,231
9.	Customer Accounts Expense	1,642,842	F7, Pt. A, Col. B			1,642,842	1.0000	1,642,842
10.	Customer Service and Informational Expense	227,917	F7, Pt. A, Col. B			227,917	1.0000	227,917
11.	Sales Expense	14,455	F7, Pt. A, Col. B			14,455	1.0000	14,455
12.	Administrative and General Expense	2,161,665	F7, Pt. A, Col. B			2,161,665	0.9836	2,126,135
13.	**Total Operation & Maintenance Expense**	67,172,813	F7, Pt. A, Col. B		-	67,172,813	0.9829	66,024,873
14.	Depreciation and Amortization Expense	4,117,770	F7, Pt. A, Col. B			4,117,770	0.8164	3,361,543
15.	Tax Expense - Property & Gross Receipts	-	F7, Pt. A, Col. B			-	0.8164	-
16.	Tax Expense - Other	175,121	F7, Pt. A, Col. B	[2]	(175,121)	-	formula	2,867,502
17.	Interest on Long-Term Debt	7,133,852	F7, Pt. A, Col. B	[3]	269,307	7,403,159	0.8068	5,973,147
18.	Interest Charged to Construction - Credit	-	F7, Pt. A, Col. B			-	0.8068	-
19.	Interest Expense - Other	112,200	F7, Pt. A, Col. B	[4]	-	112,200	0.8068	90,527
20.	Other Deductions	447,987	F7, Pt. A, Col. B			447,987	0.8068	361,453
21.	**Total Cost of Electric Service**	79,159,742	F7, Pt. A, Col. B		94,186	79,253,928	0.9927	78,679,045
22.	**Patronage Capital & Operating Margins**	(3,934,876)	F7, Pt. A, Col. B		7,107,370	3,172,493		457,617
23.	Non Operating Margins - Interest	1,200	F7, Pt. A, Col. B			1,200	0.8164	980
24.	Allowance for Funds Used During Construction	-	F7, Pt. A, Col. B			-	0.8164	-
25.	Income (Loss) from Equity Investments	3,000,000	F7, Pt. A, Col. B			3,000,000	1.0000	3,000,000
26.	Non Operating Margins - Other	12,000	F7, Pt. A, Col. B			12,000	1.0000	12,000
27.	Generation and Transmission Capital Credits	-	F7, Pt. A, Col. B			-	1.0000	-
28.	Other Capital Credits and Patr. Dividends	1,192,383	F7, Pt. A, Col. B			1,192,383	0.8068	962,059
29.	Extraordinary Items	-	F7, Pt. A, Col. B			-	1.0000	-
30.	**Patronage Capital or Margins**	270,706	F7, Pt. A, Col. B		7,107,370	7,378,076		4,432,656
31.								

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE

	ITEM	TEST YEAR 2016		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT	ADJUSTED HISTORICAL TEST YEAR 2016	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR
		($)			($)	($)		($)
32.	**B. DEBT SERVICE PAYMENTS**							
33.	Interest Expense	7,246,052	Line 17 + Line 19		269,307	7,515,359	0.8068	6,063,674
34.	Principal Payments	2,463,502	F7, Pt. O, Col. B	[5]	206,619	2,670,121	0.8068	2,154,354
35.	Total Debt Service Payments	9,709,554			475,926	10,185,480	0.8068	8,218,029
36.								
37.	**C. DEBT SERVICE MARGINS**							
38.	Patronage Capital or Margins	270,706	Line 30		7,107,370	7,378,076	0.0000	4,432,656
39.	Plus: Depreciation and Amortization Expense	4,117,770	Line 14			4,117,770	0.8164	3,361,543
40.	Plus: Interest Expense	7,246,052	Line 33		269,307	7,515,359	0.8164	6,135,165
41.	Plus: Non-Cash Other Deductions Amortizations	332,816			-	332,816	0.8164	271,694
42.	Plus: Cash Capital Credits Cash Received	775,000	F7, Pt. J, L6, Col. A			775,000	0.8164	632,671
43.	Plus: Non-Cash Income Tax Expense	175,121			(175,121)	-	formula	2,867,502
44.	Less: Income (Loss) from Equity Investments	(3,000,000)	Line 25			(3,000,000)	1.0000	(3,000,000)
45.	Less: Other Capital Credits and Patr. Dividends	(1,192,383)	Line 28			(1,192,383)	0.8164	(973,402)
46.	Total Debt Service Margins	8,725,082			7,201,556	15,926,638		13,727,830
47.								
48.	**D. DEBT SERVICE COVERAGE**	**0.90**	L45/L35			**1.56**		**1.67**
49.								
50.	**E. DEBT SERVICE PARAMETERS**						Adjusted DSC Margins are:	***In the Quiet Zone***
51.	Floor							1.60
52.	Target							1.80
53.	Ceiling							2.00
54.								
55.	**F. INITIAL OPERATING INCOME ADJUSTMENT**							
56.	DSC Adjustment Required to Achieve Target							-
57.	Debt Service Payments							8,218,029
58.	After-Tax Operating Income Adjustment							-
59.								

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE

	ITEM	TEST YEAR 2016		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT	ADJUSTED HISTORICAL TEST YEAR 2016	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR
		($)			($)	($)		($)
60.	**G. EQUITY TEST (Increase will not result in > 35% equity ratio)**				Test Year	Rate		
61.		Pre-Adjustment			Adjustment	Adjustment	Post-Adjustment	
62.	Total Margins and Equities	5,402,255	F7, Pt. C, L36					
63.	Total Assets	168,842,712	F7, Pt C, L43					
64.	Equity Ratio	3.20%	L66 / L68					
65.								
66.	**H. FINAL REVENUE ADJUSTMENT PROPOSED**							
67.	After-Tax Operating Income Adjustment							-
68.	Divided by Tax Adjustment (1 - Combined Tax Rate)							1.00
69.	Pre-tax Revenue Adjustment							-
70.	Rate Schedule Revenue							79,136,662
71.	Adjustment Percentage							0.00%

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE - ADJUSTMENTS

1.	**ADJUSTMENT [1] -- REVENUE**			
2.	***Adjustment to annualize rate adjustment implemented during historical test year***			
3.	Annual Rate Adjustment Authorized by Commission		7,156,706	Docket 380 Order
4.	Total kWh Sales During Test Year		886,423,049	Docket 380 Order
5.	Average per kWh		$0.00807	L2/L3
6.	kWh Sales Prior to Implementation of Rate Adjustment		891,978,056	Input
7.	Revenue Adjustment to Annualize Rate Adjustment	$	7,201,556	L5*L6
8.				
9.	**ADJUSTMENT [2] -- OTHER TAXES**			
10.	***Adjustment to remove non-cash income tax expense***			
11.	Cash Test Year Other Tax Expense		-	Docket 380 Order
12.	Test Year Other Tax Expense		175,121	Docket 380 Order
13.	Adjustment to Actual Other Tax Expense	$	(175,121)	L2/L3
14.				
15.	**ADJUSTMENT [3] -- Long-Term Interest Expense**			
16.	***Adjustment to reflect the Budget.***			Budget
17.	Adjustment to Long-Term Interest Expense			
18.	Actual Year Long-Term Interest Expense	$	7,133,852	
19.	Budget Year Long-Term Interest Expense		7,403,159	
20.	Adjustment to Actual Long-Term Interest Expense	$	269,307	
21.				
22.	**ADJUSTMENT [4] -- Other Interest**			
23.	***Adjustment to reflect the Budget.***			
24.	Adjustment to Other Interest Expense			
25.	Actual Year Other Interest Expense		112,200	F7, Pt. A, Col. B
26.	Budget Year Other Interest Expense		112,200	0
27.	Adjustment to Actual Other Interest Expense	$	-	L26 - L25
28.				
29.	**ADJUSTMENT [5] -- Principal Payments**			
30.	***Adjustment to reflect the Budget.***			
31.	Adjustment to Principal Payments			
32.	Actual Year Principal Payments	$	2,463,502	
33.	Budget Year Principal Payments		2,670,121	SPEC records
34.	Adjustment to Actual Principal Payments	$	206,619	

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE

	ITEM	TEST YEAR 2017		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT	ADJUSTED HISTORICAL TEST YEAR 2017	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR
		($)			($)	($)		($)
1.	**A. STATEMENT OF OPERATIONS**							
2.	Operating Revenue and Patronage Capital	76,380,565	F7, Pt. A, Col. B	[1]	7,204,777	83,585,342	Direct	80,293,238
3.	Power Production Expense	-	F7, Pt. A, Col. B			-	0.0000	-
4.	Cost of Purchased Power	56,638,930	F7, Pt. A, Col. B			56,638,930	1.0000	56,638,930
5.	Transmission Expense	1,191,349	F7, Pt. A, Col. B			1,191,349	0.0000	-
6.	Regional Market Expense		F7, Pt. A, Col. B			-	0.0000	-
7.	Distribution Expense - Operation	4,887,900	F7, Pt. A, Col. B			4,887,900	1.0000	4,887,900
8.	Distribution Expense - Maintenance	1,995,242	F7, Pt. A, Col. B			1,995,242	1.0000	1,995,242
9.	Customer Accounts Expense	1,725,946	F7, Pt. A, Col. B			1,725,946	1.0000	1,725,946
10.	Customer Service and Informational Expense	239,319	F7, Pt. A, Col. B			239,319	1.0000	239,319
11.	Sales Expense	15,177	F7, Pt. A, Col. B			15,177	1.0000	15,177
12.	Administrative and General Expense	2,270,713	F7, Pt. A, Col. B			2,270,713	0.9836	2,233,390
13.	**Total Operation & Maintenance Expense**	68,964,576	F7, Pt. A, Col. B		-	68,964,576	0.9822	67,735,905
14.	Depreciation and Amortization Expense	4,389,354	F7, Pt. A, Col. B			4,389,354	0.8164	3,583,250
15.	Tax Expense - Property & Gross Receipts	-	F7, Pt. A, Col. B			-	0.8164	-
16.	Tax Expense - Other	(267,181)	F7, Pt. A, Col. B	[2]	267,181	-	formula	2,520,478
17.	Interest on Long-Term Debt	7,403,159	F7, Pt. A, Col. B	[3]	183,920	7,587,079	0.8068	6,121,541
18.	Interest Charged to Construction - Credit	-	F7, Pt. A, Col. B			-	0.8068	-
19.	Interest Expense - Other	112,200	F7, Pt. A, Col. B	[4]	-	112,200	0.8068	90,527
20.	Other Deductions	447,987	F7, Pt. A, Col. B			447,987	0.8068	361,453
21.	**Total Cost of Electric Service**	81,050,094	F7, Pt. A, Col. B		451,101	81,501,195	0.9866	80,413,153
22.	**Patronage Capital & Operating Margins**	(4,669,529)	F7, Pt. A, Col. B		6,753,676	2,084,147		(119,915)
23.	Non Operating Margins - Interest	1,200	F7, Pt. A, Col. B			1,200	0.8164	980
24.	Allowance for Funds Used During Construction	-	F7, Pt. A, Col. B			-	0.8164	-
25.	Income (Loss) from Equity Investments	3,000,000	F7, Pt. A, Col. B			3,000,000	1.0000	3,000,000
26.	Non Operating Margins - Other	12,000	F7, Pt. A, Col. B			12,000	1.0000	12,000
27.	Generation and Transmission Capital Credits	-	F7, Pt. A, Col. B			-	1.0000	-
28.	Other Capital Credits and Patr. Dividends	1,243,314	F7, Pt. A, Col. B			1,243,314	0.8068	1,003,153
29.	Extraordinary Items	-	F7, Pt. A, Col. B			-	1.0000	-
30.	**Patronage Capital or Margins**	(413,015)	F7, Pt. A, Col. B		6,753,676	6,340,661	0.6145	3,896,217
31.								

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE

	ITEM	TEST YEAR 2017 ($)		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT ($)	ADJUSTED HISTORICAL TEST YEAR 2017 ($)	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR ($)
32.	**B. DEBT SERVICE PAYMENTS**							
33.	Interest Expense	7,515,359	Line 17 + Line 19		183,920	7,699,279	0.8068	6,212,068
34.	Principal Payments	2,670,121	F7, Pt. O, Col. B	[5]	207,330	2,877,452	0.8068	2,321,636
35.	Total Debt Service Payments	10,185,480			391,250	10,576,731	0.8068	8,533,704
36.								
37.	**C. DEBT SERVICE MARGINS**							
38.	Patronage Capital or Margins	(413,015)	Line 30		6,753,676	6,340,661	0.6145	3,896,217
39.	Plus: Depreciation and Amortization Expense	4,389,354	Line 14			4,389,354	0.8164	3,583,250
40.	Plus: Interest Expense	7,515,359	Line 33		183,920	7,699,279	0.8164	6,285,309
41.	Plus: Non-Cash Other Deductions Amortizations	332,816			-	332,816	0.8164	271,694
42.	Plus: Cash Capital Credits Cash Received	808,000	F7, Pt. J, L6, Col. A			808,000	0.8164	659,611
43.	Plus: Non-Cash Income Tax Expense	(267,181)			267,181	-	formula	2,520,478
44.	Less: Income (Loss) from Equity Investments	(3,000,000)	Line 25			(3,000,000)	1.0000	(3,000,000)
45.	Less: Other Capital Credits and Patr. Dividends	(1,243,314)	Line 28			(1,243,314)	0.8164	(1,014,980)
46.	Total Debt Service Margins	8,122,019			7,204,777	15,326,796		13,201,579
47.								
48.	**D. DEBT SERVICE COVERAGE**	**0.80**	L45/L35			**1.45**		**1.55**
49.								
50.	**E. DEBT SERVICE PARAMETERS**						Adjusted DSC Margins are:	***Below the Floor***
51.	Floor							1.60
52.	Target							1.80
53.	Ceiling							2.00
54.								
55.	**F. INITIAL OPERATING INCOME ADJUSTMENT**							
56.	DSC Adjustment Required to Achieve Target							0.25
57.	Debt Service Payments							8,533,704
58.	After-Tax Operating Income Adjustment							2,159,088
59.								

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE

	ITEM	TEST YEAR 2017		ADJUSTMENTS NO.	ADJUSTMENTS AMOUNT	ADJUSTED HISTORICAL TEST YEAR 2017	DISTRIBUTION ALLOCATION FACTOR	DISTRIBUTION FBR
		($)			($)	($)		($)
60.	**G. EQUITY TEST (Increase will not result in > 35% equity ratio)**				Test Year	Rate		
61.		Pre-Adjustment			Adjustment	Adjustment	Post-Adjustment	
62.	Total Margins and Equities	4,989,240	F7, Pt. C, L36					
63.	Total Assets	179,405,920	F7, Pt C, L43					
64.	Equity Ratio	2.78%	L66 / L68					
65.								
66.	**H. FINAL REVENUE ADJUSTMENT PROPOSED**							
67.	After-Tax Operating Income Adjustment							2,159,088
68.	Divided by Tax Adjustment (1 - Combined Tax Rate)							1.00
69.	Pre-tax Revenue Adjustment							2,159,088
70.	Rate Schedule Revenue							80,293,238
71.	Adjustment Percentage							2.69%

SOUTHERN PIONEER ELECTRIC COMPANY
FORMULA BASED RATE - ADJUSTMENTS

1.	**ADJUSTMENT [1] -- REVENUE**		
2.	***Adjustment to annualize rate adjustment implemented during historical test year***		
3.	Annual Rate Adjustment Authorized by Commission	7,201,556	Docket 380 Order
4.	Total kWh Sales During Test Year	891,978,056	Docket 380 Order
5.	Average per kWh	$0.00807	L2/L3
6.	kWh Sales Prior to Implementation of Rate Adjustment	892,377,053	Input
7.	Revenue Adjustment to Annualize Rate Adjustment	$ 7,204,777	L5*L6
8.			
9.	**ADJUSTMENT [2] -- OTHER TAXES**		
10.	***Adjustment to remove non-cash income tax expense***		
11.	Cash Test Year Other Tax Expense	-	Docket 380 Order
12.	Test Year Other Tax Expense	(267,181)	Docket 380 Order
13.	Adjustment to Actual Other Tax Expense	$ 267,181	L2/L3
14.			
15.	**ADJUSTMENT [3] -- Long-Term Interest Expense**		
16.	***Adjustment to reflect the Budget.***		Budget
17.	Adjustment to Long-Term Interest Expense		
18.	Actual Year Long-Term Interest Expense	$ 7,403,159	
19.	Budget Year Long-Term Interest Expense	7,587,079	
20.	Adjustment to Actual Long-Term Interest Expense	$ 183,920	
21.			
22.	**ADJUSTMENT [5] -- Other Deductions**		
23.	***Adjustment to reflect the Budget.***		
24.	Adjustment to Other Interest Expense		
25.	Actual Year Other Interest Expense	112,200	
26.	Budget Year Other Interest Expense	112,200	
27.	Adjustment to Actual Other Interest Expense	$ -	
28.			
29.	**ADJUSTMENT [4] -- Principal Payments**		
30.	***Adjustment to reflect the Budget.***		
31.	Adjustment to Principal Payments		
32.	Actual Year Principal Payments	$ 2,670,121	
33.	Budget Year Principal Payments	2,877,452	SPEC records
34.	Adjustment to Actual Principal Payments	$ 207,330	

Exhibit RJM-7 - Kansas Expedited Access Charge Filing

Appendix I

Expedited Access Charge Filing

An expedited access charge filing procedure will be implemented effective January 1, 1991, or as soon as all local exchange company access tariffs from this proceeding become effective. The following represents an explanation of the procedure and filing requirements.

General Description:

This expedited procedure is available to all local exchange companies except Southwestern Bell Telephone Company and the United companies. This filing is intended to address revisions to intrastate Carrier Common Line (CCL) access rates only, through the review and adjustment of intrastate intraLATA/interLATA revenue requirements of individual local exchange companies. This expedited filing process will not be used to make or propose changes in basic local exchange rates, or rates other than access. Filings must be made on behalf of individual local exchange telephone companies and not by multiple or aggregated telephone companies. Failure to file or make application in the prescribed format will result in denial of the application and thus the 120-day time frame is not initiated unless a filing is in compliance with the prescribed format. Applications will not be held open or continue to be carried on the Commission's calendar subject to a company "completing" or "updating" its filing to comply with the prescribed format.

Filing Requirements:

1) The Commission must receive written notice of the intent to file an application at least 30 days in advance of the filing.

2) The Commission will make a determination on the filing within 120 days from the application filing date. Interexchange carriers passing on changes in access rates to end users may elect to aggregate these rate changes for an annual period and revise applicable tariffs January 1 of each year, subject to existing Commission oversight.

3) There is no restriction on dates by which applications can be submitted to the Commission.

4) Existing statutes or filing requirements guiding the procedures to be used in making application with the Commission are not altered or waived by this procedure.

Filing Format:

1) The company must file using the formats attached which support the company's revenue requirements by jurisdiction, the residual CCL calculation format and the summary revenue requirement format. The total of all jurisdictional components should be reconciled to the actual book amounts by explaining any differences or adjustments between the filing and the company's books. The residual CCL calculation format should provide a reconciliation, where applicable, between components of annualized revenues (current volumes x rates) and actual book amounts by explaining any differences or adjustments.

2) The filing should incorporate the most recent actual twelve months data and should not include projected or forecasted rate base or expense components in the revenue requirements.

3) Only the intrastate intraLATA/interLATA jurisdictional revenue requirements are subject to review or revision in this proceeding.

4) The overall rate of return to be used in the expedited filing for the duration of the plan will be the company's specific Commission authorized rate of return, if applicable, or 10.00 percent, absent evidence supporting an alternative rate of return.

5) Weighted DEM is capped at 85.00 percent to toll.

6) Adjustments and level of review.

a) The intent is that the filing not incorporate or include rate case type adjustments by the filing company, nor focus on proposed rate case type adjustments by intervenors or staff. Proposed issues or adjustments should focus on compliance issues such as, but not limited to, Part 32, 36, 64, Generally Accepted Accounting Principles (GAAP) and Kansas Commission orders. Rate case type adjustments may be avoidable to the extent that applications are based on a test period representative of historical or prospective revenue requirements without any extraordinary or unusual costs. The intent is that the expedited process not be abused by the filing of an application that takes advantage of a nonrecurring or extraordinary circumstance which does not represent a reasonable revenue requirement.

b) The filing may at the company's discretion include rate case type adjustments. However, for the expedited filing to be considered complete and in compliance with filing requirements all adjustments must be separately identified, include supporting calculations and workpapers, include a narrative explanation of each adjustment and provide the total adjustment multiplied by the specific separations factor to arrive at the jurisdictional adjustment by account number. Generally, it can probably be expected that company filed rate case adjustments will prompt proposed rate case adjustments by intervenors and staff.

The attached forms are to be used by the applicants in expedited access charge filings.

TELEPHONE COMPANY ____________

TWELVE MONTHS ENDING ____________

REVENUE REQUIREMENT SUMMARY

ATTACHMENT I

		REFERENCE	TOTAL COMPANY AS ADJUSTED	INTERSTATE MESSAGE INTRA	INTERSTATE MESSAGE INTER	INTERSTATE PRIVATE LINE INTRA	INTERSTATE PRIVATE LINE INTER	INTRASTATE MESSAGE INTRA	INTRASTATE MESSAGE INTER	INTRASTATE PRIVATE LINE INTRA	INTRASTATE PRIVATE LINE INTER	TWX	EAS	EXCHANGE
1	NET RATE BASE	IIA, Ln20												
2	RATE OF RETURN													
3	RETURN	Ln1*Ln2												
4	FEDERAL INCOME TAXES	(See Note Below)												
5	STATE INCOME TAXES													
6	OPERATING EXPENSES AND TAXES	IIB, Ln26												
7	NONOPERATING EXPENSES	IIB,Ln30												
8	UNCOLLECTIBLES	IIB,Ln 34												
9	TOTAL EXPENSES	Ln4...Ln8												
10	REVENUE REQUIREMENT	Ln3+Ln9												

Note - Attach schedule showing income tax calculation and reconciliation to book amounts

Exhibit RJM-7
Page 6 of 9

TELEPHONE COMPANY ____________

TWELVE MONTHS ENDING ____________

NET PLANT INVESTMENT

ATTACHMENT II-A

	ALLOCATION FACTORS	ACCOUNT NUMBER	TOTAL COMPANY PER BOOKS	ADJSTMTS (DETAIL REQUIRED)	TOTAL COMPANY AS ADJUSTED	INTERSTATE MESSAGE INTRA	INTERSTATE MESSAGE INTER	INTERSTATE PRIVATE LINE INTRA	INTERSTATE PRIVATE LINE INTER	INTRASTATE MESSAGE INTRA	INTRASTATE MESSAGE INTER	INTRASTATE PRIVATE LINE INTRA	INTRASTATE PRIVATE LINE INTER	TWX	FAS	EXCHANGE
1	CABLE AND WIRE FACILITIES															
2	COE,IOT & C&WF															
3	TEL PLANT IN SERVICE															
	TELEPHONE PLANT IN SERVICE															
4	GENERAL SUPPORT FACILITIES	2110														
5	CENTRAL OFFICE SWITCHING EQUIP	2210														
6	OPERATOR SYSTEMS EQUIPMENT	2220														
7	CENTRAL OFFICE TRANS EQUIP	2230														
8	INFORMATION ORIG/TERM EQUIP	2310														
9	CABLE AND WIRE FACILITIES	2410														
10	TANGIBLE ASSETS	2680														
11	INTANGIBLE ASSETS	2690														
12	TOTAL PLANT IN SVC A/C 2001															
	LESS:															
13	ACCUM DEPREC - PLANT IN SVC	3100														
14	NET PLANT INVESTMENT															
	LESS:															
15	ACCUM AMORT - TANGIBLE PROP	3400														
16	DEFERRED INCOME TAXES	XXXX														
17	OTHER DEFERRED CREDITS - NET	4370														
	ADD:															
18	MATERIALS AND SUPPLIES	1220														
19	RTB STOCK	XXXX														
20	NET RATE BASE															
21	PERCENT DISTRIBUTION															

Note - "XXXX" indicates various accounts should be included as appropriate.

TELEPHONE COMPANY ______________

TWELVE MONTHS ENDING ______________

EXPENSES AND TAXES

ATTACHMENT II-B

	ALLOCATION FACTORS	ACCOUNT NUMBER	TOTAL COMPANY PER BOOKS	ADJSTMTS (DETAIL REQUIRED)	TOTAL COMPANY AS ADJUSTED	INTERSTATE MESSAGE INTRA	INTERSTATE MESSAGE INTER	INTERSTATE PRIVATE LINE INTRA	INTERSTATE PRIVATE LINE INTER	INTRASTATE MESSAGE INTRA	INTRASTATE MESSAGE INTER	INTRASTATE PRIVATE LINE INTRA	INTRASTATE PRIVATE LINE INTER	TWX	EAS	EXCHANGE
1	GENERAL SUPPORT ASSETS															
2	TELEPHONE PLANT IN SERVICE															
3	COE, IOT & C&WF															
4	NET TELEPHONE PLANT, M&S															
5	BIG THREE EXPENSES															
	OPERATING EXPENSE AND TAX															
6	NETWORK SUPPORT EXPENSE	6110														
7	GENERAL SUPPORT EXPENSE	6120														
8	CENTRAL OFFICE EXPENSE	6210														
9	INFORMATION ORIG/TERM EXPENSE	6300														
10	CABLE AND WIRE FACILITIES EXP	6400														
11	PLANT SPECIFIC OPER EXP															
12	OTHER PLANT EXPENSE	6510														
13	NETWORK OPERATIONS EXPENSE	6530														
14	ACCESS CHARGE EXPENSE	6540														
15	DEPRECIATION AND AMORT	6560														
16	PLANT NON-SPEC OPER EXP															
17	MARKETING EXPENSE	6610														
18	SERVICES EXPENSE	6620														
19	CUSTOMER OPERATIONS EXP															
20	EXECUTIVE AND PLANNING EXP	6710														
21	GENERAL AND ADMIN EXPENSE	6720														
22	CORPORATE OPERATIONS EXP															
23	SUBTOTAL OPERATING EXPENSES															
24	OTHER OPERATING TAX	7210														
25	EQUAL ACCESS EXPENSE															
26	TOTAL OPERATING EXPENSE AND TAX															
27	PERCENT DISTRIBUTION															
28	CONTRIBUTIONS (NOTE A)	7370														
29	OTHER NON OPER EXP (NOTE B)	7370														
30	TOTAL NON OPERATING EXPENSE															
	UNCOLLECTIBLES															
31	END USER MSG TOLLS	5310														
32	END USER COMMON LINE	5320														
33	IX CARRIER	5330														
34	TOTAL UNCOLLECTIBLES															

NOTE A - Include one-half of contributions above-the-line.
NOTE B - Subject to review depending on appropriateness.

TELEPHONE COMPANY ________

TWELVE MONTHS ENDING ________

CCL RESIDUAL RATE DEVELOPMENT

ATTACHMENT III

	INTERLATA					
	(A)	(B) ANNUAL UNITS	(C) CURRENT TARIFFED RATES	(D) ANNUALIZED REVENUES (B)*(C)	(E) ACTUAL BOOKED REVENUES	(F) DIFFERENCE (See Note A Below) (D)-(E)
1	LOCAL SWITCHING					
	LOCAL TRANSPORT					
2	A. TERMINATION					
3	B. FACILITY	xxxxxxx	xxxxxxx	xxxxxxx		xxxxxxx
4	INFORMATION SURCHARGE					
5	BILLING & COLLECTION	xxxxxxx	xxxxxxx	xxxxxxx		xxxxxxx
6	SPECIAL	xxxxxxx	xxxxxxx	xxxxxxx		xxxxxxx
7	FGA/B REVENUE					
8	OTHER ACCESS REVENUES					
9	NET ACCESS REVS(w/o CCL)				$	

	INTRALATA					
	(G)	(H) ANNUAL UNITS	(I) CURRENT TARIFFED RATES	(J) ANNUALIZED REVENUES (B)*(G)	(K) ACTUAL BOOKED REVENUES	(L) DIFFERENCE (See Note A Below) (J)-(K)
1	LOCAL SWITCHING					
	LOCAL TRANSPORT					
2	A. TERMINATION					
3	B. FACILITY	xxxxxxx	xxxxxxx	xxxxxxx		xxxxxxx
4	INFORMATION SURCHARGE					
5	BILLING & COLLECTION	xxxxxxx	xxxxxxx	xxxxxxx		xxxxxxx
6	PRIVATE LINE (Special Access)	xxxxxxx	xxxxxxx	xxxxxxx		xxxxxxx
7	OTHER ACCESS REVENUES					
8	NET ACCESS REVS(w/o CCL)				$	

RESIDUAL CCL RATE DETERMINATION

		INTERLATA		INTRALATA		TOTAL
		REFERENCE	AMT/QTY	REFERENCE	AMT/QTY	AMT/QTY
10	ACCESS REV RQMT	Att I, Ln 10	$	Att I, Ln 10	$	$
11	Less:NET ACCESS REVS (w/o CCL)	Col E, Ln 9	$	Col K, Ln 8	$	$
12	Less: REVENUE SHIFT	Note B	$	Note B	$	$
13	CCL RESIDUAL REVENUE RQMT	Ln10-11-12	$	Ln10-11-12	$	$
14	JURISD. CCL MOU	Input		Input		
15	CCL RATE/MINUTE					$

Note A - All differences in Column F and L must be identified and explained.
Note B - At historical levels previously approved by the Commission, not updated for current access lines.
'xxxxxxx' indicates columns do not have to be completed for this line item

Exhibit RJM-8 - Michigan Public Service Commission TIER Ratemaking Orders

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of ONTONAGON COUNTY RURAL ELECTRIFICATION ASSOCIATION for authority to file, establish and make effective increased rates for the sale of electric energy.	Case No. U-6652

At a session of the Michigan Public Service Commission held at its offices in the City of Lansing, Michigan, on the 10th day of February, 1981.

PRESENT: Hon. Daniel J. Demlow, Chairperson
Hon. Eric J. Schneidewind, Commissioner
Hon. Edwyna G. Anderson, Commissioner

OPINION AND ORDER

I.

HISTORY OF PROCEEDINGS

On October 28, 1980, Ontonagon County Rural Electrification Association (Applicant) filed an application for authority to increase its rates and charges for electric service.

Pursuant to due notice, a public hearing was held in the offices of the Commission on January 6, 1981. Applicant presented the testimony of one witness and offered six exhibits, including proposed rate schedules. The Commission Staff (Staff) cross-examined Applicant's witness and presented the testimony of one witness and offered two exhibits. On January 5, 1981, a petition to intervene was filed by Eli Sironen but he did not appear at the hearing.

At the conclusion of the hearing, all parties waived compliance with the provisions of Section 81 of the Administrative Procedures Act, 1969 PA 306, as amended, MCLA 24.281.

II.

DESCRIPTION OF APPLICANT

Applicant is a Michigan nonprofit corporation with principal offices located at Ontonagon, Michigan and is engaged in the distribution and sale of electric energy in rural portions of Ontonagon, Houghton, Keweenaw and Baraga Counties. As of June 30, 1980, Applicant had 3,209 member-customers.

III.

THE TEST PERIOD

In this, as in other rate proceedings, it is necessary to select a test period and to adjust its results for known changes in revenues and expenses so that the adjusted operating results will be representative of the future, and thereby afford a reasonable basis upon which to predicate rates which will be effective subsequent to this order. In this proceeding, Applicant submitted testimony and exhibits covering the year ending June 30, 1980, adjusted for known cost increases occurring subsequent to that date.

There having been no evidence presented covering any other period and no objection having been made to the test period ending June 30, 1980, as adjusted, the Commission adopts it as the appropriate test period.

IV.

STATEMENT OF FACTS

The basic rates now being charged by Applicant for electric service were authorized by the Commission in its order dated December 11, 1979 in Case No. U-6223.

Applicant represents that because of unprecedented levels of inflation its costs have increased while sales have been lower than anticipated. As a result, Applicant's operations have shown a loss in every month since the issuance of the Commission's order in Case No. U-6223. According to Exhibit A-2, on an unadjusted basis, Applicant's operations for the test period reflect a net loss of $129,703. Applicant seeks authority to establish rates which produce additional revenues of $118,762 annually.

Applicant and the Staff agree that the Rural Electrification Administration (REA) and the Cooperative Finance Corporation (CFC) require a Times Interest Earned Ratio (TIER) of between 1.5 and 2.5. The Commission order in Case No. U-6223 authorized revenues to yield a TIER at the minimum level of 2.43.

It appears that Applicant's financial condition is deteriorating to the point where REA funding is no longer assured. In processing Applicant's most recent loan application, REA felt compelled to establish special mechanisms because of Applicant's steadily deteriorating financial condition. As REA stated:

> "Since December 31, 1974, your [Applicant's] system has been unable to earn a positive margin from its operations. Considering the financial condition of the cooperative, we believe that if Ontonagon is unable to place into effect timely rate increases which will insure adequate feasibility for REA loans, the cooperative should consider curtailing its construction program. System improvements will have to be drastically reduced. As a further step, REA is considering placing a special condition on the 'U-4' loan. The condition would require receipt of evidence that adequate retail rates have been approved and are effective before any 'U-4' loan funds could be released."

The Commission FINDS that to ensure continuous service and to accommodate system expansion and improvements an increase in Applicant's revenues is necessary and appropriate.

While Applicant's presently authorized rates are based on revenues designed to yield a 2.43 TIER, Applicant's $118,762 request seeks an authorized TIER of 2.6. Applicant represents that a 3.0 TIER is more appropriate, but requests the 2.6 TIER as a first step toward that goal. For reasons discussed below, the

Commission need not address the propriety of raising Applicant's TIER levels.

Applicant indicates that its goal is to provide the best possible service at the lowest possible rates. Applicant represented that for that reason its retail rates have traditionally been lower than its major wholesale supplier, Upper Peninsula Power Company.

According to Exhibit A-2, Applicant's monthly expenses have consistently exceeded revenue, even after annualizing the impact of Applicant's last rate case (U-6223). Applicant indicates that these results and REA and CFC threshold interest coverage requirements have forced and will continue to force Applicant to seek repeated rate relief from this Commission.

The need for continuous rate review costs Applicant and its member-customers dearly. The Commission recognizes that rate cases are expensive affairs. Engineering and legal consultants are often hired and utility personnel invest countless hours in rate case preparation and trips to Lansing. For a cooperative located in the Upper Peninsula, regulatory expenses are even more burdensome. Especially for a utility the size of Applicant, with only 3,000 customers, rate case expense becomes a significant part of the rate relief awarded.

While this Commission's relief has been timely, there is always the unavoidable lag between the time a decision is made to seek relief and the time such relief is granted. Accordingly, in its filing, Applicant recommended a new mechanism, TIER Indexing, which it represents will reduce customer costs, decrease rate case expenses and allow Applicant to maintain revenue stability.

Mr. William J. Chabot, Applicant's General Manager, recommended TIER Indexing as an alternative to present ratemaking mechanisms. As Mr. Chabot explained, traditional mechanisms have been designed to authorize revenues which yield a TIER of approximately 2.5. When TIER fell to unacceptable levels, the cooperative would analyze its financial status, conduct a rate study, put together a detailed filing, and make application to the Commission for another rate increase.

The Commission, after a Staff evaluation, would again revise rates to yield a 2.5 target TIER. Because of economic conditions, the process repeats itself time after time.

Under TIER Indexing, as proposed by Applicant, revenues authorized herein would be designed to yield a lower TIER; to wit, approximately 2.4. In addition, Applicant would withdraw normalizing expense adjustments. The net effect of these changes would be to reduce Applicant's rate request by approximately 33%.

The next phase of TIER Indexing would occur after Applicant has experienced six months of operation under the base rate order. At this point, a review would be made to determine whether Applicant's TIER had increased or decreased from the 2.4 level authorized in the base rate order. If the six-month TIER level is between 2.0 and 2.8, there would be no adjustment in rates. If the six-month TIER level is greater than 2.8, an ex parte rate reduction would be made as necessary to bring TIER back to 2.4. If, on the other hand, TIER has fallen below 2.0, a hearing would be held to determine what revenue increase is necessary to bring TIER back to 2.4.

Once six more months of operations have been analyzed, the process would repeat itself. Applicant suggests that TIER Indexing be instituted as an experimental two-year program.

The Commission has reviewed Applicant's financial condition and the proposed TIER Indexing mechanism in depth. The Commission herein adopts, as an experimental two-year program, TIER Indexing, for the following reasons, among others:

1. Because TIER Indexing should allow Applicant to maintain revenue stability, rates established herein need not yield as high a TIER level. In the instant proceeding, this allows the rate increase authorized to be lower by a factor of approximately 33%.

2. In addition to substantial immediate reduction in member-customer rates, engineering and attorney fees should be markedly reduced, thus further reducing member-customer costs.

3. Because Applicant should be able to maintain revenue stability, financing costs should be lower, thus further reducing member-customer costs.

4. Once TIER indexing has been established, Commission and Staff resources need not be expended, to the extent they have been in the past, in rate proceedings for Applicant.

5. The process, as detailed below, is simple, mechanically non-controversial and easy to understand.

6. The characteristics of a cooperative, being owned by its customers, uniquely adapt themselves to this type of mechanism. To the extent rates increase because of imprudent management, member-customers will seek answers. In addition, the Staff is expected to monitor expenditures to assure reliability of the mechanism. Finally, management will be expected to reduce, wherever possible, expenditures.

In short, the Commission believes that adoption of TIER indexing as an experimental, two-year program is in the interest of Applicant and its member-customers.

In adopting TIER Indexing, the Commission cautions that it will carefully monitor Applicant's performance. While certain other cooperatives may, in the future, be authorized similar mechanisms, the Commission stresses that Applicant's size and financial condition, as detailed in the record, were carefully reviewed.

Applicant's proposed increase, with TIER Indexing, totaled $79,706. Applicant's present fuel and purchased power adjustment clause contains two separate basing points, one for its Ewen and Trout Creek substations, and another for its main system. Applicant's filing did not request adjustments to those basing points. However, subsequent to its filing, Applicant learned of wholesale power increases scheduled to soon go into effect. The Staff accordingly suggested a 31.62 mills per Kwh base for customers served by Applicant's Ewen and Trout Creek substations, and a 40.63 mills per Kwh base for main system customers. Applicant did not object to those revised basing points.

The Staff recommended a $79,706 increase. Applicant objected to neither the Staff's recommended revenue increase nor to its method of calculation. The Commission herein adopts the Staff's proposed revenue increase and adjustment clause basing points.

The TIER Indexing mechanism which the Commission is adopting shall operate as follows:

1. By this order, Applicant will be authorized to place into effect, for service rendered on and after February 1, 1981, rates designed to produce an annual increase in revenues of approximately $79,706.

2. By September 10, 1981, Applicant is directed to submit a calculation of its TIER for the six-month period ending July 31, 1981. If the calculated TIER is between 2.0 and 2.8, there need be no adjustment in rates. If the six-month TIER is greater than 2.8, Applicant should submit a calculation of revenue reductions necessary to bring TIER back to 2.4. If, on the other hand, TIER has fallen below 2.0, a hearing will be scheduled to determine what revenue increase is necessary to bring TIER back to 2.4.

3. Upon submission of Applicant's TIER analysis, the Staff is directed to review such calculations for methodology and accuracy. If no revenue increase is necessary, hearings need not be scheduled unless the Staff or Applicant specifically request such hearing.

4. Applicant's calculation of its six-month TIER shall be based on its unadjusted statement of operations, as reflected in its REA Form 7, with only three adjustments:

   a. Rates established in this base rate order should be annualized.

   b. Seasonal revenue, which Applicant traditionally collects in one month, should be normalized.

   c. The lag in purchased power revenue should be adjusted, where necessary, so that the analysis coincides with actual levels.

5. At the conclusion of the above-described process, Applicant shall inform its member-customers as to the determination of the Commission, and method of calculation of revised rates, if necessary. If a revenue decrease or increase is authorized, such shall be handled through a per Kwh surcharge on customer bills in the first monthly bill following such order. In subsequent months, the surcharge shall be incorporated in customer energy rates.

6. By April 1982, financial statements covering a full 12-month period since the issuance of the base rate order should be available. If a hearing is necessary (i.e., if a revenue increase is necessary), the only adjustments that need be considered relate to purchased power revenue lag and annualization of the prior six-month rate order, if an increase was warranted.

7. The process will continue every six months thereafter, subject to review by this Commission after February 1, 1983.

The Commission FINDS that the TIER indexing system established by this order should be subject to alterations, on application of Applicant or suggestion of the Staff or other parties. It would not be in the public interest to freeze the system so adjustments could not be made. The Commission is establishing an innovative program. In most innovative programs there are "bugs" which must be eliminated to make the program work properly. In addition, the long-run future is uncertain. The Commission simply must have the flexibility to deal directly with unanticipated serious problems. However, where Applicant requests a change in the TIER indexing system, Applicant will have a heavy burden to demonstrate the necessity of the change.

Neither Applicant nor the Staff recommended changes in rate design. The Commission FINDS that the rate design established in its order in Case No. U-6223 should be maintained.

With two exceptions, there were no proposals to change Applicant's Rules and Regulations. The first exception related to a proposed amendment to Applicant's Rules and Regulations to allow Applicant to assess a late payment charge not in excess of 2%, not compounded, of the bill, net of taxes, for residential customers. In the Commission's order of October 28, 1980 in Case No. U-4240, revising the Consumer Standards and Billing Practices, it specifically allowed such change in Rule 18(2). The Staff proposed a second exception involving refunds of advances for construction. The Commission FINDS that those two amendments to Applicant's Rules and Regulations are reasonable and appropriate.

The Commission FINDS that:

a. Jurisdiction is pursuant to 1909 PA 106, as amended, MCLA 460.551 et seq.; 1919 PA 419, as amended, MCLA 460.51 et seq.; 1939 PA 3, as amended, MCLA 460.1 et seq.; 1969 PA 306, as amended, MCLA 24.201 et seq.; and the

Commission's Rules of Practice and Procedure, 1954 Administrative Code, 1968 Annual Supplement, R 460.11 et seq.

b. Additional annual revenue of approximately $79,706 will yield a TIER of 2.4 and enable Applicant to meet the financing requirements of its lending agencies.

c. A TIER Indexing system as set forth in this Opinion and Order is reasonable and should be adopted. The TIER Indexing system should be implemented by keeping the record open for the receipt of evidence and any necessary adjustment of rates, according to the terms and provisions set forth in this Opinion and Order.

d. Applicant's fuel and purchased power adjustment clauses as established in Case No. U-6223 and as developed in the Commission's bimonthly decisions should be retained, the new basing points being as set forth in this Opinion and Order.

e. The electric rate schedules attached hereto as Exhibit A will increase Applicant's annual electric operating revenues as authorized by this Opinion and Order and will result in just and reasonable rates and charges for the sale of electric energy and should be made effective for service rendered on and after March 1, 1981.

THEREFORE, IT IS ORDERED that:

A. Ontonagon County Rural Electrification Association is hereby authorized to place into effect, for service rendered on and after March 1, 1981, the Standard Rules and Regulations and rate schedules attached hereto as Exhibit A. The rates are designed to produce an increase in annual revenues of approximately $79,706.

B. The record in this case is left open for the limited purpose of implementing the TIER Indexing mechanism according to the terms and procedures set forth in this Opinion and Order.

C. Ontonagon County Rural Electrification Association shall continue to implement bimonthly purchased power cost adjustment hearings as set forth in this order.

D. Ontonagon County Rural Electrification Association shall, within 30 days, submit for filing six copies of the Standard Rules and Regulations and rate schedules substantially the same as those attached hereto as Exhibit A.

The Commission specifically reserves jurisdiction of the matters herein contained and the authority to issue such further order or orders as the facts and circumstances may require.

Any party desiring to appeal this order must perfect an appeal to the Ingham County Circuit Court within 30 days after issuance and notice of the order, pursuant to MCLA 460.301.

MICHIGAN PUBLIC SERVICE COMMISSION

/s/ Daniel J. Demlow
Chairperson

(S E A L)

/s/ Eric J. Schneidewind
Commissioner

Commissioner Edwyna G. Anderson dissents and is, this date, issuing the attached Dissenting Opinion.

By the Commission and pursuant to its action of February 10, 1981.

/s/ Thomas R. Lonergan
Its Secretary

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of ONTONAGON COUNTY RURAL ELECTRIFICATION ASSOCIATION for authority to file, establish and make effective increased rates for the sale of electric energy.	)	Case No. U-6652

DISSENTING OPINION OF COMMISSIONER EDWYNA G. ANDERSON

(Submitted on February 10, 1981 concerning
order issued on same date)

Today Ontonagon County Rural Electrification Association (Ontonagon) is being granted a $79,706 rate increase for electric service. Such an increase will add approximately 6.6% to the average 500 Kwh user's bill, raising it to a monthly base in excess of $40.

A careful and complete review of all transcripts indicates that Ontonagon is in poor financial health and clearly in need of revenues generated by this Opinion and Order.

Ontonagon has been caught in a spiralling period of escalating costs and falling sales. During the test year ending June 30, 1980 Ontonagon lost $129,703. Ontonagon's monthly expenses have consistently outstripped revenues in recent months.

Such data indicates to me that the patient is obviously sick and in need of an immediate remedy. Unfortunately, I cannot agree with the majority's remedy.

The majority has introduced another "innovative" program to cure this patient. The new program is called "TIER INDEXING." TIER is an acronym for "times interest earned ratio." This ratio is computed by adding the earnings for the period plus interest expense and dividing by the interest expense.

The TIER measures the extent to which earnings can decline without resultant financial embarrassment to the firm because of inability to meet annual interest costs.

Nowhere is there any indication that the Rural Electrification Administration (REA) requires a minimum TIER of 2.0 to meet its standards. The bottom line of this TIER Indexing is to allow this co-op's earnings to vacillate between a 2.0 and a 2.8 TIER.

The majority argues that such innovation allows the Commission to grant a $79,703 increase rather than a traditional rate increase running as high as $118,672. TIER Indexing, according to the majority, further allows reduced expenses such as engineering and attorneys fees generated during rate hearings and should increase revenue stability, thereby lowering financing costs. The majority continues:

> "5. The process, as detailed below is simple, mechanically noncontroversial and easy to understand." (Order, page 6)

In reality the TIER Indexing program is no more than a thinly-disguised Consumer Price Index (CPI) program. Ontonagon currently has a TIER ratio well below 2.0. They have taken a smaller piece of the cake ($79,703) immediately to insure a larger piece (2.0 - 2.8 TIER ratio) in the future. Under this plan they will not come before this Commission unless their earnings exceed a TIER ratio of 2.8 or fall below a TIER ratio of 2.0.

Expense control and review by this Commission will be nonexistent so long as Ontonagon maintains a 2.0 - 2.8 TIER ratio.

If Ontonagon comes close to a 2.0 TIER ratio there is a tempting incentive to fall below such a ratio so as to immediately qualify for rate relief that will bring them back to a 2.4 TIER ratio. If, on the other hand, they start to approach a 2.8 TIER ratio there is an equally strong incentive to increase expenses so as to avoid Commission adjustment.

Again, the problem is simply an inability of this Commission to scrutinize, yes even regulate, this co-op. We have little or no ability to review alleged increases in relationship to overall revenues, revenue requirements, costs of service and other relevant factors relating to the co-op's fiscal condition.

I certainly agree that co-ops are unique and sometimes warrant special treatment. This may result from such factors as nonprofit capital structure and ownership by their members.

But one must wonder if Ontonagon's member/customers are aware of TIER Indexing and its rate implications.

Additionally, there is the persistent threat that the pervasive and pernicious practice of spreading these new programs to other companies will likely not stop here.

In summary, this Commission under the guise of "innovation" is adding another automatic adjustment program to its already overladen arsenal of "pass throughs." I cannot, nor will I, support such Indexing plans. I must respectfully dissent.

Edwyn G. Anderson

Edwyn G. Anderson
Commissioner

February 10, 1981
Lansing, Michigan

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the petition of **ONTONAGON COUNTY RURAL ELECTRIFICATION ASSOCIATION** for authority to effectuate the TIER Indexing Mechanism, pursuant to the Commission's order in Case No. U-6652 dated February 10, 1981.	Case No. U-6652 (TIER - Spring '83)

At a session of the Michigan Public Service Commission held at its offices in the City of Lansing, Michigan, on the 14th day of June, 1983.

PRESENT: Hon. Eric J. Schneidewind, Chairperson
Hon. Edwyna G. Anderson, Commissioner
Hon. Matthew E. McLogan, Commissioner

OPINION AND ORDER

I.

HISTORY OF PROCEEDINGS

On February 10, 1981, the Commission issued its Opinion and Order in Case No. U-6652 authorizing Ontonagon County Rural Electrification Association (Applicant) to revise its rates and charges for electric service.

Therein, the Commission adopted a new mechanism, Times Interest Earned Ratio (TIER) Indexing. As stated at pages 7 and 8 of its February 10, 1981 Opinion and Order, the TIER analysis mechanism which the Commission adopted was designed to operate as follows:

> "1. By this order, Applicant will be authorized to place into effect, for service rendered on and after February 11, 1981, rates designed to produce an annual increase in revenues of approximately $79,706.

2. By September 10, 1981, Applicant is directed to submit a calculation of its TIER for the six-month period ending July 31, 1981. If the calculated TIER is between 2.0 and 2.8, there need be no adjustment in rates. If the six-month TIER is greater than 2.8, Applicant should submit a calculation of revenue reductions necessary to bring TIER back to 2.4. If, on the other hand, TIER has fallen below 2.0, a hearing will be scheduled to determine what revenue increase is necessary to bring TIER back to 2.4.

3. Upon submission of Applicant's TIER analysis, the Staff is directed to review such calculations for methodology and accuracy. If no revenue increase is necessary, hearings need not be scheduled unless the Staff or Applicant specifically request such hearing.

* * *

5. At the conclusion of the above-described process, Applicant shall inform its member-customers as to the determination of the Commission, and method of calculation of revised rates, if necessary. If a revenue decrease or increase is authorized, such shall be handled through a per Kwh surcharge on customer bills in the first monthly bill following such order. In subsequent months, the surcharge shall be incorporated in customer energy rates.

* * *

7. The process will continue every six months thereafter, subject to review by this Commission after February 1, 1983."

On September 10, 1981, in compliance with Commission directive, Applicant filed its petition for a TIER hearing, submitting its calculation of TIER for the period ending July 31, 1981. Therein, Applicant represented that its calculation derived a TIER of 2.03 and, as a result, no rate increase was necessary. On October 16, 1981, the Commission issued its order adopting Applicant's presentation and directing that no rate adjustments be made.

Also pursuant to the above-quoted Commission directive, on March 2, 1982, Applicant submitted data necessary to calculate its TIER for the period ending January 31, 1982. Therein, Applicant represented that its calculations indicated a necessary revenue increase of $74,255, or approximately 4.96%, to bring its TIER to 2.4. On May 5, 1982, the Commission issued its order adopting Applicant's filing and authorizing the requested increase.

Also pursuant to the above-quoted Commission directive, on July 31, 1982, Applicant submitted data necessary to calculate its TIER for the period ending July 31, 1982. Therein, Applicant represented that its calculations indicated a necessary revenue increase of $55,921, or approximately 3.47%, to bring its TIER to 2.4. On October 26, 1982, the Commission issued its order adopting Applicant's filing and authorizing the requested increase.

On March 31, 1983, pursuant to Commission directive, Applicant submitted its Petition for TIER Analysis Hearing, accompanied by prepared exhibits, setting forth its calculation of TIER for the period ending January 31, 1983. Applicant represented, through its prepared testimony and exhibits, an adjusted TIER coverage of 1.78, and requested a revenue increase of $39,467, or approximately 2.36%, to bring its TIER to 2.4.

On April 15, 1983, the Commission issued its Notice of Hearing, directing that the following be addressed at a public hearing scheduled for May 9, 1983:

1. A determination of whether Applicant should be authorized to increase its revenues and, if so, in what amount.

2. A review of the TIER analysis mechanism as directed by the Commission in its Opinion and Order dated February 10, 1981.

In the Commission's Notice of Hearing, the subject matter of the proceeding was not limited to Applicant's request, but parties were authorized to "address the total cost of service and all other lawful elements properly to be considered in determining just and reasonable rates" (p. 3).

Pursuant to the Notice of Hearing, a public hearing was held in Lansing, Michigan on May 9, 1983 before Administrative Law Judge Robert E. Hollenshead. Appearing at the hearing were Applicant and the Commission Staff (Staff). At the commencement of the hearing Applicant presented an Affidavit of Publication that the Notice of Hearing had been published in a newspaper of general circulation as required. Applicant had previously submitted, on April 25, 1983, Proof of Service of the Notice of Hearing to governmental entities.

During the hearing, Applicant presented the testimony of its manager, James A. Morgan, and offered seven exhibits which were admitted into evidence. Five of the exhibits address Applicant's requested revenue increase, as follows:

Exhibit A-1 - Applicant's Form 7 for each of the 12 months ended January 31, 1983. These are the financial and statistical reports which all rural electric cooperatives must file on a monthly basis with REA. Calculations leading to the required TIER analysis revenue increase were based on numbers taken from the REA Forms 7.

Exhibit A-2 - Applicant's compilation of margins and interest for the 12 months ended January 31, 1983. On an unadjusted basis, Applicant's TIER coverage for the 12 months ended January 31, 1983 was 0.95.

Exhibit A-3 - Applicant's calculation of revenues for the 12 months ended January 31, 1983, after annualization of the rate increases authorized by the Commission in this docket dated May 5, 1982 and October 26, 1982; and recognition of the impact of 1982 PA 304. The effect of such adjustments was to increase test year revenues by $52,753. This led to a revised TIER of 1.78.

Exhibit A-4 - Applicant's calculation of the required TIER analysis increase, taking into account all necessary adjustments. As set forth thereon, the calculations indicate a required increase of $39,467, or approximately 2.36%.

Exhibit A-5 - Applicant's calculation of the necessary 2.39 mills per Kwh surcharge required to collect the TIER analysis increase. Consistent with the Commission's February 10, 1981 order, Applicant requested that the surcharge be collected in the first month following the issuance of the Commission order, with said increase being rolled into base rates in subsequent months.

Two of the exhibits address the required TIER analysis review, as follows:

Exhibit A-6 - The December 17, 1982 Order of Virginia State Corporation Commission in Case No. PUE820087, initiating proceedings which eventually led to an order implementing expedited rural electric cooperative rate proceedings tied to TIER.

Exhibit A-7 - The March 1, 1983 Final Order of the Virginia State Corporation Commission in Case No. PUE820087, formally adopting expedited rural electric cooperative rate proceedings tied to TIER.

The Commission Staff (Staff) cross-examined Applicant's witness and presented the testimony of its witness, Daniel Blair, who recommended that Applicant's proposed increase of $39,467 be adopted. Mr. Blair also presented the Staff's recommendations relating to modifications and improvements to the TIER analysis mechanism. Applicant had no objections to the Staff's proposed modifications and improvements.

At the conclusion of the hearing, Applicant and the Staff waived compliance with the provisions of Section 81 of the Administrative Procedures Act, 1969 PA 306, as amended, MCLA 24.281. Administrative Law Judge Hollenshead recommended approval of the application and adoption of the Staff's proposed modifications and improvements to the TIER analysis mechanism.

II.

DESCRIPTION OF APPLICANT

Applicant is a Michigan nonprofit corporation with principal offices located in Ontonagon, Michigan, and is engaged in the distribution and sale of electric energy to approximately 3,300 member-customers in the Counties of Ontonagon, Baraga, Houghton and Keweenaw in Michigan's Upper Peninsula.

III.

DISCUSSION

As set forth above, the issues in this proceeding addressed the following areas:

1. A determination of whether Applicant should be authorized to increase its revenues and, if so, in what amount.
2. A review of the TIER analysis mechanism as directed by the Commission in its Opinion and Order dated February 10, 1981.

Those issues are separately discussed below.

1. TIER Analysis Calculations

Based upon its review of the presentations of Applicant and the Staff, the Commission finds that an increase in revenues of approximately $39,467, or approximately 2.36%, is reasonable and appropriate. Consistent with its February 10, 1981 Opinion and Order in this case, the revenue increase should be collected through application of a 2.39 mills per Kwh surcharge in the first billing month following issuance of this order. Applicant should roll the 2.39 mills per Kwh into its base rates in subsequent months.

The Commission notes that its decision is consistent with its Order on TIER Analysis dated October 26, 1982.

2. TIER Analysis Review

As stated above, Applicant's TIER Analysis mechanism was authorized in the Commission's Opinion and Order dated February 10, 1981 in which the Commission authorized the TIER analysis mechanism, noting as follows:

> "The need for continuous rate review costs Applicant and its member-customers dearly. The Commission recognizes that rate cases are expensive affairs. Engineering and legal consultants are often hired and utility personnel invest countless hours in rate case preparation and trips to Lansing. For a cooperative located in the Upper Peninsula, regulatory expenses are even more burdensome. Especially for a utility

> the size of Applicant, with only 3,000 customers, rate case expense becomes a significant part of the rate relief awarded.
>
> While this Commission's relief has been timely, there is always the unavoidable lag between the time a decision is made to seek relief and the time such relief is granted. . . ." (Order, p. 4)

In adopting the TIER analysis mechanism, the Commission cited a number of reasons, including the following:

1. Because TIER indexing should allow revenue stability, rates established need not yield as high a TIER level. In the subject proceedings, this allowed the rate increase authorized to be lower by a factor of 20%-33%.

2. In addition to substantial immediate reductions in member-customer rates, engineering and attorney fees should be markedly reduced, thus further reducing member-customer costs.

3. Revenue stability should lead to lower financing costs, thus further reducing member-customer costs.

4. Once the TIER analysis mechanism has been established, Commission and Staff resources need not be expended, to the extent they have been in the past, in rate proceedings.

5. The process is simple, mechanically non-controversial and easy to understand.

6. The characteristics of a cooperative, being owned by its customers, uniquely adapt themselves to this type of mechanism. To the extent rates increase because of imprudent management, member-customers will seek answers. In addition, the Staff is expected to monitor expenditures to assure reliability of the mechanism. Finally, management will be expected to reduce, wherever possible, expenditures.

Set forth below is a summary of Applicant's rate and financial condition experience under the TIER analysis mechanism:

TIER ANALYSIS EXPERIENCE SUMMARY

	Order Date	Adjusted TIER	Rate Increase	
Main rate	Feb 10, 1981	0.32	$79,706	6.60%
1st hearing	Oct 16, 1981	2.03	0	0
2nd hearing	May 5, 1982	1.24	74,255	4.96
3rd hearing	Oct 26, 1982	1.53	55,921	3.47
4th hearing	June 14, 1983	1.78	39,467	2.36

Now that Applicant has been subject to TIER analysis for a full two-year period, the Commission must determine whether the mechanism should be continued, modified or terminated. Both Applicant and the Staff reviewed the mechanism and recommended continuation of the mechanism, subject to modifications.

a. Applicant's TIER Analysis Review Presentation

In its presentation, Application stated that, as a member-owned utility, it perceives two primary objectives, as follows:

1. Keeping expenditures at reasonable levels—to keep rates as low as possible.

2. Using the relative revenue stability to facilitate much needed system improvements.

In its presentation, Applicant stated that TIER analysis requires constant coordination with the Rural Electrification Administration (REA) and the Cooperative Finance Corporation (CFC); that working through the Michigan Electric Cooperative Association, REA and CFC representatives conducted TIER Indexing/Capital Credits workshops throughout the State of Michigan; and that representatives of every Michigan rural electric cooperative attended the seminars, which went into detail as to financial planning, budgeting, capital planning and expense control.

Applicant represented that, as a result of the workshops, it is working closely with REA and CFC to facilitate improved equity management and financial planning.

As to much needed system improvements, Applicant offered testimony indicating that it is upgrading its system in conjunction with the TIER analysis mechanism. Applicant's witness testified that deteriorating financial conditions had forced the layoff of two linemen (25% of labor force); that improving revenue stability allowed the recall of those employees in April 1982; and that there are no plans to lay off either of the linemen in the foreseeable future.

In addition, Applicant's witness testified that it had been without a line superintendent for nearly a year and, in view of its deteriorating financial condition, the Board had directed the manager not to hire a replacement. However, within the last year, a new line superintendent has been hired, with primary responsibility for improving system maintenance.

Therefore, within a span of five months, Applicant was able to replace or rehire three employees whose performance is crucial to maintenance of the distribution system. Applicant submitted that the result has been a new focus on much needed system improvements.

Applicant's presentation also addressed experience with TIER-types of mechanisms in other jurisdictions—specifically Virginia, Iowa and Arkansas. The Virginia and Iowa Commissions have initiated expedited rural electric cooperative rate proceedings tied to TIER coverage. The Arkansas Commission Staff will be recommending same in its next rural electric cooperative rate proceeding.

In Virginia, the mechanism went into effect on March 1, 1983, and allows rural electric cooperatives to obtain timely, expedited rate increases under the following conditions:

1. The revenues produced by the increase provide for an interest coverage ratio (TIER), on a pro forma basis, of no more than 2.5 times.
2. The increase does not exceed 10% of the cooperative's annual revenues (December 17, 1982 Order, p. 2).

In Iowa, rural electric cooperatives may phase expedited revenue increases into effect (without a hearing) as soon as their TIER coverage drops below 2.5 (using operating margins) or 3.0 (using total margins). While both Applicant and the Staff addressed the Iowa mechanism, neither recommended that it be applied in Michigan.

In concluding, Applicant's presentation provided a list of regulatory concerns and criticism which have been raised during the last two years relating to TIER analysis and addressed each of the concerns.

Applicant then offered its recommendation—continuation of the TIER analysis mechanism—with modifications to address regulatory concerns which have been raised. Most notably, Applicant recommended that the "limited purpose proceeding" requirement be eliminated by revising future notices of hearing.

Notices of hearing in past TIER analysis proceedings stated as follows:

> The hearing will be limited to the propriety of Applicant's calculations under the TIER analysis mechanism established by the Commission in its Opinion and Order in Case No. U-6652, dated February 10, 1981. (Emphasis added)

By the above notice, the Commission, its Staff and other parties were precluded from addressing any cost of service issues.

To address regulatory concerns relating to the above, Applicant recommended that the scope of future TIER ratemaking proceedings be defined by the following language:

> "The subject matter of the scheduled hearing will include review of TIER ratemaking determinations as stated in the Commission's Order dated June _____, 1983, but may not be restricted to Applicant's request. Parties may address the total cost of service and all other lawful elements properly to be considered in determining just and reasonable rates."

By the above, while Applicant may limit its filing to TIER ratemaking, the Commission, its Staff and other parties may not be prevented from addressing issues which they feel should be considered in determining just and reasonable rates.

Finally, Applicant indicated that if the Commission determined it appropriate to continue the present TIER analysis mechanism, without change in the notice of hearing language, Applicant would have no objection.

b. The Staff's TIER Analysis Review Presentation

The Staff recommended significant modifications and improvements to the present TIER analysis mechanism, as summarized below:

1. Instead of conducting TIER hearings every six months, they should be scheduled on an annual basis. This will reduce regulatory expense by about 50%. If Applicant desires more frequent increases, a standard rate case filing should be required.

2. Applicant should be limited to no greater than a 10% increase. If a larger increase is requested, a standard rate case filing should be required.

3. The Notice of Hearing should be expanded so that parties are not limited to a mathematical calculation of the revenue revision necessary to return TIER to 2.4. Instead, parties should be advised that they may address "the total cost of service and all other lawful elements properly to be considered in determining just and reasonable rates."

4. To assure that member-customers are aware of TIER ratemaking and its implications, Applicant should be directed to inform, in writing, its member-customers of the revision, and the method of calculation. This could be done through a newsletter or other appropriate means.

5. In light of financing and structural differences between rural electric cooperatives and investor-owned utilities, TIER ratemaking should apply only to rural electric cooperatives.

6. Total margins should normally be used for the TIER ratemaking calculation. However, where differences between operating and total margins represent patronage capital or other non-cash transactions, said factor may be taken into account. Through either a workpaper or exhibit, Applicant should provide a reconciliation of the differences between operating margins and total margins. Generally, use of total margins would lead to lesser rate increases.

7. Unless financially unable, every three to five years a cost of service study should be conducted to determine whether rates reflect cost causative characteristics. The Staff should work with the rural electric cooperatives to jointly develop a model cost of service study computer format, subject to review by the Commission.

By the Staff's recommendation, Applicant would be precluded from receiving any TIER ratemaking increase until the compilation of REA Form 7 data for the 12-month period ending December 31, 1983. Thereafter, it would be required to submit either a petition for hearing (where revenue adjustment is indicated) or a report to the Commission (where no adjustment is indicated) by March 1, 1984. The petition or report would include the detailed exhibits supporting Applicant's TIER ratemaking calculations. The process would repeat itself year after year, subject to fine-tuning by the Commission.

In addition, the Staff indicated that it will continue to monitor developments in other states relating to regulation of rural electric cooperatives, and continue contacts with other jurisdictions and REA to determine what improvements can be made in the future.

Finally, the Staff addressed the fact that Applicant is the only rural electric cooperative in Michigan which still has its member-customers calculate their own bills. The Staff recommended that Applicant be directed to transfer to a more efficient, more reliable computer-based billing system. The Staff recognized that its recommendation may cause a temporary cash flow problem but that, in the long run, Applicant's financial condition will be more likely to improve by the change.

c. <u>TIER Analysis Conclusions</u>

The Commission has carefully considered the advantages and disadvantages of a TIER-type of mechanism, and believes that the present system, with the improvements and safeguards recommended by the Staff, provides for prudent regulation in the interest of both Applicant and its member-customers.

In authorizing the TIER ratemaking mechanism, as recommended by the Staff, the Commission believes that two more modifications are in order, as follows:

1. If Applicant's calculations indicate that no revenue revisions are required, and such determination is not in dispute, there need be no hearing or Commission order issued.

2. The required cost of service study should be included as an issue in the proceeding in which it is offered. The Commission views the hearing at which the cost of service study is offered as a broader hearing at which a more indepth rate review may be appropriate.

In authorizing the TIER ratemaking mechanism, as recommended by the Staff, the Commission recognizes the unique characteristics of rural electric cooperatives, and indicates that this decision should not be cited as precedent for any investor-owned utilities subject to Commission regulation.

In authorizing TIER ratemaking, the Commission is not scheduling a specific date for review in the future. However, as fine-tuning is required, the Commission will direct the same. The Staff and Applicant are directed to continue to offer their recommendations, as they deem appropriate.

The Commission FINDS that:

a. Jurisdiction is pursuant to 1909 PA 106, as amended, MCLA 460.551 et seq.; 1919 PA 419, as amended, MCLA 460.51 et seq.; 1939 PA 3, as amended, MCLA 460.1 et seq.; 1969 PA 306, as amended, MCLA 24.201 et seq.; and the Commission's Rules of Practice and Procedure, 1979 Administrative Code, R. 460.11 et seq.

b. Applicant's petition, direct testimony and exhibits comply with the Commission's TIER analysis directives.

c. Applicant's adjusted TIER for the period ended January 31, 1983 has been properly calculated as 1.78, thus indicating a required revenue increase of $39,467.

d. A revenue increase of $39,467 is required to return Applicant's TIER coverage to 2.4.

e. The increase in revenues authorized herein should commence with Applicant's June 1983 billing month.

f. The $39,467 increase in revenues authorized herein should be collected by a 2.39 mills per Kwh surcharge in the June 1983 billing month.

g. Thereafter, Applicant should be authorized to incorporate said 2.39 mills per Kwh surcharge into its base rates, consistent with the tariff sheets as set forth in Exhibit A attached hereto which incorporate tariff revisions applicable to TIER analysis.

h. The modifications and improvements to the TIER analysis mechanism, as recommended by the Staff, should be adopted.

i. Applicant should be prohibited from conducting TIER ratemaking hearings on less than an annual basis. If Applicant desires more frequent increases, a standard rate case filing should be required.

j. Applicant should be limited to no greater than a 10% increase under the TIER ratemaking mechanism. If a larger increase is requested, a standard rate case filing should be required.

k. Future notices of hearing in TIER ratemaking proceedings should be expanded so that parties are not limited to a mathematical calculation of the revenue increase necessary to return TIER to 2.4. Instead, parties should be advised that they may address "the total cost of service and all other lawful elements properly to be considered in determining just and reasonable rates."

l. To ensure that member-customers are aware of TIER ratemaking and its implications, Applicant should be directed to inform, in writing, its member-customers of the revisions, and the method of calculation.

m. In light of financing and structural differences between rural electric cooperatives and investor-owned utilities, TIER ratemaking should be applicable only to rural electric cooperatives, on a case-by-case basis.

n. In future TIER ratemaking proceedings, Applicant should provide both total margins (REA Form 7, line 23) and operating margins (REA Form 7, line 17), providing a reconciliation detailing the differences, if any.

o. In the absence of a claim of financial hardship, Applicant should conduct a cost of service study every three to five years. The Staff should work with Applicant and other rural electric cooperatives to jointly develop a model cost of service study computer format, subject to review by the Commission.

p. The required cost of service study should be included as an issue in the proceeding in which it is offered. This should provide for a broader hearing at which a more indepth rate review may be appropriate.

q. Applicant should transfer from its present customer calculated billing system to a more efficient, more reliable computer-based billing system.

THEREFORE, IT IS ORDERED that:

A. Ontonagon County Rural Electrification Association is hereby authorized to place into effect, commencing with the June 1983 billing month, rates designed to produce an increase in annual revenues of approximately $39,467.

B. Ontonagon County Rural Electrification Association is authorized to collect said increased revenue by a 2.39 mills per Kwh surcharge in the June 1983 billing month.

C. Thereafter, Applicant is authorized to incorporate said 2.39 mills per Kwh surcharge into its base rates, consistent with the tariff sheets as set forth in Exhibit A attached hereto.

D. The record in this case is left open for the purpose of further implementation of the TIER ratemaking mechanism according to the terms and procedures set forth in this Opinion and Order.

E. Ontonagon County Rural Electrification Association shall, within thirty days, submit for filing six copies of rate schedules substantially the same as those attached hereto as Exhibit A.

F. The modifications and improvements to the present TIER analysis mechanism, as recommended by the Staff, are adopted for purposes of future TIER ratemaking proceedings.

G. Applicant is precluded from filing for TIER ratemaking increases on less than an annual basis. If Applicant desires more frequent increases, a standard rate case filing is required.

H. Applicant is limited to no greater than a 10% increase by the TIER ratemaking mechanism. If a larger increase is requested, a standard rate case filing is required.

I. Future notices of hearing shall be expanded so that parties are not limited to a mathematical calculation of the revenue increase necessary to return TIER to 2.4. Instead, parties must be advised that they may address "the total cost of service and all other lawful elements properly to be considered in determining just and reasonable rates."

J. To assure that member-customers are aware of TIER ratemaking and its implications, Applicant is directed to inform, in writing, its member-customers of the revisions, and the method of calculation.

K. In light of financing and structural differences between rural electric cooperatives and investor-owned utilities, the TIER ratemaking mechanism is applicable only to rural electric cooperatives on a case-by-case basis.

L. In future TIER ratemaking proceedings, Ontonagon County Rural Electrification Association is directed to provide both total margins (REA Form 7, line 23) and operating margins (REA Form 7, line 17), providing a reconciliation explaining the differences, if any.

M. In the absence of a claim of financial hardship, Ontonagon County Rural Electrification Association is directed to file a cost of service study every three to five years. The Staff is directed to work with Applicant and other rural electric cooperatives to jointly develop a model cost of service study computer format, subject to review by the Commission.

N. The required cost of service study is to be included as an issue in the proceeding in which it is offered. This should provide for a broader hearing at which a more indepth rate review may be appropriate.

O. Ontonagon County Rural Electrification Association is directed to transfer from its present system of member-customers calculating their own bills to a computer-based billing system.

The Commission specifically reserves jurisdiction of the matters herein contained and the authority to issue such further order or orders as the facts and circumstances may require.

Any party desiring to appeal this order must perfect an appeal to the Ingham County Circuit Court within thirty (30) days after issuance and notice of this order, pursuant to MCLA 462.26.

MICHIGAN PUBLIC SERVICE COMMISSION

/s/ Eric J. Schneidewind
Chairperson

I am, this date, issuing the attached Separate Opinion, Concurring in Part and Dissenting in Part.

(SEAL)

/s/ Edwyna G. Anderson
Commissioner

/s/ Matthew E. McLogan
Commissioner

By the Commission and pursuant to its action of June 14, 1983.

/s/ Thomas R. Lonergan
Its Secretary

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the petition of **ONTONAGON COUNTY RURAL ELECTRIFICATION ASSOCIATION** for authority to effectuate the TIER Indexing Mechanism, pursuant to the Commission's order in Case No. U-6652 dated February 10, 1981.)	Case No. U-6652 (TIER – Spring '83)

SEPARATE OPINION OF COMMISSIONER EDWYNA G. ANDERSON, CONCURRING IN PART AND DISSENTING IN PART

(Submitted on June 14, 1983 concerning order issued on same date)

TIER Indexing is a concept introduced for the Ontonagon County Rural Electrification Association (Ontonagon) on February 10, 1981, over my Dissenting Opinion.

TIER is an acronym for "times interest earned ratio." This ratio is computed by adding company earnings and interest for the period and dividing by the interest expense.

The 1981 system:

1. Provides for limited notice and was designed for the review only of a mathematical formula.

2. Affords no ability for any party to scrutinize or review proposed increases in relationship to overall revenue requirements, cost of service or other relevant factors relating to the cooperative's fiscal condition.

3. Provides no ability to review the cooperative's expenses or controls on expenses.

4. Raises questions as to whether the cooperative's member/customers are aware of TIER Indexing or its rate implications.

It is, in my judgment, another automatic adjustment clause.

Today's majority order grants Ontonagon a $39,467 rate increase based on the 1981 TIER Indexing Plan. This will add approximately 2.3% to the average 500 Kwh user's bill, raising it to a monthly base in excess of $55.

The record reflects that Ontonagon is financially weak and in need of revenues. However, I object to the perpetuation of this automatic flowing through of monies under the 1981 plan and must dissent from that aspect of the order.

Today's order also provides, however, for major revisions in the original TIER Indexing Plan, including:

1. Significant expansion of the scope of hearings.
2. Limitation of increases under the indexing plan to no more than 10%. (The Cooperative must file a rate case if it seeks additional monies.)
3. Provision of written information to member/customers regarding TIER ratemaking and its implications, including proposed revisions and methods of calculation.
4. Limiting of TIER ratemaking to rural electric cooperatives only, due to their unique financing and structural differences, in contrast to investor-owned utilities.
5. Development by the cooperatives of cost of service studies every 3 to 5 years.

These revisions should substantially alter the originally designed automatic nature of TIER Indexing. I therefore concur in their adoption, believing they should enhance the regulatory process if properly utilized in future cases.

Edwyna G. Anderson
Commissioner

June 14, 1983
Lansing, Michigan

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to consider revisions to the times interest earned ratio ratemaking mechanism for Michigan's rural electric cooperatives.	Case No. U-11016

At the December 12, 1996 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. John G. Strand, Chairman
Hon. John C. Shea, Commissioner
Hon. David A. Svanda, Commissioner

ORDER REJECTING SETTLEMENT AGREEMENT

On November 28, 1995, the Commission issued an order commencing a proceeding to consider changes to the times interest earned ratio (TIER) ratemaking mechanism for the nine rural electric cooperatives that use that mechanism.[1] Administrative Law Judge Theodora M. Mace conducted a prehearing conference on February 6, 1996. On March 25, 1996, the cooperatives filed the testimony and exhibits of three witnesses. On May 13, 1996, the Commission Staff filed the testimony and exhibits of two witnesses. On May 29, 1996, the testimony and exhibits were bound

[1]The nine cooperatives are Alger Delta Cooperative Electric Association, Cherryland Electric Cooperative, O&A Electric Cooperative, Oceana Electric Cooperative, The Ontonagon County Rural Electrification Association, Southeastern Michigan Rural Electric Cooperative, Inc., Thumb Electric Cooperative, Tri-County Electric Cooperative, and Western Michigan Electric Cooperative.

into the record without cross-examination and the parties submitted a proposed settlement agreement resolving all issues in this docket.

According to the terms of the settlement, the parties propose that the TIER ratemaking mechanism, with its annual filings, be discontinued and that, instead, each cooperative make a rate case filing if and when it determines that its rates should be adjusted. For those rate case filings, they propose that TIER measurements of revenue adequacy and a target TIER of 2.0 be used rather than rate of return regulation. They also propose that the cooperatives be permitted to propose the suspension of their power supply cost recovery (PSCR) mechanisms and the adoption of price cap regulation. Further, they offer procedures to continue the speedy approval of tariff filings.

After considering this matter, the Commission concludes that it should reject the proposed settlement agreement because it is not persuaded that the annual filings required by the TIER ratemaking mechanism should be discontinued. The Commission will address the remaining aspects of the proposed settlement agreement, e.g., the suspension of the PSCR mechanism and the appropriate target TIER, as they arise. Consequently, this docket can be closed.

The Commission FINDS that:

a. Jurisdiction is pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; MSA 22.151 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; MSA 22.1 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; MSA 22.13(1) et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; MSA 3.560(101) et seq.; and the Commission's Rules of Practice and Procedure, 1992 AACS, R 460.17101 et seq.

b. The proposed settlement agreement should be rejected, and this docket should be closed.

THEREFORE, IT IS ORDERED that:

A. The proposed settlement agreement is rejected and this docket is closed.

B. The electric cooperatives using the TIER ratemaking mechanism shall make their next TIER filings, based on calendar year 1996 data, no later than April 30, 1997.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26; MSA 22.45.

MICHIGAN PUBLIC SERVICE COMMISSION

/s/ John G. Strand
Chairman

(SEAL)

/s/ John C. Shea
Commissioner

/s/ David A. Svanda
Commissioner

By its action of December 12, 1996

/s/ Dorothy Wideman
Its Executive Secretary

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **ALGER DELTA COOPERATIVE ELECTRIC ASSOCIATION** for authority to revise base rates and implement a rate reduction.	Case No. U-10670
In the matter of the application of **THUMB ELECTRIC COOPERATIVE** for authority to effectuate the TIER ratemaking mechanism for the 12-month period ended December 31, 1994.	Case No. U-10819
In the matter of the application of **CHERRYLAND ELECTRIC COOPERATIVE** for authority to revise its base rates and to implement a rate reduction.	Case No. U-10821
In the matter of the application of **O & A ELECTRIC COOPERATIVE** for authority to implement TIER ratemaking revisions reflecting the 12-month period ended December 31, 1994.	Case No. U-10822
In the matter of the application of **OCEANA ELECTRIC COOPERATIVE** for authority to revise base rates and implement a rate revision.	Case No. U-10823
In the matter of the application of **THE ONTONAGON COUNTY RURAL ELECTRIFICATION ASSOCIATION** for authority to revise base rates and implement a rate reduction.	Case No. U-10824

Exhibit RJM-9 - CFC Key Ratio Trend Analysis for 2011

CFC KRTA

Pioneer Electric Cooperative, Inc.
KS044

PRODUCED BY: CFC
Woodland Park
20701 Cooperative Way
Dulles, VA 20166
1-800-424-2954

06/20/2012

2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2006–2011) Median	Plant Growth (2006–2011) NBR	Plant Growth (2006–2011) Rank
BASE GROUP (RATIOS 1–5)																
RATIO 1 --- AVERAGE TOTAL CONSUMERS SERVED																
2007	15,821	12,866	819	357	6,774	27	5	17,570	96	83	17,193	6	4	15,821	167	84
2008	16,141	13,166	818	357	6,820	27	5	17,629	95	77	17,398	6	4	22,296	83	52
2009	16,453	13,220	816	348	6,840	27	5	17,724	95	66	17,675	6	4	16,326	93	46
2010	16,606	13,250	815	348	6,869	27	5	17,580	92	62	17,825	6	4	10,913	33	11
2011	16,752	13,362	814	345	6,912	27	5	17,475	92	57	17,958	6	4	13,016	16	6
RATIO 2 --- TOTAL KWH SOLD (1,000)																
2007	709,990	267,135	819	141	110,048	27	3	318,922	96	4	474,542	6	2	331,803	167	29
2008	764,165	276,164	818	133	117,251	27	3	323,188	95	4	543,694	6	2	456,395	83	29
2009	796,604	273,002	816	122	115,102	27	3	314,542	95	4	537,798	6	2	333,602	93	22
2010	834,512	284,611	815	125	123,159	27	3	331,857	92	4	566,341	6	2	289,042	33	5
2011	910,077	287,591	814	115	122,700	27	3	319,702	92	4	581,630	6	2	377,353	16	4
RATIO 3 --- TOTAL UTILITY PLANT (1,000)																
2007	90,747.70	56,418.34	820	239	33,718.83	27	5	67,944.33	96	15	90,834.72	6	4	67,370.64	167	52
2008	105,632.17	59,850.53	819	219	34,049.82	27	4	72,828.37	95	6	103,703.59	6	3	92,801.64	84	41
2009	113,325.28	63,199.26	817	215	35,027.09	27	5	73,920.29	95	8	113,516.08	6	4	79,197.68	93	34
2010	124,533.26	66,306.87	816	201	36,709.65	27	4	81,073.74	92	6	122,682.94	6	3	58,316.90	33	8
2011	126,365.19	69,163.35	815	209	38,533.36	27	5	81,211.61	92	7	127,468.58	6	4	71,274.54	16	6
RATIO 4 --- TOTAL NUMBER OF EMPLOYEES (FULL TIME ONLY)																
2007	58	46	819	324	31	27	5	57	96	44	64	6	4	54	167	76
2008	63	47	818	293	32	27	5	56	95	33	71	6	4	75	83	45
2009	61	48	816	306	33	27	5	57	95	36	71	6	4	57	93	41
2010	64	47	815	283	34	27	5	57	92	27	71	6	4	46	33	9
2011	63	47	814	286	32	27	5	56	92	27	73	6	4	41	16	6
RATIO 5 --- TOTAL MILES OF LINE																
2007	3,760	2,550	819	224	2,141	27	6	2,742	96	16	3,645	6	3	2,901	167	48
2008	3,836	2,579	818	221	2,141	27	6	2,708	95	14	3,874	6	4	2,975	83	35
2009	3,892	2,594	816	216	2,136	27	6	2,719	95	13	3,904	6	4	2,664	93	28
2010	3,932	2,595	815	208	2,130	27	5	2,727	92	13	3,922	6	3	2,409	33	7
2011	3,978	2,602	814	211	2,130	27	5	2,740	92	14	3,944	6	3	2,664	16	4
FINANCIAL (RATIOS 6–32)																
RATIO 6 --- TIER																
2007	3.65	2.24	820	152	2.36	27	5	2.15	96	17	1.92	6	1	2.21	167	28
2008	1.53	2.27	819	692	1.93	27	22	2.06	95	82	1.39	6	3	2.14	84	70
2009	2.60	2.30	817	308	2.47	27	13	2.17	95	33	1.90	6	2	2.21	93	37
2010	3.35	2.45	816	207	2.40	27	7	2.38	92	28	2.07	6	1	2.59	33	10
2011	7.04	2.40	815	64	3.02	27	3	2.40	92	11	3.29	6	1	2.54	16	3

Exhibit RJM-9
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2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2006-2011)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 7 --- TIER (2 OF 3 YEAR HIGH AVERAGE)																
2007	3.75	2.40	820	166	2.81	27	6	2.48	96	19	2.84	6	2	2.43	167	29
2008	2.93	2.46	819	281	2.46	27	10	2.43	95	29	2.27	6	2	2.44	84	29
2009	3.13	2.48	817	246	2.61	27	7	2.38	95	27	2.26	6	1	2.56	93	32
2010	2.98	2.56	816	287	2.71	27	12	2.46	92	35	2.01	6	2	2.70	33	13
2011	5.19	2.57	815	106	2.74	27	4	2.56	92	13	2.48	6	1	3.17	16	4
RATIO 8 --- OTIER																
2007	2.90	1.73	820	134	1.87	27	6	1.64	96	15	0.74	6	1	1.72	167	26
2008	1.72	1.70	819	402	1.63	27	13	1.64	95	42	0.86	6	1	1.65	84	38
2009	2.35	1.71	817	208	1.76	27	7	1.69	95	26	1.20	6	2	1.71	93	27
2010	2.01	1.91	816	363	1.91	27	12	1.97	92	44	1.68	6	2	1.93	33	16
2011	2.23	1.80	815	257	1.81	27	9	1.79	92	30	1.67	6	2	2.04	16	5
RATIO 9 --- OTIER (2 OF 3 YEAR HIGH AVERAGE)																
2007	3.18	1.95	820	136	2.21	27	7	1.95	96	17	2.01	6	2	1.93	167	26
2008	2.31	1.93	819	256	2.09	27	11	1.90	95	32	1.41	6	2	1.95	84	28
2009	2.63	1.89	817	181	1.99	27	7	1.86	95	21	1.15	6	1	1.88	93	22
2010	2.18	1.95	816	301	1.97	27	8	1.89	92	34	1.54	6	2	2.02	33	15
2011	2.29	1.99	815	297	1.98	27	9	2.05	92	38	1.67	6	2	2.26	16	7
RATIO 10 --- MODIFIED DSC (MDSC)																
2007	2.51	1.86	820	193	1.90	27	7	1.86	96	28	2.20	6	3	1.86	167	35
2008	1.71	1.82	819	501	1.71	27	15	1.89	95	57	1.60	6	3	1.87	84	58
2009	2.31	1.85	817	210	1.70	27	5	1.89	95	30	1.86	6	2	1.86	93	25
2010	2.52	1.95	816	202	1.86	27	4	2.10	92	33	2.29	6	2	2.11	33	9
2011	2.44	1.81	815	190	1.78	27	4	1.81	92	26	2.09	6	3	2.10	16	5
RATIO 11 --- MDSC (2 OF 3 YEAR HIGH AVERAGE)																
2007	2.63	2.00	820	204	2.19	27	7	2.11	96	27	2.41	6	3	2.03	167	41
2008	2.22	1.98	819	309	2.08	27	10	1.98	95	37	1.95	6	3	2.07	84	33
2009	2.41	1.95	817	233	2.03	27	7	1.95	95	32	2.09	6	3	1.99	93	29
2010	2.42	2.00	816	242	1.95	27	6	2.07	92	33	2.21	6	3	2.21	33	13
2011	2.48	2.00	815	218	1.90	27	5	2.07	92	30	2.27	6	2	2.12	16	6
RATIO 12 --- DEBT SERVICE COVERAGE (DSC)																
2007	2.55	2.08	820	242	2.12	27	7	2.05	96	31	2.28	6	3	2.05	167	46
2008	1.52	2.07	819	715	2.08	27	23	1.96	95	81	1.92	6	5	2.09	84	76
2009	2.18	2.06	817	359	2.09	27	10	2.06	95	44	1.97	6	3	2.05	93	43
2010	3.13	2.21	816	151	2.26	27	3	2.30	92	27	2.56	6	1	2.21	33	9
2011	5.14	2.11	815	57	2.15	27	2	2.13	92	11	2.50	6	1	2.32	16	3

Exhibit RJM-9
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2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2006-2011)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 13 --- DSC (2 OF 3 YEAR HIGH AVERAGE)																
2007	2.62	2.22	820	257	2.36	27	8	2.33	96	33	2.72	6	4	2.24	167	48
2008	2.18	2.23	819	439	2.23	27	16	2.17	95	46	2.32	6	4	2.34	84	49
2009	2.36	2.23	817	341	2.27	27	11	2.20	95	38	2.41	6	4	2.31	93	44
2010	2.65	2.26	816	259	2.27	27	7	2.31	92	35	2.39	6	3	2.47	33	11
2011	4.14	2.26	815	93	2.35	27	3	2.29	92	16	2.57	6	1	2.39	16	4
RATIO 14 --- ODSC																
2007	2.17	1.75	820	233	1.74	27	8	1.74	96	30	1.56	6	1	1.75	167	45
2008	1.62	1.74	819	500	1.67	27	15	1.74	95	56	1.52	6	3	1.80	84	56
2009	2.04	1.77	817	270	1.64	27	6	1.84	95	35	1.82	6	2	1.81	93	32
2010	2.21	1.86	816	252	1.78	27	6	2.00	92	37	2.21	6	3	1.96	33	11
2011	2.14	1.76	815	242	1.75	27	5	1.72	92	31	1.77	6	2	2.05	16	6
RATIO 15 --- ODSC (2 OF 3 YEAR HIGH AVERAGE)																
2007	2.33	1.91	820	238	2.04	27	6	1.96	96	32	2.07	6	2	1.92	167	50
2008	1.89	1.87	819	400	1.90	27	15	1.90	95	49	1.64	6	3	1.98	84	47
2009	2.10	1.86	817	286	1.99	27	11	1.89	95	38	1.81	6	3	1.90	93	34
2010	2.13	1.90	816	296	1.90	27	8	1.97	92	38	2.04	6	3	2.07	33	16
2011	2.18	1.93	815	279	1.85	27	5	1.94	92	38	2.09	6	2	2.05	16	6
RATIO 16 --- EQUITY AS A % OF ASSETS																
2007	48.60	41.14	820	255	41.27	27	8	42.46	96	36	21.59	6	1	42.28	167	53
2008	47.09	40.62	819	282	40.14	27	9	41.85	95	35	21.81	6	1	38.74	84	24
2009	45.29	41.26	817	314	39.53	27	10	42.15	95	39	21.87	6	1	39.37	93	31
2010	42.51	41.78	816	390	40.98	27	11	43.69	92	50	21.14	6	1	35.95	33	12
2011	47.38	42.32	815	296	43.00	27	10	43.38	92	35	23.80	6	1	36.50	16	7
RATIO 17 --- DISTRIBUTION EQUITY (EXCLUDES EQUITY IN ASSOC. ORG'S PATRONAGE CAPITAL)																
2007	48.49	35.78	820	188	38.03	27	6	35.73	96	25	21.35	6	1	36.52	167	41
2008	46.94	34.91	819	196	36.49	27	8	35.56	95	24	21.51	6	1	33.10	84	20
2009	45.13	35.11	817	209	35.69	27	8	34.80	95	24	21.56	6	1	31.68	93	24
2010	42.34	35.87	816	263	35.95	27	9	35.39	92	31	20.80	6	1	31.99	33	9
2011	43.02	35.93	815	263	36.14	27	9	35.86	92	29	23.47	6	1	30.79	16	6
RATIO 18 --- EQUITY AS A % OF TOTAL CAPITALIZATION																
2007	58.36	47.26	820	217	47.27	27	7	48.92	96	31	38.49	6	1	48.59	167	45
2008	53.06	47.22	819	300	44.22	27	9	47.58	95	37	30.64	6	1	44.01	84	26
2009	54.68	47.63	817	263	45.23	27	7	48.18	95	34	30.96	6	1	45.08	93	29
2010	49.64	48.60	816	389	47.35	27	11	49.67	92	47	28.28	6	1	45.66	33	14
2011	53.80	49.12	815	309	47.46	27	9	48.76	92	40	29.81	6	1	42.72	16	7

2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2006-2011)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 19 --- LONG TERM DEBT AS A % OF TOTAL ASSETS																
2007	34.68	46.13	813	625	45.52	27	20	45.43	95	68	46.84	6	5	45.08	166	125
2008	41.66	45.44	811	491	46.78	27	19	45.18	94	57	59.69	6	5	46.90	83	54
2009	37.53	45.69	808	575	45.99	27	20	45.50	92	65	61.71	6	5	46.81	92	64
2010	43.13	44.72	807	446	46.88	27	18	44.42	89	50	57.65	6	6	45.69	33	23
2011	40.70	44.30	805	493	47.27	27	21	45.35	90	54	55.97	6	6	45.62	16	9
RATIO 20 --- LONG TERM DEBT PER KWH SOLD (MILLS)																
2007	50.75	93.80	813	650	112.83	27	24	93.70	95	72	89.57	6	6	88.94	166	129
2008	57.90	96.00	811	620	120.34	27	24	92.75	94	70	85.68	6	6	90.62	83	67
2009	54.79	103.19	808	648	136.31	27	25	100.33	92	72	91.88	6	6	102.20	92	76
2010	69.17	103.16	807	570	124.23	27	25	100.77	89	61	105.52	6	6	103.23	33	27
2011	66.80	104.60	805	596	133.36	27	26	107.61	90	65	112.18	6	6	107.65	16	10
RATIO 21 --- LONG TERM DEBT PER CONSUMER ($)																
2007	2,277.28	1,862.81	813	264	1,838.03	27	9	1,627.90	95	16	2,366.92	6	4	1,843.93	166	50
2008	2,741.15	1,932.21	811	171	2,063.99	27	8	1,704.63	94	10	2,531.76	6	3	1,998.97	83	19
2009	2,652.70	2,043.37	808	218	2,180.30	27	8	1,862.56	92	12	2,582.57	6	3	2,262.12	92	32
2010	3,476.12	2,063.99	807	95	2,235.49	27	5	1,946.24	89	7	2,986.50	6	3	2,640.97	33	8
2011	3,628.97	2,089.05	805	95	2,375.83	27	5	2,016.36	90	8	3,403.38	6	3	3,016.77	16	4
RATIO 22 --- NON-GOVERNMENT DEBT AS A % OF TOTAL LONG TERM DEBT																
2007	21.97	27.77	786	459	21.97	23	12	32.08	94	58	41.47	6	4	28.96	161	95
2008	15.34	26.90	786	543	16.93	23	13	28.19	94	67	38.57	6	4	25.09	82	55
2009	15.40	25.26	792	504	14.21	23	11	22.66	91	57	4.55	6	2	23.56	91	59
2010	16.24	32.80	794	631	31.19	23	16	28.03	89	63	1.45	5	2	37.43	32	25
2011	100.00	32.20	795	95	29.52	23	3	29.85	89	9	6.79	5	1	28.07	16	1
RATIO 23 --- BLENDED INTEREST RATE (%)																
2007	5.17	5.19	813	418	4.86	27	11	5.28	94	63	5.40	6	5	5.18	166	86
2008	4.60	5.12	811	664	4.86	27	16	5.15	93	80	4.15	6	3	5.01	83	66
2009	4.73	5.07	809	597	4.75	27	16	5.12	92	74	4.09	6	2	5.01	92	69
2010	5.08	4.96	807	337	4.87	27	9	5.01	89	40	4.33	6	2	5.02	33	15
2011	4.69	4.81	805	469	4.55	27	12	4.95	88	55	4.34	6	1	4.77	16	9
RATIO 24 --- ANNUAL CAPITAL CREDITS RETIRED PER TOTAL EQUITY (%)																
2007	2.36	2.02	649	271	0.98	27	8	1.75	75	30	1.17	6	2	1.90	136	58
2008	2.37	2.05	634	265	1.13	27	5	1.89	74	28	0.48	6	1	1.42	57	15
2009	2.15	1.95	631	282	0.68	26	5	1.78	77	28	0.35	6	1	1.78	66	24
2010	3.75	1.99	653	107	0.78	27	3	1.91	76	8	0.35	6	1	1.71	29	2
2011	3.06	2.18	675	199	1.24	26	4	1.92	79	21	0.32	6	1	2.17	12	3

2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2006-2011)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 25 --- LONG-TERM INTEREST AS A % OF REVENUE																
2007	3.80	5.27	813	588	5.31	27	20	5.09	94	65	4.31	6	4	5.06	166	115
2008	3.28	5.06	811	629	4.72	27	22	4.87	93	72	3.64	6	4	4.99	83	63
2009	3.51	5.14	809	596	5.34	27	23	4.99	92	66	4.84	6	5	5.12	92	64
2010	3.98	4.87	807	524	5.36	27	23	4.82	89	56	4.90	6	5	5.43	33	24
2011	3.84	4.66	805	516	5.06	27	21	4.74	88	58	4.98	6	5	4.99	16	10
RATIO 26 --- CUMULATIVE PATRONAGE CAPITAL RETIRED AS A % OF TOTAL PATRONAGE CAPITAL																
2007	33.63	24.89	695	189	23.38	25	6	21.64	79	14	24.50	6	2	26.00	143	41
2008	34.86	24.61	695	160	23.09	26	6	22.20	80	13	26.28	6	2	20.57	70	11
2009	34.63	24.59	696	159	22.44	25	6	22.43	81	13	25.11	6	2	23.29	76	9
2010	34.55	24.61	696	164	21.89	24	6	21.56	79	13	25.72	6	2	24.16	30	8
2011	31.27	24.67	697	219	21.24	24	6	22.65	80	21	21.70	6	2	22.99	13	5
RATIO 27 --- RATE OF RETURN ON EQUITY (%)																
2007	10.24	7.03	820	159	8.28	27	6	6.26	96	14	9.72	6	3	6.85	167	20
2008	2.05	6.82	819	752	6.49	27	23	6.70	95	85	1.75	6	3	6.63	84	78
2009	6.63	7.10	817	451	8.21	27	19	6.72	95	50	7.71	6	5	6.89	93	53
2010	11.09	7.62	816	146	7.85	27	5	7.68	92	15	10.35	6	3	9.96	33	8
2011	24.56	6.93	815	5	8.98	27	3	6.97	92	1	22.20	6	3	10.98	16	2
RATIO 28 --- RATE OF RETURN ON TOTAL CAPITALIZATION (%)																
2007	8.22	6.04	820	118	5.86	27	3	5.66	96	10	6.00	6	1	5.98	167	13
2008	3.13	5.99	819	769	5.78	27	24	5.98	95	87	2.99	6	3	5.69	84	79
2009	5.88	6.01	817	429	6.25	27	19	5.79	95	43	5.35	6	3	5.88	93	47
2010	7.85	6.22	816	158	6.35	27	3	6.35	92	16	6.63	6	1	6.94	33	8
2011	15.40	5.91	815	4	7.00	27	1	5.92	92	1	7.84	6	1	7.18	16	2
RATIO 29 --- CURRENT RATIO																
2007	1.36	1.21	820	345	0.88	27	9	1.20	96	37	1.15	6	2	1.23	167	75
2008	1.17	1.16	819	408	1.05	27	11	1.16	95	47	0.97	6	1	0.97	84	35
2009	0.65	1.20	817	697	0.84	27	19	1.19	95	81	0.70	6	4	1.10	93	78
2010	0.68	1.23	816	704	0.90	27	18	1.14	92	81	0.69	6	4	1.07	33	25
2011	0.53	1.23	815	772	1.08	27	23	1.39	92	91	0.72	6	4	1.05	16	15
RATIO 30 --- GENERAL FUNDS PER TUP (%)																
2007	15.38	3.91	820	62	3.96	27	3	4.24	96	7	4.80	6	2	4.68	167	13
2008	13.97	3.91	819	86	3.19	27	3	4.12	95	8	3.22	6	2	3.24	84	10
2009	15.94	3.72	817	56	2.53	27	3	3.98	95	7	4.54	6	2	4.01	93	5
2010	16.59	4.16	816	53	2.73	27	3	4.28	92	7	3.82	6	2	2.20	33	3
2011	18.10	4.21	815	42	2.99	27	2	3.59	92	5	4.75	6	1	4.20	16	1

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2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2006-2011)		
		Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 31 --- PLANT REVENUE RATIO (PRR) ONE YEAR																
2007	5.99	6.37	820	533	7.08	27	24	6.27	96	63	8.43	6	6	6.30	167	109
2008	7.79	6.44	819	106	7.10	27	9	6.30	95	9	8.18	6	6	6.46	84	14
2009	7.13	6.46	817	224	7.08	27	13	6.32	95	15	7.86	6	5	6.46	93	27
2010	7.25	6.31	816	187	6.70	27	11	6.02	92	13	7.26	6	4	6.67	33	12
2011	6.76	6.46	815	316	6.76	27	13	6.30	92	27	7.26	6	5	6.89	16	9
RATIO 32 --- INVESTMENT IN SUBSIDIARIES TO TOTAL ASSETS (%)																
2007	0.64	0.52	251	119	1.27	11	8	0.38	23	10	1.47	4	4	0.73	56	30
2008	0.59	0.67	246	128	1.96	9	9	0.40	23	11	0.83	3	3	0.41	32	15
2009	0.15	0.57	239	161	2.08	9	8	0.26	24	15	0.61	3	3	0.37	38	27
2010	0.78	0.61	246	116	2.30	10	8	0.44	24	10	1.60	4	3	0.31	12	4
2011	0.64	0.58	243	116	1.45	7	5	0.24	21	8	0.64	3	2	0.15	5	1
REVENUE & MARGINS (RATIOS 33-59)																
RATIO 33 --- TOTAL OPERATING REVENUE PER KWH SOLD (MILLS)																
2007	72.25	91.18	819	691	102.88	27	27	93.29	96	85	84.19	6	6	86.20	167	142
2008	76.88	97.15	818	688	111.75	27	27	99.21	95	86	90.37	6	6	94.81	83	70
2009	77.89	100.87	816	702	110.45	27	27	103.39	95	87	87.11	6	6	100.90	93	81
2010	81.10	102.30	815	706	116.66	27	27	103.08	92	84	95.61	6	6	98.89	33	27
2011	82.36	106.02	814	712	129.94	27	27	106.13	92	82	99.18	6	6	93.50	16	12
RATIO 34 --- TOTAL OPERATING REVENUE PER TUP INVESTMENT (CENTS)																
2007	56.53	41.13	820	136	34.34	27	2	43.69	96	16	43.82	6	1	41.50	167	31
2008	55.62	42.13	819	183	36.22	27	3	44.64	95	25	47.79	6	2	44.00	84	23
2009	54.75	42.05	817	168	34.36	27	1	44.59	95	21	44.63	6	1	43.75	93	24
2010	54.34	42.52	816	189	37.04	27	2	44.74	92	26	49.00	6	1	37.04	33	7
2011	59.31	42.31	815	120	39.21	27	1	44.29	92	15	45.29	6	1	41.18	16	3
RATIO 35 --- TOTAL OPERATING REVENUE PER CONSUMER ($)																
2007	3,242.36	1,797.89	819	52	1,754.80	27	2	1,656.69	96	2	2,423.38	6	2	1,820.45	167	10
2008	3,639.64	1,921.74	818	51	1,849.83	27	1	1,842.99	95	1	2,743.55	6	1	1,990.25	83	1
2009	3,771.08	1,981.84	816	46	1,848.04	27	1	1,926.52	95	2	2,584.21	6	1	2,020.39	93	4
2010	4,075.48	2,114.03	815	41	2,066.79	27	1	1,997.03	92	2	2,853.52	6	1	2,278.00	33	2
2011	4,474.28	2,139.09	814	39	2,290.50	27	1	2,037.55	92	2	3,059.84	6	1	2,542.52	16	4
RATIO 36 --- ELECTRIC REVENUE PER KWH SOLD (MILLS)																
2007	71.98	89.17	819	681	100.23	27	26	90.18	96	84	83.90	6	6	84.77	167	140
2008	76.62	95.42	818	675	108.69	27	27	96.22	95	85	90.06	6	6	92.39	83	68
2009	77.66	98.81	816	695	109.68	27	27	99.83	95	87	85.09	6	6	98.23	93	78
2010	80.87	100.25	815	700	114.48	27	27	99.58	92	84	92.21	6	6	95.67	33	27
2011	82.16	104.14	814	706	128.29	27	27	104.54	92	81	94.76	6	6	91.70	16	12

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2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2006-2011)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 37 --- ELECTRIC REVENUE PER CONSUMER ($)																
2007	3,230.10	1,761.38	819	50	1,731.19	27	2	1,636.21	96	2	2,414.99	6	2	1,780.90	167	10
2008	3,627.52	1,883.20	818	46	1,835.01	27	1	1,811.01	95	1	2,706.41	6	1	1,930.03	83	1
2009	3,760.18	1,940.25	816	41	1,749.75	27	1	1,877.49	95	2	2,553.27	6	1	2,003.63	93	4
2010	4,064.25	2,068.08	815	37	1,957.77	27	1	1,957.23	92	2	2,750.35	6	1	2,187.50	33	2
2011	4,463.40	2,105.70	814	36	2,170.03	27	1	2,012.22	92	2	2,921.50	6	1	2,446.84	16	4
RATIO 38 --- RESIDENTIAL REVENUE PER KWH SOLD (MILLS)																
2007	94.13	96.40	819	450	108.07	27	24	97.39	96	55	103.83	6	6	93.50	167	83
2008	93.97	102.30	818	554	115.02	27	26	103.83	95	66	109.71	6	6	99.15	83	50
2009	94.92	107.21	816	595	115.93	27	25	109.28	95	75	100.44	6	6	107.26	93	68
2010	97.69	109.01	815	582	124.13	27	27	108.22	92	68	108.71	6	6	103.37	33	23
2011	99.29	112.13	814	621	136.71	27	27	112.22	92	69	110.56	6	6	108.34	16	13
RATIO 39 --- NON-RESIDENTIAL REVENUE PER KWH SOLD (MILLS)																
2007	69.92	79.10	818	562	91.43	27	26	82.59	96	73	79.09	6	6	76.37	167	107
2008	75.14	85.43	817	564	99.32	27	26	87.41	95	66	85.30	6	6	80.34	83	58
2009	76.23	88.28	815	596	94.24	27	24	86.11	95	70	80.76	6	5	89.98	93	72
2010	79.45	89.78	814	580	99.92	27	26	88.53	92	66	87.84	6	6	85.70	33	20
2011	80.78	92.63	813	596	114.85	27	27	93.53	92	65	90.14	6	6	81.94	16	9
RATIO 41 --- IRRIGATION REVENUE PER KWH SOLD (MILLS)																
2007	94.28	100.32	399	233	125.82	18	14	99.09	41	28	93.03	6	3	102.58	75	48
2008	94.40	111.11	397	274	131.62	18	15	112.67	42	33	93.82	6	3	111.25	34	26
2009	99.53	117.82	398	284	130.48	18	16	118.39	42	34	101.89	6	4	110.47	41	29
2010	103.98	124.98	394	290	126.41	18	17	123.11	42	31	106.86	6	5	93.00	19	7
2011	99.18	120.98	399	299	130.59	18	17	116.08	47	36	110.26	6	5	104.97	12	8
RATIO 42 --- SMALL COMMERCIAL REVENUE PER KWH SOLD (MILLS)																
2007	90.08	88.67	817	376	100.62	27	22	90.72	96	52	93.92	6	5	87.04	167	69
2008	88.56	95.09	816	502	106.89	27	24	97.30	95	69	98.29	6	5	92.85	83	51
2009	88.96	99.12	813	575	107.26	27	24	100.56	95	75	94.69	6	5	100.56	93	70
2010	91.80	100.47	813	556	112.66	27	25	101.61	92	70	102.61	6	5	103.39	33	23
2011	92.30	103.13	813	599	122.70	27	26	104.87	92	70	104.50	6	5	94.80	16	10
RATIO 43 --- LARGE COMMERCIAL REVENUE PER KWH SOLD (MILLS)																
2007	54.60	63.98	680	500	75.86	18	17	65.59	88	72	72.10	5	5	60.82	147	103
2008	62.44	69.03	684	445	77.22	19	16	69.70	88	63	77.22	5	5	63.19	70	37
2009	62.40	72.21	685	478	76.84	18	14	69.44	88	63	64.03	5	4	68.88	71	49
2010	65.04	72.94	683	472	79.75	19	15	70.91	85	56	79.09	5	5	68.36	27	17
2011	66.57	75.63	686	478	84.92	19	18	71.38	85	55	82.22	5	5	77.99	15	11

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Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2006-2011) Median	Plant Growth (2006-2011) NBR	Plant Growth (2006-2011) Rank
RATIO 44 --- SALES FOR RESALE REVENUE PER KWH SOLD (MILLS)																
2007	56.87	54.82	113	48	51.06	9	3	56.46	9	4	57.79	4	3	56.02	21	9
2008	60.85	58.36	117	57	54.35	9	3	57.94	9	4	62.33	4	3	51.85	9	4
2009	54.55	61.86	121	90	52.96	8	4	61.48	9	7	57.47	4	3	55.80	12	8
2010	55.65	64.14	119	88	58.16	8	5	62.96	9	9	61.49	4	3	55.65	9	5
2011	56.29	67.23	121	100	58.50	8	5	65.70	9	9	63.04	4	3	75.63	5	5
RATIO 45 --- STREET & HIGHWAY LIGHTING REVENUE PER KWH SOLD (MILLS)																
2007	171.00	124.36	587	146	132.68	21	3	113.41	61	10	157.69	6	1	112.78	111	26
2008	171.15	132.71	586	163	144.25	21	4	126.98	61	16	169.43	6	2	147.86	63	25
2009	177.95	139.11	588	156	149.57	22	3	128.56	61	12	158.85	6	1	163.48	61	22
2010	183.01	142.73	587	159	148.42	22	4	133.93	62	14	157.68	6	1	146.83	22	4
2011	183.18	144.87	591	173	157.31	22	5	135.51	62	14	160.99	6	2	161.83	12	4
RATIO 47 --- OPERATING MARGINS PER KWH SOLD (MILLS)																
2007	5.14	2.99	819	196	5.02	27	12	2.40	96	15	-1.12	6	1	2.63	167	25
2008	1.69	2.78	818	549	2.22	27	18	2.56	95	63	-0.78	6	2	2.40	83	56
2009	3.63	3.27	816	371	5.09	27	17	3.63	95	49	0.90	6	2	2.98	93	42
2010	3.17	3.92	815	487	5.16	27	19	4.15	92	60	2.84	6	3	3.92	33	23
2011	3.79	3.47	814	376	4.37	27	16	3.38	92	41	3.08	6	3	6.05	16	10
RATIO 48 --- OPERATING MARGINS PER CONSUMER ($)																
2007	230.71	61.81	819	39	67.76	27	1	56.65	96	2	-28.93	6	1	60.63	167	6
2008	80.05	57.61	818	291	48.40	27	8	53.89	95	27	-14.52	6	1	54.23	83	29
2009	175.72	64.69	816	91	77.36	27	6	63.18	95	1	16.18	6	2	73.11	93	12
2010	159.15	81.23	815	136	91.26	27	4	79.34	92	11	85.58	6	1	96.10	33	9
2011	206.13	70.64	814	73	83.93	27	3	63.64	92	6	85.10	6	1	123.05	16	6
RATIO 49 --- NON-OPERATING MARGINS PER KWH SOLD (MILLS)																
2007	1.98	0.75	819	122	1.04	27	7	0.68	96	10	2.97	6	5	0.76	167	27
2008	-0.63	0.59	817	780	0.74	27	26	0.50	95	93	0.39	6	5	0.46	83	79
2009	0.63	0.49	816	363	0.72	27	16	0.44	95	40	0.77	6	4	0.37	93	33
2010	4.18	0.50	815	24	0.64	27	2	0.44	92	3	1.21	6	1	0.51	33	3
2011	3.06	0.52	814	42	0.79	27	3	0.50	92	4	2.74	6	3	0.66	16	1
RATIO 50 --- NON-OPERATING MARGINS PER CONSUMER ($)																
2007	89.00	15.63	819	36	16.43	27	4	12.28	96	4	93.48	6	4	16.43	167	5
2008	-29.71	12.20	817	795	11.77	27	27	9.86	95	94	10.29	6	6	10.53	83	82
2009	30.60	10.41	816	158	11.87	27	6	9.20	95	16	23.58	6	3	7.38	93	16
2010	209.88	10.27	815	2	10.81	27	1	8.37	92	1	32.77	6	1	10.81	33	1
2011	166.49	11.07	814	7	11.54	27	1	9.82	92	2	76.23	6	1	16.20	16	1

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2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2006-2011) Median	Plant Growth (2006-2011) NBR	Plant Growth (2006-2011) Rank
RATIO 51 --- TOTAL MARGINS LESS ALLOCATIONS PER KWH SOLD (MILLS)																
2007	7.12	4.01	819	154	5.75	27	11	3.26	96	7	2.48	6	2	3.63	167	26
2008	1.06	3.65	818	687	3.18	27	22	3.51	95	84	0.84	6	3	3.64	83	71
2009	4.26	4.08	816	391	4.85	27	17	4.15	95	47	3.50	6	3	3.93	93	41
2010	7.34	4.63	815	195	5.95	27	9	4.63	92	19	4.27	6	1	4.44	33	10
2011	6.86	4.37	814	205	5.43	27	11	4.26	92	18	5.05	6	2	6.88	16	9
RATIO 52 --- TOTAL MARGINS LESS ALLOCATIONS PER CONSUMER ($)																
2007	319.71	82.39	819	27	111.58	27	1	66.08	96	1	52.30	6	1	79.21	167	3
2008	50.34	75.62	818	550	68.72	27	17	65.82	95	58	33.86	6	3	70.36	83	54
2009	206.31	80.44	816	82	87.82	27	2	74.98	95	2	72.86	6	1	76.05	93	12
2010	369.02	99.63	815	19	120.39	27	1	98.70	92	1	118.34	6	1	114.15	33	3
2011	372.62	90.25	814	28	108.38	27	1	76.07	92	3	156.79	6	1	127.65	16	4
RATIO 53 --- INCOME (LOSS) FROM EQUITY INVESTMENTS PER CONSUMER ($)																
2007	4.62	0.83	246	69	0.67	7	3	0.58	27	8	4.62	3	2	1.04	59	16
2008	-49.95	1.46	251	244	11.17	8	8	0.35	27	26	-36.70	3	3	0.35	33	32
2009	-39.60	1.39	247	239	1.83	8	7	1.23	23	22	-0.02	3	3	2.43	36	35
2010	136.24	1.76	244	3	3.62	8	1	0.43	20	1	1.61	3	1	1.57	12	1
2011	83.41	1.46	241	5	9.78	7	1	0.13	21	1	75.09	3	1	5.16	7	1
RATIO 54 --- ASSOCIATED ORGANIZATION'S CAPITAL CREDITS PER KWH SOLD (MILLS)																
2007	0.15	1.46	769	713	1.60	27	25	1.71	85	82	0.28	6	6	1.27	155	141
2008	0.28	2.04	769	691	3.21	27	24	2.04	85	82	0.60	6	5	1.44	78	68
2009	0.12	2.34	767	720	5.16	27	27	2.25	86	84	0.61	6	6	2.33	89	81
2010	0.22	2.54	767	710	4.35	27	26	2.94	83	80	0.71	6	6	2.33	31	31
2011	12.24	2.75	769	4	5.98	27	1	2.89	84	1	3.88	6	1	2.57	15	1
RATIO 55 --- ASSOCIATED ORGANIZATION'S CAPITAL CREDITS PER CONSUMER ($)																
2007	6.94	29.99	769	642	24.65	27	22	32.05	85	76	7.79	6	4	28.69	155	125
2008	13.08	38.28	769	622	43.24	27	22	35.91	85	76	13.35	6	4	33.55	78	60
2009	5.89	43.39	767	670	68.62	27	25	37.57	86	83	16.50	6	6	39.58	89	74
2010	11.08	51.24	767	642	66.00	27	23	48.51	83	74	18.95	6	5	59.85	31	28
2011	665.18	54.92	769	4	89.38	27	1	48.49	84	1	85.02	6	1	78.52	15	2
RATIO 56 --- TOTAL MARGINS PER KWH SOLD (MILLS)																
2007	7.28	6.05	819	306	7.39	27	16	5.18	96	28	2.76	6	2	5.52	167	51
2008	1.34	6.13	818	754	6.12	27	24	5.41	95	86	1.02	6	3	5.08	83	77
2009	4.38	6.68	816	621	8.61	27	24	5.66	95	68	3.80	6	3	6.73	93	74
2010	7.56	7.20	815	378	9.00	27	19	7.16	92	43	5.21	6	1	8.16	33	20
2011	19.10	7.12	814	18	11.32	27	2	6.40	92	3	9.55	6	1	8.44	16	2

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2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2006-2011) Median	Plant Growth (2006-2011) NBR	Plant Growth (2006-2011) Rank
RATIO 57 --- TOTAL MARGINS PER CONSUMER ($)																
2007	326.65	118.16	819	55	121.84	27	1	96.77	96	3	58.82	6	1	113.09	167	7
2008	63.42	122.96	818	650	120.09	27	21	112.99	95	73	41.55	6	3	109.60	83	64
2009	212.21	130.60	816	166	147.56	27	6	111.14	95	5	81.47	6	2	135.78	93	24
2010	380.10	150.51	815	43	164.27	27	1	136.39	92	1	138.99	6	1	172.65	33	6
2011	1,037.81	144.88	814	8	198.33	27	1	129.12	92	1	241.80	6	1	206.67	16	2
RATIO 58 --- A/R OVER 60 DAYS AS A % OF OPERATING REVENUE																
2007	0.05	0.19	801	673	0.21	25	21	0.20	96	78	0.22	6	5	0.18	162	136
2008	0.07	0.17	806	625	0.18	26	20	0.17	94	71	0.16	6	5	0.19	83	66
2009	0.02	0.17	806	739	0.12	26	22	0.19	95	87	0.13	6	5	0.20	93	86
2010	0.02	0.17	802	754	0.16	26	25	0.18	92	87	0.21	6	6	0.17	33	31
2011	0.06	0.15	799	598	0.12	26	19	0.16	92	69	0.13	6	6	0.08	16	11
RATIO 59 --- AMOUNT WRITTEN OFF AS A % OF OPERATING REVENUE																
2007	0.03	0.18	785	712	0.10	24	15	0.21	96	95	0.16	6	4	0.21	160	148
2008	0.03	0.18	791	731	0.15	25	20	0.21	94	93	0.14	6	6	0.19	81	77
2009	0.02	0.20	784	752	0.12	24	21	0.25	94	94	0.11	6	5	0.20	92	90
2010	0.03	0.18	779	731	0.13	26	24	0.20	89	89	0.14	6	6	0.17	31	29
2011	0.01	0.17	780	754	0.09	26	22	0.20	91	90	0.11	6	6	0.14	15	15
SALES (RATIOS 60-76)																
RATIO 60 --- TOTAL MWH SOLD PER MILE OF LINE																
2007	188.85	109.02	819	186	49.46	27	3	117.64	96	21	130.46	6	3	114.24	167	37
2008	199.23	112.33	818	169	53.94	27	3	117.19	95	19	140.94	6	3	162.52	83	29
2009	204.70	110.39	816	152	53.45	27	3	111.73	95	15	143.44	6	3	125.09	93	19
2010	212.25	114.36	815	159	57.66	27	3	122.91	92	17	149.34	6	3	107.25	33	8
2011	228.78	116.06	814	133	57.01	27	3	117.39	92	14	159.69	6	3	150.70	16	4
RATIO 61 --- AVERAGE RESIDENTIAL USAGE KWH PER MONTH																
2007	1,017.75	1,198.82	819	595	981.66	27	8	1,178.74	96	73	705.43	6	1	1,218.88	167	133
2008	1,011.85	1,191.15	818	602	967.89	27	7	1,168.69	95	71	793.43	6	1	1,277.77	83	74
2009	1,021.04	1,173.32	816	586	967.61	27	7	1,141.10	95	67	812.27	6	1	1,189.46	93	72
2010	1,087.90	1,239.39	815	568	1,043.30	27	7	1,203.29	92	61	881.54	6	1	1,146.30	33	18
2011	1,133.23	1,213.00	814	504	1,049.42	27	6	1,187.17	92	50	901.70	6	1	1,088.55	16	7
RATIO 63 --- AVERAGE IRRIGATION KWH USAGE PER MONTH																
2007	17,532.92	2,125.51	399	10	1,295.39	18	1	2,157.66	41	1	1,688.20	6	1	2,639.78	75	2
2008	18,691.21	2,084.66	397	5	1,184.15	18	1	2,035.37	42	1	2,032.32	6	1	2,297.18	34	2
2009	15,962.29	1,951.34	397	10	1,278.80	18	1	2,089.37	42	1	1,876.78	6	1	2,123.41	41	2
2010	17,409.95	1,678.12	394	6	1,786.94	18	1	1,706.72	42	1	1,965.74	6	1	2,429.20	19	3
2011	22,506.08	1,943.18	399	6	2,021.99	18	1	2,241.49	47	1	2,624.99	6	1	2,242.33	12	1

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2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2006-2011)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 64 --- AVERAGE SMALL COMMERCIAL KWH USAGE PER MONTH																
2007	1,853.20	3,333.33	817	707	2,153.96	27	18	2,747.88	96	73	2,587.96	6	5	3,512.13	167	149
2008	2,020.50	3,282.35	816	674	2,225.57	27	16	2,688.44	95	71	2,909.00	6	4	2,940.23	83	71
2009	2,024.08	3,228.63	813	669	2,106.24	27	15	2,686.69	95	73	2,412.19	6	4	3,117.94	93	78
2010	2,054.95	3,283.98	813	672	2,214.67	27	16	2,744.26	92	68	2,516.62	6	4	3,067.77	33	28
2011	2,117.32	3,323.04	813	666	2,225.80	27	16	2,785.14	92	70	2,544.60	6	4	3,071.51	16	14
RATIO 65 --- AVERAGE LARGE COMMERCIAL KWH USAGE PER MONTH																
2007	1,233,962.12	525,469.44	680	146	151,468.75	18	1	500,435.19	88	14	472,635.19	5	1	593,574.07	147	36
2008	1,175,608.70	505,968.75	684	164	156,222.22	19	2	554,897.22	88	20	146,472.22	5	1	555,725.00	70	12
2009	1,184,449.28	469,224.36	685	146	314,343.75	18	2	534,100.00	88	21	632,982.46	5	1	478,883.33	71	11
2010	1,210,847.83	464,600.00	683	151	300,541.67	19	3	479,125.00	85	20	732,972.22	5	1	683,305.56	27	11
2011	1,108,923.08	464,921.88	686	165	307,083.33	19	2	489,595.77	85	18	693,578.57	5	1	537,712.96	15	6
RATIO 66 --- AVERAGE STREET & HIGHWAY LIGHTING KWH USAGE PER MONTH																
2007	4,462.96	1,553.03	583	106	1,268.80	20	3	2,309.29	61	19	1,391.52	6	2	1,166.67	111	18
2008	4,462.96	1,483.33	582	101	1,483.74	20	2	2,036.46	61	18	1,728.46	6	1	1,307.61	63	8
2009	4,472.22	1,416.67	585	100	1,347.37	21	3	2,446.43	61	18	1,711.31	6	2	1,475.38	60	12
2010	3,659.09	1,405.75	584	135	1,174.48	21	2	1,768.19	62	22	1,565.78	6	1	2,027.78	21	7
2011	3,659.09	1,402.38	587	132	1,215.05	21	3	1,669.05	62	21	1,597.64	6	2	1,725.17	12	3
RATIO 67 --- AVERAGE SALES FOR RESALE KWH USAGE PER MONTH																
2007	1,439,694.44	416,722.22	110	21	1,408,541.67	9	3	779,625.00	9	2	1,424,118.06	4	2	420,777.78	21	6
2008	1,397,333.33	326,916.67	116	21	1,299,944.44	9	3	786,354.17	9	3	1,348,638.89	4	2	774,104.17	9	3
2009	1,376,583.33	331,583.33	120	20	1,282,111.11	8	3	587,555.56	9	3	1,323,708.33	4	2	621,781.25	12	2
2010	1,481,500.00	371,883.33	117	25	1,411,902.78	8	4	162,250.00	9	3	1,411,902.78	4	2	1,481,500.00	9	5
2011	1,494,527.78	376,895.83	116	22	1,397,388.89	8	2	586,597.22	9	1	1,414,861.11	4	2	1,263,472.22	5	2
RATIO 69 --- RESIDENTIAL KWH SOLD PER TOTAL KWH SOLD (%)																
2007	8.52	61.38	819	810	58.53	27	27	62.88	96	96	19.00	6	6	62.73	167	166
2008	7.88	61.30	818	808	55.90	27	27	61.53	95	95	18.95	6	6	62.50	83	83
2009	7.68	61.33	816	808	58.62	27	27	60.98	95	95	19.56	6	6	58.85	93	92
2010	7.83	61.83	815	809	58.49	27	27	62.69	92	92	20.06	6	6	49.80	33	32
2011	7.45	61.25	814	805	60.29	27	27	60.23	92	92	19.65	6	6	41.24	16	14
RATIO 71 --- IRRIGATION KWH SOLD PER TOTAL KWH SOLD (%)																
2007	4.80	1.37	399	125	3.12	18	4	1.18	41	6	4.18	6	2	0.95	75	17
2008	8.57	1.41	397	93	2.39	18	2	1.31	42	6	5.18	6	1	2.23	34	12
2009	11.64	1.18	398	78	3.13	18	2	1.42	42	5	4.95	6	1	4.98	41	14
2010	13.04	1.06	394	70	3.33	18	2	1.25	42	4	5.31	6	1	10.29	19	9
2011	17.48	1.40	399	64	3.65	18	2	1.47	47	4	6.61	6	1	1.01	12	3

2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2006-2011)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 72 --- SMALL COMMERCIAL KWH SOLD PER TOTAL KWH SOLD (%)																
2007	33.43	17.38	817	81	27.66	27	8	15.91	96	4	32.63	6	3	16.62	167	14
2008	34.44	17.27	816	77	28.43	27	9	15.77	95	4	33.02	6	3	17.39	83	6
2009	33.37	17.44	813	77	29.35	27	10	16.43	95	7	32.98	6	3	19.61	93	15
2010	32.63	17.32	813	81	29.18	27	9	15.91	92	6	32.45	6	3	21.35	33	6
2011	31.08	17.49	813	99	28.98	27	11	16.19	92	11	31.82	6	4	19.10	16	3
RATIO 73 --- LARGE COMMERCIAL KWH SOLD PER TOTAL KWH SOLD (%)																
2007	45.88	13.41	680	54	13.77	18	2	13.69	88	6	35.58	5	2	16.06	147	9
2008	42.46	14.05	684	69	15.34	19	2	14.93	88	9	35.02	5	2	13.46	70	7
2009	41.04	13.65	685	81	13.70	18	2	14.25	88	9	32.29	5	2	16.14	71	8
2010	40.05	13.96	683	87	14.66	19	2	14.68	85	11	33.14	5	2	15.70	27	5
2011	38.02	14.14	686	105	14.09	19	3	14.62	85	14	32.80	5	2	24.18	15	5
RATIO 74 --- STREET & HIGHWAY LIGHTING KWH SOLD PER TOTAL KWH SOLD (%)																
2007	0.07	0.13	588	407	0.18	21	16	0.12	61	44	0.34	6	6	0.12	111	73
2008	0.06	0.13	587	418	0.16	21	16	0.12	61	45	0.27	6	6	0.13	63	47
2009	0.06	0.13	589	425	0.15	22	16	0.13	61	45	0.27	6	6	0.15	61	49
2010	0.06	0.13	588	431	0.15	22	16	0.12	62	46	0.33	6	6	0.11	22	16
2011	0.05	0.12	592	440	0.15	22	16	0.13	62	46	0.31	6	6	0.11	12	9
RATIO 75 --- SALES FOR RESALE PER TOTAL KWH SOLD (%)																
2007	7.30	4.33	113	37	15.17	9	9	5.48	9	3	13.69	4	4	5.80	21	8
2008	6.58	3.41	117	37	10.46	9	9	5.36	9	3	9.52	4	4	6.58	9	5
2009	6.22	2.53	121	38	9.73	8	8	3.71	9	3	9.50	4	4	4.87	12	6
2010	6.39	3.33	119	37	9.10	8	8	1.06	9	2	9.26	4	4	6.39	9	5
2011	5.91	2.78	121	40	8.80	8	8	3.91	9	1	8.94	4	4	5.91	5	3
CONTROLLABLE EXPENSES (RATIOS 77-87)																
RATIO 77 --- O & M EXPENSES PER TOTAL KWH SOLD (MILLS)																
2007	4.50	9.36	819	761	12.29	27	27	9.84	96	93	9.09	6	6	9.27	167	157
2008	5.13	9.93	818	752	12.68	27	26	10.65	95	90	8.69	6	5	8.87	83	74
2009	4.88	10.36	816	769	12.76	27	26	10.86	95	91	7.60	6	5	9.52	93	88
2010	5.47	10.49	815	742	13.41	27	27	10.64	92	86	7.80	6	6	9.98	33	28
2011	5.00	10.82	814	764	15.94	27	26	11.26	92	87	8.23	6	5	7.31	16	12
RATIO 78 --- O & M EXPENSES PER DOLLARS OF TUP (MILLS)																
2007	35.18	43.44	820	609	42.46	27	23	47.56	96	83	44.17	6	5	44.10	167	133
2008	37.14	44.27	819	592	47.04	27	24	47.77	95	82	39.24	6	4	43.50	84	60
2009	34.30	43.26	817	641	43.55	27	24	46.40	95	89	34.84	6	5	39.70	93	60
2010	36.66	44.28	816	612	45.72	27	22	46.73	92	81	35.83	6	3	43.22	33	23
2011	36.04	44.34	815	618	44.67	27	23	48.57	92	78	36.81	6	4	33.36	16	5

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2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2006-2011)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 79 --- O & M EXPENSES PER CONSUMER ($)																
2007	201.80	190.57	819	335	202.58	27	15	183.83	96	30	203.97	6	4	191.55	167	71
2008	243.03	203.55	818	235	236.10	27	13	198.25	95	15	236.92	6	3	182.82	83	18
2009	236.24	207.68	816	263	221.92	27	11	202.67	95	26	211.05	6	2	195.11	93	26
2010	274.91	217.81	815	168	236.12	27	5	207.65	92	13	222.23	6	1	232.00	33	9
2011	271.84	229.61	814	226	266.16	27	12	227.53	92	22	240.88	6	2	223.02	16	5
RATIO 80 --- CONSUMER ACCOUNTING EXPENSES PER TOTAL KWH SOLD (MILLS)																
2007	0.96	2.70	818	789	2.94	27	27	2.85	96	94	2.45	6	6	2.68	167	162
2008	0.94	2.74	818	797	2.97	27	27	2.86	95	94	2.42	6	6	2.70	83	83
2009	0.98	2.86	816	790	3.08	27	27	3.15	95	93	1.92	6	6	2.83	93	90
2010	0.91	2.84	815	797	3.25	27	27	2.99	92	92	2.12	6	6	2.34	33	31
2011	0.91	2.90	814	792	3.24	27	27	3.21	92	92	2.11	6	6	1.76	16	13
RATIO 81 --- CONSUMER ACCOUNTING EXPENSES PER CONSUMER ($)																
2007	43.15	53.45	818	624	51.50	27	20	53.53	96	70	64.50	6	6	53.02	167	131
2008	44.31	56.08	818	641	53.81	27	20	54.71	95	70	63.50	6	6	56.59	83	67
2009	47.26	57.61	816	586	54.78	27	16	56.61	95	65	51.02	6	4	57.82	93	66
2010	45.61	58.47	815	642	58.26	27	19	59.53	92	70	66.39	6	5	58.86	33	23
2011	49.55	59.35	814	584	58.71	27	18	58.88	92	64	66.04	6	5	66.48	16	12
RATIO 82 --- CUSTOMER SALES AND SERVICE PER TOTAL KWH SOLD (MILLS)																
2007	0.57	0.80	803	528	0.79	25	19	0.68	94	53	0.59	6	4	0.70	165	102
2008	0.49	0.86	806	575	0.84	25	19	0.67	92	60	0.57	6	4	0.88	83	60
2009	0.42	0.88	804	640	0.89	25	21	0.73	92	68	0.67	6	5	0.88	92	78
2010	0.44	0.88	801	618	0.89	25	21	0.67	90	64	0.62	6	5	0.89	33	24
2011	0.47	0.89	803	611	0.81	25	19	0.80	90	65	0.67	6	5	0.83	16	11
RATIO 83 --- CUSTOMER SALES AND SERVICE PER CONSUMER ($)																
2007	25.67	16.41	803	246	13.67	25	1	14.63	94	20	16.08	6	1	15.44	165	50
2008	23.14	17.27	806	293	15.57	25	3	14.66	92	22	20.46	6	2	17.86	83	27
2009	20.28	17.32	804	354	15.68	25	8	15.22	92	34	21.52	6	4	18.03	92	37
2010	22.24	18.30	801	331	17.24	25	7	15.84	90	33	22.09	6	3	22.24	33	17
2011	25.54	18.34	803	295	17.28	25	5	17.20	90	29	25.20	6	2	21.71	16	7
RATIO 84 --- A & G EXPENSES PER TOTAL KWH SOLD (MILLS)																
2007	2.85	5.34	818	720	7.09	27	26	4.71	96	84	3.97	6	5	4.92	167	139
2008	2.99	5.47	818	706	7.03	27	26	5.21	95	82	3.90	6	5	4.85	83	67
2009	3.15	5.83	816	709	7.10	27	26	5.24	95	83	4.21	6	5	5.33	93	81
2010	3.24	5.78	815	678	7.44	27	26	5.30	92	76	4.36	6	5	5.89	33	29
2011	2.81	5.98	814	741	7.90	27	27	5.42	92	85	4.94	6	6	4.60	16	14

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2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2006-2011)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 85 --- A & G EXPENSES PER CONSUMER ($)																
2007	127.88	108.30	818	297	114.32	27	10	89.65	96	13	121.19	6	3	98.64	167	50
2008	141.61	112.99	818	246	122.19	27	8	99.60	95	13	120.23	6	2	105.29	83	22
2009	152.37	115.92	816	230	117.15	27	9	104.73	95	11	132.60	6	3	117.29	93	29
2010	162.76	121.82	815	210	121.76	27	7	110.45	92	8	141.02	6	3	137.93	33	13
2011	152.89	124.90	814	272	136.92	27	9	114.48	92	15	150.74	6	3	143.62	16	7
RATIO 86 --- TOTAL CONTROLLABLE EXPENSES PER TOTAL KWH SOLD (MILLS) (SAME AS RATIO #103)																
2007	8.88	19.04	819	789	24.04	27	27	19.36	96	94	16.79	6	6	17.67	167	161
2008	9.55	19.60	818	782	24.90	27	27	19.95	95	92	15.28	6	6	17.59	83	78
2009	9.42	20.27	816	785	23.54	27	27	20.42	95	92	13.87	6	6	18.51	93	90
2010	10.06	20.31	815	772	23.65	27	27	20.33	92	88	15.39	6	6	19.51	33	30
2011	9.20	21.11	814	784	26.43	27	27	21.69	92	89	16.58	6	6	13.16	16	13
RATIO 87 --- TOTAL CONTROLLABLE EXPENSES PER CONSUMER ($) (SAME AS RATIO #104)																
2007	398.50	372.38	819	338	395.12	27	13	350.18	96	27	396.81	6	3	362.24	167	66
2008	452.09	391.92	818	265	433.64	27	12	370.34	95	17	442.87	6	3	368.02	83	19
2009	456.15	403.19	816	274	412.37	27	8	394.41	95	19	413.50	6	2	395.18	93	26
2010	505.51	422.47	815	216	439.50	27	8	406.88	92	12	458.72	6	2	460.35	33	10
2011	499.83	438.73	814	275	477.90	27	11	420.60	92	22	488.86	6	3	456.32	16	6
FIXED EXPENSES (RATIOS 88-102)																
RATIO 88 --- POWER COST PER KWH PURCHASED (MILLS)																
2007	48.92	55.43	819	521	60.10	27	23	56.74	96	68	60.11	6	6	54.32	167	110
2008	57.16	59.31	818	464	63.30	27	22	60.48	95	62	62.55	6	6	60.24	83	51
2009	55.98	61.10	814	472	63.67	27	22	63.79	95	61	56.64	6	5	63.97	93	62
2010	58.27	62.12	814	485	68.00	27	24	63.70	92	61	61.74	6	6	58.85	33	19
2011	59.61	64.72	813	519	76.00	27	27	64.78	92	63	63.48	6	6	59.22	16	8
RATIO 89 --- POWER COST PER TOTAL KWH SOLD (MILLS)																
2007	50.91	58.82	819	528	64.18	27	24	60.91	96	70	61.43	6	6	57.78	167	109
2008	59.14	63.05	818	481	68.45	27	22	64.18	95	66	67.39	6	6	64.02	83	52
2009	57.93	64.59	816	513	69.26	27	24	67.93	95	67	60.11	6	6	68.37	93	64
2010	60.51	66.26	815	511	72.81	27	27	68.32	92	63	66.07	6	6	62.00	33	21
2011	61.82	68.44	814	539	82.32	27	27	69.53	92	65	67.43	6	6	62.10	16	9
RATIO 90 --- POWER COST AS A % OF REVENUE																
2007	70.47	61.78	820	157	56.68	27	5	63.97	96	22	71.22	6	4	63.45	167	38
2008	76.93	63.10	819	50	58.08	27	2	64.35	95	7	75.07	6	2	65.47	84	8
2009	74.38	62.30	817	80	58.28	27	2	63.93	95	15	68.37	6	2	63.90	93	10
2010	74.61	62.54	816	80	59.35	27	1	63.43	92	14	68.55	6	1	59.33	33	5
2011	75.06	63.18	815	51	62.46	27	1	63.94	92	7	67.68	6	1	62.84	16	4

2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2006-2011)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 91 --- LONG-TERM INTEREST COST PER TOTAL KWH SOLD (MILLS)																
2007	2.74	4.87	813	639	5.68	27	23	4.74	94	74	3.79	6	5	4.43	166	126
2008	2.52	4.89	811	662	5.52	27	24	4.46	93	76	3.59	6	6	4.62	83	68
2009	2.73	5.16	809	649	6.57	27	24	4.85	92	71	4.21	6	5	4.88	92	74
2010	3.22	4.97	807	592	6.20	27	24	4.83	89	64	4.72	6	5	5.07	33	27
2011	3.16	4.97	805	592	6.14	27	24	5.06	88	65	4.99	6	5	5.23	16	10
RATIO 92 --- LONG-TERM INTEREST COST AS A % OF TUP																
2007	2.15	2.22	813	442	1.78	27	8	2.21	94	53	1.83	6	3	2.16	166	85
2008	1.83	2.22	811	549	1.80	27	13	2.30	93	61	1.69	6	3	2.35	83	59
2009	1.92	2.19	809	516	1.92	27	14	2.33	92	59	1.85	6	3	2.28	92	58
2010	2.16	2.12	807	383	2.08	27	10	2.23	89	49	2.12	6	3	2.11	33	15
2011	2.28	2.04	805	276	1.96	27	8	2.18	88	40	2.12	6	3	2.23	16	8
RATIO 93 --- LONG-TERM INTEREST COST PER CONSUMER ($)																
2007	123.05	95.42	813	230	92.42	27	8	84.22	94	15	104.31	6	3	94.75	166	44
2008	119.49	99.79	811	280	96.15	27	9	88.78	93	23	103.19	6	3	99.16	83	32
2009	132.28	102.64	809	229	101.53	27	9	92.67	92	17	112.38	6	3	105.73	92	33
2010	162.02	102.90	807	115	109.77	27	7	97.37	89	9	132.56	6	2	132.65	33	9
2011	171.71	102.75	805	93	115.15	27	4	99.32	88	8	145.88	6	2	149.11	16	5
RATIO 94 --- DEPRECIATION EXPENSE PER TOTAL KWH SOLD (MILLS)																
2007	3.79	6.24	819	743	8.79	27	24	6.17	96	84	3.77	6	3	5.74	167	152
2008	3.66	6.42	818	761	8.54	27	27	6.29	95	85	5.44	6	6	5.85	83	82
2009	3.79	6.81	816	768	8.88	27	27	6.80	95	88	5.70	6	6	6.39	93	92
2010	3.84	6.88	815	765	8.34	27	27	6.80	92	82	5.78	6	6	6.75	33	31
2011	3.83	7.19	814	769	8.64	27	27	7.11	92	86	6.01	6	6	6.70	16	13
RATIO 95 --- DEPRECIATION EXPENSE AS A % OF TUP																
2007	2.96	2.83	820	271	2.58	27	4	2.85	96	33	1.79	6	1	2.85	167	60
2008	2.65	2.83	819	602	2.65	27	14	2.86	95	78	2.52	6	2	2.84	84	59
2009	2.66	2.86	817	596	2.60	27	12	2.91	95	76	2.44	6	2	2.86	93	73
2010	2.57	2.87	816	669	2.66	27	19	2.92	92	78	2.59	6	4	2.74	33	22
2011	2.76	2.89	815	525	2.64	27	11	2.93	92	64	2.59	6	2	2.70	16	7
RATIO 96 --- DEPRECIATION EXPENSE PER CONSUMER ($)																
2007	169.95	122.76	819	144	122.58	27	5	108.00	96	4	97.52	6	2	115.40	167	24
2008	173.16	129.84	818	156	135.53	27	4	116.33	95	4	139.50	6	2	130.59	83	12
2009	183.43	135.05	816	148	139.24	27	4	121.32	95	5	143.58	6	2	138.24	93	24
2010	192.87	141.53	815	149	145.03	27	5	130.10	92	5	153.62	6	2	156.56	33	6
2011	207.98	147.94	814	126	149.16	27	5	135.83	92	5	169.19	6	2	176.67	16	5

2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2006-2011)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 97 --- ACCUMULATIVE DEPRECIATION AS A % OF PLANT IN SERVICE																
2007	30.84	31.12	820	420	35.86	27	21	29.13	96	40	36.27	6	5	30.84	167	84
2008	31.18	30.85	819	394	34.24	27	20	29.87	95	38	40.52	6	6	26.55	84	21
2009	29.63	30.88	817	465	32.66	27	20	30.02	95	52	38.30	6	6	28.61	93	38
2010	26.86	31.07	816	573	33.25	27	22	30.86	92	63	37.34	6	6	29.53	33	20
2011	24.33	31.33	815	660	33.29	27	23	30.94	92	70	34.72	6	6	25.32	16	9
RATIO 98 ---- TOTAL TAX EXPENSE PER TOTAL KWH SOLD (MILLS)																
2007	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2008	0.00	1.04	590	558	0.00	11	7	1.13	69	66	0.00	2	2	1.30	57	54
2009	0.01	1.00	595	532	0.01	11	6	1.12	71	66	0.01	3	3	1.28	67	60
2010	0.00	1.00	591	569	0.00	14	9	1.03	67	65	0.00	3	3	1.29	24	24
2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
RATIO 99 --- TOTAL TAX EXPENSE AS A % OF TUP																
2007	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2008	0.00	0.43	591	554	0.00	11	6	0.50	69	66	0.00	2	2	0.45	58	54
2009	0.01	0.42	596	517	0.00	11	5	0.47	71	65	0.01	3	2	0.47	67	58
2010	0.00	0.41	592	568	0.00	14	9	0.48	67	65	0.00	3	3	0.50	24	24
2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
RATIO 100 ---- TOTAL TAX EXPENSE PER CONSUMER																
2007	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2008	0.05	20.10	590	551	0.04	11	5	22.40	69	65	0.04	2	1	22.51	57	53
2009	0.36	21.14	595	505	0.22	11	5	20.67	71	64	0.36	3	2	26.17	67	58
2010	0.01	22.00	591	563	0.01	14	6	20.96	67	65	0.04	3	3	31.25	24	24
2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
RATIO 101 ---- TOTAL FIXED EXPENSES PER TOTAL KWH SOLD (MILLS)																
2007	58.23	69.51	819	586	77.22	27	25	72.24	96	77	72.20	6	6	68.22	167	119
2008	65.64	75.14	818	553	84.04	27	25	78.56	95	74	77.31	6	6	75.44	83	59
2009	64.84	78.14	816	605	82.86	27	24	80.08	95	82	71.75	6	6	80.42	93	73
2010	67.87	79.00	815	592	89.13	27	27	80.71	92	72	78.07	6	6	75.85	33	21
2011	69.36	81.50	814	620	97.97	27	27	83.18	92	73	79.66	6	6	74.15	16	11
RATIO 102 ---- TOTAL FIXED EXPENSES PER CONSUMER ($)																
2007	2,613.15	1,358.70	819	50	1,309.60	27	2	1,281.85	96	2	2,027.29	6	2	1,424.26	167	10
2008	3,107.50	1,464.63	818	46	1,419.51	27	1	1,368.86	95	1	2,369.87	6	1	1,565.76	83	1
2009	3,139.21	1,513.63	816	37	1,370.03	27	1	1,425.46	95	2	2,077.36	6	1	1,639.96	93	3
2010	3,410.82	1,601.50	815	35	1,563.92	27	1	1,496.02	92	2	2,350.08	6	1	1,654.75	33	2
2011	3,768.32	1,640.97	814	33	1,708.96	27	1	1,547.53	92	3	2,461.50	6	1	1,969.52	16	4

2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2006-2011) Median	Plant Growth (2006-2011) NBR	Plant Growth (2006-2011) Rank
TOTAL EXPENSES (RATIOS 103-107)																
RATIO 103 --- TOTAL OPERATING EXPENSES PER TOTAL KWH SOLD (MILLS)																
2007	8.88	19.04	819	789	24.04	27	27	19.36	96	94	16.79	6	6	17.67	167	161
2008	9.55	19.60	818	782	24.90	27	27	19.95	95	92	15.28	6	6	17.59	83	78
2009	9.42	20.27	816	785	23.54	27	27	20.42	95	92	13.87	6	6	18.51	93	90
2010	10.06	20.31	815	772	23.65	27	27	20.33	92	88	15.39	6	6	19.51	33	30
2011	9.20	21.11	814	784	26.43	27	27	21.69	92	89	16.58	6	6	13.16	16	13
RATIO 104 --- TOTAL OPERATING EXPENSES PER CONSUMER ($)																
2007	398.50	372.38	819	338	395.12	27	13	350.18	96	27	396.81	6	3	362.24	167	66
2008	452.09	391.92	818	265	433.64	27	12	370.34	95	17	442.87	6	3	368.02	83	19
2009	456.15	403.19	816	274	412.37	27	8	394.41	95	19	413.50	6	2	395.18	93	26
2010	505.51	422.47	815	216	439.50	27	8	406.88	92	12	458.72	6	2	460.35	33	10
2011	499.83	438.73	814	275	477.90	27	11	420.60	92	22	488.86	6	3	456.32	16	6
RATIO 105 --- TOTAL COST OF SERVICE (MINUS POWER COSTS) PER TOTAL KWH SOLD (MILLS)																
2007	16.20	31.33	819	774	39.67	27	27	31.43	96	92	27.00	6	6	29.16	167	159
2008	16.04	32.38	818	780	39.62	27	27	32.37	95	91	25.14	6	6	29.41	83	80
2009	16.32	34.03	816	782	40.33	27	27	34.64	95	91	25.57	6	6	32.34	93	90
2010	17.42	33.59	815	773	40.30	27	27	33.38	92	87	28.46	6	6	34.32	33	30
2011	16.75	34.84	814	780	42.75	27	27	35.88	92	87	29.14	6	6	27.58	16	13
RATIO 106 --- TOTAL COST OF ELECTRIC SERVICE PER TOTAL KWH SOLD (MILLS)																
2007	67.11	88.09	819	706	97.13	27	27	91.85	96	88	87.42	6	6	83.51	167	148
2008	75.19	94.48	818	677	103.76	27	27	96.14	95	85	92.05	6	6	90.48	83	68
2009	74.26	97.39	816	709	107.53	27	26	101.07	95	88	85.09	6	6	97.14	93	81
2010	77.93	98.46	815	704	109.29	27	27	98.94	92	86	94.00	6	6	94.47	33	27
2011	78.56	102.17	814	718	123.75	27	27	104.05	92	84	96.26	6	6	88.78	16	12
RATIO 107 --- TOTAL COST OF ELECTRIC SERVICE PER CONSUMER ($)																
2007	3,011.65	1,723.68	819	59	1,748.98	27	3	1,637.87	96	2	2,480.22	6	2	1,758.26	167	11
2008	3,559.59	1,865.47	818	50	1,878.61	27	1	1,797.41	95	1	2,790.29	6	1	1,921.52	83	1
2009	3,595.37	1,912.47	816	44	1,737.47	27	1	1,843.07	95	2	2,489.67	6	1	1,970.93	93	3
2010	3,916.34	2,023.01	815	38	1,982.02	27	1	1,922.35	92	2	2,808.80	6	1	2,205.85	33	2
2011	4,268.14	2,063.12	814	38	2,188.95	27	1	1,972.22	92	3	2,971.79	6	1	2,412.83	16	4
EMPLOYEES (RATIOS 108-113)																
RATIO 108 --- AVERAGE WAGE RATE PER HOUR ($)																
2007	25.82	26.16	817	440	25.97	27	15	25.45	96	44	28.06	6	6	26.04	166	90
2008	26.76	27.16	817	448	26.46	27	9	26.89	95	50	26.63	6	3	27.24	83	47
2009	30.30	28.44	814	265	27.85	27	8	27.62	95	27	30.73	6	4	28.87	93	29
2010	32.95	29.37	812	161	29.25	26	6	28.11	92	14	29.83	6	2	31.67	33	11
2011	33.81	30.50	813	181	30.14	27	5	29.57	92	16	31.65	6	2	30.17	16	4

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RATIO 109 --- TOTAL WAGES PER TOTAL KWH SOLD (MILLS)

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2006-2011) Median	Plant Growth (2006-2011) NBR	Plant Growth (2006-2011) Rank
2007	5.50	10.14	817	753	15.15	27	27	9.95	96	91	9.02	6	6	9.65	166	152
2008	5.15	10.44	817	774	14.37	27	27	10.32	95	92	8.96	6	6	8.97	83	78
2009	5.31	10.93	815	775	15.74	27	27	10.75	95	90	9.56	6	6	10.13	93	90
2010	5.28	10.59	813	766	15.05	26	26	10.01	92	89	10.83	6	6	12.62	33	31
2011	4.86	10.77	813	780	14.58	27	27	10.69	92	90	9.50	6	6	9.34	16	13

RATIO 110 --- TOTAL WAGES PER CONSUMER ($)

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2006-2011) Median	Plant Growth (2006-2011) NBR	Plant Growth (2006-2011) Rank
2007	246.82	205.69	817	266	252.09	27	15	176.91	96	14	262.12	6	4	194.70	166	47
2008	243.75	214.65	817	299	253.67	27	16	189.41	95	18	253.85	6	4	191.29	83	26
2009	257.02	218.38	815	286	271.39	27	18	190.76	95	20	265.88	6	4	218.57	93	36
2010	265.49	220.57	813	280	279.44	26	18	193.85	92	13	272.29	6	4	277.11	33	21
2011	264.22	226.74	813	300	290.93	27	20	202.52	92	17	281.69	6	5	262.44	16	8

RATIO 111 --- OVERTIME HOURS/TOTAL HOURS (%)

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2006-2011) Median	Plant Growth (2006-2011) NBR	Plant Growth (2006-2011) Rank
2007	11.54	5.30	817	26	8.05	27	5	5.88	96	4	11.43	6	3	5.23	167	6
2008	8.45	5.25	816	100	5.70	27	6	5.83	95	17	6.25	6	1	5.51	83	8
2009	7.42	4.94	814	152	5.37	27	6	5.64	95	23	4.72	6	1	4.85	93	12
2010	6.34	4.61	813	158	3.85	27	7	4.89	92	19	3.75	6	1	5.27	33	14
2011	5.74	4.91	813	276	3.70	27	6	5.61	92	43	3.98	6	1	4.63	16	6

RATIO 112 --- CAPITALIZED PAYROLL / TOTAL PAYROLL (%)

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2006-2011) Median	Plant Growth (2006-2011) NBR	Plant Growth (2006-2011) Rank
2007	36.64	23.58	816	51	31.48	27	10	24.92	96	11	32.11	6	3	24.52	166	10
2008	30.25	22.83	814	140	30.08	27	13	24.40	95	22	28.58	6	2	23.58	83	19
2009	31.26	22.12	812	119	31.48	27	16	23.34	95	20	31.37	6	4	22.06	92	14
2010	29.23	22.47	812	149	35.21	26	18	23.06	92	19	26.28	6	3	24.58	33	9
2011	25.85	21.95	810	226	33.34	26	18	22.81	92	31	24.19	6	3	25.31	15	7

RATIO 113 --- AVERAGE CONSUMERS PER EMPLOYEE

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2006-2011) Median	Plant Growth (2006-2011) NBR	Plant Growth (2006-2011) Rank
2007	272.78	282.23	819	436	226.50	27	8	306.00	96	72	239.67	6	2	290.39	167	97
2008	256.21	286.08	818	495	227.07	27	10	308.45	95	77	246.17	6	3	318.77	83	60
2009	269.72	287.19	816	460	217.11	27	8	308.69	95	73	244.31	6	2	295.30	93	53
2010	259.47	291.20	815	495	225.08	27	10	309.77	92	76	251.81	6	3	251.73	33	13
2011	265.90	295.78	814	484	225.84	27	10	316.08	92	73	247.02	6	3	248.96	16	5

GROWTH (RATIOS 114-121)

RATIO 114 --- ANNUAL GROWTH IN KWH SOLD (%)

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2006-2011) Median	Plant Growth (2006-2011) NBR	Plant Growth (2006-2011) Rank
2007	5.62	3.70	815	230	4.96	27	12	3.15	93	19	73.33	6	6	3.59	167	45
2008	7.63	1.22	817	112	2.60	27	7	1.00	95	16	12.39	6	6	1.33	83	14
2009	4.25	-1.06	816	104	-0.31	27	3	-1.59	95	8	-0.65	6	1	-0.87	93	18
2010	4.76	4.80	813	412	6.59	27	19	5.38	92	51	4.93	6	4	5.65	33	19
2011	9.06	-0.13	814	65	2.24	27	3	0.02	92	8	4.22	6	1	2.49	16	3

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		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2006-2011)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 115 ---- ANNUAL GROWTH IN NUMBER OF CONSUMERS (%)																
2007	1.74	1.35	815	295	1.74	27	14	1.35	93	31	88.29	6	6	1.24	167	43
2008	2.02	0.99	817	139	0.85	27	8	0.90	95	15	1.81	6	3	1.39	83	23
2009	1.93	0.47	816	56	1.00	27	7	0.41	95	7	1.31	6	2	0.71	93	10
2010	0.93	0.37	813	181	0.47	27	7	0.27	92	14	0.99	6	4	0.70	33	12
2011	0.88	0.30	814	181	0.46	27	7	0.29	92	20	0.68	6	2	0.52	16	5
RATIO 116 ---- ANNUAL GROWTH IN TUP DOLLARS (%)																
2007	12.52	5.72	816	53	7.67	27	10	5.74	93	3	70.27	6	6	5.95	167	5
2008	16.40	5.23	818	16	5.26	27	3	5.16	95	2	8.56	6	2	6.33	84	1
2009	7.28	4.40	817	117	4.89	27	9	4.41	95	17	6.09	6	3	5.62	93	25
2010	9.89	3.92	814	52	4.37	27	4	3.95	92	6	5.32	6	2	5.16	33	7
2011	1.47	3.92	815	751	3.61	27	22	3.72	92	87	5.57	6	6	6.89	16	15
RATIO 117 ---- CONST. W.I.P. TO PLANT ADDITIONS (%)																
2007	114.76	25.77	809	75	37.16	27	6	19.12	95	4	33.27	6	1	29.65	165	16
2008	168.54	27.04	810	45	15.59	26	1	21.24	94	4	45.67	6	1	36.01	83	5
2009	223.51	27.25	808	33	51.90	25	2	25.29	94	6	56.24	6	2	32.77	93	5
2010	245.64	30.09	808	30	35.10	27	4	23.00	91	2	72.68	6	1	37.22	33	4
2011	83.76	26.98	808	153	36.35	25	8	21.64	91	10	32.16	6	1	28.44	16	5
RATIO 118 ---- NET NEW SERVICES TO TOTAL SERVICES (%)																
2007	1.67	1.36	817	307	1.06	27	8	1.55	96	45	1.18	6	2	1.42	167	61
2008	2.29	1.06	816	72	1.04	27	6	1.04	95	10	1.03	6	2	1.39	83	9
2009	1.51	0.66	813	110	0.50	27	5	0.73	95	12	0.73	6	1	0.85	93	24
2010	1.46	0.56	811	91	0.37	27	4	0.54	92	12	0.67	6	1	0.76	33	10
2011	1.50	0.52	805	79	0.49	27	2	0.60	91	9	1.23	6	2	0.81	16	3
RATIO 119 ---- ANNUAL GROWTH IN TOTAL CAPITALIZATION (%)																
2007	2.68	5.48	816	589	6.70	27	22	5.15	93	65	39.18	6	6	4.79	167	122
2008	8.95	4.61	818	209	7.60	27	12	4.30	95	23	8.89	6	3	6.67	84	33
2009	2.17	4.11	817	584	5.51	27	23	3.78	95	65	7.21	6	6	4.95	93	74
2010	19.02	4.05	814	26	4.08	27	3	3.69	92	3	9.89	6	2	9.23	33	5
2011	14.78	3.86	815	52	6.04	27	6	4.19	92	5	9.38	6	2	6.37	16	4
RATIO 120 ---- 2 YR. COMPOUND GROWTH IN TOTAL CAPITALIZATION (%)																
2007	2.31	5.53	817	696	6.86	27	27	5.60	93	81	20.10	6	6	5.10	167	148
2008	5.77	5.62	814	397	6.57	27	17	5.53	92	43	35.75	6	6	7.62	84	61
2009	5.51	5.05	816	370	6.79	27	19	5.02	95	43	7.46	6	6	7.59	93	63
2010	10.28	4.54	814	93	6.69	27	7	4.34	92	11	8.36	6	2	7.67	33	11
2011	16.88	4.20	813	16	5.01	27	3	4.09	92	1	9.63	6	2	9.40	16	2

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		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2006-2011)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 121 --- 5 YR. COMPOUND GROWTH IN TOTAL CAPITALIZATION (%)																
2007	5.34	5.20	808	385	6.85	27	17	5.14	92	43	12.97	6	6	4.88	167	68
2008	7.11	5.64	810	224	7.01	27	13	5.22	91	23	16.37	6	6	7.25	84	47
2009	7.53	5.65	808	211	8.57	27	17	5.62	90	21	17.49	6	6	7.68	93	53
2010	6.76	5.36	809	255	7.28	27	15	5.49	89	26	16.55	6	6	8.70	33	26
2011	9.32	5.16	808	90	9.43	27	15	5.36	89	7	17.55	6	6	11.00	16	11
PLANT (RATIOS 122-145)																
RATIO 122 ---- TUP INVESTMENTS PER TOTAL KWH SOLD (CENTS)																
2007	12.78	22.02	819	755	31.01	27	27	20.67	96	86	19.57	6	6	20.34	167	153
2008	13.82	22.71	818	739	31.01	27	27	21.32	95	83	18.66	6	6	19.91	83	79
2009	14.23	23.89	816	743	32.08	27	27	23.02	95	87	19.44	6	6	21.97	93	89
2010	14.92	24.10	815	716	31.56	27	27	22.91	92	76	19.12	6	6	25.33	33	30
2011	13.89	24.89	814	750	32.24	27	27	24.07	92	84	21.37	6	6	22.32	16	14
RATIO 123 --- TUP INVESTMENT PER CONSUMER ($)																
2007	5,735.90	4,303.16	819	190	4,976.95	27	9	3,786.24	96	8	5,641.92	6	3	4,015.59	167	37
2008	6,544.34	4,473.15	818	131	5,029.48	27	3	4,007.86	95	4	5,526.36	6	1	4,383.49	83	12
2009	6,887.82	4,676.44	816	130	5,407.91	27	4	4,190.44	95	7	5,964.85	6	1	4,703.70	93	23
2010	7,499.29	4,854.04	815	106	5,492.58	27	3	4,390.59	92	3	6,048.76	6	1	5,655.06	33	9
2011	7,543.29	5,011.44	814	117	5,739.56	27	3	4,549.50	92	4	6,734.64	6	1	6,686.52	16	6
RATIO 124 --- TUP INVESTMENT PER MILE OF LINE ($)																
2007	24,137.66	23,941.64	819	406	14,139.97	27	6	24,350.27	96	50	19,629.14	6	3	23,580.37	167	78
2008	27,540.29	25,113.04	818	360	15,108.75	27	6	25,558.97	95	40	22,598.03	6	3	33,916.99	83	55
2009	29,120.41	26,205.55	816	355	16,250.47	27	6	26,699.25	95	39	23,774.92	6	3	31,391.24	93	51
2010	31,673.27	27,285.65	815	318	17,807.44	27	6	27,612.66	92	31	25,367.38	6	3	34,425.56	33	18
2011	31,766.01	28,234.95	814	342	18,381.28	27	6	28,439.34	92	36	25,981.98	6	3	31,967.91	16	9
RATIO 125 --- AVERAGE CONSUMERS PER MILE																
2007	4.21	5.93	819	556	3.02	27	7	6.25	96	84	3.88	6	3	6.12	167	123
2008	4.21	5.93	818	558	3.12	27	7	6.31	95	85	3.86	6	3	7.86	83	66
2009	4.23	5.93	816	553	3.16	27	7	6.27	95	83	3.88	6	3	6.75	93	64
2010	4.22	5.94	815	558	3.16	27	7	6.22	92	81	3.88	6	3	5.84	33	20
2011	4.21	5.96	814	560	3.18	27	7	6.13	92	81	3.88	6	3	4.45	16	10
RATIO 126 --- DISTRIBUTION PLANT PER TOTAL KWH SOLD (MILLS)																
2007	97.02	183.51	819	770	249.09	27	27	182.72	96	88	126.86	6	6	175.25	167	162
2008	98.02	189.62	818	771	259.20	27	26	190.94	95	88	138.22	6	5	166.42	83	81
2009	101.19	199.69	816	777	243.48	27	27	201.89	95	90	146.98	6	6	176.35	93	91
2010	104.17	201.11	815	767	245.06	27	27	200.84	92	86	141.13	6	6	187.41	33	29
2011	105.71	208.59	814	768	250.97	27	27	210.37	92	85	139.40	6	6	159.09	16	14

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2006-2011)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 127 --- DISTRIBUTION PLANT PER CONSUMER ($)																
2007	4,354.06	3,572.95	819	219	3,956.00	27	9	3,244.18	96	9	4,275.84	6	3	3,420.76	167	39
2008	4,640.38	3,719.00	818	211	4,199.48	27	9	3,495.57	95	8	4,221.88	6	3	3,669.31	83	18
2009	4,899.39	3,894.36	816	197	4,298.33	27	8	3,631.23	95	7	4,380.09	6	3	3,826.79	93	26
2010	5,234.78	4,029.11	815	172	4,369.94	27	6	3,776.93	92	5	4,230.86	6	2	4,401.95	33	10
2011	5,742.89	4,201.83	814	148	4,563.07	27	5	3,915.65	92	4	4,352.72	6	2	5,174.30	16	6
RATIO 128 --- DISTRIBUTION PLANT PER EMPLOYEE ($)																
2007	1,187,681.86	1,018,721.25	819	206	884,235.67	27	5	1,006,673.81	96	22	901,304.36	6	1	1,040,351.84	167	48
2008	1,188,894.14	1,080,619.33	818	268	973,065.36	27	5	1,068,933.25	95	28	962,849.79	6	2	1,138,930.80	83	38
2009	1,321,469.93	1,141,956.32	816	202	987,385.83	27	4	1,115,218.65	95	17	1,038,591.43	6	1	1,124,668.07	93	21
2010	1,358,262.30	1,198,286.18	815	230	1,027,159.89	27	4	1,161,595.03	92	20	1,174,140.06	6	1	1,087,831.15	33	12
2011	1,527,061.03	1,256,196.39	814	157	1,052,680.06	27	3	1,201,775.47	92	15	1,225,822.15	6	1	1,330,556.49	16	4
RATIO 129 --- GENERAL PLANT PER TOTAL KWH SOLD (MILLS)																
2007	6.03	14.59	819	774	18.13	27	27	12.97	96	93	9.61	6	6	13.98	167	155
2008	5.77	14.65	818	782	17.83	27	27	14.02	95	92	11.63	6	6	12.75	83	78
2009	5.77	15.68	816	786	20.66	27	27	15.33	95	93	13.18	6	6	15.76	93	90
2010	5.95	15.59	815	783	20.90	27	27	14.27	92	88	13.15	6	6	16.93	33	32
2011	5.84	16.46	813	787	20.75	27	27	15.06	92	91	14.08	6	6	15.13	16	15
RATIO 130 --- GENERAL PLANT PER CONSUMER ($)																
2007	270.40	287.56	819	458	281.87	27	16	241.20	96	38	262.19	6	3	266.35	167	82
2008	273.40	301.11	818	475	322.17	27	19	249.38	95	44	305.41	6	4	265.03	83	39
2009	279.27	314.82	816	483	360.89	27	21	259.58	95	44	329.71	6	4	319.36	93	56
2010	299.22	330.11	815	461	383.18	27	19	279.76	92	43	360.23	6	4	360.41	33	25
2011	317.29	340.41	813	456	393.74	27	19	310.63	92	44	383.02	6	4	355.27	16	11
RATIO 131 --- GENERAL PLANT PER EMPLOYEE ($)																
2007	73,759.33	80,789.70	819	498	69,971.92	27	12	76,100.64	96	53	68,845.58	6	2	78,956.89	167	95
2008	70,045.84	83,541.52	818	577	71,586.07	27	15	80,083.18	95	59	69,154.07	6	3	84,107.94	83	61
2009	75,323.80	87,912.69	816	557	77,010.50	27	16	84,463.62	95	58	78,272.64	6	5	93,052.99	93	67
2010	77,639.22	92,827.10	815	586	80,170.22	27	18	92,860.39	92	60	88,491.31	6	5	99,514.36	33	25
2011	84,367.79	96,575.58	813	546	87,331.74	27	16	99,715.94	92	60	95,044.91	6	5	92,229.15	16	12
RATIO 132 --- HEADQUARTERS PLANT PER TOTAL KWH SOLD (MILLS)																
2007	9.19	6.92	770	240	6.06	25	7	6.62	93	29	6.71	5	1	6.13	164	40
2008	8.60	7.27	770	306	7.36	26	12	6.86	92	36	7.33	5	1	9.37	77	44
2009	8.24	7.87	767	355	7.40	25	12	7.68	92	41	7.40	5	2	9.72	86	53
2010	7.88	7.87	764	381	6.98	25	12	7.88	89	45	6.97	5	2	8.89	31	17
2011	7.28	8.33	764	450	7.28	25	13	8.64	88	52	7.28	5	3	8.32	16	9

2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2006-2011) Median	Plant Growth (2006-2011) NBR	Plant Growth (2006-2011) Rank
RATIO 133 --- HEADQUARTERS PLANT PER CONSUMER ($)																
2007	412.39	140.40	770	41	108.41	25	1	126.24	93	3	113.73	5	1	132.82	164	6
2008	407.36	149.13	770	52	127.38	26	2	132.04	92	3	136.05	5	1	189.21	77	10
2009	398.85	159.95	767	68	135.19	25	2	146.01	92	4	181.20	5	1	198.34	86	16
2010	396.05	167.47	764	82	138.91	25	2	154.65	89	8	193.50	5	1	210.92	31	9
2011	395.50	179.48	764	97	140.43	25	3	168.46	88	11	310.08	5	2	313.97	16	8
RATIO 134 --- HEADQUARTERS PLANT PER EMPLOYEE ($)																
2007	112,490.48	37,886.03	770	27	22,119.40	25	1	39,073.07	93	5	32,158.44	5	1	37,565.48	164	5
2008	104,368.37	40,465.37	770	60	26,278.72	26	3	40,736.94	92	5	31,890.57	5	1	60,049.37	77	12
2009	107,577.39	43,663.11	767	64	27,913.38	25	3	42,203.69	92	6	38,105.73	5	1	57,379.66	86	13
2010	102,761.33	46,505.67	764	96	28,804.00	25	3	45,941.45	89	12	40,382.54	5	1	56,294.57	31	8
2011	105,165.97	48,256.15	764	103	31,737.70	25	3	47,668.46	88	14	70,741.90	5	1	72,208.89	16	7
RATIO 135 --- TRANSMISSION PLANT PER TOTAL KWH SOLD (MILLS)																
2007	4.12	10.99	417	306	10.22	24	21	6.11	39	24	11.20	6	6	8.08	79	54
2008	5.98	11.53	413	275	10.84	24	18	5.96	38	19	17.55	6	6	9.80	40	24
2009	3.67	12.02	413	315	11.10	24	21	5.83	38	25	19.31	6	6	14.01	49	36
2010	3.57	13.07	410	308	10.16	24	20	8.17	37	25	19.87	6	6	12.16	22	14
2011	3.68	12.85	409	311	9.67	24	20	10.91	36	26	20.02	6	6	8.39	10	8
RATIO 136 --- TRANSMISSION PLANT PER CONSUMER ($)																
2007	184.86	217.11	417	233	180.12	24	10	162.42	39	18	343.94	6	4	157.33	79	36
2008	283.24	230.14	413	186	210.97	24	11	172.68	38	14	586.74	6	5	221.98	40	18
2009	177.76	234.16	413	252	179.77	24	14	182.45	38	20	623.83	6	6	277.50	49	33
2010	179.53	248.28	410	250	180.21	24	14	212.20	37	20	654.16	6	6	292.25	22	13
2011	199.99	251.25	409	237	190.34	24	12	230.54	36	21	677.69	6	6	171.41	10	5
RATIO 137 --- TRANSMISSION PLANT PER EMPLOYEE ($)																
2007	50,426.67	61,530.42	417	233	45,443.47	24	11	44,938.86	39	18	75,855.31	6	4	44,300.30	79	35
2008	72,568.65	67,788.18	413	193	57,272.20	24	9	48,742.60	38	14	146,035.38	6	5	55,226.58	40	19
2009	47,946.66	68,926.21	413	253	49,149.75	24	13	45,465.83	38	19	153,963.99	6	6	71,579.60	49	33
2010	46,582.33	71,810.98	410	256	49,474.64	24	13	60,336.64	37	20	164,952.34	6	6	64,353.63	22	13
2011	53,178.87	73,899.91	409	244	52,772.92	24	12	70,307.76	36	21	166,573.65	6	5	45,352.43	10	5
RATIO 138 --- IDLE SERVICES TO TOTAL SERVICE (%)																
2007	5.97	7.77	797	486	6.91	27	17	10.05	95	70	6.15	6	4	8.26	164	104
2008	5.58	7.67	797	517	6.92	27	18	9.91	94	70	5.93	6	4	7.20	80	49
2009	6.21	7.86	796	480	6.57	27	16	10.62	94	68	6.14	6	3	6.37	91	48
2010	6.58	8.12	793	464	7.23	27	15	10.25	90	65	5.65	6	2	8.96	32	19
2011	10.73	8.00	793	276	7.49	27	6	10.04	91	43	5.75	6	1	10.11	16	8

2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

		US Total			State Grouping			Consumer Size			Major Current Power Supplier			Plant Growth (2006-2011)		
Year	System Value	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank	Median	NBR	Rank
RATIO 139 ---- LINE LOSS (%)																
2007	3.72	6.03	819	730	7.41	27	25	6.24	96	88	4.47	6	4	5.96	167	148
2008	3.20	6.04	818	756	7.67	27	26	6.05	95	88	5.82	6	5	5.48	83	78
2009	3.21	5.96	814	739	7.54	27	27	6.20	95	89	6.17	6	6	5.82	93	86
2010	3.54	5.98	814	724	7.36	27	26	6.27	92	84	6.28	6	6	5.97	33	26
2011	3.41	5.41	813	668	6.97	27	26	5.27	92	79	5.84	6	6	4.79	16	13
RATIO 140 ---- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - POWER SUPPLIER																
2007	0.72	0.25	820	241	1.67	27	19	0.33	96	30	0.14	6	1	0.23	167	53
2008	3.34	16.39	819	571	78.60	27	25	22.10	95	70	9.60	6	5	8.38	84	53
2009	4.09	14.80	817	554	84.81	27	23	14.80	95	66	15.19	6	5	9.60	93	59
2010	37.01	15.76	816	247	28.30	27	13	12.97	92	27	11.06	6	1	5.40	33	7
2011	8.51	15.63	815	491	84.10	27	24	9.64	92	50	23.02	6	4	11.76	16	9
RATIO 141 ---- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - EXTREME STORM																
2007	86.72	0.40	820	20	17.60	27	5	0.51	96	2	13.93	6	2	0.59	167	8
2008	13.81	28.20	819	480	33.60	27	15	71.40	95	71	7.43	6	3	20.85	84	52
2009	0.00	19.83	817	639	95.40	27	24	31.80	95	80	0.00	6	4	12.06	93	71
2010	0.00	18.79	816	658	12.00	27	24	11.82	92	76	6.00	6	5	27.47	33	28
2011	0.00	43.02	815	672	4.49	27	25	46.25	92	80	11.88	6	6	6.78	16	13
RATIO 142 ---- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - PREARRANGED																
2007	0.04	0.03	820	373	0.06	27	15	0.03	96	45	0.03	6	3	0.03	167	78
2008	14.08	2.34	819	142	2.04	27	6	1.80	95	15	7.64	6	3	2.11	84	10
2009	5.69	2.59	817	296	3.48	27	13	2.52	95	31	3.74	6	3	1.88	93	32
2010	5.53	2.23	816	260	6.00	27	15	3.18	92	28	9.45	6	4	4.00	33	15
2011	9.62	2.49	815	188	3.07	27	9	2.53	92	23	2.70	6	2	4.14	16	4
RATIO 143 ---- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - ALL OTHER																
2007	3.49	1.62	820	123	2.15	27	4	1.91	96	18	3.46	6	3	1.64	167	30
2008	92.43	99.36	819	446	158.64	27	19	102.30	95	56	106.45	6	4	96.21	84	45
2009	61.72	95.40	817	571	91.80	27	21	100.02	95	69	69.22	6	5	95.40	93	67
2010	64.78	97.35	816	589	90.74	27	22	97.14	92	70	73.94	6	4	110.03	33	23
2011	147.02	99.50	815	268	119.80	27	10	116.77	92	39	119.60	6	3	95.48	16	4
RATIO 144 ---- SYSTEM AVG. INTERRUPTION DURATION INDEX (SAIDI) - TOTAL																
2007	90.97	3.37	820	21	21.83	27	6	3.76	96	2	16.07	6	2	3.53	167	9
2008	123.66	201.96	819	588	333.00	27	25	285.00	95	75	128.83	6	4	170.65	84	62
2009	71.50	196.20	817	703	406.06	27	26	187.20	95	82	104.32	6	6	165.61	93	80
2010	107.31	188.64	816	619	228.60	27	23	177.40	92	70	148.46	6	5	190.20	33	25
2011	165.15	229.94	815	505	244.20	27	22	256.80	92	60	191.63	6	4	176.60	16	10

2011 Key Ratio Trend Analysis (KRTA)
Pioneer Electric Cooperative, Inc. (KS044)

Year	System Value	US Total Median	US Total NBR	US Total Rank	State Grouping Median	State Grouping NBR	State Grouping Rank	Consumer Size Median	Consumer Size NBR	Consumer Size Rank	Major Current Power Supplier Median	Major Current Power Supplier NBR	Major Current Power Supplier Rank	Plant Growth (2006-2011) Median	Plant Growth (2006-2011) NBR	Plant Growth (2006-2011) Rank
RATIO 145 --- AVG. SERVICE AVAILABILITY INDEX (ASAI) - TOTAL (%)																
2007	98.96	99.96	820	800	99.75	27	22	99.96	96	95	99.82	6	5	99.96	167	159
2008	99.98	99.96	819	232	99.94	27	3	99.95	95	21	99.98	6	3	99.97	84	23
2009	99.99	99.96	817	114	99.92	27	2	99.96	95	14	99.98	6	1	99.97	93	14
2010	99.98	99.96	816	198	99.96	27	5	99.97	92	23	99.97	6	2	99.96	33	9
2011	99.97	99.96	815	310	99.95	27	6	99.95	92	33	99.96	6	3	99.97	16	7

Exhibit RJM-10 - Kentucky Statute, Regulation, and Pass-Through Example

278.455 Reduction of operating expenses by G&T or distribution cooperative -- Effect on rates -- Authority for administrative regulations.

(1) Notwithstanding any other statute to the contrary, a G&T or distribution cooperative may at any time decrease regulated operating revenues by an amount to be determined solely by the cooperative utility. If the revenue reduction is allocated among and within the consumer classes on a proportional basis that will result in no change in the rate design currently in effect, the revised rates and tariffs shall be authorized and made permanent on the proposed effective date.

(2) Notwithstanding any other statute, any revenue increase authorized by the Public Service Commission or any revenue decrease authorized in subsection (1) of this section that is to flow through the effects of an increase or decrease in wholesale rates may, at the distribution cooperative's discretion, be allocated to each class and within each tariff on a proportional basis that will result in no change in the rate design currently in effect. In the event of an increase in the wholesale rates and tariffs of the wholesale supplier by the Public Service Commission, the rates and tariffs of the distribution cooperative that have been revised on a proportional basis to result in no change in the rate design shall be authorized and shall become effective on the same date as those of the wholesale supplier. In those cases where an interim increase in the power supplier's wholesale rates is authorized, the distribution cooperative's flow through rates shall be interim. The distribution cooperative's permanent rates and tariffs shall become effective on the date that the wholesale supplier's permanent rates become effective as ordered by the commission.

(3) Any rate increase or decrease as provided for in subsections (1) and (2) of this section shall not apply to special contracts under which the rates are subject to change or adjustment only as stipulated in the contract.

(4) The Public Service Commission shall promulgate administrative regulations pursuant to KRS Chapter 13A to establish filing requirements and notice requirements to the commission, the Attorney General, and the public under this section.

Effective: July 15, 1998

History: Created 1998 Ky. Acts ch. 188, sec. 2, effective July 15, 1998.

807 KAR 5:007. Filing and notice requirements for a generation and transmission cooperative or a distribution cooperative to decrease rates or for a distribution cooperative to change rates to reflect a change in the rates of its wholesale supplier.

RELATES TO: KRS 278.180, 278.455

STATUTORY AUTHORITY: KRS 278.040(3), 278.180(1), 278.455(4)

NECESSITY, FUNCTION, AND CONFORMITY: KRS 278.040(3) provides that the commission may promulgate administrative regulations to implement the provisions of KRS Chapter 278. KRS 278.180(1) provides that, except upon application of a utility for a lesser time, a change shall not be made in a rate except upon thirty (30) days' notice to the commission, stating plainly the changes proposed to be made and the time when the changed rates shall go into effect. KRS 278.455(1) provides that a generation and transmission cooperative or a distribution cooperative may decrease regulated operating revenues if the decrease is allocated proportionately among customer classes so that a change will not result to the rate design currently in effect. KRS 278.455(2) provides that a distribution cooperative may change its rates to reflect a change in the rate of its wholesale supplier if the effects of an increase or decrease are allocated to each class and within each tariff on a proportional basis that will result in no change in the rate design currently in effect. KRS 278.455(4) requires the commission to promulgate administrative regulations establishing filing requirements and notice requirements to the commission, the Attorney General, and the public for rate changes made pursuant to KRS 278.455. This administrative regulation prescribes filing and notice requirements for a generation and transmission cooperative or a distribution cooperative to decrease rates and for a distribution cooperative to change rates to reflect a change in the rates of its wholesale supplier.

Section 1. Filing Requirements. To decrease rates, a generation and transmission cooperative or a distribution cooperative shall file with the commission an original and five (5) copies, and with the Attorney General's Office of Rate Intervention one (1) copy, of the following information:

(1) The tariff incorporating the reduced rates, specifying an effective date no sooner than thirty (30) days from the date filed;
(2) The name and address of the filing cooperative;
(3) A brief statement of the facts demonstrating that the filing is made pursuant to the authority of KRS 278.455;
(4) A comparison of the current and proposed rates;
(5) An analysis demonstrating that:
(a) The rate change does not change the rate design currently in effect; and
(b) The revenue change has been allocated to each class and within each tariff on a proportional basis;
(6) A certification that a complete copy of the materials filed with the commission has been sent to the Attorney General's Office of Rate Intervention;
(7) A statement that notice of the rate change pursuant to Section 3 of this administrative regulation has been given, not more than thirty (30) days prior to the date the application is filed, by one (1) of the following methods:
(a) By typewritten notice mailed to all customers;
(b) By publication in a newspaper of general circulation in the affected area; or
(c) By publication in a periodical distributed to all members of the cooperative; and
(8) A copy of the notice given pursuant to subsection (7) of this section.

Section 2. To change rates to reflect an increase or decrease in its wholesale supplier's rates, a distribution cooperative shall file with the commission an original and five (5) copies, and with the Attorney General's Office of Rate Intervention one (1) copy, of the following information:

(1) The tariff incorporating the new rates and specifying an effective date no sooner than the effective date of the wholesale supplier's rate change; and
(2) The information required by Section 1(2) through (8) of this administrative regulation.

Section 3. Contents of Notice. Notice given pursuant to Section 1(7) of this administrative regulation shall include the following information:

(1) The name, address, and phone number of the cooperative;
(2) The existing rates and the revised rates for each customer class;
(3) The effect of the rate change, stated both in dollars and as a percentage, upon the average bill for each customer class;
(4) A statement, as appropriate, that:
(a) The rate reduction is being made at the sole discretion of the utility, pursuant to KRS 278.455(1); or
(b) The rates are being revised to reflect a change in wholesale rates pursuant to KRS 278.455(2); and
(5) A statement that a person may examine the rate application at the main office of the utility or at the office of the Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky. (25 Ky.R. 2989; Am. 26 Ky.R. 385; eff. 8-20-99.)

CLARK ENERGY
A Touchstone Energy Cooperative

RECEIVED
MAY 27 2010
PUBLIC SERVICE COMMISSION

May 27, 2010

Mr. Jeff Derouen
Executive Director
Public Service Commission
211 Sower Boulevard
Frankfort, KY 40602

Re: Clark Energy Cooperative, Inc. Pass-Through of East Kentucky Power Cooperative, Inc.Wholesale Rate Adjustment- PSC Case No. 2010-00170.

Dear Mr. Derouen:

Please find enclosed for filing with the Commission an original and 5 copies of Clark Energy Cooperative, Inc. Filing for Pass-Through of East Kentucky Power Cooperative, Inc. ("EKPC") Wholesale Rate Adjustment in Case No. 2010-00167. This filing includes the following information as required by 807 KAR 5:007:

1. The full name and filing address of the filing cooperative is: [807 KAR 5:007, Sections 1(2) and 2(2)]

   Clark Energy Cooperative, Inc.
   PO Box 748
   Winchester, KY 40392

2. Clark Energy Cooperative, Inc. Proposed Tariffs reflecting the new rates specifying an effective date of July 1, 2010, the effective date of EKPC's wholesale rate change are attached as Exhibit 1. [807 KAR 5:007, Section 2(1)]

3. This filing is pursuant to the provisions of KRS 278.455(2). [807 KAR 5:007, Sections 1(3) and 2(2)]

4. A comparison of the current and proposed rates of Clark Energy Cooperative, Inc. is attached as Exhibit 2. [807 KAR 5:007, Sections 1(4) and 2(2)]

2640 Iron Works Road • P.O. Box 748 • Winchester, Kentucky 40392 • Tel. (859) 744-4251 • 1-800-992-3269 • Fax (859) 744-4218

5. Attached as Exhibit 3 is a billing analysis which shows the existing and proposed rates for each rate class. Clark Energy Cooperative, Inc. hereby states that the effects of the increase in rates from its wholesale supplier, EKPC, are being passed through to its retail tariffs on a proportional basis and that the rate design structure proposed for each retail rate schedule does not change the rate design currently in effect. [807 KAR 5:007, Sections 1(5)(a), 1(5)(b), and 2(2)]

6. A certification that one complete copy of this filing has been filed with the Office of Rate Intervention, Office of the Attorney General, is attached as Exhibit 4. [807 KAR 5:007, Sections 1(6) and 2(2)]

7. Notice of the proposed rate change has been given, not more than thirty (30) days prior to May 27, 2010, by publication in a newspaper of general circulation in the affected area of Clark Energy Cooperative, Inc. A copy of this notice is attached as Exhibit 5. [807 KAR 5:007, Sections 1(7)(b), 1(8), and 2(2)]

8. The notice attached as Exhibit 5 contains the required information pursuant to 807 KAR 5:007, Section 3.

Clark Energy Cooperative, Inc. hereby requests that the Commission accept this filing and allow the pass-through to its retail rates of the wholesale rate adjustment granted to EKPC as of the effective date of such adjustment.

Respectfully submitted,

Clark Energy Cooperative, Inc.

Robert L. Rose
Attorney Representing Coop

CLARK ENERGY

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision SHEET NO. 43

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CANCELLING P.S.C. NO. 2

3rd Revision SHEET NO. 43

CLASSIFICATION OF SERVICE

Schedule R: Residential

AVAILABILITY

Available to all residential consumers subject to established rules and regulations of the Distributor.

CHARACTER OF SERVICE

Single phase, 60 Hertz, at available secondary voltages.

DELIVERY POINT

.he delivery point at which the secondary or utilization voltage is provided shall be specified by the Distributor.

RATES

$12.50	Facility Charge	(I)
$0.099734	per kWh for all energy	(I)

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.50. (I)

FUEL ADJUSTMENT CHARGE

The above rate may be increased or decreased by an amount per kWh equal to the fuel adjustment amount per kWh as billed by the Wholesale Power Supplier plus an allowance for line losses. The allowance for line losses will not exceed 10% and is based on a twelve month moving average of such losses.

DATE OF ISSUE: May 27, 2010 DATE EFFECTIVE: Service rendered on and after July 1, 2010

ISSUED BY: ________________________ TITLE : PRESIDENT & C.E.O.
Name of Officer

Issued by authority of an Order of the Public Service Commission in Case No. 2010-00170, dated ____________________.

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision SHEET NO. 45

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CANCELLING P.S.C. NO. 2

3rd Revision SHEET NO. 45

CLASSIFICATION OF SERVICE

Schedule D: Time of-Use Marketing Service

AVAILABILITY

Available to all Rate "R" consumers for separately metered off peak requirements subject to the established time of use restrictions. Applicable to programs approved by the Kentucky PSC as a part of EKPC wholesale marketing rates.

CHARACTER OF SERVICE

ˉingle phase, 60 Hertz, at available secondary voltages.

DELIVERY POINT

The delivery point at which the secondary or utilization voltage is provided shall be specified by the Distributor.

TIME OF DAY RESTRICTIONS

MONTH	OFF PEAK HOURS
October thru April	10:00 P.M. To 7:00 A.M., EST
	12:00 Noon to 5:00 P.M., EST
May thru September	10:00 P.M. thru 10:00 A.M., EST

RATES

$0.06757 per kWh for all energy (I)

DATE OF ISSUE: May 27, 2010 **DATE EFFECTIVE:** Service rendered on and after July 1, 2010

.SSUED BY ____________________ **TITLE** PRESIDENT & C.E.O.
Name of Officer

Issued by authority of an Order of the Public Service Commission in
Case No. 2010-00170 dated ____________________.

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision SHEET NO. 47

CANCELLING P.S.C. NO. 2

3rd Revision SHEET NO. 47

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CLASSIFICATION OF SERVICE

Schedule T: Outdoor lighting Facilities

AVAILABILITY

Available for general outdoor lighting facilities.

RATES

Lamp Rating	Annual Rate Per Lamp	Average Annual Energy Use Per Lamp	Average Monthly Energy Use Per Lamp	
400 Watt	$18.82 per mo	1,848 kWh	154 kWh	(I)

CONDITIONS OF SERVICE

Rates applicable only to lamps and associated appurtenances. Other facilities required may be provided subject to the Distributor's established contract policies and practices.

TERMS OF PAYMENT

The above charges are net and payable within ten days from the date of the bill.

FUEL ADJUSTMENT CHARGES

The above rate may be increased or decreased by an amount per kWh equal to the fuel adjustment amount per kWh as billed by the Wholesale Power Supplier plus an allowance for line losses. The

DATE OF ISSUE: May 27, 2010 **DATE EFFECTIVE:** Service rendered on and after July 1, 2010

ISSUED BY ______________________ **TITLE** PRESIDENT & C.E.O.
Name of Officer

Issued by authority of an Order of the Public Service Commission in
Case No. 2010-00170 dated ____________.

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision SHEET NO. 49

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CANCELLING P.S.C. NO. 2

3rd Revision SHEET NO. 49

CLASSIFICATION OF SERVICE

Schedule S: Outdoor Lighting Facilities

AVAILABILITY

Available for general outdoor lighting facilities.

RATES

Lamp Rating	Monthly Rate Per Lamp	Average Annual Energy Use Per Lamp	Average Monthly Energy Use Per Lamp	
175 Watt	$10.15 per mo	840 kWh	70 kWh	(I)

CONDITIONS OF SERVICE

1. Rate applicable only to lamps and associated appurtenances. Other facilities required may be provided subject to the Distributor's established policies and practices.

2. The Consumer shall execute an agreement for service under this schedule for a period of not less than one year.

FUEL ADJUSTMENT CHARGE

The above rates may be increased or decreased by an amount per kWh equal of the fuel adjustment amount per kWh as billed by the Wholesale Power Supplier plus an allowance for line losses. The allowance for line losses will not exceed 10% and is based on a twelve month moving average of such losses.

DATE OF ISSUE: May 27, 2010 DATE EFFECTIVE: Service rendered on and after July 1, 2010

ISSUED BY ______________________ TITLE PRESIDENT & C.E.O.
Name of Officer

Issued by authority of an Order of the Public Service Commission in Case No. 2010-00170 dated ______________.

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision SHEET NO. 51

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CANCELLING P.S.C. NO. 2

3rd Revision SHEET NO. 51

CLASSIFICATION OF SERVICE

Schedule E: Public Facilities

AVAILABILITY

Available to public facilities with Kilowatt (kW) demands less than 50 kW subject to established rules and regulations of the Distributor. Not applicable to outdoor lighting system requirements.

CHARACTER OF SERVICE

Single phase, 60 Hertz, at available secondary voltages.

DELIVERY POINT

The delivery point at which the secondary or utilization voltage is provided shall be specified by the Distributor.

RATES

$ 16.66	Facility Charge	(I)
$ 0.10672	All kWh	(I)

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $ 16.66. (I)

FUEL ADJUSTMENT CHARGE

The above rate may be increased or decreased by an amount per kWh equal to the fuel adjustment amount per kWh as billed by the Wholesale Power Supplier plus an allowance for line losses. The

DATE OF ISSUE: May 27, 2010 DATE EFFECTIVE: Service rendered on and after July 1, 2010

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Name of Officer

Issued by authority of an Order of the Public Service Commission in Case No. 2010-00170 dated__________________.

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision SHEET NO. 53

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CANCELLING P.S.C. NO. 2

3rd Revision SHEET NO. 53

CLASSIFICATION OF SERVICE

Schedule C: General Power Service

AVAILABILITY

Available for all non-residential general power requirements with Kilowatt (kW) demands less than 50 kW subject to established rules and regulations of the Distributor.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, at available secondary voltages.

DELIVERY POINT

The delivery point at which the secondary or utilization voltage is provided shall be specified by the Distributor.

RATES

$25.47	Facility Charge-Single Phase	(I)
$50.42	Facility Charge-Three Phase	(I)
$0.10620	Per kWh for all energy	(I)

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $25.47 single phase and $50.42 for three phase service. (I)

DATE OF ISSUE: May 27, 2010 **DATE EFFECTIVE:** Service rendered on and after July 1, 2010

ISSUED BY ______________________ **TITLE** PRESIDENT & C.E.O.
Name of Officer

Issued by authority of an Order of the Public Service Commission in Case No. 2010-00170 dated ____________.

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision SHEET NO. 56

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CANCELLING P.S.C. NO. 2

3rd Revision SHEET NO. 56

CLASSIFICATION OF SERVICE

Schedule L: General Power Service

AVAILABILITY

Available to all commercial and industrial consumers for general power requirements with Kilowatt (kW) demands of 50 kW or greater but less than 500 kW.

CONDITIONS OF SERVICE

A power contract shall be executed by the consumer for service under this rate schedule. The power contract shall specify a contract demand for minimum billing purposes of 50 kW or greater but less than 500 kW.

CHARACTER OF SERVICE

Limited to single or three phase, 60 Hertz, at a secondary delivery voltage of 480 volts or less.

DELIVERY POINT

The delivery point shall be specified within the power contract.

RATES

$64.18	Facility Charge	(I)
$ 6.51	per kW of billing demand	(I)
$ 0.07851	per kWh for all energy	(I)

DATE OF ISSUE: May 27, 2010 DATE EFFECTIVE: Service rendered on and after July 1, 2010

ISSUED BY ______________________ TITLE PRESIDENT & C.E.O.
Name of Officer

Issued by authority of an Order of the Public Service Commission in Case No. 2010-00170 dated ____________.

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision **SHEET NO.** 59

CANCELLING P.S.C. NO. 2

3rd Revision **SHEET NO.** 59

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CLASSIFICATION OF SERVICE

Schedule P: General Power Service

AVAILABILITY

Available to all commercial and industrial consumers for general power requirements with Kilowatt (kW) demands of 500 kW or greater.

CONDITIONS OF SERVICE

A power contract shall be executed by the consumer for service under this rate schedule. The power contract shall specify a contract 'emand for minimum billing purposes of 500 kW or greater.

CHARACTER OF SERVICES

Limited to three phase, 60 Hertz, at a secondary of delivery voltage specified within the power contract.

DELIVERY POINT

The delivery point shall be specified within the power contract.

RATES

$87.38	Facility Charge	(I)
$ 6.25	per kW of billing demand	(I)
$ 0.06829	per kWh for all energy	(I)

DATE OF ISSUE: May 27, 2010 **DATE EFFECTIVE:** Service rendered on and after July 1, 2010

ISSUED BY ____________________ **TITLE** PRESIDENT & C.E.O.
Name of Officer

Issued by authority of an Order of the Public Service Commission in Case No. 2010-00170 dated ____________.

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision SHEET NO. 62

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CANCELLING P.S.C. NO. 2

3rd Revision SHEET NO. 62

CLASSIFICATION OF SERVICE

Schedule M: General Power Service

AVAILABILITY

Available to all commercial and industrial consumers for general power requirements at primary delivery voltage with Kilowatt (kW) demands of 1,000 kW or greater but less than 5,000 kW.

CONDITIONS OF SERVICE

A power contract shall be executed by the consumer for service under this rate schedule. The power contract shall specify a contract demand for minimum billing purposes of 1,000 or greater but less than 5,000 kW.

CHARACTER OF SERVICE

Three phase, 60 Hertz, at a delivery voltage specified within the power contract.

DELIVERY POINT

The delivery point shall be specified within the power contract.

RATES

Demand Charge:	$10.13	per kW of billing demand	(I)
Energy Charge:	$0.07171	per kWh for all energy	(I)

DATE OF ISSUE: May 27, 2010 **DATE EFFECTIVE:** Service rendered on and after July 1, 2010

ISSUED BY ____________________ **TITLE** PRESIDENT & C.E.O.
Name of Officer

Issued by authority of an Order of the Public Service Commission in Case No. 2010-00170 dated ____________________.

EXHIBIT 2
Page 1 of 1

The present and proposed rates structures of Clark Energy Cooperative, Inc. are listed below:

Rate Class	Present	Proposed
Sch R: Residential		
Facility Charge per month	$12.00	$12.50
Energy charge per kWh	$0.095773	$0.099734
Sch D: Time of Use Marketing		
Per kWh for all energy	$0.06489	$0.06757
Sch T: Outdoor Lighting Facilities (per month)		
400 watt	$18.07	$18.82
Sch S: Outdoor Lighting Facilities (per month)		
175 watt	$9.75	$10.15
Sch E: Public Facilities		
Facility Charge per month	$16.00	$16.66
Energy charge per kWh	$0.10248	$0.10672
Sch C: General Power Service Single Phase		
Facility Charge per Month	$24.46	$25.47
Per kWh for all Energy	$0.10198	$0.10620
Sch C: General Power Service Three Phase		
Facility Charge per Month	$48.42	$50.42
Per kWh for All Energy	$0.10198	$0.10620
Sch L: General Power Service		
Facility charge per Month	$61.63	$64.18
Demand charge per kW	$6.25	$6.51
Energy charge per kWh	$0.07539	$0.07851
Sch P: General Power Service		
Facility charge per Month	$83.91	$87.38
Demand charge per kW	$6.00	$6.25
Energy charge per kWh	$0.06558	$0.06829
Sch M: General Power Service		
Demand charge per kW	$9.73	$10.13
Energy charge per kWh	$0.06886	$0.07171

Clark Energy

Billing Analysis

for the 12 month ending December 31, 2009

	Present Total Base Revenues	% of Total Revenues	Proposed Total Base Revenues	% of Total Revenues	$ Increase	% Increase
Schedule "R"	$ 34,674,549	73.92%	$ 36,109,716	73.92%	$ 1,435,167	4.14%
Schedule "D"	122,538	0.26%	127,599	0.26%	5,061	4.13%
Schedule T	160,841	0.34%	167,517	0.34%	6,676	4.15%
Schedule "S"	1,056,335	2.25%	1,099,671	2.25%	43,337	4.10%
Schedule "E"	481,005	1.03%	500,899	1.03%	19,894	4.14%
Schedule "C": Single Phase	1,958,360	4.17%	2,039,361	4.17%	81,001	4.14%
Schedule "C-3": Three-Phase	1,516,932	3.23%	1,579,696	3.23%	62,764	4.14%
Schedule "L"	5,315,985	11.33%	5,536,245	11.33%	220,260	4.14%
Schedule "P"	851,962	1.82%	887,269	1.82%	35,307	4.14%
Schedule "M"	770,550	1.64%	802,393	1.64%	31,843	4.13%
Totals	$ 46,909,057	100.00%	$ 48,850,367	100.00%	$ 1,941,311	4.14%
Total FAC Component	1,013,785		1,013,785			
Total ESc Component	2,461,676		2,461,676			
Total Green Power	957		957			
Total Incl. Surcharges	$ 50,385,475		$ 52,326,785		$ 1,941,311	3.85%

Clark Energy's Portion of EKPC's Wholesale Rate Increase	$ 1,940,310
Over (Under) Recovery due to Rounding	$ 1,001

Note: In order to appropriately match retail rates to the forecasted test year used for wholesale rates, an escalation factor was applied to each member system's 2009 actual billing determinants. The escalation factors used in this proceeding were an outcome of preliminary load forecast projections.

Clark Energy
Billing Analysis
for the 12 months ended December 30, 2009

Clark Schedule "R"	2009 Billing Determinants (1)	Escalation % (2)	Escalated Billng Determinants. (3)=(1)*(2)	Present Rate (4)	Present Revenues (5)=((4)*(3)	Actual Comp % of Base Rates	Proposed Rate (6)	Proposed Revenues (7)=(6)*(3)	Dollar Increase (7)	Percent Increase (8)	Proposed Comp.% of Base Rates
Customer Charge	290,649	1.31%	294,457	$ 12.00	$ 3,533,478	*10.19%*	$ 12.50	$ 3,680,706	$ 147,228		*10.19%*
Energy Charge per kWh	310,292,026	4.79%	325,155,014	$ 0.095773	31,141,071	*89.81%*	$ 0.099734	32,429,010.2	1,287,939		*89.81%*
Billing Adjustments					-			-	-		
Total from Base Rates					34,674,549	*100.00%*		36,109,716.4	1,435,167	4.14%	*100.00%*
Plus Fuel Adjustment					793,918			793,918.0	-		
Plus Environmental Surcharge					1,843,623			1,843,623.0	-		
Green Power					957			957.0	-		
Total Revenues					$ 37,313,047			$ 38,748,214	$ 1,435,167	$ 1,435,167	
Average					$ 126.72			$ 131.59	$ 4.87		
Percent										3.85%	

Clark Schedule "D"	2009 Billing Determinants (1)	Escalation % (2)	Escalated Billng Determinants. (3)=(1)*(2)	Present Rate (4)	Present Revenues (5)=((4)*(3)	Actual Comp % of Base Rates	Proposed Rate (6)	Proposed Revenues (7)=(6)*(3)	Dollar Increase (7)	Percent Increase (8)	Proposed Comp.% of Base Rates
Number of Bills	2,840	1.31%	2,877		$ -		$ -	$ -	$ -		
Energy	1,802,075	4.79%	1,888,394	$ 0.06489	122,538	*100.00%*	$ 0.06757	127,599	5,061		*100.00%*
Billing Adjustments					-			-	-		
Rev from Bases Rates					122,538	*100.00%*		127,599	5,061	4.13%	*100.00%*
FUEL					6,685			6,685	-		
ESC					57			57	-		
TOTAL REVENUE					$ 129,280			$ 134,341	$ 5,061	3.91%	
Average					$ 44.93			$ 46.69	$ 1.76		
Percent										3.91%	

Clark Energy
Billing Analysis
for the 12 months ended December 30, 2009

Clark Schedule T	2009 Billing Determinants (1)	Escalation % (2)	Escalated Billing Determinants. (3)=(1)*(2)	Present Rate (4)	Present Revenues (5)=((4)*(3)	Actual Comp % of Base Rates	Proposed Rate (6)	Proposed Revenues (7)=(6)*(3)	Dollar Increase (7)	Percent Increase (8)	Proposed Comp.% of Base Rates
200 WATT	-	0.00%	-	$ -	$ -		$ -	$ -	$ -		
300 WATT	-	0.00%	-	-	-		-	-	-		
400 WATT	8,901	0.00%	8,901	$ 18.07	160,841	*100.00%*	$ 18.82	167,517	6,676		*100.00%*
Billing Adjustments					-			-	-		
Rev from Bases Rates					160,841	*100.00%*		167,517	6,676	4.15%	*100.00%*
FUEL					2,752			2,752	-		
ESC					3,143			3,143	-		
TOTAL REVENUE					$ 166,736			173,412	6,676		
Average					$ 18.73			$ 19.48	$ 0.75		
Percent										4.00%	

Clark Schedule "S"	2009 Billing Determinants (1)	Escalation % (2)	Escalated Billing Determinants. (3)=(1)*(2)	Present Rate (4)	Present Revenues (5)=((4)*(3)	Actual Comp % of Base Rates	Proposed Rate (6)	Proposed Revenues (7)=(6)*(3)	Dollar Increase (7)	Percent Increase (8)	Proposed Comp.% of Base Rates
Customer Charge (Lamp Charge)	108,342	0.00%	108,342	$ 9.75	$ 1,056,335	*100.00%*	$10.15	$ 1,099,671	$ 43,337		*100.00%*
Energy Charge per kWh	7,576,576	0.00%	7,576,576	-	-		$ -	-	-		
Billing Adjustments					-			-	-		
Total from Base Rates					1,056,335	*100.00%*		1,099,671	43,337	4.10%	*100.00%*
Plus Fuel Adjustment					15,199			15,199	-		
Plus Environmental Surcharge					3,057			3,057	-		
Total Revenues					$ 1,074,591			$ 1,117,927	$ 43,337		
Average					$ 9.92			$ 10.32	$ 0.40		
Percent										4.03%	

Clark Schedule "E"	2009 Billing Determinants (1)	Escalation % (2)	Escalated Billing Determinants. (3)=(1)*(2)	Present Rate (4)	Present Revenues (5)=((4)*(3)	Actual Comp % of Base Rates	Proposed Rate (6)	Proposed Revenues (7)=(6)*(3)	Dollar Increase (7)	Percent Increase (8)	Proposed Comp.% of Base Rates
Customer Charge	3,527	0.00%	3,527	$ 16.00	$ 56,432	*11.73%*	$ 16.66	$ 58,760	$ 2,328		*11.73%*
Energy Charge per kWh	3,845,709	7.73%	4,142,982	$ 0.10248	424,573	*88.27%*	$ 0.10672	442,139	17,566		*88.27%*
Billing Adjustments					-			-	-		
Total from Base Rates					481,005	*100.00%*		500,899	19,894	4.14%	*100.00%*
Plus Fuel Adjustment					9,452			9,452	-		
Plus Environmental Surcharge					25,802			25,802	-		
Total Revenues					$ 516,259			$ 536,153	$ 19,894	$ 19,894	
Average					$ 146.37			$ 152.01	$ 5.64		
Percent										3.85%	

Exhibit RJM-10
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EXHIBIT 3
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Clark Energy
Billing Analysis
for the 12 months ended December 30, 2009

Clark
Schedule "C": Single Phase

	2009 Billing Determinants	Escalation %	Escalated Billng Determinants.	Present Rate	Present Revenues	Actual Comp % of Base Rates	Proposed Rate	Proposed Revenues	Dollar Increase	Percent Increase	Proposed Comp.% of Base Rates
	(1)	(2)	(3)=(1)*(2)	(4)	(5)=((4)*(3)		(6)	(7)=(6)*(3)	(7)	(8)	
Customer Charge	16,742	1.27%	16,955	$ 24.46	$ 414,710	21.18%	$ 25.47	$ 431,834	$ 17,124		21.17%
Energy Charge per kWh	14,050,673	7.73%	15,136,790	$ 0.10198	1,543,650	78.82%	$ 0.10620	1,607,527	63,877		78.83%
Billing Adjustments					-			-	-		
Total from Base Rates					1,958,360	100.00%		2,039,361	81,001	4.14%	100.00%
Plus Fuel Adjustment					32,605			32,605	-		
Plus Environmental Surcharge					195,122			195,122	-		
Total Revenues					$ 2,186,087			$ 2,267,088	$ 81,001		
Average					$ 128.94			$ 133.72	$ 4.78		
Percent										3.71%	

Clark
Schedule "C-3": Three-Phase

	2009 Billing Determinants	Escalation %	Escalated Billng Determinants.	Present Rate	Present Revenues	Actual Comp % of Base Rates	Proposed Rate	Proposed Revenues	Dollar Increase	Percent Increase	Proposed Comp.% of Base Rates
	(1)	(2)	(3)=(1)*(2)	(4)	(5)=((4)*(3)		(6)	(7)=(6)*(3)	(7)	(8)	
Customer Charge	2,050	1.27%	2,076	$ 48.42	$ 100,522	6.63%	$ 50.42	$ 104,674	$ 4,152		6.63%
Energy Charge per kWh	12,892,512	7.73%	13,889,103	$ 0.10198	1,416,411	93.37%	$ 0.10620	1,475,023	58,612		93.37%
Demand Charge	-	-	-	$ -	-	0.00%	$ -	-	-		0.00%
Billing Adjustments					-			-	-		
Total from Base Rates					1,516,932	100.00%		1,579,696	62,764	4.14%	100.00%
Plus Fuel Adjustment					27,466			27,466	-		
Plus Environmental Surcharge					88			88	-		
Total Revenues					$ 1,544,486			$ 1,607,250	$ 62,764		
Average					$ 743.96			$ 774.19	$ 30.23		
Percent										4.06%	

Clark
Schedule "L"

	2009 Billing Determinants	Escalation %	Escalated Billng Determinants.	Present Rate	Present Revenues	Actual Comp % of Base Rates	Proposed Rate	Proposed Revenues	Dollar Increase	Percent Increase	Proposed Comp.% of Base Rates
	(1)	(2)	(3)=(1)*(2)	(4)	(5)=((4)*(3)		(6)	(7)=(6)*(3)	(7)	(8)	
Customer Charge	1,324	1.27%	1,341	$ 61.63	$ 82,634	1.55%	$ 64.18	$ 86,053	$ 3,419		1.55%
Energy Charge per kWh	49,552,971	7.73%	53,383,416	$ 0.07539	4,024,576	75.71%	$ 0.07851	4,191,132	166,556		75.70%
Demand Charge	193,404	0.00%	193,404	$ 6.25	1,208,775	22.74%	$ 6.51	1,259,060	50,285		22.74%
Billing Adjustments					-			-	-		
Total from Base Rates					5,315,985	100.00%		5,536,245	220,260	4.14%	100.00%
Plus Fuel Adjustment					103,915			103,915	-		
Plus Environmental Surcharge					296,222			296,222	-		
Total Revenues					$ 5,716,122			$ 5,936,382	$ 220,260		
Average					$ 4,263			$ 4,427	$ 164.27		
Percent										3.85%	

Clark Energy
Billing Analysis
for the 12 months ended December 30, 2009

Clark Schedule "P"	2009 Billing Determinants (1)	Escalation % (2)	Escalated Billng Determinants. (3)=(1)*(2)	Present Rate (4)	Present Revenues (5)=((4)*(3)	Actual Comp % of Base Rates	Proposed Rate (6)	Proposed Revenues (7)=(6)*(3)	Dollar Increase (7)	Percent Increase (8)	Proposed Comp.% of Base Rates
Customer Charge	48	1.27%	49	$ 83.91	$ 4,079	*0.48%*	$ 87.38	$ 4,282	$ 203		*0.57%*
Energy Charge per kWh	9,261,900	7.73%	9,977,845	$ 0.0656	654,347	*76.80%*	$ 0.06829	681,387	27,040		*76.80%*
Demand Charge	32,256	0.00%	32,256	$ 6.00	193,536	*22.72%*	$ 6.25	201,600	8,064		*22.72%*
Billing Adjustments					-			-	-		
Total from Base Rates					851,962	*100.00%*		887,269	35,307	4.14%	*100.09%*
Plus Fuel Adjustment					14,742			14,742	-		
Plus Environmental Surcharge					49,090			49,090	-		
Total Revenues					$ 915,794			$ 951,101	$ 35,307		
Average					$ 18,840			$ 19,566	$ 726.33		
Percent										3.86%	

Clark Schedule "M"	2009 Billing Determinants (1)	Escalation % (2)	Escalated Billng Determinants. (3)=(1)*(2)	Present Rate (4)	Present Revenues (5)=((4)*(3)	Actual Comp % of Base Rates	Proposed Rate (6)	Proposed Revenues (7)=(6)*(3)	Dollar Increase (7)	Percent Increase (8)	Proposed Comp.% of Base Rates
Customer Charge	12	0.00%	12	$ -	$ -		$ -	$ -	$ -		
Energy Charge per kWh	8,584,872	0.81%	8,654,409	$ 0.06886	595,942.64	*77.34%*	$ 0.07171	620,608	24,665		*77.34%*
Demand Charge	17,840	0.59%	17,945	$ 9.73	174,607.34	*22.66%*	$ 10.13	181,785	7,178		*22.66%*
Billing Adjustments					-			-	-		
Total from Base Rates					770,549.98	*100.00%*		802,393	31,843	4.13%	*100.00%*
Plus Fuel Adjustment					7,051.00			7,051	-		
Plus Environmental Surcharge					45,472.00			45,472	-		
Total Revenues					$ 823,073		rounding	$ 854,916	$ 31,843		
Average					$ 68,589			$ 71,243	$ 2,653.60		
Percent										3.87%	

CLARK ENERGY COOPERATIVE, INC.

CASE NO. 2010-00170

I, Ann F. Wood, hereby certify that one complete copy of the materials filed with the Kentucky Public Service Commission has been sent to the Office of Rate Intervention, Office of the Attorney General.

Ann F. Wood
East Kentucky Power Cooperative, Inc.

Subscribed and sworn before me on this 27th day of May, 2010.

Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

EXHIBIT 5
Page 1 of 2

NOTICE OF PROPOSED RATE CHANGE

In accordance with the requirements of the Public Service Commission of the Commonwealth of Kentucky as set forth in 807 KAR 5:007, Section 3, of the Rules and Regulations of the Public Service Commission, notice is hereby given to the member consumers of Clark Energy Cooperative, Inc. of a proposed rate adjustment. An Application for Approval of Adjustment to Rates will be filed with the Public Service Commission on May 27, 2010, Case No. 2010-00170. The rates are being revised to reflect a change in wholesale rates pursuant to KRS 278.455(2). This adjustment will result in a general rate increase to the member-consumers of Clark Energy Cooperative, Inc. The amount and percent of increase by rate class are listed below.

Rate Class	Increase	Percent
Sch R: Residential	$1,435,167	3.85%
Sch D: Time of Use Marketing	$5,061	3.91%
Sch T: Outdoor Lighting Facilities	$6,676	4.00%
Sch S: Outdoor Lighting Facilities	$43,337	4.03%
Sch E: Public Facilities	$19,894	3.85%
Sch C: General Power Service Single Phase	$81,001	3.71%
Sch C: General Power Service Three Phase	$62,764	4.06%
Sch L: General Power Service	$220,260	3.85%
Sch P: General Power Service	$35,307	3.86%
Sch M: General Power Service	$31,843	3.87%

The effects of the proposed rates on the average monthly bill by rate class are listed below:

Rate Class	$ Increase	% Increase
Sch R: Residential	$4.87	3.85%
Sch D: Time of Use Marketing	$1.76	3.91%
Sch T: Outdoor Lighting Facilities	$0.75	4.00%
Sch S: Outdoor Lighting Facilities	$0.40	4.03%
Sch E: Public Facilities	$5.64	3.85%
Sch C: General Power Service Single Phase	$4.78	3.71%
Sch C: General Power Service Three Phase	$30.23	4.06%
Sch L: General Power Service	$164.27	3.85%
Sch P: General Power Service	$726.33	3.86%
Sch M: General Power Service	$2,653.60	3.87%

The present and proposed rates structures of Clark Energy Cooperative, Inc. are listed below:

Rate Class	Present	Proposed
Sch R: Residential		
Facility Charge per month	$12.00	$12.50
Energy charge per kWh	$0.095773	$0.099734
Sch D: Time of Use Marketing		
Per kWh for all energy	$0.06489	$0.06757

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Rate Class	Present	Proposed
Sch T: Outdoor Lighting Facilities (per month)		
400 watt	$18.07	$18.82
Sch S: Outdoor Lighting Facilities (per month)		
175 watt	$9.75	$10.15
Sch E: Public Facilities		
Facility Charge per month	$16.00	$16.66
Energy charge per kWh	$0.10248	$0.10672
Sch C: General Power Service Single Phase		
Facility Charge per Month	$24.46	$25.47
Per kWh for all Energy	$0.10198	$0.10620
Sch C: General Power Service Three Phase		
Facility Charge per Month	$48.42	$50.42
Per kWh for All Energy	$0.10198	$0.10620
Sch L: General Power Service		
Facility charge per Month	$61.63	$64.18
Demand charge per kW	$6.25	$6.51
Energy charge per kWh	$0.07539	$0.07851
Sch P: General Power Service		
Facility charge per Month	$83.91	$87.38
Demand charge per kW	$6.00	$6.25
Energy charge per kWh	$0.06558	$0.06829
Sch M: General Power Service		
Demand charge per kW	$9.73	$10.13
Energy charge per kWh	$0.06886	$0.07171

The rates contained in this notice are the rates proposed by Clark Energy Cooperative, Inc. However, the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice. Such actions may result in rates for consumers other than the rates in this notice.

Any person may examine the rate application at the main office of Clark Energy Cooperative, Inc at the following address:

Clark Energy Cooperative, Inc.
2640 Iron Works Road
Winchester, KY 40391
(859) 744-4251
www.clarkenergy.com

Any person may also examine the rate application at the office of the Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky.