weight by lenders is that financial performance demonstrates the cooperative's ability to service its obligations, which could have a direct impact on the value of the lender's investment. For example, a downgrade in a credit rating of a cooperative could decrease the value of that cooperative's bonds held in a bondholder's portfolio. The bondholder is concerned about a cooperative's credit at both the time of issuance and on an ongoing basis. Compared to an IOU, STEC's financial performance is significantly lower than that of an IOU.

Flexibility to Change Rates/Regulatory Environment

Most of the cost exposure for cooperatives, such as construction costs, is unregulated in the U.S. The cooperative needs the flexibility to raise or lower rates in order to track dramatic changes in cost levels. This holds true also for environmental requirements and capital investments to provide service. Very few cooperatives are rate regulated. Cooperatives that serve in states that are rate regulated have more difficulty raising rates compared to peers that are subject only to their boards of directors for authority to change rates. An unsupportive regulatory jurisdiction is a credit negative and leaves cooperatives with less flexibility to raise rates if needed. Of the 26 rated G&T cooperatives, only four are state regulated for generation rates, and three are regulated by the Federal Energy Regulatory Commission (FERC). The FERC regulated G&Ts use a flexible automatic adjustment formula to adjust rates which is a credit positive. Texas is the only state

I am aware of that separately regulates transmission rates for G&Ts. In Moody's evaluation of risk, financial performance and rate flexibility account for 60% of the credit evaluation. STEC credit evaluation in this rating category is considered a "mixed bag". While STEC doesn't have the flexibility to adjust transmission rates as enjoyed by some G&Ts, Texas regulation is considered positive by the rating agencies.

Long-term Wholesale Contracts

The contracts between cooperatives and their members provide a high degree of assurance that costs and capital investments can be recovered in rates. The trend in the industry is to extend existing contracts for 30 or more years. Cooperatives such as Oglethorpe have extended their member contract to 2050. Most lenders, either in the capital market or RUS, are generally not issuing new loans beyond the maturity date of existing wholesale power contracts. Shorter maturities result in fewer numbers of years to recover fixed costs, thus increasing the cost per year. This situation is considered a credit negative by the rating agencies. Generally, the longer the contract, the greater the assurance that the cost of assets will be recovered and the debt repaid. For STEC and other G&Ts, the long term contracts help mitigate the lower financial metrics earned by cooperatives. Without these assurances of cash flow cooperatives could not finance in the capital markets.

Member Profile

The member profile is important because it is the members that are the primary source of cash flow. The credit strength of the members, whether they are "end-of-line" member consumers or purchase for resale distribution members of a G&T cooperative, is an important factor to the credit strength of the cooperative. If a cooperative has members with poor credit fundamentals, it is a credit negative for the system. STEC's members are in good financial health resulting in a credit positive for STEC.

Size

This factor, while the least important, still matters, the larger the entity, the greater ability to withstand unexpected events. Also, the greater the size, the greater the ability an entity has to take advantage of economic diversity such as fuel mix and new generation. On the other hand, smaller utilities or utilities that experience substantial load loss have difficulty adjusting to significant events. Compared to a number of G&Ts, STEC's small size is considered a credit negative.

Q. WOULD YOU EXPLAIN HOW CREDIT POSITIVES AND CREDIT NEGATIVES WORK IN PARTICULAR APPLICATIONS?

A. Each utility has its own "basket of risks" to manage and still provide service on a daily basis. Most experts would agree that each utility has a collection of factors that are either credit positives or credit negatives. Since the credit crisis in 2008, and the preceding collapse of Enron, the ability to maintain credit standing has become demanding and difficult. In 2002, subsequent to the Enron collapse, there were substantially more downgrades than upgrades by S&P. The challenges for a utility are to mitigate credit negatives and improve credit positives when possible. Unfortunately, each utility has some credit negatives that are outside its ability to control. Weather and unexpected economic conditions that impact demand are good examples.

Within a rating category each cooperative has different credit negatives and positives. For example, two cooperatives may have the exact same credit rating. One cooperative may build into its rates a higher coverage ratio that could be a credit positive; however, the same cooperative may have a credit negative in that rate flexibility may be limited such as with rate regulation. Although both cooperatives have the same rating, the key in any credit evaluation is whether the credit negatives outweigh the credit positives and to what degree the lenders are exposed to a cooperative's risk.

Q. HOW IMPORTANT IS IT TO MAINTAIN A GOOD CREDIT POSITION?

A. Failure to maintain financial integrity is contrary to the interests of consumers as well as lenders.

> "An immediate effect of low earnings and earnings of low quality is to increase the financial risks of investors, and thus lead to the downgrading of securities by the rating agencies. Downgrading, in turn, means that the bonds must carry higher interest rates, a charge which is passed along to customers. Such downgrading has become a familiar phenomenon in the utility scene .... The bonds of many utilities are now rated at levels so low that many institutional investors are barred by law

> from purchasing them, and interest rates must be raised in order to sell the securities within a much smaller market. These additional capital costs force rate increases which otherwise would not be necessary, without improving the financial condition of the utilities or their ability to raise money on a low cost basis. An equally serious result of limited capability to raise money is the inability of the utilities to make the investments required in order to achieve the optimum economics of service."[2]

In STEC's case, a credit downgrade would certainly increase the debt cost and encourage the financial institution to impose constraining covenants and requirements. Any debt issued when ratings are lower would carry higher costs for the life of the debt.

In today's utility credit environment, the basis for capital attraction is the credit evaluation process. Whether the lenders are program lenders (CFC, CoBank), bond investors, commercial banks, or trade vendors, all rely on an evaluation of credit to determine if capital or credit should be advanced. In addition, this evaluation may also determine the nature of terms and conditions for capital or credit.

VI.

RATING AGENCIES AND BONDHOLDERS FOCUS ON DSC

Q. WHAT ARE THE KEY FINANCIAL RATIOS RELIED ON BY THE RATING AGENCIES?

A. Rating agencies and bondholders often construct a "peer group" of utilities to compare financial performances. Exhibit DMW-2 of my

[2] Report of an Informal Task Force to the Energy Transition Team, "Recommendations for Restoration of Financial Health to the U.S. Electric Power Industry" (mimeographed, December 17, 1980), pp. 11-12.

testimony, a publication named "Fitch Rating US Public Power Peer Study", states on page 2 of that report:

> "The ratios highlighted in this report are some of the primary financial calculations used in comparing utility systems in Fitch's committee process, and can be used by market participants to assist in making their own comparison."

Q. WAS TIER USED IN THE FITCH ANALYSIS?

A. No. TIER is not an important financial indicator in the credit evaluation process for capital market cooperatives such as STEC. On page 16 of Exhibit DMW-2, Fitch lists 7 financial metrics used in their credit evaluation process. The TIER ratio is not listed in this report. The key financial indicator used by Fitch, S&P, and bondholders is DSC. The reason it is important is the DSC ratio measures the cooperative's ability to pay total debt service, both principal and interest.

Q. HOW DOES USING DSC FOR RATEMAKING RELATE TO DSC USED BY THE RATING AGENCIES AND BONDHOLDERS?

A. Financial performance as demonstrated by DSC is a key indication of the cooperatives ability to pay debt service and relate directly to STEC's ability to attract the capital it needs to provide power and transmission services to its members. Thus, DSC must be used in ratemaking to ensure that ratemaking and the capital markets requirement are in alignment. Without earning a fair return for ratemaking, STEC will not be able to raise the necessary capital it needs.

VII.

DSC REQUIREMENTS

Q. WHAT MINIMUM COVERAGE REQUIREMENT MUST STEC MAINTAIN?

A. STEC has several base financial documents that address minimal financial performance. Exhibits of these documents are included in the attached working papers. First, STEC has a CFC loan document that states it must earn a DSC of no less than 1.00x. An excerpt showing that part of the agreement is attached to the TCOS-RFP as workpaper WP/C-2/3.1. Another financial document is its market indenture, an excerpt of which is workpaper WP/C-2/3.2, that states that it must set rates to achieve a margin for interest ("MFI") of 1.10x. Other indicators of STEC's debt service obligations are shown by the excerpts included as workpapers WP/C-2/3.3, WP/C-2/3.4, WP/C-2/3.5, and WP/C-2/3.6.

Q. CAN STEC ATTRACT CAPITAL WITH AN ACHIEVED DSC OF 1.00 OR A MFI OF 1.10X?

A. No. These indicators are considered default levels of financial performance. I am not aware of any cooperative that has issued debt in the capital markets with financial performance at or near these default levels. In other words STEC must set rates to earn margins higher than these default "levels" to attract capital it needs to both repair and build new plants.

Q. WHAT LEVEL OF DSC WOULD YOU RECOMMEND?

A. First of all, STEC's financial objective is to improve its debt rating to the "A" level. Again on page 16 of Exhibit DMW-2, the median DSC for "A" rated G&T Cooperative is 1.46x. STEC is requesting a DSC of 1.50x or equivalent to the median level in the Fitch report for a "A" rated utility.

Q. DO YOU BELIEVE STEC'S REQUESTED DSC OF 1.50X IS REASONABLE?

A. Absolutely. First, I believe, for STEC, a DSC of 1.50x earned on a consistent basis represents the financial performance needed to maintain its credit quality and is the level expected by both the rating agencies and bondholders.

Second, the second most important financial indicator for a G&T is the ratio of equity capital compared to capitalization. As a result of adding a new plant in recent years to meet load growth, STEC's 17% equity level is considered very low when compared to other cooperatives. Again, the Fitch report states that the median level of equity to capitalization is 23%. As such, the STEC level of equity is a credit negative. A DSC of 1.50x would help STEC repair its equity level.

Third, STEC is planning to complete substantial transmission projects over the next three years. Without the ability to recover its investment plus earn a DSC level of 1.50x, STEC will suffer even further degeneration of its equity level. A DSC of 1.50x will not completely mitigate this issue but will help to maintain STECs credit profile.

Fourth, the PUC's Transmission Cost of Service Rate Filing Package for Non-Investor Owned Transmission Service Providers in the Electric Reliability Council of Texas ("Non-IOU TCOS-RFP"), Schedule C-2, page 15, provides that a return corresponding to coverage of 50 basis points above the mortgage default criterion is presumed to be a reasonable level, as stated above. An authorized DSC of 1.50x would place STEC is within this guideline.

Q. DO YOU HAVE ANY OTHER COMMENTS?

A. Yes. The Texas transmission tariff structure has been recognized by credit analysts as a reasonable method to compensate a utility for the use of transmission assets. A key part of the formula, for STEC, is the use of a DSC of 1.50x to allow STEC to continue to maintain its credit profile in order to attract necessary capital to construct new transmission investments.

Q. DOES THAT COMPLETE YOUR TESTIMONY?

A. Yes.

PROFESSIONAL BACKGROUND

DANIEL M. WALKER
7106 University Drive
Richmond, Virginia 23229

SUMMARY

Thirty years of management experience includes Executive Management, Capital Market Financing, Investment Analysis, Acquisitions, Auditing, Risk Management, Internal Control, Corporate Policy and Staff Development, Personnel Management, and Utility Analysis.

PROFESSIONAL HISTORY

WALKER AND ASSOCIATES; Richmond, Virginia

Financial Advisor – Provided financial advisory services in negotiating, structuring, and implementing almost $3 billion of capital market transactions. Served as an expert witness before Federal and state jurisdictions on finance and regulatory issues.

OLD DOMINION ELECTRIC COOPERATIVE; Glen Allen, Virginia

Senior Vice President and CFO - Responsible for the accounting and financial integrity of Old Dominion and its subsidiaries and the development of financial resources to meet its obligations and objectives. Member of Senior Management team for over 20 years.

VIRGINIA STATE CORPORATION COMMISSION; Richmond, Virginia

Director, Accounting and Finance - Supervised a large staff of accountants, auditors, and financial analysts in their analysis of public utility matters under the jurisdiction of the Virginia State Corporation Commission. In charge of task force responsible for policy recommendation for the Virginia State Corporation Commission on deregulation in the electric and telecommunication industry.

EDUCATION

- **MBA** University of Richmond
- **B.S.** Appalachian State University

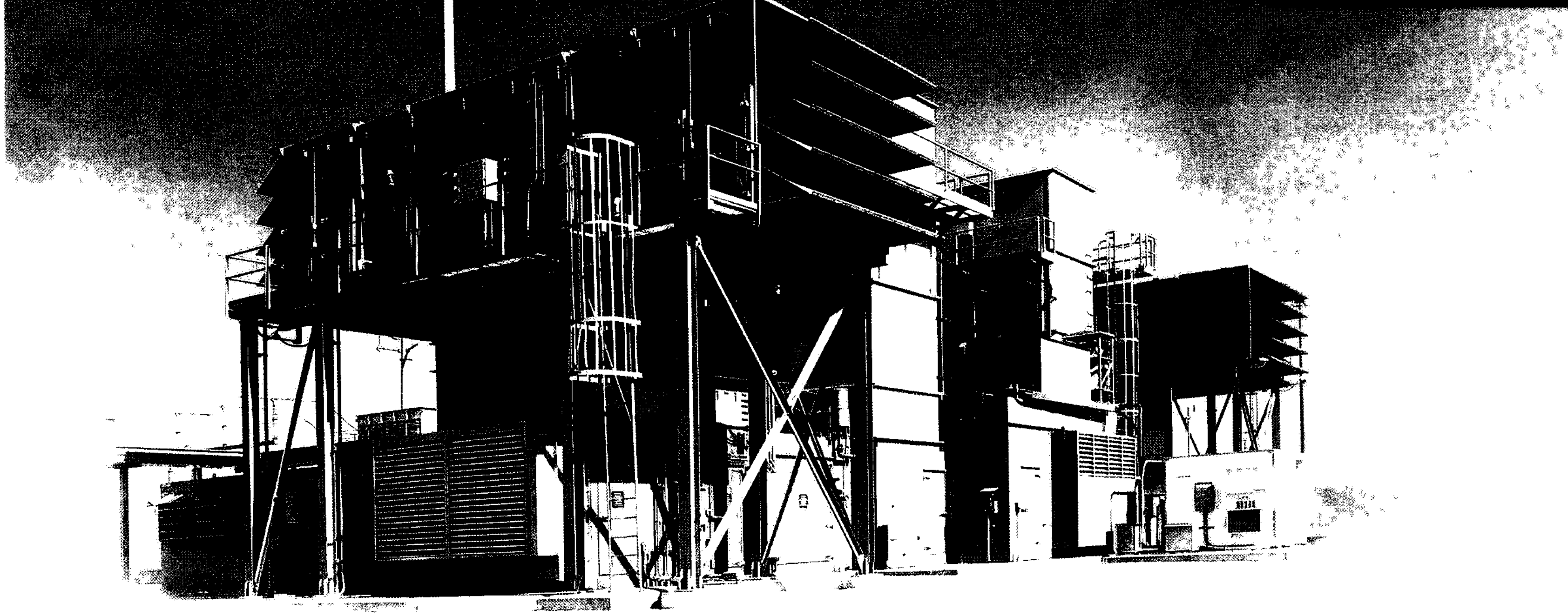
PROFESSIONAL ACTIVITY

- President, National G&T Accounting and Finance Association
- Member of G&T Alternative Finance Task Force
- Director National Society of Rates of Return Analysts
- Member of FERC-EEI Accounting Liaison Committee
- Member of NARUC Accounting Committee
- Published Article: *Public Utilities Fortnightly*
- Published Article: *William & Mary Business Review*
- Addressed Price Waterhouse's Global Structured Finance Conference in Ireland in 1999 and 2000, and in Portugal in 2001 and 2002.
- Addressed Mercedes Conference on Infrastructure Financing in Berlin, Germany in 2003.
- Adjunct faculty in Accounting and Finance, Virginia Commonwealth University
- Guest lecturer, University of Virginia, William & Mary College, Duke University and Virginia Commonwealth University
- Lecturer on various accounting and finance issues before professional groups in the United States and Europe

FitchRatings

U.S. Public Power
Peer Study

June 2012



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Related Research

Revenue-Supported Rating Criteria, June 12, 2012
U S Public Power Rating Criteria, Jan 11, 2012
2012 Outlook U S. Public Power and Electric Cooperative Sector, Dec 7, 2011
U S Public Power Peer Study Addendum. June 2012, June 20, 2011

EXHIBIT DMW-2, Page 3 of 21

Summary
- **This report highlights the financial performance of Fitch-rated public power utilities.**
- **The report utilizes eight financial ratios that are calculated from the most recent annual audits.**
- **The ratios are presented by utility type, rating category, and region.**
- **A utility's financial measures, relative to Fitch-designated regional and national peer groups, constitute an important component of Fitch's credit analysis.**

Overview

Fitch Ratings presents the 2012 edition of its annual "U.S. Public Power Peer Study." This report compares the recent financial performance of wholesale and retail public power systems, as well as rural electric cooperatives. The ratios highlighted in this report are some of the primary financial calculations used in comparing utility systems in Fitch's committee process, and can be used by market participants to assist in making their own comparisons. It is important to note that financial metrics represent only one key component, among others, in Fitch's utility credit analysis. To review Fitch's full public power criteria, please see the report, "U.S. Public Power Rating Criteria," dated Jan. 11, 2012.

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The U.S. Public Power Peer Study is a point-in-time assessment of Fitch-rated public power utilities. The ratios for each issuer are determined using audited information. While more than half of the audits used in this study are dated Dec. 31, 2011, different audit dates may skew the distribution of the ratios.

Also, financial ratios and metrics detailed in the report may occasionally differ from those reported in new issue and full rating reports. This can be a result of adjustments made by Fitch during the rating review process to reflect additional information received from the issuer, as well as circumstances unique to the credit. In each case, Fitch seeks to highlight these adjustments for the benefit of the reader in the reports and press releases it publishes during the rating process.

2011 Performance Highlights

- Debt service coverage was slightly lower for wholesale systems, but slightly higher for retail systems, reflecting lower revenues from off-system sales and wholesale rate increases that have lagged increasing debt service costs.
- Cash on hand medians increased uniformly for all systems, confirming broadly stronger liquidity throughout the sector.
- The ratio of capital expenditures to depreciation continued to decline, particularly for wholesale systems. This trend, together with increased cash on hand, is likely attributable to the deferral of certain capital expenditures.
- Leverage metrics normalized between 'AA' and 'A' rated systems, with ratios for 'A' rated systems ending the year weaker than comparable 'AA' rated systems.

What's New?

Ratios

Fitch often reviews the appropriateness of its ratios, taking into account the changing environment and revising the methodology when necessary. This year, Fitch will again publish its ratio for coverage of full obligations, which includes a portion of purchase power payments as fixed charges. In the absence of detailed, issuer-specific information, Fitch includes 30% of purchased power expenses as fixed charges. The specific ratio is detailed on pages 17 and 18.

The decision to include the coverage ratio for full obligations, which was excluded in 2011, is designed to better facilitate the comparison of electric systems. Fitch believes that the coverage metric is particularly helpful when comparing retail systems that elect to acquire, own, and finance generation resources to those systems that elect to purchase their entire power supply. The ratio will be calculated for both retail and wholesale systems.

Included Ratios
- **Coverage of full obligations — adjusting for a portion of purchased power payments as fixed charges (retail and wholesale).**

Excel Addendum

Fitch has again released the peer comparison tables in spreadsheet form to improve the peer study's use as a tool for investors and other market participants. In this year's release of the excel addendum, financial ratios and metrics for prior fiscal years (2009 and 2010), as well as the current fiscal year, will again be included to move beyond a point-in-time comparison of utilities and allow for an accessible review of historical trends.

In an effort to make the Excel addendum as useful and timely as possible, Fitch began updating the addendum in December, with audited figures from issuers whose fiscal years end between Jan. 31 and June 30. The remaining issuers are updated during the regular production of the peer study and addendum in early June, as usual. This addendum is available by clicking here.

Medians Are Not Targets

While the peer study includes median calculations for financial ratios by rating category, these should not be construed as targets for specific ratios or ratings. The medians reflect a single point in time, may not reflect relevant adjustments, and in many instances are based on a small sampling of public power issuers.

Comments Welcome

As always, Fitch welcomes comments, ideas, and suggestions from users to improve the value of the U.S. Public Power Peer Study.

Utility Systems Included in Report

The majority of utility systems rated by Fitch's public power group fall into three categories: wholesale systems, retail systems, and generation and transmission (G&T) cooperative systems. The following is a brief description of each of the sectors.

Wholesale Systems

Wholesale systems represent utilities whose revenues are primarily derived from sales to other systems or its members, and are typically organized as joint action agencies (JAAs). The number of members in JAAs can vary from three (Northern Illinois Municipal Power Agency) to more than 100 (American Municipal Power). Additionally, JAAs may be organized to own one generating unit or a diverse portfolio of resources. Wholesale providers that are not organized as JAAs, some of which are quasi-state agencies, are also included in this category.

Retail Systems

Retail utility systems derive the majority of their revenues from sales to end-user customers, who are also the "owners" of the system. Retail systems may be fully integrated utilities or distribution-only systems.

Rural Electric Cooperatives

G&T Cooperatives

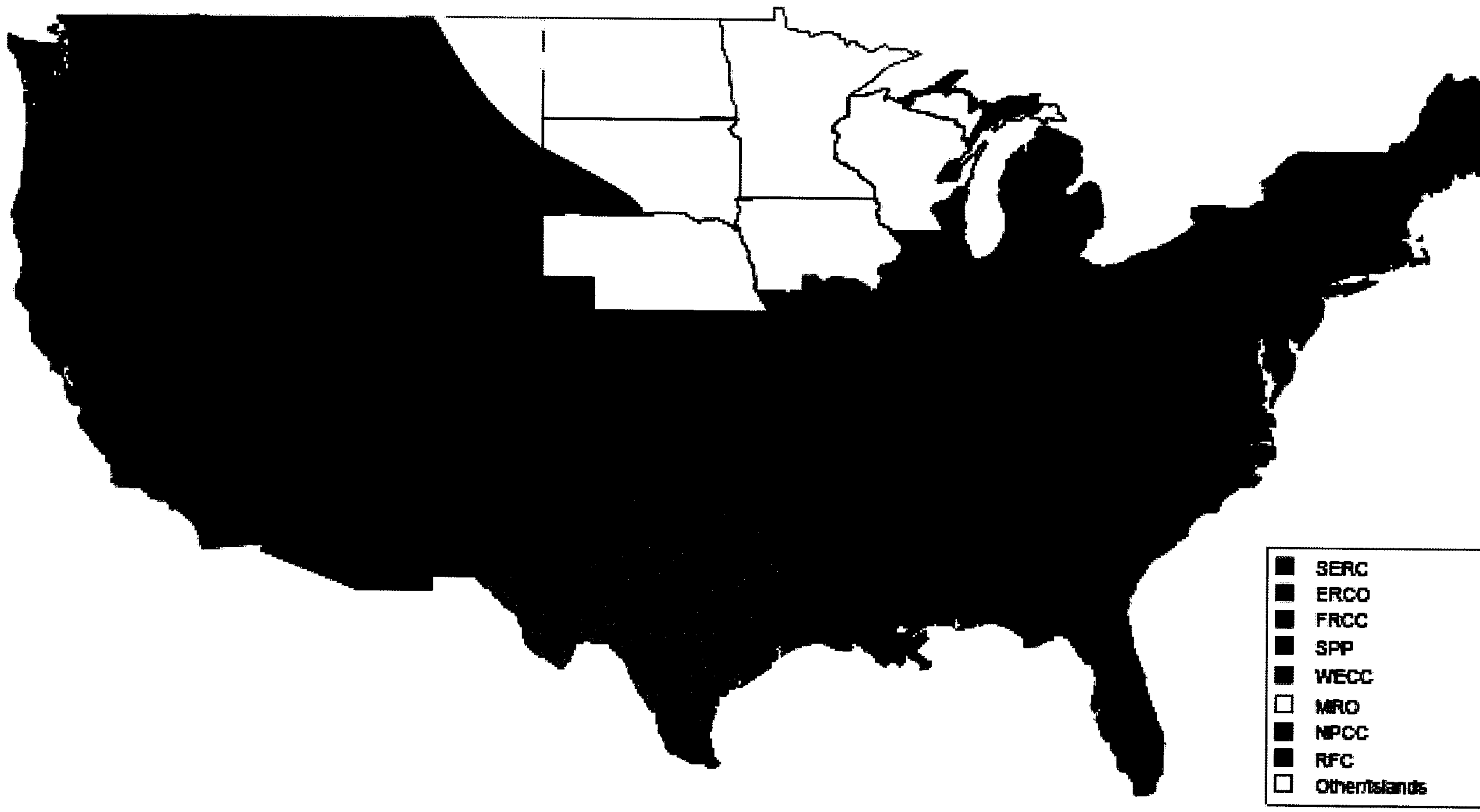
G&T cooperatives typically provide wholesale power supply and transmission services to their member distribution cooperatives. G&T revenues are primarily derived from sales and services provided to members, but may also include payments from third-party market participants. G&T cooperatives are generally organized as not-for-profit entities that operate for the benefit of their owner members.

Metrics for G&T cooperatives are included in the calculation of medians for wholesale systems, and are also presented separately in this report.

Distribution Cooperatives

Distribution cooperatives sell power to their owner members (or end-user customers), and are included in the retail category.

Fitch-Designated Regions



SERC – Southeastern Electric Reliability Council. ERCOT – Electric Reliability Council of Texas. FRCC – Florida Reliability Coordinating Council. SPP – Southwest Power Pool. WECC – Western Electricity Coordinating Council. MRO – Midwest Reliability Council. NPCC – Northeast Power Coordinating Council. RFC – Reliability First Corporation. Other Islands – Alaska, Guam, Puerto Rico, and U.S. Virgin Islands. Note: NERC regions are shown within U.S. geographical boundaries only.
Source: Fitch and NERC (North American Reliability Corporation).

Public Power Operating Profiles

Issuer	Rating	Type	Self-Regulated	Primary Fuel Exposure	Total Debt 2011 ($000)	Total Customers/ Members 2011	Total Energy Sales Growth 2011 (%)
Reliability First Corporation (RFC)							
Buckeye Power Inc., OH	**A**	**G&T-Coop**	**Yes**	**Coal**	**1,497,538**	**25**	**3.4**
Delaware Municipal Electric Corporation	A–	Wholesale	Yes	Gas	66,038	9	(1 2)
Dover Electric Revenue Fund, DE	**A+**	**Retail**	**Yes**	**Gas**	**30,084**	**23,735**	**0.0**
Indiana Municipal Power Agency	A+	Wholesale	Yes	Coal	1,306,366	55	(1.0)
Old Dominion Electric Cooperative, VA	**A**	**G&T-Coop**	**No (FERC)**	**Coal/Nuclear**	**794,420**	**11**	**4.1**
Electric Reliability Council of Texas (ERCOT)							
Austin Energy, TX	**AA–**	**Retail**	**Yes**	**Coal/Nuclear**	**1,410,888**	**417,885**	**6.7**
Boerne Utility System, TX	A	Retail	Yes	Coal	47,120	4,807	4.3
Brazos Electric Power Cooperative, TX	**A**	**G&T-Coop**	**Yes**	**Gas**	**2,846,125**	**16**	**6.6**
Brownsville Public Utilities Board, TX	A	Retail	Yes	Gas	349,777	45,500	2.5
Bryan Utilities City Electric System, TX	**A+**	**Retail**	**Yes**	**Coal/Gas**	**165,150**	**32,583**	**15.5**
Bryan Utilities Rural Electric System, TX	A+	Retail	Yes	Coal/Gas	8,945	16,033	6.2
Floresville Electric Light & Power System, TX	**AA–**	**Retail**	**Yes**	**Coal/Nuclear**	**24,869**	**13,992**	**7.5**
Garland Electric Fund, TX	AA–	Retail	Yes	Coal	296,396	68,043	1.7
Georgetown Utility Funds, TX	**AA–**	**Retail**	**Yes**	**Coal/Gas**	**64,840**	**21,230**	**5.6**
Golden Spread Electric Cooperative, TX	A	G&T-Coop	No (FERC)	Gas	512,746	16	17.8
Granbury Municipal Utilities, TX	**A+**	**Retail**	**Yes**	**Nuclear**	**15,000**	**3,198**	**4.2**
Guadalupe Valley Electric Cooperative Inc., TX	AA–	Retail	Yes	Coal	155,741	68,926	5.8
Kerrville Public Utility Board, TX	**AA–**	**Retail**	**Yes**	**Coal**	**6,741**	**21,812**	**(0.3)**
Lower Colorado River Authority — Consolidated	A+	Wholesale	No	Coal	3,219,184	43	(1.5)
New Braunfels Utilities, TX	**AA**	**Retail**	**Yes**	**Coal**	**35,085**	**75,178**	**7.8**
Pedernales Electric Cooperative Inc., TX	AA–	Retail	Yes	Coal	732,089	242,331	(1.7)
Sam Rayburn Municipal Power Agency, TX	**BBB+**	**Wholesale**	**Yes**	**Coal**	**144,787**	**3**	**20.2**
San Antonio City Public Service, TX (CPS Energy)	AA+	Retail	Yes	Coal	4,883,654	728,307	13.2
San Miguel Electric Cooperative, TX	**A–**	**G&T-Coop**	**Yes**	**Coal**	**201,198**	**2**	**3.3**
Seguin Utility Fund, TX	A+	Retail	Yes	Coal	22,764	8,210	4.1
South Texas Electric Cooperative Inc.	**A–**	**G&T-Coop**	**Yes**	**Coal**	**685,786**	**8**	**11.5**
Texas Municipal Power Agency	A+	Wholesale	Yes	Coal	853,214	4	(4.2)
Florida Reliability Coordinating Council (FRCC)							
Florida Municipal Power Agency — All-Requirements Project	**A+**	**Wholesale**	**Yes**	**Gas**	**1,318,932**	**14**	**(6.5)**
Fort Pierce Utilities Authority, FL	A+	Retail	Yes	Gas	103,407	27,752	(2.9)
Gainesville Regional Utilities, FL	**AA**	**Retail**	**Yes**	**Coal**	**1,025,180**	**92,272**	**(3.5)**
Jacksonville Beach Combined Utility Funds, FL	AA–	Retail	Yes	Gas	34,470	33,147	(2.1)
JEA — Electric System and Bulk Power Supply System, FL	**AA–**	**Retail**	**Yes**	**Coal**	**3,220,484**	**419,703**	**(6.4)**
Kissimmee Utility Authority, FL	AA–	Retail	Yes	Gas	192,420	62,873	(0.9)
Lakeland Electric Utility, FL	**AA–**	**Retail**	**Yes**	**Gas**	**511,302**	**121,377**	**(3.4)**
Leesburg Electric System, FL	A+	Retail	Yes	Gas	37,970	22,516	(4.7)
Ocala, FL Combined Utility Funds	**AA–**	**Retail**	**Yes**	**Gas**	**158,671**	**50,329**	**(0.7)**
Orlando Utilities Commission, FL	AA	Retail	Yes	Coal	1,675,790	188,430	(1.1)
Reedy Creek Improvement District — Utility Fund, FL	**A**	**Retail**	**Yes**	**Gas**	**303,663**	**1,306**	**(1.5)**
Tallahassee Electric Fund, FL	AA–	Retail	Yes	Gas	618,363	114,094	0.4
Vero Beach Electric System, FL	**AA–**	**Retail**	**Yes**	**Gas**	**53,000**	**33,981**	**(3.1)**
Winter Park Electric Services Fund, FL	AA–	Retail	Yes	Coal/Gas	71,506	13,864	(3.0)

N A. – Not available. G&T – Generation and transmission. FERC – Federal Energy Regulatory Commission. Note: Total energy sales include retail and wholesale sales *Continued on next page.*
Source: Fitch Ratings.

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Public Power Operating Profiles (Continued)

Issuer	Rating	Type	Self-Regulated	Primary Fuel Exposure	Total Debt 2011 ($000)	Total Customers/ Members 2011	Total Energy Sales Growth 2011 (%)
Midwest Reliability Organization (MRO)							
Basin Electric Power Cooperative, ND	**A+**	**G&T-Coop**	**Yes**	**Coal**	**3,938,000**	**135**	**4.3**
Batavia Electric Fund, IL[a]	A–	Retail	Yes	Coal	25,985	10,813	8.1
Big Rivers Electric Corp., KY	**BBB–**	**G&T-Coop**	**No**	**Coal**	**786,399**	**3**	**10.7**
Central Iowa Power Cooperative	A	G&T-Coop	Yes	Coal	371,098	13	0.3
East Kentucky Power Cooperative	**BBB**	**G&T-Coop**	**No**	**Coal**	**2,714,404**	**16**	**(4.6)**
Great River Energy, MN	A–	G&T-Coop	Yes	Coal	2,789,370	28	(0.4)
Illinois Municipal Electric Agency	**A+**	**Wholesale**	**Yes**	**Coal**	**1,252,795**	**32**	**7.3**
Municipal Energy Agency of Nebraska	A	Wholesale	Yes	Coal	172,575	68	3.6
Rochester Public Utilities, MN	**AA–**	**Retail**	**Yes**	**Coal**	**86,887**	**49,407**	**(2.0)**
Western Minnesota Municipal Power Agency	AA–	Wholesale	Yes	Coal	283,594	61	6.1
WPPI Energy (Wisconsin Public Power Inc.)	**A+**	**Wholesale**	**Yes**	**Coal**	**397,501**	**51**	**0.5**
Northeast Power Coordinating Council (NPCC)							
Connecticut Municipal Electric Energy Cooperative[a]	**A+**	**Wholesale**	**Yes**	**Gas**	**84,383**	**6**	**(0.1)**
Hydro-Quebec	AA–	Retail	Yes	Hydro	42,102,000	4,060,195	2.1
Long Island Power Authority, NY	**A**	**Retail**	**Yes**	**Gas**	**9,888,611**	**1,100,000**	**(1.0)**
Massachusetts Municipal Wholesale Electric Company — Consolidated	A+	Wholesale	Yes	Nuclear	371,594	28	(22.3)
New York Power Authority	**AA**	**Wholesale**	**Yes**	**Hydro**	**3,038,000**	**800**	**8.4**
Vermont Electric Cooperative, VT	BBB+	Retail	No	Purchased	60,616	37,792	0.5
Southern Electric Reliability Council (SERC)							
Arkansas Electric Cooperative Corporation	**A+**	**G&T-Coop**	**Yes**	**Coal**	**774,177**	**490,000**	**5.5**
Associated Electric Cooperative Inc., MO	AA	G&T-Coop	Yes	Coal	1,969,911	51	0 4
Bristol Utilities Authority, VA	**A–**	**Retail**	**Yes**	**Coal**	**43,572**	**16,375**	**5.2**
Chattanooga Electric Power Board — Electric System, TN	AA	Retail	Yes	Coal	290,602	171,975	3 8
City of Greenville (NC)	**A+**	**Retail**	**Yes**	**Coal/Nuclear**	**115,166**	**148,429**	**3.6**
Concord Utility Funds, NC	AA	Retail	Yes	Coal	105,615	27,447	2 2
Greer Commission of Public Works, SC	**A+**	**Retail**	**Yes**	**Nuclear**	**90,622**	**17,815**	**0.2**
Memphis Light, Gas & Water Division — Electric Division, TN	AA+	Retail	Yes	Coal	788,788	417,687	(3.1)
Municipal Electric Authority of Georgia	**A+**	**Wholesale**	**Yes**	**Coal/Nuclear**	**6,261,536**	**49**	**(2.6)**
Municipal Gas Authority of Georgia	A+	Wholesale	Yes	Gas	286,841	78	0.0
Nashville Electric Service, TN	**AA+**	**Retail**	**Yes**	**Coal**	**482,141**	**363,305**	**3.0**
North Carolina Eastern Municipal Power Agency	A–	Wholesale	Yes	Nuclear/Coal	2,281,318	32	(4.4)
North Carolina Electric Membership Corporation	**A–**	**G&T-Coop**	**Yes**	**Nuclear**	**1,145,904**	**25**	**(12.8)**
North Carolina Municipal Power Agency No 1	A	Wholesale	Yes	Nuclear	1,588,755	19	(3.0)
Oglethorpe Power Corporation, GA	**A**	**G&T-Coop**	**Yes**	**Coal**	**6,475,665**	**39**	**(13.6)**
Paducah Power System, KY	A–	Retail	Yes	Coal/Gas	170,178	20,500	3.1
Piedmont Municipal Power Agency, SC	**A–**	**Wholesale**	**Yes**	**Nuclear**	**1,094,232**	**10**	**(3.4)**
PowerSouth Energy Cooperative and Subsidiaries, AL	A–	G&T-Coop	Yes	Coal	1,413,386	20	(5.5)
South Carolina Public Service Authority (Santee Cooper)	**AA–**	**Wholesale**	**Yes**	**Coal**	**5,456,333**	**164,647**	**(2.2)**
South Mississippi Electric Power Association	A–	G&T-Coop	Yes	Coal/Gas	959,830	11	(3 6)
Tennessee Valley Authority	**AAA**	**Wholesale**	**Yes**	**Coal**	**24,431,000**	**155**	**(3.4)**

[a]Fiscal 2011 figures are unaudited. N.A. – Not available G&T – Generation and transmission. Note· Total energy sales include retail and wholesale sales. *Continued on next page.*
Source. Fitch Ratings

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Public Power Operating Profiles (Continued)

Issuer	Rating	Type	Self-Regulated	Primary Fuel Exposure	Total Debt 2011 ($000)	Total Customers/ Members 2011	Total Energy Sales Growth 2011 (%)
Southwest Power Pool (SPP)							
Grand River Dam Authority, OK	**A**	**Wholesale**	**Yes**	**Coal**	**998,606**	**24**	**2.8**
Kansas City Board of Public Utilities, KS	A+	Retail	Yes	Coal	448,348	63,376	(4.8)
Lincoln Electric System, NE	**AA**	**Retail**	**Yes**	**Coal**	**676,392**	**129,163**	**2.3**
Lubbock Power & Light Fund, TX	A+	Retail	Yes	Coal	143,327	99,660	49.7
Nebraska Public Power District	**A+**	**Wholesale**	**Yes**	**Coal**	**2,218,375**	**89,107**	**5.7**
Springfield Public Utility, MO	AA	Retail	Yes	Coal	761,160	109,469	15.8
Western Farmers Electric Cooperative, OK	**A–**	**G&T-Coop**	**Yes**	**Coal**	**865,449**	**24**	**5.6**
Western Electric Coordinating Council (WECC)							
Alameda Municipal Power — Electric Services, CA	**A+**	**Retail**	**Yes**	**Geo/Hydro**	**33,325**	**34,281**	**(0.1)**
Anaheim Electric Utilities Fund, CA	AA–	Retail	Yes	Coal	725,191	114,662	(11.0)
Benton CO Public Utility District No. 1, WA	**A+**	**Retail**	**Yes**	**Hydro**	**59,638**	**48,197**	**3.5**
Boise Kuna Irr Dist ADA and Canyon Counties (ID)	A–	Retail	Yes	Hydro	20,950	4,589	17.7
Bonneville Power Administration, WA	**AA**	**Wholesale**	**Yes**	**Hydro**	**13,565,534**	**146**	**22.2**
Bountiful Light and Power, UT	AA–	Retail	Yes	Coal/Hydro	15,280	16,527	(1.3)
Chelan CO Public Utility District No. 1 — Consolidated, WA	**AA+**	**Retail**	**Yes**	**Hydro**	**958,515**	**48,251**	**36.3**
Clark County Public Utility District — Electric System, WA	A+	Retail	Yes	Hydro	226,385	184,488	2.0
Colorado Springs Utilities, CO	**AA**	**Retail**	**Yes**	**Coal**	**2,252,488**	**212,966**	**(2.0)**
Cowlitz County Public Utility District No. 1 — Electric, WA	A	Retail	Yes	Hydro	256,825	48,194	6 7
Eagle Mountain Electric and Gas Funds (UT)	**A**	**Retail**	**Yes**	**Coal/Gas**	**19,618**	**11,064**	**6.8**
Eugene Electric Board, OR	AA–	Retail	Yes	Hydro	286,607	87,400	20.5
Farmington Utility Funds, NM	**A+**	**Retail**	**Yes**	**Gas**	**23,012**	**43,730**	**0.7**
Gallup Joint Utilities Fund, NM	AA–	Retail	Yes	Coal	23,400	10,507	(0.8)
Glendale Electric Funds, CA	**A+**	**Retail**	**Yes**	**Coal**	**119,619**	**84,962**	**50.2**
Grant CO Public Utility District No. 2 — Consolidated, WA	AA	Retail	Yes	Hydro	160,405	46,351	4 1
Grays Harbor County Public Utility District No. 1, WA	**A**	**Retail**	**Yes**	**Hydro**	**122,245**	**41,688**	**13.1**
Heber Light & Power Company, UT	AA–	Retail	Yes	Hydro/Coal/Gas	10,428	9,867	5.7
Imperial Irrigation District – Energy, CA[a]	**A+**	**Retail**	**Yes**	**Gas**	**376,913**	**146,646**	**(2.9)**
Klickitat CO Public Utility District No. 1, WA[a]	A–	Retail	Yes	Hydro	143,412	12,157	N.A.
Lodi Electric Fund, CA	**A–**	**Retail**	**Yes**	**Gas**	**77,656**	**25,384**	**(3.0)**
Los Alamos County Joint Utility System Fund, NM	A–	Retail	Yes	Coal/Hydro	67,936	29,644	3.4
Los Angeles Department of Water & Power — Power System, CA	**AA–**	**Retail**	**Yes**	**Coal**	**6,676,699**	**1,461,000**	**(5.6)**
Modesto Irrigation District, CA	A	Retail	Yes	Gas	836,645	113,650	1.3
Overton Power District No. 5, NV	**BBB+**	**Retail**	**Yes**	**Hydro/Gas**	**56,796**	**13,702**	**(7.1)**
Pasadena Water & Power, CA	AA	Retail	Yes	Coal	153,165	63,950	(1 5)
Pend Oreille County Public Utility District No. 1 — Combined, WA	**A–**	**Retail**	**Yes**	**Hydro**	**32,105**	**8,809**	**5.0**
Platte River Power Authority, CO	AA	Wholesale	Yes	Coal	273,167	148,102	0 1
Redding Electric Utility Fund, CA	**A**	**Retail**	**Yes**	**Coal/Gas**	**168,897**	**43,144**	**(0.3)**
Riverside Electric Utility, CA	AA–	Retail	Yes	Coal	615,553	106,855	(3 4)
Roseville Electric Fund, CA	**A+**	**Retail**	**Yes**	**Gas**	**260,127**	**53,467**	**(3.5)**
Sacramento Municipal Utility District, CA	A+	Retail	Yes	Gas	2,906,825	599,826	6 2
Silicon Valley Power, CA	**A+**	**Retail**	**Yes**	**Gas**	**216,460**	**52,495**	**2.1**
Snohomish CO Public Utility District No 1, WA	AA–	Retail	Yes	Hydro	381,655	322,228	11 9

[a]Fiscal 2010 audit. N.A. – Not available. G&T – Generation and transmission. Note: Total energy sales include retail and wholesale sales. *Continued on next page.*
Source: Fitch Ratings.

Public Power Operating Profiles (Continued)

Issuer	Rating	Type	Self-Regulated	Primary Fuel Exposure	Total Debt 2011 ($000)	Total Customers/ Members 2011	Total Energy Sales Growth 2011 (%)
Western Electric Coordinating Council (WECC) (Continued)							
Tacoma Power, WA	**AA–**	**Retail**	**Yes**	Hydro	**582,795**	**169,112**	10.8
Tri-State Generation & Transmission Association Inc.	A	G&T-Coop	Yes	Coal	2,897,207	44	2 8
Turlock Irrigation District, CA	**A+**	**Retail**	**Yes**	**Gas/Hydro**	**1,228,361**	**99,932**	**1.8**
Other/Islands							
Anchorage Electric Utility Fund, AK	**A+**	**Retail**	**No**	**Gas**	**240,320**	**30,599**	**5.4**
Chugach Electric Association Inc., AK	A–	Retail	No	Gas	604,450	66,941	(0.1)
Guam Power Authority	**BBB–**	**Retail**	**No**	**Oil**	**668,171**	**48,047**	**(1.2)**
Puerto Rico Electric Power Authority	BBB+	Retail	Yes	Oil	8,088,988	1,475,126	(3.8)
Virgin Islands Electric System	**BB**	**Retail**	**No**	**Oil**	**271,739**	**28,571**	**(2.2)**

N.A. –Not available. G&T – Generation and transmission Note: Total energy sales include retail and wholesale sales.
Source Fitch Ratings

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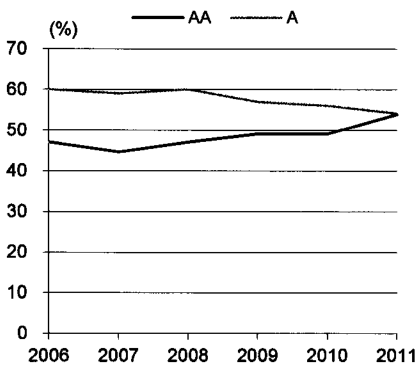
EXHIBIT DMW-2, Page 10 of 21

FitchRatings Public Finance

Retail Electric

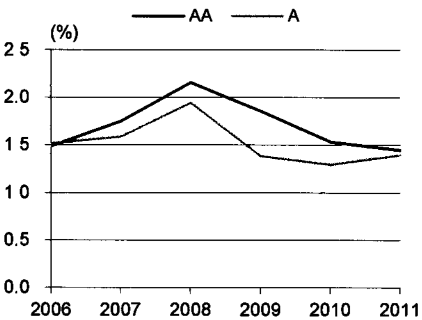
Below, the trends of 'AA' and 'A' medians for retail electric systems are displayed for eight of the financial metrics used in Fitch's analysis.

Equity/Capitalization
Indicates leverage level



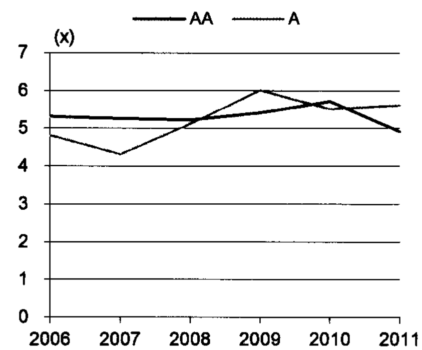
Source Fitch

Capex/Depreciation and Amortization
Indicates amount of capital spending relative to asset depreciation.



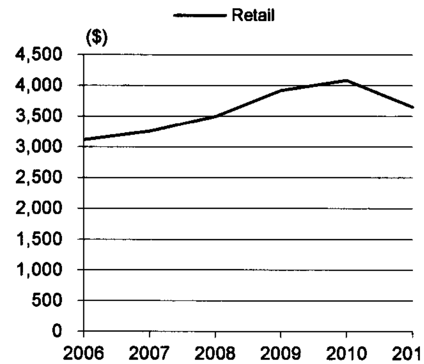
Source Fitch.

Debt/FADS
Indicates size of debt compared to the margin available for debt service.



Source: Fitch.

Debt/Customer
Indicates debt burden to ratepayers.



Source: Fitch.

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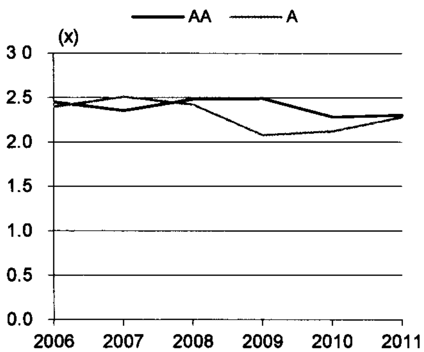
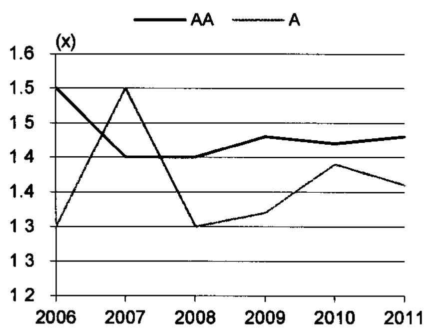
Debt Service Coverage
Indicates the margin available to meet current debt service requirements.



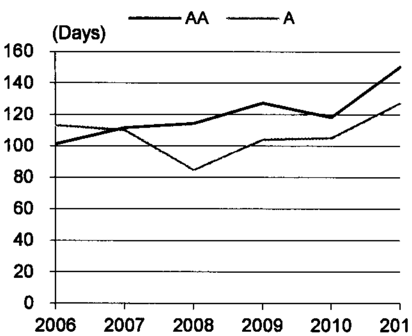
Source: Fitch.

Coverage of Full Obligations
Indicates the margin available to meet current debt service requirements and fixed charges.



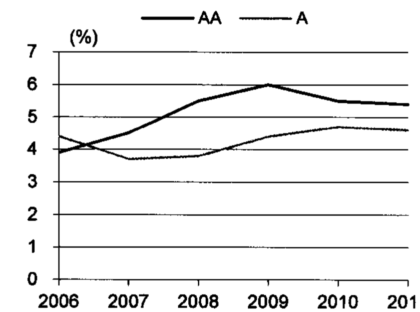
Source: Fitch

Days Cash on Hand
Indicates financial flexibility, specifically liquidity relative to expenses.



Source: Fitch

Transfer Payments/Operating Revenues
Indicates percentages of utility revenues that support GF operations.



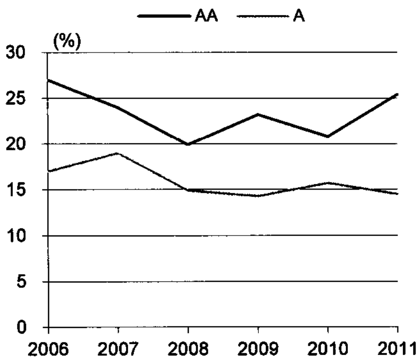
Source Fitch

FADS – Funds available for debt service. Note: Please see pages 17 and 18 for "Glossary of Terms" and "Ratio Definitions."

Wholesale Electric

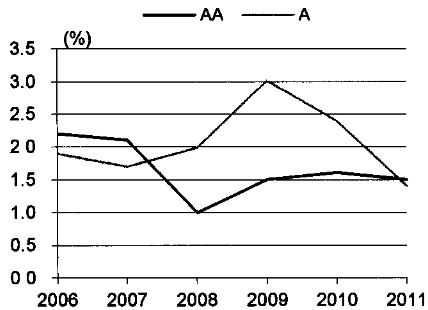
Below, the trends of 'AA' and 'A' medians for wholesale electric systems are displayed for six of the financial metrics used in Fitch's analysis.

Equity/Capitalization
Indicates leverage level



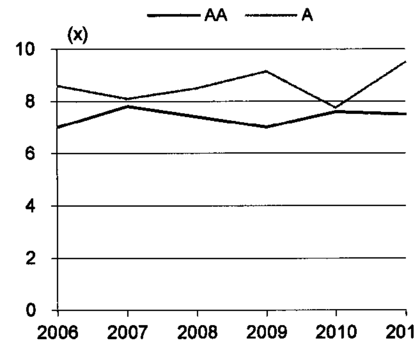
Source: Fitch

Capex/Depreciation and Amortization
Indicates amount of capital spending relative to asset depreciation.



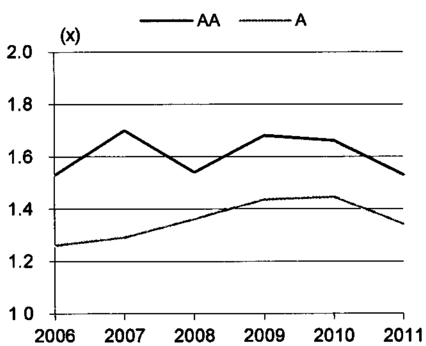
Source Fitch.

Debt/FADS
Indicates size of debt compared to the margin available for debt service.



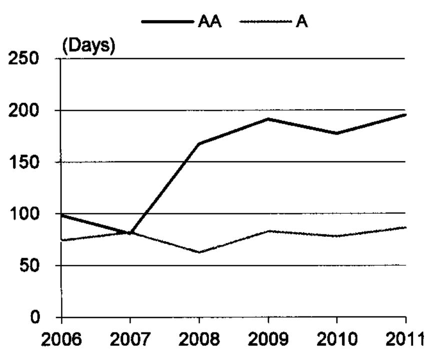
Source· Fitch.

Debt Service Coverage
Indicates the margin available to meet current debt service requirements.



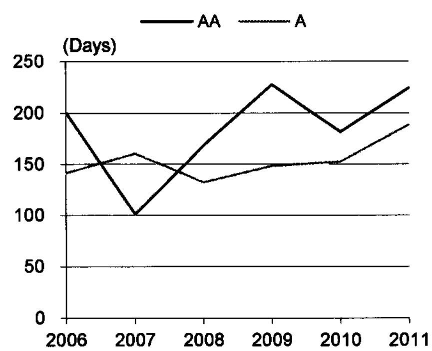
Source: Fitch.

Days Cash on Hand
Indicates financial flexibility, specifically liquidity relative to expenses.



Source Fitch.

Days Liquidity on Hand
Indicates financial flexibility, specifically liquidity relative to expenses.



Source: Fitch.

FADS – Funds available for debt service. Note: Please see pages 17 and 18 for "Glossary of Terms" and "Ratio Definitions."

Retail Systems — 2011

Retail	Region	Total Revenues ($000)	Debt Service Coverage (x)	Coverage of Full Obligations (x)	Debt/FADS (x)	Days Cash on Hand	Days Liquidity on Hand	Transfer Payment as % of Operating Revs	Capex/ Depreciation (%)	Equity/ Capitalization (%)	Dept Per Customer ($)
'AA+' Rated Senior Debt											
Chelan CO Public Utility District No. 1 — Consolidated, WA	**WECC**	**238,543**	**1.55**	**1.62**	**8.2**	**527**	**527**	**3.1**	**91.7**	**28.8**	**19,871**
Memphis Light, Gas and Water Division — Electric Division, TN	SERC	1,319,030	1.77	1.14	3.4	55	55	3.0	167.3	58.6	1,888
Nashville Electric Service, TN	**SERC**	**1,199,609**	**3.01**	**1.28**	**3.6**	**54**	**63**	**2.3**	**120.8**	**52.4**	**1,327**
San Antonio City Public Service, TX (CPS Energy)	ERCOT	2,068,686	2.33	1.36	5.8	243	243	13.4	143.6	39.4	6,705
Median		**1,259,320**	**2.05**	**1.32**	**4.7**	**149**	**153**	**3.1**	**132.2**	**48.9**	**4,297**
'AA' Rated Senior Debt											
Chattanooga Electric Power Board — Electric System, TN	**SERC**	**549,533**	**2.08**	**1.04**	**12.9**	**72**	**82**	**2.5**	**455.6**	**47.5**	**1,690**
Colorado Springs Utilities, CO	WECC	830,522	1.88	1.58	11.0	56	138	3.8	178.4	37.2	10,577
Concord Utility Funds, NC	**SERC**	**108,461**	**2.16**	**1.45**	**4.3**	**301**	**301**	**0.5**	**56.9**	**67.0**	**3,848**
Gainesville Regional Utilities, FL	FRCC	368,471	1.92	1.47	6.9	164	242	9.6	244.2	32.0	11,110
Grant CO Public Utility District No. 2 — Consolidated, WA	**WECC**	**247,183**	**3.71**	**3.71**	**2.5**	**247**	**247**	**4.9**	**408.2**	**77.0**	**3,461**
Lincoln Electric System, NE	SPP	269,043	2.10	1.57	7.0	171	216	5.0	102.0	29.1	5,237
New Braunfels Utilities, TX	**ERCOT**	**116,615**	**5.88**	**1.51**	**1.5**	**91**	**91**	**4.9**	**154.3**	**88.1**	**467**
Orlando Utilities Commission, FL	FRCC	876,009	1.93	1.55	6.2	354	354	8.8	87.6	38.1	8,893
Pasadena Water and Power, CA	**WECC**	**186,993**	**4.44**	**1.65**	**3.1**	**450**	**450**	**7.2**	**138.3**	**77.1**	**2,395**
Springfield Public Utility, MO	SPP	418,354	1.75	1.44	9.1	119	119	3.2	165.0	54.4	6,953
Median		**318,757**	**2.09**	**1.53**	**6.6**	**167**	**229**	**4.9**	**159.7**	**51.0**	**4,542**
'AA–' Rated Senior Debt											
Anaheim Electric Utilities Fund, CA	**WECC**	**381,496**	**1.74**	**1.41**	**8.5**	**71**	**71**	**4.2**	**146.5**	**31.4**	**8,325**
Austin Energy, TX	ERCOT	1,249,139	1.87	1.27	4.3	83	98	8.3	129.2	53.7	3,377
Bountiful Light and Power, UT	**WECC**	**25,916**	**58.55**	**2.10**	**2.1**	**226**	**226**	**8.8**	**678.4**	**73.8**	**925**
Eugene Electric Board, OR	WECC	254,689	2.58	1.41	4.7	103	103	5.3	128.1	53.2	3,279
Floresville Electric Light & Power System, TX	**ERCOT**	**29,895**	**2.76**	**1.23**	**6.1**	**93**	**93**	**2.7**	**159.4**	**56.6**	**1,763**
Gallup Joint Utilities Fund, NM	WECC	90,950	3.60	2.85	2.5	378	378	6.3	115.8	74.4	2,227
Garland Electric Fund, TX	**ERCOT**	**223,505**	**4.13**	**2.24**	**3.2**	**549**	**549**	**9.1**	**114.2**	**54.1**	**4,356**
Georgetown Utility Funds, TX	ERCOT	85,678	3.21	1.38	3.1	93	93	7.9	172.2	77.0	3,040
Guadalupe Valley Electric Cooperative Inc., TX	**ERCOT**	**185,574**	**4.11**	**1.57**	**4.4**	**60**	**338**	**0.0**	**219.2**	**55.7**	**2,260**
Heber Light & Power Company, UT	WECC	12,561	2.90	1.65	4.2	111	111	1.6	233.3	67.7	1,057
Hydro-Quebec	**NPCC**	**12,392,000**	**1.75**	**1.31**	**5.4**	**179**	**335**	**15.8**	**133.7**	**30.9**	**10,369**
Jacksonville Beach Combined Utility Funds, FL	FRCC	96,514	3.51	1.30	2.1	215	215	4.7	155.8	82.9	1,040
JEA – Electric System and Bulk Power Supply System, FL	**FRCC**	**1,487,778**	**2.66**	**1.76**	**6.5**	**107**	**156**	**10.2**	**106.5**	**16.2**	**7,673**
Kerrville Public Utility Board, TX	ERCOT	46,961	1.69	1.03	1.5	76	76	3.1	163.2	85.3	309
Kissimmee Utility Authority, FL	**FRCC**	**174,279**	**0.84**	**0.93**	**8.8**	**193**	**233**	**4.9**	**135.0**	**47.4**	**3,060**
Lakeland Electric Utility, FL	FRCC	340,882	2.27	1.74	4.8	190	190	7.3	144.0	38.3	4,213
Los Angeles Department of Water & Power – Power System, CA	**WECC**	**3,125,957**	**2.05**	**1.24**	**8.2**	**167**	**167**	**8.3**	**207.4**	**42.5**	**4,570**
Ocala, FL Combined Utility Funds	FRCC	166,336	2.49	1.13	5.8	224	224	6.4	81.4	64.5	3,113
Pedernales Electric Cooperative Inc., TX	**ERCOT**	**587,802.**	**2.40**	**1.51**	**5.1**	**63**	**145**	**1.0**	**177.5**	**35.4**	**3,021**
Riverside Electric Utility, CA	WECC	312,682	2.02	1.20	6.3	273	273	10.6	638.7	42.2	5,761
Rochester Public Utilities, MN	**MRO**	**142,413**	**3.72**	**1.37**	**3.0**	**135**	**135**	**5.9**	**85.9**	**63.7**	**1,759**
Snohomish CO Public Utility District No. 1, WA	WECC	586,087	3.14	1.46	4.8	280	280	5.4	151.7	75.1	1,184
Tacoma Power, WA	**WECC**	**364,325**	**1.97**	**1.34**	**5.4**	**348**	**348**	**11.2**	**107.1**	**56.8**	**3,446**
Tallahassee Electric Fund, FL	FRCC	314,856	1.61	0.97	8.4	120	120	9.4	61.0	38.5	5,420
Vero Beach Electric System, FL	**FRCC**	**84,262**	**1.93**	**1.03**	**4.1**	**93**	**93**	**6.6**	**43.8**	**67.7**	**1,562**
Winter Park Electric Services Fund, FL	FRCC	53,033	3.48	2.78	5.0	—	75	5.4	62.4	10.6	5,158
Median		**204,539**	**2.84**	**1.38**	**4.8**	**128**	**162**	**6.4**	**139.8**	**54.9**	**3,087**

FADS – Funds available for debt service *Continued on next page*
Source Fitch Ratings.

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Retail Systems — 2011 (Continued)

Retail	Region	Total Revenues ($000)	Debt Service Coverage (x)	Coverage of Full Obligations (x)	Debt/FADS (x)	Days Cash on Hand	Days Liquidity on Hand	Transfer Payment as % of Operating Revs	Capex/ Depreciation (%)	Equity/ Capitalization (%)	Dept Per Customer ($)
'A+' Rated Senior Debt											
Alameda Municipal Power — Electric Services, CA	**WECC**	**50,770**	**6.44**	**1.68**	**3.1**	**272**	**272**	**10.8**	**49.6**	**62.6**	**972**
Anchorage Electric Utility Fund, AK	Other	134,417	1.69	1 33	4 3	128	128	8.9	324.6	49.9	7,854
Benton CO Public Utility District No. 1, WA	**WECC**	**134,441**	**4.28**	**1.51**	**2.9**	**136**	**170**	**6.1**	**112.3**	**66.5**	**1,237**
Bryan Utilities City Electric System, TX	ERCOT	153,517	1.52	1 01	5.8	88	88	5.9	276.3	33.7	5,069
Bryan Utilities Rural Electric System, TX	**ERCOT**	**31,851**	**10.05**	**1.46**	**2.1**	**60**	**60**	**0.0**	**215.5**	**83.0**	**558**
City of Greenville (NC)	SERC	271,373	2 35	1.23	3.3	102	102	2.0	96.9	73.0	776
Clark County Public Utility District — Electric System, WA	**WECC**	**356,779**	**2.06**	**1.36**	**3.0**	**47**	**71**	**5.7**	**65.6**	**46.1**	**1,227**
Dover Electric Revenue Fund, DE	RFC	101,903	4 79	1.25	1.6	73	73	10.6	70.9	78.4	1,265
Farmington Utility Funds, NM	**WECC**	**110,513**	**4.68**	**1.96**	**0.6**	**350**	**350**	**9.1**	**125.3**	**94.4**	**526**
Fort Pierce Utilities Authority, FL	FRCC	98,084	2 43	1.43	4.0	151	151	5.2	49.0	63.5	3,726
Glendale Electric Funds, CA	**WECC**	**186,174**	**3.58**	**1.17**	**4.2**	**152**	**152**	**10.3**	**268.9**	**74.7**	**1,408**
Granbury Municipal Utilities, TX	ERCOT	18,706	2.55	1.46	3.8	37	37	5.9	17.7	62.4	4,690
Greer Commission of Public Works, SC	**SERC**	**70,632**	**2.08**	**1.41**	**6.7**	**125**	**125**	**1.5**	**55.0**	**61.0**	**5,087**
Imperial Irrigation District — Energy, CA[a]	WECC	436,746	4.29	1.52	6.1	211	211	0.0	346.3	70.7	2,570
Kansas City Board of Public Utilities, KS	**SPP**	**271,763**	**2.21**	**1.37**	**5.5**	**50**	**50**	**10.4**	**180.1**	**47.7**	**7,074**
Leesburg Electric System, FL	FRCC	60,621	4.45	1 24	3.3	148	148	9.5	140.2	63.0	1,686
Lubbock Power & Light Fund, TX	**SPP**	**201,459**	**2.07**	**1.13**	**3.7**	**158**	**158**	**6.2**	**488.3**	**54.3**	**1,438**
Roseville Electric Fund, CA	WECC	163,235	2.35	1.22	5.7	93	93	9 2	38.3	48.8	4,866
Sacramento Municipal Utility District, CA	**WECC**	**1,360,008**	**1.83**	**1.63**	**6.8**	**129**	**129**	**0.0**	**222.1**	**17.5**	**4,846**
Seguin Utility Fund, TX	ERCOT	43,211	5.41	4.87	2.5	252	252	2.1	165.3	72.5	2,773
Silicon Valley Power, CA	**WECC**	**277,769**	**2.73**	**1.41**	**5.7**	**261**	**261**	**5.6**	**159.9**	**73.5**	**4,123**
Turlock Irrigation District, CA	WECC	295,940	1 29	1.29	15.9	237	237	0.0	222.2	20.4	12,292
Median		**143,979**	**2.49**	**1.39**	**3.9**	**134**	**139**	**5.9**	**180.0**	**62.8**	**2,671**
'A' Rated Senior Debt											
Boerne Utility System, TX	**ERCOT**	**21,360**	**1.87**	**1.81**	**10.4**	**161**	**161**	**7.4**	**341.6**	**47.8**	**9,802**
Brownsville Public Utilities Board, TX	ERCOT	168,083	2.40	2 10	5.8	164	265	4.5	124.2	52.3	7,687
Cowlitz County Public Utility District No. 1 — Electric, WA	**WECC**	**228,882**	**1.24**	**1.07**	**9.8**	**75**	**75**	**5.0**	**159.6**	**49.6**	**5,329**
Eagle Mountain Electric and Gas Funds (UT)	WECC	11,551	1.88	1 12	6.7	252	252	0.0	14.1	37.5	1,773
Grays Harbor County Public Utility District No. 1, WA	**WECC**	**110,408**	**1.82**	**1.24**	**7.0**	**84**	**114**	**5.2**	**138.7**	**53.9**	**2,932**
Long Island Power Authority, NY	NPCC	3,684,596	1 21	0.94	19.0	50	61	8.2	99.0	3.9	8,990
Modesto Irrigation District, CA	**WECC**	**370,969**	**1.41**	**1.24**	**8.9**	**170**	**170**	**0.0**	**148.9**	**5.6**	**7,362**
Redding Electric Utility Fund, CA	WECC	168,305	1 57	1.12	8.1	77	77	3.5	113.7	38.8	3,915
Reedy Creek Improvement District — Utility Fund, FL	**FRCC**	**193,300**	**1.17**	**1.12**	**6.8**	**52**	**52**	**0.0**	**40.3**	**12.7**	**232,514**
Median		**168,305**	**1.57**	**1.12**	**8.1**	**84**	**114**	**4.5**	**124.2**	**38.8**	**7,362**
'A–' Rated Senior Debt											
Batavia Electric Fund, IL[b]	**MRO**	**38,666**	**4.41**	**1.50**	**4.1**	**125**	**125**	**1.9**	**213.4**	**64.9**	**2,403**
Boise Kuna Irr Dist ADA and Canyon Counties (ID)	WECC	50,229	3.54	1 30	3.9	53	89	0.9	231.0	61 3	4,565
Bristol Utilities Authority, VA	**SERC**	**81,390**	**4.34**	**1.67**	**3.2**	**100**	**100**	**0.0**	**182.5**	**70.1**	**2,661**
Chugach Electric Association Inc., AK	Other	283,618	2 46	2 10	10.1	28	313	0.0	324.7	21.1	9,030
Klickitat CO Public Utility District No. 1, WA[a]	**WECC**	**40,500**	**1.27**	**1.17**	**14.6**	**150**	**150**	**2.1**	**921.9**	**49.3**	**11,797**
Lodi Electric Fund, CA	WECC	62,167	1.38	0.99	7.9	35	35	4.7	16 5	0.7	3,059

[a]Fiscal 2010 audit. [b]Fiscal 2011 figures are unaudited. FADS – Funds available for debt service N.A. – Not available *Continued on next page.*
Source Fitch Ratings.

Retail Systems — 2011 (Continued)

Retail	Region	Total Revenues ($000)	Debt Service Coverage (x)	Coverage of Full Obligations (x)	Debt/FADS (x)	Days Cash on Hand	Days Liquidity on Hand	Transfer Payment as % of Operating Revs	Capex/ Depreciation (%)	Equity/ Capitalization (%)	Dept Per Customer ($)
'A–' Rated Senior Debt (Continued)											
Los Alamos County Joint Utility System Fund, NM	**WECC**	**58,235**	**1.53**	**1.43**	**4.2**	**166**	**166**	**1.8**	**105.8**	**69.6**	**2,292**
Paducah Power System, KY	SERC	63,866	0.91	N.A.	22.2	17	17	2 4	83.2	15.5	8,301
Pend Oreille County Public Utility District No. 1 — Combined, WA	**WECC**	**44,528**	**2.39**	**1.36**	**4.6**	**154**	**270**	**0.0**	**80.2**	**62.2**	**3,645**
Median		**58,235**	**2.39**	**1.40**	**4.6**	**100**	**125**	**1.8**	**182.5**	**61.3**	**3,645**
'BBB+' Rated Senior Debt											
Overton Power District No. 5, NV	**WECC**	**35,637**	**0.99**	**0.99**	**11.3**	**98**	**157**	**0.0**	**165.4**	**36.2**	**4,145**
Puerto Rico Electric Power Authority	Other	4,422,997	1.42	0.91	11 9	16	23	5.6	120.9	(2.1)	5,484
Vermont Electric Cooperative, VT	**NPCC**	**72,857**	**2.25**	**1.41**	**5.1**	**11**	**93**	**1.0**	**251.7**	**45.0**	**1,604**
Median		**72,857**	**1.42**	**0.99**	**11.3**	**16**	**93**	**1.0**	**165.4**	**36.2**	**4,145**
'BBB–' Rated Senior Debt											
Guam Power Authority	**Other**	**393,538**	**1.12**	**1.12**	**10.4**	**30**	**30**	**0.0**	**58.0**	**17.3**	**13,907**
'BB' Rated Senior Debt											
Virgin Islands Electric System	**Other**	**282,584**	**0.90**	**0.90**	**10.9**	**(2)**	**16**	**0.2**	**184.4**	**22.8**	**9,511**

[a]Fiscal 2010 audit. [b]Fiscal 2011 figures are unaudited. FADS – Funds available for debt service N.A. – Not available. *Continued on next page.*
Source Fitch Ratings

Wholesale Systems — 2011

Issuer	Region	Total Revenues ($000)	Debt Service Coverage (x)	Coverage of Full Obligations (x)	Debt/FADS (x)	Days Cash on Hand	Days Liquidity on Hand	Capex/ Depreciation (%)	Equity/ Capitalization (%)
'AAA' Rated Senior Debt									
Tennessee Valley Authority	**SERC**	11,841,000	1.51	1.43	7.0	22	105	149.1	17.6
'AA' Rated Senior Debt									
Associated Electric Cooperative Inc., MO	**SERC**	1,083,734	1.68	1.56	7.9	36	285	146.2	18.8
Bonneville Power Administration, WA	WECC	3,284,774	2.26	1.05	9.6	219	352	200.0	15 6
New York Power Authority	**NPCC**	2,655,000	2.62	2.24	5.0	195	224	56.2	52.0
Platte River Power Authority, CO	WECC	181,443	1.53	1.52	4.7	207	207	62.9	63.0
Median		1,869,367	1.97	1.54	6.5	201	255	104.6	35.4
'AA–' Rated Senior Debt									
South Carolina Public Service Authority (Santee Cooper)	**SERC**	1,914,689	1.50	1.42	9.6	97	150	185.1	25.7
Western Minnesota Municipal Power Agency	MRO	151,654	1.42	1 42	7.5	316	316	280.0	25.4
Median		1,033,172	1.46	1.42	8.6	207	233	232.6	25.6
'A+' Rated Senior Debt									
Arkansas Electric Cooperative Corporation	**SERC**	657,811	1.64	1.40	6.7	71	296	128.9	39.0
Basin Electric Power Cooperative, ND	MRO	1,706,066	3 28	3 28	13.3	92	167	343 4	20 0
Connecticut Municipal Electric Energy Cooperative[a]	**NPCC**	198,758	1.34	N.A.	5.9	85	173	684.2	9.3
Florida Municipal Power Agency - All-Requirements Project	FRCC	501,769	1.14	1.11	13.9	84	172	116.8	0.0
Illinois Municipal Electric Agency	**MRO**	176,835	1.26	1.10	43.3	84	84	4,942.0	5.8
Indiana Municipal Power Agency	RFC	374,526	1.28	1 13	20.2	93	151	557.6	11.5
Lower Colorado River Authority - Consolidated	**ERCOT**	1,185,848	1.40	1.34	8.1	119	119	206.0	24.3
Massachusetts Municipal Wholesale Electric Company – Consolidated	NPCC	304,949	1.18	1.12	4.2	124	164	141.0	0.0
Municipal Electric Authority of Georgia	**SERC**	752,914	0.88	0.88	13.5	104	164	429.3	0.0
Municipal Gas Authority of Georgia	SERC	374,277	1.16	1.16	1.8	86	188	2.4	13.6
Nebraska Public Power District	**SPP**	998,691	1.28	1.24	8.2	146	283	142.9	31.2
Texas Municipal Power Agency	ERCOT	180,586	0 98	0.69	21 5	51	51	210.9	5.7
WPPI Energy (Wisconsin Public Power Inc.)	**MRO**	445,517	1.24	1.07	9.5	79	110	55.9	32.0
Median		445,517	1.26	1.12	9.5	86	164	206.0	11.5
'A' Rated Senior Debt									
Brazos Electric Power Cooperative, TX	**ERCOT**	1,011,946	1.19	1.08	16.6	26	201	424.6	14.5
Buckeye Power Inc., OH	RFC	580,697	1.04	1.04	12.0	20	148	255.0	18.7
Central Iowa Power Cooperative	**MRO**	178,926	1.72	1.62	5.4	193	481	163.1	28.1
Golden Spread Electric Cooperative, TX	ERCOT	456,970	4.13	1.76	6.1	114	292	567.0	37 0
Grand River Dam Authority, OK	**SPP**	394,487	1.12	1.11	6.7	201	201	64.3	32.2
Municipal Energy Agency of Nebraska	MRO	145,018	1 41	1.13	10 3	101	128	20 1	24.2
North Carolina Municipal Power Agency No. 1	**SERC**	478,125	1.45	1.16	7.5	263	263	95.1	5.3
Oglethorpe Power Corporation, GA	SERC	1,390,278	1 60	1 57	11.0	195	727	425.8	8.9
Old Dominion Electric Cooperative, VA	**RFC**	891,539	1.46	1.13	7.4	49	281	110.9	31.4
Tri-State Generation & Transmission Association Inc.	WECC	1,178,793	1 09	1.07	9.6	47	197	137.5	23.3
Median		829,411	1.43	1.13	8.6	108	232	150.3	23.7

[a]Fiscal 2011 figures are unaudited FADS – Funds available for debt service. N.A. – Not available. *Continued on next page.*
Source: Fitch Ratings.

Wholesale Systems — 2011 (Continued)

Issuer	Region	Total Revenues ($000)	Debt Service Coverage (x)	Coverage of Full Obligations (x)	Debt/FADS (x)	Days Cash on Hand	Days Liquidity on Hand	Capex/ Depreciation (%)	Equity/ Capitalization (%)
'A–' Rated Senior Debt									
Delaware Municipal Electric Corporation	**RFC**	**115,159**	**2.31**	**1.14**	**7.5**	**5**	**15**	**2,656.3**	11.2
Great River Energy, MN	MRO	864,308	1 19	1 16	10 4	235	509	134.0	13 0
North Carolina Eastern Municipal Power Agency	**SERC**	**704,040**	**1.40**	**1.34**	**6.2**	**218**	**218**	110.0	**3.4**
North Carolina Electric Membership Corporation	SERC	1,008,926	1.76	1 76	7.1	37	86	91.5	7.1
Piedmont Municipal Power Agency, SC	**SERC**	**200,112**	**1.64**	**1.60**	**11.3**	**224**	**224**	**146.6**	**3.6**
PowerSouth Energy Cooperative and Subsidiaries, AL	SERC	640,183	1 31	1.21	9 6	96	224	77.2	14 0
San Miguel Electric Cooperative, TX	**ERCOT**	**140,527**	**1.37**	**1.37**	**6.7**	**8**	**118**	**89.7**	**16.9**
South Mississippi Electric Power Association	SERC	761,120	1 34	1.14	8.2	18	154	349.4	19.9
South Texas Electric Cooperative Inc.	**ERCOT**	**320,402**	**1.77**	**1.34**	**9.5**	**56**	**562**	**156.1**	**17.0**
Western Farmers Electric Cooperative, OK	SPP	462,895	1.18	1.11	10.6	24	246	129.7	17.8
Median		**551,539**	**1.39**	**1.27**	**8.8**	**47**	**221**	**131.9**	**13.5**
'BBB+' Rated Senior Debt									
Sam Rayburn Municipal Power Agency, TX	**ERCOT**	**34,570**	**1.24**	**1.19**	**7.3**	**16**	**16**	**0.0**	**(5.2)**
'BBB' Rated Senior Debt									
East Kentucky Power Cooperative	**MRO**	**877,604**	**1.25**	**1.24**	**10.4**	**93**	**134**	**220.0**	10.2
'BBB–' Rated Senior Debt									
Big Rivers Electric Corp., KY	**MRO**	**561,969**	**2.29**	**1.69**	**8.8**	**35**	**108**	**102.5**	**33.1**

FADS – Funds available for debt service. N.A. – Not available.
Source: Fitch Ratings.

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G&T Cooperative Systems — 2011

Issuer	Region	Total Revenues ($000)	Debt Service Coverage (x)	Coverage of Full Obligations (x)	Debt/FADS (x)	Days Cash on Hand	Days Liquidity on Hand	Capex/ Depreciation (%)	Equity/ Capitalization (%)
'AA' Rated Senior Debt									
Associated Electric Cooperative Inc., MO	**SERC**	**1,083,734**	**1.68**	**1.56**	**7.9**	**36**	**285**	**146.2**	**18.8**
'A+' Rated Senior Debt									
Arkansas Electric Cooperative Corporation	**SERC**	**657,811**	**1.64**	**1.40**	**6.7**	**71**	**296**	**128.9**	**39.0**
Basin Electric Power Cooperative, ND	MRO	1,706,066	3.28	3.28	13.3	92	167	343.4	20 0
Median		**1,181,939**	**2.46**	**2.34**	**10.0**	**82**	**232**	**236.2**	**29.5**
'A' Rated Senior Debt									
Brazos Electric Power Cooperative, TX	**ERCOT**	**1,011,946**	**1.19**	**1.08**	**16.6**	**26**	**201**	**424.6**	**14.5**
Buckeye Power Inc., OH	RFC	580,697	1.04	1.04	12.0	20	148	255.0	18.7
Central Iowa Power Cooperative	**MRO**	**178,926**	**1.72**	**1.62**	**5.4**	**193**	**481**	**163.1**	**28.1**
Golden Spread Electric Cooperative, TX	ERCOT	456,970	4.13	1.76	6.1	114	292	567.0	37.0
Oglethorpe Power Corporation, GA	**SERC**	**1,390,278**	**1.60**	**1.57**	**11.0**	**195**	**727**	**425.8**	**8.9**
Old Dominion Electric Cooperative, VA	RFC	891,539	1 46	1 13	7 4	49	281	110 9	31 4
Tri-State Generation & Transmission Association Inc.	**WECC**	**1,178,793**	**1.09**	**1.07**	**9.6**	**47**	**197**	**137.5**	**23.3**
Median		**891,539**	**1.46**	**1.13**	**9.6**	**49**	**281**	**255.0**	**23.3**
'A–' Rated Senior Debt									
Great River Energy, MN	**MRO**	**864,308**	**1.19**	**1.16**	**10.4**	**235**	**509**	**134.0**	**13.0**
North Carolina Electric Membership Corporation	SERC	1,008,926	1.76	1.76	7.1	37	86	91 5	7 1
PowerSouth Energy Cooperative and Subsidiaries, AL	**SERC**	**640,183**	**1.27**	**1.21**	**9.6**	**96**	**224**	**77.2**	**14.0**
San Miguel Electric Cooperative, TX	ERCOT	140,527	1.37	1.37	6.7	8	118	89.7	16 9
South Mississippi Electric Power Association	**SERC**	**761,120**	**1.34**	**1.14**	**8.2**	**18**	**154**	**349.4**	**19.9**
South Texas Electric Cooperative Inc.	ERCOT	320,402	1.77	1.34	9.5	56	562	156.1	17.0
Western Farmers Electric Cooperative, OK	**SPP**	**462,895**	**1.18**	**1.11**	**10.6**	**24**	**246**	**129.7**	**17.8**
Median		640,183	1 34	1 21	9.5	37	224	129.7	16.9
'BBB' Rated Senior Debt									
East Kentucky Power Cooperative	**MRO**	**877,604**	**1.25**	**1.24**	**10.4**	**93**	**134**	**220.0**	**10.2**
'BBB–' Rated Senior Debt									
Big Rivers Electric Corp., KY	**MRO**	**561,989**	**2.29**	**1.69**	**8.8**	**35**	**108**	**102.5**	**33.1**

FADS – Funds available for debt service
Source: Fitch Ratings.

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Financial Summary Glossary of Terms

Capitalization

Total debt plus total equity.

Debt to Customer

A measurement of leverage. Total debt divided by total customers.

Fund Available for Debt Service (FADS)

Operating income plus depreciation and amortization (taken from cash flow statement) plus interest income (taken from cash flow statement). FADS does not include any benefit from the use of (or deposit to) the rate-stabilization funds, non-operating connection fees, or capital contributions.

Full Obligations

An obligation proxy that includes annual debt service and a fixed charge related to purchase power expense. Fixed charge is calculated as 30% of purchase power expense and is an estimate of the portion of purchase power costs that are associated with debt service.

Transfer Payments

Transfer payments include payments to the general fund, payments in lieu of taxes (PILOT), free services provided and other taxes paid.

Operating Income

Operating revenue less operating expenses.

Restricted Funds

Cash and investments that are restricted in use (e.g. debt service reserve funds, debt service funds, and construction funds) and not deemed to be available to meet short-term liquidity needs.

Total Annual Debt Service

Sum of scheduled long-term principal and total annual cash interest payments (includes interest on long-term and short-term debt). Does not generally include principal amounts paid as a part of a refinancing or voluntary prepayments. Additionally, capitalized interest may be excluded for systems undertaking large construction programs.

Unrestricted Funds

Cash and short-term investments that are available for short-term liquidity needs with no limitations on use. Funds restricted solely by board or management policy may also be included.

Total Debt

Sum of long-term debt, capital leases, outstanding commercial paper, notes payable, and current maturities of long-term debt and capital leases. No adjustments are made for unamortized discounts or premiums.

Total Equity

Net assets (retained earnings plus contributed capital plus patronage capital).

Ratio Definitions

Ratio	Calculation	Significance
Cash Flow		
FADS ($)	**Operating Revenues – Operating Expenses + Depreciation + Amortization + Interest Income**	**Provides available, current cash resources.**
Debt Service Coverage (x)	FADS/Total Annual Debt Service	Indicates the margin available to meet current debt service requirements
Coverage of Full Obligations (x)	**(FADS + Fixed Charges – Transfer Payments Excluded from Operating Expenses)/(Annual Debt Service + Fixed Charges)**	**Indicates the margin available to meet current debt service requirements and proxy obligations related to purchased power.**
Debt to FADS (x)	Total Debt/FADS	Indicates the size of debt compared to the margin available for debt service
Liquidity		
Days Cash on Hand	**Unrestricted Funds/(Operating Expenses – Depreciation+ Amortization)*365**	**Indicates financial flexibility, specifically cash and short-term investments, relative to expenses.**
Days Liquidity on Hand	(Unrestricted Funds + Available Lines of Credit and Commercial Paper Capacity)/(Operating Expenses – Depreciation + Amortization)*365	Indicates financial flexibility, including all available sources of cash, short-term investments, and liquidity, relative to expenses.
Capital Structure		
Equity to Capitalization (%)	**Total Equity/Capitalization**	**Provides a measure of cost recovery, leverage, and debt capacity.**
Debt to Customer ($)	Total Debt/Total Customers	Provides a measure for relative comparison of leverage.
Other		
Capex to Depreciation and Amortization (%)	**Capex/Depreciation + Amortization**	**Indicates whether annual capital spending keeps pace with depreciation.**
Transfer Payments to Operating Revenues (%)	(General Fund Transfers + PILOT + Other taxes)/Operating Revenues	Indicates the degree to which a utility supports city or county general fund, or other governmental operations.

Source. Fitch Ratings.

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DOCKET NO. 41527

APPLICATION OF SOUTH TEXAS ELECTRIC COOPERATIVE, INC. TO CHANGE RATES FOR WHOLESALE TRANSMISSION SERVICE (NON-IOU)	§ § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

CORY J. ALLEN

ON BEHALF OF

SOUTH TEXAS ELECTRIC COOPERATIVE, INC.

May 30, 2013

DOCKET NO. 41527

APPLICATION OF SOUTH TEXAS ELECTRIC COOPERATIVE, INC. TO CHANGE RATES FOR WHOLESALE TRANSMISSION SERVICE (NON-IOU)	§ § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

DIRECT TESTIMONY

OF

CORY J. ALLEN

ON BEHALF OF SOUTH TEXAS ELECTRIC COOPERATIVE, INC.

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DIRECT TESTIMONY

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I.

POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, CURRENT EMPLOYMENT POSITION AND BUSINESS ADDRESS.

A. My name is Cory J. Allen. I am Assistant General Manager for South Texas Electric Cooperative ("STEC").

My business address is 2849 FM 447, PO BOX 119, Nursery, TX 77976.

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE WITH STEC.

A. My employment at STEC began with the position of Transmission and Substation Engineer in 1994. In 2003, I became Manager of Operations and Engineering and in 2008 assumed the position of Assistant General Manager.

Q. WHAT ARE YOUR PROFESSIONAL QUALIFICATIONS?

A. I graduated from Texas A&M University in 1987 with a Bachelor of Science degree in Electrical Engineering. I am a registered Professional Engineer in the State of Texas.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS ("PUC")?

A. Yes. I have submitted testimony in PUC Docket Nos. 32406, 33033, 34108, 35528, 35665, 36790, 37535, 38569, 38648, 39298, and 41395.

II.

PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support STEC's filing to change its wholesale rates which is in accordance with the Transmission Cost of Service Rate Filing Package for Non-Investor Owned Transmission Service Providers in the Electric Reliability Council of Texas (the "TCOS-RFP"). I discuss and sponsor changes to STEC's wholesale tariff, generally describe STEC's business organization, provide information supporting approval of STEC's expenses as reasonable and necessary, and identify significant capital projects added since STEC's last TCOS filing.

Q. PLEASE GIVE A BRIEF DESCRIPTION OF STEC'S TCOS FILING IN THIS DOCKET.

A. STEC's filing proposes transmission and distribution rate changes necessary to recover costs of facility investments and expenses. PUC approval is requested for an increase in STEC's TCOS and the associated Wholesale Transmission Service ("WTS") schedule in its tariff; changes in the Distribution Level Wholesale Transmission Service ("DWS") schedule and the resulting rate; and, replacement all pages of Sections I and III of STEC's tariff because of the extent of the changes made to the organization and to its rules and regulations.

This filing is supported by the testimony of Frances J. Nitschmann, STEC's Chief Financial Officer, who sponsors all schedules filed in accordance with the TCOS-RFP and explains supporting workpapers.

Daniel J. Walker supports STEC's filing with testimony discussing STEC's rate of return calculation methodology, financial indicators, and reasonable financial targets.

III.

DESCRIPTION OF ORGANIZATION

Q. PLEASE BRIEFLY DESCRIBE STEC.

A. STEC is a not-for-profit cooperative corporation that provides wholesale generation and transmission ("G&T") services for eight (8) member cooperatives ("Members"); Jackson Electric Cooperative, Karnes Electric Cooperative, Medina Electric Cooperative ("MEC"), Magic Valley Electric Cooperative ("MVEC"), Nueces Electric Cooperative, San Patricio Electric Cooperative, Victoria Electric Cooperative, and Wharton County Electric Cooperative. STEC's member cooperatives provide distribution services in forty-two (42) south Texas counties. STEC owns, operates, and maintains overhead transmission line, transmission switching and autotransformer stations, and delivery point substations that serve its Members. STEC owns no underground transmission line.

Listed below are quantities of certain transmission and station assets owned and operated by STEC:

	Qty
Transmission & Distribution Stations	151
Transmission Stations	28
Distribution Stations	4
69-kV Transmission Line	1,396 miles
138-kV Transmission Line	520 miles
345-kV Transmission Line	73 miles

STEC utilizes 1,316 MW of generation capacity from natural gas, lignite coal, wind, and hydroelectric resources. Included in that capacity are the STEC owned and operated Sam Rayburn Power Plant and the Pearsall Power Plant.

Q. PLEASE DESCRIBE STEC'S MEMBERS' SERVICE AREAS.

A. STEC's Members serve in 42 counties, an area of approximately 32,000 square miles, providing distribution services to about 182,000 members. A geographic transmission map depicting STEC's 2012 transmission system and locations of stations that serve the Members is attached as Exhibit CJA-1.

Q. WHEN WAS STEC FORMED AND WHAT WERE SOME OF THE SIGNIFICANT EVENTS AND CHANGES?

A. STEC was formed by ten (10) distribution cooperatives in 1944 to provide wholesale services. Six (6) distribution cooperatives remained as Members as STEC transitioned from a G&T on paper to one with its first transmission lines and substation assets energized in 1960. By 1963, STEC had constructed over 800 miles of 69-kV transmission line and sixty-five (65) stations. The Sam Rayburn power plant was completed in 1964 with two simple cycle natural gas turbine generators. In 1968, STEC added thermal generation utilizing natural gas at its Sam Rayburn facilities, installed its first 138-kV transmission line, and made its first transmission connection to another transmission company. The generation produced by the Falcon Dam was acquired in 1977. In 1980, about 170 miles of 138-kV line were installed from the Sam Rayburn Power Plant to Christine then on to Orange Grove in response to the construction of the San Miguel Power Plant. The Amistad Dam hydro generation began operations in 1983. STEC completed its first 345-kV transmission line and 345/138-kV autotransformer and switching station and commissioned the Sam Rayburn combined-cycle power plant addition in 2003. STEC's original six Members, MEC, and MVEC decided to join together to increase STEC's membership to eight, a process begun in 2005 and completed in 2008. Also in 2008, STEC acquired its first wind generation output. In 2010 STEC added approximately 200 MW of natural gas generation capacity at the Pearsall Power Plant.

Q. HOW ARE RESPONSIBILITIES DIVIDED BETWEEN STEC AND ITS MEMBERS?

A. STEC provides all wholesale generation and transmission services for its Members. STEC owns the step-down delivery point substations providing service to the Members' feeders at nominal distribution voltage levels of 24.94-kV, 13.8-kV, 13.2-kV, 12.47-kV and 4.16-kV. The ownership change points in a typical substation are at the attachments of overhead distribution line wires to the substation steel structure. STEC does not own distribution overhead line so its distribution plant consists of its substation facilities that are rated at less than 60 kV.

The Members own the overhead distribution lines and associate distribution line mounted equipment, retail meters, and any other facilities related to retail services. Member employees also perform as first responders to substation and transmission line outages. Typically the first responder duties are limited to emergency switching and isolation procedures authorized by STEC's System Operator.

IV.

CAPITAL IMPROVEMENTS

Q. DID YOU SUPPLY A LIST OF THE CAPITAL PROJECTS WITH COSTS FOR WHICH STEC REQUESTS INCLUSION IN ITS RATE BASE?

A. Yes. A complete list of projects commissioned since STEC's last TCOS filing is attached as Exhibit CJA-2. It lists the projects that were closed by work order number. Projects include multiple work order numbers if the work encompasses both transmission and distribution assets. The closed-out costs for each work order are assigned as shown by Exhibit CJA-2 to the appropriate account number.

Q. PLEASE LIST THE MAJOR TRANSMISSION LINE PROJECTS AND THE ASSOCIATED COSTS INCLUDED IN STEC'S TCOS THAT WERE COMPLETED SINCE ITS LAST TCOS FILING.

A. Included in Exhibit CJA-2 are the following transmission line installations that cost more than one million dollars:

- Palo Duro to Dilley $6,062,016
  14 miles, 138-kV new circuit added to existing 69kV line
- Alberta Road to Val Verde $2,392,449
  4.1 miles, 138-kV line reconductor
- Pearsall to Moore $2,202,814
  11 miles, 138-kV line reconductor
- West Edinburg to Palmhurst $1,603,217
  3.4 miles, 138-kV line reconductor
- Port Lavaca to Port O'Connor $8,975,905
  20 miles, new 69-kV line, Docket No. 32406
- San Miguel to Pawnee $2,914,284
  6 miles, relocate 138-kV line, part of Docket No. 21747
- San Miguel to Fashing $2,102,152
  8.5 miles, reconductor 69-kV line
- Palmhurst to Merett $1,782,886
  4.3 miles, reconductor 138-kV line

Q. WHAT ARE THE CIRCUIT MILES OF TRANSMISSION LINE FOR THE TEST YEAR AND THE FOUR PRECEEDING YEARS?

A. The annual miles of transmission line in service are as follows:

Table 1

Voltage (kV)	Circuit Miles 2008	Circuit Miles 2009	Circuit Miles 2010	Circuit Miles 2011	Circuit Miles 2012
345	31	73	73	73	73
138	379	496	496	520	520
69	1371	1371	1396	1396	1396

Q. HOW DOES STEC DETERMINE FACILITIES TO BE INCLUDED IN ITS TRANSMISSION RATE BASE?

A. STEC defines facilities to be transmission as per P.U.C. SUBST. R. 25.192(c)(1)(A)-(E). Summarizing, equipment rated at 60-kV and above and the associated expenses of the installation and commissioning of equipment rated above 60kV are considered transmission capital investment.

Q. HOW DOES STEC DETERMINE WHAT TRANSMISSION IMPROVEMENTS ARE NECESSARY?

A. Transmission improvements such as new transmission lines, existing line upgrades, breaker additions, and reactive facilities are generally needed in support of load growth, transmission network congestion mitigation, voltage support, connection of new generation capacity, or a combination of the issues. Reliability indices are calculated annually as well so that facility performance is included in improvement decisions.

Engineering includes two (2) Transmission Planning Engineers that perform load flow analyses using computer models of multiple future year projections for grid connections and load levels in concert with ERCOT personnel and neighboring transmission service provider personnel. Results are analyzed to determine the most effective and economical future projects in order to assure performance of the transmission service remains within acceptable voltage ranges and line loading capacities. Acceptable voltages, available transmission line capacities, and reliability performance criteria are addressed in STEC's Transmission Planning Criteria, attached as Exhibit CJA-3.

When a major transmission improvement is needed, a report with load flow study assumptions, violations expected, and improvement options considered is submitted to Regional Planning Group (RPG) of ERCOT. The RPG keeps transmission service providers (TSPs) informed of transmission projects that may affect them and coordinates an independent review when appropriate. STEC presents all projects requiring approval of a Certificate of Convenience and Necessity ("CCN") and all projects over a certain cost to the RPG. The RPG process concludes with ERCOT support of a proposed improvement or ERCOT's alternative recommendation.

New generation capacities requesting connection to the transmission network require system analyses in order to ensure that all expected loading, voltage, and stability performances are assessed prior to choosing appropriate transmission improvements. The generation interconnection process is administered by ERCOT but studies are assigned to the appropriate TSP. This process develops the plan for the necessary transmission improvements to accommodate the generation.

Q. HOW MANY STATIONS WERE ADDED BY STEC SINCE ITS LAST TCOS RATE CASE?

A. STEC completed 13 new delivery point substations and 2 new transmission switching stations.

Q. WHAT ARE THE MAJOR STATION PROJECTS STEC COMPLETED SINCE ITS LAST TCOS FILING?

A. Included in Exhibit CJA-2 are the following installations that cost more than one million dollars:

- Alberta Road $2,816,620
  New 3-terminal 138-kV switching station
- Palo Duro $1,882,760
  New 3-terminal 138-kV switching station
- Sioux $4,737,395
  New 138/13.2-kV substation with 4-terminal 138-kV bus
- Pearsall $1,715,702
  Upgrade 138/69-kV autotransformer
- Alton $1,133,440
  New 13.2-kV distribution breaker facility
- Las Milpas $1,334,203
  Add 138/13.2-kV transformer
- Montell $1,523,862
  New 69/24.94-kV Substation
- Sunniland $1,246,511
  New 69/24.94-kV substation
- Azteca $3,078,856
  New 138/13.2-kV substation
- Southmost $3,955,388

New 138/13.2-kV substation

- Botines — $2,559,444
  New 138/24.94-kV substation
- Burns — $1,706,498
  Add 138/13.2kV transformer
- Weslaco — $1,548,716
  Add 138/12.47-kV transformer
- Mobile Substation — $1,354,580
  New 14 MVA mobile substation
- Saltdome — $2,787,650
  New 69/12.47-kV Substation
- Hondo Creek — $1,254,059
  Upgrade 138/69-kV autotransformer
- Pharr — $1,100,285
  Add 138/13.2-kV transformer
- Merett — $1,165,915
  Add 138/13.2-kV transformer
- Seadrift — $1,482,447
  New 69/12.47-kV substation

Q. IN STATIONS THAT HAVE EQUIPMENT RATED ABOVE AND BELOW 60 KV HOW DOES STEC DETERMINE WHAT MUST BE INCLUDED IN ITS TRANSMISSION RATE BASE?

A. STEC's stations that have both transmission and distribution rated assets are charged to Account No. 362. Transmission specific and distribution specific costs are taken from continuing plant records which increase station plant values through entries for installations and decrease them for retirements. Not all costs, though, are specifically related to transmission and distribution equipment. These are the common costs of a station. Items like control houses, station service, site work, ground grids, and security fences are common facilities. Common costs at each station are allocated based upon the ratio of transmission costs to distribution costs at every station that is assigned to account 362. The percentages of transmission plant in each station are listed in the workpaper WP/B-1/1.1.1. One-line diagrams show the divisions between transmission and distribution equipment at each of the Account 362 stations. These are included as Exhibit CJA-7.

Q. ARE THERE OTHER MAJOR PROJECTS STEC HAS COMPLETED THAT AFFECT ITS TCOS?

A. Yes. STEC constructed satellite offices on its Pearsall Power Plant property and on a new property in Donna, Texas. Both offices house personnel, equipment and materials that support transmission and distribution assets and activities. The Pearsall Office cost $2,441,469. The Donna Office cost $3,761,221. The office building construction project costs are charged to Account 390.

Q. WHAT IS THE TOTAL CAPITAL COST OF THE ASSETS ADDED TO STEC'S RATE BASE?

A. The projects listed in Exhibit CJA-2 represent the investments made in transmission and distribution plant and total $81,121,783.

Q. ARE ALL OF THE CAPITAL PROJECTS INCLUDED IN STEC'S PROPOSED RATE USED BY AND USEFUL TO RATEPAYERS?

A. Yes. All of the capital projects are energized and in service.

V.

TRANSMISSION DUTIES

Q. HOW MANY EMPLOYEES HAVE TRANSMISSION RELATED DUTIES AND HOW ARE THOSE DUTIES ASSIGNED?

A. The number of STEC employees that charged at least some of their time to or performed services partially or completely in support of transmission related functions in 2012 was one hundred and sixty-three (163). Those employees were organized as indicated by Exhibit CJA-4, STEC's Personnel Organization Chart.

Eleven (11) employees in the Accounting department headed by the Chief Financial Officer provided services in support of all work, including that related to transmission.

Administration personnel provided general support of transmission functions. These personnel included grounds and building maintenance, a Compliance Coordinator, safety trainers, security officers, and clerical support. Thirteen (13) administrative personnel spent at least some time on or in support of transmission-related functions.

The Manager of Engineering directed eighteen (18) employees involved in transmission line engineering and design, substation engineering and design, transmission system planning, system protection coordination, CCN application development, project management, right-of-way and land acquisition, project management, and construction inspection. Employees in this department were involved in ERCOT working groups and committees. Two (2) transmission engineers, at least one (1) engineering assistant, and the Transmission Project Coordinator are exclusively assigned to transmission projects and two (2) Distribution Engineers were almost exclusively involved in distribution projects. Most of the remaining Engineering Department personnel split their time between transmission and distribution work by assigning hours to appropriate work order numbers.

The Chief System Operator directed 8 employees responsible for the 24-7 operation of STEC's transmission and substation assets, all transmission operator compliance measures, and coordination of transmission functions with other transmission owners. All device operations made in the field were authorized by the system operators through switching instructions.

There were 58 employees involved in Technical Services. The Manager of Technical Services directed forty-five (45) employees in the Substation, Relaying, Metering, SCADA, Communications, and Pearsall subgroups. Part of the efforts of all technical services employees were in support of transmission services. Responsibilities of these employees included those related to protective relaying, EPS metering, microwave communications, autotransformers, breakers, SCADA and RTU's, computers and networks, and cyber security. There were thirteen (13) employees based at STEC's Valley Office whose functions include technical services responsibilities. Transmission and Substation related work was supervised by the Line Superintendent directing fifty-two (52) employees performing vegetation management, transmission line operations and maintenance ("O&M") and construction, substation O&M and construction, transmission line patrol and inspection, right-of-way access maintenance, and emergency restoration of transmission line and substations. One (1) line crew, the line patrolman, tree trimmers, and right-of-way mowers worked almost exclusively on transmission related projects and services while three (3) other crews, the mechanics, and construction crews split time between transmission and substation work depending upon capital projects in progress by charging appropriate work order numbers with the appropriate labor hours and vehicle expenses.

Q. BY DEPARTMENT, HOW MANY FULL TIME STEC EMPLOYEES PERFORMED TRANSMISSION OPERATIONS AND MAINTENANCE RELATED DUTIES DURING 2012 AND HOW MANY DURING THE FOUR PREVIOUS YEARS?

A. The numbers of employees in each general function/department listed in Table 2 are those that performed transmission related duties during the indicated year.

Table 2

	EMPLOYEES BY YEAR				
Department/Function	2008	2009	2010	2011	2012
Accounting	9	9	10	11	11
Administration	12	13	11	12	13
Engineering	14	14	14	18	18
Management	2	2	2	2	2
System Operations	8	8	9	9	9
Technical Services	36	53	53	56	58
Transmission and Substation	42	49	52	52	52
Totals	123	148	151	160	163

Q. PLEASE EXPLAIN, BY DEPARTMENT, THE APPARENT EMPLOYEE NUMBER INCREASES SINCE STEC'S LAST FULL TRANSMISSION COST OF SERVICE RATE FILING.

A. The Accounting department total increased by two when the position of Benefits and Events Coordinator became necessary and when the Human Resources Manager was moved from Administration to Accounting.

Administration personnel increased by one after the Safety Trainer and Lead Security Officer positions were added and the Human Resources Manager was moved to Accounting.

Engineering increased with the addition of a Land Agent, Substation Engineer, and two (2) Engineering Assistants. These additional employees were primarily needed to keep up with projects and to support the facilities serving eight (8) Members rather than six (6).

System Operations added one operator position due to increased outage scheduling attention made necessary by ERCOT protocols and the increase