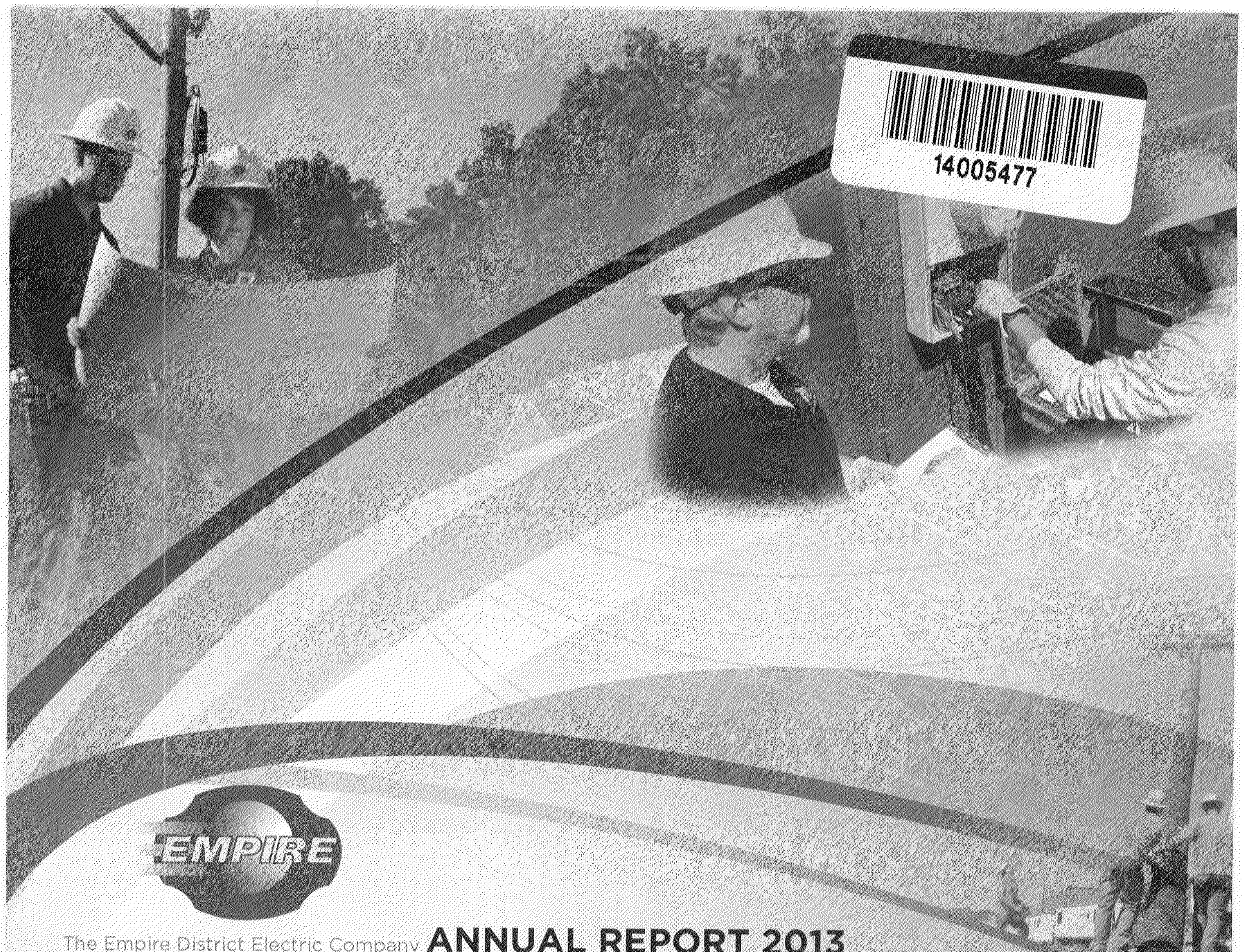
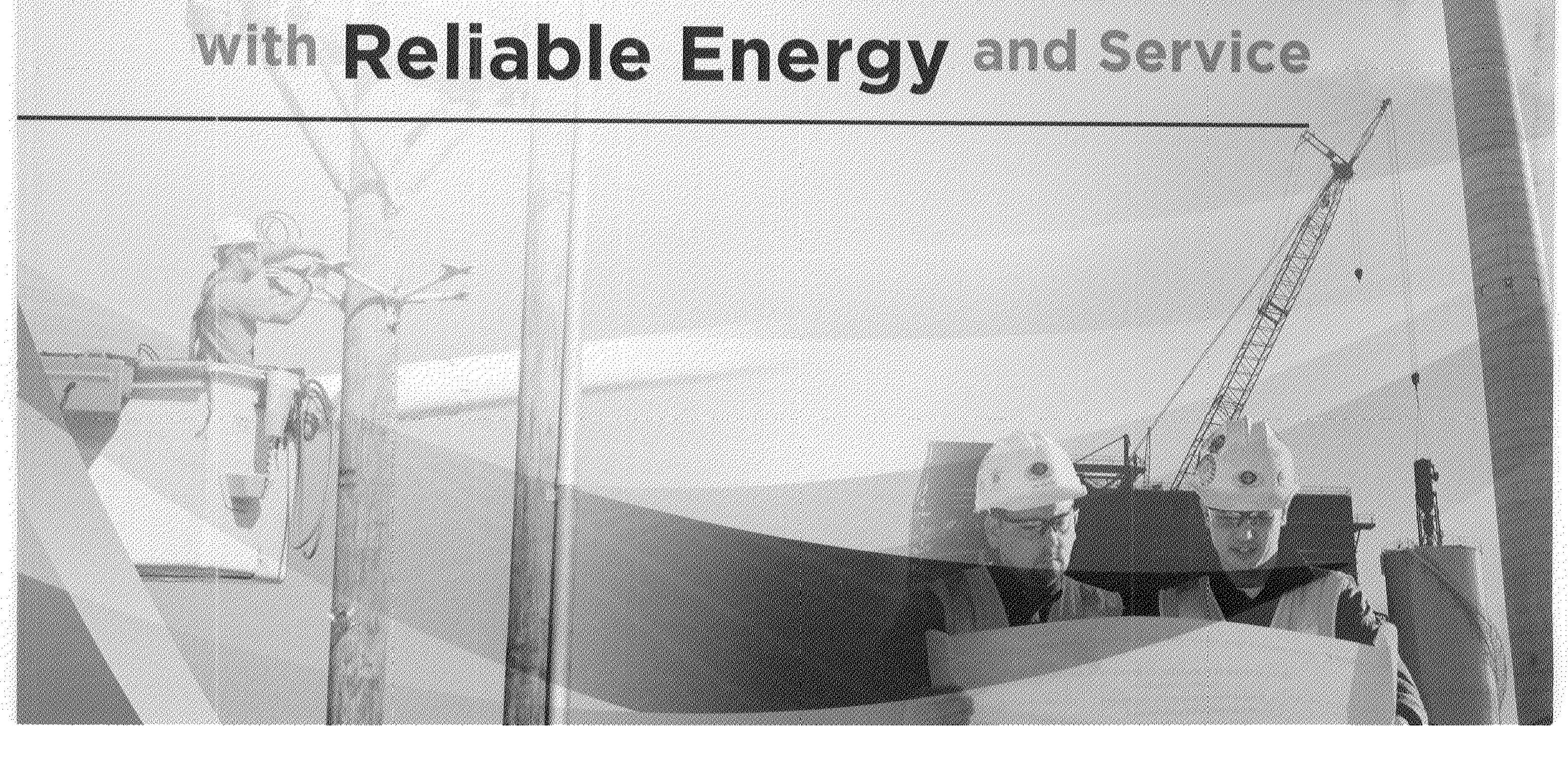


EMPIRE

The Empire District Electric Company **ANNUAL REPORT 2013**

Making Lives Better Every Day with Reliable Energy and Service



Financial **Highlights**

DECEMBER 31,	2013	2012	Percentage Change
Operating Revenues (000)	$594,330	$557,097	6.7%
Operating Income (000)	$99,663	$96,221	3.6%
Net Income (000)	$63,445	$55,681	13.9%
Earnings Per Weighted Average Common Share (Basic And Diluted)	$1.48	$1.32	12.1%
Dividends Paid Per Share	$1.005	$1.00	0.5%
Return On Common Equity (End Of Period)	8.5%	7.8%	9.0%
Book Value Per Share Of Common Stock	$17.43	$16.90	3.1%
Common Shares Outstanding (Year End) (000)	43,044	42,484	1.3%
Weighted Average Common Shares Outstanding (Basic) (000)	42,781	42,257	1.2%
Capital Expenditures (Including AFUDC) (000)	$160,196	$146,287	9.5%
Gross Plant (000)	$2,332,341	$2,284,022	2.1%
On-System Electric Sales (mWh)	4,964,227	4,912,970	1.0%
On-System Gas Sales (000) (Mcf)	8,728	7,392	18.1%
Electric Customers (Year End)	168,764	167,688	0.6%
Gas Customers (Year End)	43,956	43,991	-0.1%
Owned System Capability (Net mW)	1,377	1,391	-0.1%
System Electric Peak Demand (Net mW)	1,080	1,142	-5.4%
System Gas Peak Demand (Mcf)	60,118	58,281	3.2%
Employees	751	756	-0.7%

Letter from the President

To Our Shareholders, Customers and Employees,

For your Company, 2013 was a year of progress. Our focus remained on providing value for our customers and shareholders while ensuring our employees have the resources they need to get the job done. Guided by these purposes, we achieved measurable results.

In the fourth quarter, we announced a two percent increase in the dividend. The increase was possible due to improved financial metrics on both our income statement and balance sheet over the last two years. The increase also reflects our expected future earnings growth as we continue to execute our business strategy and complete investments in our Asbury environmental upgrade and Riverton combined cycle projects. These investments are necessary to allow us to meet new emission standards set forth by the Environmental Protection Agency for mercury, particulate matter and sulfur dioxide.

Several other factors supported the dividend increase. In April, $27.5 million in new rates became effective for Missouri customers. The new rates include tornado cost recovery and continue the fuel cost recovery mechanism. Citing the rate settlement and our effective management of regulatory risk, Standard & Poor's upgraded our credit rating in March 2013; then in January 2014, Moody's Investor Service took similar action. Also, as you'll see in our photo section, progress continues to be made since the 2011 tornado. Our customer counts have returned to pre-tornado levels and Joplin continues a successful recovery. According to the Joplin Chamber, more than 450 of the 531 businesses destroyed or severely damaged in the tornado have reopened or are in the process of reopening. Plus, approximately 150 new businesses have been established in Joplin.

The progress of the last year has been realized through careful planning and execution. Part of our planning process involves the development of an Integrated Resource Plan (IRP). The 2013 IRP sets out a preferred plan to meet the energy needs of our customers over a 20-year planning horizon using least-cost options. To arrive at the preferred plan, we evaluate reliability and resource diversity, legal mandates and energy policy, risk and uncertain factors, as well as rate impacts. We file an updated Plan with the Missouri Public Service Commission (MPSC) every three years.

Demand-side management (DSM) programs were also evaluated during the IRP process. As a result, we made a Missouri Energy Efficiency Investment Act (MEEIA) filing with the MPSC in late October. The filing seeks approval to implement an expanded portfolio of DSM programs to help customers use energy more efficiently and keep resource costs more affordable over the long term. The filing seeks a demand-side investment mechanism (DSIM) to offset the financial costs associated with the programs.

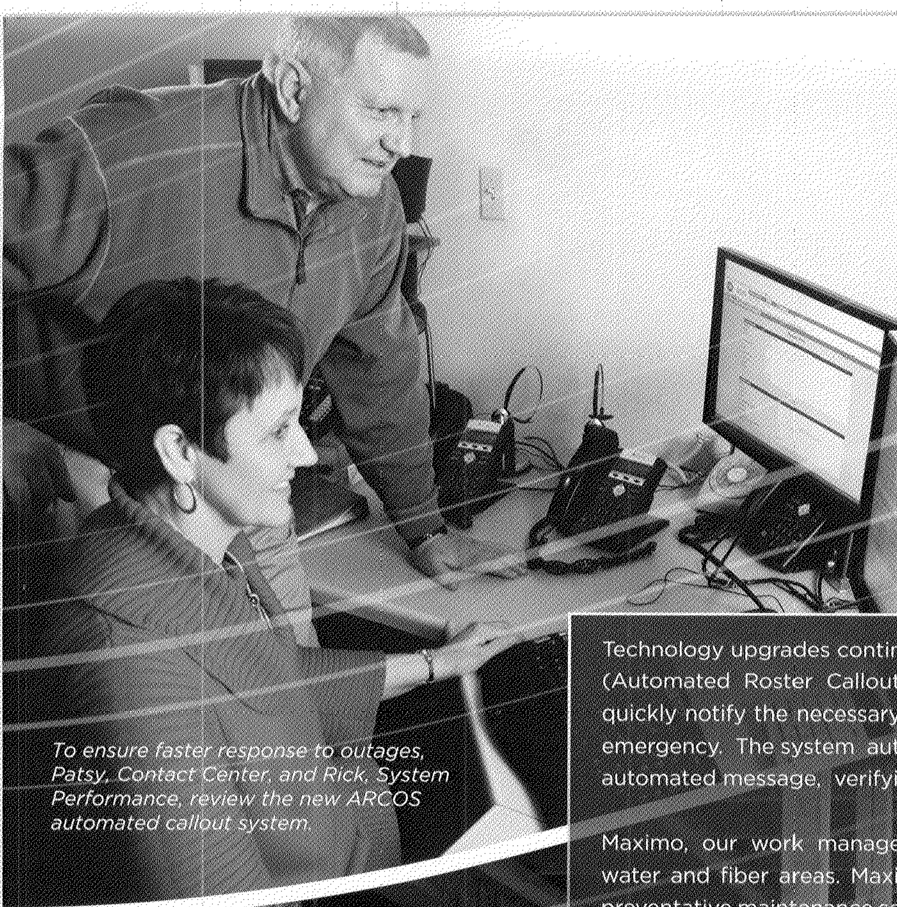
In 2013, we continued to improve the service we provide our customers. We reorganized our Customer Service area and formed a Business and Community Development group. The new group allows for increased contact within the many communities we serve. We rebranded our Call Center as a Contact Center. This reflects customer preference trends toward convenient online and mobile communications. To shorten response time when outages occur outside normal business hours, we've added an automated call-out system to contact crews. To ensure a positive experience for our customers, we've also established a quality assurance monitoring program within the Contact Center.

In October, we joined the social media world with the launch of a Facebook page. Traffic to the page continues to grow as we post timely information and respond to customer feedback. A mobile version of our website is another useful new tool. Available for download at Apple and Google Play online stores, the Empire App easily links customers to account information, outage reports, payment locations and our stock quote. Please visit our website at www.empiredistrict.com for links to our Facebook page and to download the Empire App. We hope you'll like our page and share it with your friends.

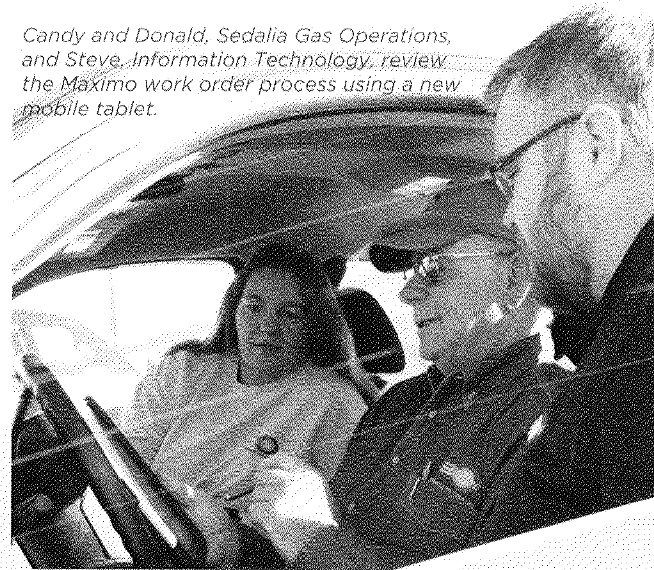
We know how important reliable service is for our customers. After posting our highest reliability numbers in 2012, we made further gains in 2013. We are close to completing one full loop around our transmission and distribution system since the adoption of enhanced tree-trimming practices six years ago. Our initiative to "harden" the electrical system and address worst-performing circuits has progressed to the point that in addition to full circuits, we now look at individual devices. Both of these strategies proved beneficial when we experienced only minor outages with the accumulation of up to three-quarters of an inch of ice in the Joplin area in December.

Project Overhaul, our multi-year effort to implement new integrated, enterprise-level software systems continues to move forward. Our purpose for the project is to standardize processes throughout the organization and realize efficiency gains by providing better tools, technology and information for our employees. This improves the effectiveness of our work planning and our resource and materials management, which helps hold down costs for customers. In 2013, we successfully implemented electronic data interchange for purchasing and invoicing as well as staged rollouts of work management systems for the energy supply and gas operations group and part of the commercial operations area. To ensure we are utilizing the software to its full benefit, a continuous improvement team has been soliciting feedback and addressing issues as the project progresses.

Efficiency and reliability are also key initiatives within the Southwest Power Pool Integrated Marketplace (IM) expected to launch in 2014. The IM will change the way we dispatch energy generation and schedule transmission, with priority placed upon cost and transmission efficiencies for the overall pool. Personnel within the



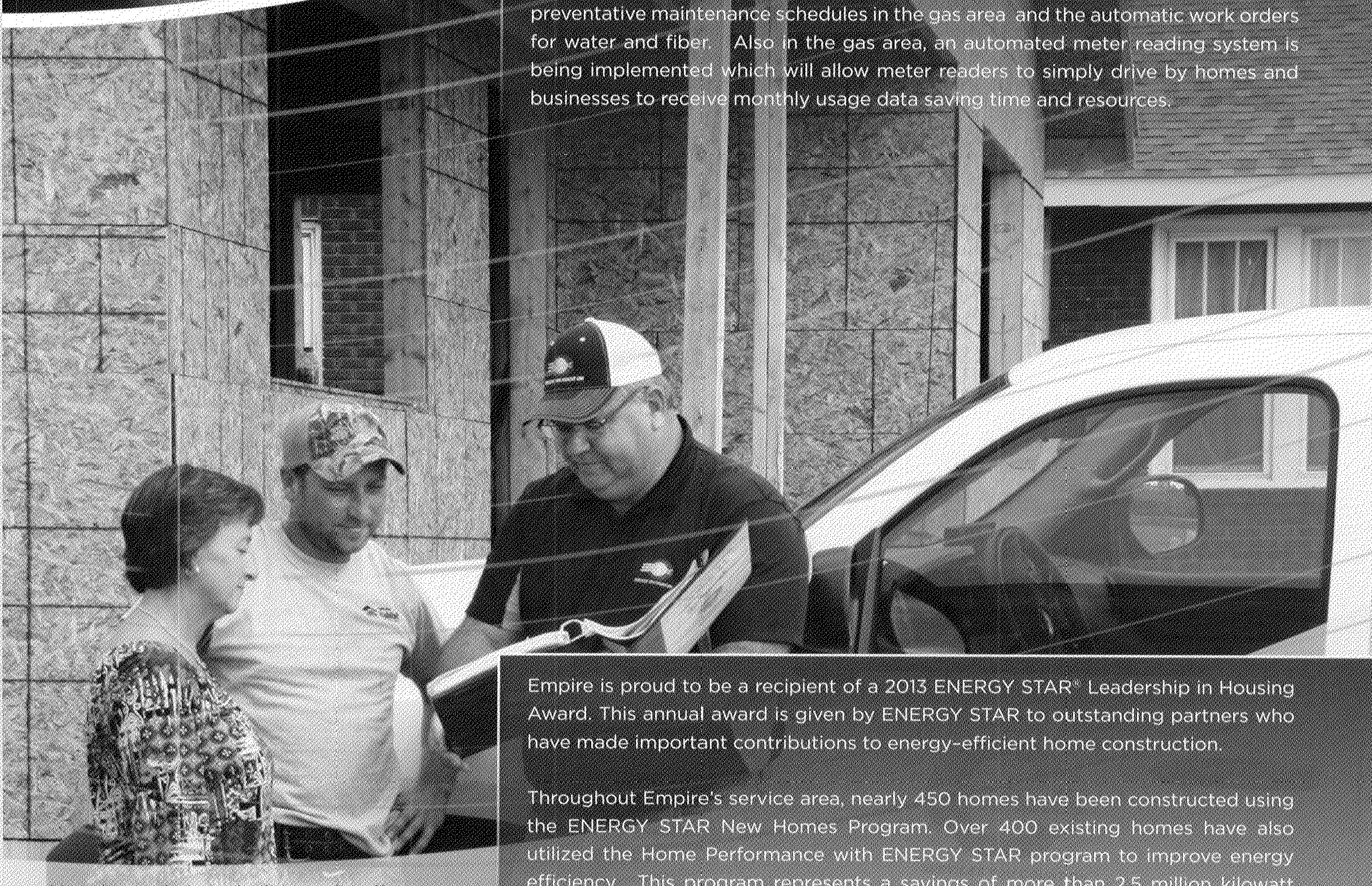
To ensure faster response to outages, Patsy, Contact Center, and Rick, System Performance, review the new ARCOS automated callout system.



Candy and Donald, Sedalia Gas Operations, and Steve, Information Technology, review the Maximo work order process using a new mobile tablet.

Technology upgrades continue to enhance efficiency throughout Empire. ARCOS (Automated Roster Callout System) is now utilized in the Contact Center to quickly notify the necessary staff needed in response to an after-hours outage or emergency. The system automatically calls staff in a pre-established order with an automated message, verifying their availability.

Maximo, our work management system, was recently put to use in the gas, water and fiber areas. Maximo is used to monitor and document the numerous preventative maintenance schedules in the gas area and the automatic work orders for water and fiber. Also in the gas area, an automated meter reading system is being implemented which will allow meter readers to simply drive by homes and businesses to receive monthly usage data saving time and resources.



Many homes being rebuilt in Joplin offer superior energy efficiency. Rick, Construction Design, with Barbie and Matt, Habitat for Humanity, at a new home under construction in Joplin.

Empire is proud to be a recipient of a 2013 ENERGY STAR® Leadership in Housing Award. This annual award is given by ENERGY STAR to outstanding partners who have made important contributions to energy-efficient home construction.

Throughout Empire's service area, nearly 450 homes have been constructed using the ENERGY STAR New Homes Program. Over 400 existing homes have also utilized the Home Performance with ENERGY STAR program to improve energy efficiency. This program represents a savings of more than 2.5 million kilowatt hours, or $250,000 in energy savings annually.

In June at the Ozark Beach Power Plant, over 100 employees and numerous state and local dignitaries joined to celebrate Empire's 100-year history in Taney County, Missouri. With the exception of a few changes and improvements, the dam stands much the same as when finished in 1913. The dam provides the Taney County area with a beautiful recreational area and Empire customers with 16 megawatts of safe, reliable and renewable power.

Ozark Beach Power Plant Team at 100th Anniversary celebration. Paul, Nathan, Dennis, Tom, Jay, Jason and Hal.

The Riverton and Asbury Power Plant projects are part of a much larger and ongoing Integrated Resource Plan to ensure safe, reliable and economical energy for Empire's customers. The Plan began nearly a decade ago as Empire sought to secure a balanced mix of energy resources including cost-effective renewables with the Elk River and Meridian Way Wind Farm contracts; a continued focus on energy efficiency programs for customers; partnerships with neighboring utilities to construct highly efficient, state-of-the-art, coal-fired generators; and the addition of air quality control systems. Empire continues to be a responsible steward of the environment.

Shovels are turned to mark a new era for the Riverton Power Plant, its employees and the community of Riverton.

October marked a new era for power generation at the Riverton Power Plant when ground was broken for the Unit 12 combined cycle expansion.

Originally completed in 2007, Unit 12 is currently a simple-cycle, natural gas-fired combustion turbine with a capacity of approximately 143 megawatts. The conversion to combined-cycle operation will include the installation of a heat recovery steam generator, steam turbine generator, auxiliary boiler and cooling tower. This highly efficient configuration will allow for the recapture of excess heat from the existing unit to produce approximately 100 megawatts of additional power. Its ability to start up quickly and rapidly adjust to changes in load are an added bonus. This is the most efficient fossil-fueled generation unit in Empire's portfolio.

Upon completion in mid 2016, the three most senior generators at Riverton, Units 7, 8 and 9, will be retired. Units 7 and 8 historically operated utilizing coal fuel, but were transitioned to natural gas operation in 2012. After more than 100 years, this transition brought to a close the coal generation era at Riverton.

Supply Management and System Operations areas have been working to integrate, test and train to ensure a smooth transition.

This year we celebrated the 100th year of operation for the Ozark Beach Hydro Electric Plant located on the White River near Forsyth, Missouri. The plant began operation on September 1, 1913, and has been a source of reliable, economical and renewable energy for Empire customers ever since. The dam's four turbines provide 16 megawatts of generating capacity and the structure spans 1,300 feet across. The dam forms Lake Taneycomo which stretches 22 miles in length and up to one mile in width and provides Taney County with a beautiful recreational area.

In our gas operations area, we had several notable achievements. A new city gate, or take point, for gas delivery was installed in north Chillicothe. This greatly improves reliability for this developing area. Community extensions completed in our northwest area resulted in the addition of grain drying customers in the communities of Fortescue and Langdon in 2013. In addition, technology upgrades are enhancing efficiency with the implementation of automated meter reading and electronic service order processing with orders dispatched to mobile tablets.

One of our proudest moments of the year came on November 27. On that day, Empire employees achieved one million hours worked without incurring a lost-time injury. The million-hour mark has been attained only six times in our Company's history. The last time was in July 2004. We're very proud of the safety awareness demonstrated by our employees in reaching this mark, but more importantly, we're happy to see each of them return home safely to their families at the end of each day.

In March we will say goodbye to Mike Palmer, vice president, Transmission Policy and Corporate Services, who is retiring after nearly 28 years of service. We thank Mike for his dedication and wish him all the best. Mike's responsibilities will be reallocated among the remaining senior management team.

In the year to come, your Company will move forward with the business plan we have established - that of a pure-play regulated electric and gas utility. We remain focused on executing the projects at hand and planning to meet the challenges ahead. We do this to ensure reliable energy for our customers and a fair rate of return for our shareholders.

Brad Beecher

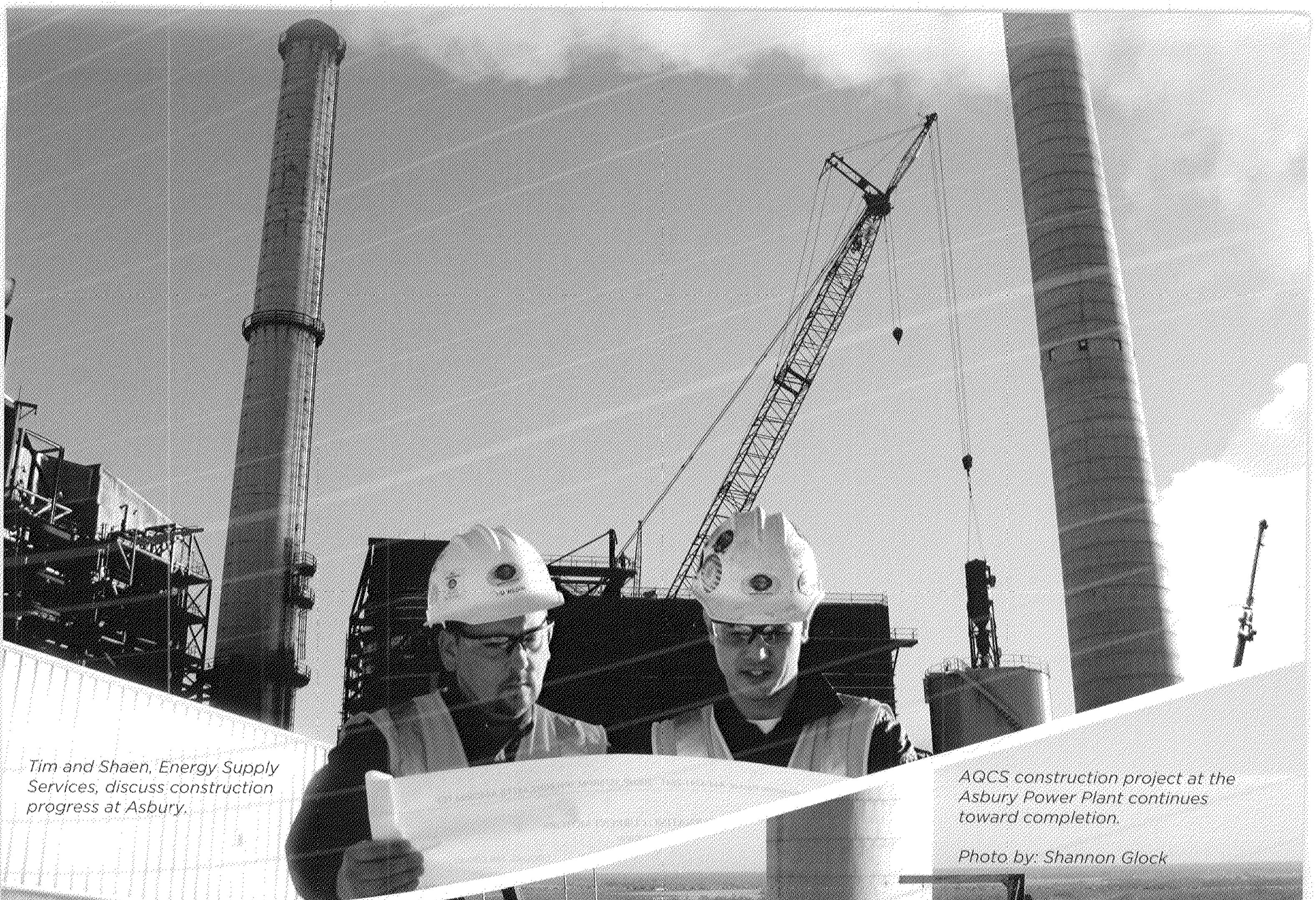
Brad Beecher
President and CEO
February 21, 2014

In an effort to improve service reliability to our customers, Empire developed a more aggressive line clearance plan to reduce outages due to vegetation. Crews have nearly completed a full loop around the system, which includes approximately 200,000 poles, 11,000 pad-mount devices, more than 6,000 miles of distribution line and about 1,300 miles of transmission line.

Wright Tree Service performing necessary tree removal and trimming along power lines.

Safety on the job conveys its own reward, but Empire employees received an additional honor from the National Safety Council of the Ozarks to mark the achievement of 1,000,000 hours worked without a lost-time injury. The injury-free period stretched over eight months dating back to April 2013. This significant safety milestone has only been attained six times in Company history. The last time was in July 2004.

Members of Empire's safety team are presented with the Les Reynolds Million Hour Award by the National Safety Council of the Ozarks.



Tim and Shaen, Energy Supply Services, discuss construction progress at Asbury.

AQCS construction project at the Asbury Power Plant continues toward completion.

Photo by: Shannon Glock

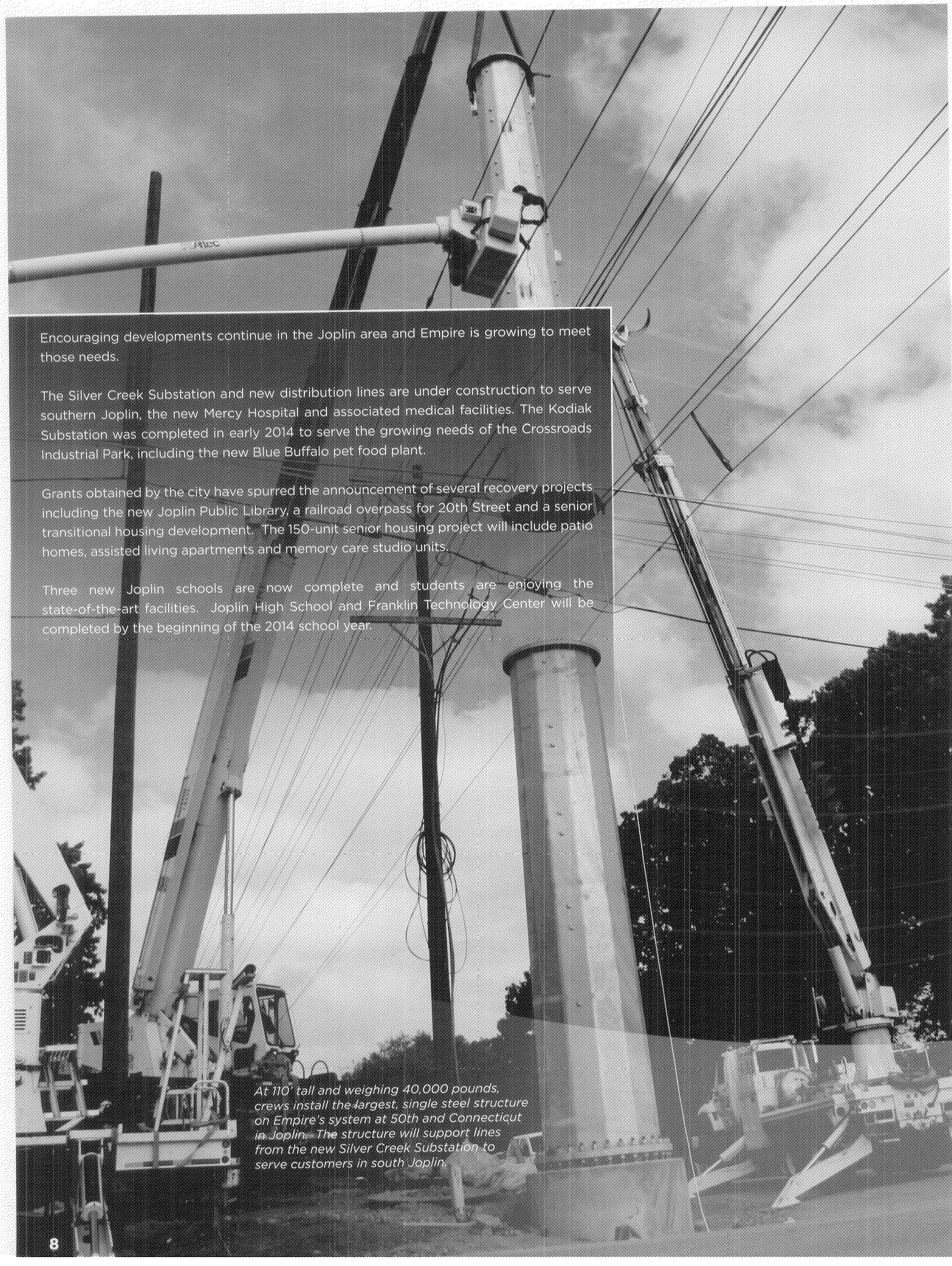
In response to new regulations from the Environmental Protection Agency, work continued on the air quality control system (AQCS) at the Asbury Power Plant. The three-year project began in the spring of 2012. The AQCS consists of a circulating dry scrubber to control sulfur dioxide, a pulse jet fabric filter (baghouse) to control particulate matter and a powder-activated carbon injection system to reduce mercury emissions. The AQCS project is scheduled for completion in early 2015.

Encouraging developments continue in the Joplin area and Empire is growing to meet those needs.

The Silver Creek Substation and new distribution lines are under construction to serve southern Joplin, the new Mercy Hospital and associated medical facilities. The Kodiak Substation was completed in early 2014 to serve the growing needs of the Crossroads Industrial Park, including the new Blue Buffalo pet food plant.

Grants obtained by the city have spurred the announcement of several recovery projects including the new Joplin Public Library, a railroad overpass for 20th Street and a senior transitional housing development. The 150-unit senior housing project will include patio homes, assisted living apartments and memory care studio units.

Three new Joplin schools are now complete and students are enjoying the state-of-the-art facilities. Joplin High School and Franklin Technology Center will be completed by the beginning of the 2014 school year.



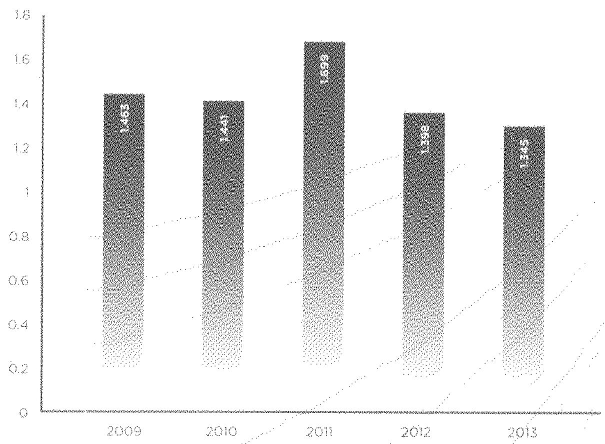
At 110' tall and weighing 40,000 pounds, crews install the largest, single steel structure on Empire's system at 50th and Connecticut in Joplin. The structure will support lines from the new Silver Creek Substation to serve customers in south Joplin.

Service Reliability

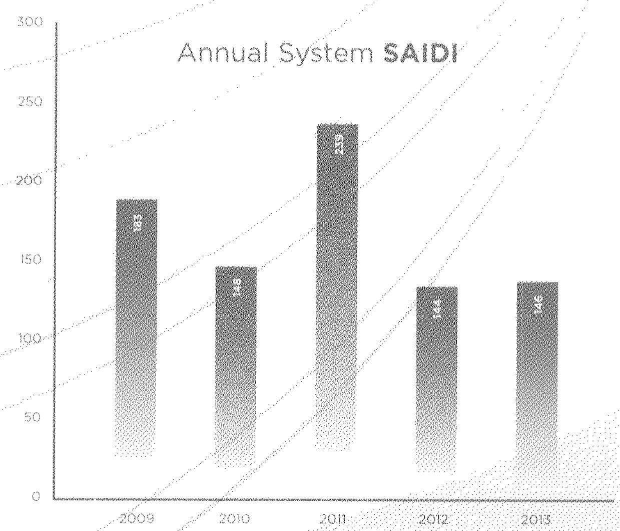
In 2013 we continued to improve service reliability. Reliability is measured using two primary factors – interruption frequency and duration. We posted a four percent improvement in SAIFI (System Average Interruption Frequency Index). We had been on track for a three percent improvement in SAIDI (System Average Interruption Duration Index), but closed out the year relatively unchanged, due to a late December ice storm. The minimal impact of the ice storm speaks to the system improvements we've made.

The 2012 update to the Outage Management System, the continuation of Operation Toughen Up, a 10-year, $100 million initiative to strengthen our delivery system, and enhanced vegetation management practices are driving our improvements in reliability. Our long-term goal remains to achieve a SAIFI of 1.00 and a SAIDI of 100.

Annual System **SAIFI**



Annual System **SAIDI**



SAIFI

An index of 1.3 means the average customer would experience 1.3 outages during the year.

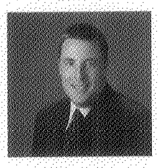
SAIDI

An index of 140 means the average customer experienced a total of 140 outage minutes during the year.

Two-and-a-half years after the tornado, a welcome milestone was reached in January 2014 as students of Irving Elementary (pictured), Soaring Heights Elementary and East Middle School moved into new state-of-the-art facilities.

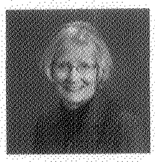
Construction progress at Mercy Hospital.

Officers[1]



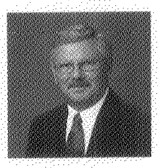
Bradley P. Beecher
President and Chief Executive Officer
(Age 48, 24 years of service)

Martin O. Penning
Vice President – Commercial Operations
(Age 59, 33 years of service)

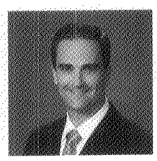


Laurie A. Delano
Vice President – Finance and Chief Financial Officer
(Age 58, 23 years of service)

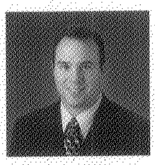
Kelly S. Walters
Vice President and Chief Operating Officer – Electric
(Age 48, 21 years of service)



Ronald F. Gatz
Vice President and Chief Operating Officer – Gas
(Age 63, 12 years of service)



Robert W. Sager
Controller, Assistant Secretary and Assistant Treasurer
(Age 39, 7 years of service)



Blake A. Mertens
Vice President – Energy Supply
(Age 36, 12 years of service)

Janet S. Watson
Secretary – Treasurer
(Age 61, 19 years of service)

Michael E. Palmer
Vice President – Transmission Policy and Corporate Services
(Age 57, 27 years of service)

Committees of the Board

Audit Committee – Allen[2], Hartley, Lind[2], Mueller[2] (Chair)

Compensation Committee – Allen, Laney, Ohlmacher (Chair), Portney, Schmidt

Nominating/Corporate Governance Committee – Allen, Hartley (Chair), Laney, Lind, Sullivan

Retirement Committee – Gipson, Lind (Chair), Mueller, Ohlmacher, Sullivan

Strategic Projects Committee – Gipson, Ohlmacher, Portney (Chair), Schmidt, Sullivan

Executive Committee – Beecher (Chair), Gipson, Laney, Mueller, Schmidt

Risk Oversight Committee – Hartley, Laney (Chair), Mueller, Ohlmacher, Portney

[1] Ages shown as of March 1, 2014.
[2] Audit Committee Financial Expert.

Directors[1]

Kenneth R. Allen
Vice President – Finance and Chief Financial Officer
Texas Industries, Inc.
Dallas, Texas
(Age 56, Director since 2005)

Bradley P. Beecher
President and Chief Executive Officer
The Empire District Electric Company
(Age 48, Director since 2011)

William L. Gipson
Retired President and Chief Executive Officer
The Empire District Electric Company
Shell Knob, Missouri
(Age 57, Director since 2002)

Ross C. Hartley
Co-Founder and Director, NIC, Inc.
Teton Village, Wyoming
(Age 66, Director since 1988)

D. Randy Laney
Chairman of the Board of Directors
The Empire District Electric Company
Farmington, Arkansas
(Age 59, Director since 2003)

Bonnie C. Lind
Senior Vice President, Chief Financial Officer and Treasurer
Neenah Paper, Inc.
Alpharetta, Georgia
(Age 55, Director since 2009)

B. Thomas Mueller
Founder, President and Chief Executive Officer, SALOV North America Corporation
Montclair, New Jersey
(Age 66, Director since 2003)

Thomas M. Ohlmacher
Retired President and Chief Operating Officer, Non-regulated Energy
Black Hills Corporation
Fort Collins, Colorado
(Age 62, Director since 2011)

Paul R. Portney
Professor of Economics and former Dean, Eller College of Management
University of Arizona
Tucson, Arizona
(Age 68, Director since 2009)

Herbert J. Schmidt
Retired Executive Vice President, Con-way Inc. and President, Con-way Truckload
Bronaugh, Missouri
(Age 58, Director since 2010)

C. James Sullivan
Principal
The Sullivan Group LLC
Birmingham, Alabama
(Age 67, Director since 2010)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ **Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2013

or

☐ **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from to .

Commission file number: 1-3368

THE EMPIRE DISTRICT ELECTRIC COMPANY
(Exact name of registrant as specified in its charter)

Kansas (State of Incorporation)	**44-0236370** (I.R.S. Employer Identification No.)
602 S. Joplin Avenue, Joplin, Missouri (Address of principal executive offices)	**64801** (zip code)

Registrant's telephone number: (417) 625-5100

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock ($1 par value)	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the registrant's voting common stock held by nonaffiliates of the registrant, based on the closing price on the New York Stock Exchange on June 30, 2013, was approximately $955,552,315.

As of February 3, 2014, 43,093,133 shares of common stock were outstanding.

The following documents have been incorporated by reference into the parts of the Form 10-K as indicated:

The Company's proxy statement, filed pursuant to Regulation 14A under the Securities Exchange Act of 1934, for its Annual Meeting of Stockholders to be held on May 1, 2014	Part of Item 10 of Part III All of Item 11 of Part III Part of Item 12 of Part III All of Item 13 of Part III All of Item 14 of Part III

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FORWARD LOOKING STATEMENTS

Certain matters discussed in this annual report are "forward-looking statements" intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. Such statements address or may address future plans, objectives, expectations and events or conditions concerning various matters such as capital expenditures, earnings, pension and other costs, competition, litigation, our construction program, our generation plans, our financing plans, potential acquisitions, rate and other regulatory matters, liquidity and capital resources and accounting matters. Forward-looking statements may contain words like "anticipate", "believe", "expect", "project", "objective" or similar expressions to identify them as forward-looking statements. Factors that could cause actual results to differ materially from those currently anticipated in such statements include:

- weather, business and economic conditions and other factors which may impact sales volumes and customer growth;
- the costs and other impacts resulting from natural disasters, such as tornados and ice storms;
- the amount, terms and timing of rate relief we seek and related matters;
- the results of prudency and similar reviews by regulators of costs we incur, including capital expenditures and fuel and purchased power costs, including any regulatory disallowances that could result from prudency reviews;
- unauthorized physical or virtual access to our facilities and systems and acts of terrorism, including, but not limited to, cyber-terrorism;
- legislation and regulation, including environmental regulation (such as NOx, SO_2, mercury, ash and CO_2) and health care regulation;
- the periodic revision of our construction and capital expenditure plans and cost and timing estimates;
- costs and activities associated with markets and transmission, including the Southwest Power Pool (SPP) Energy Imbalance Services Market, SPP regional transmission organization (RTO) transmission development, and SPP Day-Ahead Market;
- the impact of energy efficiency and alternative energy sources;
- electric utility restructuring, including ongoing federal activities and potential state activities;
- rate regulation, growth rates, discount rates, capital spending rates, terminal value calculations and other factors integral to the calculations utilized to test the impairment of goodwill, in addition to market and economic conditions which could adversely affect the analysis and ultimately negatively impact earnings;
- volatility in the credit, equity and other financial markets and the resulting impact on short term debt costs and our ability to issue debt or equity securities, or otherwise secure funds to meet our capital expenditure, dividend and liquidity needs;
- the effect of changes in our credit ratings on the availability and cost of funds;
- the performance of our pension assets and other post employment benefit plan assets and the resulting impact on our related funding commitments;
- our exposure to the credit risk of our hedging counterparties;
- performance of acquired businesses;

- the cost and availability of purchased power and fuel, including costs and activities associated with the transition to the SPP Day-Ahead Market, and the results of our activities (such as hedging) to reduce the volatility of such costs;
- interruptions or changes in our coal delivery, gas transportation or storage agreements or arrangements;
- operation of our electric generation facilities and electric and gas transmission and distribution systems, including the performance of our joint owners;
- changes in accounting requirements;
- costs and effects of legal and administrative proceedings, settlements, investigations and claims; and
- other circumstances affecting anticipated rates, revenues and costs.

All such factors are difficult to predict, contain uncertainties that may materially affect actual results, and may be beyond our control. New factors emerge from time to time and it is not possible for management to predict all such factors or to assess the impact of each such factor on us. Any forward-looking statement speaks only as of the date on which such statement is made, and we do not undertake any obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made.

We caution you that any forward-looking statements are not guarantees of future performance and involve known and unknown risk, uncertainties and other factors which may cause our actual results, performance or achievements to differ materially from the facts, results, performance or achievements we have anticipated in such forward-looking statements.

PART I

ITEM 1. BUSINESS

General

We operate our businesses as three segments: electric, gas and other. The Empire District Electric Company (EDE), a Kansas corporation organized in 1909, is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company (EDG) is our wholly owned subsidiary engaged in the distribution of natural gas in Missouri. Our other segment consists of our fiber optics business.

Our gross operating revenues in 2013 were derived as follows:

Electric segment sales*	90.3%
Gas segment sales	8.4
Other segment sales	1.3

* Sales from our electric segment include 0.4% from the sale of water.

The territory served by our electric operations embraces an area of about 10,000 square miles, located principally in southwestern Missouri, and also includes smaller areas in southeastern Kansas, northeastern Oklahoma and northwestern Arkansas. The principal economic activities of these areas include light industry, agriculture and tourism. As of December 31, 2013, our electric operations served approximately 168,800 customers.

Our retail electric revenues for 2013 by jurisdiction were derived as follows:

Missouri	89.8%
Kansas	4.8
Arkansas	2.5
Oklahoma	2.9

We supply electric service at retail to 119 incorporated communities as of December 31, 2013, and to various unincorporated areas and at wholesale to four municipally owned distribution systems. The largest urban area we serve is the city of Joplin, Missouri, and its immediate vicinity, with a population of approximately 160,000. We operate under franchises having original terms of twenty years or longer in virtually all of the incorporated communities. Approximately 49% of our electric operating revenues in 2013 were derived from incorporated communities with franchises having at least ten years remaining and approximately 21% were derived from incorporated communities in which our franchises have remaining terms of ten years or less. Although our franchises contain no renewal provisions, in recent years we have obtained renewals of all of our expiring electric franchises prior to the expiration dates.

Our three largest classes of on-system customers are residential, commercial and industrial, which provided 42.6%, 30.4%, and 15.1%, respectively, of our electric operating revenues in 2013.

Our largest single on-system wholesale customer is the city of Monett, Missouri, which in 2013 accounted for approximately 2.7% of electric revenues. No single retail customer accounted for more than 1.6% of electric revenues in 2013.

Our gas operations serve customers in northwest, north central and west central Missouri. As of December 31, 2013, our gas operations served approximately 44,000 customers. We provide natural gas distribution to 48 communities and 377 transportation customers as of December 31, 2013. The largest urban area we serve is the city of Sedalia with a population of over 20,000. We operate under franchises having original terms of twenty years in virtually all of the incorporated communities. Eighteen of the franchises have 10 years or more remaining on their term and 26 of the franchises have less than 10 years remaining on their term. Although our franchises contain no renewal provisions, since our acquisition we have obtained renewals of all our expiring gas franchises prior to the expiration dates.

Our gas operating revenues in 2013 were derived as follows:

Residential	63.1%
Commercial	27.3
Industrial	1.0
Miscellaneous	8.6

No single retail customer accounted for more than 1% of gas revenues in 2013.

Our other segment consists of our fiber optics business. As of December 31, 2013, we have 118 fiber customers.

Electric Generating Facilities and Capacity

At December 31, 2013, our generating plants consisted of:

Plant	Capacity (megawatts)[1]	Primary Fuel
Asbury	189[2]	Coal
Riverton — Natural Gas	279	Natural Gas
Iatan (12% ownership)	190[3]	Coal
Plum Point Energy Station (7.52% ownership)	50[3]	Coal
State Line Combined Cycle (60% ownership)	297[3]	Natural Gas
Empire Energy Center	262	Natural Gas
State Line Unit No. 1	94	Natural Gas
Ozark Beach	16	Hydro
TOTAL	1,377	

(1) Based on summer rating conditions as utilized by Southwest Power Pool.

(2) Does not include Asbury unit 2 (14 megawatts) which was retired at the end of 2013.

(3) Capacity reflects our allocated shares of the capacity of these plants.

See Item 2, "Properties — Electric Segment Facilities" for further information about these plants.

We, and most other electric utilities with interstate transmission facilities, have placed our facilities under the Federal Energy Regulatory Commission (FERC) regulated open access tariffs that provide all wholesale buyers and sellers of electricity the opportunity to procure transmission services (at the same rates) that the utilities provide themselves. We are a member of the Southwest Power Pool Regional Transmission Organization (SPP RTO). See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Markets and Transmission."

We currently supplement our on-system generating capacity with purchases of capacity and energy from other sources in order to meet the demands of our customers and the capacity margins applicable to us under current pooling agreements and National Electric Reliability Council rules. The SPP requires its members to maintain a minimum 12% capacity margin.

We have a long-term (30 year) agreement for the purchase of 50 megawatts of capacity from the Plum Point Energy Station (Plum Point), a 670-megawatt, coal-fired generating facility near Osceola, Arkansas. We began receiving purchased power under this agreement on September 1, 2010. We also own, through an undivided interest, 50 megawatts of the unit's capacity. We have the option to purchase an undivided ownership interest in the 50 megawatts covered by the purchased power agreement in 2015. We evaluated this purchase option as part of our Integrated Resource Plan (IRP), which was filed with the Missouri Public Service Commission (MPSC) in mid-2013. While it is not currently our intention to exercise this option in 2015, we will continue to evaluate this purchase option through the exercise date as well as explore other options with the purchase power agreement holder, Plum Point Energy Associates (PPEA), related to this option.

We have a 20-year purchased power agreement, which began on December 15, 2008, with Cloud County Windfarm, LLC, owned by EDP Renewables North America LLC, Houston, Texas to purchase the energy generated at the approximately 105-megawatt Phase 1 Meridian Way Wind Farm located in Cloud County, Kansas. We also have a 20-year contract, which began on December 15, 2005, with Elk River Windfarm, LLC, owned by IBERDROLA RENEWABLES, Inc., to purchase the energy generated at the 150-megawatt Elk River Windfarm located in Butler County, Kansas. We do not own any portion of either windfarm.

The following chart sets forth our purchase commitments and our anticipated owned capacity (in megawatts) during the indicated years. The capacity ratings we use for our generating units are based on summer rating conditions under SPP guidelines. The portion of the purchased power that may be counted as capacity from the Elk River Windfarm, LLC and the Cloud County Windfarm, LLC is included in this chart. Because the wind power is an intermittent, non-firm resource, SPP rating criteria does not allow us to count a substantial amount of the wind power as capacity. See Item 7, "Managements' Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources."

Year	Purchased Power Commitment(1)	Anticipated Owned Capacity	Total Megawatts
2014	62	1377	1439(2)
2015	62	1381	1443(3)
2016	62	1384	1446(4)
2017	62	1384	1446
2018	62	1384	1446

(1) Includes 7 megawatts for the Elk River Windfarm, LLC and 5 megawatts for the Cloud County Windfarm, LLC.

(2) Reflects the retirement of Asbury Unit 2.

(3) Reflects the Asbury turbine retrofit and added pollution control equipment.

(4) Reflects the retirement of Riverton Units 7, 8 and 9 and conversion of Riverton Unit 12 to a combined cycle.

The maximum hourly demand on our system reached a record high of 1,199 megawatts on January 8, 2010. Our previous winter peak of 1,100 megawatts was established on December 22, 2008. Our maximum hourly summer demand of 1,198 megawatts was set on August 2, 2011.

Gas Facilities

At December 31, 2013, our principal gas utility properties consisted of approximately 87 miles of transmission mains and approximately 1,160 miles of distribution mains.

The following table sets forth the three pipelines that serve our gas customers:

Service Area	Name of Pipeline
South	Southern Star Central Gas Pipeline
North	Panhandle Eastern Pipe Line Company
Northwest	ANR Pipeline Company

Our all-time peak of 73,280 mcfs was established on January 7, 2010.

Construction Program

Total property additions (including construction work in progress but excluding AFUDC) for the three years ended December 31, 2013, totaled $397.7 million and retirements during the same period totaled $39.3 million. Please refer to Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" for more information.

Our total capital expenditures, excluding AFUDC and expenditures to retire assets, were $155.4 million in 2013 and for the next three years are estimated for planning purposes to be as follows:

	Estimated Capital Expenditures (amounts in millions)			
	2014	2015	2016	Total
New electric generating facilities:				
Riverton Unit 12 combined cycle conversion	$ 79.9	$ 62.5	$ 16.1	$158.5
Additions to existing electric generating facilities:				
Asbury	16.1	3.4	8.9	28.4
Environmental upgrades — Asbury	24.2	12.4	—	36.6
Other	9.9	12.9	8.0	30.8
Electric transmission facilities	25.9	29.3	27.5	82.7
Electric distribution system additions	36.9	39.9	36.6	113.4
General and other additions	11.3	9.3	6.7	27.3
Gas system additions	7.7	4.1	4.0	15.8
Non-regulated additions	1.8	2.1	2.3	6.2
TOTAL	$213.7	$175.9	$110.1	$499.7

Our estimated total capital expenditures (excluding AFUDC) for 2017 and 2018 are $99.2 million and $95.9 million, respectively. Construction expenditures for additions to our transmission and distribution systems, the conversion of Riverton Unit 12 to a combined cycle unit and environmental upgrades at Asbury constitute the majority of the projected capital expenditures for the three-year period listed above beyond routine capital expenditures.

Estimated capital expenditures are reviewed and adjusted for, among other things, revised estimates of future capacity needs, the cost of funds necessary for construction, costs to recover from natural disasters and the availability and cost of alternative power. Actual capital expenditures may vary significantly from the estimates due to a number of factors including changes in customer requirements, construction delays, changes in equipment delivery schedules, ability to raise capital, environmental matters, the extent to which we receive timely and adequate rate increases, the extent of competition from independent power producers and cogenerators, other changes in business conditions and changes in legislation and regulation, including those relating to the energy industry. See "— Regulation" below and Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Markets and Transmission."

Fuel and Natural Gas Supply

Electric Segment

Our total system output for 2013 and 2012, based on kilowatt-hours generated, was as follows:

	2013	2012
Steam generation units — coal	47.0%	48.0%
Steam generation units — natural gas	0.0	0.2
Combustion turbine generation units — natural gas	24.3	24.9
Hydro generation	1.0	1.0
Purchased power — windfarms	14.8	15.0
Purchased power — other	12.9	10.9

Below are the total fuel requirements for our generating units in 2013 and 2012 (based on kilowatt-hours generated):

	2013	2012
Coal	65.9%	65.6%
Natural gas	34.0	34.3
Fuel oil	0.1	0.1

Our Asbury Plant is fueled primarily by coal with oil being used as start-up fuel. In 2013, Asbury burned a coal blend consisting of approximately 92.4% Western coal (Powder River Basin) and 7.6% blend coal on a tonnage basis. Our average coal inventory target at Asbury is approximately 60 days. As of December 31, 2013, we had sufficient coal on hand to supply full load requirements at Asbury for 38-59 days, as compared to 102-107 days as of December 31, 2012, depending on the actual blend ratio. The inventory decreased during 2013 as Asbury readjusted back to target levels following the 2012 transition of Riverton Units 7 and 8 to natural gas.

The following table sets forth the percentage of our anticipated coal requirements we have secured through a combination of contracts and binding proposals for the following years:

Year	Percentage secured
2014	97%
2015	39%
2016	19%

All of the Western coal used at our Asbury plant is shipped by rail, a distance of approximately 800 miles. We have a coal transportation agreement with the Burlington Northern and Santa Fe Railway Company (BNSF) and the Kansas City Southern Railway Company which runs through 2019. We currently lease one aluminum unit train full time to deliver Western coal to the Asbury Plant.

Unit 1 and Unit 2 at the Iatan Plant are coal-fired generating units which are jointly-owned by KCP&L, a subsidiary of Great Plains Energy, Inc., Missouri Joint Municipal Electric Utility Commission, Kansas Electric Power Cooperative (KEPCO) and us, with our share of ownership being 12% in each plant. KCP&L is the operator of these plants and is responsible for arranging their fuel supply. KCP&L has secured contracts for low sulfur Western coal in quantities sufficient to meet 70% of Iatan's requirements for 2014 and approximately 30% for 2015 and 15% for 2016. Coal is transported to Iatan by rail. In 2013, KCP&L and KCP&L Greater Missouri Operations entered into agreements with the railroads for transportation services through December 31, 2018.

The Plum Point Energy Station is a 670-megawatt, coal-fired generating facility near Osceola, Arkansas. We own, through an undivided interest, 50 megawatts of the plant's capacity. North America

Energy Services is the operator of this plant. Plum Point Services Company, LLC (PPSC), the project management company acting on behalf of the joint owners, is responsible for arranging its fuel supply. PPSC has secured contracts for low sulfur Western coal in quantities sufficient to meet approximately 86% of Plum Point's requirements for 2014, 86% for 2015 and 94% for 2016. We have a 15-year lease agreement, expiring in 2024, for 54 railcars for our ownership share of Plum Point and another 15-year lease agreement, expiring in 2025, for an additional 54 railcars associated with our Plum Point purchased power agreement.

Since its transition from coal in 2012, our Riverton Plant is fueled primarily by natural gas with oil available as backup for Units 9, 10 and 11. Units 7 and 8, along with Unit 12, are fueled 100% by natural gas. Based on kilowatt hours generated during 2013, Riverton's generation was 100% natural gas.

Our Energy Center and State Line Unit No.1 combustion turbine facilities (not including the State Line Combined Cycle (SLCC) Unit, which is fueled 100% by natural gas) are fueled primarily by natural gas with oil also available for use primarily as backup. Based on kilowatt hours generated during 2013, 100% of the Energy Center generation was produced from natural gas and 89% of the State Line Unit 1 generation came from natural gas with the remainder being fuel oil. As of December 31, 2013, oil inventories were sufficient for approximately 2 days of full load operation on Units No. 1, 2, 3 and 4 at the Energy Center and 5 days of full load operation for State Line Unit No. 1. As typical oil usage is minimal, these inventories are sufficient for our current requirements.

We have firm transportation agreements with Southern Star Central Pipeline, Inc. with current expiration dates of June 24, 2017, for the transportation of natural gas to the SLCC. This date is adjusted for periods of contract suspension by us during outages of the SLCC. This transportation agreement can also supply natural gas to State Line Unit No.1, the Energy Center or the Riverton Plant, as elected by us on a secondary basis. We also have a precedent agreement with Southern Star, which provides additional transportation capability until 2022. This contract provides firm transport to the sites listed above that previously were only served on a secondary basis. We expect that these transportation agreements will serve nearly all of our natural gas transportation needs for our generating plants over the next several years. Any remaining gas transportation requirements, although small, will be met by utilizing capacity release on other holder contracts, interruptible transport, or delivered to the plants by others.

The majority of our physical natural gas supply requirements will be met by short-term forward contracts and spot market purchases. Forward natural gas commodity prices and volumes are hedged several years into the future in accordance with our Risk Management Policy in an attempt to lessen the volatility in our fuel expenditures and gain predictability. In addition, we have an agreement with Southern Star to purchase one million Dths of firm gas storage service capacity for a period of five years, expiring in 2016. The reservation charge for this storage capacity is approximately $1.1 million annually. This storage capacity enables us to better manage our natural gas commodity and transportation needs for our electric segment.

The following table sets forth a comparison of the costs, including transportation and other miscellaneous costs, per million Btu, of various types of fuels used in our electric facilities:

Fuel Type / Facility	2013	2012	2011
Coal — Iatan	$ 1.756	$ 1.760	$ 1.603
Coal — Asbury	2.432	2.395	2.315
Coal — Riverton(1)	0.000	2.541	2.314
Coal — Plum Point	2.123	1.804	1.858
Natural Gas	4.952	4.493	5.475
Oil	21.870	20.291	21.304
Weighted average cost of fuel burned per kilowatt-hour generated	$2.8074	$2.6742	$2.9558

(1) Reflects the September 2012 transition of Riverton Units 7 and 8 from operation on coal to full operation on natural gas.

Gas Segment

We have agreements with many of the major suppliers in both the Midcontinent and Rocky Mountain regions that provide us with both supply and price diversity. We continue to expand our supplier base to enhance supply reliability as well as provide for increased price competition.

The following table sets forth the current costs, including storage, transportation and other miscellaneous costs, per mcf of gas used in our gas operations:

Service Area	Name of Pipeline	2013	2012	2011
South	Southern Star Central Gas Pipeline	$5.4998	$6.4329	$6.1619
North	Panhandle Eastern Pipe Line Company	5.9746	6.8990	6.1449
Northwest	ANR Pipeline Company	4.7589	5.0898	5.4230
	Weighted average cost per mcf	$5.4949	$6.3305	$6.0542

Employees

At December 31, 2013, we had 751 full-time employees, including 50 employees of EDG. 328 of the EDE employees are members of Local 1474 of The International Brotherhood of Electrical Workers (IBEW). On December 10, 2013, the Local 1474 IBEW voted to ratify a new five-year agreement, effective December 2, 2013, which will extend through October 31, 2018. At December 31, 2013, 33 EDG employees were members of Local 1464 of the IBEW. In May 2013, Local 1464 of the IBEW ratified a four-year agreement with EDG, effective June 1, 2013.

ELECTRIC OPERATING STATISTICS[1]

	2013	2012	2011	2010	2009
Electric Operating Revenues (000's):					
Residential	$ 227,656	$ 214,526	$ 221,687	$ 204,900	$ 180,404
Commercial	162,444	158,837	157,435	146,310	135,800
Industrial	80,497	78,786	78,925	69,684	65,983
Public authorities[2]	14,707	13,755	13,653	12,099	11,411
Wholesale on-system	20,036	18,555	19,140	19,254	18,199
Miscellaneous[3]	13,223	8,520	8,194	7,573	6,814
Interdepartmental	229	197	201	199	178
Total system	518,792	493,176	499,235	460,019	418,789
Wholesale off-system	15,488	15,687	23,271	22,891	14,344
Total electric operating revenues[4]	**534,280**	**508,863**	**522,506**	**482,910**	**433,133**
Electricity generated and purchased (000's of kWh):					
Steam	2,813,441	2,865,037	2,805,744	2,650,042	2,259,304
Hydro	57,449	57,719	48,898	88,104	76,733
Combustion turbine	1,452,936	1,486,643	1,484,472	1,566,074	926,934
Total generated	4,323,826	4,409,399	4,339,114	4,304,220	3,262,971
Purchased	1,660,193	1,545,327	1,870,901	2,085,550	2,516,702
Total generated and purchased	5,984,019	5,954,726	6,210,015	6,389,770	5,779,673
Interchange (net)	432	(87)	(1,298)	(1,716)	(568)
Total system output	5,984,451	5,954,639	6,208,717	6,388,054	5,779,105
Transmission by others losses[5]	(15,817)	(17,300)	(16,597)	(5,688)	—
Total system input	**5,968,634**	**5,937,339**	**6,192,120**	**6,382,366**	**5,779,105**
Maximum hourly system demand (Kw)	1,080,000	1,142,000	1,198,000	1,199,000	1,085,000
Owned capacity (end of period) (Kw)	1,377,000	1,391,000	1,392,000	1,409,000	1,257,000
Annual load factor (%)	56.18	52.17	51.95	53.17	55.38
Electric sales (000's of kWh):					
Residential	1,936,603	1,850,813	1,982,704	2,060,368	1,866,473
Commercial	1,541,717	1,558,297	1,576,342	1,644,917	1,579,832
Industrial	1,015,492	1,028,416	1,022,765	1,007,033	992,165
Public authorities[2]	127,370	122,369	126,724	124,554	121,816
Wholesale on-system	343,045	353,075	364,866	355,807	332,061
Total system	4,964,227	4,912,970	5,073,401	5,192,679	4,892,347
Wholesale off-system	653,996	704,028	740,009	798,084	515,899
Total Electric Sales	**5,618,223**	**5,616,998**	**5,813,410**	**5,990,763**	**5,408,246**
Company use (000's of kWh)[6]	9,049	9,066	9,371	9,598	9,088
kWh losses (000's of kWh)[7]	341,362	311,275	369,339	382,005	361,771
Total System Input	**5,968,634**	**5,937,339**	**6,192,120**	**6,382,366**	**5,779,105**
Customers (average number):					
Residential	141,376	140,602	139,641	141,693	141,206
Commercial	24,080	24,036	24,155	24,505	24,412
Industrial	345	353	357	358	355
Public authorities[2]	2,214	2,124	2,021	2,003	1,995
Wholesale on-system	4	4	4	4	4
Total System	168,019	167,119	166,178	168,563	167,972
Wholesale off-system	22	22	25	22	19
Total	**168,041**	**167,141**	**166,203**	**168,585**	**167,991**
Average annual sales per residential customer (kWh)	13,698	13,163	14,199	14,541	13,218
Average annual revenue per residential customer	$ 1,610	$ 1,526	$ 1,588	$ 1,446	$ 1,278
Average residential revenue per kWh	11.76¢	11.59¢	11.18¢	9.94¢	9.67¢
Average commercial revenue per kWh	10.54¢	10.19¢	9.99¢	8.89¢	8.60¢
Average industrial revenue per kWh	7.93¢	7.66¢	7.72¢	6.92¢	6.65¢

(1) See Item 6, "Selected Financial Data" for additional financial information regarding Empire.

(2) Includes Public Street & Highway Lighting and Public Authorities.

(3) Includes transmission service revenues, late payment fees, renewable energy credit sales, rent, etc.

(4) Before intercompany eliminations.

(5) Energy provided in-kind to third party transmission providers to compensate for transmission losses associated with delivery of capacity and energy under their transmission tariffs.

(6) Includes kWh used by Company and Interdepartmental.

(7) 2012 includes the effect of our unbilled revenue adjustment.

GAS OPERATING STATISTICS[1]

	2013	2012	2011	2010	2009
Gas Operating Revenues (000's):					
Residential	$31,561	$24,744	$28,999	$32,245	$36,176
Commercial	13,673	10,797	12,506	13,336	15,552
Industrial	515	464	682	812	2,066
Public authorities	342	247	324	342	365
Total retail sales revenues	46,091	36,252	42,511	46,735	54,159
Miscellaneous[2]	435	400	464	436	221
Transportation revenues	3,515	3,197	3,455	3,714	2,934
Total Gas Operating Revenues	**50,041**	**39,849**	**46,430**	**50,885**	**57,314**
Maximum Daily Flow (mcf)	**60,118**	**58,281**	**67,789**	**73,280**	**70,046**
Gas delivered to customers (000's of mcf sales)[3]					
Residential	2,744	2,012	2,560	2,675	2,687
Commercial	1,349	1,050	1,268	1,265	1,278
Industrial	72	58	102	108	218
Public authorities	35	23	33	33	30
Total retail sales	4,200	3,143	3,963	4,081	4,213
Transportation sales	4,528	4,249	4,528	4,829	4,330
Total gas operating and transportation sales	8,728	7,392	8,491	8,910	8,543
Company use[3]	2	2	4	4	3
Transportation sales (cash outs)	—	—	—	—	—
Mcf losses	96	27	(47)	70	36
Total system sales	**8,826**	**7,421**	**8,448**	**8,984**	**8,582**
Customers (average number):					
Residential	37,777	37,897	38,051	38,277	38,621
Commercial	4,917	4,921	4,951	4,968	5,038
Industrial	24	23	26	26	25
Public authorities	140	138	136	137	131
Total retail customers	42,858	42,979	43,164	43,408	43,815
Transportation customers	340	326	311	313	296
Total gas customers	**43,198**	**43,305**	**43,475**	**43,721**	**44,111**

(1) See Item 6, "Selected Financial Data" for additional financial information regarding Empire.

(2) Primarily includes miscellaneous service revenue and late fees.

(3) Includes mcf used by Company and Interdepartmental mcf.

Executive Officers and Other Officers of Empire

The names of our officers, their ages and years of service with Empire as of December 31, 2013, positions held during the past five years and effective dates of such positions are presented below. All of our officers have been employed by Empire for at least the last five years.

Name	Age at 12/31/13	Positions With the Company	With the Company Since	Officer Since
Bradley P. Beecher	48	President and Chief Executive Officer (2011). Executive Vice President (2011), Executive Vice President and Chief Operating Officer — Electric (2010), Vice President and Chief Operating Officer — Electric (2006)	2001	2001
Laurie A. Delano	58	Vice President — Finance and Chief Financial Officer, (2011), Controller, Assistant Secretary and Assistant Treasurer and Principal Accounting Officer (2005)	2002	2005
Ronald F. Gatz	63	Vice President and Chief Operating Officer — Gas (2006)	2001	2001
Blake Mertens	36	Vice President — Energy Supply (2011), General Manager — Energy Supply (2010), Director of Strategic Projects, Safety and Environmental Services (2010), Associate Director of Strategic Projects (2009), Manager of Strategic Projects (2006)	2001	2011
Michael E. Palmer(1)	57	Vice President — Transmission Policy and Corporate Services (2011), Vice President — Commercial Operations (2001)	1986	2001
Martin O. Penning	58	Vice President — Commercial Operations, (2011), Director of Commercial Operations (2006)	1980	2011
Kelly S. Walters	48	Vice President and Chief Operating Officer — Electric (2011), Vice President — Regulatory and Services (2006)	2001	2006
Janet S. Watson	61	Secretary — Treasurer (1995)	1994	1995
Robert W. Sager	39	Controller, Assistant Secretary and Assistant Treasurer and Principal Accounting Officer (2011), Director of Financial Services (2006)	2006	2011

(1) Michael E. Palmer will retire from his position as Vice-President — Transmission Policy and Corporate Services effective March 31, 2014.

Regulation

Electric Segment

General. As a public utility, our electric segment operations are subject to the jurisdiction of the Missouri Public Service Commission (MPSC), the State Corporation Commission of the State of Kansas (KCC), the Corporation Commission of Oklahoma (OCC) and the Arkansas Public Service Commission (APSC) with respect to services and facilities, rates and charges, regulatory accounting, valuation of property, depreciation and various other matters. Each such Commission has jurisdiction over the creation of liens on property located in its state to secure bonds or other securities. The KCC also has jurisdiction over the issuance of all securities because we are a regulated utility incorporated in Kansas. Our transmission and sale at wholesale of electric energy in interstate commerce and our facilities are also subject to the jurisdiction of the FERC, under the Federal Power Act. FERC jurisdiction extends to, among other things, rates and charges in connection with such transmission and sale; the sale, lease or other disposition of such facilities and accounting matters. See discussion in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Markets and Transmission."

Electric operating revenues received during 2013 were comprised of the following:

Retail customers	90.9%
Sales subject to FERC jurisdiction	8.3
Miscellaneous sources	0.8

The percentage of retail regulated revenues derived from each state follows:

Missouri	89.8%
Kansas	4.8
Oklahoma	2.9
Arkansas	2.5

Rates. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Rate Matters" for information concerning recent electric rate proceedings.

Fuel Adjustment Clauses. Typical fuel adjustment clauses permit the distribution to customers of changes in fuel costs, subject to routine regulatory review, without the need for a general rate proceeding. Fuel adjustment clauses are presently applicable to our retail electric sales in Missouri, Oklahoma and Kansas and system wholesale kilowatt-hour sales under FERC jurisdiction. We have an Energy Cost Recovery Rider in Arkansas that adjusts for changing fuel and purchased power costs on an annual basis.

Gas Segment

General. As a public utility, our gas segment operations are subject to the jurisdiction of the MPSC with respect to services and facilities, rates and charges, regulatory accounting, valuation of property, depreciation and various other matters. The MPSC also has jurisdiction over the creation of liens on property to secure bonds or other securities.

Purchased Gas Adjustment (PGA). The PGA clause allows EDG to recover from our customers, subject to routine regulatory review, the cost of purchased gas supplies, transportation and storage costs, including costs associated with our use of natural gas financial instruments to hedge the purchase price of natural gas and related carrying costs. This PGA clause allows us to make rate changes periodically (up to four times) throughout the year in response to weather conditions and supply demands, rather than in one possibly extreme change per year.

Environmental Matters

See Note 11 of "Notes to Consolidated Financial Statements" under Item 8 for information regarding environmental matters.

Conditions Respecting Financing

Our EDE Indenture of Mortgage and Deed of Trust, dated as of September 1, 1944, as amended and supplemented (the EDE Mortgage), and our Restated Articles of Incorporation (Restated Articles), specify earnings coverage and other conditions which must be complied with in connection with the issuance of additional first mortgage bonds or cumulative preferred stock, or the incurrence of unsecured indebtedness. The principal amount of all series of first mortgage bonds outstanding at any one time under the EDE Mortgage is limited by terms of the mortgage to $1.0 billion. Substantially all of the property, plant and equipment of The Empire District Electric Company (but not its subsidiaries) is subject to the lien of the EDE Mortgage. Restrictions in the EDE mortgage bond indenture could affect our liquidity. The EDE Mortgage contains a requirement that for new first mortgage bonds to be issued, our net earnings (as defined in the EDE Mortgage) for any twelve consecutive months within the fifteen months preceding issuance must be two times the annual interest requirements (as defined in the EDE Mortgage) on all first mortgage bonds then outstanding and on the prospective issue of new first mortgage bonds. Our earnings for the year ended December 31, 2013, would permit us to issue approximately $599.1 million of new first mortgage bonds based on this test at an assumed interest rate of 5.5%. In addition to the interest coverage requirement, the EDE Mortgage provides that new bonds must be issued against, among other things, retired bonds or 60% of net property additions. At December 31, 2013, we had retired bonds and net property additions which would enable the issuance of at least $856.7 million principal amount of bonds if the annual interest requirements are met. As of December 31, 2013, we are in compliance with all restrictive covenants of the EDE Mortgage.

Under our Restated Articles, (a) cumulative preferred stock may be issued only if our net income available for interest and dividends (as defined in our Restated Articles) for a specified twelve-month period is at least 1½ times the sum of the annual interest requirements on all indebtedness and the annual dividend requirements on all cumulative preferred stock to be outstanding immediately after the issuance of such additional shares of cumulative preferred stock, and (b) so long as any preferred stock is outstanding, the amount of unsecured indebtedness outstanding may not exceed 20% of the sum of the outstanding secured indebtedness plus our capital and surplus. We have no outstanding preferred stock. Accordingly, the restriction in our Restated Articles does not currently restrict the amount of unsecured indebtedness that we may have outstanding.

The EDG Indenture of Mortgage and Deed of Trust, dated as of June 1, 2006, as amended and supplemented (the EDG Mortgage) contains a requirement that for new first mortgage bonds to be issued, the amount of such new first mortgage bonds shall not exceed 75% of the cost of property additions acquired after the date of the Missouri Gas acquisition. The principal amount of all series of first mortgage bonds outstanding at any one time under the EDG Mortgage is limited by terms of the mortgage to $300.0 million. Substantially all of the property, plant and equipment of The Empire District Gas Company is subject to the lien of the EDG Mortgage. The mortgage also contains a limitation on the issuance by EDG of debt (including first mortgage bonds, but excluding short-term debt incurred in the ordinary course under working capital facilities) unless, after giving effect to such issuance, EDG's ratio of EBITDA (defined as net income plus interest, taxes, depreciation, amortization and certain other non-cash charges) to interest charges for the most recent four fiscal quarters is at least 2.0 to 1.0. As of December 31, 2013, this test would allow us to issue approximately $15.8 million principal amount of new first mortgage bonds at an assumed interest rate of 5.5%.

See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources."

Our Web Site

We maintain a web site at www.empiredistrict.com. Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on form 8-K and related amendments are available free of charge through our web site as soon as reasonably practicable after such reports are filed with or furnished to the SEC electronically. Our Corporate Governance Guidelines, our Code of Business Conduct and Ethics, our Code of Ethics for the Chief Executive Officer and Senior Financial Officers, the charters for our Audit Committee, Compensation Committee and Nominating/Corporate Governance Committee, our Procedures for Reporting Complaints on Accounting, Internal Accounting Controls and Auditing Matters, our Procedures for Communicating with Non-Management Directors and our Policy and Procedures with Respect to Related Person Transactions can also be found on our web site. All of these documents are available in print to any interested party who requests them. Our web site and the information contained in it and connected to it shall not be deemed incorporated by reference into this Form 10-K.

ITEM 1A. RISK FACTORS

Investors should review carefully the following risk factors and the other information contained in this Form 10-K. The risks we face are not limited to those in this section. There may be additional risks and uncertainties (either currently unknown or not currently believed to be material) that could adversely affect our financial position, results of operations and liquidity.

Readers are cautioned that the risks and uncertainties described in this Form 10-K are not the only ones facing Empire. Additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations. Our business, financial condition or results of operations (including our ability to pay dividends on our common stock) could suffer if the concerns set forth below are realized.

We are exposed to increases in costs and reductions in revenue which we cannot control and which may adversely affect our business, financial condition and results of operations.

The primary drivers of our electric operating revenues in any period are: (1) rates we can charge our customers, (2) weather, (3) customer growth and usage and (4) general economic conditions. Of the factors driving revenues, weather has the greatest short-term effect on the demand for electricity for our regulated business. Mild weather reduces demand and, as a result, our electric operating revenues. In addition, changes in customer demand due to downturns in the economy or energy efficiency could reduce our revenues.

The primary drivers of our electric operating expenses in any period are: (1) fuel and purchased power expenses, (2) operating, maintenance and repairs expense, including repairs following severe weather and plant outages, (3) taxes and (4) non-cash items such as depreciation and amortization expense. Although we generally recover these expenses through our rates, there can be no assurance that we will recover all, or any part of, such increased costs in future rate cases.

The primary drivers of our gas operating revenues in any period are: (1) rates we can charge our customers, (2) weather, (3) customer growth, (4) the cost of natural gas and interstate pipeline transportation charges and (5) general economic conditions. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our natural gas service territory and a significant amount of our natural gas revenues are recognized in the first and fourth quarters related to the heating seasons. Accordingly, our natural gas operations have historically generated less revenues and income when weather conditions are warmer in the winter.

The primary driver of our gas operating expense in any period is the price of natural gas.

Significant increases in electric and gas operating expenses or reductions in electric and gas operating revenues may occur and result in a material adverse effect on our business, financial condition and results of operations.

We are exposed to factors that can increase our fuel and purchased power expenditures, including disruption in deliveries of coal or natural gas, decreased output from our power plants, failure of performance by purchased power counterparties and market risk in our fuel procurement strategy.

Fuel and purchased power costs are our largest expenditures. Increases in the price of coal, natural gas or the cost of purchased power will result in increased electric operating expenditures. Given we have a fuel cost recovery mechanism in all of our jurisdictions, our net income exposure to the impact of the risks discussed above is significantly reduced. However, cash flow could still be impacted by these increased expenditures. We are also subject to prudency reviews which could negatively impact our net income if a regulatory commission would conclude our costs were incurred imprudently.

We depend upon regular deliveries of coal as fuel for our Asbury, Iatan and Plum Point plants. Substantially all of this coal comes from mines in the Powder River Basin of Wyoming and is delivered to the plants by train. Production problems in these mines, railroad transportation or congestion problems, or unavailability of trains could affect delivery cycle times required to maintain plant inventory levels, causing us to implement coal conservation and supply replacement measures to retain adequate reserve inventories at our facilities. These measures could include some or all of the following: reducing the output of our coal plants, increasing the utilization of our gas-fired generation facilities, purchasing power from other suppliers, adding additional leased trains to our supply system and purchasing locally mined coal which can be delivered without using the railroads. Such measures could result in increased fuel and purchased power expenditures.

We have also established a risk management practice of purchasing contracts for future fuel needs to meet underlying customer needs and manage cost and pricing uncertainty. Within this activity, we may incur losses from these contracts. By using physical and financial instruments, we are exposed to credit risk and market risk. Market risk is the exposure to a change in the value of commodities caused by fluctuations in market variables, such as price. The fair value of derivative financial instruments we hold is adjusted cumulatively on a monthly basis until prescribed determination periods. At the end of each determination period, which is the last day of each calendar month in the period, any realized gain or loss for that period related to the contract will be reclassified to fuel expense and recovered or refunded to the customer through our fuel adjustment mechanisms. Credit risk is the risk that the counterparty might fail to fulfill its obligations under contractual terms.

We are subject to regulation in the jurisdictions in which we operate.

We are subject to comprehensive regulation by federal and state utility regulatory agencies, which significantly influences our operating environment and our ability to recover our costs from utility customers. The utility commissions in the states where we operate regulate many aspects of our utility operations, including the rates that we can charge customers, siting and construction of facilities, pipeline safety and compliance, customer service and our ability to recover costs we incur, including capital expenditures and fuel and purchased power costs.

The FERC has jurisdiction over wholesale rates for electric transmission service and electric energy sold in interstate commerce. Federal, state and local agencies also have jurisdiction over many of our other activities.

Information concerning recent filings requesting increases in rates and related matters is set forth under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Rate Matters."

We are also subject to prudency and similar reviews by regulators of costs we incur, including capital expenditures, fuel and purchased power costs and other operating costs.

We are unable to predict the impact on our operating results from the regulatory activities of any of these agencies, including any regulatory disallowances that could result from prudency reviews. Despite our requests, these regulatory commissions have sole discretion to leave rates unchanged, grant increases or order decreases in the base rates we charge our utility customers. They have similar authority with respect to our recovery of increases in our fuel and purchased power costs. If our costs increase and we are unable to recover increased costs through base rates or fuel adjustment clauses, or if we are unable to fully recover our investments in new facilities, our results of operations could be materially adversely affected. Changes in regulations or the imposition of additional regulations could also have a material adverse effect on our results of operations.

Operations risks may adversely affect our business and financial results.

The operation of our electric generation, and electric and gas transmission and distribution systems involves many risks, including breakdown or failure of expensive and sophisticated equipment, processes and personnel performance; inability to attract and retain management and other key personnel; workplace and public safety; operating limitations that may be imposed by workforce issues, equipment conditions, environmental or other regulatory requirements; fuel supply or fuel transportation reductions or interruptions; transmission scheduling constraints; unauthorized physical access to our facilities; and catastrophic events such as fires, explosions, severe weather, acts of terrorism or other similar occurrences.

In addition, our power generation and delivery systems, information technology systems and network infrastructure may be vulnerable to internal or external cyber attack, physical attack, unauthorized physical or virtual access, computer viruses or other attempts to harm our systems or misuse our confidential information.

We have implemented training and preventive maintenance programs and have security systems and related protective infrastructure in place, but there is no assurance that these programs will prevent or minimize future breakdowns, outages or failures of our generation facilities or related business processes. In those cases, we would need to either produce replacement power from our other facilities or purchase power from other suppliers at potentially volatile and higher cost in order to meet our sales obligations, or implement emergency back-up business system processing procedures.

The SPP RTO is mandated by the FERC to ensure a reliable power supply, an adequate transmission infrastructure and competitive wholesale electricity prices. The SPP RTO functions as reliability coordination, tariff administration and regional scheduler for its member utilities, including us. Essentially, the SPP RTO independently operates our transmission system as it interfaces and coordinates with the regional power grid. SPP RTO activities directly impact our control of owned generating assets and the development and cost of transmission infrastructure projects within the SPP RTO region. The cost allocation methodology applied to these transmission infrastructure projects will increase our operating expenses.

The SPP RTO expects to implement a Day-Ahead Market, or Integrated Marketplace, in March 2014. The SPP Integrated Marketplace will function as a centralized dispatch, where we and other members will submit offers to sell power and bids to purchase power. The SPP will match offers and bids to supply our and other members' next day generation needs. It is expected that 90% – 95% of all next day generation needed throughout the SPP territory will be cleared through this Integrated Marketplace. This change could impact our fuel costs, however, the net financial effect of these Integrated Marketplace transactions will be processed through our fuel adjustment mechanisms.

These and other operating events and conditions may reduce our revenues, increase costs, or both, and may materially affect our results of operations, financial position and cash flows.

Information concerning recent and pending SPP RTO and other FERC activities can be found under Note 3 of "Notes to Consolidated Financial Statements" under Item 8.

We may be unable to recover increases in the cost of natural gas from our natural gas utility customers, or may lose customers as a result of any price increases.

In our natural gas utility business, we are permitted to recover the cost of gas directly from our customers through the use of a purchased gas adjustment provision. Our purchased gas adjustment provision is regularly reviewed by the MPSC. In addition to reviewing our adjustments to customer rates, the MPSC reviews our costs for prudency as well. To the extent the MPSC may determine certain costs were not incurred prudently, it could adversely affect our gas segment earnings and cash flows. In addition, increases in natural gas costs affect total prices to our customers and, therefore, the competitive position of gas relative to electricity and other forms of energy. Increases in natural gas costs may also result in lower usage by customers unable to switch to alternate fuels. Such disallowed costs or customer losses could have a material adverse effect on our business, financial condition and results of operations.

Any reduction in our credit ratings could materially and adversely affect our business, financial condition and results of operations.

Currently, our corporate credit ratings and the ratings for our securities are as follows:

	Fitch	Moody's	Standard & Poor's
Corporate Credit Rating	n/r*	Baa1	BBB
EDE First Mortgage Bonds	BBB+	A2	A-
Senior Notes	BBB	Baa1	BBB
Commercial Paper	F3	P-2	A-2
Outlook	Stable	Stable	Stable

* Not rated.

The ratings indicate the agencies' assessment of our ability to pay the interest and principal of these securities. A rating is not a recommendation to purchase, sell or hold securities and each rating should be evaluated independently of any other rating. The lower the rating, the higher the interest cost of the securities when they are sold. In addition, a downgrade in our senior unsecured long-term debt rating would result in an increase in our borrowing costs under our bank credit facility. If any of our ratings fall below investment grade (investment grade is defined as Baa3 or above for Moody's and BBB− or above for Standard & Poor's and Fitch), our ability to issue short-term debt, commercial paper or other securities or to market those securities would be impaired or made more difficult or expensive. Therefore, any such downgrades could have a material adverse effect on our business, financial condition and results of operations. In addition, any actual downgrade of our commercial paper rating from Moody's or Fitch, may make it difficult for us to issue commercial paper. To the extent we are unable to issue commercial paper, we will need to meet our short-term debt needs through borrowings under our revolving credit facilities, which may result in higher costs.

We cannot assure you that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant.

We are subject to environmental laws and the incurrence of environmental liabilities which may adversely affect our business, financial condition and results of operations.

We are subject to extensive federal, state and local regulation with regard to air and other environmental matters. Failure to comply with these laws and regulations could have a material adverse effect on our results of operations and financial position. In addition, new environmental laws and regulations, and new interpretations of existing environmental laws and regulations, have been adopted and may in the future be adopted which may substantially increase our future environmental expenditures for both new facilities and our existing facilities. Compliance with current and potential future air emission standards (such as those limiting emission levels of sulfur dioxide (SO2), emissions of mercury, other hazardous pollutants (HAPS), nitrogen oxide (NOx), and carbon dioxide (CO2)) has required, and may in the future require, significant environmental expenditures. Although we have historically recovered such costs through our rates, there can be no assurance that we will recover all, or any part of, such increased costs in future rate cases. The incurrence of additional material environmental costs which are not recovered in our rates may result in a material adverse effect on our business, financial condition and results of operations.

The cost and schedule of construction projects may materially change.

Our capital expenditure budget for the next three years is estimated to be $499.7 million. This includes expenditures for environmental upgrades to our existing facilities and additions to our transmission and distribution systems. There are risks that actual costs may exceed budget estimates, delays may occur in obtaining permits and materials, suppliers and contractors may not perform as required under their contracts, there may be inadequate availability, productivity or increased cost of qualified craft labor, start-up activities may take longer than planned, the scope and timing of projects may change, and other events beyond our control may occur that may materially affect the schedule, budget, cost and performance of projects. To the extent the completion of projects is delayed, we expect that the timing of receipt of increases in base rates reflecting our investment in such projects will be correspondingly delayed. Costs associated with these projects will also be subject to prudency review by regulators as part of future rate case filings and all costs may not be allowed recovery.

Financial market disruptions may increase financing costs, limit access to the credit markets or cause reductions in investment values in our pension plan assets.

We estimate our capital expenditures to be $213.7 million in 2014. Although we believe it is unlikely we will have difficulty accessing the markets for the capital needed to complete these projects (if such a need arises), financing costs could fluctuate. Financial market disruptions can also cause reductions in investment value in our pension plan assets, which could lead to increased funding obligations. We expect to fund approximately $15.0 million during 2014 for pension and OPEB liabilities. Although positive asset performance in 2013 led to decreased liabilities in 2013, future market changes could result in increased pension and OPEB liabilities and funding obligations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Electric Segment Facilities

Our generating facilities consist of three coal-fired generating plants, two natural gas generating plants and one hydroelectric generating plant. At December 31, 2013, we owned generating facilities with an aggregate generating capacity of 1,377 megawatts. We retired the 14-megawatt Unit 2 at our Asbury Plant on December 31, 2013, as required by the addition of air quality control equipment being installed at our Asbury plant (discussed below) in order to comply with forthcoming environmental regulations.

The Asbury Plant, located near Asbury, Missouri, is a coal-fired generating station. The plant consisted of two steam turbine generating units with 203 megawatts of generating capacity until the end of 2013 when we retired Unit 2. In 2013, the plant accounted for approximately 14% of our owned generating capacity and accounted for approximately 29.9% of the energy generated by us. As part of our environmental Compliance Plan, discussed in Note 11 of "Notes to Consolidated Financial Statements" under Item 8, we are in the process of installing a scrubber, fabric filter and powder activated carbon injection system at our Asbury plant. The addition of this air quality control equipment is expected to be completed in early 2015 and required the retirement of Asbury Unit 2 at the end of 2013, reducing the plant's capacity to 189 megawatts. This reduces our owned generating facilities aggregate generating capacity to 1,377 megawatts in 2014. Routine plant maintenance, during which the entire plant is taken out of service, is scheduled annually, normally for approximately three to four weeks in the spring. Approximately every fifth year, the maintenance outage is scheduled to be extended to approximately six weeks to permit inspection of the Unit No. 1 turbine. The next such outage is scheduled to take place in the fall of 2014. When the Asbury Plant is out of service, we typically experience increased purchased power and fuel expenditures associated with replacement energy, which is likely to be recovered through our fuel adjustment clauses.

We own a 12% undivided interest in the coal-fired Unit No. 1 and Unit No. 2 at the Iatan Generating Station located near Weston, Missouri, 35 miles northwest of Kansas City, Missouri, as well as a 3% interest in the site and a 12% interest in certain common facilities. Unit No. 2 entered commercial operation on December 31, 2010. We are entitled to 12% of the units' available capacity, currently 85 megawatts for Unit No. 1 and 105 megawatts for Unit No. 2, and are obligated to pay for that percentage of the operating costs of the units. KCP&L operates the units for the joint owners.

We own a 7.52% undivided interest in the coal-fired Plum Point Energy Station located near Osceola, Arkansas. We are entitled to 50 megawatts, or 7.52% of the unit's available capacity. The Plum Point Energy Station entered commercial operation on September 1, 2010.

Our generating plant located at Riverton, Kansas, has four gas-fired combustion turbine units (Units 9, 10, 11 and 12) and two gas-fired steam generating units (Units 7 and 8) with an aggregate generating capacity of 279 megawatts. In September 2012, Units 7 and 8 were transitioned from operation on coal to full operation on natural gas. Unit 12 began commercial operation on April 10, 2007 and is scheduled to be converted from a simple cycle combustion turbine to a combined cycle unit, with scheduled completion in mid-2016.

Our State Line Power Plant, which is located west of Joplin, Missouri, consists of Unit No. 1, a combustion turbine unit with generating capacity of 94 megawatts and a Combined Cycle Unit with generating capacity of 495 megawatts of which we are entitled to 60%, or 297 megawatts. The Combined Cycle Unit consists of the combination of two combustion turbines, two heat recovery steam generators, a steam turbine and auxiliary equipment. The Combined Cycle Unit is jointly owned with Westar Generating Inc., a subsidiary of Westar Energy, Inc., which owns the remaining 40% of the unit. We are the operator of the Combined Cycle Unit and Westar reimburses us for a percentage of the operating costs per our joint ownership agreement. All units at our State Line Power Plant burn natural gas as a primary fuel with Unit No. 1 having the additional capability of burning oil.

We have four combustion turbine peaking units at the Empire Energy Center in Jasper County, Missouri, with an aggregate generating capacity of 262 megawatts. These peaking units operate on natural gas, as well as oil.

Our hydroelectric generating plant (FERC Project No. 2221), located on the White River at Ozark Beach, Missouri, has a generating capacity of 16 megawatts. We have a long-term license from FERC to operate this plant which forms Lake Taneycomo in southwestern Missouri. As part of the Energy and Water Development Appropriations Act of 2006 (the Appropriations Act), a new minimum flow pattern was established with the intent of increasing minimum flows on recreational streams in Arkansas. To accomplish this, the level of Bull Shoals Lake was increased an average of 5 feet. The increase at Bull Shoals will decrease the net head waters available for generation at Ozark Beach by 5 feet and, thus, reduce our electrical output. We estimate the lost production to be up to 16% of our average annual energy production for this unit. The loss in this facility will require us to replace it with additional generation from our gas-fired and coal-fired units or with purchased power. The Appropriations Act required the Southwest Power Administration (SWPA), in coordination with us and our relevant public service commissions, to determine our economic detriment assuming a January 1, 2011 implementation date. On September 16, 2010, we received a $26.6 million payment from the SWPA, which was deferred and recorded as a noncurrent liability. The SWPA payment, net of taxes, is being used to reduce fuel expense for our customers in all our jurisdictions. It is our understanding that the lake level change for Bull Shoals was implemented in July of 2013.

At December 31, 2013, our transmission system consisted of approximately 22 miles of 345 kV lines, 441 miles of 161 kV lines, 745 miles of 69 kV lines and 81 miles of 34.5 kV lines. Our distribution system consisted of approximately 6,882 miles of line at December 31, 2013 and December 31, 2012.

Our electric generation stations, other than Plum Point Energy Station, are located on land owned in fee. We own a 3% undivided interest as tenant in common in the land for the Iatan Generating Station. We own a similar interest in 60% of the land used for the State Line Combined Cycle Unit. Substantially all of our electric transmission and distribution facilities are located either (1) on property leased or owned in fee; (2) over streets, alleys, highways and other public places, under franchises or other rights; or (3) over private property by virtue of easements obtained from the record holders of title. Substantially all of our electric segment property, plant and equipment are subject to the EDE Mortgage.

We also own and operate water pumping facilities and distribution systems consisting of a total of approximately 89 miles of water mains in three communities in Missouri.

Gas Segment Facilities

At December 31, 2013, our principal gas utility properties consisted of approximately 87 miles of transmission mains and approximately 1,160 miles of distribution mains.

Substantially all of our gas transmission and distribution facilities are located either (1) on property leased or owned in fee; (2) under streets, alleys, highways and other public places, under franchises or other rights; or (3) under private property by virtue of easements obtained from the record holders of title. Substantially all of our gas segment property, plant and equipment are subject to the EDG Mortgage.

Other Segment

Our other segment consists of our leasing of fiber optics cable and equipment (which we also use in our own utility operations).

ITEM 3. LEGAL PROCEEDINGS

See Note 11 of "Notes to Consolidated Financial Statements" under Item 8, which description is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed on the New York Stock Exchange (ticker symbol: EDE). On February 3, 2014, there were 4,379 record holders and 28,500 individual participants in security position listings. The following table presents the high and low sales prices (and quarter end closing sales prices) for our common stock as reported by the New York Stock Exchange for composite transactions, and the amount per share of quarterly dividends declared and paid on the common stock for each quarter during 2013 and 2012.

	High	Low	Close	Dividends Paid Per Share
2013 Quarter Ended:				
March 31	$22.41	$20.57	$22.40	$0.250
June 30	23.35	21.26	22.31	0.250
September 30	24.32	20.77	21.66	0.250
December 31	23.26	21.27	22.69	0.255
2012 Quarter Ended:				
March 31	$21.34	$19.55	$20.35	$0.250
June 30	21.24	19.51	21.10	0.250
September 30	21.94	21.02	21.55	0.250
December 31	22.04	19.59	20.38	0.250

Holders of our common stock are entitled to dividends, if, as, and when declared by the Board of Directors, out of funds legally available therefore subject to the prior rights of holders of any outstanding cumulative preferred stock and preference stock. Payment of dividends is determined by our Board of Directors after considering all relevant factors, including the amount of our retained earnings, which is essentially our accumulated net income less dividend payouts.

In the fourth quarter of 2013, the Board of Directors increased the dividend by 2%, from $0.25 per share on common stock to $0.255 per share. In the first quarter of 2014, the Board of Directors declared a quarterly dividend of $0.255 per share on common stock payable on March 17, 2014 to holders of record as of March 3, 2014. As of December 31, 2013, our retained earnings balance was $67.6 million, compared to $47.1 million at December 31, 2012. A reduction of our dividend per share, partially or in whole, could have an adverse effect on our common stock price.

See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operation — Dividends" for information on limitations on our ability to pay dividends on our common stock.

During 2013, no purchases of our common stock were made by or on behalf of us.

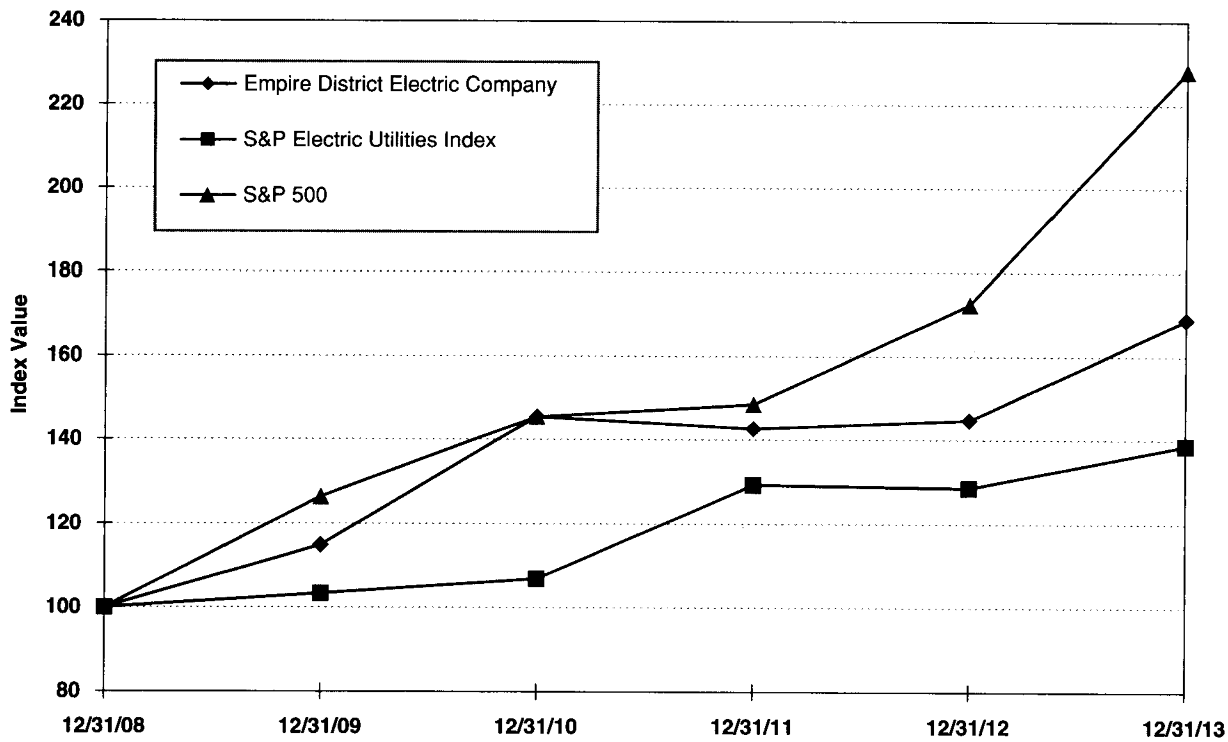
Participants in our Dividend Reinvestment and Stock Purchase Plan may acquire, at a 3% discount, newly issued common shares with reinvested dividends. Participants may also purchase, at an averaged market price, newly issued common shares with optional cash payments on a weekly basis, subject to certain restrictions. We also offer participants the option of safekeeping for their stock certificates.

Our By-laws provide that K.S.A. Sections 17-1286 through 17-1298, the Kansas Control Share Acquisitions Act, will not apply to control share acquisitions of our capital stock.

See Note 4 of "Notes to Consolidated Financial Statements" under Item 8 for additional information regarding our common stock and equity compensation plans.

The following graph and table indicates the value at the end of the specified years of a $100 investment made on December 31, 2008, in our common stock and similar investments made in the securities of the companies in the Standard & Poor's 500 Composite Index (S&P 500 Index) and the Standard & Poor's Electric Utilities Index (S&P Electric Utility). The graph and table assume that dividends were reinvested when received.

Total Return Performance



Total Return Analysis	12/31/2008	12/31/2009	12/31/2010	12/31/2011	12/31/2012	12/31/2013
The Empire District Electric Company	$100.00	$114.96	$145.53	$142.70	$144.79	$168.77
S&P Electric Utilities Index	$100.00	$103.38	$106.93	$129.35	$128.63	$138.66
S&P 500 Index	$100.00	$126.46	$145.51	$148.59	$172.37	$228.19

ITEM 6. SELECTED FINANCIAL DATA

(in thousands, except per share amounts)

	2013	2012	2011	2010	2009
Operating revenues	$ 594,330	$ 557,097	$ 576,870	$ 541,276	$ 497,168
Operating income	$ 99,663	$ 96,221	$ 96,934	$ 80,495	$ 74,495
Total allowance for funds used during construction	$ 5,940	$ 1,928	$ 512	$ 10,174	$ 14,133
Net income	$ 63,445	$ 55,681	$ 54,971	$ 47,396	$ 41,296
Weighted average number of common shares outstanding — basic	42,781	42,257	41,852	40,545	34,924
Weighted average number of common shares outstanding — diluted	42,803	42,284	41,887	40,580	34,956
Earnings from continuing operations per weighted average share of common stock — basic and diluted	$ 1.48	$ 1.32	$ 1.31	$ 1.17	$ 1.18
Total earnings per weighted average share of common stock — basic and diluted	$ 1.48	$ 1.32	$ 1.31	$ 1.17	$ 1.18
Cash dividends per share	$ 1.005	$ 1.00	$ 0.64	$ 1.28	$ 1.28
Common dividends paid as a percentage of net income	67.8%	75.9%	48.6%	109.7%	108.5%
Allowance for funds used during construction as a percentage of net income	9.4%	3.5%	0.9%	21.5%	34.2%
Book value per common share (actual) outstanding at end of year	$ 17.43	$ 16.90	$ 16.53	$ 15.82	$ 15.75
Capitalization:					
Common equity	$ 750,124	$ 717,798	$ 693,989	$ 657,624	$ 600,150
Long-term debt	$ 743,428	$ 691,626	$ 692,259	$ 693,072	$ 640,156
Ratio of earnings to fixed charges	2.97X	2.89X	2.87X	2.63X	2.15X
Total assets	$2,145,045	$2,126,369	$2,021,835	$1,921,311	$1,839,846
Plant in service at original cost	$2,332,341	$2,284,022	$2,176,650	$2,108,115	$1,718,584
Capital expenditures (including AFUDC)	$ 160,196	$ 146,287	$ 101,177	$ 108,157	$ 148,804

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

EXECUTIVE SUMMARY

Electric Segment

As a traditional, vertically integrated regulated utility, the primary drivers of our electric operating revenues in any period are: (1) rates we can charge our customers, (2) weather, (3) customer growth and usage and (4) general economic conditions. The utility commissions in the states in which we operate, as well as the Federal Energy Regulatory Commission (FERC), set the rates which we can charge our customers. In order to offset expenses, we depend on our ability to receive adequate and timely recovery of our costs (primarily fuel and purchased power) and/or rate relief. We assess the need for rate relief in all of the jurisdictions we serve and file for such relief when necessary. The effects of timing of rate relief are discussed in detail in Note 3 of "Notes to the Consolidated Financial Statements" under Item 8. Of the factors driving revenues, weather has the greatest short-term effect on the demand for electricity for our regulated business. Very hot summers and very cold winters increase electric demand, while mild weather reduces demand. Residential and commercial sales are impacted more by weather than industrial sales, which are mostly affected by business needs for electricity and by general economic conditions.

Customer growth, which is the growth in the number of customers, contributes to the demand for electricity. We expect our electric customer and sales growth to be less than 1.0% annually over the next several years. Our electric customer growth for the year ended December 31, 2013 was 0.5%. We define electric sales growth to be growth in kWh sales period over period excluding the estimated impact of weather. The primary drivers of electric sales growth are customer growth, customer usage and general economic conditions.

The primary drivers of our electric operating expenses in any period are: (1) fuel and purchased power expense, (2) operating maintenance and repairs expense, including repairs following severe weather and plant outages, (3) taxes and (4) non-cash items such as depreciation and amortization expense. We have a fuel cost recovery mechanism in all of our jurisdictions, which significantly reduces the impact of fluctuating fuel and purchased power costs on our net income.

Gas Segment

The primary drivers of our gas operating revenues in any period are: (1) rates we can charge our customers, (2) weather, (3) customer growth and usage, (4) the cost of natural gas and interstate pipeline transportation charges and (5) general economic conditions. The MPSC sets the rates which we can charge our customers. In order to offset expenses, we depend on our ability to receive adequate and timely recovery of our costs (primarily commodity natural gas) and/or rate relief. We assess the need for rate relief and file for such relief when necessary. A Purchased Gas Adjustment (PGA) clause is included in our gas rates, which allows us to recover our actual cost of natural gas from customers through rate changes, which are made periodically (up to four times) throughout the year in response to weather conditions, natural gas costs and supply demands. Weather affects the demand for natural gas. Very cold winters increase demand for gas, while mild weather reduces demand. Due to the seasonal nature of the gas business, revenues and earnings are typically concentrated in the November through March period, which generally corresponds with the heating season.

Customer growth, which is the growth in the number of customers, contributes to the demand for gas. Our annual customer growth is calculated by comparing the number of customers at the end of a year to the number of customers at the end of the prior year. Our gas segment customer contraction for the year ended December 31, 2013 was 0.1%, which we believe was due to depressed economic conditions. We expect gas customer growth to be flat during the next several years. We define gas sales growth to be growth in mcf sales excluding the impact of weather. The primary drivers of gas sales growth are customer growth and general economic conditions.

The primary driver of our gas operating expense in any period is the price of natural gas. However, because gas purchase costs for our gas utility operations are normally recovered from our customers, any change in gas prices does not have a corresponding impact on income unless such costs are deemed imprudent or cause customers to reduce usage.

Earnings

For the year ended December 31, 2013, basic and diluted earnings per weighted average share of common stock were $1.48 on $63.4 million of net income compared to $1.32 on $55.7 million of net income for the year ended December 31, 2012. Increased electric gross margins (defined as electric revenues less fuel and purchased power costs) positively impacted net income for 2013 as compared to 2012, reflecting an increase in electric revenues of approximately $25.7 million, mainly due to increased electric rates for our Missouri customers effective April 1, 2013. Improved electric customer counts, favorable winter weather and increased AFUDC due to higher levels of construction activity during 2013 also positively impacted results. Increased regulatory operating expense and depreciation and amortization expense negatively impacted 2013 results.

The table below sets forth a reconciliation of basic and diluted earnings per share between 2012 and 2013, which is a non-GAAP presentation. The economic substance behind our non-GAAP earnings per share (EPS) measure is to present the after tax impact of significant items and components of the statement of income, including segment revenues and operating expenses, on a per share basis before the impact of additional stock issuances. The dilutive effect of additional shares issued included in the table reflects the estimated impact of all shares issued during the period.

We believe this presentation is useful to investors because the statement of income does not readily show the EPS impact of the various components, including the effect of new stock issuances. This could limit the readers' understanding of the reasons for the EPS change from the previous year's EPS. This information is useful to management, and we believe this information is useful to investors, to better understand the reasons for the fluctuation in EPS between the prior and current years on a per share basis.

In addition, although a non-GAAP presentation, we believe the presentation of gross margin (in the table below and elsewhere in this report) is useful to investors and others in understanding and analyzing changes in our electric operating performance from one period to the next, and have included the analysis as a complement to the financial information we provide in accordance with GAAP. This reconciliation and margin information may not be comparable to other companies' presentations or more useful than the GAAP presentation included in the statements of income or elsewhere in this report. We also note that this presentation does not purport to be an alternative to earnings per share determined in accordance with GAAP as a measure of operating performance or any other measure of financial performance presented in accordance with GAAP. Management compensates for the limitations of using non-GAAP financial measures by using them to supplement GAAP results to provide a more complete understanding of the factors and trends affecting the business than GAAP results alone.

Earnings Per Share — 2012	$ 1.32
Revenues	
Electric segment	0.38
Gas segment	0.15
Other segment	0.02
Total Revenue	0.55
Electric fuel and purchased power	0.05
Cost of natural gas sold and transported	(0.11)
Gross Margin	0.49
Operating — electric segment	(0.15)
Operating — gas segment	(0.01)
Operating — other segment	(0.01)
Maintenance and repairs	(0.01)
Depreciation and amortization	(0.13)
Loss on plant disallowance	(0.03)
Other taxes	(0.05)
AFUDC	0.06
Change in effective income tax rates	0.02
Other income and deductions	(0.02)
Earnings Per Share — 2013	$ 1.48

Fourth Quarter Results

Earnings for the fourth quarter of 2013 were $15.2 million, or $0.35 per share, as compared to $9.6 million, or $0.23 per share, in the fourth quarter of 2012. Electric segment gross margins increased during the quarter ending December 31, 2013 compared to the 2012 quarter, reflecting the impact of colder weather experienced during the fourth quarter of 2013 as compared to the same period in 2012 and the April 2013 Missouri electric rate increase, partially offset by increased electric operating and maintenance expenses.

2013 Activities

Regulatory Matters

On December 3, 2013, we filed a request with the Arkansas Public Service Commission for changes in rates for our Arkansas electric customers. We are seeking an annual increase in total revenue of approximately $2.2 million, or approximately 18%. The rate increase was requested to recover costs incurred to ensure continued reliable service for our customers, including capital investments, operating systems replacement costs and ongoing increases in other operation and maintenance expenses and capital costs.

On February 22, 2013, we filed a Nonunanimous Stipulation and Agreement (Agreement) with the Missouri Public Service Commission (MPSC) which issued an order approving the Agreement on February 27, 2013, effective March 6, 2013. The Agreement provided for an annual increase in base revenues for our Missouri electric customers in the amount of approximately $27.5 million, effective April 1, 2013, and the continuation of the current fuel adjustment mechanism.

On May 18, 2012, we filed a request with the Federal Energy Regulatory Commission (FERC) to implement a cost-based transmission formula rate (TFR). On June 13, 2013, we, the Kansas Corporation Commission and the cities of Monett, Mt. Vernon and Lockwood, Missouri and Chetopa, Kansas, filed a unanimous Settlement Agreement (Agreement) with the FERC. The Agreement includes a TFR that establishes an ROE of 10.0%. The FERC conditionally approved the Agreement on November 18, 2013, and we made a compliance filing with the FERC on December 18, 2013 in connection with this conditional approval. Final FERC action on our compliance filing is pending.

For additional information on all these cases, see Note 3 of "Notes to Consolidated Financial Statements" under Item 8 for information regarding regulatory matters.

Integrated Resource Plan

We filed our Integrated Resource Plan (IRP) with the MPSC on July 1, 2013. The IRP analysis of future loads and resources is normally conducted once every three years. Our IRP supports our Compliance Plan discussed in Note 11 of "Notes to Consolidated Financial Statements" under Item 8.

As part of our IRP, we agreed to introduce additional demand-side management programs to help our customers use energy more efficiently. On October 30, 2013 we filed a request with the MPSC to implement a portfolio of demand-side management programs under the Missouri Energy Efficiency Investment Act (MEEIA). The request, subject to regulatory approval, would implement new energy efficiency programs for customers in 2014. The request also includes a Demand-Side Program Investment Mechanism (DSIM) that would be added to monthly customer bills if approved by the MPSC. The DSIM charge is designed to offset the financial costs associated with the programs. On January 14, 2014, the MPSC granted a motion to suspend the procedural schedule to allow the parties to the case more time to hold additional technical conferences and perform additional financial analysis on our proposed demand-side management portfolio.

Financings

On October 30, 2012, we entered into a Bond Purchase Agreement for a private placement of $30.0 million of 3.73% First Mortgage Bonds due May 30, 2033 and $120.0 million of 4.32% First Mortgage Bonds due May 30, 2043. The delayed settlement of both series of bonds occurred on May 30, 2013. Interest is payable semi-annually on the bonds on each May 30 and November 30, commencing November 30, 2013.

A portion of the proceeds from the above sale of bonds was used to redeem all $98.0 million aggregate principal amount of our Senior Notes, 4.50% Series due June 15, 2013. The remaining proceeds were used for general corporate purposes.

For additional information, see Note 6 of "Notes to Consolidated Financial Statements" under Item 8.

RESULTS OF OPERATIONS

The following discussion analyzes significant changes in the results of operations for the years 2013, 2012 and 2011.

The following table represents our results of operations by operating segment for the applicable years ended December 31 (in millions):

	2013	2012	2011
Electric	$58.6	$52.6	$50.6
Gas	2.3	1.3	2.7
Other	2.5	1.8	1.6
Net income	**$63.4**	**$55.7**	**$54.9**

Electric Segment

Overview

Our electric segment income for 2013 was $58.6 million as compared to $52.6 million and $50.6 million for 2012 and 2011, respectively.

Electric operating revenues comprised approximately 89.9% of our total operating revenues during 2013. Electric operating revenues for 2013, 2012, and 2011 were comprised of the following:

	2013	2012	2011
Residential	42.6%	42.2%	42.4%
Commercial	30.4	31.2	30.1
Industrial	15.1	15.5	15.1
Wholesale on-system	3.7	3.6	3.7
Wholesale off-system	2.9	3.1	4.5
Miscellaneous sources*	2.8	2.7	2.6
Other electric revenues	2.5	1.7	1.6

* Primarily other public authorities

Gross Margin

The table below represents our electric gross margins for the years ended December 31 (in millions).

	2013	2012	2011
Electric segment revenues	$536.4	$510.7	$524.3
Fuel and purchased power	175.4	178.9	200.3
Electric segment gross margins	$361.0	$331.8	$324.0
Margin as % of total electric segment revenues	67.3%	65.0%	61.8%

As shown in the table above, electric segment gross margin, defined as electric revenues less fuel and purchased power costs, increased approximately $29.2 million during 2013 as compared to 2012. Increased electric rates for our Missouri customers, an increase in average electric customer counts and colder weather in the first and fourth quarters of 2013 positively impacted revenues and gross margin during 2013. These increases were partially offset by a change in our unbilled revenue estimate in the third quarter of 2012.

The electric gross margin increased approximately $7.8 million during 2012 as compared to 2011. Decreased sales demand, resulting from mild winter weather in the first quarter of 2012 and less favorable weather in the third quarter of 2012 as compared to the same period in 2011, negatively impacted revenues and margins. This negative impact was partially offset by a full year of electric customer rate increases for our Missouri customers and improving electric customer counts as customers continued to return to the system following the May 2011 tornado. The change in our unbilled revenue estimate in the third quarter of 2012 also positively impacted gross margin. Decreases in non-volume fuel expenses also increased margin by approximately $4.3 million over 2011.

Sales and Revenues

The amounts and percentage changes from the prior periods in kilowatt-hour ("kWh") sales by major customer class for on-system and off-system sales were as follows:

	kWh Sales (in millions)					
Customer Class	2013	2012	% Change(1)	2012	2011	% Change(1)
Residential	1,936.6	1,850.8	4.6%	1,850.8	1,982.7	(6.7)%
Commercial	1,541.7	1,558.3	(1.1)	1,558.3	1,576.3	(1.1)
Industrial	1,015.5	1,028.4	(1.3)	1,028.4	1,022.8	0.6
Wholesale on-system	343.1	353.1	(2.8)	353.1	364.9	(3.2)
Other(2)	129.4	124.2	4.2	124.2	128.7	(3.5)
Total on-system sales	4,966.3	4,914.8	1.0	4,914.8	5,075.4	(3.2)
Off-system	654.0	704.0	(7.1)	704.0	740.0	(4.9)
Total KWh Sales	5,620.3	5,618.8	0.0	5,618.8	5,815.4	(3.4)

(1) Percentage changes are based on actual kWh sales and may not agree to the rounded amounts shown above.

(2) Other kWh sales include street lighting, other public authorities and interdepartmental usage.

KWh sales for our on-system customers increased slightly during 2013 as compared to 2012 primarily due to increased demand due to colder temperatures in the first and fourth quarters of 2013 as compared to the same periods in 2012. Residential kWh sales, the most weather sensitive class, increased 4.6% primarily due to these weather impacts and an increase in the average residential customer count.

Commercial sales decreased 1.1% primarily due to a net unbilled sales adjustment recorded in 2012. Industrial sales decreased 1.3% during 2013 as compared to 2012 due to operating reductions by several large industrial customers. On-system wholesale kWh sales decreased during 2013 as compared to 2012 reflecting the closure of a large dairy facility in Monett, Missouri. Total heating degree days (the sum of the number of degrees that the daily average temperature for each day during that period was below 65° F) for 2013 were 31.7% more than 2012 and 5.0% more than the 30-year average. Total cooling degree days (the cumulative number of degrees that the average temperature for each day during that period was above 65° F) for 2013 were 19.7% less than 2012 although they were 2.1% more than the 30-year average. The weather was unseasonably hot in June and July of 2012.

KWh sales for our on-system customers decreased approximately 3.2% during 2012 as compared to 2011 primarily due to decreased demand due to milder winter temperatures in 2012 as compared to 2011 and a trend toward more efficient utilization of electric power by our customers. Residential and commercial kWh sales decreased primarily due to these weather impacts and efficient utilization of electric power. Industrial sales increased slightly during 2012 as compared to 2011. On-system wholesale kWh sales decreased during 2012 as compared to 2011 reflecting the milder weather in 2012.

The amounts and percentage changes from the prior period's electric segment operating revenues by major customer class for on-system and off-system sales were as follows:

	Electric Segment Operating Revenues ($ in millions)					
Customer Class	**2013**	**2012**	**% Change[1]**	**2012**	**2011**	**% Change[1]**
Residential	$227.7	$214.5	6.1%	$214.5	$221.7	(3.2)%
Commercial	162.4	158.8	2.3	158.8	157.4	0.9
Industrial	80.5	78.8	2.2	78.8	78.9	(0.2)
Wholesale on-system	20.0	18.6	8.0	18.6	19.1	(3.1)
Other[2]	15.0	14.0	7.0	14.0	13.9	0.7
Total on-system revenues	505.6	484.7	4.3	484.7	491.0	(1.3)
Off-system	15.5	15.7	(1.3)	15.7	23.3	(32.6)
Total revenues from KWh sales	521.1	500.4	4.1	500.4	514.3	(2.7)
Miscellaneous revenues[3]	13.2	8.5	55.2	8.5	8.2	4.0
Total electric operating revenues	$534.3	$508.9	5.0	$508.9	$522.5	(2.6)
Water revenues	2.1	1.8	19.2	1.8	1.8	1.2
Total Electric Segment Operating Revenues	$536.4	$510.7	5.0	$510.7	$524.3	(2.6)

(1) Percentage changes are based on actual revenues and may not agree to the rounded amounts shown above.

(2) Other operating revenues include street lighting, other public authorities and interdepartmental usage.

(3) Miscellaneous revenues include transmission service revenues, late payment fees, renewable energy credit sales, rent, etc.

Revenues for our on-system customers increased approximately $20.9 million (4.3%) during 2013 as compared to 2012. Rate changes, primarily the April 2013 Missouri rate increase, contributed an estimated $24.6 million to revenues. Weather and other related factors increased revenues an estimated $3.1 million in 2013 as compared to 2012. Improved customer counts increased revenues an estimated $2.7 million. These revenue increases were partially offset by a $6.1 million decrease in fuel recovery revenue (and corresponding reduction in fuel expenses, resulting in no net effect on gross margin) from Missouri customers during 2013 as compared to 2012. The change in our unbilled revenue estimate recorded in the third quarter of 2012, as mentioned below, negatively impacted revenues as compared to 2012, making up the remainder of the change.

Revenues for our on-system customers decreased approximately $6.4 million (1.3%) during 2012 as compared to 2011. Weather and other related factors decreased revenues an estimated $25.6 million in 2012 as compared to 2011, primarily due to mild weather in the first quarter of 2012 and less favorable weather in the third quarter of 2012 as compared to the same period in 2011. Rate changes, primarily the June 2011 Missouri rate increase, the March 2011 Oklahoma rate increase, the January 2012 Kansas rate increase and the April 2011 Arkansas rate increase, contributed an estimated $12.0 million to revenues. Improved customer counts increased revenues an estimated $4.2 million. Additionally, a $3.4 million period over period change in our estimate of unbilled revenues during the third quarter of 2012 contributed $3.0 million to revenues.

On-system revenues increased in all classes during 2013 primarily due to the April 2013 Missouri rate increase.

Residential revenues decreased during 2012 due to the milder weather and efficient utilization of electric power. Commercial revenues increased primarily due to the Missouri, Kansas, Oklahoma and Arkansas rate increases. Industrial revenues decreased slightly.

Off-System Electric Transactions

In addition to sales to our own customers, we also sell power to other utilities as available, including through the Southwest Power Pool (SPP) energy imbalance services (EIS) market. See "— Markets and Transmission" below. The majority of our off-system sales margins are included as a component of the fuel adjustment clause in our Missouri, Kansas and Oklahoma jurisdictions and our transmission rider in our Arkansas jurisdiction and generally adjust the fuel and purchased power expense. As a result, nearly all of the off-system sales margin flows back to our on-system customers and has little effect on net income.

Off-system sales and revenues decreased during 2013 as compared to 2012 mainly due to low third quarter demand in the SPP market.

Off-system sales and revenues decreased during 2012 as compared to 2011 primarily due to the milder weather in 2012 as compared to 2011, as well as lower gas and purchased power prices.

Miscellaneous Revenues

Our miscellaneous revenues increased approximately $4.7 million during 2013 as compared to 2012 and approximately $0.3 million in 2012 as compared to 2011, primarily due to increased Southwest Power Pool (SPP) transmission revenues. These miscellaneous revenues are comprised mainly of transmission revenues, late payment fees and renewable energy credit sales.

Operating Revenue Deductions — Fuel and Purchased Power

The table below is a reconciliation of our actual fuel and purchased power expenditures (netted with the regulatory adjustments) to the fuel and purchased power expense shown on our statements of income for 2013, 2012 and 2011.

(in millions)	2013	2012	2011
Actual fuel and purchased power expenditures	$182.1	$173.6	$196.5
Missouri fuel adjustment recovery[(1)]	(2.7)	3.4	7.3
Missouri fuel adjustment deferral[(2)]	(0.6)	5.3	(2.7)
Kansas and Oklahoma regulatory adjustments[(2)]	(0.3)	1.0	(0.6)
SWPA amortization[(3)]	(2.8)	(2.8)	(1.5)
Unrealized (gain)/loss on derivatives	(0.3)	(1.6)	1.3
Total fuel and purchased power expense per income statement	$175.4	$178.9	$200.3

(1) A positive amount indicates costs recovered from customers from under recovery in prior deferral periods. A negative amount indicates costs refunded to customers from over recovery in prior deferral periods.

(2) A negative amount indicates costs have been under recovered from customers and a positive amount indicates costs have been over recovered from customers.

(3) Missouri ten year amortization of the $26.6 million payment received from the SWPA in September, 2010.

Operating Revenue Deductions — Other Than Fuel and Purchased Power

The table below shows regulated operating expense increases/(decreases) during 2013 as compared to 2012 and during 2012 as compared to 2011.

(in millions)	2013 vs. 2012	2012 vs. 2011
Transmission and distribution expense[(1)]	$ 4.8	$ 1.7
General labor expense	2.0	0.4
Regulatory reversal of gain on prior period sale of assets[(2)]	1.2	0.0
Customer accounts expense	0.9	(0.5)
Steam power other operating expense	0.6	2.0
Regulatory commission expense	0.5	(0.5)
Other power supply expense	0.7	0.1
Employee pension expense	0.5	1.4
Employee health care expense	0.2	2.4
Property insurance	0.5	0.6
Customer assistance expense	0.4	0.0
Injuries and damages expense	0.0	(0.7)
Professional services	(0.5)	2.1
Banking fees	(0.7)	(0.6)
Other miscellaneous accounts (netted)	0.0	0.4
TOTAL	$11.1	$ 8.8

(1) Mainly due to increased SPP transmission charges.

(2) Regulatory reversal of a prior period gain on the sale of our Asbury unit train as part of our 2013 rate case Agreement with the MPSC.

The table below shows maintenance and repairs expense increases/(decreases) during 2013 as compared to 2012 and during 2012 as compared to 2011.

(in millions)	2013 vs. 2012	2012 vs. 2011
Distribution maintenance expense	$ 0.4	$(1.1)
Transmission maintenance expense	0.7	(0.3)
Maintenance and repairs expense at the Asbury plant	(0.9)	0.9
Maintenance and repairs expense to SLCC	(1.1)	0.6
Maintenance and repairs expense at the State Line plant	0.5	(0.2)
Maintenance and repairs expense at the Iatan plant	0.4	(0.8)
Maintenance and repairs expense at the Plum Point plant	0.4	(0.1)
Maintenance and repairs expense at the Riverton plant — steam	(0.2)	(0.1)
Maintenance and repairs expense at the Riverton plant — gas	(0.5)	0.5
Iatan deferred maintenance expense	0.5	(0.1)
Other miscellaneous accounts (netted)	0.2	0.1
TOTAL	$ 0.4	$(0.6)

Depreciation and amortization expense increased approximately $8.3 million (15.1%) during 2013 as compared to 2012, primarily due to increased depreciation rates resulting from our recent Missouri rate case settlement and increased plant in service.

Depreciation and amortization expense decreased approximately $2.9 million (5.0%) during 2012 as compared to 2011. This reflects a decrease in regulatory amortization expense of $6.6 million during 2012 due to the termination of construction accounting as of June 15, 2011, the effective date of rates for our 2010 Missouri rate case, offset by increased plant in service.

Other taxes increased approximately $3.3 million in 2013 and $0.9 million in 2012 due to increased property tax reflecting our additions to plant in service and increased municipal franchise taxes.

Gas Segment

Gas Operating Revenues and Sales

The following table details our natural gas sales for the years ended December 31:

	Total Gas Delivered to Customers					
(bcf sales)	2013	2012	% Change	2012	2011	% Change
Residential	2.74	2.01	36.4%	2.01	2.56	(21.4)%
Commercial	1.35	1.05	28.5	1.05	1.27	(17.2)
Industrial	0.07	0.06	23.9	0.06	0.10	(42.9)
Other[(1)]	0.04	0.02	44.8	0.02	0.03	(29.5)
Total retail sales	4.20	3.14	33.6	3.14	3.96	(20.7)
Transportation sales[(1)]	4.53	4.25	6.6	4.25	4.53	(6.2)
Total gas operating sales	8.73	7.39	18.1	7.39	8.49	(13.0)

(1) Other includes other public authorities and interdepartmental usage.

The following table details our natural gas revenues for the years ended December 31:

($ in millions)	Operating Revenues and Cost of Gas Sold					
	2013	2012	% Change	2012	2011	% Change
Residential	$31.6	$24.7	27.6%	$24.7	$29.0	(14.7)%
Commercial	13.7	10.8	26.6	10.8	12.5	(13.7)
Industrial	0.5	0.5	11.0	0.5	0.7	(31.9)
Other[1]	0.3	0.3	38.7	0.3	0.3	(23.9)
Total retail revenues	$46.1	$36.3	27.1	$36.3	$42.5	(14.7)
Other revenues	0.4	0.3	7.5	0.3	0.4	(13.4)
Transportation revenues[1]	3.5	3.2	10.0	3.2	3.5	(7.5)
Total gas operating revenues	$50.0	$39.8	25.6	$39.8	$46.4	(14.2)
Cost of gas sold	25.8	18.6	38.4	18.6	22.8	(18.1)
Gas segment gross margins	$24.2	$21.2	14.3	$21.2	$23.6	(10.4)

(1) Other includes other public authorities and interdepartmental usage.

Gas retail sales and revenues increased during 2013 as compared to 2012 reflecting colder weather in 2013 as compared to 2012. Heating degree days were 38.1% higher in 2013 than 2012 and 8.3% higher than the 30-year average. Sales increased in all classes during 2013, reflecting the colder weather. As a result, our gas gross margin (defined as gas operating revenues less cost of gas in rates) for 2013 increased $3.0 million compared to 2012.

Gas retail sales and revenues decreased during 2012 as compared to 2011 reflecting mild weather in 2012 and customer contraction of 0.2%. Heating degree days were 22.9% lower in 2012 than 2011 and 23.2% lower than the 30-year average. Residential and commercial sales decreased during 2012 due to the mild weather and customer contraction. Industrial sales decreased 42.9% during 2012 reflecting the transfer of customers from industrial sales to transportation during the first quarter of 2012. As a result, our gas gross margin for 2012 decreased $2.4 million compared to 2011.

We have a PGA clause in place that allows us to recover from our customers, subject to routine regulatory review, the cost of purchased gas supplies, transportation and storage, including costs associated with the use of financial instruments to hedge the purchase price of natural gas. Pursuant to the provisions of the PGA clause, the difference between actual costs incurred and costs recovered through the application of the PGA are reflected as a regulatory asset or regulatory liability until the balance is recovered from or credited to customers. As of December 31, 2013, we had unrecovered purchased gas costs of $1.0 million recorded as a current regulatory asset and $1.2 million recorded as a non-current regulatory liability as compared to unrecovered purchased gas costs of $1.7 million recorded as a current regulatory asset and $0.2 million recorded as a non-current regulatory liability as of December 31, 2012.

Operating Revenue Deductions

The table below shows regulated operating expense increases/(decreases) for the years ended December 31:

(in millions)	2013 vs. 2012	2012 vs. 2011
Distribution operation expense	$ 0.2	$0.1
Transmission operation expense	(0.1)	0.0
Customer accounts expense[1]	0.3	0.0
Miscellaneous	0.1	0.0
TOTAL	$ 0.5	$0.1

(1) Primarily uncollectible accounts.

Depreciation and amortization expense increased approximately $0.1 million (3.1%) during 2013 and increased approximately $0.1 million (3.0%) during 2012.

Our gas segment had net income of $2.3 million in 2013 as compared to $1.3 million in 2012 and $2.7 million in 2011.

Consolidated Company

Income Taxes

The following table shows our consolidated provision for income taxes (in millions) and our consolidated effective federal and state income tax rates for the applicable years ended December 31:

	2013	2012	2011
Consolidated provision for income taxes	$37.5	$34.2	$34.3
Consolidated effective federal and state income tax rates	37.1%	38.0%	38.4%

The effective tax rate for 2013 is lower than 2012 and 2011 primarily due to higher equity AFUDC income in 2013 compared with 2012 and 2011.

See Note 9 of "Notes to Consolidated Financial Statements" under Item 8 for information and discussion concerning our income tax provision and effective tax rates.

Nonoperating Items

The following table shows the total allowance for funds used during construction (AFUDC) for the applicable periods ended December 31. AFUDC increased in 2013 as compared to 2012 and 2011 reflecting the environmental retrofit project at our Asbury plant. See Note 1 of "Notes to Consolidated Financial Statements" under Item 8.

($ in millions)	2013	2012	2011
Allowance for equity funds used during construction	$3.8	$1.1	$0.3
Allowance for borrowed funds used during construction	2.1	0.8	0.2
Total AFUDC	$5.9	$1.9	$0.5

Total interest charges on long-term and short-term debt for 2013, 2012 and 2011 are shown below. The change in long-term debt interest for 2013 reflects the issuance, on May 30, 2013, of $30.0 million of 3.73% First Mortgage Bonds due May 30, 2033 and $120.0 million of 4.32% First Mortgage Bonds due May 30, 2043. We used a portion of the proceeds from the sale of these bonds to redeem all $98.0 million aggregate principal amount of our Senior Notes, 4.50% Series due June 15, 2013.

The change in long-term debt interest for 2012 compared to 2011 reflects the redemption on April 1, 2012 of all $74.8 million aggregate principal amount of our First Mortgage Bonds, 7.00% Series due 2024 and the redemption of all $5.2 million of our First Mortgage Bonds, 5.20% Pollution Control Series due 2013, and all $8.0 million of our First Mortgage Bonds, 5.30% Pollution Control Series due 2013. These bonds were replaced by an issuance of $88.0 million aggregate principal amount of 3.58% First Mortgage

Bonds due April 2, 2027. The first settlement of $38.0 million occurred on April 2, 2012 and the second settlement of $50.0 million occurred on June 1, 2012.

	Interest Charges ($ in millions)					
	2013	2012	Change	2012	2011	Change
Long-term debt interest	$40.3	$40.2	0.4%	$40.2	$42.6	(5.6)%
Short-term debt interest	0.1	0.2	(68.2)	0.2	0.1	>100.0
Other interest*	1.1	1.1	(2.1)	1.1	(1.2)	>(100.0)
Total interest charges	$41.5	$41.5	0.0	$41.5	$41.5	(0.1)

* Includes deferred Iatan 1and Iatan 2 carrying charges to reflect construction accounting in accordance with our agreement with the MPSC. Deferral ended when the plants were placed in rates. The Iatan 1 environmental upgrade was placed in rates in September 2010. Iatan 2 was placed in rates June 15, 2011. See Note 3 of "Notes to Consolidated Financial Statements" under Item 8 for information regarding carrying charges.

RATE MATTERS

We routinely assess the need for rate relief in all of the jurisdictions we serve and file for such relief when necessary.

Our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are determined on a "cost of service" basis. Rates are designed to provide, after recovery of allowable operating expenses, an opportunity for us to earn a reasonable return on "rate base." "Rate base" is generally determined by reference to the original cost (net of accumulated depreciation and amortization) of utility plant in service, subject to various adjustments for deferred taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation, amortization and retirement of utility plant or write-off's as ordered by the utility commissions. In general, a request of new rates is made on the basis of a "rate base" as of a date prior to the date of the request and allowable operating expenses for a 12-month test period ended prior to the date of the request. Although the current rate making process provides recovery of some future changes in rate base and operating costs, it does not reflect all changes in costs for the period in which new retail rates will be in place. This results in a lag (commonly referred to as "regulatory lag") between the time we incur costs and the time when we can start recovering the costs through rates.

The following table sets forth information regarding electric and water rate increases since January 1, 2011:

Jurisdiction	Date Requested	Annual Increase Granted	Percent Increase Granted	Date Effective
Missouri — Electric	July 6, 2012	$27,500,000	6.78%	April 1, 2013
Missouri — Water	May 21, 2012	$ 450,000	25.5%	November 23, 2012
Missouri — Electric	September 28, 2010	$18,700,000	4.70%	June 15, 2011
Kansas — Electric	June 17, 2011	$ 1,250,000	5.20%	January 1, 2012
Oklahoma — Electric	June 30, 2011	$ 240,000	1.66%	January 4, 2012
Oklahoma — Electric	January 28, 2011	$ 1,063,100	9.32%	March 1, 2011
Arkansas — Electric	August 19, 2010	$ 2,104,321	19.00%	April 13, 2011

See Note 3 of "Notes to Consolidated Financial Statements" under Item 8 for additional information regarding rate matters.

MARKETS AND TRANSMISSION

Electric Segment

Energy Imbalance Services: The Southwest Power Pool (SPP) regional transmission organization (RTO) energy imbalance services market (EIS) provides real time energy for most participating members within the SPP regional footprint. Imbalance energy prices are based on market bids and status/availability of dispatchable generation and transmission within the SPP market footprint. In addition to energy imbalance service, the SPP RTO performs a real time security-constrained economic dispatch of all generation voluntarily offered into the EIS market to the market participants to also serve the native load.

Day Ahead Market: The SPP RTO expects to implement a Day-Ahead Market, or Integrated Marketplace, with unit commitment and co-optimized ancillary services market, in March 2014. As part of the Integrated Marketplace, the SPP RTO will create, prior to implementation of such market, a single NERC approved balancing authority to take over balancing authority responsibilities for its members, including Empire, which is expected to provide operational and economic benefits for our customers. The SPP Integrated Marketplace will function as a centralized dispatch, where we and other members will submit offers to sell power and bids to purchase power. The SPP will match offers and bids to supply our and other members' next day generation needs. It is expected that 90% — 95% of all next day generation needed throughout the SPP territory will be cleared through this Integrated Marketplace. This change could impact our fuel costs, however, the net financial effect of these Integrated Marketplace transactions will be processed through our fuel adjustment mechanisms. Information concerning recent and pending SPP RTO and other FERC activities can be found under Note 3 of "Notes to Consolidated Financial Statements" under Item 8.

LIQUIDITY AND CAPITAL RESOURCES

Overview. Our primary sources of liquidity are cash provided by operating activities, short-term borrowings under our commercial paper program (which is supported by our credit facilities) and borrowings from our unsecured revolving credit facility. As needed, we raise funds from the debt and equity capital markets to fund our liquidity and capital resource needs.

Our issuance of various securities, including equity, long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies including state public service commissions and the SEC. We estimate that internally generated funds (funds provided by operating activities less dividends paid) will provide approximately 45% of the funds required in 2014 for our budgeted capital expenditures (as discussed in "Capital Requirements and Investing Activities" below). We believe the amounts available to us under our credit facilities and the issuance of debt and equity securities, together with the cash provided by operating activities, will allow us to meet our needs for working capital, pension contributions, our continuing construction expenditures, anticipated debt redemptions, interest payments on debt obligations, dividend payments and other cash needs through the next several years.

We will continue to evaluate our need to increase available liquidity based on our view of working capital requirements, including the timing of our construction programs and other factors. See Item 1A, "Risk Factors" for additional information on items that could impact our liquidity and capital resource requirements. The following table provides a summary of our operating, investing and financing activities for the last three years.

Summary of Cash Flows

(in millions)	Fiscal Year 2013	2012	2011
Cash provided by/(used in):			
Operating activities	$ 157.5	$ 159.1	$ 134.6
Investing activities	(153.3)	(136.9)	(105.1)
Financing activities	(4.1)	(24.2)	(34.6)
Net change in cash and cash equivalents	$ 0.1	$ (2.0)	$ (5.1)

Cash flow from Operating Activities

We prepare our statement of cash flows using the indirect method. Under this method, we reconcile net income to cash flows from operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments during the period. These reconciling items include depreciation and amortization, pension costs, deferred income taxes, equity AFUDC, changes in commodity risk management assets and liabilities and changes in the consolidated balance sheet for working capital from the beginning to the end of the period.

Year-over-year changes in our operating cash flows are attributable primarily to working capital changes resulting from the impact of weather, the timing of customer collections, payments for natural gas and coal purchases, the effects of deferred fuel recoveries and the size and timing of pension contributions. The increase or decrease in natural gas prices directly impacts the cost of gas stored in inventory.

2013 compared to 2012. In 2013, our net cash flows provided from operating activities remained relatively the same, decreasing only $1.6 million or 1.0% from 2012. This decrease was primarily a result of:

- Increase in net income — $7.8 million.
- Non-cash loss on regulatory plant disallowance as a result of our 2013 Missouri electric rate case — $2.4 million.
- Regulatory reversal of a prior period gain on the sale of assets as a result of our 2013 Missouri electric rate case — $1.2 million.
- Working capital changes for accounts receivable, accounts payable and other current assets and liabilities — $7.2 million.
- Pension contributions increased $5.1 million, partially offset by changes in pension expense accruals of $1.5 million — $(3.6) million net.
- Tax timing differences mostly related to depreciation and amortizations — $(3.6) million.
- Increase in equity AFUDC mostly attributable to higher construction work in progress balances — $(2.7) million.
- Changes in non-cash loss on derivatives — $(4.2) million.
- Long-term regulatory fuel adjustment deferrals — $(5.9) million.
- Deferred revenues — $(1.4) million.

2012 compared to 2011. In 2012, our net cash flows provided from operating activities was $159.1 million, an increase of $24.5 million or 18.2% from 2011. This increase was primarily a result of:

- Changes in net income — $0.7 million.
- Reduced pension contributions net of expense accruals — $22.1 million.

- Changes in fuel and other inventory — $17.1 million.
- Changes in fuel adjustment deferrals and regulatory trackers and amortizations reflected in prepaid or other current assets — $13.9 million.
- Return of cash from energy trading margin accounts — $3.0 million.
- Changes in accruals related to interest, taxes and customer deposits — $1.9 million.
- Changes in depreciation and amortization, mostly reflecting lower regulatory amortization offset by increased plant in service and other amortizations — $(8.6) million.
- Lower deferrals of income tax due to reduced tax depreciation benefits — $(13.2) million.
- Changes in accounts receivable and accrued unbilled revenues — $(11.0) million.
- Changes in accounts payable partially offset by lower accrued taxes — $(1.0) million.

Capital Requirements and Investing Activities

Our net cash flows used in investing activities increased $16.4 million from 2012 to 2013. The increase was primarily the result of an increase in electric plant additions and replacements, mainly due to the environmental retrofit in progress at our Asbury plant.

Our net cash flows used in investing activities increased $31.8 million from 2011 to 2012, primarily due to an increase in electric plant additions and replacements resulting from the environmental retrofit in progress at our Asbury plant.

Our capital expenditures totaled approximately $160.2 million, $146.3 million, and $101.1 million in 2013, 2012 and 2011, respectively.

A breakdown of these capital expenditures for 2013, 2012 and 2011 is as follows:

	Capital Expenditures		
(in millions)	2013	2012	2011
Distribution and transmission system additions	$ 58.5	$ 63.3	$ 46.5
Additions and replacements — electric plant	61.8	46.9	13.4
New generation — Iatan 2	0.0	0.0	4.5
New generation — Riverton 12 combined cycle	13.2	0.6	0.0
Storms	1.0	5.0	15.9
Transportation	4.5	3.7	3.9
Gas segment additions and replacements	4.1	3.3	3.9
Other (including retirements and salvage — net)(1)	14.7	20.7	9.2
Subtotal	**$157.8**	**$143.5**	**$ 97.3**
Non-regulated capital expenditures (primarily fiber optics)	2.4	2.8	3.8
Subtotal capital expenditures incurred(2)	$160.2	$146.3	$101.1
Adjusted for capital expenditures payable(3)	(5.4)	(9.3)	1.4
Total cash outlay	$154.8	$137.0	$102.5

(1) Other includes equity AFUDC of $(3.9) million, $(1.1) million and $(0.3) million for 2013, 2012 and 2011, respectively. Also included are insurance proceeds of $(7.8) million for 2013.

(2) Expenditures incurred represent the total cost for work completed for the projects during the year. Discussion of capital expenditures throughout this 10-K is presented on this basis. These capital expenditures include AFUDC, capital expenditures to retire assets and benefits from salvage.

(3) The amount of expenditures paid/(unpaid) at the end of the year to adjust to actual cash outlay reflected in the Investing Activities section of the Statement of Cash Flows.

Approximately 74%, 85% and 100% of our cash requirements for capital expenditures for 2013, 2012 and 2011, respectively, were satisfied from internally generated funds (funds provided by operating activities less dividends paid). The remaining amounts of such requirements were satisfied from short-term borrowings and proceeds from our sales of common stock and debt securities discussed below.

Our estimated capital expenditures (excluding AFUDC) for 2014, 2015 and 2016 are detailed below. See Item 1, "Business — Construction Program." We anticipate that we will spend the following amounts over the next three years for the following projects:

Project	2014	2015	2016	Total
Asbury environmental upgrades	$ 24.2	$ 12.4	$ —	$ 36.6
Riverton Unit 12 combined cycle conversion	79.9	62.5	16.1	158.5
Electric distribution system additions	36.9	39.9	36.6	113.4
Electric transmission facilities	25.9	29.3	27.5	82.7
Other	46.8	31.8	29.9	108.5
Total	$213.7	$175.9	$110.1	$499.7

Our estimated total capital expenditures (excluding AFUDC) for 2017 and 2018 are $99.2 million and $95.9 million, respectively.

We estimate that internally generated funds will provide approximately 45% of the funds required in 2014 for our budgeted capital expenditures. We intend to utilize short-term debt to finance any additional amounts needed beyond those provided by operating activities for such capital expenditures. If additional financing is needed, we intend to utilize a combination of debt and equity securities. The estimates herein may be changed because of changes we make in our construction program, unforeseen construction costs, our ability to obtain financing, regulation and for other reasons. See further discussion under "Financing Activities" below.

Financing Activities

2013 compared to 2012.

Our net cash flows used in financing activities was $4.1 million in 2013, a decrease of $20.1 million as compared to 2012, primarily due to the following:

- Issuance of $150.0 million of first mortgage bonds offset by repayment of $98.0 million of senior notes in 2013 compared to no cash impact from $88.0 million in bond refinancing in 2012.
- Repayment of $20.0 million in short-term debt in 2013 as compared to borrowing $12.0 million in 2012, which resulted in an $8.0 million net use of cash when comparing 2013 to 2012.

2012 compared to 2011.

Our net cash flows used in financing activities was $24.2 million in 2012, a decrease of $10.4 million as compared to 2011, primarily due to the following:

- Cash used to pay dividends was $42.3 million, an increase in use of cash of $(15.5) million.
- Borrowings of $12.0 million in short-term debt in 2012 as compared to repaying $12.0 million in 2011, which provided $24.0 million of cash when comparing 2012 to 2011.
- Proceeds from the issuance of common stock, primarily from the dividend reinvestment plan, increased $2.2 million.
- Refinancings of $88.0 million of bonds in 2012, which had almost no impact on cash flow.

Shelf Registration.

On December 13, 2013, we filed a $200.0 million shelf registration statement on Form S-3 with the SEC covering our common stock, unsecured debt securities, preference stock, and first mortgage bonds. This shelf registration statement will be effective for a three-year period beginning with the date of filing. We plan to use the proceeds under this shelf to fund capital expenditures, refinance existing debt or general corporate needs during the effective period. The issuance of securities under this shelf is subject to the receipt of state regulatory approvals. We have filed applications for such approvals in all four state jurisdictions in our electric service territory.

Credit Agreements.

On January 17, 2012, we entered into the Third Amended and Restated Unsecured Credit Agreement which amended and restated our Second Amended and Restated Unsecured Credit Agreement dated January 26, 2010. This agreement extended the termination date of the revolving credit facility from January 26, 2013 to January 17, 2017. The agreement also removed the letter of credit facility and includes a swingline loan facility with a $15 million swingline loan sublimit. The aggregate amount of the revolving credit commitments remains $150 million, inclusive of the $15 million swingline loan sublimit. There were no outstanding borrowings under this agreement at December 31, 2013. However $4.0 million was used to back up our outstanding commercial paper. See Note 7 of "Notes to Consolidated Financial Statements" under Item 8 for additional information regarding this amendment and our unsecured line of credit.

EDE Mortgage Indenture.

The principal amount of all series of first mortgage bonds outstanding at any one time under the EDE Mortgage is limited by terms of the mortgage to $1.0 billion. Substantially all of the property, plant and equipment of The Empire District Electric Company (but not its subsidiaries) is subject to the lien of the EDE Mortgage. Restrictions in the EDE mortgage bond indenture could affect our liquidity. The EDE Mortgage contains a requirement that for new first mortgage bonds to be issued, our net earnings (as defined in the EDE Mortgage) for any twelve consecutive months within the fifteen months preceding issuance must be two times the annual interest requirements (as defined in the EDE Mortgage) on all first mortgage bonds then outstanding and on the prospective issue of new first mortgage bonds. Our earnings for the year ended December 31, 2013 would permit us to issue approximately $599.1 million of new first mortgage bonds based on this test with an assumed interest rate of 5.5%. In addition to the interest coverage requirement, the EDE Mortgage provides that new bonds must be issued against, among other things, retired bonds or 60% of net property additions. At December 31, 2013, we had retired bonds and net property additions which would enable the issuance of at least $856.7 million principal amount of bonds if the annual interest requirements are met. However, based on the $1 billion limit on the principal amount of first mortgage bonds outstanding set forth by the EDE mortgage, and our current level of outstanding first mortgage bonds, we are limited to the issuance of $417 million of new first mortgage bonds. As of December 31, 2013, we are in compliance with all restrictive covenants of the EDE Mortgage.

EDG Mortgage Indenture.

The principal amount of all series of first mortgage bonds outstanding at any one time under the EDG Mortgage is limited by terms of the mortgage to $300.0 million. Substantially all of the property, plant and equipment of The Empire District Gas Company is subject to the lien of the EDG Mortgage. The EDG Mortgage contains a requirement that for new first mortgage bonds to be issued, the amount of such new first mortgage bonds shall not exceed 75% of the cost of property additions acquired after the date of the Missouri Gas acquisition. The mortgage also contains a limitation on the issuance by EDG of debt (including first mortgage bonds, but excluding short-term debt incurred in the ordinary course under working capital facilities) unless, after giving effect to such issuance, EDG's ratio of EBITDA (defined as net income plus interest, taxes, depreciation, amortization and certain other non-cash charges) to interest charges for the most recent four fiscal quarters is at least 2.0 to 1.0. As of December 31, 2013, this test would allow us to issue approximately $15.8 million principal amount of new first mortgage bonds at an assumed interest rate of 5.5%.

Corporate credit ratings and the ratings for our securities are as follows:

	Fitch	Moody's	Standard & Poor's
Corporate Credit Rating	n/r*	Baa1	BBB
EDE First Mortgage Bonds	BBB+	A2	A−
Senior Notes	BBB	Baa1	BBB
Commercial Paper	F3	P-2	A-2
Outlook	Stable	Stable	Stable

* Not rated.

On January 30, 2014, Moody's upgraded our corporate credit rating to Baa1 from Baa2, senior secured debt to A2 from A3, senior unsecured debt to Baa1 from Baa2 and affirmed our commercial paper rating at P-2. Moody's outlook for Empire is stable. On March 6, 2013, Standard & Poor's upgraded our corporate credit rating to BBB from BBB−, senior secured debt to A- from BBB+, senior unsecured debt to BBB from BBB− and our commercial paper rating to A-2 from A-3. Standard & Poor's outlook for Empire is stable. On March 24, 2011, Fitch revised our commercial paper rating from F2 to F3 and reaffirmed our other ratings. The rating action was not based on a specific action or event on our part, but reflected their traditional linkage of long-term and short-term Issuer Default Ratings. On May 24, 2013, Fitch reaffirmed our ratings.

A security rating is not a recommendation to buy, sell or hold securities. Each rating is subject to revision or withdrawal at any time by the assigning rating organization. Each security rating agency has its own methodology for assigning ratings, and, accordingly, each rating should be considered independently of all other ratings.

CONTRACTUAL OBLIGATIONS

Set forth below is information summarizing our contractual obligations as of December 31, 2013. Other pension and postretirement benefit plans are funded on an ongoing basis to match their corresponding costs, per regulatory requirements, and have been estimated for 2014 – 2018 as noted below.

	Payments Due By Period (in millions)				
Contractual Obligations(1)	Total	Less Than 1 Year	1 – 3 Years	3 – 5 Years	More Than 5 Years
Long-term debt (w/o discount)	$ 740.0	$ —	$ 25.0	$ 90.0	$ 625.0
Interest on long-term debt	666.1	39.2	78.2	70.9	477.8
Short-term debt	4.0	4.0	—	—	—
Capital lease obligations	6.4	0.6	1.1	1.1	3.6
Operating lease obligations(2)	4.0	0.8	1.4	1.3	0.5
Electric purchase obligations(3)	469.8	49.2	66.7	59.5	294.4
Gas purchase obligations(4)	91.5	11.3	17.8	17.8	44.6
Open purchase orders	188.7	31.7	157.0	—	—
Postretirement benefit obligation funding	11.7	2.2	4.2	5.3	—
Pension benefit funding	48.9	12.0	21.0	15.9	—
Other long-term liabilities(5)	3.1	0.1	0.3	0.3	2.4
TOTAL CONTRACTUAL OBLIGATIONS	$2,234.2	$151.1	$372.7	$262.1	$1,448.3

(1) Some of our contractual obligations have price escalations based on economic indices, but we do not anticipate these escalations to be significant.

(2) Excludes payments under our Elk River Wind Farm, LLC and Cloud County Wind Farm, LLC agreements, as payments are contingent upon output of the facilities. Payments under the Elk River Wind Farm, LLC agreement can run from zero up to a maximum of approximately $16.9 million per year based on a 20 year average cost and an annual output of 550,000 megawatt hours. Payments under the Meridian Way Wind Farm agreement can range from zero to a maximum of approximately $14.6 million per year based on a 20-year average cost.

(3) Includes a water usage contract for our SLCC facility, fuel and purchased power contracts and associated transportation costs, as well as purchased power for 2014 through 2039 for Plum Point.

(4) Represents fuel contracts and associated transportation costs of our gas segment.

(5) Other long-term liabilities primarily represent electric facilities charges paid to City Utilities of Springfield, Missouri of $11,000 per month over 30 years.

DIVIDENDS

Holders of our common stock are entitled to dividends if, as, and when declared by the Board of Directors, out of funds legally available therefore, subject to the prior rights of holders of any outstanding cumulative preferred stock and preference stock. Payment of dividends is determined by our Board of Directors after considering all relevant factors, including the amount of our retained earnings (which is essentially our accumulated net income less dividend payouts). A reduction of our dividend per share, partially or in whole, could have an adverse effect on our common stock price.

The following table shows our diluted earnings per share, dividends paid per share, total dividends paid and retained earnings balance for the years ended December 31, 2013, 2012 and 2011:

(in millions, except per share amounts)	2013	2012	2011
Diluted earnings per share	$ 1.48	$1.32	$1.31
Dividends paid per share[1]	$1.005	$1.00	$0.64
Total dividends paid	$ 43.0	$42.3	$26.7
Retained earnings year-end balance	$ 67.6	$47.1	$33.7

(1) In response to the expected loss of revenues resulting from the May 22, 2011 tornado, our level of retained earnings and other relevant factors, our Board of Directors suspended our quarterly dividend for the third and fourth quarters of 2011. On February 2, 2012, the Board of Directors re-established the dividend and declared a quarterly dividend of $0.25 per share on common stock payable on March 15, 2012 to holders of record as of March 1, 2012.

Under Kansas corporate law, our Board of Directors may only declare and pay dividends out of our surplus or, if there is no surplus, out of our net profits for the fiscal year in which the dividend is declared or the preceding fiscal year, or both. Our surplus, under Kansas law, is equal to our retained earnings plus accumulated other comprehensive income/(loss), net of income tax. However, Kansas law does permit, under certain circumstances, our Board of Directors to transfer amounts from capital in excess of par value to surplus. In addition, Section 305(a) of the Federal Power Act (FPA) prohibits the payment by a utility of dividends from any funds "properly included in capital account". There are no additional rules or regulations issued by the FERC under the FPA clarifying the meaning of this limitation. However, several decisions by the FERC on specific dividend proposals suggest that any determination would be based on a fact-intensive analysis of the specific facts and circumstances surrounding the utility and the dividend in question, with particular focus on the impact of the proposed dividend on the liquidity and financial condition of the utility.

In addition, the EDE Mortgage and our Restated Articles contain certain dividend restrictions. The most restrictive of these is contained in the EDE Mortgage, which provides that we may not declare or pay any dividends (other than dividends payable in shares of our common stock) or make any other distribution on, or purchase (other than with the proceeds of additional common stock financing) any shares of, our common stock if the cumulative aggregate amount thereof after August 31, 1944 (exclusive of the first quarterly dividend of $98,000 paid after said date) would exceed the sum of $10.75 million and the earned surplus (as defined in the EDE Mortgage) accumulated subsequent to August 31, 1944, or the date of succession in the event that another corporation succeeds to our rights and liabilities by a merger or consolidation. On June 9, 2011, we amended the EDE Mortgage in order to provide us with additional flexibility to pay dividends to our shareholders by permitting the payment of any dividend or distribution on, or purchase of, shares of its common stock within 60 days after the related date of declaration or notice of such dividend, distribution or purchase if (i) on the date of declaration or notice, such dividend, distribution or purchase would have complied with the provisions of the EDE Mortgage and (ii) as of the last day of the calendar month ended immediately preceding the date of such payment, our ratio of total indebtedness to total capitalization (after giving pro forma effect to the payment of such dividend, distribution, or purchase) was not more than 0.625 to 1.

OFF-BALANCE SHEET ARRANGEMENTS

We have no off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources, other than operating leases entered into in the normal course of business.

CRITICAL ACCOUNTING POLICIES

Set forth below are certain accounting policies that are considered by management to be critical and that typically require difficult, subjective or complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain (other accounting policies may also require assumptions that could cause actual results to be different than anticipated results). A change in assumptions or judgments applied in determining the following matters, among others, could have a material impact on future financial results.

Pensions and Other Postretirement Benefits (OPEB). We recognize expense related to pension and other postretirement benefits as earned during the employee's period of service. Related assets and liabilities are established based upon the funded status of the plan compared to the accumulated benefit obligation. Our pension and OPEB expense or benefit includes amortization of previously unrecognized net gains or losses. Additional income or expense may be recognized when our unrecognized gains or losses as of the most recent measurement date exceed 10% of our postretirement benefit obligation or fair value of plan assets, whichever is greater. For pension benefits and OPEB benefits, unrecognized net gains or losses as of the measurement date are amortized into actuarial expense over ten years.

We have electric rate orders in Missouri, Kansas and Oklahoma that allow us to recover pension and OPEB costs consistent with our GAAP policy noted above. In accordance with the rate orders, we prospectively calculate the value of plan assets using a market related value method as allowed by the Accounting Standard Codification (ASC) guidance on defined benefit plans disclosure. In addition, our rate orders allow us to defer any pension and OPEB costs that are different from those allowed recovery in rate cases.

In our agreement with the MPSC regarding the purchase of Missouri Gas by EDG, we were allowed to adopt this pension cost recovery methodology for EDG, as well. Also, it was agreed that the effects of purchase accounting entries related to pension and other post-retirement benefits would be recoverable in future rate proceedings. Thus the fair value adjustment acquisition entries have been recorded as regulatory assets, as these amounts are probable of recovery in future rates. The regulatory asset is reduced by an amount equal to the difference between the regulatory costs and the estimated GAAP costs. The difference between this total and the costs being recovered from customers is deferred as a regulatory asset or liability in accordance with the ASC guidance on regulated operations, and recovered over a period of 5 years.

We expect future pension expense or benefits are probable of full recovery in our rates, thus lowering our sensitivity to accounting risks and uncertainties.

Based on the regulatory treatment of pension and OPEB recovery afforded in our jurisdictions, we record the amount of unfunded defined benefit pension and postretirement plan obligation as regulatory assets on our balance sheet rather than as reductions of equity through comprehensive income.

Our funding policy is to contribute annually an amount at least equal to the actuarial cost of postretirement benefits. The actual minimum pension funding requirements will be determined based on the results of the actuarial valuations and the performance of our pension assets during the current year. See Note 8 of "Notes to Consolidated Financial Statements" under Item 8.

Risks and uncertainties affecting the application of our pension accounting policy include: future rate of return on plan assets, interest rates used in valuing benefit obligations (i.e. discount rates), demographic assumptions (i.e. mortality and retirement rates) and employee compensation trend rates. Factors that could result in additional pension expense and/or funding include: a lower discount rate than estimated, higher compensation rate increases, lower return on plan assets, and longer retirement periods.

Risks and uncertainties affecting the application of our OPEB accounting policy and related funding include: future rate of return on plan assets, interest rates used in valuing benefit obligations (i.e. discount rates), healthcare cost trend rates, Medicare prescription drug costs and demographic assumptions (i.e. mortality and retirement rates). See Note 1 and Note 8 of "Notes to Consolidated Financial Statements" under Item 8 for further information.

Regulatory Assets and Liabilities. In accordance with the ASC accounting guidance for regulated activities, our financial statements reflect ratemaking policies prescribed by the regulatory commissions having jurisdiction over us (Missouri, Kansas, Arkansas, Oklahoma and FERC).

In accordance with accounting guidance for regulated activities, we record a regulatory asset for all or part of an incurred cost that would otherwise be charged to expense in accordance with the accounting guidance, which requires that an asset be recorded if it is probable that future revenue in an amount at least equal to the capitalized cost will be allowable for costs for rate making purposes and the current available evidence indicates that future revenue will be provided to permit recovery of the cost. Additionally, we follow the accounting guidance for regulated activities which says that a liability should be recorded when a regulator has provided current recovery for a cost that is expected to be incurred in the future. We follow this guidance for incurred costs or credits that are subject to future recovery from or refund to our customers in accordance with the orders of our regulators.

Historically, all costs of this nature, which are determined by our regulators to have been prudently incurred, have been recoverable through rates in the course of normal ratemaking procedures. Regulatory assets and liabilities are ratably eliminated through a charge or credit, respectively, to earnings while being recovered in revenues and fully recognized if and when it is no longer probable that such amounts will be recovered through future revenues. We continually assess the recoverability of our regulatory assets. Although we believe it unlikely, should retail electric competition legislation be passed in the states we serve, we may determine that we no longer meet the criteria set forth in the ASC accounting guidance for regulated activities with respect to continued recognition of some or all of the regulatory assets and liabilities. Any regulatory changes that would require us to discontinue application of ASC accounting guidance for regulated activities based upon competitive or other events may also impact the valuation of certain utility plant investments. Impairment of regulatory assets or utility plant investments could have a material adverse effect on our financial condition and results of operations.

As of December 31, 2013, we have recorded $177.1 million in regulatory assets and $137.7 million as regulatory liabilities. See Note 3 of "Notes to Consolidated Financial Statements" under Item 8 for detailed information regarding our regulatory assets and liabilities.

Risks and uncertainties affecting the application of this accounting policy include: regulatory environment, external regulatory decisions and requirements, anticipated future regulatory decisions and their impact of deregulation and competition on ratemaking process, unexpected disallowances, possible changes in accounting standards (including as a result of adoption of IFRS) and the ability to recover costs.

Fuel Adjustment Clause. Typical fuel adjustment clauses permit the distribution to customers of changes in fuel costs, subject to routine regulatory review, without the need for a general rate proceeding. Fuel adjustment clauses are presently applicable to our retail electric sales in Missouri, Oklahoma and Kansas and system wholesale kilowatt-hour sales under FERC jurisdiction. We have an Energy Cost Recovery Rider in Arkansas that adjusts for changing fuel and purchased power costs on an annual basis.

The MPSC established a base cost in rates for the recovery of fuel and purchased power expenses used to supply energy. The fuel adjustment clause permits the distribution to our Missouri customers of 95% of the changes in fuel and purchased power costs prudently incurred above or below the base cost. Off-system sales margins are also part of the recovery of fuel and purchased power costs. As a result, nearly all of the off-system sales margin flows back to the customer.

Unbilled Revenue. At the end of each period we estimate, based on expected usage, the amount of revenue to record for energy and natural gas that has been provided to customers but not billed. Risks and uncertainties affecting the application of this accounting policy include: projecting customer energy usage, estimating the impact of weather and other factors that affect usage (such as line losses) for the unbilled period and estimating loss of energy during transmission and delivery. Assumptions such as electrical load requirements, customer billing rates, and line loss factors are used in the estimation process and are evaluated periodically. Changes to certain assumptions during the evaluation process can lead to a change in the estimate.

Contingent Liabilities. We are a party to various claims and legal proceedings arising in the ordinary course of our business, which are primarily related to workers' compensation and public liability. We regularly assess our insurance deductibles, analyze litigation information with our attorneys and evaluate our loss experience. Based on our evaluation as of the end of 2013, we believe that we have accrued liabilities in accordance with ASC accounting guidance sufficient to meet potential liabilities that could result from these claims. This liability at December 31, 2013 and 2012 was $4.0 million and $4.2 million, respectively.

Risks and uncertainties affecting these assumptions include: changes in estimates on potential outcomes of litigation and potential litigation yet unidentified in which we might be named as a defendant.

Goodwill. As of December 31, 2013, the consolidated balance sheet included $39.5 million of goodwill. All of this goodwill was derived from our gas acquisition and recorded in our gas segment, which is also the reporting unit for goodwill testing purposes. Accounting guidance requires us to test goodwill for impairment on an annual basis or whenever events or circumstances indicate possible impairment. Absent an indication of fair value from a potential buyer or a similar specific transaction, a combination of the market and income approaches is used to estimate the fair value of goodwill.

We use the market approach which estimates fair value of the gas reporting unit by comparing certain financial metrics to comparable companies. Comparable companies whose securities are actively traded in the public market are judgmentally selected by management based on operational and economic similarities. We utilize EBITDA (earnings before interest, taxes, depreciation, and amortization) multiples of the comparable companies in relation to the EBITDA results of the gas reporting unit to determine an estimate of fair value.

We also utilize a valuation technique under the income approach which estimates the discounted future cash flows of operations. Our procedures include developing a baseline test and performing sensitivity analysis to calculate a reasonable valuation range. The sensitivities are derived from altering those assumptions which are subjective in nature and inherent to a discounted cash flows calculation. Other qualitative factors and comparisons to industry peers are also used to further support the assumptions and ultimately the overall evaluation. A key qualitative assumption considered in our evaluation is the impact of regulation, including rate regulation and cost recovery for the gas reporting unit. Some of the key quantitative assumptions included in our tests involve: regulatory rate design and results; the discount rate; the growth rate; capital spending rates and terminal value calculations. If negative changes occurred to one or more key assumptions, an impairment charge could result. With the exception of the capital spending rate, the key assumptions noted are significantly determined by market factors and significant changes in market factors that impact the gas reporting unit would somewhat be mitigated by our current and future regulatory rate design to some extent. Other risks and uncertainties affecting these assumptions include: changes in business, industry, laws, technology and economic conditions. Actual results for the gas reporting unit indicate a slight decline in gas customer count and demand. A continued decline in customer count or demand coupled with an increase in the discount rate would have adverse impacts on the valuation and could result in an impairment charge in the future. Our forecasts anticipate flat customer counts over the next several years.

We weight the results of the two approaches discussed above in order to estimate the fair value of the gas reporting unit. Our annual test performed as of October 2013 indicated the estimated fair market value of the gas reporting unit to be $10 – 14 million higher than its carrying value at that time. While we believe the assumptions utilized in our analysis were reasonable, adverse developments in future periods could negatively impact goodwill impairment considerations, which could adversely impact earnings. Specifically, the quantitative assumptions noted previously, such as an increase to the discount rate or decline in the terminal value calculation could lead to an impairment charge in the future.

Use of Management's Estimates. The preparation of our consolidated financial statements in conformity with generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. We evaluate our estimates on an on-going basis, including those related to unbilled utility revenues, collectibility of accounts receivable, depreciable lives, asset impairment and goodwill evaluations, employee benefit obligations, contingent liabilities, asset retirement obligations, the fair value of stock based compensation and tax provisions. Actual amounts could differ from those estimates.

RECENTLY ISSUED ACCOUNTING STANDARDS

See Note 1 of "Notes to Consolidated Financial Statements" under Item 8 for further information regarding Recently Issued and Proposed Accounting Standards.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our fuel procurement activities involve primary market risk exposures, including commodity price risk and credit risk. Commodity price risk is the potential adverse price impact related to the fuel procurement for our generating units. Credit risk is the potential adverse financial impact resulting from non-performance by a counterparty of its contractual obligations. Additionally, we are exposed to interest rate risk which is the potential adverse financial impact related to changes in interest rates.

Market Risk and Hedging Activities. Prices in the wholesale power markets can be extremely volatile. This volatility impacts our cost of power purchased and our participation in energy trades. If we were unable to generate an adequate supply of electricity for our customers, we would attempt to purchase power from others. Such supplies are not always available. In addition, congestion on the transmission system can limit our ability to make purchases from (or sell into) the wholesale markets.

We engage in physical and financial trading activities with the goals of reducing risk from market fluctuations. In accordance with our established Energy Risk Management Policy, which typically includes entering into various derivative transactions, we attempt to mitigate our commodity market risk. Derivatives are utilized to manage our gas commodity market risk. We also acquire Transmission Congestion Rights (TCR) in an attempt to lessen the cost of power we will purchase from the SPP Integrated Market due to congestion costs. See Note 14 of "Notes to Consolidated Financial Statements" under Item 8 for further information.

Commodity Price Risk. We are exposed to the impact of market fluctuations in the price and transportation costs of coal, natural gas, and electricity and employ established policies and procedures to manage the risks associated with these market fluctuations, including utilizing derivatives.

We satisfied 65.8% of our 2013 generation fuel supply need through coal. Approximately 96% of our 2013 coal supply was Western coal. We have contracts and binding proposals to supply a portion of the fuel for our coal plants through 2016. These contracts satisfy approximately 97% of our anticipated fuel requirements for 2014, 39% for 2015 and 19% for 2016 for our Asbury coal plants. In order to manage our exposure to fuel prices, future coal supplies will be acquired using a combination of short-term and long-term contracts.

We are exposed to changes in market prices for natural gas we must purchase to run our combustion turbine generators. Our natural gas procurement program is designed to manage our costs to avoid volatile natural gas prices. We enter into physical forward and financial derivative contracts with counterparties relating to our future natural gas requirements that lock in prices (with respect to predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in our fuel expenditures and improve predictability. As of December 31, 2013, 61%, or 6.2 million Dths's, of our anticipated volume of natural gas usage for our electric operations for 2014 is hedged. See Note 14 of "Notes to Consolidated Financial Statements" under Item 8 for further information.

Based on our expected natural gas purchases for our electric operations for 2014, if average natural gas prices should increase 10% more in 2014 than the price at December 31, 2013, our natural gas expenditures would increase by approximately $1.3 million based on our December 31, 2013 total hedged positions for the next twelve months. However, such an increase would be probable of recovery through fuel adjustment mechanisms in all of our jurisdictions, which significantly reduces the impact of fluctuating fuel costs.

We attempt to mitigate a portion of our natural gas price risk associated with our gas segment using physical forward purchase agreements, storage and derivative contracts. As of December 31, 2013, we have 0.9 million Dths in storage on the three pipelines that serve our customers. This represents 47% of our storage capacity. We have an additional 0.2 million Dths hedged through financial derivatives and physical contracts.

See Note 14 of "Notes to Consolidated Financial Statements" under Item 8 for further information.

Credit Risk. In order to minimize overall credit risk, we maintain credit policies, including the evaluation of counterparty financial condition and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. See Note 14 of "Notes to Consolidated Financial Statements" under Item 8 regarding agreements containing credit risk contingent features. In addition, certain counterparties make available collateral in the form of cash held as margin deposits as a result of exceeding agreed-upon credit exposure thresholds or may be required to prepay the transaction. Conversely, we are required to post collateral with counterparties at certain thresholds, which is typically the result of changes in commodity prices. Amounts reported as margin deposit liabilities represent counterparty funds we hold that result from various trading counterparties exceeding agreed-upon credit exposure thresholds. Amounts reported as margin deposit assets represent our funds held on deposit for our NYMEX contracts with our broker and other financial contracts with other counterparties that resulted from us exceeding agreed-upon credit limits established by the counterparties. The following table depicts our margin deposit assets at December 31, 2013 and December 31, 2012. There were no margin deposit liabilities at these dates.

(in millions)	2013	2012
Margin deposit assets	$5.2	$4.2

Our exposure to credit risk is concentrated primarily within our fuel procurement process, as we transact with a smaller, less diverse group of counterparties and transactions may involve large notional volumes and potentially volatile commodity prices. Below is a table showing our net credit exposure at December 31, 2013, reflecting that our counterparties are exposed to Empire for the net unrealized mark-to-market losses for physical forward and financial natural gas contracts carried at fair value.

(in millions)	
Net unrealized mark-to-market losses for physical forward natural gas contracts	$0.5
Net unrealized mark-to-market losses for financial natural gas contracts	4.5
Net credit exposure	$5.0

The $4.5 million net unrealized mark-to-market loss for financial natural gas contracts is comprised entirely of $4.5 million that our counterparties are exposed to Empire for unrealized losses. We are holding no collateral from any counterparty since we are below the $10 million mark-to-market collateral threshold in our agreements. As noted above, as of December 31, 2013, we have $5.2 million on deposit for NYMEX contract exposure to Empire, of which $4.5 million represents our collateral requirement. If NYMEX gas prices decreased 25% from their December 31, 2013 levels, our collateral requirement would increase $8.9 million. If these prices increased 25%, our collateral requirement would decrease $3.4 million. Our other counterparties would not be required to post collateral with Empire.

We sell electricity and gas and provide distribution and transmission services to a diverse group of customers, including residential, commercial and industrial customers. Credit risk associated with trade accounts receivable from energy customers is limited due to the large number of customers. In addition, we enter into contracts with various companies in the energy industry for purchases of energy-related commodities, including natural gas in our fuel procurement process.

Interest Rate Risk. We are exposed to changes in interest rates as a result of financing through our issuance of commercial paper and other short-term debt. We manage our interest rate exposure by limiting our variable-rate exposure (applicable to commercial paper and borrowings under our unsecured credit agreement) to a certain percentage of total capitalization, as set by policy, and by monitoring the effects of market changes in interest rates. See Notes 6 and 7 of "Notes to Consolidated Financial Statements" under Item 8 for further information.

If market interest rates average 1% more in 2014 than in 2013, our interest expense would increase, and income before taxes would decrease by less than $0.3 million. This amount has been determined by considering the impact of the hypothetical interest rates on our highest month-end commercial paper balance for 2013. These analyses do not consider the effects of the reduced level of overall economic activity that could exist in such an environment. In the event of a significant change in interest rates, management would likely take actions to further mitigate its exposure to the change. However, due to the uncertainty of the specific actions that would be taken and their possible effects, the sensitivity analysis assumes no changes in our financial structure.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
of the Empire District Electric Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15 present fairly, in all material respects, the financial position of The Empire District Electric Company and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control — Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP
St. Louis, Missouri
February 21, 2014

THE EMPIRE DISTRICT ELECTRIC COMPANY

Consolidated Balance Sheets

	December 31, 2013	December 31, 2012
	($-000's)	
Assets		
Plant and property, at original cost:		
Electric and water	$2,219,605	$2,176,188
Natural gas	72,834	69,851
Other	39,902	37,983
Construction work in progress	152,330	56,347
	2,484,671	2,340,369
Accumulated depreciation and amortization	732,737	682,737
	1,751,934	1,657,632
Current assets:		
Cash and cash equivalents	3,475	3,375
Restricted cash	2,872	4,357
Accounts receivable — trade, net of allowance of $1,025 and $1,388, respectively	50,137	38,874
Accrued unbilled revenues	26,694	23,254
Accounts receivable — other	13,101	13,277
Fuel, materials and supplies	48,811	61,870
Prepaid expenses and other	15,954	21,806
Unrealized gain in fair value of derivative contracts	2,469	96
Regulatory assets	7,743	6,377
	171,256	173,286
Noncurrent assets and deferred charges:		
Regulatory assets	169,333	243,958
Goodwill	39,492	39,492
Unamortized debt issuance costs	8,826	7,606
Unrealized gain in fair value of derivative contracts	41	191
Other	4,163	4,204
	221,855	295,451
Total assets	**$2,145,045**	**$2,126,369**

(Continued)

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY

Consolidated Balance Sheets (Continued)

	December 31, 2013	December 31, 2012
	($-000's)	
Capitalization and liabilities		
Common stock, $1 par value, 100,000,000 shares authorized, 43,044,185 and 42,484,363 shares issued and outstanding, respectively	$ 43,044	$ 42,484
Capital in excess of par value	639,525	628,199
Retained earnings	67,554	47,115
Total common stockholders' equity	750,123	717,798
Long-term debt (net of current portion)		
Obligations under capital lease	4,167	4,441
First mortgage bonds and secured debt	637,578	487,541
Unsecured debt	101,683	199,644
Total long-term debt	743,428	691,626
Total long-term debt and common stockholders' equity	1,493,551	1,409,424
Current liabilities:		
Accounts payable and accrued liabilities	71,375	66,559
Current maturities of long-term debt	274	714
Short-term debt	4,000	24,000
Regulatory liabilities	5,681	6,303
Customer deposits	12,543	12,001
Interest accrued	6,352	5,902
Unrealized loss in fair value of derivative contracts	1,889	3,403
Taxes accrued	3,386	2,992
Other current liabilities	299	—
	105,799	121,874
Commitments and contingencies (Note 11)		
Noncurrent liabilities and deferred credits:		
Regulatory liabilities	132,012	131,055
Deferred income taxes	324,266	301,967
Unamortized investment tax credits	18,431	18,897
Pension and other postretirement benefit obligations	51,405	120,808
Unrealized loss in fair value of derivative contracts	2,799	3,819
Other	16,782	18,525
	545,695	595,071
Total capitalization and liabilities	**$2,145,045**	**$2,126,369**

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY

Consolidated Statements of Income

	Year Ended December 31,		
	2013	2012	2011
	(000's, except per share amounts)		
Operating revenues:			
Electric	$536,413	$510,653	$524,275
Gas	50,041	39,849	46,430
Other	7,876	6,595	6,165
	594,330	557,097	576,870
Operating revenue deductions:			
Fuel and purchased power	175,406	178,896	200,256
Cost of natural gas sold and transported	25,795	18,633	22,760
Regulated operating expenses	105,333	94,371	85,442
Other operating expenses	3,142	2,730	2,098
Maintenance and repairs	40,873	40,444	41,041
Loss on plant disallowance	2,409	—	150
Depreciation and amortization	69,306	60,447	63,537
Provision for income taxes	37,465	34,096	34,071
Other taxes	34,938	31,259	30,581
	494,667	460,876	479,936
Operating income	99,663	96,221	96,934
Other income and (deductions):			
Allowance for equity funds used during construction	3,853	1,147	294
Interest income	566	972	555
Provision for other income taxes	(27)	(63)	(227)
Other — non-operating expense, net	(1,218)	(1,910)	(1,283)
	3,174	146	(661)
Interest charges:			
Long-term debt	40,354	40,192	42,581
Short-term debt	60	187	86
Allowance for borrowed funds used during construction	(2,087)	(781)	(218)
Other	1,065	1,088	(1,147)
	39,392	40,686	41,302
Net income	**$ 63,445**	**$ 55,681**	**$ 54,971**
Weighted average number of common shares outstanding — basic	42,781	42,257	41,852
Weighted average number of common shares outstanding — diluted	42,803	42,284	41,887
Total earnings per weighted average share of common stock — basic and diluted	**$ 1.48**	**$ 1.32**	**$ 1.31**
Dividends declared per share of common stock	**$ 1.005**	**$ 1.000**	**$ 0.640**

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY

Consolidated Statements of Common Stockholders' Equity

	Common Stock	Capital in excess of Par	Retained earnings	Total
		($-000's)		
Balance at December 31, 2010	$41,577	$610,579	$ 5,468	$657,624
Net income			54,971	54,971
Stock/stock units issued through:				
Public offering				
Stock purchase and reinvestment plans	401	7,725		8,126
Dividends declared			(26,732)	(26,732)
Balance at December 31, 2011	41,978	618,304	33,707	693,989
Net income			55,681	55,681
Stock/stock units issued through:				
Public offering				
Stock purchase and reinvestment plans	506	9,895		10,401
Dividends declared			(42,273)	(42,273)
Balance at December 31, 2012	42,484	628,199	47,115	717,798
Net income			63,445	63,445
Stock/stock units issued through:				
Public offering				
Stock purchase and reinvestment plans	560	11,326		11,886
Dividends declared			(43,006)	(43,006)
Balance at December 31, 2013	$43,044	$639,525	$ 67,554	$750,123

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY

Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2013	2012	2011
		($-000's)	
Operating activities:			
Net income	$ 63,445	$ 55,681	$ 54,971
Adjustments to reconcile net income to cash flows from operating activities:			
Depreciation and amortization including regulatory items	71,734	71,160	79,751
Pension and other postretirement benefit costs, net of contributions	(1,888)	1,689	(20,379)
Deferred income taxes and unamortized investment tax credit, net	28,272	31,899	45,051
Allowance for equity funds used during construction	(3,853)	(1,147)	(294)
Stock compensation expense	2,984	2,285	2,147
Loss on plant disallowance	2,409	—	—
Non-cash loss on derivatives	14	4,174	1,187
Regulatory reversal of gain on sale of assets	1,236	—	—
Other	—	(16)	381
Cash flows impacted by changes in:			
Accounts receivable and accrued unbilled revenues	(14,312)	(688)	10,342
Fuel, materials and supplies	10,891	369	(16,682)
Prepaid expenses, other current assets and deferred charges	689	(9,238)	(23,163)
Accounts payable and accrued liabilities	(880)	(1,297)	(318)
Asset retirement obligation	(734)	—	—
Interest, taxes accrued and customer deposits	1,386	875	(980)
Other liabilities and other deferred credits	(3,942)	3,360	3,172
Accumulated provision — rate refunds	—	—	(578)
Net cash provided by operating activities	157,451	159,106	134,608

(Continued)

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY

Consolidated Statements of Cash Flows (Continued)

	Year Ended December 31,		
	2013	2012	2011
		($-000's)	
Investing activities:			
Capital expenditures — regulated	$(152,524)	$(134,272)	$ (99,162)
Capital expenditures and other investments — non-regulated	(2,259)	(2,670)	(3,375)
Restricted cash	1,485	(1)	(2,586)
Total net cash used in investing activities	(153,298)	(136,943)	(105,123)
Financing activities:			
Proceeds from first mortgage bonds, net	150,000	88,000	—
Long-term debt issuance costs	(1,879)	(1,074)	—
Proceeds from issuance of common stock, net of issuance costs	9,546	8,114	5,884
Repayment of first mortgage bonds	—	(88,029)	—
Redemption of senior notes	(98,000)	—	—
Net short-term borrowings (repayments)	(20,000)	12,000	(12,000)
Dividends	(43,006)	(42,273)	(26,732)
Other	(714)	(934)	(1,754)
Net cash used in financing activities	(4,053)	(24,196)	(34,602)
Net increase (decrease) in cash and cash equivalents	100	(2,033)	(5,117)
Cash and cash equivalents, beginning of year	3,375	5,408	10,525
Cash and cash equivalents, end of year	$ 3,475	3,375	$ 5,408

	2013	2012	2011
Supplemental cash flow information:			
Interest paid	$ 39,033	$ 38,802	$ 41,088
Income taxes (refunded) paid, net of refund	10,584	(592)	(14,300)
Supplementary non-cash investing activities:			
Change in accrued additions to property, plant and equipment not reported above	$ 5,420	$ 9,345	$ (1,387)
Capital lease obligations for purchase of new equipment	—	—	29

The accompanying notes are an integral part of these consolidated financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

We operate our businesses as three segments: electric, gas and other. The Empire District Electric Company (EDE), a Kansas corporation organized in 1909, is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company (EDG) is our wholly owned subsidiary engaged in the distribution of natural gas in Missouri. Our other segment consists of our fiber optics business. See Note 12. Our gross operating revenues in 2013 were derived as follows:

Electric segment sales*	90.3%
Gas segment sales	8.4
Other segment sales	1.3

* Sales from our electric segment include 0.4% from the sale of water.

The utility portions of our business are subject to regulation by the Missouri Public Service Commission (MPSC), the State Corporation Commission of the State of Kansas (KCC), the Corporation Commission of Oklahoma (OCC), the Arkansas Public Service Commission (APSC) and the Federal Energy Regulatory Commission (FERC). Our accounting policies are in accordance with the ratemaking practices of the regulatory authorities and conform to generally accepted accounting principles as applied to regulated public utilities.

Our electric operations serve approximately 168,800 customers as of December 31, 2013, and the 2013 electric operating revenues were derived as follows:

Customer	% of revenue
Residential	42.6%
Commercial	30.4
Industrial	15.1
Wholesale on-system	3.7
Wholesale off-system	2.9
Miscellaneous sources, primarily public authorities	2.8
Other electric revenues	2.5

Our retail electric revenues for 2013 by jurisdiction were as follows:

Jurisdiction	% of revenue
Missouri	89.8%
Kansas	4.8
Arkansas	2.5
Oklahoma	2.9

Our gas operations serve approximately 44,000 customers as of December 31, 2013, and the 2013 gas operating revenues were derived as follows:

Customer	% of revenue
Residential	63.1%
Commercial	27.3
Industrial	1.0
Other	8.6

Basis of Presentation

The consolidated financial statements include the accounts of EDE, EDG, and our other subsidiaries. The consolidated entity is referred to throughout as "we" or the "Company". All intercompany balances and transactions have been eliminated in consolidation. See Note 12 for additional information regarding our three segments.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements. Estimates also affect the reported amounts of revenues and expenses during the period. Areas in the financial statements significantly affected by estimates and assumptions include unbilled utility revenues, collectibility of accounts receivable, depreciable lives, asset impairment and goodwill impairment evaluations, employee benefit obligations, contingent liabilities, asset retirement obligations, the fair value of stock based compensation, tax provisions and derivatives. Actual amounts could differ from those estimates.

Accounting for the Effects of Regulation

In accordance with the Accounting Standard Codification (ASC) guidance for regulated operations, our financial statements reflect ratemaking policies prescribed by the regulatory commissions having jurisdiction over our regulated generation and other utility operations (the MPSC, the KCC, the OCC, the APSC and the FERC).

We record a regulatory asset for all or part of an incurred cost that would otherwise be charged to expense in accordance with the ASC guidance for regulated operations which say that an asset should be recorded if it is probable that future revenue in an amount at least equal to the capitalized cost will be allowable for costs for rate making purposes and the current available evidence indicates that future revenue will be provided to permit recovery of the cost. This guidance also indicates that a liability should be recorded when a regulator has provided current recovery for a cost that is expected to be incurred in the future. We follow this guidance for incurred costs or credits that are subject to future recovery from or refund to our customers in accordance with the orders of our regulators.

Historically, all costs of this nature, which are determined by our regulators to have been prudently incurred, have been recoverable through rates in the course of normal ratemaking procedures. Regulatory assets and liabilities are ratably amortized through a charge or credit, respectively, to earnings while being recovered in revenues and fully recognized if and when it is no longer probable that such amounts will be recovered through future revenues. We continually assess the recoverability of our regulatory assets. Although we believe it unlikely, should retail electric competition legislation be passed in the states we serve, we may determine that we no longer meet the criteria set forth in the ASC guidance for regulated operations with respect to continued recognition of some or all of the regulatory assets and liabilities. Any regulatory changes that would require us to discontinue application of this guidance based upon competitive or other events may also impact the valuation of certain utility plant investments. Impairment of regulatory assets or utility plant investments could have a material adverse effect on our financial condition and results of operations. (See Note 3 for further discussion of regulatory assets and liabilities).

Revenue Recognition

For our utility operations, we use cycle billing and accrue estimated, but unbilled, revenue for services provided between the last bill date and the period end date. Unbilled revenues represent the estimate of receivables for energy and natural gas services delivered, but not yet billed to customers. The accuracy of our unbilled revenue estimate is affected by factors including fluctuations in energy demands, weather, line losses and changes in the composition of customer classes. During 2012, the Company recorded an increase in electric unbilled revenues as a result of certain changes to the assumptions used in determining estimated unbilled revenues.

Municipal Franchise Taxes

Municipal franchise taxes are collected for and remitted to their respective entities and are included in operating revenues and other taxes in the Consolidated Statements of Income. Municipal franchise taxes of $11.2 million, $10.4 million and $11.0 million were recorded for each of the years ended December 31, 2013, 2012 and 2011, respectively.

Accounts Receivable

Accounts receivable are recorded at the tariffed rates for customer usage, including applicable taxes and fees and do not bear interest. We review the outstanding accounts receivable monthly, as well as the bad debt write-offs experienced in the past, and establish an allowance for doubtful accounts. Account balances are charged off against the allowance when management determines it is probable the receivable will not be recovered.

Property, Plant & Equipment

The costs of additions to utility property and replacements for retired property units are capitalized. Costs include labor, material, an allocation of general and administrative costs, and an allowance for funds used during construction (AFUDC). The original cost of units retired or disposed of and the costs of removal are charged to accumulated depreciation, unless the removed property constitutes an operating unit or system. In this case a gain or loss is recognized upon the disposal of the asset. Maintenance expenditures and the removal of minor property items are charged to income as incurred. A liability is created for any additions to electric or gas utility property that are paid for by advances from developers. For a period of five years the Company refunds, to the developer, a pro rata amount of the original cost of the extension for each new customer added to the extension. Nonrefundable payments at the end of the five year period are applied as a reduction to the cost of the plant in service. The liability as of December 31, 2013 and 2012 was $4.2 million and $5.2 million, respectively.

Depreciation

Provisions for depreciation are computed at straight-line rates in accordance with GAAP consistent with rates approved by regulatory authorities. These rates are applied to the various classes of utility assets on a composite basis. Provisions for depreciation for our other segment are computed at straight-line rates over the estimated useful life of the properties (See Note 2 for additional details regarding depreciation rates).

As of December 31, 2013 and 2012, we had recorded accrued cost of removal of $81.3 million and $77.3 million, respectively, for our electric operating segment. This represents an estimated cost of dismantling and removing plant from service upon retirement, accrued as part of our depreciation rates. We accrue cost of removal in depreciation rates for mass property (including transmission, distribution and general plant assets). These accruals are not considered an asset retirement obligation under the guidance provided on asset retirement obligations within the ASC. We reclassify the accrued cost of dismantling and removing plant from service upon retirement from accumulated depreciation to a regulatory liability. We have a similar cost of removal regulatory liability for our gas operating segment. This amount at December 31, 2013 and 2012 was $7.2 million and $6.1 million, respectively. These amounts are net of our actual cost of removal expenditures.

Asset Retirement Obligation

We record the estimated fair value of legal obligations associated with the retirement of tangible long-lived assets in the period in which the liabilities are incurred and capitalize a corresponding amount as part of the book value of the related long-lived asset. In subsequent periods, we are required to adjust asset retirement obligations based on changes in estimated fair value, and the corresponding increases in asset book values are depreciated over the useful life of the related asset. Uncertainties as to the probability, timing or cash flows associated with an asset retirement obligation affect our estimate of fair value.

We have identified asset retirement obligations associated with the future removal of certain river water intake structures and equipment at the Iatan Power Plant, in which we have a 12% ownership. We also have a solid waste land fill at the Plum Point Energy Station, and asset retirement obligations associated with the removal of asbestos located at the Riverton and Asbury Plants, and a liability for containment of the ash landfill at the Riverton Power Plant. As a result of the fuel use transition from coal to natural gas at the Riverton Power Plant, the closure of the Riverton ash landfill is underway (Note 11).

In addition, we have a liability for the removal and disposal of Polychlorinated Biphenyls (PCB) contaminants associated with our transformers and substation equipment. These liabilities have been estimated based upon either third party costs or historical review of expenditures for the removal of similar past liabilities. The potential costs of these future expenditures are based on engineering estimates of third party costs to remove the assets in satisfaction of the associated obligations. This liability will be accreted over the period up to the estimated settlement date.

All of our recorded asset retirement obligations have been estimated as of the expected retirement date, or settlement date, and have been discounted using a credit adjusted risk-free rate ranging from 4.5% to 5.52% depending on the settlement date. Revisions to these liabilities could occur due to changes in the cost estimates, anticipated timing of settlement or federal or state regulatory requirements. During the 2012 year, the liabilities for both the ash landfill at the Riverton Power Plant, and PCB contaminants were re-evaluated. Changes in the cost estimates and timing resulted in cash flow revisions for these liabilities.

The balances at the end of 2012 and 2013 are shown below.

(000's)	Liability Balance 12/31/12	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions	Liability Balance at 12/31/13
Asset Retirement Obligation	$4,711	$ —	$(734)	$213	$ —	$4,190

(000's)	Liability Balance 12/31/11	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions	Liability Balance at 12/31/12
Asset Retirement Obligation	$3,944	$ —	$ —	$252	$515	$4,711

Upon adoption of the standards on the retirement of long lived assets and conditional asset retirement obligations, we recorded a liability and regulatory asset because we expect to recover these costs of removal in electric and gas rates either through depreciation accruals or direct expenses. We also defer the liability accretion and depreciation expense as a regulatory asset. At December 31, 2013 and 2012, our regulatory assets relating to asset retirement obligations totaled $4.7 million and $4.4 million, respectively.

Also as noted previously under property, plant and equipment, we reclassify the accrued cost of dismantling and removing plant from service upon retirement, which is not considered an asset retirement obligation under this guidance, from accumulated depreciation to a regulatory liability. This balance sheet reclassification has no impact on results of operations.

Allowance for Funds Used During Construction

As provided in the FERC regulatory Uniform System of Accounts, utility plant is recorded at original cost, including an allowance for funds used during construction (AFUDC) when first placed in service. The AFUDC is a utility industry accounting practice whereby the cost of borrowed funds and the cost of equity funds applicable to our construction program are capitalized as a cost of construction. This accounting practice offsets the effect on earnings of the cost of financing current construction, and treats such financing costs in the same manner as construction charges for labor and materials.

AFUDC does not represent current cash income. Recognition of this item as a cost of utility plant is in accordance with regulatory rate practice under which such plant costs are permitted as a component of rate base and the provision for depreciation.

In accordance with the methodology prescribed by the FERC, we utilized aggregate rates (on a before-tax basis) of 7.3% for 2013, 5.6% for 2012, and 5.2% for 2011, compounded semiannually.. The specific Iatan 2 AFUDC rate was a result of our Experimental Regulatory Plan approved by the MPSC on August 2, 2005, and it terminated on June 15, 2011. In this agreement, we were allowed to receive the regulatory amortization discussed above, in rates prior to the completion of Iatan 2. As a result, the equity portion of our AFUDC rate for the Iatan 2 project was reduced by 2.5 percentage points (See Note 3 for additional discussion of our regulatory plan).

Asset Impairments (excluding goodwill)

We review long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. To the extent that certain assets may be impaired, analysis is performed based on undiscounted forecasted cash flows to assess the recoverability of the assets and, if necessary, the fair value is determined to measure the impairment amount. None of our assets were impaired as of December 31, 2013 and 2012.

Goodwill

As of December 31, 2013, the consolidated balance sheet included $39.5 million of goodwill. All of this goodwill was derived from our gas acquisition and recorded in our gas segment, which is also the reporting unit for goodwill testing purposes. Accounting guidance requires us to test goodwill for impairment on an annual basis or whenever events or circumstances indicate possible impairment. Absent an indication of fair value from a potential buyer or a similar specific transaction, a combination of the market and income approaches is used to estimate the fair value of goodwill.

We use the market approach which estimates fair value of the gas reporting unit by comparing certain financial metrics to comparable companies. Comparable companies whose securities are actively traded in the public market are judgmentally selected by management based on operational and economic similarities. We utilize EBITDA (earnings before interest, taxes, depreciation, and amortization) multiples of the comparable companies in relation to the EBITDA results of the gas reporting unit to determine an estimate of fair value.

We also utilize a valuation technique under the income approach which estimates the discounted future cash flows of operations. Our procedures include developing a baseline test and performing sensitivity analysis to calculate a reasonable valuation range. The sensitivities are derived from altering those assumptions which are subjective in nature and inherent to a discounted cash flows calculation. Other qualitative factors and comparisons to industry peers are also used to further support the assumptions and ultimately the overall evaluation. A key qualitative assumption considered in our evaluation is the impact of regulation, including rate regulation and cost recovery for the gas reporting unit. Some of the key quantitative assumptions included in our tests involve: regulatory rate design and results; the discount rate; the growth rate; capital spending rates and terminal value calculations. If negative changes occurred to one or more key assumptions, an impairment charge could result. With the exception of the capital spending rate, the key assumptions noted are significantly determined by market factors and significant changes in market factors that impact the gas reporting unit would somewhat be mitigated by our current and future regulatory rate design. Other risks and uncertainties affecting these assumptions include: changes in business, industry, laws, technology and economic conditions. Actual results for the gas reporting unit indicate a slight decline in gas customer count and demand. A continued decline in customer count or demand coupled with an increase in the discount rate would have adverse impacts on the valuation and could result in an impairment charge in the future. Our forecast anticipate flat customer counts over the next several years.

We weight the results of the two approaches discussed above in order to estimate the fair value of the gas reporting unit. Our annual test performed as of October 2013 indicated the estimated fair market value of the gas reporting unit to be $10-14 million higher than its carrying value at that time. While we believe the assumptions utilized in our analysis were reasonable, adverse developments in future periods could negatively impact goodwill impairment considerations, which could adversely impact earnings. Specifically, the quantitative assumptions noted previously, such as an increase to the discount rate or decline in the terminal value calculation could lead to an impairment charge in the future.

Fuel and Purchased Power

Electric Segment

Fuel and purchased power costs are recorded at the time the fuel is used, or the power purchased. This amount is adjusted to reflect regulatory treatment for our Missouri and Kansas fuel adjustment mechanisms discussed below.

In our Missouri jurisdiction, the MPSC established a base cost for the recovery of fuel and purchased power expenses used to supply energy for our fuel adjustment clause (FAC). The FAC permits the distribution to customers of 95% of the changes in fuel and purchased power costs prudently incurred above or below the base cost. Off-system sales margins are also part of the recovery of fuel and purchased power costs. As a result, nearly the entire off-system sales margin flows back to the customer. Rates related to the fuel adjustment clause are modified twice a year subject to the review and approval by the MPSC. In accordance with the ASC guidance for regulated operations, 95% of the difference between the actual costs of fuel and purchased power and the base cost of fuel and purchased power recovered from our customers is recorded as an adjustment to fuel and purchased power expense with a corresponding regulatory asset or regulatory liability. If the actual fuel and purchased power costs are higher or lower than the base fuel and purchased power costs billed to customers, 95% of these amounts will be recovered or refunded to our customers when the fuel adjustment clause is modified.

In our Kansas jurisdiction, the costs of fuel are recovered from customers through a fuel adjustment clause, based upon estimated fuel costs and purchased power. The adjustments are subject to audit and final determination by regulators. The difference between the costs of fuel used and the cost of fuel recovered from our Kansas customers is recorded as a regulatory asset or a regulatory liability if the actual costs are higher or lower than the costs billed to customers, in accordance with the ASC guidance for regulated operations. Similar fuel recovery mechanisms are in place for our Oklahoma, Arkansas and FERC jurisdictions. At December 31, 2013 and 2012, our Missouri, Kansas and Oklahoma fuel and purchased power costs were in a net over-recovered position by $0.6 million and $4.0 million, respectively, which are reflected in our regulatory assets and liabilities.

We receive the renewable attributes associated with the power purchased through our purchased power agreements with Elk River Windfarm LLC and Cloud County Windfarm, LLC. These renewable attributes are converted into renewable energy credits, which are considered inventory, and recorded at zero cost (See Note 11). Revenue from the sale of renewable energy credits reduces fuel and purchased power expense.

We have a Stipulation and Agreement with the MPSC granting us authority to manage our SO2 allowance inventory in accordance with our SO2 Allowance Management Policy (SAMP). The SAMP allows us to exchange banked allowances for future vintage allowances and/or monetary value and, in extreme market conditions, to sell SO2 allowances outright for monetary value. We have not yet exchanged or sold any allowances. We classify our allowances as inventory and they are recorded at cost, with allocated allowances being recorded at zero cost. The allowances are removed from inventory on a FIFO basis, and used allowances are considered to be a part of fuel expense (See Note 11). We had 1,834 and 5,187 SO2 allowances in inventory at December 31, 2013 and 2012, respectively. .

Gas Segment

Fuel expense for our gas segment is recognized when the natural gas is delivered to our customers, based on the current cost recovery allowed in rates. A Purchased Gas Adjustment (PGA) clause allows EDG to recover from our customers, subject to audit and final determination by regulators, the cost of purchased gas supplies and related carrying costs associated with the Company's use of natural gas financial instruments to hedge the purchase price of natural gas. This PGA clause allows us to make rate changes periodically (up to four times) throughout the year in response to weather conditions and supply demands, rather than in one possibly extreme change per year.

We calculate the PGA factor based on our best estimate of our annual gas costs and volumes purchased for resale. The calculated factor is reviewed by the MPSC staff and approved by the MPSC.

Elements considered part of the PGA factor include cost of gas supply, storage costs, hedging contracts, revenue and refunds, prior period adjustments and transportation costs.

Pursuant to the provisions of the PGA clause, the difference between actual costs incurred and costs recovered through the application of the PGA (including costs, cost reductions and carrying costs associated with the use of financial instruments) are reflected as a regulatory asset or liability. The balance is amortized as amounts are reflected in customer billings.

Derivatives

We utilize derivatives to help manage our natural gas commodity market risk resulting from purchasing natural gas, to be used as fuel in our electric business or sold in our natural gas business, on the spot market and to manage certain interest rate exposure. We also acquire Transmission Congestion Rights (TCR) in an attempt to mitigate congestion costs associated with the power we will purchase from the SPP Integrated Market (see Note 14).

Electric Segment

Pursuant to the ASC guidance on accounting for derivative instruments and hedging activities, derivatives are required to be recognized on the balance sheet at their fair value. On the date a derivative contract is entered into, the derivative is designated as (1) a hedge of a forecasted transaction or of the variability of cash flows to be received or paid related to a recognized asset or liability ("cash-flow" hedge); or (2) an instrument that is held for non-hedging purposes (a "non-hedging" instrument). We record the mark-to-market gains or losses on derivatives used to hedge our fuel and congestion costs as regulatory assets or liabilities. This is in accordance with the ASC guidance on regulated operations, given that those regulatory assets and liabilities are probable of recovery through our fuel adjustment mechanism.

We also enter into fixed-price forward physical contracts for the purchase of natural gas, coal and purchased power. These contracts, if they meet the definition of a derivative, are not subject to derivative accounting because they are considered to be normal purchase normal sales (NPNS) transactions. If these transactions don't qualify for NPNS treatment, they would be marked to market for each reporting period through regulatory assets or liabilities.

Gas Segment

Financial hedges for our natural gas business are recorded at fair value on our balance sheet. Because we have a commission approved natural gas cost recovery mechanism (PGA), we record the mark-to-market gain/loss on natural gas financial hedges each reporting period to a regulatory asset/liability account. The regulatory asset/liability account tracks the difference between revenues billed to customers for natural gas costs and actual natural gas expense which is trued up at the end of August each year and included in the Actual Cost Adjustment (ACA) factor to be billed to customers during the next year. This is consistent with the ASC guidance on regulated operations, in that we will be recovering our costs after the annual true up period (subject to a prudency review by the MPSC).

Cash flows from hedges for both electric and gas segments are classified within cash flows from operations.

Pension and Other Postretirement Benefits

We recognize expense related to pension and other postretirement benefits as earned during the employee's period of service. Related assets and liabilities are established based upon the funded status of the plan compared to the projected benefit obligation. Our pension and OPEB expense or benefit includes amortization of previously unrecognized net gains or losses. Additional income or expense may be recognized when our unrecognized gains or losses as of the most recent measurement date exceed 10% of our postretirement benefit obligation or fair value of plan assets, whichever is greater. For pension benefits and OPEB benefits, unrecognized net gains or losses as of the measurement date are amortized into actuarial expense over ten years.

Pensions

We have rate orders with Missouri, Kansas and Oklahoma that allow us to recover pension costs consistent with our GAAP policy noted above. In accordance with the rate orders, we prospectively calculate the value of plan assets using a market-related value method as allowed by the ASC guidance on pension benefits. As a result, we are allowed to record the Missouri, Kansas and Oklahoma portion of any costs above or below the amount included in rates as a regulatory asset or liability, respectively. The MPSC has allowed us to adopt this pension cost recovery methodology for EDG as well.

Other Postretirement Benefits (OPEB)

We have regulatory treatment for our OPEB costs similar to the treatment described above for pension costs. This includes the use of a market-related value of assets, the amortization of unrecognized gains or losses into actuarial expense over ten years and the recognition of regulatory assets and liabilities as described above.

In accordance with the guidance provided in the ASC on the Medicare Prescription Drug, Improvement and Modernization Act of 2003, the accumulated postretirement benefit obligation (APBO) and net cost recognized for OPEB reflects the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Act provides for a federal subsidy, beginning in 2006, of 28% of prescription drug costs between $250 and $5,000 for each Medicare-eligible retiree who does not join Medicare Part D, to companies whose plans provide prescription drug benefits to their retirees that are "actuarially equivalent" to the prescription drug benefits provided under Medicare. Equivalency must be certified annually by the Federal Government. Our plan provides prescription drug benefits that are "actuarially equivalent" to the prescription drug benefits provided under Medicare and have been certified as such.

Additional guidance in the ASC on employers' accounting for defined benefit pension and other postretirement plans requires an employer to recognize the over funded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity. The guidance also requires an employer to measure the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. Pension and other postretirement employee benefits tracking mechanisms are utilized to allow for future rate recovery of these obligations. We record these as regulatory assets on the balance sheet rather than as reductions of equity through comprehensive income (See Note 8).

Unamortized Debt Discount, Premium and Expense

Discount, premium and expense associated with long-term debt are amortized over the lives of the related issues. Costs, including gains and losses, related to refunded long-term debt are amortized over the lives of the related new debt issues, in accordance with regulatory rate practices.

Liability Insurance

We are primarily self-insured for workers' compensation claims, general liabilities, benefits paid under employee healthcare programs and long-term disability benefits. Accruals are primarily based on the estimated undiscounted cost of claims. We self-insure up to certain limits that vary by segment and type of risk. Periodically, we evaluate the level of insurance coverage over the self-insured limits and adjust insurance levels based on risk tolerance and premium expense. We carry excess liability insurance for workers' compensation and public liability claims for our electric segment. In order to provide for the cost of losses not covered by insurance, an allowance for injuries and damages is maintained based on our loss experience. Our gas segment is covered by excess liability insurance for public liability claims, and workers' compensation claims are covered by a guaranteed cost policy (See Note 11).

Other Noncurrent Liabilities

Other noncurrent liabilities are comprised of accruals and other accounting estimates not sufficiently large enough to merit individual disclosure. At December 31, 2013, the balance of other noncurrent liabilities is primarily comprised of accruals for self-insurance, customer advances for construction and asset retirement obligations.

Cash & Cash Equivalents

Cash and cash equivalents include cash on hand and temporary investments purchased with an initial maturity of three months or less. It also includes checks and electronic funds transfers that have been issued but have not cleared the bank, which are also reflected in current accrued liabilities and were $22.1 million and $19.7 million at December 31, 2013 and 2012, respectively.

Restricted Cash

As part of our Plum Point ownership agreement, we are required to have funds available in an escrow account which guarantees payment of certain operating and construction costs. The cash is held at a financial institution and restricted as to withdrawal or use. The restrictions on these funds related to construction costs, which were approximately $2.5 million at December 31, 2012, were released by all parties in January 2013. The amounts restricted for operating costs, which were $1.8 million at December 31, 2013 and 2012, may increase or decrease based on an annual review.

We are required to post secured collateral with Southwest Power Pool (SPP) to participate in Transmission Congestion Rights (TCR) auctions. The cash is held at a financial institution and restricted as to withdrawal or use. The restrictions on these funds were $1.1 million at December 31, 2013.

Fuel, Materials and Supplies

Fuel, materials and supplies consist primarily of coal, natural gas in storage and materials and supplies, which are reported at average cost. These balances are as follows (in thousands):

	2013	2012
Electric fuel inventory	$17,003	$27,954
Natural gas inventory	3,584	4,776
Materials and supplies	28,224	29,140
TOTAL	$48,811	$61,870

Income Taxes

Deferred tax assets and liabilities are recognized for the tax consequences of transactions that have been treated differently for financial reporting and tax return purposes, measured using statutory tax rates (See Note 9).

Investment tax credits utilized in prior years were deferred and are being amortized over the useful lives of the properties to which they relate. The longest remaining amortization period for investment tax credits is approximately 50 years.

Accounting for Uncertainty in Income Taxes

In 2006, the FASB issued guidance which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with the ASC guidance on accounting for income taxes. We file consolidated income tax returns in the U.S. federal and state jurisdictions. With few exceptions, we are no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years before 2009. At December 31, 2013 and 2012, our balance sheet did not include any unrecognized tax benefits. We do not expect any material changes to unrecognized tax benefits within the next twelve months. We recognize interest accrued and penalties related to unrecognized tax benefits in other expenses.

Computations of Earnings Per Share

The ASC guidance on earnings per share requires dual presentation of basic and diluted earnings per share. Basic earnings per share does not include potentially dilutive securities and is computed by dividing net income by the weighted average number of common shares outstanding. Diluted earnings per share assumes the issuance of common shares pursuant to the Company's stock-based compensation plans at the beginning of each respective period, or at the date of grant or award if later. Shares attributable to stock options are excluded from the calculation of diluted earnings per share if the effect would be antidilutive.

	2013	2012	2011
Weighted Average Number Of Shares			
Basic	42,781,382	42,256,641	41,851,759
Dilutive Securities:			
Performance-based restricted stock awards	12,142	14,500	18,222
Dividend equivalents	—	6,329	9,585
Employee stock purchase plan	1,729	1,996	3,815
Stock options	61	3,160	3,240
Time-based restricted stock awards	7,907	1,820	807
Total dilutive securities	21,839	27,805	35,669
Diluted weighted average number of shares	42,803,221	42,284,446	41,887,428
Antidilutive Shares	107,100	128,500	128,500

Potentially dilutive shares are not expected to have a material impact unless significant appreciation of the Company's stock price occurs.

Stock-Based Compensation

We have several stock-based compensation plans, which are described in more detail in Note 4. In accordance with the ASC guidance on stock-based compensation, we recognize compensation expense over the requisite service period of all stock-based compensation awards based upon the fair-value of the award as of the date of issuance.

Recently Issued and Proposed Accounting Standards

Balance Sheet Offsetting: In December 2011, the FASB amended the guidance governing the offsetting, or netting, of assets and liabilities on the balance sheet. Under the revised guidance, an entity would be required to disclose both the gross and net information about instruments and transactions that are eligible for offset on the balance sheet, as well as instruments or transactions subject to a master netting agreement. This standard is effective for annual periods beginning after January 1, 2013. The application of this standard did not have a material impact on our results of operations, financial position or liquidity.

Presentation of an unrecognized tax benefit: In July 2013, The FASB issued new guidance on the presentation of unrecognized tax benefits. Under this guidance, an unrecognized tax benefit would be presented as a reduction to a deferred tax asset when a tax credit carryforward, net operating loss carryforward, or similar tax loss exists. To the extent that the loss or credit carryforward is not available at the reporting date, or the entity does not intend to use the deferred tax asset for such a purpose, the unrecognized tax benefit should be presented as a liability and not be combined with deferred tax assets. This standard is effective for annual periods beginning after December 15, 2013. The application of this standard is not expected to have a material impact on our results of operations, financial position or liquidity.

2. PROPERTY, PLANT AND EQUIPMENT

Our total property, plant and equipment are summarized below (in thousands).

	December 31, 2013	December 31, 2012
Electric plant		
Production	$1,035,095	$1,034,114
Transmission	263,398	251,769
Distribution	793,024	766,026
General(1)	115,427	111,963
Electric plant	2,206,944	2,163,872
Less accumulated depreciation and amortization	697,128	651,627
Electric plant net of depreciation and amortization	1,509,816	1,512,245
Construction work in progress	150,636	55,957
Net electric plant	**1,660,452**	**1,568,202**
Gas plant	72,834	69,851
Less accumulated depreciation and amortization	15,204	12,940
Gas plant net of accumulated depreciation	57,630	56,911
Construction work in progress	1,156	184
Net gas plant	**58,786**	**57,095**
Water plant	12,661	12,316
Less accumulated depreciation and amortization	4,806	4,440
Water plant net of depreciation and amortization	7,855	7,876
Construction work in progress	—	1
Net water plant	**7,855**	**7,877**
Other		
Fiber	39,902	37,983
Less accumulated depreciation and amortization	15,599	13,730
Non-regulated net of depreciation and amortization	24,303	24,253
Construction work in progress	538	205
Net non-regulated property	**24,841**	**24,458**
TOTAL NET PLANT AND PROPERTY	**$1,751,934**	**$1,657,632**

(1) Includes intangible property of $38.1 and $36.4 million as of December 31, 2013 and 2012, respectively, primarily related to capitalized software and investments in facility upgrades owned by other utilities. Accumulated amortization related to this property in 2013 and 2012 was $13.6 and $10.7 million, respectively.

The table below summarizes the total provision for depreciation and the depreciation rates for continuing operations, both capitalized and expensed, for the years ended December 31 (in thousands):

	2013	2012	2011
Provision for depreciation			
Regulated — Electric and Water	$63,192	$57,467	$54,628
Regulated — Gas	3,763	3,602	3,485
Non-Regulated	1,938	1,538	1,807
TOTAL	**68,893**	**62,607**	**59,920**
Amortization(1)	2,492	1,041	7,445
TOTAL	**$71,385**	**$63,648**	**$67,365**

(1) Includes $6.6 million of regulatory amortization for 2011. This was granted by the MPSC effective January 1, 2007 and updated August 23, 2008, and September 10, 2010. This regulatory amortization terminated as of June 15, 2011 as a result of our 2010 Missouri rate case.

	2013	2012	2011
Annual depreciation rates			
Electric and water	3.0%	2.8%	2.7%
Gas	5.4%	5.4%	5.5%
Non-Regulated	5.0%	4.2%	5.4%
TOTAL COMPANY	**3.1%**	**2.9%**	**2.9%**

The table below sets forth the average depreciation rate for each class of assets for each period presented:

	2013	2012	2011
Annual Weighted Average Depreciation Rate			
Electric fixed assets:			
Production plant	2.4%	2.0%	2.1%
Transmission plant	2.4%	2.4%	2.3%
Distribution plant	3.6%	3.6%	3.6%
General plant	5.8%	5.9%	6.1%
Water	2.8%	2.7%	2.7%
Gas	5.4%	5.4%	5.5%
Non-regulated	5.0%	4.2%	5.4%

3. REGULATORY MATTERS

Regulatory Assets and Liabilities and Other Deferred Credits

Changes

Changes to regulatory assets and liabilities regarding their rate base inclusion or amortizable lives from December 31, 2012 to December 31, 2013 resulted from our 2012 Missouri rate case. As a result of this case, deferred costs from the tornado that hit our service territory on May 22, 2011 will be recovered over the next ten years. In addition, the order also included the continuation of tracking mechanisms for expenses related to employee pension, retiree health care, vegetation management, and Iatan 2, Iatan Common and Plum Point operating and maintenance costs and the capitalization of banking and line of credit fees. There were no changes to regulatory assets and liabilities with regards to their rate base inclusion or amortizable lives from December 31, 2011 to December 31, 2012.

The following table sets forth the components of our regulatory assets and regulatory liabilities on our consolidated balance sheet (in thousands).

	December 31,	
	2013	**2012**
Regulatory Assets:		
Current:		
Under recovered fuel costs	$ 1,411	$ 2,885
Current portion of long-term regulatory assets	6,332	3,492
Regulatory assets, current	7,743	6,377
Long-term:		
Pension and other postretirement benefits[1]	70,035	136,480
Income taxes	48,033	48,759
Deferred construction accounting costs[2]	16,275	16,717
Unamortized loss on reacquired debt	11,078	12,142
Unsettled derivative losses — electric segment	4,269	6,557
System reliability — vegetation management	7,539	9,002
Storm costs[3]	4,911	4,828
Asset retirement obligation	4,673	4,430
Customer programs	4,935	4,356
Unamortized loss on interest rate derivative	989	1,147
Deferred operating and maintenance expense	2,095	2,049
Under recovered fuel costs	—	314
Current portion of long-term regulatory assets	(6,332)	(3,492)
Other	833	669
Regulatory assets, long-term	169,333	243,958
Total Regulatory Assets	$177,076	$250,335
Regulatory Liabilities		
Current:		
Over recovered fuel costs	$ 2,212	$ 3,214
Current portion of long-term regulatory liabilities	3,469	3,089
Regulatory liabilities, current	5,681	6,303
Long-term:		
Costs of removal	88,469	83,368
SWPA payment for Ozark Beach lost generation	19,405	22,242
Income taxes	11,677	11,972
Deferred construction accounting costs — fuel[4]	8,011	8,156
Unamortized gain on interest rate derivative	3,371	3,541
Pension and other postretirement benefits	2,177	2,007
Over recovered fuel costs	2,371	2,858
Current portion of long-term regulatory liabilities	(3,469)	(3,089)
Regulatory liabilities, long-term	132,012	131,055
Total Regulatory Liabilities	$137,693	$137,358

(1) Primarily consists of unfunded pension and OPEB liability. See Note 8.

(2) Reflects deferrals resulting from 2005 regulatory plan relating to Iatan 1, Iatan 2 and Plum Point. These amounts are being recovered over the life of the plants.

(3) Reflects ice storm costs incurred in 2007 and costs incurred as a result of the May 2011 tornado including an accrued carrying charge and deferred depreciation totaling $3.7 million at December 31, 2013.

(4) Resulting from regulatory plan requiring deferral of the fuel and purchased power impacts of Iatan 2.

Unamortized losses on debt and losses on interest rate derivatives are not included in rate base, but are included in our capital structure for rate base purposes. The remainder of our regulatory assets are not included in rate base, generally because they are not cash items. However, as of December 31, 2013, the costs of all of our regulatory assets are currently being recovered except for approximately $61.2 million of pension and other postretirement costs primarily related to the unfunded liabilities for future pension and OPEB costs. The amount and timing of recovery of this item will be based on the changing funded status of the pension and OPEB plans in future periods.

The regulatory income tax assets and liabilities are generally amortized over the average depreciable life of the related assets. The loss on reacquired debt and the loss and gain on interest rate derivatives are amortized over the life of the related new debt issue, which currently ranges from 1 to 28 years. The unrecovered fuel costs are generally recovered within a year following their recognition. Severe storm costs and the Asbury maintenance outage costs are recovered over five years. Pension and other postretirement benefit tracking mechanisms are recovered over a five year period. The cost of removal regulatory liability is amortized as removal costs are incurred.

RATE MATTERS

We routinely assess the need for rate relief in all of the jurisdictions we serve and file for such relief when necessary.

Our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are determined on a "cost of service" basis. Rates are designed to provide, after recovery of allowable operating expenses, an opportunity for us to earn a reasonable return on "rate base." "Rate base" is generally determined by reference to the original cost (net of accumulated depreciation and amortization) of utility plant in service, subject to various adjustments for deferred taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation, amortization and retirement of utility plant or write-off's as ordered by the utility commissions. In general, a request of new rates is made on the basis of a "rate base" as of a date prior to the date of the request and allowable operating expenses for a 12-month test period ended prior to the date of the request. Although the current rate making process provides recovery of some future changes in rate base and operating costs, it does not reflect all changes in costs for the period in which new retail rates will be in place. This results in a lag (commonly referred to as "regulatory lag") between the time we incur costs and the time when we can start recovering the costs through rates.

The following table sets forth information regarding electric and water rate increases since January 1, 2011:

Jurisdiction	Date Requested	Annual Increase Granted	Percent Increase Granted	Date Effective
Missouri — Electric	July 6, 2012	$27,500,000	6.78%	April 1, 2013
Missouri — Water	May 21, 2012	$ 450,000	25.5%	November 23, 2012
Missouri — Electric	September 28, 2010	$18,700,000	4.70%	June 15, 2011
Kansas — Electric	June 17, 2011	$ 1,250,000	5.20%	January 1, 2012
Oklahoma — Electric	June 30, 2011	$ 240,722	1.66%	January 4, 2012
Oklahoma — Electric	January 28, 2011	$ 1,063,100	9.32%	March 1, 2011
Arkansas — Electric	August 19, 2010	$ 2,104,321	19.00%	April 13, 2011

Electric Segment

Missouri

2012 Rate Case

On February 22, 2013, we filed a Nonunanimous Stipulation and Agreement (Agreement) with the MPSC which issued an order approving the Agreement on February 27, 2013. The Agreement provided for an annual increase in base revenues for our Missouri electric customers in the amount of approximately $27.5 million, effective April 1, 2013, and the continuation of the current fuel adjustment mechanism. In 2011 the MPSC permitted us to defer actual incremental operating and maintenance expenses associated with the repair, restoration and rebuilding activities resulting from the May 2011 tornado. In addition, depreciation related to the capital expenditures was allowed to be deferred and a carrying charge accrued. Approximately $3.7 million was deferred in total for the tornado costs. Recovery of these costs over the ten years was included in the Agreement

The Agreement also included an increase in depreciation rates, and the continuation of tracking mechanisms for expenses related to employee pension, retiree health care, vegetation management, and Iatan 2, Iatan Common and Plum Point operating and maintenance costs. In addition, the Agreement included a write-off of approximately $3.6 million, consisting of a $2.4 million disallowance for the prudency of certain construction expenditures for Iatan 2 and a $1.2 million regulatory reversal of a prior period gain on sale of our Asbury unit train, which is included in regulated operating expenses. We also agreed not to implement a Missouri general rate increase prior to October 1, 2014.

As initially filed on July 6, 2012, we requested an annual increase in base rates for our Missouri electric customers in the amount of $30.7 million, or 7.56%, and the continuation of the fuel adjustment clause. This request was primarily designed to recover operation and maintenance expenses and capital costs associated with the May 22, 2011 tornado, Southwest Power Pool transmission charges allocated to us, operating systems replacement costs for new software systems, vegetation management costs, new depreciation rates and amortization of a regulatory asset related to the tax benefits of cost of removal, the balance of which was approximately $9.6 million at December 31, 2012.

On May 21, 2012, we filed a rate increase request with the MPSC for an annual increase in revenues for our Missouri water customers in the amount of approximately $516,400, or 29.6%. On October 18, 2012, we, the MPSC staff and the Office of the Public Counsel filed a unanimous agreement with the MPSC for an increase of $450,000. The MPSC issued an order approving the agreement on October 31, 2012, with rates effective November 23, 2012.

2010 Rate Case

On September 28, 2010, we filed a rate increase request with the MPSC for an annual increase in base rates for our Missouri electric customers in the amount of $36.5 million, or 9.2% to recover the Iatan 2 costs and other cost of service items not included in our 2009 Missouri rate case, effective September 10, 2010. A settlement agreement among the parties to the case was reached and filed with the MPSC on May 27, 2011 reflecting an overall annual increase in rates of $18.7 million, or approximately 4.7% effective on June 15, 2011. Due to rate design changes, this rate increase, however, primarily impacted our winter season rates which generally run from October through May. Also as part of the settlement, regulatory amortization expense of $14.5 million annually and construction accounting terminated as of June 15, 2011. The MPSC approved the settlement agreement on June 1, 2011 and the new rates were effective on June 15, 2011. The approved settlement included authorization of a tracker mechanism for the SWPA payment associated with the capacity restrictions to be implemented for our Ozark Beach hydro facility. We agreed to flow the SWPA payment, net of tax, back to our customers over a ten year period using a tracker mechanism resulting in an annual decrease to expenses of approximately $1.4 million. The settlement agreement also allowed for a tracker mechanism related to Plum Point, Iatan 2 and Iatan common plant operating expenses. We record a regulatory asset or liability for the difference between actual expenses (excluding fuel and fuel related expenses) and the amount of expense included in base rates.

Kansas

2011 Rate Case

On June 17, 2011, we filed an application with the KCC seeking a rate increase of $1.5 million, or 6.39%. The rate increase was requested to recover the costs associated with our investment in the Iatan 1, Iatan 2 and Plum Point generating units and the depreciation and operation and maintenance costs deferred since the in-service dates of the units. The June 17, 2011 filing was made under the KCC's abbreviated rate case rules which the KCC authorized in our 2009 Kansas rate case. The case included a request to recover the Iatan and Plum Point cost deferrals over a 3-year period. A joint settlement agreement was filed on November 10, 2011 and approved by the KCC on December 21, 2011, resulting in an increase in annual revenues of $1.25 million, or approximately 5.2%. The new rates became effective on January 1, 2012.

Oklahoma

On June 30, 2011, we filed a request with the Oklahoma Corporation Commission (OCC) for an annual increase in base rates for our Oklahoma electric customers in the amount of $0.6 million, or 4.1% over the base rate and Capital Reliability Rider (CRR) revenues that were currently in effect. A stipulation and agreement, reached by all parties participating in the case, was filed on November 16, 2011. This agreement, which was approved by the OCC on January 4, 2012, made rates previously collected under the CRR permanent, and will result in a net overall increase of total annual revenues of $0.2 million, or approximately 1.66%. The agreement also removed fuel and purchase power costs from base rates. Fuel and purchase power costs are now listed as a separate line item, identified as the Fuel Adjustment Charge, on customer bills.

Arkansas

On December 3, 2013, we filed a request with the Arkansas Public Service Commission for changes in rates for our Arkansas electric customers. We are seeking an annual increase in total revenue of approximately $2.2 million, or approximately 18%. The rate increase was requested to recover costs incurred to ensure continued reliable service for our customers, including capital investments, operating systems replacement costs and ongoing increases in other operation and maintenance expenses and capital costs.

FERC

On May 18, 2012, we filed a request with the FERC to implement a TFR to be effective August 1, 2012. On July 31, 2012, the FERC suspended the TFR for five months and set the filing for hearing and settlement procedures. On June 13, 2013, we, the Kansas Corporation Commission and the cities of Monett, Mt. Vernon and Lockwood, Missouri and Chetopa, Kansas, filed a unanimous Settlement Agreement (Agreement) with the FERC. The Agreement included a TFR that would establish an ROE of 10.0%. The Agreement calls for the TFR to be updated annually with the new updated TFR rates effective on July 1 of each year. FERC conditionally approved the Agreement on November 18, 2013, and we made a compliance filing with FERC on December 18, 2013 in connection with this conditional approval. Final FERC action on our compliance filing is pending.

On March 12, 2010, we filed new annual GFR tariffs with the FERC which we propose to be utilized for our wholesale customers. On May 28, 2010, the FERC issued an order that conditionally approved our GFR filing subject to refund effective June 1, 2010. On September 15, 2010, the parties agreed to a settlement in principle and on May 24, 2011, we, the Missouri Public Utility Alliance and the cities of Monett, Mt. Vernon and Lockwood, Missouri filed a Settlement Agreement and Offer of Settlement with the FERC. We refunded approximately $1.3 million, including interest, in November 2011 as a result of this settlement. A GFR update will be completed annually for rates effective June 1.

MARKETS AND TRANSMISSION

Electric Segment

Energy Imbalance Services: The Southwest Power Pool (SPP) regional transmission organization (RTO) energy imbalance services market (EIS) provides real time energy for most participating members within the SPP regional footprint. Imbalance energy prices are based on market bids and status of dispatchable generation and transmission within the SPP market footprint. In addition to energy imbalance service, the SPP RTO performs a real time security-constrained economic dispatch of all generation voluntarily offered into the EIS market to the market participants to also serve the native load.

Day-Ahead Market: We continue to prepare for a March 1, 2014 implementation of the SPP Integrated Marketplace (or Day-Ahead Market), which will replace the existing EIS market described above. Prior to implementation of the Integrated Marketplace, the SPP RTO will create a single NERC-approved balancing authority to take over balancing authority responsibilities for its members, including Empire. This action is expected to provide operational and economic benefits for our customers.

As part of the Integrated Marketplace, SPP members will be able to offer their committed resources into the SPP market for a centralized dispatch. Members will submit offers to sell and bids to purchase power. SPP will match offers and bids based upon a security constrained analysis. It is expected that 90%-95% of all generation needed (for the next day) throughout the SPP territory will be cleared through this Integrated Marketplace. We also acquire Transmission Congestion Rights (TCR) in an attempt to mitigate congestion costs associated with the power we will purchase from the SPP Integrated Market (see Note 14). The net financial effect of these Integrated Marketplace transactions will be processed through our fuel adjustment mechanisms.

FERC Order No. 1000: In July 2011, the FERC issued Order No. 1000 (Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities) which requires all public utility transmission providers to allow transmission developers outside their retail distribution service territory to participate in regional transmission planning. Order No. 1000 eliminates the federal right of first refusal for entities that develop transmission projects within their own retail distribution service territories to construct transmission facilities selected in a regional transmission plan. This order will directly affect our rights to build 161kV and above transmission facilities within our retail service territory.

Order No. 1000 also directed transmission providers to develop policy and procedures for regional and interregional transmission planning as well as regional and interregional transmission cost allocation (see "SPP Regional Transmission Development" below) for approved transmission projects. We continue to participate in the SPP processes to understand the impact of these FERC orders on our ability to construct new facilities within our service territory as well as their influence on promoting construction of transmission projects on or near our borders with our neighbors. SPP has completed and filed with the FERC a required interregional policy and procedure compliance filing, with implementation scheduled for January 2015. FERC's decision on SPP's Order No. 1000 interregional compliance filing is pending.

SPP Regional Transmission Development: In 2010, SPP received FERC approval to implement a new highway/byway cost allocation methodology for new SPP Board of Directors (BOD) approved transmission projects, a number which are currently in progress. We are concerned with the SPP's policy to allocate to us the costs of transmission projects from which we would receive either no benefits or benefits that are not roughly commensurate with the allocated costs. We estimate net transmission costs will increase between $2 and $3 million in 2014 as a result of SPP's allocation methodology over what we currently recover in customer rates. We have cost recovery mechanisms in place in our Arkansas and Oklahoma jurisdictions that allow us to recover the additional SPP transmission costs outside the traditional rate case process. Currently no mechanism is in place to timely recover additional costs resulting from the portion of these transmission projects allocated to us other than through the traditional rate case process in our Missouri and Kansas jurisdictions.

The highway/byway allocation methodology requires the costs of SPP approved transmission projects to be allocated to 1) members across the entire SPP region; 2) members within certain localized service territories or zones; or 3) a combination of both regional and zonal allocation. The allocation is based on project voltage, as follows:

Transmission Project Voltage	Regional Funding Percentage	Zonal Funding Percentage
300 kV and Above	100.0%	0.0%
100kV to 299kV	33.3%	66.7%
Below 100 kV	0.0%	100.0%

At the October 2013 SPP regional state committee meeting, SPP's regional cost allocation review and imbalance analysis indicated that our projected benefits (along with five other members) compared to the allocation of transmission costs over the next several years would be below the roughly commensurate benefit to cost threshold that initiates an equity remedy review by SPP staff. SPP will evaluate potential construction equity improvement remedies during the upcoming 2014 Integrated Transmission Planning (ITP) process with any recommendations expected in January 2015

SPP/Midcontinent Independent System Operator (MISO) Joint Operating Agreement: On December 19, 2013, Entergy integrated its generation, transmission, and load into the MISO regional transmission organization. Based on the current terms and conditions of MISO membership, Entergy's participation in

MISO will not be beneficial to our customers as it will significantly increase transmission delivery costs for our Plum Point power station as well as utilize our transmission system without compensation.

Prior to Entergy's integration into MISO, the SPP filed a Petition for Review of FERC's Orders on the interpretation of the SPP/MISO Joint Operating Agreement at the United States Court of Appeals for the District of Columbia (DC). In early December 2013, the DC Court vacated and remanded FERC's Orders that agreed with MISO regarding interpretation of the Joint Operating Agreement to utilize SPP's system to integrate Entergy into MISO. SPP believes MISO's intentional and free use of ours and the other SPP transmission owners systems is unjust and unreasonable. We and other SPP members have intervened in SPP's Petition and are actively involved in SPP stakeholder processes and other FERC dockets to address our concerns. FERC's actions regarding the remand and review of the FERC orders are pending.

Gas Segment

Non-residential gas customers whose annual usage exceeds certain amounts may purchase natural gas from a source other than EDG. EDG does not have a non-regulated energy marketing service that sells natural gas in competition with outside sources. EDG continues to receive non-gas related revenues for distribution and other services if natural gas is purchased from another source by our eligible customers.

Other — Rate Matters

In accordance with ASC guidance on regulated operations, we currently have deferred approximately $1.2 million of expense related to rate cases under other non-current assets and deferred charges. These amounts will be amortized over varying periods based upon the completion of the specific cases. Based on past history, we expect all these expenses to be recovered in rates.

4. COMMON STOCK

Stock Based Compensation

We have several stock-based awards and programs, which are described below. Performance-based restricted stock awards, time-vested restricted stock and stock options are valued as liability awards, in accordance with fair value guidelines. We allow employees to elect to have taxes in excess of the minimum statutory requirements withheld from their awards and, therefore, the awards are classified as liability instruments under the ASC guidance on share based payment. Awards treated as liability instruments must be revalued each period until settled, and cost is accrued over the requisite service period and adjusted to fair value at each reporting period until settlement or expiration of the award.

We recognized the following amounts in compensation expense and tax benefits for all of our stock-based awards and programs for the applicable years ended December 31 (in thousands):

	2013	2012	2011
Compensation expense	$2,577	$1,863	$1,765
Tax benefit recognized	929	649	614

Stock Incentive Plans

Our 2006 Stock Incentive Plan (the 2006 Incentive Plan) was adopted by shareholders at the annual meeting on April 28, 2005 and provides for grants of up to 650,000 shares of common stock through January 2016. The 2006 Stock Incentive Plan permits grants of stock options and restricted stock to qualified employees and permits Directors and, if approved by the Compensation Committee of the Board of Directors, qualified employees to receive common stock in lieu of cash. Certain executive officers and other senior managers applied to receive annual incentive awards related to 2011, 2012 and 2013 performance in the form of Empire common stock rather than cash. These requests were granted by the Compensation Committee of the Board of Directors under the terms of our 2006 Stock Incentive Plan. The terms and conditions of any option or stock grant are determined by the Board of Directors Compensation Committee, within the provisions of these Stock Incentive Plans.

Time-Vested Restricted Stock Awards

Beginning in 2011, we began granting, to qualified individuals, time-vested restricted stock awards that vest after a three-year period, in lieu of stock options. No dividend rights accumulate during the vesting period. Time-vested restricted stock is valued at an amount equal to the fair market value of our common stock on the date of grant. If employment terminates during the vesting period because of death, retirement, or disability, the participant is entitled to a pro-rata portion of the time-vested restricted stock awards such participant would otherwise have earned, which is distributed six months following the date of termination, with the remainder of the award forfeited. If employment is terminated during the vesting period for reasons other than those listed above, the time-vested restricted stock awards will be forfeited on the date of the termination, unless the Board of Directors Compensation Committee determines, in its sole discretion, that the participant is entitled to a pro-rata portion of the award.

The fair value measurements for each grant year are noted in the following table:

	Fair Value of Grants Outstanding at December 31	
	2013	2012
Total unrecognized compensation cost (in millions)	$0.2	less than $0.1
Recognition period	0.1 years to 2.1 years	1.6 years
Fair value	$19.88	$18.38

No shares of time-vested restricted stock were granted in 2012 as a result of the limitation on incentive compensation in place in 2011. A summary of time vested restricted stock activity under the plan for 2013, 2012 and 2011 is presented in the table below:

	2013		2012		2011	
	Number of Shares	Weighted Average Grant Date Fair Value	Number of Shares	Weighted Average Grant Date Fair Value	Number Of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1,	3,300	$20.38	3,433	$21.84	—	—
Granted	21,600	$21.36	—	—	10,200	$21.84
Vested	—	—	—	—	794	$19.32
Distributed	—	—	(133)	$20.13	(661)	$21.02
Forfeited	—	—	—	—	(6,106)	—
Vested but not distributed	—	—	—	—	133	$20.13
Outstanding at December 31,	24,900	$22.69	3,300	$20.38	3,433	$21.84

All time-vested restricted stock awards are classified as liability instruments, which must be revalued each period until settled. The cost of the awards is generally recognized over the requisite (explicit) service period.

Performance-Based Restricted Stock Awards

Performance-based restricted stock awards are granted to qualified individuals consisting of the right to receive a number of shares of common stock at the end of the restricted period assuming performance criteria are met. The performance measure for the award is the total return to our shareholders over a three-year period compared with an investor-owned utility peer group. The threshold level of performance under the 2011, 2012 and 2013 grants was set at the 20th percentile level of the peer group, target at the 50th percentile level, and the maximum at the 80th percentile level. Shares would be earned at the end of the three-year performance period as follows: 100% of the target number of shares if the target level of performance is reached, 50% if the threshold is reached, and 200% if the percentile ranking is at or above the maximum, with the number of shares interpolated between these levels. However, no shares would be payable if the threshold level is not reached. As noted previously, all performance-based restricted stock awards are classified as liability instruments, which must be revalued each period until settled. The fair value of the outstanding restricted stock awards was estimated as of December 31, 2013, 2012 and 2011 using a Monte Carlo option valuation model. The assumptions used in the model for each grant year are noted in the following table:

	Fair Value of Grants Outstanding at December 31,		
	2013	2012	2011
Risk-free interest rate	0.13% to 0.38%	0.16% to 0.25%	0.12% to 0.23%
Expected volatility of Empire stock	20.2%	20.6%	23.8%
Expected volatility of peer group stock	12.3% to 27.5%	12.4% to 29.2%	15.7% to 57.4%
Expected dividend yield on Empire stock	4.5%	4.9%	4.7%
Expected forfeiture rates	3%	3%	3%
Plan cycle	3 years	3 years	3 years
Fair value percentage	0.0% to 108.0%	18.0% to 96.0%	51.0% to 75.0%
Weighted average fair value per share	$18.47	$10.94	$13.67

Non-vested performance-based restricted stock awards (based on target number) as of December 31, 2013, 2012 and 2011 and changes during the year ended December 31, 2013, 2012 and 2011 were as follows:

	2013		2012		2011	
	Number of Shares	Weighted Average Grant Date Fair Value	Number of Shares	Weighted Average Grant Date Fair Value	Number Of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1,	33,900	$20.25	37,400	$19.28	47,500	$19.86
Granted	26,300	$21.36	10,000	$20.97	10,900	$21.84
Awarded	(4,460)	$18.36	(7,823)	$18.12	(39,621)	$21.92
Awarded in excess of target			—	$ —	18,621	$21.92
Not awarded	(8,540)	$18.36	(5,677)	$18.12	—	$ —
Nonvested at December 31,	47,200	$21.39	33,900	$20.25	37,400	$19.28

At December 31, 2013 and 2012, unrecognized compensation expense related to estimated outstanding awards was $0.5 million and $0.1 million, respectively.

Stock Options

Prior to 2011 stock options were issued with an exercise price equal to the fair market value of the shares on the date of grant. They became exercisable after three years and, expire ten years after the date granted. Dividend equivalent awards, under which dividend equivalents accumulated during the vesting period, were also issued to recipients of the stock options. Participants' options and dividend equivalents that were not vested were forfeited when participants left Empire, except for terminations of employment under certain specified circumstances. There were no stock options or dividend equivalents granted in 2013, 2012, or 2011. Beginning in 2011, we began issuing time-vested restricted stock in lieu of stock options and dividend equivalents.

As noted previously, all outstanding stock option awards are classified as liability instruments, which must be revalued each period until settled. Stock option grants vest upon satisfaction of service conditions. The cost of the awards is generally recognized over the requisite (explicit) service period. The fair value of the outstanding options was estimated as of December 31, 2013, 2012 and 2011, under a Black-Scholes methodology. The assumptions used in the valuations are shown below:

	Fair Value of Grants Outstanding at December 31,		
	2013	2012	2011
Risk-free interest rate	0.10% to 0.38%	0.11% to 0.44%	0.12% to 0.72%
Dividend yield	4.5%	4.9%	4.7%
Expected volatility	24.0%	24.0%	25.0%
Expected life in months	6.5 to 24.5	78	78
Market value	$22.69	$20.38	$21.09
Weighted average fair value per option	$1.57	$1.34	$2.08

A summary of option activity under the plan during the years ended December 31, 2013, 2012 and 2011 is presented below:

	2013		2012		2011	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Outstanding at January 1,	163,300	$22.13	190,300	$21.56	267,400	$21.69
Granted		$ —	0	$ —	0	$ —
Exercised	(50,800)	$21.78	(27,000)	$18.12	(77,100)	$22.02
Outstanding at December 31,	112,500	$23.27	163,300	$22.13	190,300	$21.56
Exercisable, end of year	112,500	$23.27	128,500	$23.15	128,500	$23.15

The intrinsic value of the unexercised options is the difference between the Company's closing stock price on the last day of the period and the exercise price multiplied by the number of in-the-money options, had all option holders exercised their options on the last day of the period. The intrinsic value is zero if such closing price is less than the exercise price. The table below shows the aggregate intrinsic values at December 31, 2013, 2012, and 2011:

	2013	2012	2011
Aggregate intrinsic value (in millions)	Less than $0.1	$0.1	$0.2
Weighted-average remaining contractual life of outstanding options	2.1 years	3.2 years	5.1 years
Range of exercise prices	$21.92 to $23.81	$18.36 to $23.81	$18.12 to $23.81
Total unrecognized compensation expense (in millions) related to non-vested options and related dividend equivalents granted under the plan	—	Less than $0.1	$0.1
Recognition period	—	1 month	1 year

Employee Stock Purchase Plan

Our Employee Stock Purchase Plan (ESPP) permits the grant to eligible employees of options to purchase common stock at 90% of the lower of market value at date of grant or at date of exercise. The lookback feature of this plan is valued at 90% of the Black-Scholes methodology plus 10% of the maximum subscription price. As of December 31, 2013, there were 127,774 shares available for issuance in this plan.

	2013	2012	2011
Subscriptions outstanding at December 31,	60,413	70,850	70,756
Maximum subscription price	$ 19.58[(1)]	$ 17.95	$ 17.27
Shares of stock issued	68,099	65,919	69,229
Stock issuance price	$ 17.95	$ 17.27	$ 16.06

(1) Stock will be issued on the closing date of the purchase period, which runs from June 1, 2013 to May 31, 2014.

Assumptions for valuation of these shares are shown in the table below.

	2013	2012	2011
Weighted average fair value of grants	$ 2.78	$ 3.19	$ 3.17
Risk-free interest rate	0.14%	0.17%	0.18%
Dividend yield	4.60%	5.00%	2.60%
Expected volatility[(1)]	14.00%	24.00%	22.00%
Expected life in months	12	12	12
Grant date	6/1/13	6/1/12	6/1/11

(1) One-year historic volatility

Stock Unit Plan for Directors

Our Stock Unit Plan for directors (Stock Unit Plan) provides a stock-based compensation program for directors. This plan enhances our ability to attract and retain competent and experienced directors and allows the directors the opportunity to accumulate compensation in the form of common stock units. The Stock Unit Plan also provides directors the opportunity to convert previously earned cash retirement benefits to common stock units. All eligible directors who had benefits under the prior cash retirement plan converted their cash retirement benefits to common stock units.

As of December 31, 2013, a total of 400,000 shares were authorized under this plan. Each common stock unit earns dividends in the form of common stock units and can be redeemed for shares of common stock. The number of units granted annually is computed by dividing an annual credit (determined by the Compensation Committee) by the fair market value of our common stock on January 1 of the year the units are granted. Common stock unit dividends are computed based on the fair market value of our stock on the dividend's record date. We record the related compensation expense at the time we make the accrual for the directors' benefits as the directors provide services. Shares accrued to directors' accounts and shares available for issuance under this plan at December 31 are shown in the table below:

	2013	2012
Shares accrued to directors' accounts	154,402	143,058
Shares available for issuance	236,056	258,960

Units accrued for service and dividends as well as units redeemed for common stock at December 31 are shown in the table below:

	2013	2012	2011
Units accrued for service and dividends	34,252	30,426	25,287
Units redeemed for common stock	22,908	21,324	31,243

401(k) Plan and ESOP

Our Employee 401(k) Plan and ESOP (the 401(k) Plan) allows participating employees to defer up to 25% of their annual compensation up to an Internal Revenue Service specified limit. We match 50% of each employee's deferrals by contributing shares of our common stock, with such matching contributions not to exceed 3% of the employee's eligible compensation. We record the compensation expense at the time the quarterly matching contributions are made to the plan. At December 31, 2013 and 2012, there were 256,448 and 320,576 shares available to be issued, respectively.

	2013	2012	2011
Shares contributed	64,128	65,502	68,523

Effective January 1, 2014, new employees, and on January 1, 2015, employees who have elected to convert from our average salary pension formula to a cash balance formula, will be eligible for an enhanced matching contribution. Under the enhancement, we will match 100% of the first 6% a participant defers in the 401(k) Plan. The first 3% of the match will be in shares of our common stock with the remaining portion of the match being in cash (see Note 8).

Dividends

Holders of our common stock are entitled to dividends if, as, and when declared by the Board of Directors, out of funds legally available therefore, subject to the prior rights of holders of any outstanding cumulative preferred stock and preference stock. Payment of dividends is determined by our Board of Directors after considering all relevant factors, including the amount of our retained earnings (which is essentially our accumulated net income less dividend payouts). A reduction of our dividend per share, partially or in whole, could have an adverse effect on our common stock price.

The following table shows our diluted earnings per share, dividends paid per share, total dividends paid and retained earnings balance for the years ended December 31, 2013, 2012 and 2011:

(in millions, except per share amounts)	2013	2012	2011
Diluted earnings per share	$ 1.48	$1.32	$1.31
Dividends paid per share(1)	$1.005	$1.00	$0.64
Total dividends paid	$ 43.0	$42.3	$26.7
Retained earnings year-end balance	$ 67.6	$47.1	$33.7

(1) In response to the expected loss of revenues resulting from the May 22, 2011 tornado, our level of retained earnings and other relevant factors, our Board of Directors suspended our quarterly dividend for the third and fourth quarters of 2011. On February 2, 2012, the Board of Directors re-established the dividend and declared a quarterly dividend of $0.25 per share on common stock payable on March 15, 2012 to holders of record as of March 1, 2012.

Under Kansas corporate law, our Board of Directors may only declare and pay dividends out of our surplus or, if there is no surplus, out of our net profits for the fiscal year in which the dividend is declared or the preceding fiscal year, or both. Our surplus, under Kansas law, is equal to our retained earnings plus accumulated other comprehensive income/(loss), net of income tax. However, Kansas law does permit, under certain circumstances, our Board of Directors to transfer amounts from capital in excess of par value to surplus. In addition, Section 305(a) of the Federal Power Act (FPA) prohibits the payment by a utility of dividends from any funds "properly included in capital account". There are no additional rules or regulations issued by the FERC under the FPA clarifying the meaning of this limitation. However, several decisions by the FERC on specific dividend proposals suggest that any determination would be based on a fact-intensive analysis of the specific facts and circumstances surrounding the utility and the dividend in question, with particular focus on the impact of the proposed dividend on the liquidity and financial condition of the utility.

In addition, the EDE Mortgage and our Restated Articles contain certain dividend restrictions. The most restrictive of these is contained in the EDE Mortgage, which provides that we may not declare or pay any dividends (other than dividends payable in shares of our common stock) or make any other distribution on, or purchase (other than with the proceeds of additional common stock financing) any shares of, our common stock if the cumulative aggregate amount thereof after August 31, 1944 (exclusive of the first quarterly dividend of $98,000 paid after said date) would exceed the sum of $10.75 million and the earned surplus (as defined in the EDE Mortgage) accumulated subsequent to August 31, 1944, or the date of succession in the event that another corporation succeeds to our rights and liabilities by a merger or consolidation. On June 9, 2011, we amended the EDE Mortgage in order to provide us with additional flexibility to pay dividends to our shareholders by permitting the payment of any dividend or distribution on, or purchase of, shares of its common stock within 60 days after the related date of declaration or notice of such dividend, distribution or purchase if (i) on the date of declaration or notice, such dividend, distribution or purchase would have complied with the provisions of the EDE Mortgage and (ii) as of the last day of the calendar month ended immediately preceding the date of such payment, our ratio of total indebtedness to total capitalization (after giving pro forma effect to the payment of such dividend, distribution, or purchase) was not more than 0.625 to 1.

5. PREFERRED AND PREFERENCE STOCK

We have 2.5 million shares of preference stock authorized, including 0.5 million shares of Series A Participating Preference Stock, none of which have been issued. We have 5 million shares of $10.00 par value cumulative preferred stock authorized. There was no preferred stock issued and outstanding at December 31, 2013 or 2012.

6. LONG-TERM DEBT

At December 31, 2013 and 2012, the balance of long-term debt outstanding was as follows (in thousands):

	2013	2012
First mortgage bonds (EDE):		
7.20% Series due 2016	$ 25,000	$ 25,000
5.875% Series due 2037[1]	80,000	80,000
6.375% Series due 2018[1]	90,000	90,000
4.65% Series due 2020[1]	100,000	100,000
5.20% Series due 2040[1]	50,000	50,000
3.58% Series due 2027[1]	88,000	88,000
3.73% Series due 2033[1]	30,000	—
4.32% Series due 2043[1]	120,000	—
First mortgage bonds (EDG):		
6.82% Series due 2036[1]	55,000	55,000
	638,000	488,000
Senior Notes, 4.50% Series due 2013[1]	—	98,000
Senior Notes, 6.70% Series due 2033[1]	62,000	62,000
Senior Notes, 5.80% Series due 2035[1]	40,000	40,000
Other	4,441	5,155
Less unamortized net discount	(739)	(815)
	743,702	692,340
Less current obligations of long-term debt	—	(415)
Less current obligations under capital lease	(274)	(299)
TOTAL LONG-TERM DEBT	**$743,428**	**$691,626**

(1) We may redeem some or all of the notes at any time at 100% of their principal amount, plus a make-whole premium, plus accrued and unpaid interest to the redemption date.

Debt Financing Activities

On October 30, 2012, we entered into a Bond Purchase Agreement for a private placement of $30.0 million of 3.73% First Mortgage Bonds due 2033 and $120.0 million of 4.32% First Mortgage Bonds due 2043. The delayed settlement occurred on May 30, 2013. A portion of the proceeds were used to redeem all $98.0 million aggregate principal amount of our Senior Notes, 4.50% Series due June 15, 2013. The remaining proceeds were used for general corporate purposes. The bonds have not been registered under the Securities Act of 1933, as amended, and may not be offered or sold in the United States absent registration or an applicable exemption from registration requirements. The bonds were issued under the EDE Mortgage.

On April 2, 2012, we entered into a Bond Purchase Agreement for a private placement of $88 million aggregate principal amount of 3.58% First Mortgage Bonds due April 2, 2027. The first settlement of $38 million occurred on April 2, 2012 and the second settlement of $50 million occurred on June 1, 2012. All bonds of this new series will mature on April 2, 2027. Interest is payable semi-annually on the bonds on each April 2 and October 2, commencing October 2, 2012. The bonds may be redeemed, at our option, at any time prior to maturity, at par plus a make whole premium, together with accrued and unpaid interest, if any, to the redemption date. The bonds have not been registered under the Securities Act of 1933, as amended, and may not be offered or sold in the United States absent registration or an applicable exemption from registration requirements. We used the proceeds from the sale of these bonds to redeem the called bonds discussed above (including repaying short term debt initially used for such purpose). They were issued under the EDE Mortgage.

On April 1, 2012, we redeemed all $74.8 million aggregate principal amount of our First Mortgage Bonds, 7.00% Series due 2024. All $5.2 million of our First Mortgage Bonds, 5.20% Pollution Control Series due 2013, and all $8.0 million of our First Mortgage Bonds, 5.30% Pollution Control Series due 2013 were also redeemed with payment made to the trustee prior to March 31, 2012.

Shelf Registration

On December 13, 2013, we filed a $200.0 million shelf registration statement on Form S-3 with the SEC covering our common stock, unsecured debt securities, preference stock, and first mortgage bonds. This shelf registration statement will be effective for a three-year period beginning with the date of filing. We plan to use the proceeds under this shelf to fund capital expenditures, refinance existing debt or general corporate needs during the effective period. The issuance of securities under this shelf is subject to the receipt of local regulatory approvals. We have filed applications for such approvals in all four state jurisdictions in our electric service territory.

EDE Mortgage Indenture

The principal amount of all series of first mortgage bonds outstanding at any one time under the EDE Mortgage is limited by terms of the mortgage to $1 billion. Substantially all of the property, plant and equipment of The Empire District Electric Company (but not its subsidiaries) is subject to the lien of the EDE Mortgage. Restrictions in the EDE mortgage bond indenture could affect our liquidity. The EDE Mortgage contains a requirement that for new first mortgage bonds to be issued, our net earnings (as defined in the EDE Mortgage) for any twelve consecutive months within the fifteen months preceding issuance must be two times the annual interest requirements (as defined in the EDE Mortgage) on all first mortgage bonds then outstanding and on the prospective issue of new first mortgage bonds. Our earnings for the year ended December 31, 2013 would permit us to issue approximately $599.1 million of new first mortgage bonds based on this test with an assumed interest rate of 5.5%. In addition to the interest coverage requirement, the EDE Mortgage provides that new bonds must be issued against, among other things, retired bonds or 60% of net property additions. At December 31, 2013, we had retired bonds and net property additions which would enable the issuance of at least $856.7 million principal amount of bonds if the annual interest requirements are met. However, based on the $1 billion limit on the principal amount of first mortgage bonds outstanding set forth by the EDE mortgage, and our current level of outstanding first mortgage bonds, we are limited to the issuance of $417 million of new first mortgage bonds. As of December 31, 2013, we are in compliance with all restrictive covenants of the EDE Mortgage.

EDG Mortgage Indenture

The principal amount of all series of first mortgage bonds outstanding at any one time under the EDG Mortgage is limited by terms of the mortgage to $300 million. Substantially all of the property, plant and equipment of The Empire District Gas Company is subject to the lien of the EDG Mortgage. The EDG Mortgage contains a requirement that for new first mortgage bonds to be issued, the amount of such new first mortgage bonds shall not exceed 75% of the cost of property additions acquired after the date of the Missouri Gas acquisition. The mortgage also contains a limitation on the issuance by EDG of debt (including first mortgage bonds, but excluding short-term debt incurred in the ordinary course under working capital facilities) unless, after giving effect to such issuance, EDG's ratio of EBITDA (defined as net income plus interest, taxes, depreciation, amortization and certain other non-cash charges) to interest charges for the most recent four fiscal quarters is at least 2.0 to 1. As of December 31, 2013, this test would allow us to issue approximately $15.8 million principal amount of new first mortgage bonds at an assumed interest rate of 5.5%.

Our long-term debt obligations over the next five years are as follows (in thousands):

Long-Term Debt Payout Schedule (Excluding Unamortized Discount (in thousands)	Payments Due By Period		
	Total	Regulated Entity Debt Obligations	Capital Lease Obligations
2014	$ 274	$ —	$ 274
2015	292	—	292
2016	25,308	25,000	308
2017	325	—	325
2018	90,347	90,000	347
Thereafter	627,895	625,000	2,895
Total long-term debt obligations	**744,441**	**$740,000**	**$4,441**
Less current obligations and unamortized discount	1,013		
TOTAL LONG-TERM DEBT	**$743,428**		

7. SHORT-TERM BORROWINGS

At December 31, 2013, total short-term borrowings consisted of $4.0 million in commercial paper and no borrowings from our line of credit. During 2013 and 2012 our short-term borrowings outstanding averaged (in millions)

	2013	2012
Average borrowings outstanding	$ 8.7	$17.8
Highest month end balance	$29.0	$55.7

The weighted average interest rates and the weighted average interest rate of borrowings outstanding at December 31, 2013 and 2012 were:.

	2013	2012
Weighted average interest rate	0.69%	1.05%
Weighted average interest rate of borrowings outstanding	0.33%	0.91%

On January 17, 2012, we entered into the Third Amended and Restated Unsecured Credit Agreement which amended and restated our Second Amended and Restated Unsecured Credit Agreement dated January 26, 2010. This agreement extended the termination date of the revolving credit facility from January 26, 2013 to January 17, 2017. The agreement also removed the letter of credit facility and included a swingline loan facility with a $15 million swingline loan sublimit. The aggregate amount of the revolving credit commitments remains $150 million, inclusive of the $15 million swingline loan sublimit. In addition, the pricing and fees under the facility were amended. Interest on borrowings under the facility accrues at a rate equal to, at our option, (i) the highest of (A) the bank's prime commercial rate, (B) the federal funds effective rate plus 0.5% or (C) one month LIBOR plus 1.0%, plus a margin or (ii) one month, two month or three month LIBOR, in each case, plus a margin. Each margin is based on our current credit ratings and the pricing schedule in the facility. As of the date hereof, and based on our current credit ratings, the LIBOR margin under the facility is 1.25%. A facility fee is payable quarterly on the full amount of the commitments under the facility based on our current credit ratings (the fee is currently 0.20%). In addition, upon entering into the amended and restated facility, we paid an upfront fee to the revolving credit banks of $262,500 in the aggregate. There were no other material changes to the terms of the facility.

The facility is used for working capital, general corporate purposes and to back-up our use of commercial paper. This facility requires our total indebtedness to be less than 62.5% of our total capitalization at the end of each fiscal quarter and our EBITDA (defined as net income plus interest, taxes, depreciation and amortization) to be at least two times our interest charges for the trailing four fiscal quarters at the end of each fiscal quarter. Failure to maintain these ratios will result in an event of default under the credit facility and will prohibit us from borrowing funds thereunder. As of December 31, 2013, we are in compliance with these ratios. Our total indebtedness was 49.8% of our total capitalization as of December 31, 2013 and our EBITDA for 2013 was 5.3 times our interest charges. This credit facility is also subject to cross-default if we default on in excess of $10 million in the aggregate on our other indebtedness. This arrangement does not serve to legally restrict the use of our cash in the normal course of operations. There were no outstanding borrowings under this agreement at December 31, 2013. However, $4.0 million was used to back up our outstanding commercial paper.

8. RETIREMENT BENEFITS

We record retirement benefits in accordance with the ASC guidance on accounting for pension and other postretirement benefits, and have recorded the appropriate liabilities to reflect the unfunded status of our benefit plans, with offsetting entries to a regulatory asset, because we believe it is probable the unfunded amount of these plans will be afforded rate recovery. Additionally, the MPSC agreed that the effects of purchase accounting entries related to pension and other post-retirement benefits would be recoverable in future rate proceedings. These amounts were recorded as regulatory assets and are being amortized. The tax effects of these entries are reflected as deferred tax assets and liabilities and regulatory liabilities.

Annually we evaluate the discount rate, retirement age, compensation rate increases, expected return on plan assets and healthcare cost trend rate assumptions related to pension benefit and post-retirement medical plan. We utilize an interest rate yield curve to determine an appropriate discount rate. The yield curve is constructed based on the yields on over 500 high-quality, non-callable corporate bonds with maturities between zero and thirty years. A theoretical spot rate curve constructed from this yield curve is then used to discount the annual benefit cash flows of the Empire pension plan and develop a single point discount rate matching the plan's payout structure. In evaluating these assumptions, many factors are considered, including, current market conditions, asset allocations, changes in demographics and the views of leading financial advisors and economists. In evaluating the expected retirement age assumption, we consider the retirement ages of past employees eligible for pension and medical benefits together with expectations of future retirement ages. It is reasonably possible that changes in these assumptions will occur in the near term and, due to the uncertainties inherent in setting assumptions, the effect of such changes could be material to the Company's consolidated financial statements. A roll forward technique is used to value the year ending pension obligations. The roll forward technique values the year-end obligation by rolling forward the beginning-of-year obligation using the demographic assumptions shown below. The economic assumptions are updated as of the end of the year. All of the benefit plans have been measured as of December 31, 2013, consistent with previous years. See Note 1.

Pensions

Our noncontributory defined benefit pension plan includes all employees meeting minimum age and service requirements. The benefits are based on years of service and the employee's average annual basic earnings. During 2013 changes were made to the benefits calculation for all employees hired after January 1, 2014. The benefit for employees hired after this date will accrue based on a cash balance methodology, with an enhanced 401(k) contribution. Additionally, employees hired prior to January 1, 2014 will be given the option to convert to the cash balance formula, or remain with the average annual basic earnings formula which will now allow for a lump sum distribution, with a decision to be made by December 31, 2014. Additionally, during 2013, for a limited period of time, we permitted former participants with a vested benefit in the plan, to take a lump sum distribution of their benefit. Our actuary has considered these changes in the calculations below.

Annual contributions to the plan are at least equal to the greater of either minimum funding requirements of ERISA or the accrued cost of the Plan, as required by the Missouri Public Service Commission. We also have a supplemental retirement program ("SERP") for designated officers of the Company, which we fund from Company funds as the benefits are paid.

Our net pension liability decreased $49.2 million in 2013. The decrease was recorded as a decrease in regulatory assets as we believe it is probable of recovery through customer rates based on rate orders received in our jurisdictions. Our contribution is estimated to be approximately $12 million for 2014. We expect future pension funding commitments to continue at least at the level of our accrued cost, as required by our regulator. The actual minimum funding requirements will be determined based on the results of the actuarial valuations and, in the case of 2015, the performance of our pension assets during 2014.

Expected benefit payments are as follows (in millions):

Year	Payments from Trust	Payments from Company Funds
2014	$19.6	$0.4
2015	20.5	0.4
2016	19.8	0.4
2017	20.7	0.5
2018	19.8	0.4
2019 – 2023	92.4	2.5

Other Postretirement Benefits (OPEB)

We provide certain healthcare and life insurance benefits to eligible retired employees, their dependents and survivors through trusts we have established. Participants generally become eligible for retiree healthcare benefits after reaching age 55 with 5 years of service. Employees hired after January 1, 2014 will be offered unsubsidized retiree healthcare benefits upon retirement.

Our net liability decreased $20.8 million in 2013. The decrease was recorded as a reduction in regulatory assets as we believe it is probable of recovery through customer rates based on rate orders received in our jurisdictions. Our funding policy is to contribute annually an amount at least equal to the actuarial cost of postretirement benefits. We expect to be required to fund approximately $3.0 million in 2014.

Estimated benefit payments are as follows (in millions):

Year	Payments from Trust	Expected Federal Subsidy	Payments from Company Funds
2014	$ 2.5	$0.3	$0.1
2015	2.9	0.3	0.2
2016	3.2	0.4	0.2
2017	3.5	0.4	0.2
2018	3.8	0.5	0.2
2019 – 2023	23.2	3.2	0.9

The following tables set forth the Company's benefit plans' projected benefit obligations, the fair value of the plans' assets and the funded status (in thousands).

Reconciliation of Projected Benefit Obligations:

	Pension		SERP		OPEB	
	2013	2012	2013	2012	2013	2012
Benefit obligation at beginning of year	$248,004	$215,088	$6,365	$4,863	$ 94,738	$83,226
Service cost	7,454	6,261	135	51	2,941	2,401
Interest cost	10,063	10,258	315	263	3,827	4,037
Net actuarial (gain)/loss	(23,300)	25,882	604	1,511	(12,767)	6,955
Plan participant's contribution	—	—	—	—	949	910
Benefits and expenses paid	(17,090)	(9,485)	(311)	(323)	(4,396)	(3,156)
Federal subsidy	—	—	—	—	40	365
Benefit obligation at end of year	**$225,131**	**$248,004**	**$7,108**	**$6,365**	**$ 85,332**	**$94,738**

Reconciliation of Fair Value of Plan Assets:

	Pension		SERP		OPEB	
	2013	2012	2013	2012	2013	2012
Fair value of plan assets at beginning of year	$160,175	$140,975	$ —	$ —	$67,667	$58,384
Actual return on plan assets — gain/(loss)	27,260	17,562	—	—	10,361	7,148
Employer contribution	16,202	11,123	—	—	4,360	3,970
Benefits paid	(17,090)	(9,485)	—	—	(4,229)	(3,045)
Plan participant's contribution	—	—	—	—	901	864
Federal subsidy	—	—	—	—	38	346
Fair value of plan assets at end of year	**$186,547**	**$160,175**	**$ —**	**$ —**	**$79,098**	**$67,667**

Reconciliation of Funded Status:

	Pension		SERP		OPEB	
	2013	2012	2013	2012	2013	2012
Fair value of plan assets	$ 186,547	$ 160,175	$ —	$ —	$ 79,098	$ 67,667
Projected benefit obligations	(225,131)	(248,004)	(7,108)	(6,365)	(85,332)	(94,738)
Funded status	**$ (38,584)**	**$ (87,829)**	**$(7,108)**	**$(6,365)**	**$ (6,234)**	**$(27,071)**

The employee pension plan accumulated benefit obligation at December 31, 2013 and 2012 is presented in the following table (in thousands):

	Pension Benefits		SERP	
	2013	2012	2013	2012
Accumulated benefit obligation	$201,258	$219,659	$5,702	$6,014

Amounts recognized in the balance sheet consist of (in thousands):

	Pension		SERP		OPEB	
	2013	2012	2013	2012	2013	2012
Accounts Payable and Accrued Liabilities	$ —	$ —	$ 372	$ 313	$ 147	$ 144
Pension and other postretirement benefit obligation	$38,584	$87,829	$6,736	$6,052	$6,087	$26,927

Net periodic benefit pension cost for 2013, 2012 and 2011, some of which is capitalized as a component of labor cost and some of which is deferred as a regulatory asset (see Note 3), is comprised of the following components (in thousands):

Net Periodic Pension Benefit Cost:

	Pension			OPEB		
	2013	2012	2011	2013	2012	2011
Service cost	$ 7,454	$ 6,261	$ 5,596	$ 2,941	$ 2,401	$ 2,266
Interest cost	10,063	10,258	10,405	3,827	4,037	4,383
Expected return on plan assets	(12,428)	(12,309)	(11,139)	(4,353)	(4,135)	(4,157)
Amortization of prior service cost(1)	532	531	532	(1,011)	(1,011)	(1,011)
Amortization of actuarial loss(1)	10,445	7,935	5,494	2,261	1,661	1,762
Net periodic benefit cost	**$ 16,066**	**$ 12,676**	**$ 10,888**	**$ 3,665**	**$ 2,953**	**$ 3,243**

Net Periodic Pension Benefit Cost:

	SERP		
	2013	2012	2011
Service cost	$ 135	$ 51	$ 93
Interest cost	315	263	183
Expected return on plan assets	—	—	—
Amortization of prior service cost[1]	(8)	(8)	(8)
Amortization of actuarial loss[1]	567	389	171
Net periodic benefit cost	**$1,009**	**$695**	**$439**

(1) Amounts are amortized from our regulatory asset originally recorded upon recognizing our net pension liability on the balance sheet.

The tables below present the activity in the regulatory asset accounts for the year (in thousands).

Regulatory Assets	Beginning Balance 12/31/12	Amount Recognized: Current Year Actuarial (Gain)/Loss	Amount Recognized: Amortization of Actuarial Loss	Amount Recognized: Amortization of Prior Service (Cost)/Credit	Ending Balance 12/31/13
Pension	$105,818	(38,132)	(10,445)	(532)	$56,709
SERP	$ 4,143	604	(567)	8	$ 4,188
OPEB	$ 20,311	(18,776)	(2,261)	1,011	$ 285

Regulatory Assets	Beginning Balance 12/31/11	Amount Recognized: Current Year Actuarial Loss	Amount Recognized: Amortization of Actuarial Loss	Amount Recognized: Amortization of Prior Service (Cost)/Credit	Ending Balance 12/31/12
Pension	$93,656	20,628	(7,935)	(531)	$105,818
SERP	$ 3,012	1,512	(389)	8	$ 4,143
OPEB	$17,020	3,941	(1,661)	1,011	$ 20,311

The following table presents the amount of net actuarial gains / losses, transition obligations / assets and prior period service costs in regulatory assets not yet recognized as a component of net periodic benefit cost. It also shows the amounts expected to be recognized in the subsequent year. The following table presents those items for the employee pension plan and other benefits plan at December 31, 2013, and the subsequent twelve-month period (in thousands):

	Pension Benefits		SERP		OPEB	
	2013	Subsequent Period	2013	Subsequent Period	2013	Subsequent Period
Net actuarial loss	$55,261	$6,595	$4,210	$421	$ 3,879	$ 914
Prior service cost (benefit)	1,448	418	(22)	(8)	(3,594)	(1,011)
Total	**$56,709**	**$7,013**	**$4,188**	**$413**	**$ 285**	**$ (97)**

The measurement date used to determine the pension and other postretirement benefits is December 31. The assumptions used to determine the benefit obligation and the periodic costs are as follows:

Weighted-average assumptions used to determine the benefit obligation as of December 31:

	Pension Benefits		OPEB	
	2013	2012	2013	2012
Discount rate	4.90%	4.00%	5.00%	4.11%
Rate of compensation increase	3.50%	3.50%	3.50%	3.50%

Weighted-average assumptions used to determine the net benefit cost (income) as of January 1:

	Pension Benefits			OPEB		
	2013	2012	2011	2013	2012	2011
Discount rate	4.00%	4.70%	5.50%	4.11%	4.90%	5.50%
Expected return on plan assets	7.75%	7.90%	8.00%	6.52%	6.65%	7.00%
Rate of compensation increase	3.50%	3.50%	4.50%	3.50%	3.50%	4.50%

The expected long-term rate of return assumption was based on historical return and adjusted to estimate the potential range of returns for the current asset allocation. The assumed 2013 cost trend rate used to measure the expected cost of healthcare benefits and benefit obligation is 7.5%. Each trend rate decreases 0.50% through 2019 to an ultimate rate of 5.0% in 2019 and subsequent years.

The healthcare cost trend rate affects projected benefit obligations. A 1% change in assumed healthcare cost growth rates would have the following effects (in thousands):

	1% Increase	1% Decrease
Effect on total of service and interest cost	$ 1,450	$ (1,115)
Effect on post-retirement benefit obligation	$14,027	$(11,179)

Fair value measurements of plan assets

See Note 15 for a discussion of fair value measurements. The Company believes that it is appropriate for the pension fund to assume a moderate degree of investment risk with diversification of fund assets among different classes (or types) of investments, as appropriate, as a means of reducing risk. Although the pension fund can and will tolerate some variability in market value and rates of return in order to achieve a greater long-term rate of return, primary emphasis is placed on preserving the pension fund's principal. Full discretion is delegated to the investment managers to carry out investment policy within stated guidelines. The guidelines and performance of the managers are monitored by the Company's Investment Committee. The following is a description of the valuation methodologies used for assets measured at fair value using significant other observable, or significant unobservable inputs.

Short-term investments: Valued at cost, which approximates fair value.

Common/Collective trusts: Valued at the fair value based on audited financials of the trusts.

U.S. corporate and foreign issue debt: Valued at quoted market prices when available in an active market. If quoted market prices are not available, then fair values are estimated by using pricing models, quoted prices of securities with similar characteristics, or discounted cash flows.

Equity long/short hedge funds: Valued at the net asset value reported in the annual audited financial statements and updated monthly based on changes in the value of the underlying funds reported by the fund manager.

Pension

We utilize fair value in determining the market-related values for the different classes of our pension plan assets. The market-related value is determined based on smoothing actual asset returns in excess of (or less than) expected return on assets over a 5-year period.

The Company's primary investment goals for pension fund assets are based around four basic elements:

1. Preserve capital,
2. Maintain a minimum level of return equal to the actuarial interest rate assumption,
3. Maintain a high degree of flexibility and a low degree of volatility, and
4. Maximize the rate of return while operating within the confines of prudence and safety.

During 2013 we approved a change in investment strategy for the pension plan. The strategy, referred to as a de-risking glide path, seeks to increase the fixed income allocation as the plan's funded status improves. As the pension plan reaches set funded status milestones, the plan's assets will be rebalanced to shift more assets from equity to fixed income. The current target allocations for plan assets are approximately 70% return seeking assets, and approximately 30% long duration bonds.

The following fair value hierarchy table presents information about the pension fund assets measured at fair value as of December 31, 2013 and December 31, 2012 (in thousands):

	Fair Value Measurements as of December 31, 2013				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Short term investments	$74	$ —	$ —	$ 74	0.1%
Equity securities					
Common collective trusts	—	104,713	—	104,713	56.1%
Fixed income					
Common collective trust	—	45,031	—	45,031	24.1%
Other types of investments					
Equity long/short hedge funds	—		36,729	36,729	19.7%
	$74	$149,744	$36,729	$186,547	100.0%

	Fair Value Measurements as of December 31, 2012				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Short term investments	$ —	$ 2,398	$ —	$ 2,398	1.5%
Equity securities					
U.S. equity	63,655	—	—	63,655	39.7%
International equity	22,074	—	—	22,074	13.8%
Fixed income					
Common collective trust	—	26,110	—	26,110	16.3%
U.S. corporate debt	—	15,518	—	15,518	9.7%
U.S. government debt	1,535	—	—	1,535	1.0%
Other types of investments					
Equity long/short hedge funds	—	—	28,885	28,885	18.0%
	$87,264	$44,026	$28,885	$160,175	100.0%

Fair Value Measurements Using Significant Unobservable Inputs (Level 3) — December 31,

	2013	2012
	Equity long/short hedge funds	Equity long/short hedge funds
Beginning Balance, January 1,	$ 28,885	$27,419
Actual return on plan assets:		
Relating to assets still held at the reporting date	(356)	1,466
Relating to assets sold during the period	4,583	—
Purchases	26,500	—
Sales	(22,883)	—
Settlements	—	—
Transfers into and (out of) Level 3	—	—
Ending Balance, December 31,	$ 36,729	$28,885

Permissible Investments

Listed below are the investment vehicles specifically permitted:

Permissible Investments

Equity Oriented

- Common Stocks
- Preferred Stocks
- Convertible Preferred Stocks
- Convertible Bonds
- Covered Options
- Hedged Equity Funds of Funds

Fixed Income Oriented and Real Estate

- Bonds
- GICs, BICs
- Corporate Bonds (minimum quality rating of Baa or BBB)
- Cash-Equivalent Securities (e.g., U.S. T-Bills, Commercial Paper, etc.)
- Certificates of Deposit in institutions with FDIC/FSLIC protection
- Money Market Funds / Bank STIF Funds
- Real Estate — Publicly Traded

The above assets can be held in commingled (mutual) funds as well as privately managed separate accounts.

Those investments prohibited by the Investment Committee without prior approval are:

Prohibited Investments Requiring Pre-approval

- Privately Placed Securities
- Commodities Futures
- Securities of Empire District
- Derivatives
- Warrants
- Short Sales
- Index Options

OPEB

The Company's primary investment goals for the component of the OPEB fund used to pay current benefits are liquidity and safety. The primary investment goals for the component of the OPEB fund used to accumulate funds to provide for payment of benefits after the retirement of plan participants are preservation of the fund with a reasonable rate of return. The target allocations for plan assets are 0% - 10% cash and cash equivalents, 40% - 60% fixed income securities and 40% - 60% in equity. The following fair value hierarchy table presents information about the OPEB fund assets measured at fair value as of December 31, 2013 and December 31, 2012 (in thousands):

	Fair Value Measurements as of December 31, 2013				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Cash and cash equivalents	$ 1,317	$ —	$—	$ 1,317	1.7%
Fixed income					
U.S. corporate debt	—	17,592	—	17,592	22.2%
Foreign debt	—	2,871	—	2,871	3.6%
Mutual funds — fixed income	8,325	—	—	8,325	10.5%
Equity securities					
U.S. equity	27,779	—	—	27,779	35.1%
International equity	9,316	—	—	9,316	11.8%
Mutual funds — equity	11,633	—	—	11,633	14.7%
	$58,370	$20,463	$—	78,833	
Accrued interest & dividends				265	0.4%
				$79,098	100%

	Fair Value Measurements as of December 31, 2012				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Cash and cash equivalents	$ 895	$ —	$ —	$ 895	1.3%
Fixed income					
U.S. government debt	729	—	—	729	1.1%
U.S. corporate debt	—	19,437	—	19,437	28.7%
Foreign debt	—	2,250	—	2,250	3.3%
Mutual funds — fixed income	3,914	—	—	3,914	5.8%
Equity securities					
U.S. equity	20,795	—	—	20,795	30.7%
International equity	1,548	—	—	1,548	2.3%
Mutual funds — equity	17,818	—	—	17,818	26.3%
	$45,699	$21,687	$ —	67,386	
Accrued interest & dividends				281	0.5%
				$67,667	100%

The Company's guideline in the management of this fund is to endorse a long-term approach, but not expose the fund to levels of volatility that might adversely affect the value of the assets. Full discretion is delegated to the investment managers to carry out investment policy within stated guidelines. The guidelines and performance of the managers are monitored by the Company's Investment Committee.

Permissible Investments

Listed below are the investment vehicles specifically permitted:

Permissible Investments

Equity

- Common Stocks
- Preferred Stocks

Fixed Income

- Cash-Equivalent Securities with a maturity of one-year or less
- Bonds
- Money Market Funds / Bank STIF Funds
- Certificates of Deposit in institutions with FDIC protection
- Corporate Bonds (minimum quality rating of A)

The above assets can be held in commingled (mutual) funds as well as privately managed separate accounts.

Listed below are those investments prohibited by the Investment Committee:

Prohibited Investments

- Privately Placed Securities
- Commodities Futures
- Securities of Empire District
- Derivatives
- Instrumentalities in violation of the Prohibited Transactions Standards of ERISA
- Margin Transactions
- Short Sales
- Index Options
- Real Estate and Real Property
- Restricted Stock

9. INCOME TAXES

Income tax expense components for the years ended December 31 are as follows (in thousands):

	2013	2012	2011
Current income taxes:			
Federal	$ 6,726	$ 1,552	$ (8,604)
State	2,495	708	(2,120)
TOTAL	9,221	2,260	(10,724)
Deferred income taxes:			
Federal	24,954	28,210	39,096
State	3,554	4,018	6,297
TOTAL	28,508	32,228	45,393
Investment tax credit amortization	(237)	(329)	(371)
TOTAL INCOME TAX EXPENSE	**$37,492**	**$34,159**	**$ 34,298**

Deferred Income Taxes

Deferred tax assets and liabilities are reflected on our consolidated balance sheets as follows (in thousands):

	December 31,	
Deferred Income Taxes	**2013**	**2012**
Current deferred tax assets, net[1]	$ 7,222	$ 13,000
Non-current deferred tax liabilities, net	324,266	301,967
NET DEFERRED TAX LIABILITIES	**$317,044**	**$288,967**

(1) Current deferred tax assets are included in prepaid expenses and other on the balance sheets.

Temporary differences related to deferred tax assets and deferred tax liabilities are summarized as follows (in thousands):

Temporary Differences	December 31, 2013	December 31, 2012
Deferred tax assets:		
Net operating loss	$ —	$ 13,000
Disallowed plant costs	1,841	1,010
Gains on hedging transactions	1,324	1,389
Plant related basis differences	23,344	21,571
Regulated liabilities related to income taxes	13,576	13,871
Pensions and other post-retirement benefits	544	693
Carry forward of income tax credit	6,374	3,722
Other	1,633	2,262
Total deferred tax assets	$ 48,636	$ 57,518
Deferred tax liabilities:		
Depreciation, amortization and other plant related differences	$297,175	$279,604
Regulated assets related to income	37,806	39,553
Loss on reacquired debt	4,085	4,489
Amortization of intangibles	8,089	7,009
Deferred construction accounting costs	6,977	7,323
Other	11,548	8,507
Total deferred tax liabilities	365,680	346,485
NET DEFERRED TAX LIABILITIES	**$317,044**	**$288,967**

Effective Income Tax Rates

The difference between income taxes and amounts calculated by applying the federal legal rate to income tax expense for continuing operations were as follows:

Effective Income Tax Rates	2013	2012	2011
Federal statutory income tax rate	35.0%	35.0%	35.0%
Increase (decrease) in income tax rate resulting from:			
State income tax (net of federal benefit)	3.1	3.1	3.1
Investment tax credit amortization	(0.2)	(0.4)	(0.4)
Effect of ratemaking on property related differences	(1.1)	(0.2)	0.2
Other	0.3	0.5	0.5
EFFECTIVE INCOME TAX RATE	**37.1%**	**38.0%**	**38.4%**

Unrecognized Tax Benefits	2013	2012	2011
Unrecognized tax benefits — January 1,	$—	$—	$ 359,000
The gross amounts of increases in unrecognized tax benefits taken during prior periods	—	—	—
The gross amounts of decreases in unrecognized tax benefits taken during the period relating to positions accepted by taxing authorities	—	—	—
Reductions to unrecognized tax benefits as a result of a lapse of the applicable statute of limitations	—	—	(359,000)
UNRECOGNIZED TAX BENEFITS — December 31,	$—	$—	$ —

We do not expect any significant changes to our unrecognized tax benefits over the next twelve months. The reserve balance related to unrecognized tax benefits as of December 31, 2010 was $359,000. With the expiration of the statute of limitations on these unrecognized tax benefits on September 15, 2011, there are no unrecognized tax benefits at December 31, 2013, 2012 and 2011.

We received $17.7 million, of investment tax credits based on our investment in Iatan 2. We utilized $0.7 million of these credits when preparing our 2012 tax return. We expect to utilize approximately $10.7 million of these credits on our 2013 tax return. We expect to use the remaining credits on our 2014 tax return. The tax credit will have no significant income statement impact as the credits will flow to our customers as we amortize the tax credits over the life of the plant.

The American Taxpayer Relief Act of 2012 (the "Act") was signed into law on January 2, 2013. The Act restored several expired business tax provisions, including bonus depreciation for 2013. The Company's 2014 tax payments are expected to be higher than 2013 due to the expiration of bonus depreciation. However, the Company expects to utilize investment tax credits noted above to partially offset the 2014 payments.

On September 13, 2013, the IRS and the Treasury Department released final regulations under Sections 162(a) and 263(a) on the deduction and capitalization of expenditures related to tangible property. These regulations apply to tax years beginning on or after January 1, 2014, and the Company plans to utilize the book capitalization method as allowable under the final regulations. The Company expects an immaterial impact to the effective tax rate.

10. COMMONLY OWNED FACILITIES

We own a 12% undivided interest in the coal-fired Units No. 1 and No. 2 at the Iatan Generating Station located near Weston, Missouri, 35 miles northwest of Kansas City, Missouri, as well as a 3% interest in the site and a 12% interest in certain common facilities. At December 31, 2013 and 2012, our property, plant and equipment accounts included the amounts in the following chart (in millions):

Iatan	2013	2012
Cost of ownership in plant in service	$367.1	$364.1
Accumulated Depreciation	$ 91.1	$ 83.2
Expenditures[1]	$ 31.6	$ 30.0

(1) Operating, maintenance, and fuel expenditures excluding depreciation expense.

We are entitled to 12% of each unit's available capacity and are obligated to pay for that percentage of the operating costs of the units. KCP&L and KCP&L Greater Missouri Operations Co. own 70% and 18% respectively, of Unit 1, and 54% and 18%, respectively, of Unit 2. KCP&L operates the units for the joint owners.

We and Westar Generating, Inc, ("WGI"), a subsidiary of Westar Energy, Inc., share joint ownership of a nominal 500-megawatt combined cycle unit at the State Line Power Plant (the "State Line Combined Cycle Unit"). We are responsible for the operation and maintenance of the State Line Combined Cycle Unit, and are entitled to 60% of the available capacity and are responsible for approximately 60% of its costs. At December 31, 2013 and 2012, our property, plant and equipment accounts included the amounts in the following chart (in millions):

State Line Combined Cycle Unit	2013	2012
Cost of ownership in plant in service	$163.3	$164.4
Accumulated Depreciation	$ 37.0	$ 36.7
Expenditures[(1)]	$ 52.6	$ 42.7

(1) Operating, maintenance, and fuel expenditures excluding depreciation expense.

We own a 7.52% undivided interest in the coal-fired Plum Point Energy Station located near Osceola, Arkansas. We are entitled to 7.52% of the station's capacity, and are obligated to pay for that percentage of the station's operating costs. At December 31, 2013 and 2012, our property, plant and equipment accounts included the amounts in the following chart (in millions):

Plum Point Energy Station	2013	2012
Cost of ownership in plant in service	$108.2	$108.0
Accumulated Depreciation	$ 7.3	$ 4.9
Expenditures[(1)]	$ 11.3	$ 7.8

(1) Operating, maintenance and fuel expenditures excluding depreciation expense.

All of the dollar amounts listed above represent our ownership share of costs.

11. COMMITMENTS AND CONTINGENCIES

We are a party to various claims and legal proceedings arising out of the normal course of our business. Management regularly analyzes this information, and has provided accruals for any liabilities, in accordance with the guidelines presented in the ASC on accounting for contingencies. In the opinion of management, it is not probable, given the company's defenses, that the ultimate outcome of these claims and lawsuits will have a material adverse effect upon our financial condition, or results of operations or cash flows.

(in millions)	Firm physical gas and transportation contracts	Coal and coal transportation contracts
January 1, 2014 through December 31, 2014	$24.9	$23.8
January 1, 2015 through December 31, 2016	$31.4	$28.8
January 1, 2017 through December 31, 2018	$30.2	$22.6
January 1, 2019 and beyond	$45.9	$11.3

In addition to the above, we have an agreement with Southern Star Central Pipeline, Inc. to purchase one million Dths of firm gas storage service capacity for our electric business for a period of five years, expiring in April 2016. The reservation charge for this storage capacity is approximately $1.1 million annually.

We have entered into long and short-term agreements to purchase coal and natural gas for our energy supply and natural gas operations. Under these contracts, the natural gas supplies are divided into firm physical commitments and derivatives that are used to hedge future purchases. In the event that this gas cannot be used at our plants, the gas would be liquidated at market price. The firm physical gas and transportation commitments are detailed in the table above.

We have coal supply agreements and transportation contracts in place to provide for the delivery of coal to the plants. These contracts are written with Force Majeure clauses that enable us to reduce tonnages or cease shipments under certain circumstances or events. These include mechanical or electrical maintenance items, acts of God, war or insurrection, strikes, weather and other disrupting events. This reduces the risk we have for not taking the minimum requirements of fuel under the contracts.

Purchased Power

We currently supplement our on-system generating capacity with purchases of capacity and energy from other entities in order to meet the demands of our customers and the capacity margins applicable to us under current pooling agreements and National Electric Reliability Council (NERC) rules.

The Plum Point Energy Station (Plum Point) is a 670-megawatt, coal-fired generating facility near Osceola, Arkansas. We own, through an undivided interest, 50 megawatts of the unit's capacity. We also have a long-term (30 year) agreement for the purchase of capacity from Plum Point. We have the option to purchase an undivided ownership interest in the 50 megawatts covered by the purchased power agreement in 2015. At this time it is not our intention to exercise this option. Rather, we intend to continue to meet our demand and capacity requirements with the continuation of this long-term purchased power agreement. Commitments under this agreement are approximately $297.2 million through August 31, 2039, the end date of the agreement.

We have a 20-year purchased power agreement, which began on December 15, 2008, with Cloud County Windfarm, LLC, owned by EDP Renewables North America LLC, Houston, Texas to purchase the energy generated at the approximately 105-megawatt Phase 1 Meridian Way Wind Farm located in Cloud County, Kansas. We do not own any portion of the windfarm. Annual payments are contingent upon output of the facility and can range from zero to a maximum of approximately $14.6 million based on a 20-year average cost.

We also have a 20-year contract, which began on December 15, 2005, with Elk River Windfarm, LLC, owned by IBERDROLA RENEWABLES, Inc., to purchase the energy generated at the 150-megawatt Elk River Windfarm located in Butler County, Kansas. We do not own any portion of the windfarm. Annual payments are contingent upon output of the facility and can range from zero to a maximum of approximately $16.9 million based on a 20-year average cost.

Payments for these agreements are recorded as purchased power expenses, and, because of the contingent nature of these payments, are not included in the operating lease obligations shown below.

New Construction

On July 9, 2013, we signed a contract with a third party vendor to complete engineering, procurement, and construction activities at our Riverton plant to convert Riverton Unit 12 from a simple cycle combustion turbine to a combined cycle unit. The conversion will include the installation of a heat recovery steam generator (HRSG), steam turbine generator, auxiliary boiler, cooling tower, and other auxiliary equipment. The Air Emission Source Construction Permit necessary for this project was issued by Kansas Department of Health and Environment on July 11, 2013.

On January 16, 2012, we signed a contract with a third party vendor to complete environmental retrofits at our Asbury plant. The retrofits will include the installation of a pulse-jet fabric filter (baghouse), circulating dry scrubber and powder activated carbon injection system. This equipment will enable us to comply with the recently finalized Mercury and Air Toxics Standard (MATS).

See "Environmental Matters" below for more information and for project costs for both of these projects.

Leases

We have purchased power agreements with Cloud County Windfarm, LLC and Elk River Windfarm, LLC, which are considered operating leases for GAAP purposes. Details of these agreements are disclosed in the Purchased Power section of this note.

We also currently have short-term operating leases for two unit trains to meet coal delivery demands, for garage and office facilities for our electric segment and for one office facility related to our gas segment. In addition, we have capital leases for certain office equipment and 108 railcars to provide coal delivery for our ownership and purchased power agreement shares of the Plum Point generating facility.

The gross amount of assets recorded under capital leases total $5.5 million at December 31, 2013.

Our lease obligations over the next five years are as follows (in thousands):

	Capital Leases	Operating Leases
2014	$ 553	$ 764
2015	553	722
2016	549	720
2017	547	681
2018	546	646
Thereafter	3,553	485
Total minimum payments	**6,301**	**$4,018**
Less amount representing interest	1,860	
Present value of net minimum lease payments	**$4,441**	

Expenses incurred related to operating leases were $0.8 million, $0.9 million and $1.0 million for 2013, 2012, and 2011, respectively, excluding payments for wind generated purchased power agreements. The accumulated amount of amortization for our capital leases was $1.3 million and $1.0 million at December 31, 2013 and 2012, respectively.

Environmental Matters

We are subject to various federal, state, and local laws and regulations with respect to air and water quality and with respect to hazardous and toxic materials and hazardous and other wastes, including their identification, transportation, disposal, record-keeping and reporting, as well as remediation of contaminated sites and other environmental matters. We believe that our operations are in material compliance with present environmental laws and regulations. Environmental requirements have changed frequently and become more stringent over time. We expect this trend to continue. While we are not in a position to accurately estimate compliance costs for any new requirements, we expect any such costs to be material, although recoverable in rates.

Electric Segment

The Federal Clean Air Act (CAA) and comparable state laws regulate air emissions from stationary sources such as electric power plants through permitting and/or emission control and related requirements. These requirements include maximum emission limits on our facilities for sulfur dioxide (SO2), particulate matter, nitrogen oxides (NOx), carbon monoxide (CO), and hazardous air pollutants including mercury. In the future they will include limits on greenhouse gases (GHG) such as carbon dioxide (CO2).

Compliance Plan

In order to comply with current and forthcoming environmental regulations, Empire is taking actions to implement its compliance plan and strategy (Compliance Plan). The Mercury Air Toxic Standards (MATS) and the Clean Air Interstate Rule (CAIR) and its subsequent replacement rule, both regulations which we discuss further below, are the drivers behind our Compliance Plan and its implementation schedule. The MATS, which was published for power plants by the Environmental Protection Agency (EPA) in 2011, requires reductions in mercury, acid gases and other emissions considered hazardous air pollutants (HAPS). It became effective in April 2012 and requires full compliance by April 16, 2015 (with flexibility for extensions for reliability reasons). The Cross State Air Pollution Rule (CSAPR — formerly the Clean Air Transport Rule, or CATR) was first proposed by the EPA in July 2010 as a replacement of CAIR and was set to take effect on January 1, 2012. CSAPR was stayed in late December 2011, then vacated by court order in August 2012. Consequently, CAIR will remain in effect until a valid replacement is developed by the EPA. We anticipate compliance costs associated with the MATS and CAIR (or its subsequent replacement) regulations to be recoverable in our rates.

Our Compliance Plan largely follows the preferred plan presented in our Integrated Resource Plan (IRP), filed in mid-2013 with the MPSC. As described above under New Construction, we are in the process of installing a scrubber, fabric filter, and powder activated carbon injection system at our Asbury plant. The addition of this air quality control equipment is expected to be completed by early 2015 at a cost ranging from \$112.0 million to \$130.0 million, excluding AFUDC. Construction costs through December 31, 2013 were \$83.6 million for the project to date, excluding AFUDC. This addition required the retirement of Asbury Unit 2, a steam turbine rated at 14 megawatts that was used for peaking purposes. Asbury Unit 2 was retired on December 31, 2013.

In September 2012, we completed the transition of our Riverton Units 7 and 8 from operation on coal and natural gas to operating completely on natural gas. Riverton Units 7 and 8, along with Riverton Unit 9, a small combustion turbine that requires steam from Unit 7 or 8 for start-up, will be retired upon the conversion of Riverton Unit 12, a simple cycle combustion turbine, to a combined cycle unit. This conversion is currently scheduled to be completed in mid-2016 at a cost estimated to range from \$165 million to \$175 million, excluding AFUDC. This amount is included in our five-year capital expenditure plan. Construction costs, consisting of pre-engineering and site preparation activities thus far, through December 31, 2013 were \$13 million for 2013 and \$13.6 million for the project to date, excluding AFUDC.

Air Emissions

The CAA regulates the amount of NOx and SO2 an affected unit can emit. As currently operated, each of our affected units is in compliance with the applicable NOx and SO2 limits. Currently, NOx emissions are regulated by the CAIR and National Ambient Air Quality Standard (NAAQS) rules for ozone (discussed below). SO2 emissions are currently regulated by the Title IV Acid Rain Program and the

CAIR. The EPA is expected to propose a CSAPR replacement, which if finalized and upheld, would also replace CAIR. In the meantime, both the Title IV Acid Rain Program and CAIR will remain in effect.

CAIR:

The CAIR generally calls for fossil-fueled power plants greater than 25 megawatts to reduce emission levels of SO2 and/or NOx in 28 eastern states and the District of Columbia, including Missouri, where our Asbury, Energy Center, State Line and Iatan Units No. 1 and No. 2 are located. Kansas was not included in CAIR and our Riverton Plant was not affected. Arkansas, where our Plum Point Plant is located, was included for ozone season NOx but not for SO2.

SO2 allowance allocations under the Title IV Acid Rain Program are used for compliance in the CAIR SO2 Program. Based on current SO2 allowance usage projections, we expect to have sufficient allowances to take us through 2018. Pursuant to the CAIR regulations, we had excess NOx allowances during 2013 which were banked for future use and will be sufficient for compliance through at least the middle of 2015.

Mercury Air Toxics Standard (MATS):

As described above, the MATS standard became effective in April 2012, and requires compliance by April 2015 (with flexibility for extensions for reliability reasons). For all existing and new coal-fired electric utility steam generating units (EGUs), the MATS standard will be phased in over three years, and allows states the ability to give facilities a fourth year to comply. On March 28, 2013, the EPA finalized updates to certain emission limits for new power plants under the MATS. The new standards affect only new coal and oil-fired power plants that will be built in the future. The update does not change the final emission limits or other requirements for existing power plants.

National Ambient Air Quality Standards (NAAQS):

Under the CAA, the EPA sets NAAQS for certain emissions considered harmful to public health and the environment, including particulate matter (PM), NOx, CO, SO2, and ozone which result from fossil fuel combustion. Our facilities are currently in compliance with all applicable NAAQS.

In January 2013, the EPA finalized the revised PM 2.5 primary annual standard at 12 ug/m^3 (micrograms per cubic meter of air). States are required to meet the primary standard in 2020. The standard should have no impact on our existing generating fleet because the regional ambient monitor results are below the PM 2.5 required level. However, the PM 2.5 standards could impact future major modifications/construction projects that require additional permits.

Ozone, also called ground level smog, is formed by the mixing of NOx and Volatile Organic Compounds (VOCs) in the presence of sunlight. Based on the current standard, our service territory is designated as attainment, meaning that it is in compliance with the standard. A revised Ozone NAAQS is expected to be proposed by the EPA in early 2014.

Greenhouse Gases (GHGs):

Under regulations known as the Tailoring Rule, the EPA regulates carbon dioxide and other GHG emissions from certain stationary sources. EDE and EDG's GHG emissions for 2011, 2012, and 2013 have been reported to the EPA as required by the Tailoring Rule.

In addition to the Tailoring Rule, there are a number of federal and state regulatory initiatives aimed at the regulation of GHGs. However, because of the uncertainties regarding future GHG regulation (discussed below), the ultimate cost of compliance cannot be determined at this time. In any case, we expect the cost of complying with any such regulations to be recoverable in our rates.

In April 2012, the EPA proposed a Carbon Pollution Standard for new power plants to limit the amount of carbon emitted by EGUs. This standard was rescinded, and a re-proposal of standards of performance for affected fossil fuel-fired EGUs was published in January 2014. The proposed rule applies only to new EGUs and sets separate standards for natural gas-fired combustion turbines and for fossil fuel-fired utility boilers. The proposal would not apply to existing units, including modifications such as those required to meet other air pollution standards which are currently being undertaken at our Asbury facility and at the Riverton facility with the conversion of simple cycle Unit 12 to combined cycle.

In response to President Obama's June 2013 memorandum to the EPA regarding carbon pollution standards for the power industry, the EPA is undertaking a process to identify approaches to establish GHG standards for currently operating power plants. The memorandum requested that the EPA issue proposed GHG standards, for modified, reconstructed, and existing power plants by June 1, 2014; issue final standards, regulations, or guidelines, for modified, reconstructed, and existing power plants by June 1, 2015; and include in the guidelines addressing existing power plants a requirement that states submit implementation plans to the EPA by June 30, 2016. In October 2013, the U.S. Supreme Court agreed to review an appeals court decision that said the EPA could regulate GHG emissions from fixed sources based on a previous decision on GHG emissions from cars.

In addition, certain states in which we have EGUs have taken steps to develop cap and trade programs and/or other regulatory systems to measure and report Carbon Dioxide Equivalent (CO2e) emissions that may or may not be more stringent than any federal requirements. However, at this time such states are not proposing regulatory systems pending federal legislative developments.

Water Discharges

We operate under the Kansas and Missouri Water Pollution Plans pursuant to the Federal Clean Water Act (CWA). Our plants are in material compliance with applicable regulations and have received all necessary discharge permits.

The Riverton Units 7 and 8 and Iatan Unit 1, which utilize once-through cooling water, were affected by regulations for Cooling Water Intake Structures issued by the EPA under the CWA Section 316(b) Phase II. In 2007, the United States Court of Appeals remanded key sections of these CWA regulations to the EPA. The EPA suspended the regulations. Following a series of court approved delays; the EPA was obligated to finalize the rule by January 14, 2014, a deadline the EPA missed but which may again be extended. We will not know the full impact of these rules until they are finalized. If adopted in their present form, we expect the regulations to have a limited impact at Riverton. The retirement of units 7 and 8 is scheduled in 2016. A new intake structure design and cooling tower will be constructed as part of the Unit 12 conversion at Riverton. Impacts at Iatan 1 could range from flow velocity reductions or traveling screen modifications for fish handling to installation of a closed cycle cooling tower retrofit. Our new Iatan Unit 2 and Plum Point Unit 1 are covered by the proposed regulation, but were constructed with cooling towers, the proposed Best Technology Available. We expect them to be unaffected or minimally impacted by the final rule.

Surface Impoundments

We own and maintain coal ash impoundments located at our Riverton and Asbury Power Plants. Additionally, we own a 12% interest in a coal ash impoundment at the Iatan Generating Station and a 7.52% interest in a coal ash impoundment at Plum Point. On April 19, 2013, the EPA signed a notice of proposed rulemaking to revise its wastewater effluent limitation guidelines and standards under the CWA for coal-fired power plants. The proposal calls for updates to operating permits beginning in July 2017. Once the new guidelines are issued, the EPA and states would incorporate the new standards into wastewater discharge permits, including permits for coal ash impoundments. We do not have sufficient information at this time to estimate additional costs that might result from any new standards. All of our coal ash impoundments are compliant with existing state and federal regulations.

In June 2010, the EPA proposed to regulate coal combustion residuals (CCRs) under the Federal Resource Conservation and Recovery Act (RCRA). In the proposal, the EPA presented two options: (1) regulation of CCR under RCRA subtitle C as a hazardous waste and (2) regulation of CCR under RCRA subtitle D as a non-hazardous waste. It is anticipated that the final regulation will be published in 2014. We expect compliance with either option to result in the need to construct a new landfill and the conversion of existing ash handling from a wet to a dry system(s) at a potential cost of up to $15 million at our Asbury Power Plant. This preliminary estimate will likely change based on the final CCR rule and its requirements. We expect resulting costs to be recoverable in our rates.

As a result of the transition from coal to natural gas fuel for Riverton Units 7 and 8, closure of the Riverton ash impoundment is in progress in compliance with Kansas regulations. We expect to complete the closure in early 2014. We have received preliminary permit approval in Missouri for a new utility waste landfill adjacent to the Asbury plant. Construction of the new landfill is expected in 2016.

Renewable Energy

Missouri regulations currently require Empire and other investor-owned utilities in Missouri to generate or purchase electricity from renewable energy sources, such as solar, wind, biomass and hydro power, or purchase Renewable Energy Credits (RECs), in amounts equal to at least 5% of retail sales in 2014, increasing to at least 15% by 2021. We are currently in compliance with this regulatory requirement as a result of purchased power agreements with Cloud County Windfarm, LLC, located in Cloud County, Kansas and Elk River Windfarm, LLC, located in Butler County, Kansas. The regulations also require that 2% of the energy from renewable energy sources must be solar; however, we are exempted by statute from that solar requirement. On January 30, 2013, a complaint was filed with the MPSC by Renew Missouri and others regarding several aspects of our 2011 Renewable Energy Standard (RES) Compliance Report and our 2012 – 2014 RES Compliance Plan. That complaint also again raised a challenge to our statutory exemption from the solar requirement. In two separate orders, in late 2013, the MPSC granted our motions to dismiss all counts of the complaint against Empire. On January 3, 2014, the Commission issued an order denying the complainants' application for rehearing on all issues related to their challenge of the solar exemption statute.

Kansas established a renewable portfolio standard (RPS), effective November 19, 2010. It requires 10% of our Kansas retail customer peak capacity requirements to be sourced from renewables in 2012, increasing to 15% by 2016, and 20% by 2020. We are currently in compliance with this regulatory requirement as a result of purchased power agreements with Cloud County Windfarm, LLC, located in Cloud County, Kansas and Elk River Windfarm, LLC, located in Butler County, Kansas. In addition, there are several proposals currently before the U.S. Congress to adopt a nationwide RPS.

12. SEGMENT INFORMATION

We operate our business as three segments: electric, gas and other. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company is our wholly owned subsidiary formed to provide gas distribution service in Missouri. The other segment consists of our non-regulated businesses which is primarily our fiber optics business.

The tables below present statement of income information, balance sheet information and capital expenditures of our business segments.

	For the year ended December 31,				
	2013				
	Electric	Gas	Other	Eliminations	Total
Statement of Income Information:					
Revenues	$536,413	$50,041	$9,147	$(1,271)	$594,330
Depreciation and amortization	63,659	3,709	1,938	—	69,306
Federal and state income taxes	34,478	1,484	1,530	—	37,492
Operating income	90,984	6,194	2,485	—	99,663
Interest income	537	115	8	(94)	566
Interest expense	37,683	3,890	—	(94)	41,479
Income from AFUDC (debt and equity)	5,910	30	—	—	5,940
Income from continuing operations	$ 58,603	$ 2,355	$2,487	$ —	$ 63,445
Capital Expenditures	$153,401	$ 4,419	$2,388	$ —	$160,208

	2012				
	Electric	Gas	Other	Eliminations	Total
Statement of Income Information:					
Revenues	$510,653	$39,849	$7,187	$(592)	$557,097
Depreciation and amortization	55,312	3,598	1,537	—	60,447
Federal and state income taxes	32,266	789	1,104	—	34,159
Operating income	89,445	5,005	1,771	—	96,221
Interest income	946	323	7	(304)	972
Interest expense	37,866	3,905	—	(304)	41,467
Income from AFUDC (debt and equity)	1,918	10	—	—	1,928
Income from continuing operations	$ 52,631	$ 1,256	$1,794	$ —	$ 55,681
Capital Expenditures	$140,117	$ 3,571	$2,599	$ —	$146,287

	2011				
	Electric	Gas	Other	Eliminations	Total
Statement of Income Information:					
Revenues	$524,276	$46,430	$6,756	$(592)	$576,870
Depreciation and amortization	58,236	3,494	1,807	—	63,537
Federal and state income taxes	31,643	1,676	979	—	34,298
Operating income	88,590	6,514	1,830	—	96,934
Interest income	554	259	—	(258)	555
Interest expense	37,860	3,910	8	(258)	41,520
Income from AFUDC (debt and equity)	509	3	—	—	512
Income from continuing operations	$ 50,670	$ 2,709	$1,592	$ —	$ 54,971
Capital Expenditures	$ 93,499	$ 4,122	$3,556	$ —	$101,177

	December 31, 2013				
	Electric	Gas(1)	Other	Eliminations	Total
Balance Sheet Information:					
Total assets	$2,034,234	$123,736	$31,306	$(44,231)	$2,145,045

	December 31, 2012				
	Electric	Gas(1)	Other	Eliminations	Total
Balance Sheet Information:					
Total assets	$2,034,399	$148,814	$28,871	$(85,715)	$2,126,369

(1) Includes goodwill of $39,492 at December 31, 2013 and 2012.

13. SELECTED QUARTERLY INFORMATION (UNAUDITED)

The following is a summary of quarterly results for 2013 and 2012 (dollars in thousands except per share amounts):

	Quarters			
Quarterly Results for 2013	First	Second	Third	Fourth
Operating revenues	$151,140	$136,646	$157,486	$149,058
Operating income	$ 21,858	$ 21,110	$ 32,896	$ 23,799
Net Income	$ 12,630	$ 11,658	$ 23,996	$ 15,162
Basic and Diluted Earnings Per Share	$ 0.30	$ 0.27	$ 0.56	$ 0.35

	Quarters			
Quarterly Results for 2012	First	Second	Third	Fourth
Operating revenues	$137,144	$131,632	$159,202	$129,119
Operating income	$ 20,810	$ 20,762	$ 35,282	$ 19,367
Net Income	$ 9,804	$ 10,708	$ 25,542	$ 9,627
Basic and Diluted Earnings Per Share	$ 0.23	$ 0.25	$ 0.60	$ 0.23

The sum of the net income and quarterly earnings per share of common stock may not equal the net income and earnings per share of common stock as computed on an annual basis due to rounding.

14. RISK MANAGEMENT AND DERIVATIVE FINANCIAL INSTRUMENTS

We engage in hedging activities in an effort to minimize our risk from volatile natural gas prices and power cost risk associated with exposure to congestion costs. We enter into both physical and financial contracts with counterparties relating to our future natural gas requirements that lock in prices (with respect to a range of predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in our fuel expenditures and gain predictability. Beginning in 2013, we also acquire Transmission Congestion Rights (TCR) in an attempt to lessen the cost of power we will purchase from the SPP Integrated Market due to congestion costs. TCRs entitle the holder to a stream of revenues (or charges) based on the day-ahead congestion on the TCR path. TCRs can be purchased or self-converted using rights allocated based on prior investments made in the transmission system. We recognize that if risk is not timely and adequately balanced or if counterparties fail to perform contractual obligations, actual results could differ materially from intended results.

All derivative instruments are recognized at fair value on the balance sheet with the unrealized losses or gains from derivatives used to hedge our fuel and purchased power costs in our electric segment recorded in regulatory assets or liabilities. All gains and losses from derivatives related to the gas segment are also recorded in regulatory assets or liabilities. This is in accordance with the ASC guidance on regulated operations, given that those regulatory assets and liabilities are probable of recovery through our fuel adjustment mechanism.

Risks and uncertainties affecting the determination of fair value include: market conditions in the energy industry, especially the effects of price volatility, regulatory and global political environments and requirements, fair value estimations on longer term contracts, the effectiveness of the derivative instrument in hedging the change in fair value of the hedged item, estimating underlying fuel demand and counterparty ability to perform. If we estimate that we have overhedged forecasted demand, the gain or loss on the overhedged portion will be recognized immediately as fuel and purchased power expense in our Consolidated Statement of Income and subject to our fuel adjustment clause.

As of December 31, 2013 and 2012, we have recorded the following assets and liabilities representing the fair value of derivative financial instruments held as of December 31, (in thousands):

ASSET DERIVATIVES

Non-designated hedging instruments due to regulatory accounting	Balance Sheet Classification	2013 Fair Value	2012 Fair Value
Natural gas contracts, gas segment	Current assets	$ 35	$ 3
	Non-current assets and deferred charges — Other	—	17
Natural gas contracts, electric segment	Current assets	467	93
	Non-current assets and deferred charges — Other	41	174
Transmission congestion rights, electric segment	Current assets	1,967	—
Total derivatives assets		**$2,510**	**$287**

LIABILITY DERIVATIVES

Non-designated as hedging instruments due to regulatory accounting	Balance Sheet Classification	2013 Fair Value	2012 Fair Value
Natural gas contracts, gas segment	Current liabilities	$ 8	$ 104
	Non-current liabilities and deferred credits	—	—
Natural gas contracts, electric segment	Current liabilities	1,881	3,299
	Non-current liabilities and deferred credits	2,799	3,819
Transmission congestion rights, electric segment	Current liabilities	—	—
Total derivatives liabilities		**$4,688**	**$7,222**

Electric

At December 31, 2013, approximately $1.9 million of unrealized losses are applicable to financial instruments which will settle within the next twelve months.

There were no "mark-to-market" pre-tax gains/(losses) from ineffective portions of our hedging activities for the electric segment for the years ended December 31, 2013 and 2012, respectively.

The following tables set forth "mark-to-market" pre-tax gains/ (losses) from non-designated derivative instruments for the electric segment for each of the years ended December 31, (in thousands):

Non-Designated Hedging Instruments — Due to Regulatory Accounting Electric Segment

	Balance Sheet Classification of Gain/(Loss) on Derivative	Amount of Gain/(Loss) Recognized on Balance Sheet	
		2013	2012
Commodity contracts — electric segment	Regulatory (assets)/liabilities	$ (338)	$(2,448)
Transmission congestion rights — electric segment	Regulatory (assets)/liabilities	1,967	—
Total — Electric Segment		**$1,629**	**$(2,448)**

Non-Designated Hedging Instruments — Due to Regulatory Accounting Electric Segment

	Statement of Operations Classification of Loss on Derivative	Amount of Gain/(Loss) Recognized in Income on Derivative	
		2013	2012
Commodity contracts	Fuel and purchased power expense	$(2,725)	$(3,985)
Transmission congestion rights — electric segment	Fuel and purchased power expense	81	—
Total — Electric Segment		**$(2,644)**	**$(3,985)**

We also enter into fixed-price forward physical contracts for the purchase of natural gas, coal and purchased power. These contracts are not subject to fair value accounting because they qualify for the normal purchase normal sale exemption. We have a process in place to determine if any future executed contracts that otherwise qualify for the normal purchase normal sale exception contain a price adjustment feature and will account for these contracts accordingly.

At December 31, 2013, the following volumes and percentages of our anticipated volume of natural gas usage for our electric operations for 2014 and the next four years are hedged at the following average prices per Dekatherm (Dth):

Year	% Hedged	Dth Hedged Physical	Dth Hedged Financial	Average Price
2014	61%	1,560,000	4,640,000	$4.411
2015	41%	—	4,010,000	$4.578
2016	22%	—	2,100,000	$4.415
2017	10%	—	1,050,000	$4.430
2018	0%	—	—	$ —

We utilize the following procurement guidelines for our electric segment, allowing the flexibility to hedge up to 100% of the current year's and 80% of any future year's expected requirements while being cognizant of volume risk. The 80% guideline is an annual target and volumes up to 100% can be hedged in any given month. For years beyond year four, additional factors of long term uncertainty (including with respect to required volumes and counterparty credit) are also considered.

Year	End of Year Minimum % Hedged
Current	Up to 100%
First	60%
Second	40%
Third	20%
Fourth	10%

At December 31, 2013, the following transmission congestion rights (TCR) have been obtained from TCR auctions to hedge congestion costs in the SPP Integrated Market:

Year	Monthly MWH Hedged	$ Value
2014	1,918	$1,966,846

Gas

We attempt to mitigate our natural gas price risk for our gas segment by a combination of (1) injecting natural gas into storage during the off-heating season months, (2) purchasing physical forward contracts and (3) purchasing financial derivative contracts. We target to have 95% of our storage capacity full by November 1 for the upcoming winter heating season. As the winter progresses, gas is withdrawn from storage to serve our customers. As of December 31, 2013 we had 0.9 million Dths in storage on the three pipelines that serve our customers. This represents 47% of our storage capacity.

The following table sets forth our long-term hedge strategy of mitigating price volatility for our customers by hedging a minimum of expected gas usage for the current winter season and the next two winter seasons by the beginning of the ACA year at September 1 and illustrates our hedged position as of December 31, 2013 (Dth in thousands).

Season	Minimum % Hedged	Dth Hedged Financial	Dth Hedged Physical	Dth in Storage	Actual % Hedged
Current	50%	240,000	—	948,850	59%
Second	Up to 50%	—	—	—	—
Third	Up to 20%	—	—	—	—

A Purchased Gas Adjustment (PGA) clause is included in our rates for our gas segment operations, therefore, we mark to market any unrealized gains or losses and any realized gains or losses relating to financial derivative contracts to a regulatory asset or regulatory liability account on our balance sheet.

The following table sets forth "mark-to-market" pre-tax gains / (losses) from derivatives not designated as hedging instruments for the gas segment for the years ended December 31, (in thousands):

Non-Designated Hedging Instruments Due to Regulatory Accounting — Gas Segment

	Balance Sheet Classification of Loss on Derivative	Amount of Loss Recognized on Balance Sheet 2013	2012
Commodity contracts	Regulatory assets	$(5)	$(461)
Total — Gas Segment		**$(5)**	**$(461)**

15. FAIR VALUE MEASUREMENTS

The accounting guidance on fair value measurements establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: (i) Level 1, defined as quoted prices in active markets for identical instruments; (ii) Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and (iii) Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. Our Level 2 fair value measurements consist of both quoted price inputs and inputs that are derived principally from or corroborated by observable market data. Our Level 3 fair value measurements consist of both quoted price inputs and unobservable quoted inputs.

The guidance also requires that the fair value measurement of assets and liabilities reflect the nonperformance risk of counterparties and the reporting entity, as applicable. Therefore, using credit default spreads, we factored the impact of our own credit standing and the credit standing of our counterparties, as well as any potential credit enhancements (e.g. collateral) into the consideration of nonperformance risk for both derivative assets and liabilities. The results of this analysis were not material to the financial statements.

Our Transmission congestion rights positions (TCR), which are acquired on the SPP Integrated Market, are valued using the most recent monthly auction clearing prices. Our commodity contracts are valued using the market value approach on a recurring basis. The following fair value hierarchy table presents information about our TCR and commodity contracts measured at fair value as of December 31, 2013:

Fair Value Measurements at Reporting Date Using

($ in 000's) Description	Assets/(Liabilities) at Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
December 31, 2013				
Derivative assets	$ 2,510	$ 543	$1,967	—
Derivative liabilities	$(4,688)	$(4,688)	$ —	—
December 31, 2012				
Derivative assets	$ 287	$ 287	—	—
Derivative liabilities	$(7,222)	$(7,222)	—	—

* The only recurring measurements are derivative related.

Other fair value considerations

Our cash and cash equivalents approximate fair value because of the short-term nature of these instruments, and are classified as Level 1 in the fair value hierarchy. The carrying amount of our short-term debt, which is composed of Empire issued commercial paper or revolving credit borrowings, also approximates fair value because of their short-term nature. These instruments are classified as Level 2 in the fair value hierarchy as they are valued based on market rates for similar market transactions.

The carrying amount of our total long-term debt exclusive of capital leases at December 31, 2013 and 2012 was $739 million and $688 million, compared to a fair market value of approximately $715 million and $747 million, respectively. These estimates were based on a bond pricing model, utilizing inputs classified as Level 2 in the fair value hierarchy, which include the quoted market prices for the same or similar issues or on the current rates offered to us for debt of the same remaining maturities. The estimated fair market value may not represent the actual value that could have been realized as of December 31, 2013 or that will be realizable in the future.

16. REGULATED OPERATING EXPENSE

The following table sets forth the major components comprising "regulated operating expenses" under "Operating Revenue Deductions" on our consolidated statements of income for the years ended (in thousands):

	December 31,		
	2013	2012	2011
Power operation expense (other than fuel)	$ 15,643	$15,045	$12,685
Electric transmission and distribution expense	21,863	17,083	15,361
Natural gas transmission and distribution expense	2,498	2,443	2,385
Customer accounts & assistance expense	11,180	10,211	10,210
Employee pension expense(1)	10,736	10,180	8,805
Employee healthcare plan(1)	10,190	9,825	7,439
General office supplies and expense	12,850	10,776	10,158
Administrative and general expense	14,800	15,091	14,295
Bad debt expense	3,665	3,038	3,425
Regulatory reversal of gain on sale of assets	1,236	—	—
Miscellaneous expense	672	679	679
TOTAL	$105,333	$94,371	$85,442

(1) Does not include the capitalized portion of actuarially calculated costs, but reflects the GAAP expensed portion of these costs plus or minus costs deferred to a regulatory asset or recognized as a regulatory liability for Missouri and Kansas jurisdictions.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, an evaluation was carried out, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as such term is defined in Rule 13a-15(e) of the Securities Exchange Act of 1934). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2013.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2013.

Audit of Internal Control Over Financial Reporting

The effectiveness of our internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during the fourth quarter of 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Except as set forth below, the information required by this Item may be found in our proxy statement for our Annual Meeting of Stockholders to be held May 1, 2014, which is incorporated herein by reference.

Pursuant to instruction 3 of paragraph (b) of Item 401 of Regulation S-K, the information required by this Item with respect to executive officers is set forth in Item 1 of Part I of this Form 10-K under "Executive Officers and Other Officers of Empire."

We have adopted a Code of Ethics for the Chief Executive Officer and Senior Financial Officers. A copy of the code is available on our website at www.empiredistrict.com. Any future amendments or waivers to the code will be posted on our website at www.empiredistrict.com.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this item may be found in our proxy statement for our Annual Meeting of Stockholders to be held May 1, 2014, which is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this item may be found in our proxy statement for our Annual Meeting of Stockholders to be held May 1, 2014, which is incorporated herein by reference.

There are no arrangements the operation of which may at a subsequent date result in a change in control of Empire.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item may be found in our proxy statement for our Annual Meeting of Stockholders to be held May 1, 2014 which is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item may be found in our proxy statement for our Annual Meeting of Stockholders to be held May 1, 2014 which is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Index to Financial Statements and Financial Statement Schedule Covered by Report of Independent Registered Public Accounting Firm

All other schedules are omitted as the required information is either not present, is not present in sufficient amounts, or the information required therein is included in the financial statements or notes thereto.

List of Exhibits

(3)(a) The Restated Articles of Incorporation of Empire (Incorporated by reference to Exhibit 4(a) to Registration Statement No. 33-54539 on Form S-3).

(b) By-laws of Empire as amended February 6, 2014 (Incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K dated February 6, 2014 and filed February 7, 2014, File No. 1-3368).

(4)(a) Indenture of Mortgage and Deed of Trust dated as of September 1, 1944 and First Supplemental Indenture thereto among Empire, The Bank of New York Mellon Trust Company, N.A. and UMB Bank, N.A., (Incorporated by reference to Exhibits B(1) and B(2) to Form 10, File No. 1-3368).

(b) Third Supplemental Indenture to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 2(c) to Form S-7, File No. 2-59924).

(c) Sixth through Eighth Supplemental Indentures to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 2(c) to Form S-7, File No. 2-59924).

(d) Fourteenth Supplemental Indenture to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4(f) to Registration Statement No. 33-56635 on Form S-3).

(e) Twenty-Fourth Supplemental Indenture dated as of March 1, 1994 to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4(m) to Annual Report on Form 10-K for the year ended December 31, 1993, File No. 1-3368).

(f) Twenty-Eighth Supplemental Indenture dated as of December 1, 1996 to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4 to Annual Report on Form 10-K for the year ended December 31, 1996, File No. 1-3368).

(g) Thirty-First Supplemental Indenture dated as of March 26, 2007 to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated March 26, 2007 and filed March 28, 2007, File No. 1-3368).

(h) Thirty-Second Supplemental Indenture dated as of March 11, 2008 to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K dated March 11, 2008 and filed March 12, 2008, File No. 1-3368).

(i) Thirty-Third Supplemental Indenture dated as of May 16, 2008 to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated May 16, 2008 and filed May 16, 2008, File No. 1-3368).

(j) Thirty-Fifth Supplemental Indenture, dated as of May 28, 2010, to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated May 28, 2010 and filed May 28, 2010, File No. 1-3368).

(k) Thirty-Sixth Supplemental Indenture, dated as of August 25, 2010, to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated August 25, 2010 and filed August 26, 2010, File No. 1-3368).

(l) Thirty-Seventh Supplemental Indenture, dated as of June 9, 2011, to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K dated June 9, 2011 and filed June 10, 2011, File No. 1-3368).

(m) Thirty-Eighth Supplemental Indenture, dated as of April 2, 2012, to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K dated April 2, 2012 and filed April 2, 2012, File No. 1-3368).

(n) Thirty-Ninth Supplemental Indenture, dated as of May 30, 2013, to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K dated May 30, 2013 and filed May 30, 2013, File No. 1-3368).

(o) Bond Purchase Agreement, dated as of April 2, 2012, by and among the Company and the Purchasers named therein (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated April 2, 2012 and filed April 2, 2012, File No. 1-3368).

(p) Bond Purchase Agreement, dated as of October 30, 2012, by and among the Company and the Purchasers named therein (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated October 30, 2012 and filed November 2, 2012, File No. 1-3368).

(q) Indenture for Unsecured Debt Securities, dated as of September 10, 1999 between Empire and Wells Fargo Bank, National Association (Incorporated by reference to Exhibit 4(v) to Registration Statement No. 333-87015 on Form S-3).

(r) Securities Resolution No. 4, dated as of June 10, 2003, of Empire under the Indenture for Unsecured Debt Securities (Incorporated by reference to Exhibit 4 to Current Report on Form 8-K dated June 10, 2003 and filed July 29, 2003, File No. 1-3368).

(s) Securities Resolution No. 5, dated as of October 29, 2003, of Empire under the Indenture for Unsecured Debt Securities (Incorporated by reference to Exhibit 4 to Quarterly Report on Form 10-Q for quarter ended September 30, 2003), File No. 1-3368).

(t) Securities Resolution No. 6, dated as of June 27, 2005, of Empire under the Indenture for Unsecured Debt Securities (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated June 27, 2005 and filed June 28, 2005, File No. 1-3368).

(u) Bond Purchase Agreement dated June 1, 2006 among The Empire District Gas Company and the purchasers party thereto (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated June 1, 2006 and filed June 6, 2006, File No. 1-3368).

(v) Indenture of Mortgage and Deed of Trust dated as of June 1, 2006 by The Empire District Gas Company, as Grantor, to Spencer R. Thomson, Deed of Trust Trustee for the Benefit of The Bank of New York Trust Company, N.A., Bond Trustee, as Grantee (Incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K dated June 1, 2006 and filed June 6, 2006, File No. 1-3368).

(w) First Supplemental Indenture of Mortgage and Deed of Trust dated as of June 1, 2006 by The Empire District Gas Company, as Grantor, to Spencer R. Thomson, Deed of Trust Trustee for the Benefit of The Bank of New York Trust Company, N.A., Bond Trustee, as Grantee (Incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K dated June 1, 2006 and filed June 6, 2006, File No. 1-3368).

(10)(a) 1996 Stock Incentive Plan (Incorporated by reference to Exhibit 4.1 to Form S-8, File No. 33-64639).†

(b) First Amendment to 1996 Stock Incentive Plan. (Incorporated by reference to Exhibit 10(b) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(c) 2006 Stock Incentive Plan (Incorporated by reference to Exhibit 4(u) to Form S-8, File No. 333-130075).†

(d) First Amendment to 2006 Stock Incentive Plan. (Incorporated by reference to Exhibit 10(d) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(e) Second Amendment to 2006 Stock Incentive Plan (Incorporated by reference to Exhibit 10(e) to Annual Report on Form 10-K for the year ended December 31, 2008, File No. 1-3368). †

(f) Deferred Compensation Plan for Directors as amended and restated effective January 1, 2008. (Incorporated by reference to Exhibit 10(e) to Annual Report on Form 10-K for the year ended December 31, 2007). †

(g) The Empire District Electric Company Change in Control Severance Pay Plan as amended and restated effective January 1, 2008. (Incorporated by reference to Exhibit 10(f) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(h) Form of Severance Pay Agreement under The Empire District Electric Company Change in Control Severance Pay Plan. (Incorporated by reference to Exhibit 10(g) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(i) The Empire District Electric Company Supplemental Executive Retirement Plan as amended and restated effective January 1, 2008. (Incorporated by reference to Exhibit 10(h) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(j) Retirement Plan for Directors as amended August 1, 1998 (Incorporated by reference to Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 1998, File No. 1-3368).†

(k) Stock Unit Plan for Directors of The Empire District Electric Company (Incorporated by reference to Exhibit 10(i) to Annual Report on Form 10-K for the year ended December 31, 2005, File No. 1-3368).†

(l) First Amendment to Stock Unit Plan for Directors. (Incorporated by reference to Exhibit 10(k) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(m) Summary of Annual Incentive Plan. (Incorporated by reference to Exhibit 10(l) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(n) Form of Notice of Award of Dividend Equivalents. (Incorporated by reference to Exhibit 10(n) to Annual Report on Form 10-K for the year ended December 31, 2008, File No. 1-3368)†

(o) Form of Notice of Award of Non-Qualified Stock Options. (Incorporated by reference to Exhibit 10(o) to Annual Report on Form 10-K for the year ended December 31, 2008, File No. 1-3368).†

(p) Form of Notice of Award of Performance-Based Restricted Stock. (Incorporated by reference to Exhibit 10(p) to Annual Report on Form 10-K for the year ended December 31, 2008, File No. 1-3368).†

(q) Form of Notice of Award of Time-Based Restricted Stock. (Incorporated by reference to Exhibit 10(r) to Annual Report on Form 10-K for the year ended December 31, 2012, File No. 1-3368).

(r) Summary of Compensation of Non-Employee Directors. † (Incorporated by reference to Exhibit 10(r) to Annual Report on Form 10-K for the year ended December 31, 2012, File No. 1-3368).

(s) Form of Indemnity Agreement (Incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K dated February 5, 2009 and filed February 10, 2009, File No. 1-3368).†

(t) Third Amended and Restated Unsecured Credit Agreement dated as of January 17, 2012, among The Empire District Electric Company, UMB Bank, N.A. as administrative agent, Bank of America, N.A., as syndication agent, Wells Fargo Bank, N.A., as documentation agent, and the lenders named therein (Incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K dated January 17, 2012 and filed January 19, 2012, File No. 1-3368).

(12) Computation of Ratios of Earnings to Fixed Charges.*

(21) Subsidiaries of Empire.*

(23) Consent of PricewaterhouseCoopers LLP.*

(24) Powers of Attorney.*

(31)(a) Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*

(31)(b) Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*

(32)(a) Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*~

(32)(b) Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*~

(101) The following financial information from The Empire District Electric Company's Annual Report on Form 10-K for the period ended December 31, 2013, filed with the SEC on February 21, 2014, formatted in Extensible Business Reporting Language (XBRL): (i) the Consolidated Statements of Income for 2013, 2012 and 2011, (ii) the Consolidated Balance Sheets at December 31, 2013 and December 31, 2012, (iii) the Consolidated Statements of Cash Flows for 2013, 2012 and 2011, and (iv) Notes to Consolidated Financial Statements.**

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† This exhibit is a compensatory plan or arrangement as contemplated by Item 15(a)(3) of Form 10-K.

* Filed herewith.

** Pursuant to Rule 406T of Regulation S-T, the XBRL related information in Exhibit 101 to this Annual Report on Form 10-K shall not be deemed to be "filed" by the Company for purposes of Section 18 of the Exchange Act of 1934, as amended, or otherwise subject to the liability of that section, and shall not be deemed incorporated by reference into, or part of a registration statement, prospectus or other document filed under the Securities Act of 1933, as amended or the Exchange Act except as shall be expressly set forth by specific reference in such filings.

~ This certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Company for purposes of Section 18 or any other provision of the Securities Exchange Act of 1934, as amended.

SCHEDULE II

Valuation and Qualifying Accounts

Years ended December 31, 2013, 2012 and 2011:

		Additions			Deductions From Reserve		
			Charged to Other Accounts				
	Balance At Beginning Of Period	Charged To Income	Description	Amount	Description	Amount	Balance At Close of Period
Year ended **December 31, 2013:**							
Reserve deducted from assets: accumulated provision for uncollectible accounts.	$1,387,673	$2,213,988	Recovery of amounts previously written off	$2,013,959	Accounts written off	$4,590,443	$1,025,177
Year ended **December 31, 2012:**							
Reserve deducted from assets: accumulated provision for uncollectible accounts.	$1,137,644	$3,052,397	Recovery of amounts previously written off	$1,956,549	Accounts written off	$4,758,917	$1,387,673
Year ended **December 31, 2011:**							
Reserve deducted from assets: accumulated provision for uncollectible accounts.	$ 865,236	$3,737,630	Recovery of amounts previously written off	$1,847,527	Accounts written off	$5,312,749	$1,137,644

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE EMPIRE DISTRICT ELECTRIC COMPANY

Date: February 21, 2014

By /s/ BRADLEY P. BEECHER

Bradley P. Beecher, President and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Date: February 21, 2014

/s/ BRADLEY P. BEECHER

Bradley P. Beecher, President,
Chief Executive Officer, Director
(Principal Executive Officer)

/s/ LAURIE A. DELANO

Laurie A. Delano, Vice President-Finance
(Principal Financial Officer)

/s/ ROBERT W. SAGER

Robert W. Sager, Controller, Assistant
Secretary and Assistant Treasurer
(Principal Accounting Officer)

D. RANDY LANEY*

D. Randy Laney, Director

KENNETH R. ALLEN*

Kenneth R. Allen, Director

PAUL R. PORTNEY*

Paul R. Portney, Director

WILLIAM L. GIPSON*

William L. Gipson, Director

ROSS C. HARTLEY*

Ross C. Hartley, Director

HERBERT J. SCHMIDT*

Herbert J. Schmidt, Director

THOMAS OHLMACHER*

Thomas Ohlmacher, Director

B. THOMAS MUELLER*

B. Thomas Mueller, Director

C. JAMES SULLIVAN*

C. James Sullivan, Director

BONNIE C. LIND*

Bonnie C. Lind, Director

LAURIE A. DELANO

*By (Laurie A. Delano, as attorney in fact for
each of the persons indicated)

EXHIBIT (12)

Computation of Ratios of Earnings to Fixed Charges
Year ended December 31,

	2013	2012	2011	2010	2009
Income before provision for income taxes and fixed charges (Note A)	$152,117,322	$137,251,581	$136,980,092	$125,706,453	$114,457,760
Fixed Charges:					
Interest on long-term debt	$ 40,354,153	$ 40,192,347	$ 42,580,987	$ 41,958,541	$ 42,084,023
Interest on short-term debt	59,504	187,132	86,406	630,913	1,124,883
Interest on trust preferred securities	—	—	—	2,089,583	4,250,000
Other interest	1,064,869	1,087,719	(1,147,472)	(2,332,530)	(680,863)
Rental expense representative of an interest factor (Note B)	9,700,747	5,944,675	6,190,709	5,430,863	6,501,484
TOTAL FIXED CHARGES	$ 51,179,273	$ 47,411,873	$ 47,710,630	$ 47,777,370	$ 53,279,527
Ratio of earnings to fixed charges	2.97	2.89	2.87	2.63	2.15

NOTE A: For the purpose of determining earnings in the calculation of the ratio, net income has been increased by the provision for income taxes, non-operating income taxes and by the sum of fixed charges as shown above.

NOTE B: One-third of rental expense (which approximates the interest factor).

EXHIBIT (31)(a)

CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Bradley P. Beecher, certify that:

1. I have reviewed this annual report on Form 10-K of The Empire District Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

   a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2014

By: /s/ Bradley P. Beecher

Name: Bradley P. Beecher
Title: President and Chief Executive Officer

EXHIBIT (31)(b)

**CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Laurie A. Delano, certify that:

1. I have reviewed this annual report on Form 10-K of The Empire District Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

   a. designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2014

By: /s/ Laurie A. Delano

Name: Laurie A. Delano
Title: Vice President — Finance and Chief Financial Officer

EXHIBIT (32)(a)

**Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350,
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002***

In connection with the Annual Report of The Empire District Electric Company (the "Company") on Form 10-K for the period ending December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Bradley P. Beecher, as Chief Executive Officer of the Company, certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

By: /s/ Bradley P. Beecher

Name: Bradley P. Beecher
Title: President and Chief Executive Officer

Date: February 21, 2014

A signed original of this written statement required by Section 906 or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to The Empire District Electric Company and will be retained by The Empire District Electric Company and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT (32)(b)

Certification of Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002*

In connection with the Annual Report of The Empire District Electric Company (the "Company") on Form 10-K for the period ending December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Laurie A. Delano, as Chief Financial Officer of the Company, certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

By: /s/ Laurie A. Delano

Name: Laurie A. Delano
Title: Vice President — Finance and Chief Financial Officer

Date: February 21, 2014

A signed original of this written statement required by Section 906 or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to The Empire District Electric Company and will be retained by The Empire District Electric Company and furnished to the Securities and Exchange Commission or its staff upon request.

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Annual Meeting

The annual meeting of shareholders will be held Thursday, May 1, 2014, at 10:30 a.m., CDT, at the Holiday Inn, 3615 South Range Line, Joplin, Missouri.

Company Headquarters

The Empire District Electric Company
602 S. Joplin Avenue
P.O. Box 127
Joplin, Missouri 64802-0127
Telephone (417) 625-5100

Independent Registered Public Accounting Firm

PricewaterhouseCoopers LLP
St. Louis, Missouri

Registrar, Transfer Agent and Dividend Agent

Wells Fargo Bank, N.A.
Shareowner Services
P.O. Box 64854
St. Paul, Minnesota 55164-0854
(800) 468-9716 (toll free in the United States)
(651) 450-4064 (outside the United States)
www.shareowneronline.com (for registered shareholders & general inquiries)

Stock Trading

As of December 31, 2013, there were 4,397 common shareholders of record. Empire common stock is listed on the New York Stock Exchange under the ticker symbol EDE.

Stock Prices and Dividends

2013	Quarter	High	Low	Dividend Paid
	First	$22.41	$20.57	$0.25
	Second	$23.35	$21.26	$0.25
	Third	$24.32	$20.77	$0.25
	Fourth	$23.26	$21.27	$0.255

2012	Quarter	High	Low	Dividend Paid
	First	$21.34	$19.55	$0.25
	Second	$21.24	$19.51	$0.25
	Third	$21.94	$21.02	$0.25
	Fourth	$22.04	$19.59	$0.25

Credit Ratings

	Standard & Poor's	Moody's	Fitch
Corporate Credit Rating	BBB	Baa1	N/R*
First Mortgage Bonds	A-	A2	BBB+
Commercial Paper	A-2	P-2	F3
Senior Notes	BBB	Baa1	BBB
Outlook	Stable	Stable	Stable

*Not Rated

Direct Registration

Empire is a participant in the Direct Registration System ("DRS"). This system allows us to issue shares to our registered shareholders in a book-entry form called Direct Registration. All transfers or issuances of shares will be issued in Direct Registration unless a stock certificate is specifically requested.

Dividend Reinvestment and Stock Purchase Plan

The Dividend Reinvestment and Stock Purchase Plan offers a variety of convenient, low-cost services for current shareholders. It is designed for long-term investors who wish to invest and build their share ownership over time. All registered holders of Empire common stock can participate in the Plan. If you are a beneficial owner of shares in a brokerage account and wish to reinvest your dividends, you can request that your shares become registered or make arrangements with your broker or nominee to participate on your behalf. The Plan offers a 3 percent discount on the purchase of shares with reinvested dividends. Optional features (applicable to registered holders only) include:

- Additional cash purchases, as often as weekly, with $50 minimum per transaction up to $125,000 per year;
- Automatic deduction from your bank account for additional cash purchases;
- Safekeeping of your certificates;
- Participation in the Plan with full, partial or no reinvestment of dividends; and
- Sale of shares through the Plan.

The Plan Administrator may be contacted as follows to request a prospectus describing the Plan, an enrollment form or to make an optional cash investment:

Wells Fargo Bank, N.A.
Shareowner Services
P.O. Box 64856
St. Paul, Minnesota 55164-0856
(800) 468-9716 (toll free in the United States)
(651) 450-4064 (outside the United States)
www.shareowneronline.com (for registered shareholders & general inquiries)

Financial Report – Form 10-K

Copies of this report which includes the Annual Report on Form 10-K including financial statements, as filed with the Securities and Exchange Commission, are available without charge upon written request to Janet S. Watson, The Empire District Electric Company, P.O. Box 127, Joplin, Missouri 64802-0127. This report may also be accessed via our website, www.empiredistrict.com. This report is not intended to induce any securities' sale or purchase.

Sarbanes-Oxley Certifications

Empire filed the CEO and CFO certifications required by Section 302 of the Sarbanes-Oxley Act as exhibits to its Annual Report on Form 10-K for the year ended December 31, 2013.

Inquiries

Investor, shareholder and financial information is also available from:

The Empire District Electric Company
Janet S. Watson, Secretary-Treasurer
P.O. Box 127
Joplin, Missouri 64802-0127
Telephone (417) 625-5108
investor.relations@empiredistrict.com

Internet

We invite you to learn more about our Company by connecting with us at: ***www.empiredistrict.com***.

The Empire District Electric Company

602 S. Joplin Avenue | PO Box 127 | Joplin, MO 64802-0127

www.empiredistrict.com