SERVICES YOU COUNT ON

THE EMPIRE DISTRICT ELECTRIC COMPANY

602 S. Joplin Avenue
Joplin, Missouri 64801

March 13, 2013

Dear Stockholder:

You are cordially invited to attend our Annual Meeting of Stockholders to be held at 10:30 a.m., CDT, on Thursday, April 25, 2013, at the Holiday Inn, 3615 South Range Line, Joplin, Missouri.

At the meeting, stockholders will be asked to:

- Elect three persons to our Board of Directors for three-year terms,
- Ratify the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm,
- Vote upon a non-binding advisory proposal to approve the compensation of our named executive officers, and
- Vote upon a stockholder proposal, if properly presented, requesting the Company prepare a report on plans to reduce risk throughout its energy portfolio by pursuing cost effective energy efficiency resources.

Your participation in this meeting, either in person or by proxy, is important. Even if you plan to attend the meeting, please promptly vote the enclosed proxy through the Internet, by telephone or by mail. Please note that brokers may not vote your shares on the election of directors in the absence of your specific instructions as to how to vote. Please return your proxy card so your vote can be counted.

At the meeting, if you desire to vote in person, you may withdraw the proxy.

Sincerely,

Bradley P. Beecher
President and Chief Executive Officer

THE EMPIRE DISTRICT ELECTRIC COMPANY

602 S. Joplin Avenue
Joplin, Missouri 64801

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS

To the Holders of Common Stock:

Notice is hereby given that the Annual Meeting of Stockholders of The Empire District Electric Company will be held on Thursday, the 25th of April, 2013, at 10:30 a.m., CDT, at the Holiday Inn, 3615 South Range Line, Joplin, Missouri, for the following purposes:

1. To elect three persons named in the accompanying proxy statement as Directors for terms of three years.
2. To ratify the appointment of PricewaterhouseCoopers LLP as Empire's independent registered public accounting firm for the fiscal year ending December 31, 2013.
3. To vote upon a non-binding advisory proposal to approve the compensation of our named executive officers as disclosed in this proxy statement.
4. To vote upon a stockholder proposal, if properly presented, requesting the Company prepare a report on plans to reduce risk throughout its energy portfolio by pursuing cost effective energy efficiency resources.
5. To transact such other business as may properly come before the meeting or at any adjournment or adjournments thereof.

Any of the foregoing may be considered or acted upon at the first session of the meeting or at any adjournment or adjournments thereof.

This year, we are once again pleased to be using the U.S. Securities and Exchange Commission rule that allows companies to furnish their proxy materials over the Internet. As a result, we are mailing to many of our stockholders a notice instead of a paper copy of this proxy statement and our 2012 Annual Report. The notice contains instructions on how to access those documents over the Internet. The notice also contains instructions on how each of those stockholders can receive a paper copy of our proxy materials, including this proxy statement, our 2012 Annual Report and a form of proxy card or voting instruction card. All stockholders who do not receive a notice will receive a paper copy of the proxy materials by mail. We believe that this process will conserve natural resources and reduce the costs of printing and distributing our proxy materials.

Holders of Common Stock of record on the books of Empire at the close of business on February 25, 2013 will be entitled to vote on all matters which may come before the meeting or any adjournment or adjournments thereof. A complete list of the stockholders entitled to vote at the meeting will be open at our office located at 602 S. Joplin Avenue, Joplin, Missouri, to examination by any stockholder for any purpose germane to the meeting, for a period of ten days prior to the meeting, and also at the meeting.

Stockholders are requested, regardless of the number of shares of stock owned, to either vote the proxy through the Internet or by telephone or sign and date the proxy and mail it promptly in the envelope provided, to which no postage need be affixed if mailed in the United States. A stockholder who plans to attend the meeting in person may withdraw the proxy and vote at the meeting.

Please note that brokers may not vote your shares on the election of directors in the absence of your specific instructions as to how to vote. Please return your proxy card so your vote can be counted.

Joplin, Missouri
Dated: March 13, 2013

Janet S. Watson
Secretary—Treasurer

PROXY STATEMENT

THE EMPIRE DISTRICT ELECTRIC COMPANY

602 S. Joplin Avenue
Joplin, Missouri 64801

PROXY STATEMENT

ANNUAL MEETING OF STOCKHOLDERS

April 25, 2013

1. GENERAL INFORMATION

This proxy statement is furnished in connection with the solicitation on behalf of the Board of Directors of The Empire District Electric Company, hereinafter referred to as Empire (Empire), a Kansas corporation, of proxies to be voted at our Annual Meeting of Stockholders to be held on Thursday, April 25, 2013, and at any and all adjournments of the meeting.

A form of proxy is available for execution by stockholders. The proxy reflects the number of shares registered in a stockholder's name. Any stockholder giving a proxy has the right to revoke it at any time before the proxy is exercised by written notice to the Secretary—Treasurer of Empire, by duly executing a proxy bearing a later date or by voting in person at the meeting.

A copy of our Annual Report for the year ended December 31, 2012 has been mailed or made available electronically to each stockholder of record for the meeting. You are urged to read the entire Annual Report.

The entire cost of the solicitation of proxies will be borne by us. Solicitation, commencing on or about March 13, 2013, will be made by use of the mails, telephone, Internet and fax and by our regular employees without additional compensation. We will request brokers or other persons holding stock in their names, or in the names of their nominees, to forward proxy material to the beneficial owners of stock or request authority for the execution of the proxies and will reimburse those brokers or other persons for their expense in so doing.

February 25, 2013 has been fixed as the record date for the determination of stockholders entitled to vote at the meeting and at any adjournment or adjournments thereof. The stock transfer books will not be closed. As of the record date, there were 42,411,176 shares of common stock outstanding. Holders of common stock will be entitled to one vote per share on all matters presented to the meeting.

The holders of a majority of the shares entitled to vote at the Annual Meeting, represented in person or by proxy, shall constitute a quorum for the purpose of transacting business at the Annual Meeting. Each outstanding share shall be entitled to one vote on each matter submitted to a vote at the Annual Meeting. Directors will be elected by a plurality of the votes of the stockholders present in person or represented by proxy at the meeting. For the ratification of the appointment of Empire's independent registered public accounting firm, the vote of a majority of the shares voted on such matter, assuming a quorum is present, shall be the act of the stockholders on such matter.

With respect to the non-binding advisory proposal to approve the compensation of our named executive officers, the votes that stockholders cast "for" must exceed the votes that stockholders cast "against" to approve this advisory vote. However, because your votes are advisory on this proposal, they will not be binding.

To be approved, the stockholder proposal requesting the Company prepare a report on plans to reduce risk throughout its energy portfolio by pursuing cost effective energy efficiency resources must receive a "for" vote from a majority of the shares voted on such matter, assuming a quorum is present.

A stockholder voting for the election of directors may withhold authority to vote for all or certain director nominees. A stockholder may also abstain from voting on any of the other proposals. Votes withheld from the election of any nominee for director, abstentions from any other proposal and broker non-votes will be treated as shares that are present and entitled to vote for purposes of determining the presence of a quorum, but will not be counted in the number of votes cast on a matter. With respect to shares allocated to a participant's account under our 401(k) Plan and ESOP, such participant may direct the trustee of the plan, as indicated on the proxy card, on how to vote the shares allocated to such participant's account. If no direction is given with respect to the shares allocated to a participant's account under the plan, the trustee will vote such shares in the same proportion as the shares for which directions were received from other participants in the plan.

A "broker non-vote" occurs if a broker or other nominee who is entitled to vote shares on behalf of a record owner has not received instructions with respect to a particular item to be voted on, and the broker or nominee does not otherwise have discretionary authority to vote on that matter. Under the rules of the New York Stock Exchange ("NYSE"), brokers may vote a client's proxy in their own discretion on certain items even without instructions from the beneficial owner, but may not vote a client's proxy without voting instructions on "non-discretionary" items. The ratification of Empire's independent registered public accounting firm is considered a "discretionary" item. However, the election of directors is a "non-discretionary" item and brokers may not vote your shares on the election of directors in the absence of your specific instructions as to how to vote. The non-binding advisory proposal with respect to executive compensation and the stockholder proposal are also "non-discretionary" items. Please return your proxy card so your vote can be counted.

2. MATTERS TO BE CONSIDERED AT THE ANNUAL MEETING

A. ELECTION OF DIRECTORS

(Item 1 on Proxy Card)

The Board of Directors is divided into three classes with the Directors in each class serving for a term of three years. The term of office of one class of Directors expires each year in rotation so that one class is elected at each Annual Meeting for a full three-year term. Directors are required to retire when they reach the retirement age of 73. Empire's Articles of Incorporation permit the Board of Directors to vary in size from 9 to 11 members. The Board of Directors determines the appropriate size of the Board within this range, which may vary to accommodate the needs of Empire and its stockholders and the availability of suitable candidates. In 2011, the Board approved an increase in the size of the Board from 10 to 11 members.

During 2012, the Board of Directors held four regular meetings and two special meetings. At these meetings, the Board considered a wide variety of matters involving, among other things:

- Strategic planning
- New generation projects
- The Company's financial condition and results of operations
- Financings
- Capital and operating budgets
- Regulatory proceedings
- Personnel matters
- Succession planning
- Risk management
- Industry issues
- Accounting practices and disclosure
- Corporate governance practices

All of the members of the Board of Directors attended more than 75% of the aggregate of the Board meetings and meetings held by all committees of the Board on which the Director served during the periods that the Director served.

Unless otherwise specified, the persons named in the accompanying proxy intend to vote the shares represented by proxies for the election of Mr. Ross C. Hartley, Mr. Herbert J. Schmidt and Mr. C. James Sullivan, all who are current members of the Board of Directors, as Class II Directors. While it is not expected that any of the nominees will be unable to qualify for or accept office, if for any reason one or more shall be unable to do so, proxies will be voted for nominees selected by the Board of Directors.

Information about Nominees and Directors

The Nominating/Corporate Governance Committee selects as candidates those nominees it believes would best represent the interests of the stockholders. This assessment includes such issues as experience, integrity, competence, diversity, skills and dedication in the context of the needs of the Board. The Committee does not have a formal diversity policy; however, the Committee endeavors to select candidates with a broad mix of professional and personal backgrounds in order to best meet the needs of the Board, Empire and our stockholders. The Nominating/Corporate Governance Committee begins the director search process by identifying specific experience, qualifications, attributes or skills they believe to be the most beneficial in enabling the Board of Directors to satisfy its responsibilities effectively in light of our business and structure. These have included financial expertise, capital markets experience, environmental and regulatory experience, utility leadership experience and service-area business experience. A third-party search firm is sometimes paid a fee to assist in the process of identifying and evaluating candidates that have the experience, qualifications, attributes and skills to match the search criteria. The Director nominees must also have a reputation for integrity, honesty and adherence to high ethical standards and have demonstrated superior business acumen and an ability to exercise sound judgment.

The name, age, principal occupation for the last five years, period of service as a Director of Empire, other directorships of each Director and the qualifications of each Director are set forth below. In addition, included in the information below, is a discussion of the specific experience, qualifications, attributes or skills that led to the conclusion that the person should serve as a Director of Empire in light of our business and structure. See "—Director Nomination Process" below for more information on the selection of director nominees.

Nominees for Director

CLASS II DIRECTORS
Nominated Term Expiring at the 2016 Annual Meeting

Ross C. Hartley, age 65, joined our Board of Directors in 1988. Mr. Hartley is a private investor. He is also the Co-Founder and has been a Director of NIC Inc., an investor-owned company that is a leader in providing e-government solutions for federal, state and local governments since 1991. Mr. Hartley was a long-time leader in the independent insurance business in our tri-state area and has varied experience on both public and private boards including significant experience serving on Finance and Audit Committees. Mr. Hartley is a successful entrepreneur and is valued by the Board of Directors for his business acumen and experience gained from 25 years of service as a Director.

Herbert J. Schmidt, age 57, joined our Board of Directors in 2010. Mr. Schmidt served as the Executive Vice President of Con-way Inc. and President of Con-way Truckload (trucking services) from 2007 to 2012. Prior to the merger of Contract Freighters, Inc. ("CFI") with Conway Inc. in 2007, Mr. Schmidt held positions at CFI of President and Chief Executive Officer from 2005 to 2007 and President from 2000 to 2005. Prior to his becoming President and CEO in 2005, he was employed in a series of progressively more responsible positions at CFI where he gained extensive knowledge in risk management, safety, insurance, benefits, security, and compliance. Mr. Schmidt, a long-time, service-area resident and businessman, has demonstrated exceptional management ability, community involvement and leadership, and his knowledge of Empire's service area, customers and stockholders brings valuable insight to the Board of Directors.

C. James Sullivan, age 66, joined our Board of Directors in 2010. Mr. Sullivan has served as Principal of Sullivan Group LLC (utility and energy consulting) since 2008. He served as President of the Alabama Public Service Commission (the public utility regulator in Alabama) from 1983 to 2008 and has been active in the National Association of Regulatory Utility Commissioners ("NARUC") serving in various capacities including President from 1998-1999. He served as a member of the University of Chicago Board of Governors which administers the Argonne National Laboratory for the Department of Energy. He is also a member of the Alabama State Bar. Mr. Sullivan's diverse experience and vast knowledge of utility issues brings to the Board of Directors critical insight into utility regulation, the regulatory process and the challenges facing the utility industry.

The Board of Directors unanimously recommends that you vote FOR each nominee.

Members of the Board of Directors Continuing in Office

CLASS I DIRECTORS
Term Expiring at the 2015 Annual Meeting

D. Randy Laney, age 58, joined our Board of Directors in 2003 and has served as the Non-Executive Vice Chairman of the Board from 2008 to 2009 and Non-Executive Chairman of the Board since April 23, 2009. He retired as Vice-Chairman of Investlinc Group (private investment and wealth services) in 2008, a position he had held since 2003. Mr. Laney spent 23 years with Wal-Mart Stores in positions of Corporate Counsel/Corporate Secretary, Director of Finance, Vice President of Finance, Benefits and Risk Management and Vice President of Finance and Treasurer. In addition, Mr. Laney has provided strategic advisory services to both private and public companies and served on numerous profit and non-profit boards. Mr. Laney brings significant management and capital markets experience, and strategic and operational understanding to his position as Chairman of the Board.

Bonnie C. Lind, age 54, joined our Board of Directors in 2009. Ms. Lind has served as Senior Vice President, Chief Financial Officer and Treasurer, of Neenah Paper Inc. (global manufacturer of premium performance based papers) since 2004. Prior to the spin-off of Neenah Paper from Kimberly-Clark Corporation in 2004, she held various financial and strategic management positions at Kimberly-Clark from 1982 to 2003, most recently as the Assistant Treasurer from 1999 to 2003. Ms. Lind has significant financial, capital markets and banking experience in a cyclical industry which consumes large quantities of energy and is affected by energy prices. Her financial, capital markets and banking experience in a small-cap, NYSE listed company brings to the Board and the Audit Committee a wealth of knowledge in dealing with financial and accounting matters in a comparable public company. Ms. Lind has been designated an Audit Committee Financial Expert.

B. Thomas Mueller, age 65, joined our Board of Directors in 2003. Mr. Mueller is the Founder and has served as the President since 1987 of SALOV North America Corporation, a U.S. subsidiary of an Italian multi-national group that imports and markets Filippo Berio olive oil throughout the U.S. As a Certified Public Accountant and an attorney, Mr. Mueller was formerly an international tax partner with KPMG Peat Marwick. His leadership skills and accounting and finance experience, as well as his experience with complex global financial issues, make him a skilled advisor with the knowledge necessary to lead our Audit Committee. Mr. Mueller has been designated an Audit Committee Financial Expert.

Paul R. Portney, age 67, joined our Board of Directors in 2009. Dr. Portney served as Dean of the Eller College of Management at the University of Arizona from 2005 to 2011, where he continues as a professor, teaching such courses as "Energy, Environment and Business Strategy." Dr. Portney has been at the center of public environmental policy for three decades. At Resources for the Future, where he worked from 1972-2005 and was President and Chief Executive Officer from 1995 to 2005, he conducted research on environmental protection and regulation, natural resources policy, federal energy policy, air pollution, health and safety regulation, and provision of public goods. Dr. Portney is author and co-author of ten books, including *Public Policies for Environmental Protection*. The Board of Directors values his deep knowledge of environmental policy and the environmental challenges and regulation facing our industry.

CLASS III DIRECTORS
Term Expiring at the 2014 Annual Meeting

Kenneth R. Allen, age 55, joined our Board of Directors in 2005. Mr. Allen has served as Vice President, Finance and Chief Financial Officer of Texas Industries, Inc. (cement, aggregate and concrete products firm) since 2008 and was the Vice President, Treasurer and Director of Investor Relations from 1996 to 2008. Mr. Allen also worked as an economist and an analyst for an electric industry consultant early in his career which gives him additional insight into some of the challenges facing the industry. Mr. Allen has significant financial, capital markets, and investor relations experience with a small-cap, NYSE listed company in a highly capital and energy intensive industry. He also has considerable experience developing incentive compensation plans which serves him well as a member of the Compensation Committee. Mr. Allen has been designated an Audit Committee Financial Expert.

Bradley P. Beecher, age 47, joined our Board of Directors in 2011. Mr. Beecher, a professional engineer, has served as President and Chief Executive Officer of Empire since June 1, 2011. Mr. Beecher has also held the offices of Executive Vice President of Empire, Executive Vice President and Chief Operating Officer—Electric, Vice President—Energy Supply, Director of Strategic Planning as well as other operational and management positions during his career. His engineering background combined with 24 years of broad-based electric industry experience and proven leadership skills position him well to serve as a Director and leader of the Company.

William L. Gipson, age 56, joined our Board of Directors in 2002 and served as President and Chief Executive Officer of Empire from 2002 to 2011. Mr. Gipson held various operational and management positions during his thirty year career with Empire. His deep knowledge of all aspects of our business, combined with his exceptional business acumen and drive for innovation and excellence are invaluable to the Board of Directors.

Thomas M. Ohlmacher, age 61, joined our Board of Directors in 2011. Mr. Ohlmacher served as President and Chief Operating Officer, Non-regulated Energy from Black Hills Corporation from 2002 to 2011. He began his utility career with Black Hills Corporation (diversified energy company) in 1974 as a Performance Engineer and held various operational, strategic planning, and managerial positions. Mr. Ohlmacher's experience includes the construction and operation of conventional coal and natural gas fired generation and the integration of renewable wind, solar and hydro generation. He brings to the Board of Directors a wealth of industry and technical knowledge, as well as considerable insight into the leadership and business strategy of a public utility company.

Director Independence

The Board of Directors has adopted the following standards to assist it in making determinations of independence in accordance with the New York Stock Exchange (the "NYSE") Listed Company Manual:

1. A Director shall not fail to meet any of the independence tests set forth in Section 303A.02(b) of the NYSE Listed Company Manual or any successor provisions thereto.
2. The Board of Directors shall affirmatively determine that, after taking into account all relevant facts and circumstances, the Director has no material relationships with Empire (either directly or as a partner, stockholder or officer of an organization that has a relationship with Empire). For purposes of this determination, the following relationships are not material (unless otherwise prohibited by clause 1 above):
   a. If a Director (or any family member of a Director) is a current or former customer, or a current or former employee or Director of a customer (or an affiliate of a customer), of Empire.
   b. If a Director is a former employee of an organization which provides investment banking services to Empire or which publishes research opinions with respect to any securities of Empire.
   c. If a family member of a Director is an employee of, or otherwise affiliated with, a charitable organization to which Empire contributes less than $25,000 in any fiscal year.
   d. If a Director (or any family member of a Director) receives benefits payments under Empire's Retirement Plan or Empire's Supplemental Executive Retirement Plan.
   e. If a Director is an executive officer of an organization which is affiliated with an organization where an executive officer of Empire serves on the board.

The Board of Directors has determined that each of the following meet the independence standards adopted above: Kenneth R. Allen, Ross C. Hartley, D. Randy Laney, Bonnie C. Lind, B. Thomas Mueller, Thomas M. Ohlmacher, Paul R. Portney, Herbert J. Schmidt, and C. James Sullivan. The Board of Directors has determined that Bradley P. Beecher and William L. Gipson do not meet the independence standards adopted above.

Executive Sessions

The terms of our Corporate Governance Guidelines provide that Directors will meet in two separate executive sessions chaired by the Chairman of the Board, as follows: (1) all of the Directors will meet in executive session and (2) all of the independent Directors will meet in executive session. Such is the practice at each Board meeting. With the exception of Mr. Beecher and Mr. Gipson, all of the Directors of Empire are independent Directors.

Board Leadership Structure

The positions of Chairman of the Board and Chief Executive Officer have been held by separate individuals since 2002 in recognition of the differences between the two roles. The Chairman of the Board provides leadership to the Board and works with the Board to define its structure and activities in the fulfillment of its responsibilities. The Chairman works with the Chief Executive Officer and other Board members to provide strong, independent oversight of our management and affairs. The Chairman approves Board meeting agendas and presides over meetings of the full Board.

Risk Oversight

Our Board of Directors is responsible for the oversight of management's responsibility to assess and manage our major financial and other risk exposures, including operational, legal, regulatory, business, financial, commodity, strategic, environmental, credit, liquidity, and reputation risks. The Board reviews with management the categories of risk we face, including any risk concentrations and risk interrelationships, as well as the likelihood of occurrence, the potential impact of those risks and mitigating measures. In addition, the Board reviews management's implementation of its risk practices, policies and procedures to assess whether they are being followed and are effective. As part of this oversight role, the Board participates in a bi-annual enterprise risk management assessment.

While the Board of Directors has the ultimate oversight responsibility for risk management activities, various committees of the Board also have responsibility for the oversight of risk management. In particular, the Audit Committee focuses on financial risk, including counterparty credit risk, internal controls, and receives risk assessment reports from our internal auditors. In addition, in setting compensation, the Compensation Committee strives to create incentives that encourage a level of risk-taking behavior consistent with our business strategy. The Strategic Projects Committee works with management to oversee utility capital projects and operational issues of strategic importance.

The Risk Oversight Committee assists the Board in fulfilling its responsibility to oversee our risk management activities. The members of the Risk Oversight Committee consist of the Chairman of the Board as well as the Chairperson of each of the Audit, Compensation, Nominating/Corporate Governance and Strategic Projects Committees.

Committees of the Board of Directors

Audit Committee

We have an Audit Committee of the Board of Directors. The Board has adopted and approved a written charter for the Audit Committee. The charter is available on our website at *www.empiredistrict.com*. The Audit Committee meets the definition of an audit committee as set forth in Section 3(a)(58)(A) of the Securities Exchange Act of 1934 (the "Exchange Act").

In accordance with its written charter, the Audit Committee assists the Board in its oversight of:

- The integrity of our financial statements,
- Our compliance with legal and regulatory requirements,
- The Independent Registered Public Accounting Firms' qualification and independence, and
- The performance of our internal audit function and independent auditors.

In addition, the Audit Committee is directly responsible for the appointment, compensation, retention, termination and oversight of the work of our independent auditors. The Audit Committee held nine meetings during 2012. The members of the Audit Committee are Ms. Lind and Messrs. Allen, Hartley and Mueller, each of whom is independent (as independence is defined in the NYSE Listing Standards and the rules of the Securities and Exchange Commission (the "SEC") applicable to audit committee members) and is financially literate (as determined by the Board in its business judgment in accordance with NYSE Listing Standards). The Board has also determined that Ms. Lind and Messrs. Allen and Mueller are "audit committee financial experts" (as defined in the instructions to Item 407(d)(5)(i) of Regulation S-K). None of the members of the Audit Committee serve on the Audit Committee of another public company. The report of the Audit Committee can be found below under the heading "Other Matters—Audit Committee Report."

Compensation Committee and Compensation Committee Interlocks and Insider Participation

We have a Compensation Committee of the Board of Directors. The Compensation Committee assists the Board in establishing and overseeing Director and executive officer compensation policies and practices of Empire on behalf of the Board. The Compensation Committee determines the compensation of each of our executive officers as more fully described under "Executive Compensation—Compensation Discussion and Analysis." Also, as more fully described under "Executive Compensation—Compensation Discussion and Analysis," our Chief Executive Officer makes recommendations to the Compensation Committee with respect to certain aspects of executive compensation. The charter for the Compensation Committee is available on our website at *www.empiredistrict.com*. The Compensation Committee held five meetings during 2012. The members of our Compensation Committee are Messrs. Allen, Laney, Ohlmacher, Portney and Schmidt. The Board has determined that each member of the Compensation Committee is "independent" as defined by the NYSE Listing Standards. The report of the Compensation Committee can be found below under the heading "Executive Compensation—Compensation Committee Report."

None of the members of our Compensation Committee has ever been an officer or employee of Empire or any of its subsidiaries. None of the members of our Compensation Committee had any relationship requiring disclosure under "Transactions with Related Persons" below. None of our current executive officers has ever served as a Director or member of the Compensation Committee (or other Board committee performing equivalent functions) of another for-profit corporation.

Nominating/Corporate Governance Committee

We have a Nominating/Corporate Governance Committee of the Board of Directors. The Nominating/Corporate Governance Committee is primarily responsible for:

- Identifying individuals qualified to become Board members, consistent with criteria approved by the Board, and recommending that the Board select (or re-nominate) the Director nominees for the next annual meeting of stockholders,
- Developing and recommending to the Board a set of corporate governance guidelines applicable to Empire,
- Developing, approving and administering policies and procedures with respect to related person transactions,
- Overseeing the evaluation of the Board and its committees,
- Annually reviewing and recommending Board committee membership, and
- Working with the Board to evaluate and/or nominate potential successors to the CEO.

The charter for the Nominating/Corporate Governance Committee is available on our website at *www.empiredistrict.com*. The Committee held three meetings in 2012. The members of the Committee are Ms. Lind and Messrs. Allen, Hartley, Laney, and Sullivan. The Board has determined that each member of the Nominating/Corporate Governance Committee is "independent" as defined by the NYSE Listing Standards. The report of the Nominating/Corporate Governance Committee can be found below under the heading "—Nominating/Corporate Governance Committee Report."

Director Nomination Process

The Nominating/Corporate Governance Committee selects as candidates those nominees it believes would best represent the interests of the stockholders. This assessment includes such issues as experience, integrity, competence, diversity, skills and dedication in the context of the needs of the Board. The Committee does not have a formal diversity policy; however, the Committee endeavors to select candidates with a broad mix of professional and personal backgrounds in order to best meet the needs of the Board, Empire and our stockholders. In addition, the Committee takes into account the nature of and time involved in the Director's other employment and service on other boards. The Committee reviews with the Board, as required, the requisite skills and characteristics of individual Board members, as well as the composition of the Board as a whole, in the context of the needs of Empire. The Director nominees must also have a reputation for integrity, honesty and adherence to high ethical standards and have demonstrated superior business acumen and an ability to exercise sound judgment. When seeking new candidates, the Committee has sometimes paid a fee to a third party to assist in the process of identifying and evaluating candidates.

The Nominating/Corporate Governance Committee will consider nominees recommended by stockholders for election to the Board of Directors. In order to be considered, proposals for nominees for director by stockholders must be submitted in writing to Corporate Secretary: The Empire District Electric Company, 602 S. Joplin Avenue, Joplin, Missouri 64801.

In order to nominate a director at the Annual Meeting, Empire's By-Laws require that a stockholder follow the procedures set forth in Article VI, Section 5 of Empire's Restated Articles of Incorporation. In order to recommend a nominee for a director position, a stockholder must be a stockholder of record at the time it gives notice of recommendation and must be entitled to vote for the election of directors at the meeting at which such nominee will be considered. Stockholder recommendations must be made pursuant to written notice delivered (i) in the case of a nomination for election at an annual meeting, not less than 35 days nor more than 50 days prior to the annual meeting; and (ii) in the event that less than 45 days notice or prior public disclosure of the date of the meeting is given or made to stockholders, notice by the stockholder to be timely must be received not later than the close of business on the tenth day following the day on which notice of the date of the meeting was mailed or the public disclosure was made.

The stockholder notice must set forth the following:

- As to each person the stockholder proposes to nominate for election or re-election as a director, all information relating to such person that is required to be disclosed in solicitations of proxies for the election of directors, or is otherwise required by applicable law (including the person's written consent to being named as a nominee and to serving as a director if elected), and
- As to the nominating stockholder on whose behalf the nomination is made, (a) the name and address, as they appear on Empire's books, (b) a representation that the stockholder is a holder of record of the common stock entitled to vote at the meeting on the date of the notice and intends to appear in person or by proxy at the meeting to nominate the person or persons specified in the notice, and (c) a description of all arrangements or understandings between the stockholder and each nominee and any other person or persons (naming such person or persons) pursuant to which the nomination or nominations are to be made by the stockholder.

In addition to complying with the foregoing procedures, any stockholder nominating a director must also comply with all applicable requirements of the Exchange Act and the rules and regulations thereunder. We did not receive any recommendations for director nominees for the current Annual Meeting of Stockholders by any of our stockholders.

Nominating/Corporate Governance Committee Report

The Nominating/Corporate Governance Committee recommended that the Board of Directors nominate Mr. Ross C. Hartley, Mr. Herbert J. Schmidt and Mr. C. James Sullivan as Class II Directors. Mr. Hartley, Mr. Schmidt and Mr. Sullivan have been nominated by the Board as Class II Directors subject to stockholder approval, for three-year terms ending at the Annual Meeting of Stockholders in 2016.

Empire's Board of Directors operates pursuant to a set of written Corporate Governance Guidelines that set forth Empire's corporate governance philosophy and the governance policies and practices that the Board has established to assist in governing Empire and its affiliates. The Guidelines describe the Board membership criteria and the internal policies and practices by which Empire is operated and controlled on behalf of its stockholders.

In 2012, the Board and its committees continued to examine their processes and strengthen them as appropriate, and the Board's evaluation of Empire's corporate governance processes is ongoing. This assures that the Board and its committees have the necessary authority and practices in place to review and evaluate Empire's business operations as needed, and to make decisions that are independent of Empire's management. As examples, the Board and its committees undertake an annual self-evaluation process, meet regularly without members of management present, have full access to officers and employees of Empire, and retain their own advisors as they deem appropriate.

The Code of Business Conduct and Ethics, which is applicable to all of our Directors, officers and employees, and the Corporate Governance Guidelines comply with the Sarbanes-Oxley Act of 2002 and the listing standards of the New York Stock Exchange. We also have a separate code of ethics that applies to our chief executive officer and our senior financial officers, including our chief financial officer and our chief accounting officer. All of our corporate governance materials, including our codes of conduct and ethics, our Corporate Governance Guidelines, and our Policy and Procedures with Respect to Related Person Transactions are available for public viewing on our website at *www.empiredistrict.com* under the heading Investors, Corporate Governance. Copies of our corporate governance materials are also available without charge to interested parties who request them in writing from: Corporate Secretary, The Empire District Electric Company, 602 S. Joplin Avenue, Joplin, Missouri 64801.

Ross C. Hartley, Chairman
Kenneth R. Allen
D. Randy Laney
Bonnie C. Lind
C. James Sullivan

Attendance at Annual Meetings

Empire's Corporate Governance Guidelines provide that Directors are expected to attend the annual meeting of stockholders. All members of Empire's Board of Directors attended the Annual Meeting of Stockholders in 2012.

B. RATIFICATION OF APPOINTMENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

(Item 2 on Proxy Card)

Empire is asking the stockholders to ratify the appointment of PricewaterhouseCoopers LLP ("PwC") as our independent registered public accounting firm for the fiscal year ending December 31, 2013. PwC was appointed by the Audit Committee of the Board of Directors on February 6, 2013, and has acted in this capacity since 1992.

Although ratification by the stockholders is not required by law, the Board of Directors has determined that it is desirable to request approval of this selection by the stockholders. In the event the stockholders fail to ratify the appointment, the Audit Committee will consider this factor when making any future determination regarding PwC. Even if the selection is ratified, the Audit Committee, in its discretion, may direct the appointment of a different independent accounting firm at any time during the year if it determines that such a change would be in the best interests of Empire and its stockholders.

Passage of the proposal requires the affirmative vote of a majority of the votes cast.

The Board of Directors unanimously recommends that you vote FOR the ratification of the appointment of PwC as the independent registered public accounting firm for fiscal year ending December 31, 2013.

C. NON-BINDING ADVISORY VOTE OF THE STOCKHOLDERS ON THE COMPENSATION OF OUR NAMED EXECUTIVE OFFICERS

(Item 3 on Proxy Card)

The Company is providing its stockholders with the opportunity to cast an advisory vote on executive compensation (a "say-on-pay advisory proposal") as described below. The Company believes that it is appropriate to seek the views of stockholders on the design and effectiveness of the Company's executive compensation program.

At our annual meetings of stockholders held in April 2012 and April 2011, a substantial majority of the votes cast on the say-on-pay advisory proposal were voted in favor of the proposal. The Compensation Committee believes this affirms the stockholders' support of our approach to executive compensation.

As described in detail under the heading "Executive Compensation—Compensation Discussion and Analysis," our executive compensation program is designed to provide a competitive compensation package that will enable us to attract and retain highly talented individuals for key positions and promote the accomplishment of our performance objectives. The overarching objective is to provide a conservative, yet secure, base salary, with the opportunity to earn a significantly higher total level of compensation under programs that link executive compensation to Company and individual performance factors.

We are asking our stockholders to indicate their support for our named executive officer compensation as described in this proxy statement. This say-on-pay advisory proposal gives our stockholders the opportunity to express their views on our named executive officers' compensation. This vote is not intended to address any specific item of compensation, but rather the overall compensation of our named executive officers and the philosophy, policies and practices described in this proxy statement pursuant to Item 402 of Regulation S-K, the compensation disclosure rule of the SEC. Accordingly, we will ask our stockholders to vote "FOR" the following resolution at the Annual Meeting of Stockholders:

"RESOLVED, that the Company's stockholders approve, on a non-binding advisory basis, the compensation of the named executive officers, as disclosed in the Company's Proxy Statement for the 2013 Annual Meeting of Stockholders pursuant to Item 402 of Regulation S-K, including the Compensation Discussion and Analysis, the compensation tables and narrative discussion."

The say-on-pay vote is advisory, and therefore not binding on the Company, the Compensation Committee or our Board of Directors. Our Board of Directors and our Compensation Committee value the opinions of our stockholders, including those expressed by their vote on this proposal, and will consider the outcome of this vote when making future decisions with respect to our executive compensation program.

The Board of Directors unanimously recommends a vote "FOR" the approval of the compensation of our named executive officers, as disclosed in this proxy statement pursuant to Item 402 of Regulation S-K.

D. STOCKHOLDER PROPOSAL—EXPANDING ENERGY EFFICIENCY
(Item 4 on Proxy Card)

Empire has been notified that a stockholder or his representative intends to present the following proposal for consideration at the 2013 Annual Meeting. The stockholder making this proposal has presented the proposal and supporting statement below, and we are presenting the proposal as it was submitted to us. The name, address and share ownership of the stockholder will be furnished upon oral or written request.

The Board of Directors recommends that stockholders vote AGAINST this proposal for the reasons noted in Empire's opposition statement following the stockholder's proposal.

Stockholder Proposal:

EXPANDING ENERGY EFFICIENCY

WHEREAS:

Navigant Consulting recently observed that, "the changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history."

In 2008 the Brattle Group projected that the U.S. electric utility industry would need to invest capital at historic levels between 2010 and 2030 to replace aging infrastructure, deploy new technologies, and meet future consumer needs and government policy requirements. In all, Brattle predicted that total industry-wide capital expenditures from 2010 to 2030 would amount to between $1.5 trillion and $2.0 trillion.

In May 2011 a National Academy of Sciences report warned that the risk of dangerous climate change impacts is growing with every ton of greenhouse gases emitted into the atmosphere. The report also emphasized that, "the sooner that serious efforts to reduce greenhouse gas emissions proceed, the lower the risks posed by climate change, and the less pressure there will be to make larger, more rapid, and potentially more expensive reductions later."

The Tennessee Valley Authority's ("TVA") 2011 integrated resource plan, which employed a sophisticated approach to risk management determined that the lowest-cost, lowest-risk strategies were the ones that diversified TVA's resource portfolio by increasing investments in energy efficiency and renewable energy.

In October 2012 the American Council for an Energy Efficient Economy released a report ranking Missouri 43rd among all states in terms of energy efficiency performance.

A 2009 study by McKinsey & Company found that investments in energy efficiency could realistically cut U.S. energy consumption by 23% by 2020. These efficiency gains could save consumers nearly $700 billion.

In 2009 the Missouri General Assembly passed the Missouri Energy Efficiency Investment Act ("MEEIA"). In 2010 the Missouri Public Service Commission ("PSC") interpreted MEEIA and issued final rules that remove financial disincentives for regulated utilities to invest in energy efficiency. The rules allow utilities to recover costs of efficiency investments and resulting lost margins.

In 2012 both Ameren Missouri and Kansas City Power and Light Greater Missouri Operations received approval from the PSC for efficiency programs within the MEEIA framework, investing respectively $145 million and $40 million in efficiency demand side mechanisms over the next three years.

In 2012 Ceres issued a report identifying efficiency as the least cost and least risk energy resource.

The Empire District Electric Company has not disclosed in SEC Filings or other public communications a significant accounting of investments in demand side energy efficiency.

RESOLVED:

Stockholders request a report [reviewed by a board committee of independent directors] on actions the company is taking or could take to reduce risk throughout its energy portfolio by pursuing all cost effective energy efficiency resources. The report should be provided by September 1, 2013 at a reasonable cost and omit proprietary information.

Opposing Statement

The Board of Directors recommends that stockholders vote AGAINST this proposal.

The Board has considered the proposal that Empire issue a report on actions it is taking or could take to reduce risk throughout its energy portfolio by pursuing all cost effective energy efficiency resources, and believes that the preparation of such a report would not provide additional benefit to Empire or its stockholders. As further discussed below, the Board believes that Empire's publicly available documents (including filings with the SEC, the Missouri Public Service Commission ("MPSC") and other state utility commissions), information available on Empire's website and Empire's upcoming filings with the MPSC and other state utility commissions currently provides (or will provide) stockholders with extensive information that effectively addresses the proponent's proposal.

In particular, Empire's Integrated Resource Plan, filed with the MPSC in September 2010 (the "2010 IRP"), its website and its SEC reports already provide information on Empire's existing programs designed to reduce usage through energy efficiency and demand response. Current programs applicable to our Missouri electric customers (which customers account for approximately 89% of our electric revenues), include:

- Low Income Weatherization and High Efficiency Program,
- Low Income New Home Program,
- Home Performance with ENERGY STAR® Program,
- Residential High Efficiency Central Air Conditioning Program,
- ENERGY STAR® New Homes Program,
- Commercial & Industrial Rebate Program,
- Building Operator Certification Program,
- Interruptible Service Program, and
- Apogee HomeEnergy Suite and the Commercial Energy Suite energy calculators and educational libraries.

Similar programs are available to many of our other electric and gas customers.

In connection with the 2010 IRP and subsequent stipulations and agreements entered into in April 2011 and June 2012 among Empire, the staff of the MPSC, the Office of the Public Counsel, Missouri Department of Natural Resources and other interested parties (the "Energy Efficiency Agreements"), which agreements were approved by the MPSC, Empire agreed to make a filing pursuant to the Missouri Energy Efficiency Investment Act ("MEEIA") and to abide by certain provisions relating to

Empire's existing and potential portfolio of demand-side management ("DSM") programs. The parties to the Energy Efficiency Agreements agreed, among other matters, that Empire would:

- Make a filing with the MPSC requesting approval of identified DSM programs and a demand-side programs investment mechanism pursuant to the MPSC's MEEIA rules (the "MEEIA Filing") within approximately 120 days of Empire's next Integrated Resource Plan filing, which is currently expected to be filed with the MPSC in mid-2013 (the "2013 IRP"). It is anticipated that this MEEIA Filing will include information regarding Empire's new and potentially expanded energy efficiency portfolio and energy efficiency investments.
- Continue its existing DSM portfolio until such time as the MEEIA Filing is approved, rejected or modified by the MPSC.
- Work with a stakeholder advisory group on both new DSM programs and Empire's existing DSM portfolio.
- Complete a DSM market potential study as part of the 2013 IRP (the "DSM Study"), which will assess the various categories of electrical energy efficiency and demand response potential in the residential, commercial and industrial sectors for Empire's Missouri service area.
- Implement and/or consider implementing new DSM programs pending the 2013 IRP analysis and the MEEIA Filing.

The parties to the Energy Efficiency Agreements agreed that setting the timing of the MEEIA Filing as noted above will afford Empire the opportunity to complete its DSM Study and use the results of the DSM Study to provide for a comprehensive 2013 IRP filing and then a comprehensive MEEIA Filing. In connection with the preparation of its 2013 IRP filing, Empire has conducted and is continuing to conduct an integrated resource plan survey of its customers in order to understand what issues are most important to its customers. The 2013 IRP filing will include (1) information on Empire's current plans for meeting consumer needs while also balancing reliability, uncertainty, affordable cost, state and federal energy policies (e.g., energy efficiency and renewable standards) and environmental pressures, (2) a robust evaluation of Empire's various types of generation and identifiable risks, including natural gas and coal prices, environmental regulations, and construction costs, to most efficiently and cost effectively meet our customers' demand and energy requirements and (3) information on Empire's proposed DSM programs. The 2013 IRP and the MEEIA Filing will both be publicly available once they are filed. In addition, a summary of the 2013 IRP will be posted on Empire's website and all new DSM programs will be listed on Empire's website once adopted.

The Board believes that the analysis being conducted in preparation for the 2013 IRP filing and the MEEIA Filing, in conjunction with our normal planning process, provides us with a thorough and balanced approach to developing our energy portfolio and evaluating a variety of resources and programs, including DSM programs. While Empire and the Board are committed to maintaining and expanding Empire's DSM programs to the extent that it best matches the needs of its customers, the Board believes that preparing a static report, in addition to Empire's SEC reports, the DSM Study, the 2013 IRP Filing and the MEEIA Filing, would not provide additional benefit to Empire or its stockholders.

The Board of Directors recommends that stockholders vote AGAINST this proposal.

3. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Stock Ownership of Directors and Officers

The following table shows information with respect to the number of shares of our common stock beneficially owned as of February 25, 2013 by each of our executive officers named in the Summary Compensation Table, each Director, each Director nominee and our Directors and executive officers as a group.

Name	Position	Shares of Common Stock Beneficially Owned(1)
D. Randy Laney	Director, Chairman of the Board	17,912
Kenneth R. Allen	Director	12,488
William L. Gipson(2)	Director	77,549
Ross C. Hartley(3)	Director	45,872
Bonnie C. Lind	Director	500
B. Thomas Mueller	Director	10,073
Thomas M. Ohlmacher	Director	3,178
Paul R. Portney	Director	5,366
Herbert J. Schmidt	Director	2,500
C. James Sullivan	Director	7,845
Bradley P. Beecher(2)	President and Chief Executive Officer and Director	35,604
Laurie A. Delano	Vice President—Finance and Chief Financial Officer	6,214
Ronald F. Gatz(2)	Vice President and Chief Operating Officer—Gas	40,982
Michael E. Palmer(2)	Vice President—Transmission Policy and Corporate Services	31,082
Kelly S. Walters(2)	Vice President and Chief Operating Officer—Electric	13,929
Directors and named executive officers, as a group		311,094

(1) No Director or executive officer owns more than 0.5% of the outstanding shares of our common stock and all Directors and executive officers as a group own less than 1% of the outstanding shares of our common stock.

(2) Includes 48,200, 15,500, 21,800, 13,500 and 5,600 shares, respectively, issuable upon the exercise of currently exercisable stock options for Mr. Gipson, Mr. Beecher, Mr. Gatz, Mr. Palmer, and Ms. Walters.

(3) Includes 2,314 shares for which Mr. Hartley holds a power of attorney for a non-resident relative.

Other Stock Ownership

The following table reflects the holdings of those known to us to own beneficially more than 5% of our common stock as of February 25, 2013.

Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
BlackRock, Inc. .... 40 East 52nd Street New York, NY 10022	2,355,039(1)	5.55%
The Vanguard Group .... 100 Vanguard Boulevard Malvern, PA 19355	2,398,780(2)	5.65%

(1) Based on a Schedule 13G/A dated February 8, 2013, filed with the Securities and Exchange Commission by BlackRock, Inc. BlackRock, Inc. has sole voting and dispositive power with respect to 2,355,039 shares.

(2) Based on a Schedule 13G dated February 12, 2013, filed with the Securities and Exchange Commission by The Vanguard Group. The Vanguard Group has sole voting power with respect to 77,774 shares, sole dispositive power with respect to 2,337,906 shares and shared dispositive power with respect to 60,874 shares. Vanguard Fiduciary Trust Company, a wholly-owned subsidiary of The Vanguard Group, Inc., is the beneficial owner of 60,874 shares or 0.14% of the Common Stock outstanding of the Company as a result of its serving as investment manager of collective trust accounts. Vanguard Investments Australia, Ltd., a wholly-owned subsidiary of The Vanguard Group, Inc., is the beneficial owner of 16,900 shares or 0.04% of the Common Stock outstanding of the Company as a result of its serving as investment manager of Australian investment offerings.

4. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Executive Summary

The compensation program for executive officers is designed to provide a conservative yet competitive compensation package that will enable us to attract and retain highly talented individuals for key positions, promote the accomplishment of our performance objectives, and achieve Company results beneficial to our stockholders, customers and other stakeholders. The program is administered by our Compensation Committee ("Committee") which is composed entirely of non-employee, independent directors who are appointed by and serve at the sole discretion of the Board of Directors. The overarching objective of the Committee is to provide a conservative, yet secure, base salary, with the opportunity to earn a significantly higher total level of compensation under cash and equity incentive opportunities that link executive compensation to Company and individual performance factors.

In order to align the Company's executive compensation program with the interests of our stockholders, a significant portion of each executive's total compensation opportunity is presented in the form of equity compensation. In addition, equity and other at-risk elements of compensation are tied to both short-term and long-term performance measures. In essence, at-risk compensation must be "re-earned" annually.

The Committee is assisted in accomplishing its responsibilities by an independent compensation consultant ("Consultant"). The Committee is directly responsible for the appointment, compensation and oversight of the work of the Consultant. The Consultant does not perform other services for us outside of its engagement with the Committee, but may interact directly with the President and CEO, our legal counsel and/or other Company personnel for the purpose of obtaining executive officer compensation and performance data to be used in its review and analysis. The Committee retains all decision-making and approval authority with regard to determining executive compensation levels.

The Committee structures the executive compensation program to motivate executives to achieve specified business goals and to reward the achievement of those goals. Compensation decisions made by the Committee are based on market analysis, Company performance, achievement of individual performance objectives, the level and nature of the executive's responsibilities and the level of experience in his or her position.

Our compensation program includes three basic compensation elements:

- Base Salary
- Annual Cash Incentives
- Long-Term Stock Incentives

Base Salary combined with Annual Cash Incentives make up Total Cash Compensation. Total Cash Compensation combined with Long-Term Incentives make up Total Direct Compensation. Each of these compensation elements is discussed more fully below.

By design, Base Salary is set significantly lower than the median Base Salary of the national market (our former benchmark) and our industry-specific peer group (our current benchmark). Annual Cash Incentive and Long-Term Incentive targets are set at fixed percentages of Base Salary. These incentive compensation elements provide each executive the potential to earn higher levels of Total Direct Compensation depending on Company and individual performance.

The Committee believes the compensation approach discussed above appropriately balances stockholder, customer and other stakeholder interests and is a responsible approach to executive compensation. It includes the following features:

- Short-term incentive compensation focused on tactical near-term objectives that support the Company's longer-term goals,
- Limitations on potential incentive compensation awards equal to 200% of target opportunity,
- Long-term performance-based stock awards linked to stockholder returns over a three-year period,
- Time-vested stock awards designed to promote a proper focus on the creation of stockholder value,
- Participation in the same health and welfare benefits and qualified pension plan offered to all our full-time employees, and
- A traditional supplemental retirement plan that only covers compensation not included in the qualified pension plan due solely to tax limitations.

In addition, the executive compensation approach includes the following provisions:

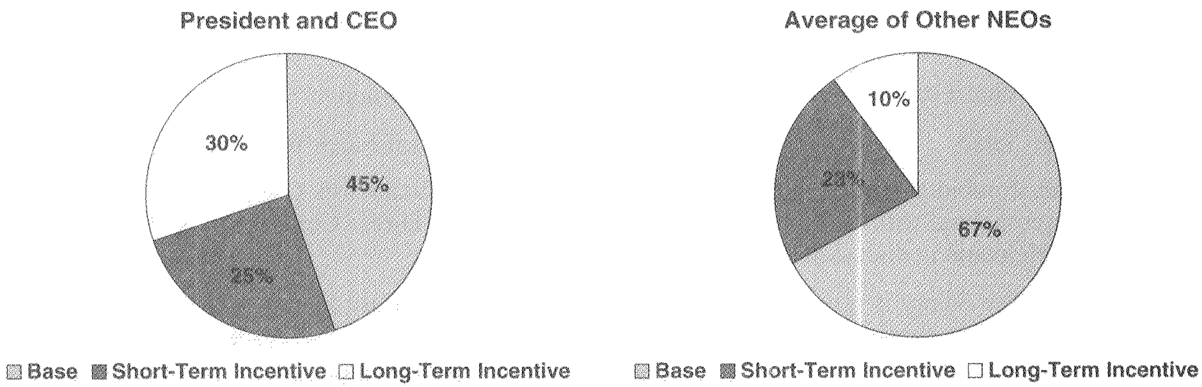
- A Change In Control Severance Pay Plan ("Severance") that includes a "double-trigger" (requiring a change in control and termination of employment) and a reasonable payment equal to 36 months of severance pay benefits (see discussion under "—Potential Payments upon Termination and Change in Control"),
- A provision that non-vested equity awards do not accelerate after a change in control unless the executive is terminated, and

• No employment agreements or guaranteed compensation arrangements between the Company and the executive officers other than the severance agreement.

Analysis of Executive Officer Compensation

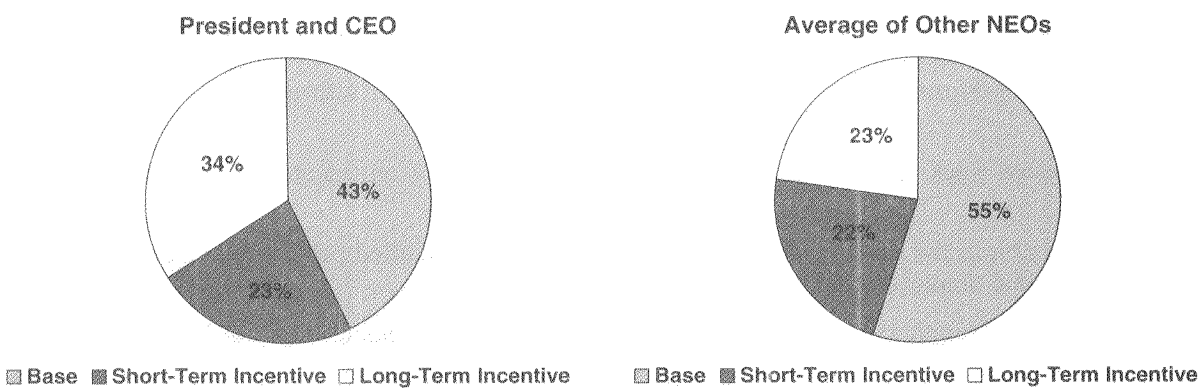
The Committee believes the 2012 mix of compensation elements (based on target-level incentive opportunities) available to our President and Chief Executive Officer ("CEO") and all other Named Executive Officers ("NEOs") as illustrated below reflects our commitment to an executive compensation program that rewards individuals for performance.

2012 Compensation Mix



Beginning in 2013, the Committee has elected to make modifications to executive officer base salaries and the mix of compensation elements, placing more compensation in the form of incentive compensation. Each of these modifications is discussed more fully below. The 2013 mix of compensation elements (based on target-level incentive opportunities) following the implementation of these changes is illustrated below.

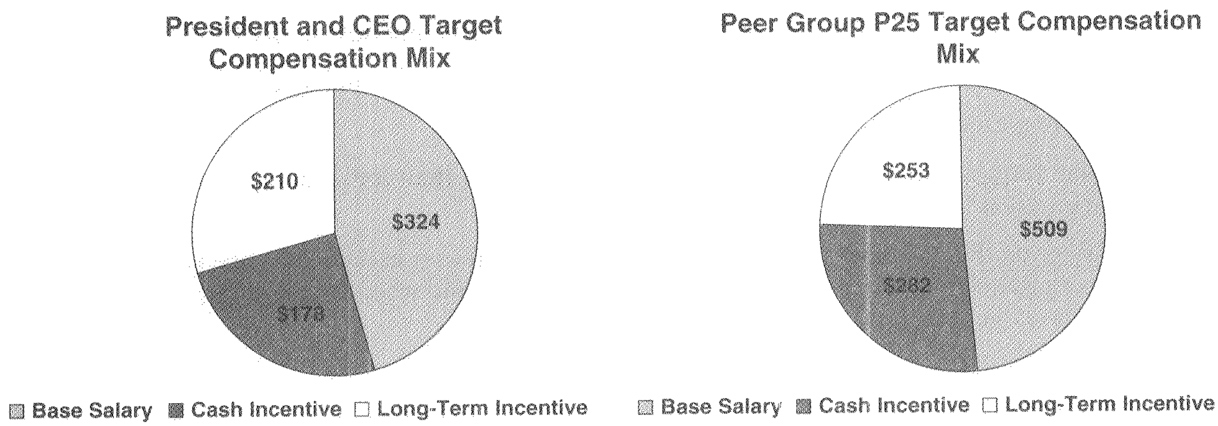
2013 Compensation Mix



The Committee believes this modification strengthens the relationship between pay and performance, as a larger portion of each executive officer's Total Direct Compensation has been placed in the form of at-risk short-term and long-term incentive compensation.

With respect to the 2012 compensation of Mr. Bradley P. Beecher, our President and Chief Executive Officer, approximately 55% of his total target direct compensation opportunity consisted of at-risk compensation in the form of short-term and long-term incentives. As illustrated below, Mr. Beecher's total 2012 target direct compensation opportunity was conservative when compared to the 25th percentile compensation opportunities of our industry-specific peer group of companies. Moreover, the Consultant has informed the Committee that the 2012 Total Direct Compensation opportunity of each of the CEOs included in our industry-specific peer group, at target performance levels, was greater than that of Mr. Beecher.

2012 Compensation Mix



When establishing Mr. Beecher's compensation, the Committee considers the actuarially-estimated change in pension value reported under the "—Change in Pension Value and Nonqualified Deferred Compensation Earnings" column in the Summary Compensation Table of our Proxy Statements. The Committee believes that the estimated change in pension value does not represent current compensation paid to Mr. Beecher for his service as President and CEO, as Mr. Beecher's pension benefits are not realizable until the time of his retirement. In calculating Mr. Beecher's future pension benefits, his total years of service with our Company are included in our benefit formula, rather than only those years he has served as our President and CEO. Additionally, the estimated change in Mr. Beecher's pension value is based on a life expectancy of 83 years. The table below shows Mr. Beecher's total compensation as reported in our Summary Compensation Tables since his election to the position of President and CEO in 2011, the annual amounts of estimated change in pension value included in his total compensation since and including his year of election, and the amount of his compensation that excludes the change in his estimated pension value.

Year	Total Compensation Reported on Summary Compensation Table	Change in Pension Value Reported on Summary Compensation Table	Total Compensation Excluding Change in Pension Value
2012	$927,089	$252,290	$674,799
2011	$683,706	$277,308	$406,398

The Committee believes the Total Compensation Excluding Change in Pension Value is more representative of the actual compensation value Mr. Beecher received for his service as President and CEO during each year of service. This same assessment regarding actuarially-estimated change in pension value and the realization of pension benefits is applicable to each NEO.

The Role of the Compensation Committee

The Compensation Committee ("Committee"), on behalf of the Board of Directors, administers our director and executive compensation programs. The Committee meets at scheduled times during the year and on an as-needed basis. The duties and responsibilities of the Committee are described in its charter (which has been approved by the full Board of Directors) and include:

- Assisting the Board of Directors in establishing and overseeing director and executive officer compensation policies and practices,
- Hiring, terminating and directing the activities of the independent compensation consultant,
- Reviewing and analyzing general industry and peer group compensation data,
- Reviewing and approving executive officer goals, objectives and compensation levels,
- Evaluating executive officer performance,
- Making recommendations to the Board of Directors as to the form and amount of director compensation levels, and
- Considering the outcome of the stockholder advisory votes on executive compensation when evaluating executive compensation policies and practices and when making future executive compensation decisions.

The Role of the President and CEO

The President and CEO attends Committee meetings, including the meeting where the Committee deliberates base salary changes and annual incentive metrics and performance measures for executive officers. His role at these meetings includes:

- Reviewing the performance of each executive officer against position accountabilities and Annual Incentive Plans ("AIP") metrics and performance measures, and recommending AIP awards for the just-ended fiscal year for each executive officer,
- Making base salary adjustment recommendations for the ensuing performance year for each executive officer,
- Reviewing and recommending AIP metrics and performance measures for the ensuing fiscal year, and
- Responding to questions Committee members may have regarding base salary levels and AIP metrics, performance measures and awards.

The President and CEO does not directly participate in the deliberations of the Committee and he is not present during nor does he take part in any way in the Committee's deliberations with respect to establishing his compensation.

The Role of the Consultant

During 2012, the Committee directly engaged Hay Group, an independent compensation consulting firm (the "Consultant"). Work performed for the Committee by the Consultant during 2012 included:

- Analysis of leading practices and trends in the utility industry,
- Analysis of the relative positioning of each of our executive officer positions to similar positions within its proprietary national market database,
- Review and evaluation of our compensation program and compensation levels as compared to compensation practices of other companies with similar characteristics, including size and type of business (see discussion of industry-specific peer group under "—Benchmarking"),
- Recommendation of appropriate industry-specific peer group of companies,

- Performing calculations necessary to determine recommendations for performance-based equity awards, and
- Recommending the structure of the executive compensation program relative to the results of its analysis of national market and industry-specific peer group companies.

The Consultant's 2012 review will serve as the basis for compensation decisions beginning in 2013 and continue until such time that the Committee engages an independent consultant to perform a subsequent review. The most recent executive compensation review prior to the 2012 review was performed by the same Consultant in 2010. The work performed by the Consultant during its 2010 review was substantially similar to the work performed during its 2012 review. The 2010 review served as the basis for compensation decisions related to 2012 performance.

The Role of Stockholder Say-on-Pay Advisory Votes

We provide our stockholders with the opportunity to cast an annual advisory vote on executive compensation (a "say-on-pay advisory proposal" as described under Section 2, "—MATTERS TO BE CONSIDERED AT THE ANNUAL MEETING"). At our annual meeting of stockholders held in April 2012, a substantial majority of the votes cast on the say-on-pay advisory proposal at that meeting were voted in favor of the proposal. The Committee believes this affirms stockholders' support of our approach to executive compensation.

Compensation Philosophy

The Committee sets target compensation levels in a manner designed to:

- Be competitive and permit us to attract and retain executive talent,
- Be conservative with respect to our peer group and, prior to 2013, the national market, and
- Provide incentive for executives to achieve individual and company performance goals.

During 2012, the Committee utilized a compensation philosophy that targeted a certain level for each element of executive pay based on the results of a 2009 national market survey developed by the Consultant. This survey is discussed in more detail below under "Benchmarking". During 2012, Base Salary was targeted within a range surrounding the mid-point between the 25th and 50th percentiles of the 2009 national market survey. The Committee believes the use of a range is appropriate to recognize the level of experience each executive may have in the position he or she holds. If an executive's Base Salary was established at the mid-point described above, then Total Cash Compensation and Total Direct Compensation was also targeted to approximate the mid-point between the 25th and 50th percentiles of the same national market survey. However, as we will discuss below, these two elements of compensation are expressed as percentages of Base Salary. Therefore, the relative positioning of each executive's target Total Cash Compensation and Total Direct Compensation opportunity with respect to the mid-point between the 25th and 50th percentiles of the national market survey was affected by their positioning within the Base Salary range discussed above.

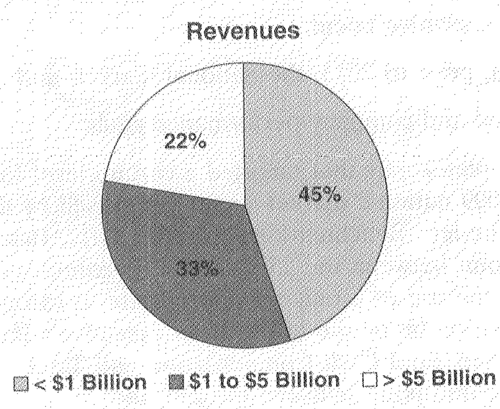
During the 2010 review, the Consultant also found that the most prevalent approach used to deliver long-term incentive compensation to executives in the utility industry, and in particular to executives of our peer group of companies discussed below, was a combination of performance shares and time-vested restricted stock. Effective January 1, 2011, as a result of these findings, the Committee elected to replace the stock option and dividend equivalent portions of the Long-Term Incentive element of the executive compensation program with time-vested restricted stock awards.

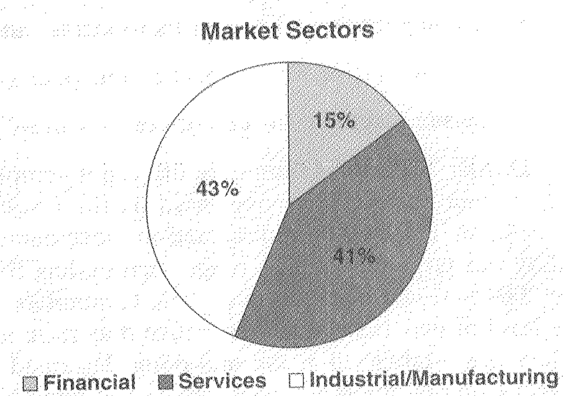
Beginning in 2013, the Committee has modified its compensation philosophy described above to target the 25th percentile levels of the industry-specific peer group of companies (see "—Benchmarking" below) for Base Salary, Total Cash Compensation and Total Direct Compensation, while continuing to maintain a range concept to recognize differing levels of experience. The Committee believes the comparison to compensation levels of similar peer group positions is more reflective of our executive officer's roles and responsibilities and is therefore more appropriate than the most recently utilized comparison to the national market survey.

Benchmarking

As noted above, during 2012 the Committee set the benchmarks (i.e., the 25th percentile, the 50th percentile and the midpoint between the 25th and 50th percentiles) based on a 2009 national market survey developed by the Consultant. Once these levels were set, the Committee compared the values resulting from this benchmarking process to the corresponding compensation levels at an industry-specific peer group of companies also developed by the Consultant. This comparison was done to ensure that total compensation was competitive within the industry and appropriate when certain levels of performance were achieved. If, based on this comparison, the Committee determined that the levels set through the benchmarking process were not competitive or were not appropriate, the Committee may have adjusted the applicable compensation levels and targets accordingly. This comparison was a contributing factor in the Committee's decision to modify its compensation philosophy beginning in 2013 to both reduce the targets to the 25th percentile levels and to change the benchmark to that of the industry-specific peer group of companies.

At the time the last executive compensation review was performed in 2010, the Consultant informed us that the national market survey discussed above contained information on thousands of executives from over 1,400 parent organizations and independent operating units across all industry sectors. Characteristics of participating organizations included:





In addition, approximately 57% of the organizations participating in the survey had less than 5,000 employees, while approximately 30% had more than 10,000 employees. Included within the industrial/ manufacturing sector were 48 utility companies and 83 general manufacturing companies. The Committee relied on the Consultant to conduct its own research, compile its own survey data and provide a summarization of such data relevant to the Committee's decisions with respect to setting compensation levels. Hence, the Committee did not review the names of the participating survey companies prior to making compensation decisions. However, the names of the parent companies that participated in the national market survey most recently utilized by the Consultant in work performed for the Committee are attached hereto as Appendix A.

During 2012 the industry-specific peer group of companies that was recommended by the Consultant and adopted by the Committee represented publicly traded electric or electric and gas utilities that were comparable to Empire in terms of sales, market value, growth, etc. The 2012 peer group consisted of:

Black Hills Corporation	El Paso Electric Company	Otter Tail Corporation
Central Vermont Public Service	Idacorp Inc.	South Jersey Industries, Inc.
CH Energy Group, Inc.	The LaClede Group	UIL Holdings Corporation
Chesapeake Utilities Corporation	MGE Energy Inc.	Unisource Energy Corporation
Cleco Corporation	NorthWestern Corporation	Unitil Corporation

Beginning in 2013, the Consultant recommended, and the Committee has adopted, a revised set of industry-specific peer companies that represent publicly traded electric, gas, combined electric and gas, and water utilities comparable to Empire in terms of sales, market value, growth characteristics, and assets. The 2013 peer group of companies consists of:

ALLETE, Inc.	Cleco Corporation	NorthWestern Corporation
American States Water Company	El Paso Electric Company	Otter Tail Corporation
Aqua America, Inc.	IDACORP, Inc.	South Jersey Industries, Inc.
Black Hills Corporation	MGE Energy, Inc.	Unitil Corporation
California Water Services Group	Northwest Natural Gas Company	UNS Energy Corporation
Chesapeake Utilities		

As described above under "—Compensation Philosophy", 2013 compensation benchmarks will be set based on the 25th percentile of the revised industry-specific peer group of companies.

An essential part of the benchmarking process involves the Consultant's use of a systematic approach to evaluate the duties and responsibilities of our executive positions. This approach recognizes the practical reality that job responsibilities of persons with similar titles may vary significantly from company to company, and that a person's title is not necessarily descriptive of a person's duties. In its evaluation, the Consultant considered the scope and complexity of incumbent positions and compared those positions to the scope and complexity of our executive positions. The result was an assessment of the relative position of the compensation being paid to our executives in light of the compensation being paid to persons performing duties of similar scope and complexity. The Committee used this assessment to assist it in making decisions regarding appropriate compensation levels for our executive positions. The underlying principle of the evaluation methodology is to focus on identifying those positions that have a scope and complexity of responsibilities that are comparable to those duties exercised by each of our particular executives.

Base Salary

The Consultant makes base salary target recommendations to the Committee for each position with consideration given to our compensation philosophy. Base salary targets are reviewed periodically as described above to ensure our executive positions are comparable with the marketplace in terms of expertise, scope and accountability.

At the beginning of the fiscal year, the President and CEO reviewed executive officer performance with, and made Base Salary recommendations to, the Committee for all executive officers other than himself. Based upon his review and recommendations, and with consideration given to market information provided by the Consultant, the Committee set the Base Salary of each such executive officer for the fiscal year. The Committee independently appraised the performance of the President and CEO, and set his Base Salary accordingly. The Committee will determine any Base Salary adjustments necessary throughout the year should material changes in office or responsibilities occur.

As mentioned above, the Committee has modified its compensation philosophy beginning in 2013 to target the 25th percentile levels of the industry-specific peer group of companies, including the 25th percentile of Base Salary. The 25th percentile Base Salary of the President and CEO position of the industry-specific peer group determined by the Consultant in its 2012 review was $509,000. In order to begin the transition of Mr. Beecher's Base Salary to this 25th percentile level, the Committee set his 2013 Base Salary at $459,000. Similarly, the Committee set 2013 base salaries for each of the other NEOs as follows: Ms. Delano, $261,000; Mr. Gatz, $250,000; Mr. Palmer, $225,000; and Ms. Walters, $266,000.

Annual Cash Incentives

2012

During 2012, the Annual Cash Incentive portion of Total Cash Compensation was derived from individual Annual Incentive Plans ("AIP"), whereby executive officers can earn additional cash compensation based on performance measured against short-term tactical goals that focus on operating conditions and circumstances of a particular year. These tactical goals are developed from and lend support to our long-term vision and goals. Each executive officer provided the President and CEO input on a set of proposed metrics and performance measures for the 2012 fiscal year. One or more performance measures were developed for each metric. Each performance measure was assigned a percentage weighting, summing to 100% in aggregate. The President and CEO evaluated the proposed metrics and performance measures, made any necessary modifications, and presented the proposed annual metrics and performance measures for himself and all other executive officers to the Committee. The Committee reviewed his recommendations for consistency, measurability, and equity relative to individual responsibilities and, together with their assessment of our near-term objectives, made any necessary adjustments to individual AIP before approving.

Once metrics, performance measures and weightings were determined, total target Annual Cash Incentive amounts were calculated for each executive officer with consideration given to the Total Cash Compensation philosophy discussed above. During 2012, for the President and CEO, the Annual Cash Incentive amount available at target levels of performance was equal to 55% of annual base salary, while the amount available for executive officers other than the President and CEO, at target levels of performance, equaled 35% of their annual base salary.

Threshold and maximum performance levels may also be developed for each performance measure. Threshold and maximum amounts are equal to 50% and 200%, respectively, of the target level amount. If an executive does not perform at least at a threshold level of expected performance with regard to any particular individual performance measure, no incentive compensation is awarded with respect to that performance measure. Likewise, no award greater than the maximum award is paid when performance exceeds the maximum level of expected performance required to earn such award.

Each executive officer's AIP performance and indicated payout were reviewed by the President and CEO with the Committee following the conclusion of the fiscal year. The Committee considered his review and recommendations, made any appropriate adjustments and determined the amount of Annual Cash Incentive earned by each executive. The Committee independently appraised the performance of the President and CEO, and determined his incentive award accordingly.

Generally, each executive's AIP will include an Earnings Per Share, Expense Control, and Safety metric. Additional metrics commonly applied to the President and CEO and the Vice President—Finance and CFO relate to Capital Markets and Corporate Governance. Executive officers who have responsibilities over our operational areas have specific operational metrics related to their areas of responsibilities. Examples include Project Completion, Customer Service, Regulatory Performance, and Operations.

Performance measure ranges are generally linked to the threshold, target and maximum performance award levels. For instance, to qualify for the threshold performance award under a performance measure of budgetary control, an executive must operate their responsibility area at no greater than +10% of budgeted expenses. To qualify for the maximum performance award under the same performance measure, an executive must operate their responsibility area at −10% of budgeted expenses. The qualification criteria for other performance measures may be whether the executive accomplished or did not accomplish the measure. Under this criterion, the executive must fully accomplish the measure to qualify for any award. AIP measurements may be either quantitative or qualitative. Measurements considered qualitative are identified as such below.

Metrics developed for the 2012 AIP consisted of:

- *Expense Control.* Measures included control of operating/maintenance, capital and fuel and purchased power expenses.
- *Regulatory Performance/Strategic Initiatives/Southwest Power Pool.* Measures consisted of the planning, developing, and filing of rate proceedings, planning and implementation associated with facilities upgrades and our enterprise application software upgrade (a qualitative measure), compliance with safety and environmental regulations, and our participation in Southwest Power Pool Board and Regional State Committee meetings (a qualitative measure).
- *Earnings Per Share ("EPS")/Capital Markets/Finance/Corporate Governance.* Measures consisted of EPS results, management of our long-term and short-term debt costs, involvement in conferences with rating agencies and institutional investors (a qualitative measure), the identification or lack thereof of material weaknesses in internal control, and other financing activities.
- *Operations/Safety/Communications.* Measures included minimization of employee lost-time incidents, gas segment safety audits conducted by the Missouri Public Service Commission, gas segment residential and non-residential customer growth, and development of an internal management communications plan (a qualitative measure).
- *Customer Service.* Measures included the frequency and duration of customer outages, upgrade of call center software and improvement of call center performance (a qualitative measure), minimization of generating station forced outages, minimization of customer complaints to state public service commissions, and management of certain field operations labor practices.

The target incentive award opportunity for the Expense Control and Finance metrics comprised the most significant portion of the 2012 AIP, encompassing approximately 24% of the overall targeted incentive award opportunity. With continuing economic and operating environment challenges, the need to control expenses was paramount. The executive team managed operating and maintenance expenses, capital expenditures, interest expense, and fuel and purchased power expenses to well under budgeted levels. Target award opportunities for Mr. Beecher, Ms. Delano, Mr. Gatz, Mr. Palmer and Ms. Walters under this metric were 30%, 20%, 20%, 20% and 30% respectively, of their total target incentive award opportunity. Of similar significance to the Expense Control metric, the target incentive award opportunity for the Earnings Per Share ("EPS") results metric, which was a new metric during the 2012 performance year, accounted for 20% of each executive officer's total target incentive award opportunity, and therefore 20% of the overall targeted incentive award opportunity. Performance against quantitative measures under these two metrics was evaluated as follows:

	Performance Measures	Threshold Performance	Target Performance(1) (in thousands, except $/mwh and EPS amounts)	Maximum Performance	Actual Performance Relative to Target	Award Amount
Mr. Beecher . . .	O & M Expense	Target +10%	$ 137,756	Target −10%	Minus 0.15%	$18,078
	Total Capital Expenditures	Target +10%	$ 148,379	Target −10%	Minus 2.6%	$22,441
	Fuel & Purchased Power Expense(2)	Target +10%	$ 32.89	Target −10%	Minus 9.3%	$34,374
	Earnings Per Share	$1.00	$1.23 - $1.37	Above Range	$1.32	$35,621
Ms. Delano . . .	O & M Expense	Target +10%	$ 10,309	Target −10%	Minus 1.5%	$ 7,151
	Interest Expense(3)	Target +5%	$ 43,746	Target −5%	Minus 5.2%	$12,437
	Earnings Per Share	$1.00	$1.23 - $1.37	Above Range	$1.32	$12,437
Mr. Gatz	O & M Expense	Target +10%	$ 9,441	Target −10%	Minus 2.6%	$ 8,630
	Capital Expenditures	Target +10%	$ 3,929	Target −10%	Minus 16.7%	$13,699
	Earnings Per Share	$1.00	$1.23 - $1.37	Above Range	$1.32	$13,699
Mr. Palmer . . .	O & M Expense	Target +10%	$ 8,455	Target −10%	Minus 10.7%	$14,240
	Capital Expenditures	Target +10%	$ 19,003	Target −10%	Minus 2.6%	$ 8,971
	Earnings Per Share	$1.00	$1.23 - $1.37	Above Range	$1.32	$14,240
Ms. Walters . . .	O & M Expense	Target +10%	$ 82,754	Target −10%	Plus 0.4%	$ 8,154
	Capital Expenditures	Target +10%	$ 151,011	Target −10%	Minus 3.0%	$11,041
	Fuel & Purchased Power Expense(2)	Target +10%	$ 32.89	Target −10%	Minus 9.3%	$16,392
	Earnings Per Share	$1.00	$1.23 - $1.37	Above Range	$1.32	$16,987

(1) Target Performance values for the O & M Expense and Capital Expenditures Performance Measures may vary for each Named Executive Officer as such measures are related to each Named Executive Officer's area of responsibility.

(2) Expressed as dollars per megawatt hour net system input, with demand charges.

(3) No incentive amount is payable if at any time during the applicable year our bank line of credit limit is exceeded.

The cumulative target incentive award opportunity for the remaining performance metrics discussed below encompassed approximately 56% of the overall target incentive award opportunity. Under these performance metrics, Mr. Beecher, Ms. Delano, Mr. Gatz, Mr. Palmer and Ms. Walters earned incentive awards of $110,245, $54,970, $47,022, $55,821, and $60,303, respectively. These metrics are related primarily to qualitative measures, but also include some less significant quantitative measures. The Committee evaluated 2012 performance against these measures as generally near target level.

The Customer Service and Operations/Safety metrics comprised approximately 23% of the overall targeted incentive award opportunity. A stated goal of the Company is to effectively meet our customer's expectations. Reliability of our electric and gas distribution system, generating stations, and communication services is essential in meeting this goal. These assets performed at or above expectations during the year. Additionally, executive management guided the workforce in reaching nearly one million hours of work (on a man hours worked basis) without a lost-time injury. It was the Committee's evaluation that the executive team managed overall electric and gas distribution systems, generating station, and customer communication services availability and operations effectively, efficiently and safely.

The Regulatory Performance, Strategic Initiatives and Southwest Power Pool metrics comprised approximately 22% of the overall targeted incentive award opportunity. Executive management is strongly committed to maintaining ongoing compliance with safety, environmental, and other regulatory requirements. Our stated goals include providing a safe and positive work experience for our employees and acting as responsible stewards of the environment. The executive management team provided effective leadership in accomplishing a year that included zero safety and environmental citations or notices of violation.

The Capital Markets, Corporate Governance and Communications metrics comprised approximately 11% of the overall targeted incentive award opportunity. The Capital Markets/Finance metric was applicable to Mr. Beecher and Ms. Delano. The Corporate Governance metric was applicable to Ms. Delano. The Communications metric was applicable to Ms. Walters.

The table below indicates the amount and percentage of each Named Executive Officer's 2012 target and actual incentive award for each applicable metric discussed above (on a dollar basis and as a percentage of total target opportunity).

	Expense Control/ EPS/Finance Dollars (% of Total Target Award Opportunity)(1)	Customer Service/ Operations/Safety Dollars (% of Total Target Award Opportunity)(1)	Regulatory Performance/ Strategic Initiatives/ Southwest Power Pool Dollars (% of Total Target Award Opportunity)(1)	Capital Markets/ Corporate Governance Communications Dollars (% of Total Target Award Opportunity)(1)	Total Dollars (% of Total Target Award Opportunity)
Mr. Beecher					
Target Award	$ 89,051 (50)%	$35,620 (20)%	$35,620 (20)%	$17,810 (10)%	$178,101 (100)%
Actual Award . . .	$110,514 (62)%	$52,362 (30)%	$35,620 (20)%	$22,263 (13)%	$220,759 (124)%
Ms. Delano					
Target Award	$ 24,875 (40)%	$ 3,109 (5)%	$ 9,328 (15)%	$24,876 (40)%	$ 62,188 (100)%
Actual Award . . .	$ 32,025 (51)%	$ 5,223 (8)%	$18,655 (30)%	$31,092 (50)%	$ 86,995 (139)%
Mr. Gatz					
Target Award	$ 27,398 (40)%	$41,100 (60)%	N/A	N/A	$ 68,498 (100)%
Actual Award . . .	$ 36,028 (53)%	$47,022 (69)%	N/A	N/A	$ 83,050 (122)%
Mr. Palmer					
Target Award	$ 28,480 (40)%	$ 3,560 (5)%	$39,160 (55)%	N/A	$ 71,200 (100)%
Actual Award . . .	$ 37,451 (53)%	$ 5,981 (8)%	$49,840 (70)%	N/A	$ 93,272 (131)%
Ms. Walters					
Target Award	$ 42,466 (50)%	$21,234 (25)%	$16,987 (20)%	$ 4,247 (5)%	$ 84,934 (100)%
Actual Award . . .	$ 52,574 (62)%	$34,823 (41)%	$16,987 (20)%	$ 8,493 (10)%	$112,877 (133)%

(1) "N/A" indicates metric(s) were Not Applicable to the Named Executive Officer during 2012.

No single performance measure is material to the compensation program overall; for example, the average NEO target opportunity per performance measure in the 2012 AIP was $10,107. Since the adoption of the current form of the Executive Officer AIP in 2001, the average Annual Cash Incentive award for all executive officers, including the President and CEO and the 2011 award that was earned but not paid, but excluding executive officers who have since retired, was approximately 119% of the target opportunity amounts.

2013

Beginning in 2013, in order to provide the opportunity to achieve the 25th percentile level of peer group Total Cash Compensation, the Committee has modified the Annual Cash Incentive amount available at target levels of performance for the Vice-President and Chief Operating Officer—Electric, the Vice President and Chief Operating Officer—Gas, and the Vice President and Chief Financial Officer to represent 40% of their annual base salary (compared to 35% in 2012). Annual Cash Incentive amounts available at target levels of performance for the other NEOs remained unchanged compared to 2012.

Additionally, the Committee has structured the 2013 AIP to include a common Corporate Performance Metric and related performance measures that, at target-level performance, is equal to

50% of the Annual Cash Incentive opportunity available to each executive officer (or 60% of the President and CEO's Annual Cash Incentive opportunity). This new performance metric, which is a combination of several performance metrics used in 2012, is driven from our overall corporate goals and features the following performance measures:

Corporate Performance Metric

Performance Measures	Weighting(1)	Threshold 50%	Target 100%	Maximum 200%
Earnings Per Share(1)	20%	$1.00	$1.26 - $1.43	> $1.43
Corporate Level Expense Control				
Capital Expenditures	10%	Budget +10%	At Budget	Budget −10%
Operating and Maintenance Expense	10%	Budget +5%	At Budget	Budget −5%
Safety Performance				
DART Rate(2)	5%	2.95	2.35	2.10
Man hours worked no lost time	5%	300,000	500,000	1,000,000

(1) Mr. Beecher's Earnings Per Share performance measure is weighted at 30% of his total target Annual Cash Incentive opportunity, therefore his total Corporate Performance Metric is equal to 60% of his Annual Cash Incentive opportunity.

(2) Days Away from work, Restricted work activity, or job Transfer.

In addition to the Corporate Performance Metric, 20% of Mr. Beecher's Annual Cash Incentive opportunity reflects total Company-level operational metrics and performance measures as illustrated below.

Mr. Beecher

Metric Performance Measures	Weighting	Threshold 50%	Target 100%	Maximum 200%
Expense Control				
Fuel and Purchased Power Expenses	10%	Budget +10%	At Budget	Budget −10%
Capital Markets/Governance				
Rating Agency Interaction	5%	Present once to Each Agency	Threshold + present to 1 agency 2 times	Present to Each Agency 2 Times
Institutional Investors Interactions	5%	5	10	15

Similarly, (40%) of the Annual Cash Incentive opportunity for each other NEO reflects specific operational metrics related to their areas of responsibility. These metrics and associated performance measures are illustrated below.

Ms. Delano

Metric Performance Measures	Weighting	Threshold 50%	Target 100%	Maximum 200%
Operational Area Expense Control				
Operating and Maintenance Expenses	10%	Budget +10%	At Budget	Budget −10%
Capital Markets/Governance				
Rating Agency Interactions	5%	Present once to Each Agency	Threshold + present to 1 agency 2 times	Present to Each Agency 2 Times
Institutional Investors Interactions	5%	5	10	15
Investor Relations	10%	Plan Development	Plan Dev/Updated	Target +5 Contacts
Analyst Coverage	10%	Current Coverage	Threshold + 1	Threshold + 2

Mr. Gatz

Metric Performance Measures	Weighting	Threshold 50%	Target 100%	Maximum 200%
Operational Area Expense Control				
Capital Expenditures	10%	Budget +10%	At Budget	Budget −10%
Operating and Maintenance Expenses	10%	Budget +10%	At Budget	Budget −10%
Operations				
Annual Missouri Public Service Commission (MPSC) Safety Audits	5%	No Material Probable Violations (PV) + >50% No Material Areas of Concern (AC)	No Material PVs + >75% No Material ACs	No Material PVs +100% No Material ACs
Residential Customer Growth	10%	−0.50%	0.00%	0.50%
MPSC Non-Payment Related Commission Complaints (CC)	5%	CCs >=25	Non-Payment Related CCs =15	CCs <=5

Metric Performance Measures	Weighting	Threshold 50%	Target 100%	Maximum 200%
Operational Area Expense Control				
Purchasing Capital Expenditures	6%	Budget +10%	At Budget	Budget −10%
Operating and Maintenance Expenses	10%	Budget +10%	At Budget	Budget −10%
Operations				
North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection Audit Performance	6%	Develop Action Plan to Mitigate Audit Findings	Plan to Mitigate Potential Alleged Violations (PAV) + No Material NERC Action Expected	No Violations/ PAV/ Penalties
Cyber/Physical Security Plan	6%	Establish Team, Develop Recommendations	50% Recomendations Implemented	All Recommendations Implemented
Legislative Changes	6%	Infrastructure System Replacement Surcharge (ISRS) Passed Through 1 Missouri Chamber	ISRS Passed Through 2 Missouri Chambers	ISRS Becomes Law
Social Media	6%	Develop Strategy	Threshold + 50% Implementation	Implement All New Strategy

Ms. Walters

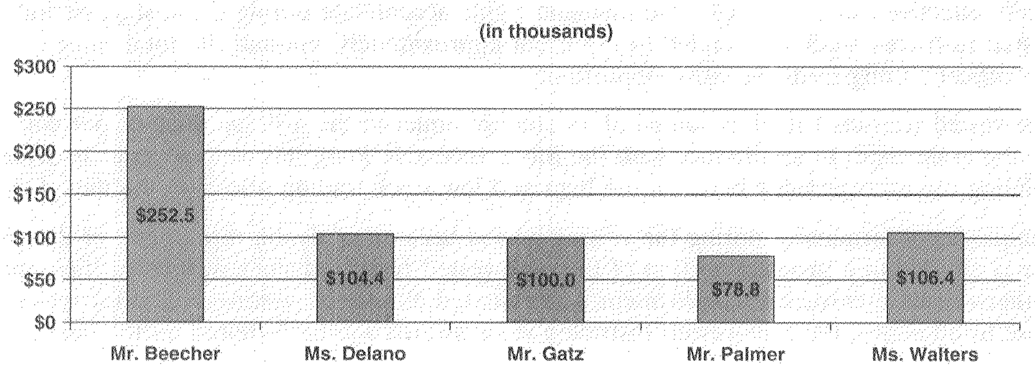
Metric Performance Measures	Weighting	Threshold 50%	Target 100%	Maximum 200%
Operational Area Expense Control				
Operating and Maintenance Expense	10%	Budget +10%	At Budget	Budget −10%
Fuel and Purchased Power Expenses	5%	Budget +10%	At Budget	Budget −10%
Operations				
Customer Service—SAIFI Rate(1)	5%	1.64	1.43	1.22
Customer Service—SAIDI Rate(2)	5%	183	159	135
Customer Response Performance	2.5%	<= 30 Second Response, 60% or Greater	<= 30 Second Response, 70% or Greater	<= 30 Second Response, 80% or Greater
Customer Service Structure	2.5%	Customer Service Restructuring Plan	Threshold + Completed Restructuring	Target + achieved Cost Reduction and/or Service Improvement
Project Completion				
Riverton Unit 12 Combined Cycle	5%	Air/Intake Permits by December 31, 2013	Air/Intake Permits by July 1, 2013	Air/Intake Permits by May 1, 2013
Asbury Air Quality Control System Project	5%	On Schedule and Budget +10%	On Schedule and Budget	On Schedule and Budget −10%

(1) System Average Interruption Frequency Index

(2) System Average Interruption Duration Index

In addition to the Corporate Performance Metric and other operational metrics, each executive officer has a common subjective performance review metric whereby they are evaluated in areas of leadership, engagement of workforce, accountability, and overall job performance. This subjective performance metric is weighted at 20% of the total target Annual Cash Incentive opportunity for the President and CEO and 10% of the total target Annual Cash Incentive opportunity for each other NEO.

Total AIP target award opportunities attainable by each of the Company's NEOs during fiscal 2013 are:



Long-Term Incentives

Long-Term Incentives consist of time-vested restricted stock awards (which replaced stock options and dividend equivalent rights effective January 1, 2011) and performance-based restricted stock awards.

Equity awards are granted under our 2006 Stock Incentive Plan, which was approved by stockholders in 2005. Both forms of award are discussed in more detail below. The Long-Term Incentive element is designed to motivate executive officers over the long-term to put forth maximum effort in contributing to the continued success and growth of Empire, and to ensure the interests of the executive officers are aligned with those of stockholders. In addition, Long-Term Incentives provide a measure of retention incentive for executive officers, leading to enhanced stability of our senior management team. During 2012, the target Long-Term Incentive opportunity for the President and CEO was equal to 65% of his annual base salary, while the target Long-Term Incentive opportunity for executive officers other than the President and CEO was equal to 15% of their annual base salaries. In accordance with our compensation philosophy described above, during 2012 the target Total Cash Compensation of our executive officers, plus their target level Long-Term Incentive opportunity, was designed to approximate the midpoint between the 25th and 50th percentile of the national market for Total Direct Compensation as adjusted to reflect their individual positioning within the Base Salary range.

Beginning in 2013, in order to provide the opportunity to achieve the 25th percentile level of peer group Total Direct Compensation, the Committee has modified the Long-Term Incentive opportunity for the President and CEO to represent 80% of his annual base salary. Similarly, the Committee modified the Long-Term Incentive opportunity for the Vice-President and Chief Operating Officer—Electric, the Vice President and Chief Operating Officer—Gas, and the Vice President and Chief Financial Officer to represent 45% of their annual base salary. The Long-Term Incentive opportunity for all other executive officers was modified to represent 30% of their annual base salary. As with Total Cash Compensation, Total Direct Compensation at target-level performance will approximate the 25th percentile of the Total Direct Compensation of the industry-specific peer group of companies for all executive officers.

At target levels of performance, the time-vested restricted stock is intended to represent approximately one-half the total value of each executive officer's Long-Term Incentive opportunity, with the performance-based restricted stock awards representing the remaining half.

Time-Vested Restricted Stock

Time-vested restricted stock awards granted to executive officers provide the opportunity to receive a number of shares of common stock at the end of a three-year vesting period. As noted above, this award replaced the stock option and dividend equivalent portions of the Long-Term Incentive opportunity effective January 1, 2011. No dividend rights accumulate during the vesting period. Time-vested restricted stock is intended to represent approximately one-half the total value of each executive officer's Long-Term Incentive opportunity.

Time-vested restricted stock is valued at an amount equal to the average price of our common stock on the grant date. In accordance with the Stock Incentive Plan, this average price is determined by calculating the average value between the high and low stock trading prices on the day of the grant.

If employment terminates during the vesting period because of death, retirement, or disability, the executive is entitled to a pro-rata portion of the time-vested restricted stock awards such executive would otherwise have earned. 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 Committee determines, in its sole discretion, that the executive is entitled to a pro-rata portion of such award.

Performance-Based Restricted Stock

Performance-based restricted stock awards granted to executive officers provide the opportunity to receive a number of shares of common stock at the end of a three-year performance period if performance goals set forth in the award are satisfied. The performance goals are tied to the percentile ranking of Empire's total stockholder return (share price appreciation or decline over the performance period plus cumulative value of dividends paid over the performance period, assuming reinvestment, divided by the stock price at the beginning of the performance period) for the three-year performance period as measured over the same period against all publicly traded, investor-owned electric utility companies. The target level of performance under the 2012 grants was set at the 50th percentile ranking when compared to this group. The threshold level was set at the 20th percentile, while the maximum level was set at the 80th percentile. At the end of the performance period (December 31, 2014 for awards granted in 2012), the executive would earn 100% of the target number of shares if the target (50th percentile) level of performance is reached. If the threshold level of performance is reached, the executive would earn 50% of the target number of shares. If performance reaches or exceeds the maximum level, the executive would earn 200% of the target number of shares. When performance levels are between the threshold and maximum performance levels, the amount of shares the executive earns is interpolated. No shares are earned if the threshold level of performance is not reached. The Consultant prepares an analysis of our total stockholder return percentile ranking for the just-ended three-year performance period relative to the comparator group described above. Based upon this analysis, the Consultant calculates the appropriate number of performance-based restricted stock shares to be awarded each executive. Performance-based restricted stock awards are approved by the Committee at the first meeting of the year. The total stockholder return for the three year performance period ended December 31, 2012 (for awards granted in 2010), was 8.0%, or just above the 22ndth percentile of the comparator group. Since the adoption of the 2006 Stock Incentive Plan, we have averaged a total stockholder return ranking slightly under the 43rd percentile.

If employment terminates during the performance period because of death, retirement, or disability, the executive is entitled to a pro-rata portion of the performance-based restricted stock awards such executive would otherwise have earned. If employment is terminated during the performance period for reasons other than those listed above, the performance-based restricted stock awards will be forfeited on the date of the termination unless the Committee determines, in its sole discretion, that the executive is entitled to a pro-rata portion of such award.

Limitations on Incentive Compensation

Prior to 2012, we had a compensation limitation in effect which provided that, regardless of the extent to which any performance goals were met in any calendar year, no incentive compensation was to be provided to any executive officer for any year in which we did not pay dividends per share of common stock at least equal to the dividends per share paid in the preceding year. The dividend was temporarily suspended for the 3rd and 4th quarters of 2011 following the devastating EF-5 tornado that struck the Joplin, Missouri area on May 22, 2011, thereby triggering the incentive compensation limitation.

In the Committee's view, the incentive compensation limitation restricted its ability to consider management's response to events or circumstances. As a result, management could be penalized rather than rewarded for outstanding efforts as they manage the Company through significant uncontrollable events such as the EF-5 tornado mentioned above. Therefore, due to the possibly Draconian effect this policy had on incentive compensation, the Committee reassessed the policy and determined to replace it with a limitation measured through a distinct stockholder-based metric in each executive officer's AIP.

In making this determination, the Committee considered that a limitation that could eliminate all incentive compensation and be triggered by events outside the control of the executive officers was too harsh and not in line with our overall compensation philosophy. In addition, the declaration of dividends is a Board of Directors decision and generally not within the control of executive officers. By design, the equity portions of the Company's compensation program align the interest of the executive officers with stockholders. Accordingly, the Committee determined the AIP is an appropriate place to include a replacement provision to the compensation limitation. The Committee believes an Earnings Per Share metric is a close proxy to the incentive compensation limitation in that a sufficient level of Earnings Per Share would permit the Company to continue payment of the dividend at the current level.

Therefore, to moderate the all or nothing effect of the incentive compensation limitation, the Committee added an Earnings Per Share metric based on achievement of specific Earnings Per Share levels to the AIP for 2012, accounting for 20% of each executive officer's total target Annual Cash Incentive award opportunity. During 2013, this 20% level will continue in place for each NEO's total target Annual Cash Incentive award opportunity, with the exception that the level put in place for the President and CEO has been increased by the Committee to 30%.

Change in Control

We maintain a Change In Control Severance Pay Plan that covers executive officers as well as our other key employees who are not executive officers. The purpose of the plan is to assure continuity in leadership, continued focus, and dedication to customer and stockholder interests during and immediately after a change in control by mitigating the personal concerns that may confront a participant as a result of such an event. The plan provides severance pay benefits upon termination of employment after a change in control. This requirement of a "double-trigger" (i.e., the requirement that there be a change in control and a termination of employment) was instituted to balance the interests of the executive, Empire and our stockholders. There are several conditions that could constitute a change in control, but primarily, a change in control occurs if a merger or consolidation with, or sale to, another corporation or entity is consummated. The Change In Control Severance Pay Plan is discussed more fully under the section entitled "—Potential Payments upon Termination and Change in Control."

We have not entered into any form of employment agreements with any executive officer other than agreements under the Change In Control Severance Pay Plan.

Other Benefits

Executive officers participate in the same Retirement Plan that covers substantially all our other employees. This plan is a noncontributory, trusteed pension plan designed to meet the requirements of Section 401(a) of the Internal Revenue Code. Normal retirement is at age 65, with early retirement at a reduced benefit level permitted under certain conditions. We also maintain a Supplemental Executive Retirement Plan which covers the executive officers who participate in the Retirement Plan. This supplemental plan is intended to provide benefits which, except for the applicable limits of Section 415 and Section 401(a)(17) of the Internal Revenue Code, would have been payable under the Retirement Plan. The supplemental plan is not qualified under the Internal Revenue Code and benefits payable under the plan are paid out of our general funds.

Our Articles of Incorporation and bylaws contain provisions permitted by the Kansas General Corporation Code which, in general terms, provide that officers and directors will be indemnified by us for all losses that may be incurred by them in connection with any claim or legal action in which they may become involved by reason of their service as our officer or director, if they meet certain specified conditions, and provide for the advancement by us to the officers and directors of expenses incurred by them in defending suits arising out of their service as an officer or director. The Board has authorized us to enter into indemnity agreements with officers and directors that provide for similar indemnification and advancement of expenses. The officers and directors are also covered by insurance indemnifying them against certain liabilities which might be incurred by them in their capacities as officers and directors. The premium for this insurance is paid by us.

With the exception of certain plans specifically referenced in this discussion, the executive officers participate in the same health and welfare plans and under the same plan provisions available to all our other employees.

Compensation Committee Report

The Committee has reviewed and discussed the Compensation Discussion and Analysis (which is set forth above) with management. Based on this review and discussions, the Committee recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this proxy statement.

Thomas M. Ohlmacher, Chairman
D. Randy Laney
Kenneth R. Allen
Paul R. Portney
Herbert J. Schmidt

Summary Compensation Table

Set forth below is summary compensation information for each person who was (1) at any time during 2012 our Chief Executive Officer or Chief Financial Officer and (2) at December 31, 2012, one of our three most highly compensated executive officers, other than the Chief Executive Officer and the Chief Financial Officer (collectively, the "Named Executive Officers").

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Bonus(1) ($) (d)	Stock Awards(2)(3) ($) (e)	Option Awards(2)(4) ($) (f)	Non-Equity Incentive Plan Compensation(5) ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings(6) ($) (h)	All Other Compensation(7)(8) ($) (i)	Total ($) (j)
Bradley P. Beecher, . . .	2012	323,825	0	123,114	0	220,759	252,290	9,210	929,198
President and Chief	2011	292,798	60,317	43,601	0	0	277,308	9,682	683,706
Executive Officer	2010	275,000	2,500	39,049	5,950	130,979	146,599	10,658	610,735
Laurie A. Delano, ...	2012	177,677	0	19,312	0	86,995	114,080	5,865	403,929
Vice President— Finance and Chief Financial Officer	2011	143,691	20,506	0	0	0	82,164	5,039	251,400
Ronald F. Gatz	2012	195,700	0	19,312	0	83,050	114,587	9,767	422,416
Vice President and	2011	190,000	39,152	27,746	0	0	152,893	8,374	418,165
Chief Operating Officer—Gas	2010	180,000	0	26,581	3,910	85,239	93,481	7,981	397,192
Michael E. Palmer, . . .	2012	203,425	0	21,726	0	93,272	211,760	11,599	540,445
Vice President—	2011	197,500	40,698	29,897	0	0	295,244	9,752	573,091
Transmission Policy and Corporate Services	2010	193,000	0	26,949	4,080	108,084	163,638	9,395	505,146
Kelly S. Walters, ...	2012	242,667	2,000	24,140	0	112,877	186,552	7,936	576,851
Vice President and	2011	224,000	46,159	33,861	0	0	189,636	6,789	500,445
Chief Operating Officer—Electric	2010	180,000	0	26,581	3,910	87,161	97,188	7,099	401,939

(1) Ms. Walter's 2012 award is related to efforts put forth during the implementation of our enterprise application software upgrade. 2011 awards represent discretionary cash awards paid to executives in recognition of exceptional performance during 2011 following the devastating EF-5 tornado that struck the Joplin, Missouri area in May 2011. This event subsequently lead to the decision by the Board of Directors to temporarily suspend the common stock dividend, thereby triggering the limitation on incentive compensation, as described above under "Limitations on Incentive Compensation." Ms. Delano's 2011 award also includes an amount earned related to goal performance prior to her election as Vice President—Finance and Chief Financial Officer.

(2) Amounts shown for stock and option awards represent the grant date fair value determined in accordance with Financial Accounting Standards Board Accounting Standard Codification Topic 718 ("FASB ASC Topic 718") for the applicable year relating to such awards. A discussion of the assumptions used to value these awards can be found under Note 4 to our Consolidated Financial Statements included in our Annual Report on Form 10-K for the year ended December 31, 2012 (the "2012 10-K").

(3) Represents the grant date fair value (determined in accordance with FASB ASC Topic 718) for the applicable year relating to awards of time-vested restricted stock, performance-based restricted stock and dividend equivalents. Time-vested restricted stock was first granted in 2011. No time-vested restricted stock awards were made by the Compensation Committee in 2012 due to the triggering of the limitation on incentive compensation described in Note 1 above. The 2012 performance-based restricted stock awards were also subject to this same limitation on incentive compensation. However, in order to recognize outstanding efforts by management subsequent to the triggering event described in Note 1 above, the Compensation Committee granted discretionary performance-based restricted stock awards in 2012. No awards of dividend equivalent have been made since 2010.

Includes amounts relating to grants of time-vested restricted stock as follows:

	February 2011
B.P. Beecher	$19,940
L.A. Delano	N/A
R.F. Gatz	$12,689
M.E. Palmer	$12,689
K.S. Walters	$14,502

Includes amounts relating to grants of performance-based restricted stock as follows:

	February		
	2010	2011	2012
B.P. Beecher	$26,169	$23,661	$123,114
L.A. Delano	N/A	N/A	$ 19,312
R.F. Gatz	$18,117	$15,057	$ 19,312
M.E. Palmer	$18,117	$17,208	$ 21,726
K.S. Walters	$18,177	$19,359	$ 24,140

Includes amounts relating to grants of dividend equivalents as follows:

	February 2010
B.P. Beecher	$12,880
L.A. Delano	N/A
R.F. Gatz	$ 8,464
M.E. Palmer	$ 8,832
K.S. Walters	$ 8,464

The amounts set forth in the table relating to performance-based restricted stock represent the grant date fair value of such awards assuming the target level of performance is attained. Assuming the maximum level of performance is attained, the grant date fair value of such awards would be as follows:

	February		
	2010	2011	2012
B.P. Beecher	$52,338	$47,332	$246,228
L.A. Delano	N/A	N/A	$ 38,624
R.F. Gatz	$36,234	$30,114	$ 38,624
M.E. Palmer	$36,234	$34,416	$ 43,452
K.S. Walters	$36,234	$38,718	$ 48,280

(4) Represents grant date fair value (determined in accordance with FASB ASC Topic 718) for the applicable year relating to awards of options to purchase common stock.

(5) Represents cash awards under our Executive Officer Annual Incentive Plan (AIP). Ms. Delano and Mr. Palmer requested their 2012 awards be paid in the form of Empire common stock rather than cash. No earned awards were granted under the AIP for 2011 performance due to the triggering of the limitation on incentive compensation described in Note 1 above.

(6) Represents the difference between the actuarial present value of each Named Executive Officer's accumulated benefit under all defined benefit plans at December 31 of the applicable year and the actuarial present value of each Named Executive Officer's accumulated benefit under all defined benefit plans at December 31 of the preceding year. Mr. Beecher, Ms. Delano, Mr. Gatz, Mr. Palmer and Ms. Walters participate in The Empire District Electric Company Employees' Retirement Plan ("Retirement Plan") and The Empire District Electric Company Supplemental Executive Retirement Plan ("SERP"). The actuarial present value of each Named Executive Officer's accumulated benefit is affected in part by the discount rate assumption. The discount rate used to determine the actuarial present value of each Named Executive Officer's accumulated benefit during the 2012 measurement period was decreased to 4.70% from 5.50% used for the 2011 measurement period. Other factors that affected the accumulated benefit for each Named Executive Officer during the 2012 measurement period included an additional year of credited service, increased average annual earnings as a result of an additional year of compensated service, and decreased pension-eligible incentive compensation as a result of the triggering during 2011 of the limitation on incentive compensation described in Note 1 above. These factors are described more fully in the narrative discussion to the Pension Benefits table below. The amount of change in the pension value attributable to the Retirement Plan and the SERP is as follows:

	2010	2011	2012
B.P. Beecher			
Retirement Plan	$ 67,585	$112,318	$134,915
SERP	$ 79,014	$164,990	$117,375
L.A. Delano			
Retirement Plan	N/A	$ 82,164	$114,080
SERP	N/A	$ 0	$ 0
R.F. Gatz			
Retirement Plan	$ 76,114	$ 98,693	$ 95,610
SERP	$ 17,367	$ 54,200	$ 18,977
M.E. Palmer			
Retirement Plan	$114,186	$165,291	$165,544
SERP	$ 49,452	$129,953	$ 46,216
K.S. Walters			
Retirement Plan	$ 74,569	$127,837	$153,527
SERP	$ 22,619	$ 61,799	$ 33,025

None of the Named Executive Officers participated in a non-qualified deferred compensation arrangement.

(7) Includes matching contributions under our 401(k) Retirement Plan and payment of term life insurance premiums as follows:

	2010	2011	20121
B.P. Beecher			
401(k) Matching Contribution	$7,727	$7,972	$7,500
Term Life premium	$1,709	$1,710	$1,710
L.A. Delano			
401(k) Matching Contribution	N/A	$4,265	$5,091
Term Life premium	N/A	$ 774	$ 774
R.F. Gatz			
401(k) Matching Contribution	$5,372	$5,688	$5,843
Term Life premium	$2,609	$2,686	$3,924
M.E. Palmer			
401(k) Matching Contribution	$5,762	$5,919	$6,073
Term Life premium	$2,008	$3,833	$3,924
K.S. Walters			
401(k) Matching Contribution	$5,158	$6,122	$7,232
Term Life premium	$ 593	$ 667	$ 705

(8) Includes perquisites and personal benefits if the aggregate value of such perquisites and personal benefits for each Named Executive Officer exceeds $10,000. Other Compensation for 2010 for Mr. Beecher, Mr. Palmer and Ms. Walters includes a tax "gross-up" of $1,222, $1,625, and $1,348 respectively, related to the provision of a medical examination. Perquisites and other personal benefits for 2010 for all other Named Executive Officers were not included in the Summary Compensation Table because the aggregate value, based upon the actual cost to Empire of the perquisites, did not exceed $10,000. Perquisites and other personal benefits for 2011 for Named Executive Officers were not included in the Summary Compensation Table because the aggregate value, based upon the actual cost to Empire of the perquisites, did not exceed $10,000. Other compensation for 2012 for Mr. Palmer includes a tax "gross-up" of $1,601 related to the provision of a medical examination. Perquisites and other personal benefits for 2012 for all other Named Executive Officers were not included in the Summary Compensation Table because the aggregate value, based upon the actual cost to Empire of the perquisites, did not exceed $10,000.

Grants of Plan-Based Awards

The following table shows information about plan-based awards granted during fiscal 2012 to the Named Executive Officers.

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards(1)			Estimated Future Payouts Under Equity Incentive Plan Awards(2)			All other Stock Awards: Number of Shares of Stock or Units	Grant Date Fair Value of Stock Awards(3)
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	(#) (i)	($) (j)
B.P. Beecher	02/06/2012	89,052	178,104	356,208					N/A
	02/06/2012				2,550	5,100	10,200		123,114
L.A. Delano	02/06/2012	31,092	62,183	124,366					N/A
	02/06/2012				400	800	1,600		19,312
R.F. Gatz	02/06/2012	34,248	68,495	136,990					N/A
	02/06/2012				400	800	1,600		19,312
M.E. Palmer	02/06/2012	35,600	71,199	142,398					N/A
	02/06/2012				450	900	1,800		21,726
K.S. Walters	02/06/2012	42,467	84,933	169,866					N/A
	02/06/2012				500	1,000	2,000		24,140

(1) Represents cash award opportunities under our Executive Officer Annual Incentive Plan. As described above under "Limitations on Incentive Compensation," no AIP awards were paid in 2012 with respect to 2011 performance.

(2) Represents awards of performance-based restricted stock.

(3) In the case of performance-based restricted stock, represents the value of such awards at the grant date based upon the target level of performance, which is consistent with the estimate of the aggregate compensation cost to be recognized over the service period determined as of the grant date under FASB ASC Topic 718, excluding the effect of estimated forfeitures.

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

Annual Cash Incentives

Grants of awards under our Executive Officer Annual Incentive Plan are disclosed in the Grants of Plan-Based Awards Table in the year they are granted. The value of the award is disclosed in the Summary Compensation Table in the year when the performance criteria under the plan are satisfied and the compensation earned. For example, the amount set forth in the Summary Compensation Table for 2012 represents the award made in the beginning of 2012 to be paid in early 2013 based on the performance during 2012. As noted above, no awards were paid in early 2012 as a result of a limitation on incentive compensation in place in 2011. This limitation provided that, regardless of the extent to which any performance goals were met in any calendar year, no incentive compensation was to be provided to any executive for any year in which we did not pay dividends per share of common stock at least equal to the dividends per share paid in the preceding year. At the request of Ms. Delano and Mr. Palmer, their 2012 awards were paid in the form of Empire common stock rather than cash.

Performance-Based Restricted Stock

Grants of awards of performance-based restricted stock and the grant date fair value (determined in accordance with FASB ASC Topic 718) of such awards are disclosed in the Grants of Plan-Based Awards Table in the year they are granted. The grant date fair value of such awards is also disclosed under Stock Awards in the Summary Compensation Table in the year when the awards are made. The performance-based restricted share awards underlying the Stock Awards in the Summary Compensation Table for each Named Executive Officer are as follows:

	2010 Award	2011 Award	2012 Award
B.P. Beecher	1,300	1,100	5,100
L.A. Delano	N/A	N/A	800
R. F. Gatz	900	700	800
M.E. Palmer	900	800	900
K.S. Walters	900	900	1,000

Stock Options

Grants of awards of options to purchase stock and the full grant date fair value (determined in accordance with FASB ASC Topic 718) of such awards are disclosed in the Grants of Plan-Based Awards Table in the year they are granted. The grant date fair value of such awards is also disclosed under Option Awards in the Summary Compensation Table in the year when the awards are made. No awards of stock options have been made since 2010. The stock option awards underlying the Option Awards in the Summary Compensation Table for each Named Executive Officer are as follows:

	2010 Award
B.P. Beecher	3,500
L.A. Delano	N/A
R. F. Gatz	2,300
M.E. Palmer	2,400
K.S. Walters	2,300

Dividend Equivalents

Grants of awards of dividend equivalents and the full grant date fair value (determined in accordance with FASB ASC Topic 718) of such awards are disclosed in the Grants of Plan-Based

Awards Table in the year they are granted. The grant date fair value of such awards is also disclosed under Stock Awards in the Summary Compensation Table in the year when the awards are made. No awards of dividend equivalents have been made since 2010.

Time-Vested Restricted Stock

Beginning in 2011, as discussed in the Compensation Discussion and Analysis above, stock option and dividend equivalent awards were replaced with time-vested restricted stock awards. Grants of awards of time-vested restricted stock and the full grant date fair value (determined in accordance with FASB ASC Topic 718) of such awards are disclosed in the Grants of Plan-Based Awards Table in the year they are granted. The grant date fair value of such awards is also disclosed under Stock Awards in the Summary Compensation Table in the year when the awards are made. No time-vested restricted shares were granted in 2012 due to the triggering during 2011 of the limitation on incentive compensation described in Note 1 to the "Summary Compensation Table". The time-vested restricted stock awards underlying the Stock Awards in the Summary Compensation Table for each Named Executive Officer are as follows:

	2011 Award
B.P. Beecher	1,100
L.A. Delano	N/A
R. F. Gatz	700
M.E. Palmer	700
K.S. Walters	800

Outstanding Equity Awards at Fiscal Year-End

The following table provides information with respect to the common stock that may be issued upon the exercise of options and other awards under our existing equity compensation plans as of December 31, 2012.

	Option Awards					Stock Awards			
Name (a)	Number of Securities Underlying Unexercised Options (#) Exercisable(1) (b)	Number of Securities Underlying Unexercised Options (#) Unexercisable(2) (c)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) (d)	Option Exercise Price ($) (e)	Option Expiration Date (f)	Number of Shares or Units of Stock That Have Not Vested (#) (g)(3)	Market Value of Shares or Units of Stock That Have Not Vested ($) (h)(4)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested(5)(6) (#) (i)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested(7) ($) (j)
B.P. Beecher	3,500	0		22.770	02/02/2015	1,100	22,418	7,500	152,850
	3,600	0		22.230	02/01/2016			501	10,220
	8,400	0		23.805	01/31/2017				
	0	3,500		18.355	02/03/2020				
L.A. Delano(8)	N/A	N/A		N/A	N/A	N/A	N/A	800	16,304
R. F. Gatz	4,200	0		21.790	01/28/2014	700	14,266	2,400	48,912
	3,000	0		22.770	02/02/2015			329	6,716
	3,100	0		22.230	02/01/2016				
	6,100	0		23.805	01/31/2017				
	5,400	0		21.915	01/30/2018				
	0	2,300		18.355	02/03/2020				
M.E. Palmer	3,400	0		22.770	02/02/2015	700	14,266	2,600	52,988
	3,500	0		22.230	02/01/2016			343	7,008
	6,600	0		23.805	01/31/2017				
	0	2,400		18.355	02/03/2020				
K.S. Walters	5,600	0		23.805	01/31/2017	800	16,304	2,800	57,064
	0	2,300		18.355	02/03/2020			329	6,716

(1) The vesting date for the exercisable options was (a) January 28, 2007, in the case of options with an expiration date of January 28, 2014, (b) February 2, 2008, in the case of options with an expiration date of February 2, 2015, (c) February 1, 2009, in the case of options with an expiration date of February 1, 2016, (d) January 31, 2010, in the case of options with an expiration date of January 31, 2017, and (e) January 30, 2011, in the case of options with an expiration date of January 30, 2018.

(2) The vesting date for the unexercisable options is February 3, 2013, in the case of options with an expiration date of February 3, 2020.

(3) Represents the number of shares attainable at fiscal year-end 2012 underlying the time-vested restricted stock granted in 2011.

(4) Represents the value, based on the stock price at December 31, 2012, of the time-vested restricted stock listed in column (g).

(5) The first number in column (i) represents the total number of shares attainable at the target level of performance for the 2010, 2011 and 2012 grants of performance-based restricted stock.

(6) The second number in column (i) represents the number of shares attainable at fiscal year-end 2012 through the dividend equivalents awarded with the 2010 option grants. The number of shares is derived by dividing the accumulated value of the dividend equivalents by the closing price of our common stock at year-end.

(7) The first number represents the value, based on the stock price at December 31, 2012, of the performance-based restricted stock listed in column (i) and the second number represents the value of the shares listed in column (i) attainable through dividend equivalents awarded with the 2010 option grants.

(8) Ms. Delano was not eligible for equity awards prior to becoming an executive officer on August 1, 2011.

Option Exercises and Stock Vested

The following table provides information with respect to the number and value of shares acquired during 2012 from the exercise of vested stock options, dividend equivalents and the vesting of performance-based and time-vested stock awards.

Name (a)	Option Awards: Number of Shares Acquired on Exercise (#) (b)	Option Awards: Value Realized on Exercise ($) (c)	Stock Awards: Number of Shares Acquired on Vesting(1)(2) (#) (d)	Stock Awards: Value Realized on Vesting ($) (e)
B.P. Beecher	381	8,039	1,279	26,849
L.A. Delano(2)	N/A	N/A	N/A	N/A
R. F. Gatz	254	5,359	875	18,368
M.E. Palmer	268	5,655	956	20,067
K.S. Walters	254	5,359	875	18,368

(1) Represents the vesting of the following awards granted in 2009: performance-based restricted stock and dividend equivalents.

(2) Ms. Delano was not eligible for equity awards prior to becoming an executive officer on August 1, 2011.

Pension Benefits

We maintain The Empire District Electric Company Employees' Retirement Plan ("Retirement Plan") covering substantially all of our employees. The Retirement Plan is a noncontributory, trusteed pension plan designed to meet the requirements of Section 401(a) of the Internal Revenue Code. Each covered employee is eligible for retirement at normal retirement date (age 65), with early retirement at a reduced benefit level permitted under certain conditions. We also maintain The Empire District Electric Company Supplemental Executive Retirement Plan ("SERP") which covers our officers who are participants in the Retirement Plan. We desire to provide a retirement benefit to our executive officers that is proportional, with respect to percentage of final average annual earnings, to the retirement benefit available to all other eligible employees. However the amount of average annual earnings that can be used to calculate retirement benefits under the Retirement Plan is restricted by Internal Revenue Code limitations. As explained below, the SERP is designed to restore retirement benefits an executive officer would otherwise lose due to such limitations. The SERP is not qualified under the Internal Revenue Code and benefits payable under the plan are paid out of our general funds.

The following table sets forth, with respect to each Named Executive Officer, the actuarial present value at December 31, 2012 of accumulated benefits under the Retirement Plan and the SERP, the number of years of credited service and the payments made under such plans during 2012.

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit(1) ($) (d)	Payments During Last Fiscal Year ($) (e)
B.P. Beecher	The Empire District Electric Company Employee's Retirement Plan	23.1	527,904	0
	The Empire District Electric Company Supplemental Executive Retirement Plan	23.1	414,761	0
L.A. Delano	The Empire District Electric Company Employee's Retirement Plan	20.8	420,016	0
	The Empire District Electric Company Supplemental Executive Retirement Plan	20.8	0	0
R.F. Gatz	The Empire District Electric Company Employee's Retirement Plan	11.8	475,007	0
	The Empire District Electric Company Supplemental Executive Retirement Plan	11.8	96,917	0
M.E. Palmer	The Empire District Electric Company Employee's Retirement Plan	26.6	856,665	0
	The Empire District Electric Company Supplemental Executive Retirement Plan	26.6	246,202	0
K.S. Walters	The Empire District Electric Company Employee's Retirement Plan	20.5	504,200	0
	The Empire District Electric Company Supplemental Executive Retirement Plan	20.5	120,470	0

(1) Value represents Actuarial Present Value of age 65 monthly benefit. Assumed discount rate of 4.00%, no pre-retirement mortality or decrements, no collar adjustment and post-retirement mortality tables for males and females (projected on a static basis) required by the Pension Protection Act of 2006 and published by the Internal Revenue Service for funding valuations in 2012.

Normal retirement under the Retirement Plan is age 65, or, for individuals hired after December 31, 1996 and within 5 years of their 65th birthday, normal retirement will be the 5th anniversary of their hire date. Retirement benefits are calculated based on credited service, average annual earnings, and Social Security covered compensation. The formula used to determine normal retirement benefits is as follows:

- 1.2625% of average annual earnings up to Social Security covered compensation times years of credited service up to 35 years, plus
- 1.64125% of average annual earnings in excess of Social Security covered compensation times years of credited service up to 35 years, plus
- 1.64125% of average annual earnings times years of credited service in excess of 35 years up to a maximum of 5 additional years of covered service.

Earnings include base salary, cash incentive amounts, the value of performance-based restricted stock and time-vested restricted stock on the award date, and dividend equivalents. The 2012 calculation of pension benefits was impacted by the triggering of the limitation on incentive compensation described above which reduced the level of pension-eligible incentive compensation that was considered in the benefit calculation. Average annual earnings is the average of annual earnings over the five consecutive years within the ten-year period prior to termination of employment which produces the highest average. Early retirement is available at age 55 with 5 years of eligibility service. The benefit is calculated in the same manner as the normal retirement benefit before applying early retirement reduction factors which reduce the normal retirement benefit by a certain percentage. For instance, the normal retirement benefit is reduced by 25% if an employee elects to retire at age 55. If an employee terminates employment after completing five years of vesting service (a plan year after age 18 in which the employee completes 1,000 hours of service), such employee is entitled to a benefit beginning at age 65. The benefit is calculated in the same manner as the normal retirement benefit. Forms of benefits include life only, and 25%, 33⅓%, 66⅔%, or 75% joint and survivor ("J&S") benefits. Election of the J&S benefit (only available to married participants) has the effect of reducing the employee's benefit. The reduction is dependent on the employee's age, the spouse's age, and the J&S benefit percentage elected.

Executive officers whose accrued benefit under the Retirement Plan is reduced by the limits set forth in Section 401 or Section 415 of the Internal Revenue Code, or whose anticipated earnings for any year exceed $120,000, become a participant in the SERP. Generally, benefits payable under the SERP equal the difference between the benefit calculated under the Retirement Plan without regard to Internal Revenue Code limitations, and the benefit calculated under the Retirement Plan as limited by the Internal Revenue Code. Actuarial equivalencies are determined in accordance with the actuarial assumptions set forth in the Retirement Plan.

Ms. Delano is eligible for early retirement under the terms of the Retirement Plan. Mr. Palmer and Mr. Gatz are eligible for early retirement under the terms of the Retirement Plan and the SERP. The present value of Ms. Delano's, Mr. Palmer's, and Mr. Gatz's approximate early retirement benefit under the Retirement Plan, payable as a single life annuity and assuming retirement at December 31, 2012, is $555,245, $1,180,989, and $545,107, respectively. The present value of Mr. Palmer's and Mr. Gatz's approximate early retirement benefit under the SERP, payable as a single life annuity and assuming retirement at December 31, 2012, is $339,442 and $111,217, respectively. These amounts are not included in the table above.

Potential Payments upon Termination and Change in Control

The Board of Directors adopted a Change In Control Severance Pay Plan ("Severance Plan") in 1991, amended most recently in 2008, that covers our executive officers as well as our other key employees who are not executive officers. The Severance Plan provides severance payments and other benefits upon involuntary or voluntary termination of employment after a Change In Control.

Change In Control

A Change In Control will be deemed to have occurred if:

1. A merger or consolidation of Empire with any other corporation is consummated, other than a merger or consolidation which would result in our voting securities held by such stockholders outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by converting into voting securities of the surviving entity) more than 75% of the voting securities of Empire or such surviving entity outstanding immediately after such merger or consolidation;
2. A sale, exchange or other disposition of all or substantially all the assets of Empire for the securities of another entity, cash or other property is consummated;

3. Empire stockholders approve a plan of liquidation or dissolution of Empire;
4. Any person, other than a trustee or other fiduciary holding securities under an employee benefit plan of Empire or other than a corporation owned directly or indirectly by the stockholders of Empire in substantially the same proportions as their ownership of voting securities of Empire, is or becomes the beneficial owner, directly or indirectly, of voting securities of Empire representing at least 25% of the total voting power represented by such securities then outstanding; or
5. Individuals who on January 1, 2001 constituted the Empire Board of Directors and any new director whose election by the Empire Board of Directors or nomination for election by Empire's stockholders was approved by a vote of at least two-thirds of the directors then still in office who either were directors on January 1, 2001 or whose election or nomination for election was previously so approved, cease for any reason to constitute a majority thereof.

Involuntary Termination

An involuntary termination is deemed to occur if (1) we terminate the employment of the executive officer or key employee within two years after a Change In Control other than for certain reasons (such as specified acts of willful misconduct, felony convictions or failure to perform duties) or (2) the executive officer or key employee terminates the employment within two years after a Change In Control and within 180 days after a material reduction or material change in responsibilities or authority, reassignment to another geographic location, or a reduction in base salary or incentive compensation or other benefits. Should an involuntary termination occur, an executive officer would be eligible under the Severance Plan for a payment equal to 36 months of compensation. This compensation is based on the executive officer's annual base salary in effect immediately prior to the date of termination plus the average of annual awards of incentive compensation made to the executive in the form of cash or restricted stock in the three calendar years immediately preceding the calendar year of the involuntary termination. Payments pursuant to an involuntary termination of employment are made in the form of a lump sum within 30 days following termination.

Voluntary Termination

A voluntary termination is deemed to occur if the executive officer or key employee elects to terminate his or her employment between the first anniversary date of a Change In Control and the date that is 18 months after the Change In Control. In the case of a voluntary termination, the executive officer or key employee would be eligible for the same compensation as if it were an involuntary termination, with payment made in the form of a lump sum within 30 days following termination. In the event such executive officer becomes re-employed, including certain forms of self-employment, within the 36 month period following a voluntary termination, the executive officer is required to repay a pro-rata portion of the lump sum received under the Severance Plan to the Company.

Estimated lump-sum severance payments and other benefits payable to named executive officers in the event of a Change In Control based on involuntary termination are as follows:

Name	Severance Benefit ($)	Annual Incentive Bonus(1) ($)	Stock Options ($)	Dividend Equivalents ($)	Restricted Stock ($)	Benefits Continuation ($)	Excise Tax and Related Gross-Up ($)	Retirement Enhancement ($)	Total Change in Control Benefit ($)
B.P. Beecher	1,302,348	220,759	7,087	10,220	63,912	42,142	612,394	204,740	2,463,602
L.A. Delano	589,870	86,995	0	0	5,441	11,938	390,763	278,695	1,363,702
R.F. Gatz	780,244	83,050	4,657	6,716	24,069	11,938	396,570	237,910	1,545,154
M.E. Palmer	843,843	93,272	4,860	7,008	26,086	42,142	416,588	210,648	1,644,447
K.S. Walters	956,879	112,877	4,657	6,716	29,429	21,946	464,861	174,550	1,771,915

(1) Represents cash incentive awards under the AIP that were earned by the NEO prior to the assumed involuntary termination date, but not paid.

The amounts in the above table assume that the Change In Control and the involuntary termination occurred on December 31, 2012, and the price of our common stock was the closing market price on December 31, 2012. In order to receive Change in Control benefit payments outlined above, an executive officer is not required to satisfy any additional condition or obligation.

Executive officers or key employees are eligible for continuation (under similar cost sharing arrangements as immediately prior to a Change In Control) of benefits and service credit for benefits they would have received had they remained an employee of Empire (in the case of involuntary termination of an executive officer, a period of 36 months or, in the case of a voluntary termination, for the period during which the executive officer is entitled to receive the other severance benefits). Benefits include medical, life and accidental death and dismemberment insurance. Executive officers or key employees accumulate additional age and service credits as a result of a Change In Control equal to the period corresponding to the multiple used to calculate the severance benefit (e.g., 36 months in the case of an executive officer). Such executive officers or key employees are eligible to receive an enhanced retirement benefit equal to the difference between the retirement benefit they would receive (including Retirement Plan and SERP benefits) had they not received additional age and service credits and the retirement benefit they would receive when such additional age and service credits are included.

All stock options granted become immediately exercisable in full and all time-vested restricted stock and performance-based restricted stock granted becomes immediately payable in full upon an involuntary or voluntary termination following a Change In Control. If any payments to qualifying individuals are subject to the excise tax on "excess parachute payments" under Section 4999 of the Internal Revenue Code, such qualifying individual(s) will receive an additional gross-up amount designed to place them in the same after-tax position as if the excise tax had not been imposed.

Director Compensation

Our non-employee Directors received the following aggregate amounts of compensation during the year ended December 31, 2012.

Name (a)	Fees Earned or Paid in Cash ($) (b)	Stock Awards ($)(1) (c)	Option Awards ($) (d)	Non-Equity Incentive Plan Compensation ($) (e)	Change in Pension Value and Nonqualified Deferred Compensation Earnings (f)	All Other Compensation ($)(2) (g)	Total ($) (h)
K.R. Allen	57,500	50,000	0	0	0	16,224	123,724
W.L. Gipson	58,000	50,000	0	0	0	3,828	111,828
R.C. Hartley	62,500	50,000	0	0	0	32,059	144,559
D.R. Laney	162,500	50,000	0	0	0	12,965	225,465
B.C. Lind	62,500	50,000	0	0	0	9,328	121,828
B.T. Mueller	68,000	50,000	0	0	0	20,798	138,798
T.M. Ohlmacher	60,000	50,000	0	0	0	3,803	113,803
P.R. Portney	62,000	50,000	0	0	0	7,731	120,231
H.J. Schmidt	55,000	50,000	0	0	0	6,199	111,199
C.J. Sullivan(3)	55,000	50,000	0	0	0	6,501	111,501

(1) Represents the annual award accrued to each Director under the Stock Unit Plan for Directors.

(2) Represents dividends paid on accrued stock units earned under the Stock Unit Plan for Directors and interest on fees accumulated quarterly for Mr. Sullivan.

(3) Mr. Sullivan has elected to receive 100% of his Director compensation in Empire common stock under the 2006 Stock Incentive Plan. The entire amount of $55,000 listed in column (b) was paid in the form of common stock. He receives prime rate interest on his earned fees until the shares of common stock are issued quarterly. He earned $302 in interest in 2012 which is included in column (g).

An analysis of the fees and retainers earned by the non-employee Directors in 2012 is provided in the following table:

Name (a)	Annual Retainer ($) (b)	Chairman and Committee Chair Fees ($) (c)	Director Training Fees ($) (d)	Annual Award of Stock Units ($) (e)	All Other Compensation ($) (f)	Total ($) (g)
K.R. Allen	55,000	2,500	0	50,000	16,224	123,724
W.L. Gipson	55,000	0	3,000	50,000	3,828	111,828
R.C. Hartley	55,000	7,500	0	50,000	32,059	144,559
D.R. Laney	55,000	107,500	0	50,000	12,965	225,465
B.C. Lind	55,000	7,500	0	50,000	9,328	121,828
B.T. Mueller	55,000	10,000	3,000	50,000	20,798	138,798
T.M. Ohlmacher	55,000	5,000	0	50,000	3,803	113,803
P.R. Portney	55,000	7,500	0	50,000	7,731	120,231
H.J. Schmidt	55,000	0	0	50,000	6,199	111,199
C.J. Sullivan	55,000	0	0	50,000	6,501	111,501

Narrative to Director Compensation Table

For 2012, each Director who was not an officer or full-time employee of Empire was paid a monthly retainer for his or her services as a Director at a rate of $55,000 per annum which increased to $65,000 effective January 1, 2013. The Chairman of each Committee received an additional annual retainer of $7,500 ($10,000 for the Chairman of the Audit Committee). The Chairman of the Board received an additional annual retainer of $100,000. One-twelfth of the annual retainers for the Directors, the Committee Chairman, and the Chairman of the Board are paid each month that the Director serves in that position. In addition, each non-employee Director is paid a $1,000 per day fee in the event an individual Committee or the Board meets more than 10 times per year and a $1,000 per day stipend for outside training.

Our 2006 Stock Incentive Plan permits our Directors to receive shares of common stock in lieu of all or a portion of any cash payment for services rendered as a Director. In addition, a Director may defer all or part of any compensation payable for his or her services under the terms of our Deferred Compensation Plan for Directors. Amounts so deferred are credited to an account for the benefit of the Director and accrue an interest equivalent at a rate equal to the prime rate. A Director is entitled to receive all amounts deferred in a number of annual installments following retirement, as elected by him or her.

In addition to the cash retainer and fees for non-employee Directors, we maintain a Stock Unit Plan for non-employee Directors, which we refer to as the Stock Unit Plan, to provide Directors the opportunity to accumulate compensation in the form of common stock units. When implemented in 1998, the Stock Unit Plan provided Directors the opportunity to convert cash retirement benefits earned under our prior cash retirement plan for Directors into common stock units. All eligible Directors who had benefits under the prior cash retirement plan converted their cash retirement benefits to common stock units. Each common stock unit earns dividends in the form of common stock units and can be redeemed for one share of common stock upon retirement or death of the Director, or on a date elected in advance by the Director with respect to awards made on or after January 1, 2006. The number of units granted annually is calculated by dividing the annual contribution rate, which is either the annual retainer fee or such other amount as is established by the Compensation Committee of the Board of Directors, by the fair-market value of our common stock on January 1 of the year the units are granted. The annual contribution rate for 2012 was $50,000 and increased to $55,000 effective January 1, 2013. Common stock unit dividends are computed based on the fair market value of our common stock on the dividend's record date. During 2012, 21,325 units were converted to common stock by retired and current Directors, 23,563 units were granted for services provided in 2012 (based on an annual contribution rate of $50,000), and 6,864 units were granted pursuant to the provisions of the plan providing for the reinvestment of dividends on stock units in additional stock units.

In accordance with Empire's Corporate Governance Guidelines, Empire encourages Directors to attend education programs relating to the responsibilities of directors of public companies. The expenses for the Directors to attend these courses are paid by Empire. Empire reimburses Directors for expenses incurred in connection with their position as a Director including the reimbursement of expenses for transportation. Empire maintains $250,000 of business travel accident insurance for non-employee Directors while traveling on Empire business.

5. TRANSACTIONS WITH RELATED PERSONS

Transactions with Related Persons

There were no reportable transactions with related persons during 2012.

Review, Approval or Ratification of Transactions with Related Persons

Our Nominating/Corporate Governance Committee has adopted a written Policy and Procedures with Respect to Related Person Transactions (the "Policy"). The Policy is available on our website at *www.empiredistrict.com*. The Policy provides that any proposed Related Person Transaction be submitted to the Nominating/Corporate Governance Committee for consideration. In determining whether or not to approve the transaction, the Policy provides that the Committee shall consider all of the relevant facts and circumstances available to the Committee, including (if applicable) but not limited to: the benefits to us; the impact on a Director's independence; the availability of other sources for comparable products or services; the terms of the transaction; and the terms available to unrelated third parties or to employees generally. The Policy provides that the Committee will approve only those Related Person Transactions that are in, or are not inconsistent with, the best interests of Empire and its stockholders, as the Committee determines in good faith.

For purposes of the Policy, a "Related Person Transaction" is a transaction, arrangement or relationship (or any series of similar transactions, arrangements or relationships) in which Empire (including any of its subsidiaries) was, is or will be a participant and the amount involved exceeds $25,000, and in which any Related Person had, has or will have a direct or indirect material interest.

For purposes of the Policy, a "Related Person" means:

1. any person who is, or at any time since the beginning of our last fiscal year was, a Director or executive officer or a nominee to become a Director of Empire;
2. any person who is known to be the beneficial owner of more than 5% of any class of our voting securities; and
3. any immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law, or sister-in-law of the Director, executive officer, nominee or more than 5% beneficial owner, and any person (other than a tenant or employee) sharing the household of such Director, executive officer, nominee or more than 5% beneficial owner.

The policy specifically provides that transactions involving the rendering of services by us (in our capacity as a public utility) to a Related Person at rates or charges fixed in conformity with law or governmental authority will not be considered Related Person Transactions.

6. OTHER MATTERS

Audit Committee Report

The Audit Committee reviews Empire's financial reporting process on behalf of the Board of Directors. In fulfilling its responsibilities, the Committee has reviewed and discussed the audited financial statements to be included in the 2012 Annual Report on Form 10-K with Empire's management and the Independent Registered Public Accounting Firm ("Independent Auditors"). Management is responsible for the financial statements and the reporting process, as well as maintaining effective internal control over financial reporting and assessing such effectiveness. The Independent Auditors are responsible for expressing an opinion on the conformity of those audited financial statements with accounting principles generally accepted in the United States, as well as expressing an opinion on whether Empire maintained effective internal control over financial reporting.

The Audit Committee has discussed with the Independent Auditors the matters required to be discussed by the statement on Auditing Standards No. 61, as amended (AICPA, Professional Standards, Vol. 1. AU section 380), as adopted by the Public Company Accounting Oversight Board in Rule 3200T. In addition, the Audit Committee has received the written disclosures and the letter from the Independent Auditors required by applicable requirements of the Public Company Accounting Oversight Board regarding the Independent Auditors' communications with the Audit Committee concerning independence, and has discussed with the Independent Auditors, the auditor's independence. The Audit Committee has considered whether the services provided by the Independent Auditors in 2012, described in this proxy statement, are compatible with maintaining the auditor's independence and has concluded that the auditor's independence has not been impaired by its engagement to perform these services.

In reliance on the reviews and discussions referred to above, the Audit Committee recommended to the Board of Directors that the audited financial statements be included in Empire's Annual Report on Form 10-K for the year ended December 31, 2012, for filing with the Securities and Exchange Commission.

B. Thomas Mueller, Chairman
Kenneth R. Allen
Ross C. Hartley
Bonnie C. Lind

Fees Billed by Our Independent Registered Public Accounting Firm During Each of the Fiscal Years Ended December 31, 2012 and December 31, 2011

Representatives of PricewaterhouseCoopers LLP are expected to be present at the meeting for the purpose of answering questions which any stockholder may wish to ask, and such representatives will have an opportunity to make a statement at the meeting.

Audit Fees

The aggregate fees billed by our Independent Auditors for professional services rendered in connection with the audit of our financial statements included in our Annual Report on Form 10-K, the audit of our internal control over financial reporting, the review of our interim financial statements included in our Quarterly Reports on Form 10-Q, as well as services provided in connection with certain of our equity and debt offerings, totaled $929,275 for the year ended December 31, 2012, as compared to $773,000 for the year ended December 31, 2011.

Audit-Related Fees

The aggregate fees billed by our Independent Auditors for audit-related services during the years ended December 31, 2012 and 2011 totaled $690,000 and $60,000, respectively, related to services provided by PwC in connection with a planned information system implementation and accounting consultations.

Tax Fees

There were no fees billed by our Independent Auditors for tax services during each of the years ended December 31, 2012 and 2011.

All Other Fees

No other fees were billed by our Independent Auditors during the years ended December 31, 2012 and 2011.

Audit Committee Pre-Approval Policies and Procedures

All auditing services and non-audit services provided to us by our Independent Auditors must be pre-approved by the Audit Committee (other than the de minimis exceptions provided by the Exchange Act). All of the Audit, Audit-Related, Tax Fees and All Other Fees shown above for 2012 and 2011 satisfied these Audit Committee procedures.

Communications with the Board of Directors

The Board of Directors provides a process for interested parties (including security holders) to send communications to the Board, including those communications intended for non-management or independent Directors. These procedures may be found on our website at *www.empiredistrict.com*.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our Directors and executive officers to file reports of changes in ownership of our equity securities with the SEC and the NYSE. SEC regulations require that Directors and executive officers furnish to us copies of all Section 16(a) forms they file. To our knowledge, based solely on review of the copies of such reports furnished to us and written representations that no other reports were required, during the fiscal year ended December 31, 2012, all our executive officers and Directors complied with applicable Section 16(a) filing requirements.

Other Business

At the date of this proxy statement, the Board of Directors has no knowledge of any business other than that described herein which will be presented for consideration at the meeting. In the event any other business is presented at the meeting, the persons named in the enclosed proxy will vote such proxy thereon in accordance with their judgment in the best interests of Empire and its stockholders.

7. STOCKHOLDER PROPOSALS FOR 2014 ANNUAL MEETING

The 2014 Annual Meeting is tentatively scheduled to be held on May 1, 2014. Specific proposals of stockholders intended to be presented at that meeting (1) must comply with the requirements of the Exchange Act and the rules and regulations promulgated thereunder and our Articles of Incorporation, and (2) if intended to be included in our proxy materials for the 2014 Annual Meeting, must be received at Empire's principal office not later than November 13, 2013. If the date of the 2014 Annual Meeting is changed by more than 30 days from May 1, 2014, stockholders will be advised of such change and of the new date for submission of proposals. If a stockholder intends to submit a proposal that is not to be included in our proxy materials for the 2014 Annual Meeting, the stockholder must give us notice of not less than 35 days and no more than 50 days before the date of the 2014 Annual Meeting in accordance with the requirements set forth in our Articles of Incorporation.

8. HOUSEHOLDING

Pursuant to the SEC rules regarding delivery of proxy statements, annual reports or Notice of Internet availability of proxy materials to stockholders sharing the same address, we may deliver a single proxy statement, annual report or Notice of Internet availability of proxy materials to an address shared by two or more of our stockholders. This delivery method is referred to as "householding" and can result in significant cost savings for us. In order to take advantage of this opportunity, we may have delivered only one proxy statement, annual report or Notice of Internet availability of proxy materials to multiple stockholders who share an address, unless we received contrary instructions from the impacted stockholders prior to the mailing date. We undertake to deliver promptly, upon written or oral request, a separate copy of the proxy statement, annual report or Notice of Internet availability of proxy materials, as requested, to any stockholder at the shared address to which a single copy of those documents was delivered. If you prefer to receive separate copies of a proxy statement, annual report or Notice of Internet availability of proxy materials, either now or in the future, send your request in writing to us at the following address: Investor Relations Department, The Empire District Electric Company, 602 S. Joplin Avenue, Joplin, Missouri 64801.

If you are currently a stockholder sharing an address with another stockholder and wish to have your future proxy statements and annual reports householded (i.e., receive only one copy of each document for your household), please contact us at the above address.

9. ELECTRONIC PROXY VOTING

Registered stockholders can vote their shares via (1) a toll-free telephone call from the U.S.; (2) the Internet; or (3) by mailing their signed proxy card. The telephone and Internet voting procedures are designed to authenticate stockholders' identities, to allow stockholders to vote their shares and to confirm that their instructions have been properly recorded. Specific instructions to be followed by any registered stockholder interested in voting via telephone or the Internet are set forth on the enclosed proxy card.

10. INTERNET AVAILABILITY OF PROXY MATERIALS

This year, we are once again pleased to be using the new U.S. Securities and Exchange Commission rule that allows companies to furnish their proxy materials over the Internet. As a result, we are mailing to many of our stockholders a notice about the Internet availability of the proxy materials instead of a paper copy of the proxy materials. All stockholders receiving the notice will have the ability to access the proxy materials over the Internet. They may also request to receive a paper copy of the proxy materials by mail. Instructions on how to access the proxy materials over the Internet or to request a paper copy may be found on the notice.

The proxy statement and 2012 Annual Report are available online at *www.ematerials.com/ede.* Please have the 3-digit company number, 11-digit control number and the last 4 digits of your Social Security Number or Tax Identification Number available in order to vote your proxy. The 3-digit company number and 11-digit control number are located in the box in the upper right hand corner on the front of the proxy card and the Important Notice Regarding the Availability of Proxy Materials.

11. DIRECTIONS TO THE ANNUAL MEETING

Directions to the Annual Meeting being held at the Holiday Inn, 3615 South Range Line, Joplin, Missouri, are as follows:

To Joplin from the West: Take I-44 East to Exit 8B. Merge onto US-71 BUS N/S Range Line Road for about 0.4 miles. Turn right onto Hammons Boulevard. The Holiday Inn will be on the right.

To Joplin from the North: From MO-171, turn South onto S. Madison Street. Travel 1.2 miles. Continue on Range Line Road for 5 miles. Turn left onto Hammons Boulevard, just before the I-44 intersection. The Holiday Inn will be on the right.

To Joplin from the East: Take I-44 West to Exit 8B. Make right onto Range Line Road and turn right immediately onto Hammons Boulevard. The Holiday Inn will be on the right.

Dated: March 13, 2013

It is important that proxies be returned promptly. Therefore, stockholders are urged to either vote the proxy through the Internet or by telephone or sign, date and return the proxy in the envelope provided, to which no postage need be affixed if mailed in the united states. A stockholder who plans to attend the meeting in person may withdraw the proxy and vote at the meeting.

APPENDIX A

Listed below are the names of the companies that participated in the national market survey compiled by the compensation Consultant. The number of parent organizations participating in the survey was over 500.

7-Eleven
A.H. Belo—Dallas Morning News, The
AAI
Abercrombie & Fitch
Ace Hardware
ACE INA
ACUITY
Advance Auto Parts
AEGON
Aeropostale
AES
Aetna
AFC Enterprises
Ahold USA—Stop & Shop Supermarket
Air Liquide America
Air Products
AK Steel
Akzo Nobel—Functional Chemicals
Alex Lee
Alexander & Baldwin
Alliant Techsystems
Almatis
Alticor
Altria Group
Amcor—Amcor PET Packaging
American Crystal Sugar
American Eagle Outfitters
American Enterprise Group
American Institute of Graphic Arts
American National Insurance
Amerigroup
Amsted Industries—Consolidated Metco
Anaheim Public Utilities
Andersons, The
Anheuser-Busch
AnnTaylor Stores
Applebee's International
Aramark
ArcelorMittal
Arch Chemicals
Argonne National Laboratory
Arkansas Blue Cross and Blue Shield
ArvinMeritor
Ashland
Associated Materials
Assurant—Assurant Health
Atmos Energy
AutoZone
Avista
Baker Petrolite
Bank of Montreal—Harris Bancorp
BASF
Belk
Benihana
BEP Colorado Restaurants
Best Buy
Blockbuster
Blue Cross and Blue Shield of Alabama
Blue Cross and Blue Shield of Florida
Blue Cross and Blue Shield of Kansas
Blue Cross and Blue Shield of Kansas City, MO
Blue Cross and Blue Shield of Massachusetts
Blue Cross Blue Shield of South Carolina
Blue Shield of California
Bluestar Silicones
Bob Evans Farms
Boddie-Noell Enterprises
BoJangles' Restaurants
Bon-Ton Stores, The
Boston Beer
Boston Market
Briad Group
Brinker International
Brown-Forman
Buca
Buckman Laboratories
Buffalo Wild Wings
Buffet Partners
Buffets
Bunge
Burger King
Burlington Northern and Santa Fe Railway
C&S Wholesale Grocers
Cabot
Calgon Carbon
California Independent System Operator
Capital Metropolitan Transportation Authority
CareFirst Blue Cross Blue Shield
Caribou Coffee
Carlson Restaurants Worldwide
Carrols Restaurant Group
Carter's
Carus Chemical
Caterpillar
Cato
CBC Restaurant
CBRL Group
CDX Gas
CEC Entertainment
Centene
CenterPoint Energy
Champion Technologies
Checkers Drive-In Restaurants
Cheesecake Factory
Chemtura
Chevron Phillips Chemical
Chicago Mercantile Exchange
Chico's FAS
Children's Place, The
Chipotle Mexican Grill
Chiquita Brands International
CHS
Ciba Specialty Chemicals
CIGNA
Circuit City Stores
City of Austin—Austin Energy
CKE Restaurants
Claim Jumper Restaurants
Clariant
Coach
Cognis

Colgate-Palmolive
Collective Brands
Collin County
Colorado Springs Utilities
Comcast Cable Communications
Concessions International
ConnectiCare
Constellation Brands
Cooper Industries
Costco Wholesale
Coty
COUNTRY Insurance & Financial Services
Coventry Health Care
CPS Energy
Crate and Barrel
Culvers Franchising System
CUNA Mutual
Curtiss-Wright
CVS/Caremark
D&B
Dal-Tile
Darden Restaurants
Dave & Buster's
Deere
Del Monte Foods
Delta Dental Plan of Colorado
Denny's
Diageo North America
Dick's Sporting Goods
Dollar General
Dollar Tree Stores
Dominion Resources
Domino's Pizza
Donatos Pizzeria
Dow Chemical
Dow Corning
Dow Reichhold Specialty Latex
DPL
Duke and King Acquisition
Dunkin' Brands
DuPage County Government
E & J Gallo Winery
E. I. du Pont de Nemours
East Bay Municipal Utility District, CA
Eastman Chemical
Eat'n Park Hospitality Group
Eaton
El Pollo Loco
Electric Reliability Council of Texas
ElectriCities of North Carolina
Employers Mutual Casualty
Energy Future Holdings
Envision
Erie Insurance Group
Esmark
Express
Exterran
Fabri-Kal
Fairplex
Fallon Community Health Plan
Family Dollar Stores
Famous Dave's of America
Fazoli's System Management
FBL Financial Group
FedEx—FedEx Express
Fired Up
Flowserve
FMC
Foot Locker
Friendly Ice Cream
Frisch's Restaurants
Fuller Foundation
GameStop
Gap
Garden Fresh Restaurants
Gardener's Supply
Gardner Denver
GenCorp
GEO Specialty Chemicals
Georgia Baptist Foundation
Georgia Gulf
Global Aero Logistics
Global Cash Access
Golden Corral
Goodrich
Great Plains Energy—Kansas City Power & Light
Group Health Cooperative
Gymboree
H.B. Fuller
h.h. gregg
Hallmark Cards
Hard Rock Café Restaurants
Harleysville Group
Harris Holdings
Harris Teeter
Harvard Pilgrim
Harvard Vanguard Medical Associates
Health Care Service
Health Net
Health New England
Health Partners
HealthPartners
HealthSpring
Heaven Hill Distilleries
Hercules
Hershey Foods
Hexion Specialty Chemicals
Hilcorp Energy
Hillwood Development
HMS Host
Home Depot, The
Hooters of America
Horizon Blue Cross Blue Shield of New Jersey
Hormel Foods
Hot Topic
Huhtamaki
IHOP
Ilitch Holdings—Little Caesar Enterprises
Illinois Tool Works
Independence Blue Cross
Independent Bank
Ingersoll-Rand
Innophos
In-N-Out Burger
Institute of Nuclear Power Operations
International Copper Association
International Dairy Queen
International Flavors & Fragrances
Iroquois Pipeline
J. C. Penney
J.Crew
Jack in the Box
Jacmar—Shakey's USA
JEA
Jewelers Mutual Insurance
Jewelry Television
Johnny Rockets Group
Joy Global
K & W Cafeterias
Kaiser Foundation Health Plan
Kansas City Life Insurance

Kellogg
Kennametal
Kforce
Kinder Morgan
King Pharmaceuticals
Knoxville Utilities Board
Kohl's
Krispy Kreme Doughnuts
Krystal Companies, The
L.L. Bean
La Madeleine de Corps
Landauer
Landmark Education
Legal Sea Foods
Lehigh Hanson
Lennox International
Leukemia & Lymphoma Society, The
LifeWay Christian Resources
Limited Brands
Limited Stores
Liz Claiborne
Logan's Roadhouse
LOMA
Lord & Taylor
L'Oreal USA
Louisiana Workers' Compensation
Lowe's
Lubrizol
M&T Bank
Macy's
Maidenform Brands
Main Street America Group, The
Make-a-Wish Foundation of America
Marmon Group—Union Tank Car
Massachusetts Society of Certified Public Accountants
Masterfoods USA
Matthews International
Mazzio's
McCormick & Company
McDonald's
McGraw-Hill
MeadWestvaco
Medco Health Solutions
Medicines
Meijer
Memphis Light, Gas & Water
Mervyns
MetLife
Metromedia Restaurant Group
Metropolitan Water District of Southern California
Metso Minerals Industries
Michaels Stores
Micro Electronics
Mid-Continent Research for Education and Learning
Midwest Independent Transmission System Operator
Millennium Inorganic Chemicals
Minnkota Power Cooperative
Mirant
Missouri Employers' Mutual Insurance
Modine Manufacturing
Molson Coors Brewing
Montana Dakota Utility
Moog
Morton's Restaurant Group
Mosaic
Multiplan
Mutual of America
MVP Health Care
NACCO Materials Handling
Nashville Electric Service
National Shooting Sports Foundation
Neighborhood Health Plan
Nestle USA
New Jersey Transit
New York & Company
New York City Department of Education
New York Community Bancorp
New York Independent System Operator
New York Power Authority
Newark InOne
NewMarket
Noranda Aluminum
Nordstrom
NOVA Chemicals
Novo Nordisk
NPC
NRT
Nuvelo
Occidental Petroleum—Occidental Chemical
Ocean Spray Cranberries
O'Charley's
Office Depot
OfficeMax
Olathe Health Systems
Old Dominion Electric Cooperative
Orbital Sciences
Orchid Ceramics
Orlando Utilities Commission
P.F. Chang's China Bistro
Panda Restaurant Group
Panera Bread
Papa Gino's
Papa John's International
Pappas Restaurants
Penn National Insurance
Pepsi Bottling Group
Perkins Restaurant & Bakery
Pernod Ricard SA—Pernod Ricard USA
Philip Morris International
Phillips-Van Heusen
Piedmont Natural Gas
Pier 1 Imports
PJM Interconnection
Platte River Power Authority
Ply Gem Siding Group
Polo Ralph Lauren
Port Authority of New York and New Jersey
Portland General Electric
Potash Corporation of Saskatchewan
Potbelly Sandwich Works
Powersouth
PPG Industries
Praxair
Premera Blue Cross
Premier
Primesouth
Protestant Guild for Human Services
Public Works Commission of the City of Fayetteville, North Carolina
Quiznos Master
RadioShack
Raising Cane's Restaurants

Ranbaxy Pharmaceuticals
Real Mex Restaurants
Red Robin Gourmet Burgers
Regence Group
Restaurants Unlimited
Restoration Hardware
Retail Ventures—DSW
Retail Ventures—Value City Department Stores
RGA Reinsurance
Rhodia
Riverside Public Utilities
Rock Bottom Restaurants
Rockwell Collins
Rohm and Haas
Round Table Pizza
Ruby Tuesday
Ruth's Chris Steak House
Sacramento Municipal Utilities District
Safe Auto Insurance
Sagittarius Brands
SAIF
Saint-Gobain
Saks
San Diego County Water Authority
Sanofi Pasteur
Santee Cooper
Sasol North America
Sazerac
Scottish Re
Sears Holdings
Securian
Securities America
Security Mutual Life Insurance of New York
Sepracor
Shepherd Chemical
ShopKo Stores—ShopKo Stores
ShoreBank
Sierra Southwest Co-Op Services
Snohomish County, WA—Snohomish County Public Utility District
Solvay America
Sonic Automotive
Sonic Restaurants
Sonoco Products
South Jersey Industries
Southeast Corporate
Southern Minnesota Municipal Power Agency
Southern Star Concrete
Southern Union
Southwest Gas
Southwest Power Pool
Sports Authority, The
Stage Stores
Staples
Starboard Cruise Services
Starbucks
Steak 'n Shake
Sterling Chemicals
Subaru of America
SUEZ Energy
Summa Health System—SummaCare
Sunoco—Chemical
SuperValu
Supresta
Survey Sampling International
Swarovski (D.)—Swarovski North America
T.D. Williamson
Taco John's International
Target
Tarrant County
Tate & Lyle Americas
Texas Society of Certified Public Accountants
Thomas & King
Tipp Enterprises—Novamex
TJX Companies
Tommy Hilfiger
Toyota Material Handling, USA
Toys "R" Us
Travis County Human Resources Management
Tredegar
Triarc Restaurant Group
Tronox
Trustmark Insurance
Tufts Health Plan
Tween Brands
Tyson Foods
Umicore
Union Pacific
United Church of Christ
United States Steel
United Stationers
UnitedHealth Group
Unitil
Universal Parks & Resorts
University of Southern California
University of Tennessee
Uno Restaurant Holding
Voith—Voith Premier Manufacturing Support Services
Wackenhut Services
Wal-Mart Stores
Warner Chilcott
Watson Pharmaceuticals
Wawa
Wellmark Blue Cross Blue Shield
Wendy's
West Ed
Weston Solutions
Whataburger
White Castle System
Williams Companies
Williams-Sonoma
Workers Compensation Fund
YRC Worldwide
Yum!
Zale
ZF North American Operations

BeyondRecovery

The Empire District Electric Company ANNUAL REPORT

2012

Financial Highlights

DECEMBER 31,	2012	2011	Percentage Change
Operating Revenues (000)	$557,097	$576,870	-3.4%
Operating Income (000)	$96,221	$96,934	-0.7%
Net Income (000)	$55,681	$54,971	1.3%
Earnings Per Weighted Average Common Share (Basic And Diluted)	$1.32	$1.31	0.8%
Dividends Paid Per Share	$1.00	$0.64	56.3%
Return On Common Equity (End Of Period)	7.8%	7.9%	-1.3%
Book Value Per Share Of Common Stock	$16.90	$16.53	2.2%
Common Shares Outstanding (Year End) (000)	42,484	41,978	1.2%
Weighted Average Common Shares Outstanding (Basic)(000)	42,257	41,852	1.0%
Capital Expenditures (Including AFUDC) (000)	$146,287	$101,177	44.6%
Gross Plant (000)	$2,284,022	$2,176,650	4.9%
On-System Electric Sales (mWh)	4,912,970	5,073,401	-3.2%
On-System Gas Sales (000) (Mcf)	7,392	8,491	-12.9%
Electric Customers (Year End)	167,688	166,477	0.7%
Gas Customers (Year End)	43,991	44,082	-0.2%
Owned System Capability (Net mW)	1,391	1,392	-0.1%
System Electric Peak Demand (Net mW)	1,142	1,198	-4.7%
System Gas Peak Demand (Mcf)	58,281	67,789	-14.0%
Employees	756	746	1.3%

Letter from the President

To Our Shareholders, Customers, and Employees,

In 2012, your Company moved beyond tornado recovery back to our normal. Know this, our normal does not mean stagnant – it is remaining focused on maintaining, building, and improving our infrastructure, our customer experiences, and our business practices.

The electrical industry as a whole has seen a decline in the usage of our product. We too have seen a reduction in individual usage due to demand side management and efficiency programs, such as air conditioner rebate programs, offered in each jurisdiction. But, this reduction is counterbalanced by the demand from active construction projects throughout our service territory which have insulated us from the decline felt by other companies.

The Joplin area recovery effort represents the majority of construction bringing customers to our system. As of the end of 2012, in the Joplin area, we were approximately 1,000 customers down from pre-tornado levels, but large scale plans, which will impact the community for many years, are now gaining traction. A master developer was retained by the City of Joplin, and development has begun on a variety of projects worth an estimated $800 million.

In addition to those businesses that have already rebuilt, others continue the process such as the $335 million Mercy Hospital project scheduled for completion in 2015. New businesses, like Blue Buffalo, an all-natural pet food company, have also been attracted to the area post-tornado and have broken ground on large-scale projects.

A positive sign for our area is the development underway independent from the storm. In Oklahoma, Downstream Casino Resort recently added a second hotel with 152 rooms to its property. This $50 million project created nearly 100 new jobs for the local economy. Orthopaedic Specialists of the Four States, located in Galena, Kansas, opened a new $5 million medical office building in the fall and began construction on a $13.5 million, 16-bed specialty hospital expected to be completed in early 2013.

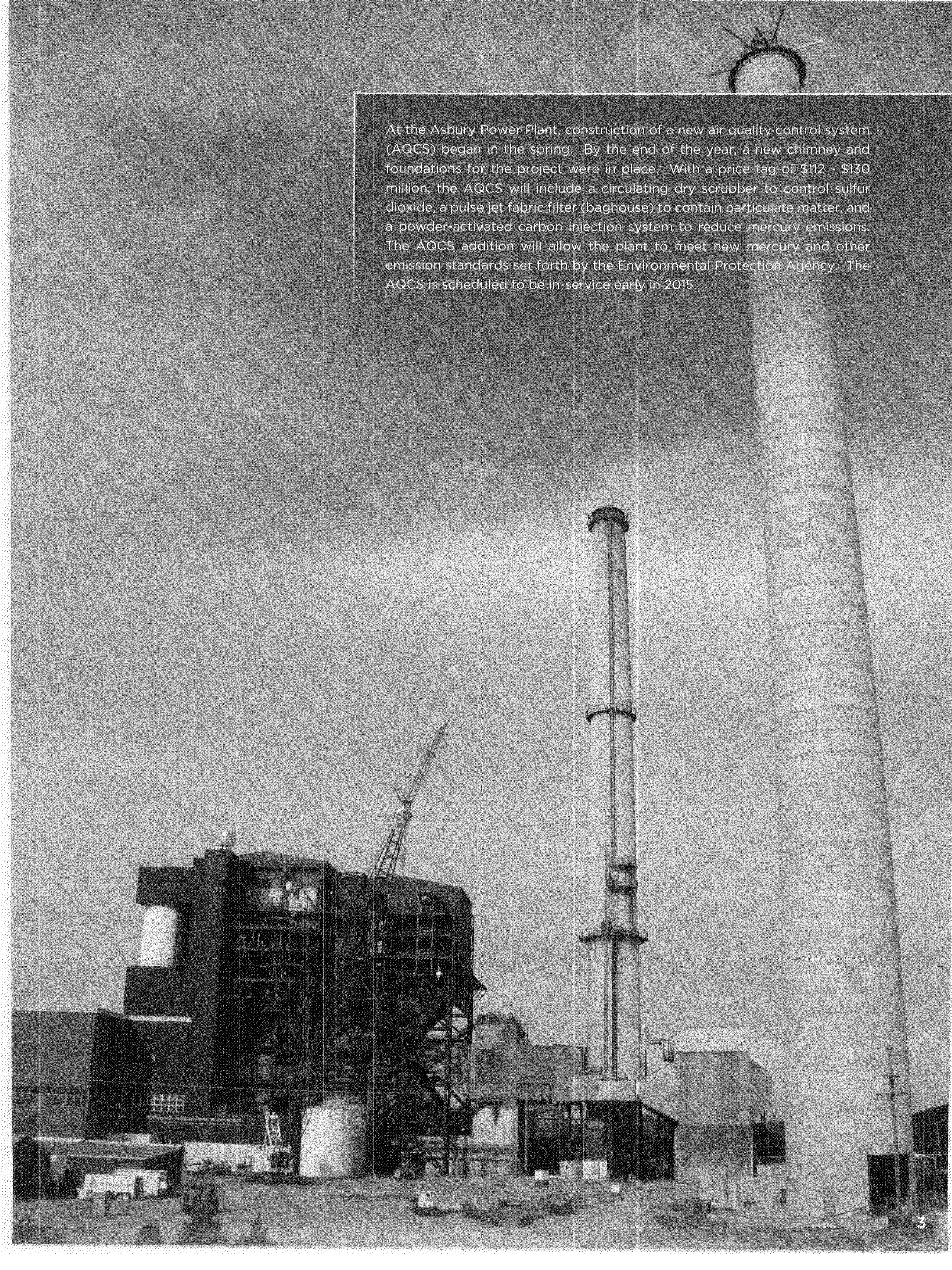
The focus of 2012 was not merely on outside infrastructure projects. Completion of large-scale internal projects remained as front-burner issues for employees throughout the Company.

Our most senior plant, Riverton Power Plant, underwent a major change in 2012. As outlined in previous annual reports, our current Integrated Resource Plan (IRP) on file with the Missouri Public Service Commission (MPSC) called for the transition from coal to exclusive use of natural gas at Riverton. After 107 years of using coal, on September 18 the switch was made when Units 7 and 8 began solely using natural gas. The next step in the process will be the conversion of Unit 12 to a combined cycle configuration. Once this is complete in 2016, Units 7, 8, and 9 will be retired. These steps allow us to comply with regulations from the Environmental Protection Agency (EPA) and continue energy generation for use by our customers.

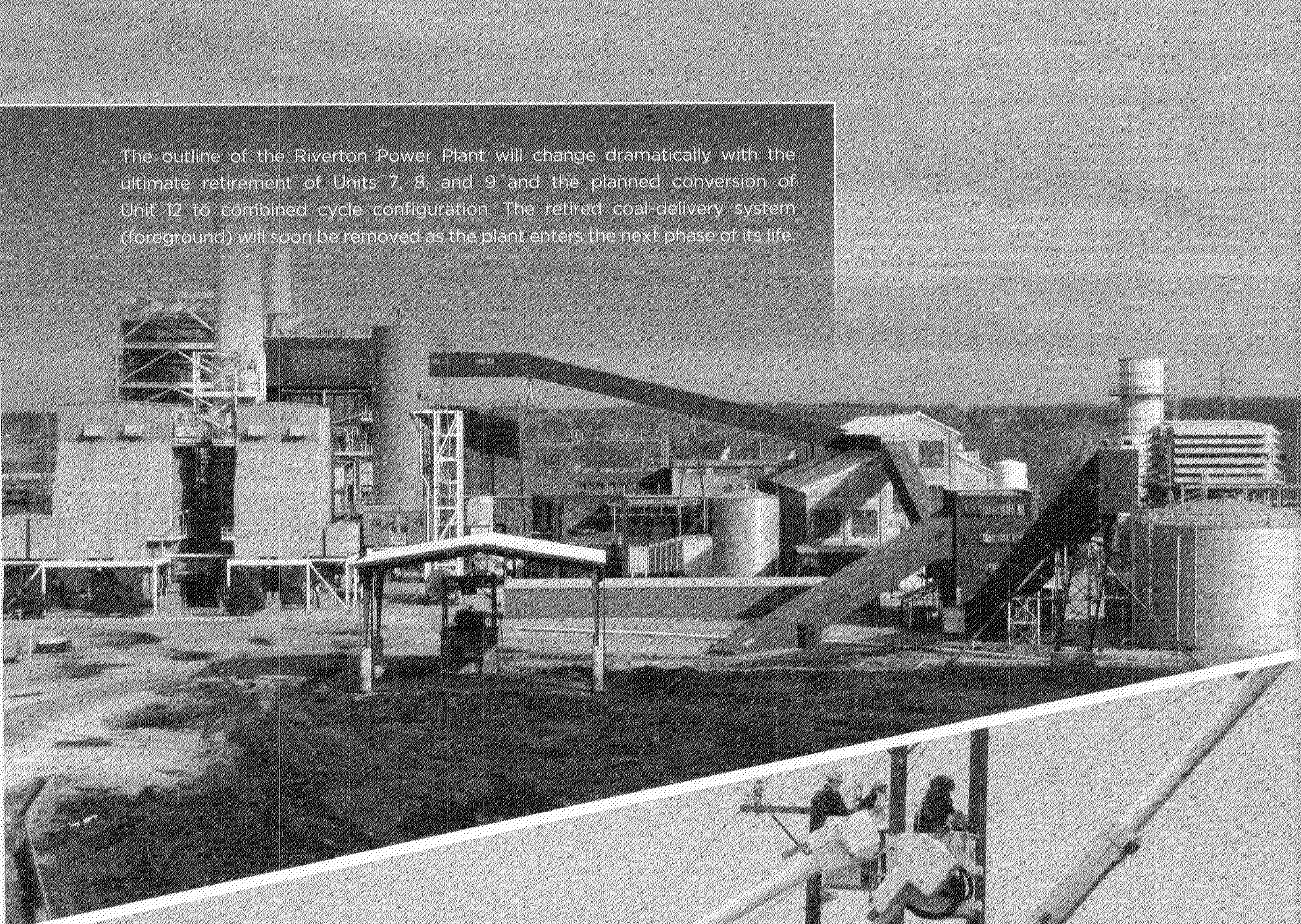
Our Web site underwent a renovation in June as a new, more user-friendly format was unveiled. Along with easier navigation, improved customer service features were added. Customers can submit online requests for their service to be transferred or stopped. They can also now receive their Empire bill in their inbox rather than their mailbox with the summer introduction of MyEbill. Over 2,800 customers had signed up by year end, and this number continues to grow. Additionally, we enhanced online payment and pay-by-phone options for customers with lower convenience fees. Further upgrades to provide more payment options are anticipated in the coming year.

The customer service team dedicated 2012 to improving our customer experience in the call center. We knew we had an opportunity to change customer perception by focusing on our call center statistics. From the first to the third quarter, we improved our percent of calls answered by five percent. At the beginning of the year, it took an average of one minute and 42 seconds before a caller was connected to a representative – in our opinion, too long for a customer to listen to on-hold messages. By the end of the third quarter, most callers were speaking with a customer service representative within 34 seconds – much better than the industry average of 45 seconds. Additionally, only three percent of callers disconnected with us before having their problem solved, surpassing the industry average of five percent. These changes all happened without adding personnel; instead customer service leadership challenged our employees to see what progress could be made. These phenomenal improvements show our call center representatives' dedication to doing an outstanding job of handling customer calls more efficiently.

The first phase of the implementation of Project Overhaul successfully occurred in 2012. A large team of employees from throughout the Company was tasked with completely overhauling the software systems for human resource support, financial reporting, and asset management as the current software systems no longer had vendor support. In addition, the first phase of new resource planning software was implemented.



At the Asbury Power Plant, construction of a new air quality control system (AQCS) began in the spring. By the end of the year, a new chimney and foundations for the project were in place. With a price tag of $112 - $130 million, the AQCS will include a circulating dry scrubber to control sulfur dioxide, a pulse jet fabric filter (baghouse) to contain particulate matter, and a powder-activated carbon injection system to reduce mercury emissions. The AQCS addition will allow the plant to meet new mercury and other emission standards set forth by the Environmental Protection Agency. The AQCS is scheduled to be in-service early in 2015.



The outline of the Riverton Power Plant will change dramatically with the ultimate retirement of Units 7, 8, and 9 and the planned conversion of Unit 12 to combined cycle configuration. The retired coal-delivery system (foreground) will soon be removed as the plant enters the next phase of its life.

Crews work along the Branson Highway 76 Strip to restore power after the February 29, 2012, tornado. Damage in the communities of Buffalo and Branson, Missouri, included nearly 50 transmission structures and 125 distribution poles.

Employees now have the ability to handle compensation and benefit administration online – from work or home. The new asset management and resource planning system improves the way we record, transfer, and manage information while providing enhanced capabilities for analysis and financial reporting. This is a multi-year project with the introduction of new elements planned for 2013.

Our natural gas business completed the replacement of the remaining 1930s-era high pressure distribution pipe on our system. During the year, we extended service to three new communities which are supported by our service center in Maryville, Missouri. This addition to our certificated area brought nearly 100 new customers.

The year was not without its challenges. On February 29, 2012, customers in Branson and Buffalo, Missouri, experienced highly unusual winter tornados. In Branson, the storm travelled down the famed "76 Strip" damaging our infrastructure. Local attractions and hotels bore the brunt of the storm, unfortunately, just a few days before the official kick-off of the tourist season. Our crews worked diligently, and within five days restored all customers who were able to receive service.

We continue to seek rate recovery through the regulatory commission in each jurisdiction for our ongoing investments to improve service and comply with environmental requirements. In July we filed for new rates for our Missouri electric customers. Our request seeks to recover operation and maintenance expenses and capital costs associated with the May 22, 2011, tornado, transmission charges allocated to Empire by the Southwest Power Pool (SPP) resulting from its efforts to make the transmission system more robust, operating system replacement expenses for our new software, costs associated with adhering to vegetation management rules required by the MPSC, and changes in depreciation rates. Local public hearings were held in early January 2013 on this case, and rates should be in place by June 2013.

Also on the regulatory front, we finalized new rates for our water customers in November providing approximately $450,000 in additional annual revenue.

In mid-2013, we plan to file our IRP with the MPSC. This plan serves as a comprehensive road map on how Empire plans to provide safe, reliable power to our customers, while anticipating challenges in our business from a variety of fronts. The results of the IRP are largely driven by outside forces such as the EPA, with new and changing environmental standards, and SPP, mandating new construction projects.

Low interest rates provided the opportunity to reduce interest costs. We refinanced approximately $88 million of First Mortgage Bonds – reducing our interest to 3.58 percent from 7 percent in the second quarter. We also have a commitment for financing of $30 million of First Mortgage Bonds at 3.73 percent and $120 million of First Mortgage Bonds at 4.32 percent all of which will be received in May 2013. This financing will replace $98 million of 4.5 percent bonds with the rest used for general corporate purposes.

The end of the year was dominated by discussion of the "fiscal cliff." Automatic increases would have nearly tripled the dividend tax rate if an agreement had not been reached by January 1. But, the New Year's Day deal prevented a majority of investors from seeing larger tax bills. Throughout the year we reminded our investors and employees to contact their representatives and senators to make their opinions known. A fair tax rate allows Empire to retain current shareholders and attract new investors, providing the capital necessary to fund projects – including our environmental upgrades at the Asbury Power Plant. We appreciate our investors who heard our call and responded with hundreds of letters and phone calls to members of Congress.

We closed 2012 with consolidated earnings of $55.7 million, or $1.32 per share. This compares with 2011 earnings of $54.9 million, or $1.31 per share. The board re-established the dividend in 2012 at an indicated annual rate of $1.00 per share. This indicated rate places our payout ratio more in line with our industry peers. In February 2012, we began providing annual earnings guidance and will continue to do so in 2013.

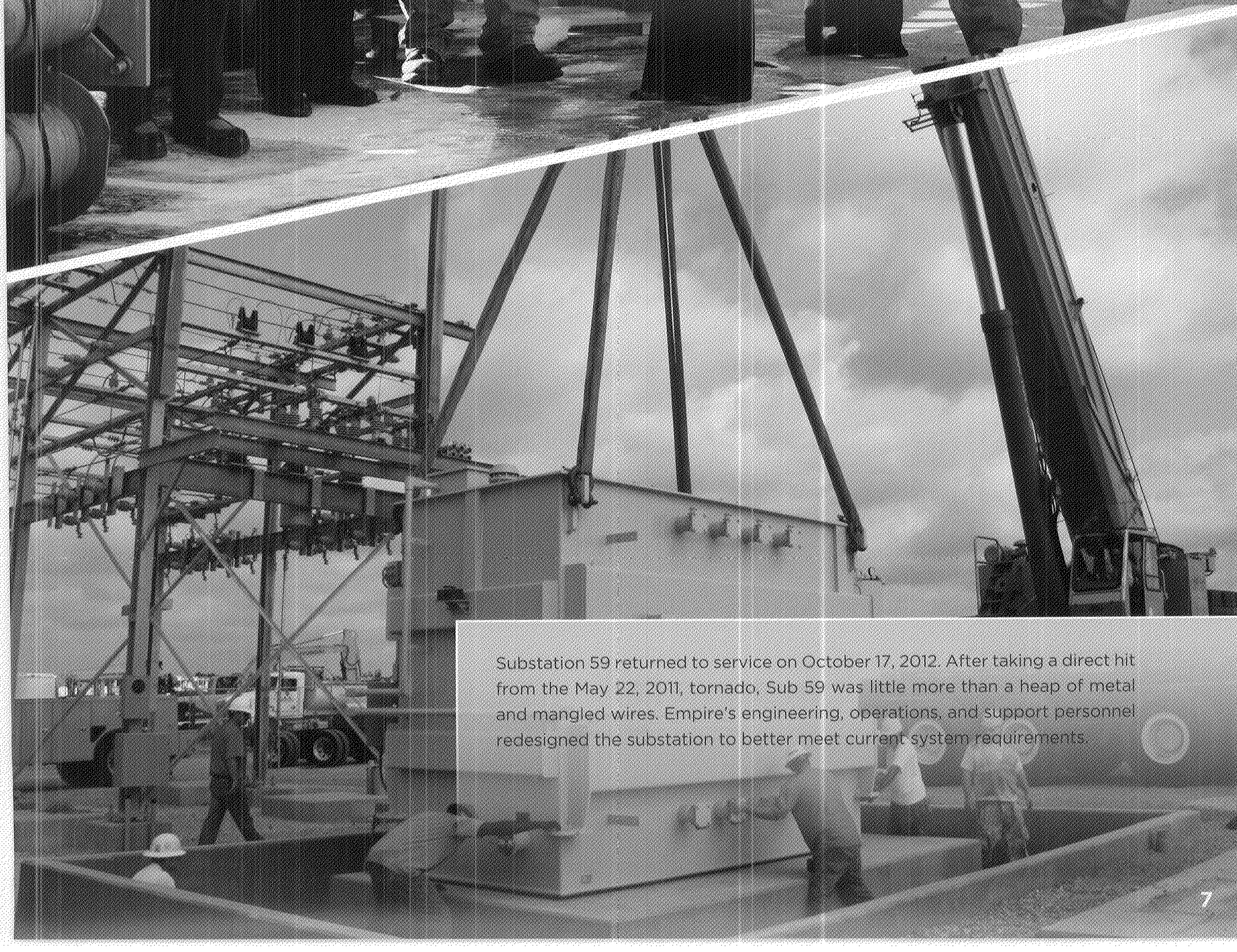
Moving into 2013, we keep a positive outlook for your Company. We do not take the trust you place in us lightly, so know Empire's focus remains on bringing a quality reliable product to our customers while providing a fair rate of return to our shareholders.

Brad Beecher

Brad Beecher
President and CEO
February 22, 2013

Project Overhaul included employees from every area of the Company during the demanding process of software development, testing, training, and implementation. Additional stages of the project will be launched in 2013 with a focus on continuous improvement.

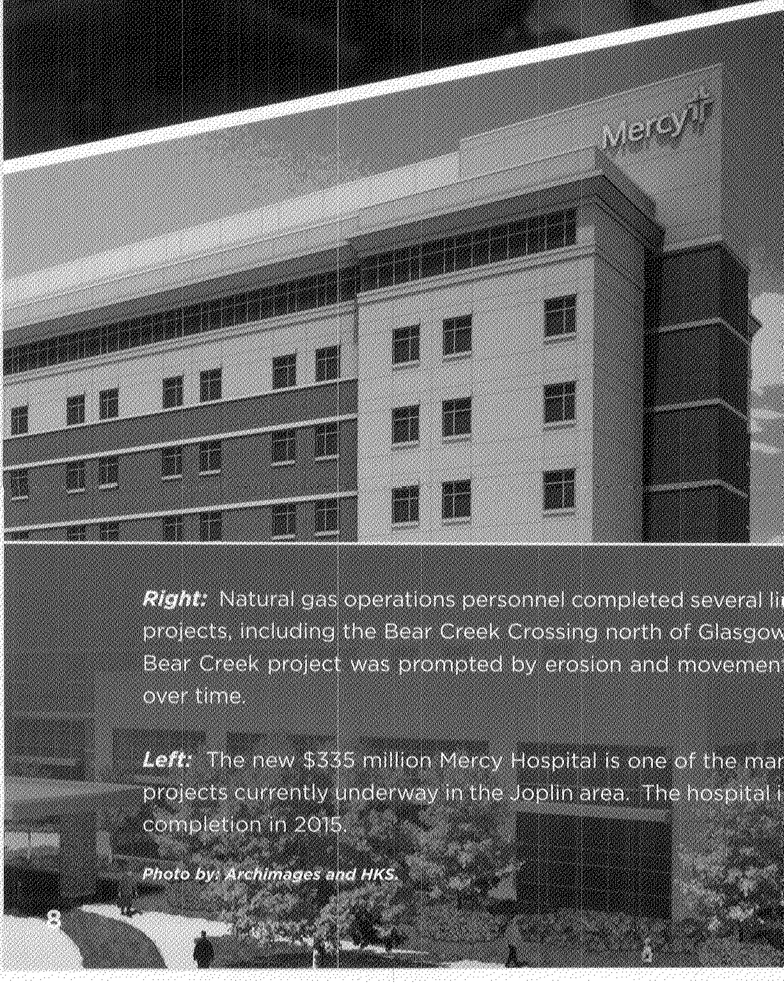
Pictured:* *Flo - General Accounting, Myra - Purchasing, Bill - Energy Supply, Ed - Construction Design, Yvonne - Information Technology, Nancy - Human Resources, Dema - Stores.



Substation 59 returned to service on October 17, 2012. After taking a direct hit from the May 22, 2011, tornado, Sub 59 was little more than a heap of metal and mangled wires. Empire's engineering, operations, and support personnel redesigned the substation to better meet current system requirements.

Call center representatives improved customer experiences with a concerted effort to shorten caller wait times. Resource improvements in the call center include a software upgrade and conversion to Voice Over Internet Protocol (VoIP) capability using Empire's existing network. This updated technology, completed in the fourth quarter, provides the call center with greater telecommunications flexibility and efficiency in managing periods of high call volumes. In addition, the VoIP solution replaces several independently maintained phone systems to achieve cost savings. Conversion to VoIP is continuing across the Company.

Pictured: Hayley (front), Tammy, Carla (standing), Rebecca.



Right: Natural gas operations personnel completed several line replacement projects, including the Bear Creek Crossing north of Glasgow, Missouri. The Bear Creek project was prompted by erosion and movement of creek beds over time.

Left: The new $335 million Mercy Hospital is one of the many construction projects currently underway in the Joplin area. The hospital is scheduled for completion in 2015.

Photo by: Archimages and HKS.

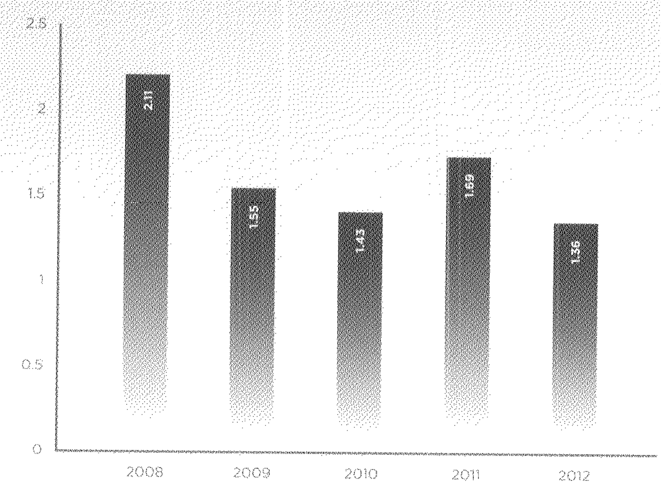
Service Reliability

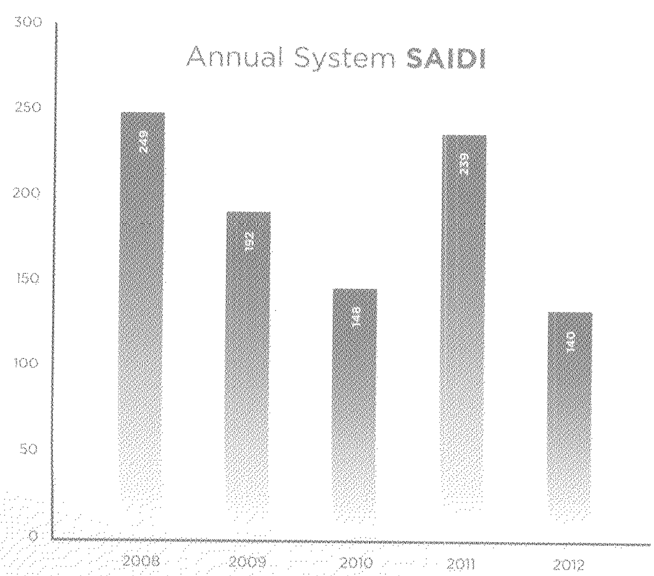
In 2012, we posted our best year yet in terms of service reliability. The data is measured using two primary factors - interruption frequency and duration. Since 2008, outage frequency has been reduced by more than 35 percent and outage duration has declined by over 43 percent. These positive results can largely be attributed to Operation Toughen Up, our 10-year, $100 million initiative to strengthen our delivery system, coupled with enhanced vegetation management practices.

Even with this progress, there is still work to be done. Our goal is to achieve a System Average Interruption Frequency Index (SAIFI) of 1.00 and a System Average Interruption Duration Index (SAIDI) of 100. The graphs below illustrate our progress. Major weather events are excluded from the data, although it is important to recognize that the residual effect of events like the May 22, 2011, tornado cannot be entirely eliminated from the data.

A major update to our Outage Management System completed in 2012 will further enhance service reliability for customers in 2013 and beyond. The upgraded system now utilizes cellular capability to improve the speed, efficiency, and reliability of data communications. This allows for better outage analysis and response.

Annual System **SAIFI**





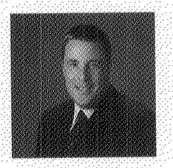
SAIFI

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

SAIDI

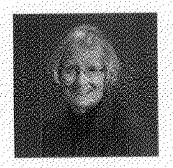
An index of 140 means the average customer experienced a total of 140 outage minutes during the year.

Officers[1]



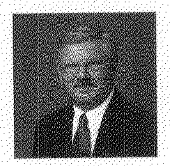
Bradley P. Beecher
President and Chief Executive Officer
(Age 47, 23 years of service)

Martin O. Penning
Vice President – Commercial Operations
(Age 58, 32 years of service)



Laurie A. Delano
Vice President – Finance and Chief Financial Officer
(Age 57, 22 years of service)

Kelly S. Walters
Vice President and Chief Operating Officer – Electric
(Age 47, 20 years of service)



Ronald F. Gatz
Vice President and Chief Operating Officer – Gas
(Age 62, 11 years of service)

Robert W. Sager
Controller, Assistant Secretary and Assistant Treasurer
(Age 38, 6 years of service)

Blake A. Mertens
Vice President – Energy Supply
(Age 35, 11 years of service)

Janet S. Watson
Secretary – Treasurer
(Age 60, 18 years of service)

Michael E. Palmer
Vice President – Transmission Policy and Corporate Services
(Age 56, 26 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, 2013.
[2] Audit Committee Financial Expert.

Directors

Kenneth R. Allen
Vice President – Finance and Chief Financial Officer
Texas Industries, Inc.
Dallas, Texas
(Age 55, Director since 2005)

Bradley P. Beecher
President and Chief Executive Officer
The Empire District Electric Company
(Age 47, Director since 2011)

William L. Gipson
Retired President and Chief Executive Officer
The Empire District Electric Company
(Age 56, Director since 2002)

Ross C. Hartley
Co-Founder and Director NIC, Inc.
Teton Village, Wyoming
(Age 65, Director since 1988)

D. Randy Laney
Chairman of the Board of Directors
The Empire District Electric Company
Farmington, Arkansas
(Age 58, Director since 2003)

Bonnie C. Lind
Senior Vice President, Chief Financial Officer, and Treasurer
Neenah Paper, Inc.
Alpharetta, Georgia
(Age 54, Director since 2009)

B. Thomas Mueller
Founder, President, and Chief Executive Officer, SALOV North America Corporation
Montclair, New Jersey
(Age 65, Director since 2003)

Thomas M. Ohlmacher
Retired President and Chief Operating Officer, Non-regulated Energy
Black Hills Corporation
Morrison, Colorado
(Age 61, Director since 2011)

Paul R. Portney
Professor of Economics and former Dean, Eller College of Management
University of Arizona
Tucson, Arizona
(Age 67, Director since 2009)

Herbert J. Schmidt
Retired Executive Vice President Con-way Inc and President Con-way Truckload
Joplin, Missouri
(Age 57, Director since 2010)

C. James Sullivan
Principal
The Sullivan Group LLC
Birmingham, Alabama
(Age 66, Director since 2010)

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

MAR 13 2013

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, 2012

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, 2012, was approximately $892,694,285.

As of February 1, 2013, 42,535,367 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 April 25, 2013	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, impacts from the 2011 tornado, 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, recovery and rebuilding efforts relating to the 2011 tornado 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, fuel and purchased power costs and Southwest Power Pool (SPP) regional transmission organization (RTO) expansion costs, including any regulatory disallowances that could result from prudency reviews;
- legislation and regulation, including environmental regulation (such as NOx, SO_2, mercury, ash and CO_2) and health care regulation;
- competition and markets, including the SPP Energy Imbalance Services Market and SPP Day-Ahead Market;
- electric utility restructuring, including ongoing federal activities and potential state activities;
- volatility in the credit, equity and other financial markets and the resulting impact on our 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;
- the periodic revision of our construction and capital expenditure plans and cost and timing estimates;
- our exposure to the credit risk of our hedging counterparties;
- changes in accounting requirements (including the potential consequences of being required to report in accordance with IFRS rather than U. S. GAAP);
- unauthorized physical or virtual access to our facilities and systems and acts of terrorism, including, but not limited to, cyber-terrorism;
- the timing of accretion estimates, and integration costs relating to completed and contemplated acquisitions and the performance of acquired businesses;
- 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;

- the success of efforts to invest in and develop new opportunities;
- the cost and availability of purchased power and fuel, 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;
- 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 1

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 2012 were derived as follows:

Electric segment sales*	91.7%
Gas segment sales	7.1
Other segment sales	1.2

* Sales from our electric segment include 0.3% 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, 2012, our electric operations served approximately 167,900 customers.

Our retail electric revenues for 2012 by jurisdiction were derived as follows:

Missouri	89.3%
Kansas	5.1
Arkansas	2.7
Oklahoma	2.9

We supply electric service at retail to 119 incorporated communities as of December 31, 2012, 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 52% of our electric operating revenues in 2012 were derived from incorporated communities with franchises having at least ten years remaining and approximately 18% 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 42.2%, 31.2%, and 15.5%, respectively, of our electric operating revenues in 2012.

Our largest single on-system wholesale customer is the city of Monett, Missouri, which in 2012 accounted for approximately 2.8% of electric revenues. No single retail customer accounted for more than 1.7% of electric revenues in 2012.

Our gas operations serve customers in northwest, north central and west central Missouri. As of December 31, 2012, our gas operations served approximately 44,000 customers. We provide natural gas distribution to 48 communities and 330 transportation customers as of December 31, 2012. 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. Twenty of the franchises have 10 years or more 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 2012 were derived as follows:

Residential	62.1%
Commercial	27.1
Industrial	1.2
Miscellaneous	9.6

No single retail customer accounted for more than 1% of gas revenues in 2012.

Our other segment consists of our fiber optics business. As of December 31, 2012, we have 106 fiber customers.

Electric Generating Facilities and Capacity

At December 31, 2012, our generating plants consisted of:

Plant	Capacity (megawatts)(1)	Primary Fuel
Asbury	203	Coal
Riverton — Coal	0(2)	Coal
Riverton — Natural Gas	279(2)	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	1,391	

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

(2) In September 2012, Riverton Units 7 and 8 transitioned from operation on coal to full operation on natural gas.

(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 — Competition."

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. Our long-term contract with Westar Energy for the purchase of 162 megawatts of capacity and energy ended May 31, 2010. In order to replace this capacity and energy, we entered into contracts for energy and capacity from two new plants that became operational in 2010, Plum Point Energy Station and the Iatan 2 generating facility, each of which is described below.

The Plum Point Energy Station (Plum Point) is a 670-megawatt, coal-fired generating facility near Osceola, Arkansas which entered commercial operation on September 1, 2010. 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 began receiving purchased power under this agreement on September 1, 2010. 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. We will, however, continue to analyze this option during our 2013 Integrated Resource Plan (IRP) process, which we expect to file with the Missouri Public Service Commission (MPSC) in mid-2013.

We also own an undivided ownership interest in the coal-fired Iatan 2 generating facility operated by Kansas City Power & Light Company (KCP&L) and located at the site of the existing 85-megawatt Iatan Generating Station (Iatan 1) near Weston, Missouri. We own 12%, or approximately 105 megawatts, of the 850-megawatt unit, which entered commercial operation on December 31, 2010.

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 (formerly Horizon Wind Energy), 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
2013	65	1391	1456
2014	65	1391	1456
2015	65	1377	1442(2)
2016	65	1383	1448(3)
2017	65	1383	1448

(1) Includes 7 megawatts for the Elk River Windfarm, LLC and 8 megawatts for the Cloud County Windfarm, LLC.

(2) Reflects the planned retirement of Asbury Unit 2.

(3) Reflects the planned 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. Our previous summer record peak of 1,173 megawatts was established on August 15, 2007.

Gas Facilities

At December 31, 2012, our principal gas utility properties consisted of approximately 87 miles of transmission mains and approximately 1,148 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, replacing the previous record of 70,820 mcfs which was set on January 4, 2010.

Construction Program

Total property additions (including construction work in progress but excluding AFUDC) for the three years ended December 31, 2012, amounted to $343.6 million and retirements during the same period amounted to $36.8 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 $142.6 million in 2012 and for the next three years are estimated for planning purposes to be as follows:

	Estimated Capital Expenditures (amounts in millions)			
	2013	2014	2015	Total
New electric generating facilities:				
Riverton Unit 12 combined cycle conversion	$ 15.1	$ 40.4	$ 65.3	$120.8
Additions to existing electric generating facilities:				
Asbury	11.1	16.7	8.1	35.9
Environmental upgrades — Asbury	55.8	24.8	12.1	92.7
Other	10.7	4.9	9.4	25.0
Electric transmission facilities	12.1	26.7	36.3	75.1
Electric distribution system additions	42.9	38.3	36.3	117.5
General and other additions	10.1	7.9	4.8	22.8
Gas system additions	4.1	4.1	4.1	12.3
Non-regulated additions	1.5	1.7	1.7	4.9
TOTAL	$163.4	$165.5	$178.1	$507.0

Our estimated total capital expenditures (excluding AFUDC) for 2016 and 2017 are $107.0 million and $108.2 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.

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 — Competition."

Fuel and Natural Gas Supply

Electric Segment

Our total system output for 2012 and 2011, based on kilowatt-hours generated, was as follows:

	2012	2011
Steam generation units — coal	48.0%	45.0%
Steam generation units — natural gas	0.2	2.3
Combustion turbine generation units — natural gas	24.9	23.9
Hydro generation	1.0	0.8
Purchased power — windfarms	15.0	13.4
Purchased power — other	10.9	14.6

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

Coal	65.6%
Natural gas	34.3
Fuel oil	0.1

The amount and percentage of electricity generated by natural gas increased in 2012 as compared to 2011 while the amount of energy we purchased decreased, primarily reflecting that it was more economical to produce gas-fired generation than to purchase power during this period.

During 2012, we utilized our remaining coal inventory at our Riverton Plant, completing our transition of Units 7 and 8 to natural gas. This was done as part of our environmental Compliance Plan, discussed in Note 11 of "Notes to Consolidated Financial Statements" under Item 8. Riverton Unit 12, a Siemens V84.3A2 gas combustion turbine installed in 2007, and three other smaller units are also fueled by natural gas. Natural gas is now the primary fuel at our Riverton Plant.

Our Asbury Plant is fueled primarily by coal with oil being used as start-up fuel. In 2012, Asbury burned a coal blend consisting of approximately 92.7% Western coal (Powder River Basin) and 7.3% blend coal on a tonnage basis. Our average coal inventory target at Asbury is approximately 60 days. As of December 31, 2012, we had sufficient coal on hand to supply full load requirements at Asbury for 102-107 days, as compared to 47-94 days as of December 31, 2011, depending on the actual blend ratio. The inventory increased during 2012 as coal destined for Riverton was diverted to Asbury to facilitate the conversion 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
2013	100%
2014	58%
2015	26%

All of the Western coal used at our Asbury plant is shipped by rail, a distance of approximately 800 miles. We entered into an amended coal transportation contract on August 7, 2012, with the Burlington Northern and Santa Fe Railway Company (BNSF) and the Kansas City Southern Railway Company due to the reduction of coal usage resulting from Riverton's conversion to natural gas. The amendment reduces the annual minimum tons for the years 2013 through 2016 and extends the contract 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 100% of Iatan's requirements for 2013 and approximately 75% for 2014 and 20% for 2015. The coal is transported by rail under a contract with BNSF Railway, which expires on December 31, 2013. KCP&L and KCP&L Greater Missouri Operations are currently in negotiations with the railroads for transportation services beyond 2013.

The Plum Point Energy Station is a 670-megawatt, coal-fired generating facility near Osceola, Arkansas. The plant began commercial operation on September 1, 2010. 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 2013, 86% 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. In December 2010, we entered into another 15-year lease agreement for an additional 54 railcars associated with our Plum Point purchased power agreement.

Our Energy Center and State Line 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 2012, Energy Center generation was 99.0% natural gas with the remainder being fuel oil, and 100% of the State Line Unit 1 generation came from natural gas. As of December 31, 2012, 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. Additional oil will be purchased as needed.

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	2012	2011	2010
Coal — Iatan	$ 1.760	$ 1.603	$ 1.193
Coal — Asbury	2.395	2.315	1.877
Coal — Riverton	2.541	2.314	1.833
Coal — Plum Point	1.804	1.858	1.799
Natural Gas	4.493	5.475	6.061
Oil	20.291	21.304	15.443
Weighted average cost of fuel burned per kilowatt-hour generated	2.6742	2.9558	2.9936

Gas Segment

We have 10,000 MMBtus per day of firm transportation from Cheyenne Plains Pipeline Company. This can provide us with up to 75% of our natural gas purchases from the Rocky Mountain gas area. Cheyenne Plains interconnects with all of the interstate pipelines listed below that feed our market area.

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	2012	2011	2010
South	Southern Star Central Gas Pipeline	$6.4329	$6.1619	$6.7068
North	Panhandle Eastern Pipe Line Company	6.8990	6.1449	6.1151
Northwest	ANR Pipeline Company	5.0898	5.4230	5.3216
	Weighted average cost per mcf	$6.3305	$6.0542	$6.3745

Employees

At December 31, 2012, we had 756 full-time employees, including 51 employees of EDG. 331 of the EDE employees are members of Local 1474 of The International Brotherhood of Electrical Workers (IBEW). On October 17, 2011, the Local 1474 IBEW voted to ratify a new two-year agreement which will extend through October 31, 2013. At December 31, 2012, 34 EDG employees were members of Local 1464 of the IBEW. In June 2009, Local 1464 of the IBEW ratified a four-year agreement with EDG, which expires on June 1, 2013. Negotiations toward new contracts will occur during 2013 in advance of contract expiration with both Local 1474 and Local 1464.

ELECTRIC OPERATING STATISTICS[1]

	2012	2011	2010	2009	2008
Electric Operating Revenues (000's):					
Residential	$ 214,526	$ 221,687	$ 204,900	$ 180,404	$ 179,293
Commercial	158,837	157,435	146,310	135,800	132,888
Industrial	78,786	78,925	69,684	65,983	67,353
Public authorities[2]	13,755	13,653	12,099	11,411	10,876
Wholesale on-system	18,555	19,140	19,254	18,199	19,229
Miscellaneous[3]	8,520	8,194	7,573	6,814	6,976
Interdepartmental	197	201	199	178	154
Total system	493,176	499,235	460,019	418,789	416,769
Wholesale off-system	15,687	23,271	22,891	14,344	29,697
Total electric operating revenues[4]	**508,863**	**522,506**	**482,910**	**433,133**	**446,466**
Electricity generated and purchased (000's of kWh):					
Steam	2,865,037	2,805,744	2,650,042	2,259,304	2,228,716
Hydro	57,719	48,898	88,104	76,733	32,601
Combustion turbine	1,486,643	1,484,472	1,566,074	926,934	1,480,729
Total generated	4,409,399	4,339,114	4,304,220	3,262,971	3,742,046
Purchased	1,545,327	1,870,901	2,085,550	2,516,702	2,440,246
Total generated and purchased	5,954,726	6,210,015	6,389,770	5,779,673	6,182,292
Interchange (net)	(87)	(1,298)	(1,716)	(568)	(436)
Total system output	5,954,639	6,208,717	6,388,054	5,779,105	6,181,856
Transmission by others losses[5]	(17,300)	(16,597)	(5,688)	—	—
Total system input	**5,937,339**	**6,192,120**	**6,382,366**	**5,779,105**	**6,181,856**
Maximum hourly system demand (Kw)	1,142,000	1,198,000	1,199,000	1,085,000	1,152,000
Owned capacity (end of period) (Kw)	1,391,000	1,392,000	1,409,000	1,257,000	1,255,000
Annual load factor (%)	52.17	51.95	53.17	55.38	54.29
Electric sales (000's of kWh):					
Residential	1,850,813	1,982,704	2,060,368	1,866,473	1,952,869
Commercial	1,558,297	1,576,342	1,644,917	1,579,832	1,622,048
Industrial	1,028,416	1,022,765	1,007,033	992,165	1,073,250
Public authorities[2]	122,369	126,724	124,554	121,816	122,375
Wholesale on-system	353,075	364,866	355,807	332,061	344,525
Total system	4,912,970	5,073,401	5,192,679	4,892,347	5,115,067
Wholesale off-system	704,028	740,009	798,084	515,899	688,203
Total Electric Sales	**5,616,998**	**5,813,410**	**5,990,763**	**5,408,246**	**5,803,270**
Company use (000's of kWh)[6]	9,066	9,371	9,598	9,088	9,209
kWh losses (000's of kWh)[7]	311,275	369,339	382,005	361,771	369,377
Total System Input	**5,937,339**	**6,192,120**	**6,382,366**	**5,779,105**	**6,181,856**
Customers (average number):					
Residential	140,602	139,641	141,693	141,206	140,791
Commercial	24,036	24,155	24,505	24,412	24,532
Industrial	353	357	358	355	361
Public authorities[2]	2,124	2,021	2,003	1,995	1,935
Wholesale on-system	4	4	4	4	4
Total System	167,119	166,178	168,563	167,972	167,623
Wholesale off-system	22	25	22	19	22
Total	**167,141**	**166,203**	**168,585**	**167,991**	**167,645**
Average annual sales per residential customer (kWh)	13,163	14,199	14,541	13,218	13,871
Average annual revenue per residential customer	$ 1,526	$ 1,588	$ 1,446	$ 1,278	$ 1,273
Average residential revenue per kWh	11.59¢	11.18¢	9.94¢	9.67¢	9.18¢
Average commercial revenue per kWh	10.19¢	9.99¢	8.89¢	8.60¢	8.19¢
Average industrial revenue per kWh	7.66¢	7.72¢	6.92¢	6.65¢	6.28¢

(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) Includes the effect of our unbilled revenue adjustment.

GAS OPERATING STATISTICS[1]

	2012	2011	2010	2009	2008
Gas Operating Revenues (000's):					
Residential	$24,744	$28,999	$32,245	$36,176	$39,639
Commercial	10,797	12,506	13,336	15,552	17,416
Industrial	464	682	812	2,066	5,069
Public authorities	247	324	342	365	416
Total retail sales revenues	36,252	42,511	46,735	54,159	62,540
Miscellaneous[2]	400	464	436	221	231
Transportation revenues	3,197	3,455	3,714	2,934	2,667
Total Gas Operating Revenues	**39,849**	**46,430**	**50,885**	**57,314**	**65,438**
Maximum Daily Flow (mcf)	**58,281**	**67,789**	**73,280**	**70,046**	**66,005**
Gas delivered to customers (000's of mcf sales)[3]					
Residential	2,012	2,560	2,675	2,687	2,949
Commercial	1,050	1,268	1,265	1,278	1,397
Industrial	58	102	108	218	553
Public authorities	23	33	33	30	35
Total retail sales	3,143	3,963	4,081	4,213	4,934
Transportation sales	4,249	4,528	4,829	4,330	4,059
Total gas operating and transportation sales	7,392	8,491	8,910	8,543	8,993
Company use[3]	2	4	4	3	4
Transportation sales (cash outs)	—	—	—	—	—
Mcf losses	27	(47)	70	36	140
Total system sales	**7,421**	**8,448**	**8,984**	**8,582**	**9,137**
Customers (average number):					
Residential	37,897	38,051	38,277	38,621	39,159
Commercial	4,921	4,951	4,968	5,038	5,119
Industrial	23	26	26	25	26
Public authorities	138	136	137	131	127
Total retail customers	42,979	43,164	43,408	43,815	44,431
Transportation customers	326	311	313	296	272
Total gas customers	**43,305**	**43,475**	**43,721**	**44,111**	**44,703**

(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, 2012, 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 12/31/12	Positions With the Company	With the Company Since	Officer Since
Bradley P. Beecher	47	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	57	Vice President — Finance and Chief Financial Officer, (2011), Controller, Assistant Secretary and Assistant Treasurer and Principal Accounting Officer (2005)	2002	2005
Ronald F. Gatz	62	Vice President and Chief Operating Officer — Gas (2006)	2001	2001
Blake Mertens	35	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	56	Vice President — Transmission Policy and Corporate Services (2011), Vice President — Commercial Operations (2001)	1986	2001
Martin O. Penning	57	Vice President — Commercial Operations, (2011), Director of Commercial Operations (2006)	1980	2011
Kelly S. Walters	47	Vice President and Chief Operating Officer — Electric (2011), Vice President — Regulatory and Services (2006)	2001	2006
Janet S. Watson	60	Secretary — Treasurer (1995)	1994	1995
Robert W. Sager	38	Controller, Assistant Secretary and Assistant Treasurer and Principal Accounting Officer (2011), Director of Financial Services (2006)	2006	2011

Regulation

Electric Segment

General. As a public utility, our electric segment operations are subject to the jurisdiction of the 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 — Competition."

During 2012, approximately 91.6% of our electric operating revenues was received from retail customers. Sales subject to FERC jurisdiction represented approximately 7.6% of our electric operating revenues during 2012 with the remaining 0.8% being from miscellaneous sources. The percentage of retail regulated revenues derived from each state follows:

Missouri	89.3%
Kansas	5.1
Oklahoma	2.9
Arkansas	2.7

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, 2012, would permit us to issue approximately $609.2 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, 2012, we had retired bonds and net property additions which would enable the issuance of at least $776.7 million principal amount of bonds if the annual interest requirements are met. As of December 31, 2012, 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, 2012, this test would allow us to issue approximately $12.8 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) 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; 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, 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. 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.

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.

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*	Baa2	BBB−
EDE First Mortgage Bonds	BBB+	A3	BBB+
Senior Notes	BBB	Baa2	BBB−
Commercial Paper	F3	P-2	A-3
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 $507.0 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 $163.4 million in 2013. 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. Our pension plan and Other Postretirement Benefits (OPEB) costs increased, resulting in an $8.2 million increase in our 2011 net pension and OPEB liability. During 2012, our net pension and OPEB liability increased $15.9 million. We expect to fund approximately $20.1 million in 2013 for pension and OPEB liabilities. 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

At December 31, 2012, we owned generating facilities with an aggregate generating capacity of 1,391 megawatts.

Our principal electric baseload generating plant is the Asbury Plant with 203 megawatts of generating capacity. The plant, located near Asbury, Missouri, is a coal-fired generating station with two steam turbine generating units. The plant presently accounts for approximately 14% of our owned generating capacity and in 2012 accounted for approximately 26.5% of the energy generated by us. 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 now likely to be recovered through our fuel adjustment clauses. The Unit No. 2 turbine is inspected approximately every 35,000 hours of operations and was last inspected in 2001. As of December 31, 2012, Unit No. 2 has operated approximately 3,393 hours since its last turbine inspection in 2001. As part of our environmental Compliance Plan, discussed in Note 11 of "Notes to Consolidated Financial Statements" under Item 8, we have begun the installation of 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 and will require the retirement of Asbury Unit 2.

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 2016.

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 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. Westar reimburses us for a percentage of the operating costs per our joint ownership agreement. We are the operator of the Combined Cycle Unit. 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 will be 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 would 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 June 17, 2010, the SWPA posted a revised Final Determination that our customers' damages were $26.6 million. On September 16, 2010, we received a $26.6 million payment from the SWPA, which was deferred and recorded as a noncurrent liability. We originally increased our current tax liability by approximately $10.0 million recognizing that the $26.6 million payment might have been considered taxable income in 2010. During the first quarter of 2011, we submitted a pre-filing agreement with the Internal Revenue Service (IRS) requesting that a determination be made regarding whether or not the payment could be deferred under certain sections of the Internal Revenue code. The IRS accepted our position that the payment be deferred for tax purposes and recognized over the next twenty years. As such, we reduced the current tax liability in accordance with this deferral. The SWPA payment, net of taxes, is being used to reduce fuel expense for our customers in all our jurisdictions. In addition, it is our current understanding that the SWPA has delayed the implementation of the new minimum flows until 2016.

At December 31, 2012, 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 6,862 miles of line at December 31, 2012 as compared to 6,842 miles of line at December 31, 2011.

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, 2012, our principal gas utility properties consisted of approximately 87 miles of transmission mains and approximately 1,148 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 1, 2013, there were 4,548 record holders and 29,051 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 2012 and 2011.

	High	Low	Close	Dividends Paid Per Share
2012 Quarter Ended:				
March 31	$21.34	$19.55	$20.35	$0.25
June 30	21.24	19.51	21.10	0.25
September 30	21.94	21.02	21.55	0.25
December 31	22.04	19.59	20.38	0.25
2011 Quarter Ended:				
March 31	$22.40	$20.70	$21.79	$0.32
June 30	23.26	18.01	19.26	0.32
September 30	21.12	18.10	19.38	0.00
December 31	21.40	18.41	21.09	0.00

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 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. As of December 31, 2012, our retained earnings balance was $47.1 million, compared to $33.7 million at December 31, 2011. 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 2012, 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.

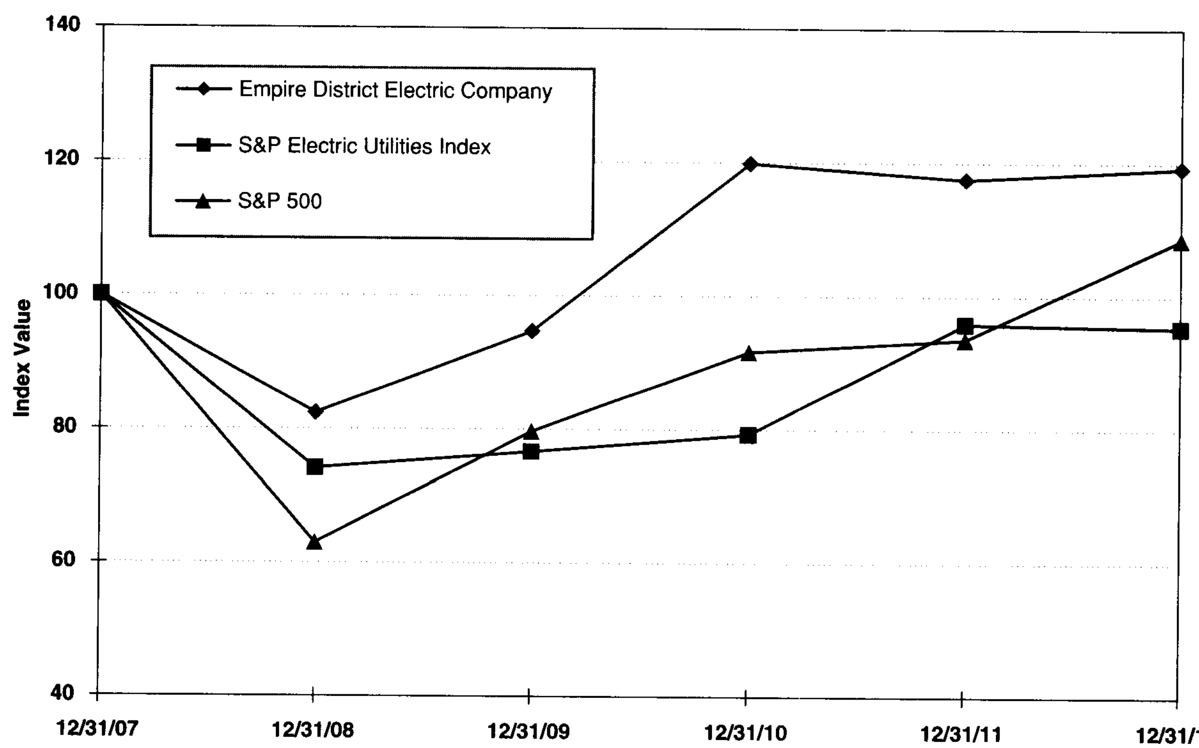
Our shareholders rights plan, dated July 26, 2000, expired July 25, 2010, pursuant to its terms. See Note 5 of "Notes to Consolidated Financial Statements" under Item 8 for additional information. In addition, we have stock based compensation programs which are described in Note 4 of "Notes to Consolidated Financial Statements" under Item 8.

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, 2007, 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	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011	12/31/2012
The Empire District Electric Company	$100.00	$82.37	$94.70	$119.87	$117.55	$119.27
S&P Electric Utilities Index	$100.00	$74.16	$76.66	$ 79.30	$ 95.92	$ 95.39
S&P 500 Index	$100.00	$63.00	$79.68	$ 91.68	$ 93.61	$108.59

ITEM 6. SELECTED FINANCIAL DATA

(in thousands, except per share amounts)

	2012	2011	2010	2009	2008
Operating revenues	**$ 557,097**	$ 576,870	$ 541,276	$ 497,168	$ 518,163
Operating income	**$ 96,221**	$ 96,934	$ 80,495	$ 74,495	$ 71,012
Total allowance for funds used during construction	**$ 1,928**	$ 512	$ 10,174	$ 14,133	$ 12,518
Income from continuing operations	**$ 55,681**	$ 54,971	$ 47,396	$ 41,296	$ 39,722
Net income	**$ 55,681**	$ 54,971	$ 47,396	$ 41,296	$ 39,722
Weighted average number of common shares outstanding — basic	**42,257**	41,852	40,545	34,924	33,821
Weighted average number of common shares outstanding — diluted	**42,284**	41,887	40,580	34,956	33,860
Earnings from continuing operations per weighted average share of common stock — basic and diluted	**$ 1.32**	$ 1.31	$ 1.17	$ 1.18	$ 1.17
Total earnings per weighted average share of common stock — basic and diluted	**$ 1.32**	$ 1.31	$ 1.17	$ 1.18	$ 1.17
Cash dividends per share	**$ 1.00**	$ 0.64	$ 1.28	$ 1.28	$ 1.28
Common dividends paid as a percentage of net income	**75.9%**	48.6%	109.7%	108.5%	109.0%
Allowance for funds used during construction as a percentage of net income	**3.5%**	0.9%	21.5%	34.2%	31.5%
Book value per common share (actual) outstanding at end of year	**$ 16.90**	$ 16.53	$ 15.82	$ 15.75	$ 15.56
Capitalization:					
Common equity	**$ 717,798**	$ 693,989	$ 657,624	$ 600,150	$ 528,872
Long-term debt	**$ 691,626**	$ 692,259	$ 693,072	$ 640,156	$ 611,567
Ratio of earnings to fixed charges	**2.89X**	2.87X	2.63X	2.15X	2.19x
Total assets	**$2,126,369**	$2,021,835	$1,921,311	$1,839,846	$1,713,846
Plant in service at original cost	**$2,284,022**	$2,176,650	$2,108,115	$1,718,584	$1,586,152
Capital expenditures (including AFUDC)	**$ 146,287**	$ 101,177	$ 108,157	$ 148,804	$ 206,405

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. 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. Due to the devastating EF-5 tornado that hit the Joplin, Missouri area on May 22, 2011, damaging or destroying thousands of homes and businesses (discussed below), our system-wide customer count was down by approximately 400 customers as of December 31, 2012 as compared to the customer count levels prior to the May 2011 tornado. We expect an average annual customer growth range of approximately 0.7% to 1.2% over the next several years. We expect the corresponding weather normalized sales growth to be approximately 1.5% in the near term as the Joplin area rebuilding activity continues. We then expect sales growth to flatten to a range of 0.4% to 0.9% over the next several years. We define electric sales growth to be growth in kWh sales period over period excluding the 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, 2012 was 0.2%, 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, 2012, basic and diluted earnings per weighted average share of common stock were $1.32 on $55.7 million of net income compared to $1.31 on $54.9 million of net income for the year ended December 31, 2011. Increased electric gross margins (defined as electric revenues less fuel and purchased power costs) positively impacted net income for the twelve months ended December 31, 2012 as compared to the same period in 2011, reflecting a decrease in revenues of approximately $13.6 million and a decrease in electric fuel and purchased power expenses of approximately $21.4 million compared to 2011. Decreased depreciation, reflecting a decrease in regulatory amortization expense due to the termination of construction accounting as of June 15, 2011 also positively impacted net income for the twelve months ended December 31, 2012. Other operating and maintenance expenses increased during 2012, negatively impacting net income.

The table below sets forth a reconciliation of basic and diluted earnings per share between 2011 and 2012, 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 on a per share basis before the impact of additional stock issuances.

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 previous years. 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.

This reconciliation may not be comparable to other companies or more useful than the GAAP presentation included in the statements of income. 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. The dilutive effect of additional shares issued included in the table reflects the estimated impact of all shares issued during the period.

Earnings Per Share — 2011	$ 1.31
Revenues	
Electric segment	$(0.20)
Gas segment	(0.10)
Other segment	0.01
Total Revenue	(0.29)
Electric fuel and purchased power	0.31
Cost of natural gas sold and transported	0.06
Margin	0.08
Operating — electric segment	(0.13)
Operating — gas segment	0.00
Operating — other segment	(0.01)
Maintenance and repairs	0.01
Depreciation and amortization	0.05
Other taxes	(0.01)
Interest charges	0.00
AFUDC	0.02
Change in effective income tax rates	0.01
Dilutive effect of additional shares issued	(0.01)
Other income and deductions	0.00
Earnings Per Share — 2012	**$ 1.32**

Fourth Quarter Results

Earnings for the fourth quarter of 2012 were $9.6 million, or $0.23 per share, as compared to $8.7 million, or $0.21 per share, in the fourth quarter of 2011. Electric segment gross margins grew slightly during the quarter ending December 31, 2012 compared to the 2011 quarter, reflecting decreased revenues of approximately $3.9 million and a decrease in fuel and purchased power costs of approximately $4.4 million. The impact of milder weather experienced during the fourth quarter of 2012 was offset by improving electric customer counts. Depreciation and amortization expense increased approximately $0.8 million and other regulated operating expenses increased $0.8 million in the fourth quarter of 2012, primarily related to increased employee health care expense. These increases were offset by a $1.8 million decrease in maintenance and repairs expense.

2012 Activities

Financings

During the year we took advantage of lower interest rates.

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 is anticipated to occur on or about May 30, 2013, subject to customary closing conditions. We expect to use the proceeds from the sale of the bonds to redeem all $98.0 million aggregate principal amount of our Senior Notes, 4.50% Series due June 15, 2013 with the remaining proceeds to be used for general corporate purposes. The bonds will be 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. To replace this financing, on April 2, 2012, we entered into a Bond Purchase Agreement for a private placement 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. All bonds of this new series will mature on April 2, 2027.

For additional information, see Note 7 of "Notes to Consolidated Financial Statements" under Item 8.

Compliance Plan

Our environmental Compliance Plan, discussed in Note 11 of "Notes to Consolidated Financial Statements" under Item 8, continues on schedule. Construction is proceeding on the installation of a scrubber, fabric filter, and powder activated carbon injection system at our Asbury plant. Initial construction costs through December 31, 2012 were $29.0 million for 2012 and $30.3 million for the project to date, excluding AFUDC. This project is expected to be completed in early 2015 at a cost ranging from $112.0 million to $130.0 million, excluding AFUDC. The addition of this air quality control equipment will require the retirement of Asbury Unit 2, an 18 megawatt steam turbine that is currently used for peaking purposes.

In September 2012, as part of the Compliance Plan, we completed the transition of our Riverton Units 7 and 8 from operation on coal to full operation on natural gas. These units, along with Riverton Unit 9, will be retired upon conversion of Riverton Unit 12, a simple cycle combustion turbine, to a combined cycle unit, with scheduled completion in 2016.

Regulatory Matters

On July 6, 2012, we filed a rate increase with the Missouri Public Service Commission (MPSC) for changes in rates for our Missouri electric customers. We are seeking an annual increase in base rate revenues of approximately $30.7 million, or 7.56%. On February 15, 2013, the MPSC issued an order to delay the procedural schedule, indicating we reached an agreement in principle with the parties to our case. The order also indicated a joint stipulation is anticipated to be filed with the MPSC as early as February 22, 2013, and is still subject to final approval by the MPSC. Details of the stipulation are confidential until it is filed with the MPSC. We do not anticipate the outcome to have a materially negative impact on our financial statements.

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.

On May 18, 2012, we filed with the Federal Energy Regulatory Commission (FERC) proposed revisions to our Open Access Transmission Tariff to implement a cost-based transmission formula rate to be effective August 1, 2012. On July 31, 2012, the FERC suspended the rate for five months and set the filing for hearing and settlement procedures.

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

Tornado Recovery and Activity

As of December 31, 2012, our system-wide customer count was down by approximately 400 as compared to the customer count levels prior to the May 2011 tornado. Joplin, Missouri continues to recover from the May 2011 tornado. During 2012, the city of Joplin approved an $800 million Master Development Plan, which includes several municipal and commercial projects, as well as 1,400 new homes in and around the area impacted by the May 2011 EF-5 tornado. These projects are expected to be funded through grants, tax credits, tax revenue (including such revenues from a city-approved Tax Increment Financing district encompassing over 3,000 acres within the city), and other private lending. Projects are expected to be completed by 2019. All our transmission lines and structures damaged in the storm have been repaired and the distribution system has been rebuilt to all customers able to receive power. We continue to extend services to customers as they rebuild. Our substation destroyed in the tornado has been rebuilt and is again providing service to our customers. We anticipate insurance proceeds of approximately $6.5 million will cover most of the cost of the substation rebuild. Total storm restoration costs were approximately $27.3 million as of December 31, 2012. The majority of these costs have been capitalized. We expect the loss of electric load and corresponding revenues to abate as customers rebuild.

RESULTS OF OPERATIONS

The following discussion analyzes significant changes in the results of operations for the years 2012, 2011 and 2010.

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

	2012	2011	2010
Electric	$52.6	$50.6	$43.2
Gas	1.3	2.7	2.6
Other	1.8	1.6	1.6
Net income	**$55.7**	**$54.9**	**$47.4**

Electric Segment

Overview

Our electric segment income for 2012 was $52.6 million as compared to $50.6 million for 2011.

Electric operating revenues comprised approximately 91.3% of our total operating revenues during 2012. Electric operating revenues for 2012, 2011, and 2010 were comprised of the following:

	2012	2011	2010
Residential	42.2%	42.4%	42.4%
Commercial	31.2	30.1	30.3
Industrial	15.5	15.1	14.4
Wholesale on-system	3.6	3.7	4.0
Wholesale off-system	3.1	4.5	4.7
Miscellaneous sources*	2.7	2.6	2.6
Other electric revenues	1.7	1.6	1.6

* Primarily other public authorities

Gross Margin

As shown in the table below, electric segment gross margin, defined as electric revenues less fuel and purchased power costs, increased approximately $7.8 million during 2012 as compared to 2011, reflecting a decrease in revenues of approximately $13.6 million and a decrease in electric fuel and purchased power expenses of approximately $21.4 million 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 last year, 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. A 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 last year.

The electric gross margin increased approximately $38.6 million during 2011 as compared to 2010 mainly due to the September 2010 Missouri rate increase, the July 2010 Kansas rate increase, the September 2010 and March 2011 Oklahoma rate increases and the April 2011 Arkansas rate increase.

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

	2012	2011	2010
Electric segment revenues	$510.7	$524.3	$484.7
Fuel and purchased power	178.9	200.3	199.3
Electric segment gross margins	$331.8	$324.0	$285.4
Margin as % of total electric segment revenues	65.0%	61.8%	58.9%

Although a non-GAAP presentation, we believe the presentation of gross margin 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. However, these margins may not be comparable to other companies' presentations or more useful than the GAAP information we provide elsewhere in this report.

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	**2012**	**2011**	**% Change(1)**	**2011**	**2010**	**% Change(1)**
Residential	1,850.8	1,982.7	(6.7)%	1,982.7	2,060.4	(3.8)%
Commercial	1,558.3	1,576.3	(1.1)	1,576.3	1,644.9	(4.2)
Industrial	1,028.4	1,022.8	0.6	1,022.8	1,007.0	1.6
Wholesale on-system	353.1	364.9	(3.2)	364.9	355.8	2.5
Other(2)	124.2	128.7	(3.5)	128.7	126.5	1.8
Total on-system sales	4,914.8	5,075.4	(3.2)	5,075.4	5,194.6	(2.3)
Off-system	704.0	740.0	(4.9)	740.0	798.1	(7.3)
Total KWh Sales	5,618.8	5,815.4	(3.4)	5,815.4	5,992.7	(3.0)

(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 decreased approximately 3.2% during 2012 as compared to 2011 primarily due to decreased demand due to milder 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. Total cooling degree days (the cumulative number of degrees that the average temperature for each day during that period was above 65° F) for 2012 were 2.8% less than 2011 although they were 29.3% more than the 30-year average, mainly due to unseasonably hot weather in June and July of 2012. 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 2012 were 20.3% less than 2011 and 20.6% less than the 30-year average.

KWh sales for our on-system customers decreased approximately 2.3% during 2011 as compared to 2010 primarily due to the loss of customers due to damaged or destroyed structures resulting from the May 22, 2011 tornado, although some of the effect was offset by temporary housing units. Residential and commercial kWh sales decreased in 2011 primarily due to the loss of residences and businesses in the May 22, 2011 tornado. Industrial kWh sales increased 1.6% in 2011 as compared to 2010 when there was a slowdown created by economic uncertainty. On-system wholesale kWh sales increased during 2011 as compared to 2010 reflecting the warmer weather in the third quarter of 2011.

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	**2012**	**2011**	**% Change(1)**	**2011**	**2010**	**% Change(1)**
Residential	$214.5	$221.7	(3.2)%	$221.7	$204.9	8.2%
Commercial	158.8	157.4	0.9	157.4	146.3	7.6
Industrial	78.8	78.9	(0.2)	78.9	69.7	13.3
Wholesale on-system	18.6	19.1	(3.1)	19.1	19.2	(0.6)
Other(2)	14.0	13.9	0.7	13.9	12.3	12.7
Total on-system revenues	484.7	491.0	(1.3)	491.0	452.4	8.5
Off-system	15.7	23.3	(32.6)	23.3	22.9	1.7
Total revenues from KWh sales	500.4	514.3	(2.7)	514.3	475.3	8.2
Miscellaneous revenues(3)	8.5	8.2	4.0	8.2	7.6	8.2
Total electric operating revenues	$508.9	$522.5	(2.6)	$522.5	$482.9	8.2
Water revenues	1.8	1.8	1.2	1.8	1.8	(1.9)
Total Electric Segment Operating Revenues	$510.7	$524.3	(2.6)	$524.3	$484.7	8.2

(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 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 last year. 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 change in our estimate of unbilled revenues during the third quarter of 2012 contributed $3.0 million to revenues.

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.

Revenues for our on-system customers increased approximately $38.6 million (8.5%) during 2011 as compared to 2010. Rate changes, primarily the September 2010 Missouri rate increase, the July 2010 Kansas rate increase, the September 2010 and March 2011 Oklahoma rate increases and the April 2011 Arkansas rate increase, contributed an estimated $49.2 million to revenues. We estimate the impact of the tornado, after adjusting for weather, was an approximate 2% reduction in kilowatt hour sales for 2011. This reduction is reflected in a $7.7 million reduction in revenues, which includes customer growth in the first quarter of 2011, offset by negative sales growth (contraction) for the second, third and fourth quarters of 2011, resulting from the loss of customers due to the loss of residences and businesses. Weather and other related factors decreased revenues an estimated $2.9 million in 2011 as compared to 2010, primarily due to mild weather in the first and fourth quarters of 2011.

Residential, commercial and industrial revenues increased during 2011 primarily due to the rate increases discussed above. On-system wholesale kWh revenues decreased 0.6% primarily due to the portion of FERC revenues that were subject to refund while we were waiting on approval of the Settlement Agreement and Offer of Settlement filed with the FERC on May 24, 2011. We refunded approximately $1.3 million of these revenues, including interest, in November 2011 as a result of this settlement.

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 "— Competition" 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 the customer and has little effect on net income.

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.

Off-system sales decreased during 2011 as compared to 2010 primarily due to limited power available for sale during the third quarter of 2011 as the excessive heat required us to use our resources to serve our own load. Off-system revenues increased 1.7%. Total purchased power related expenses are included in our discussion of purchased power costs below.

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 2012, 2011 and 2010. As shown below, fuel and purchased power costs decreased in 2012 as compared to 2011 mainly due to lower volumes, the Southwest Power Administration (SWPA) amortization and changes in derivative expenses not recovered in fuel adjustments. During 2011, total fuel and purchased power expenses increased approximately $1.0 million (0.5%) as compared to 2010.

(in millions)	2012	2011	2010
Actual fuel and purchased power expenditures	$173.6	$196.5	$200.0
Missouri fuel adjustment recovery(1)	3.4	7.3	3.1
Missouri fuel adjustment deferral(2)	5.3	(2.7)	(4.5)
Kansas and Oklahoma regulatory adjustments(2)	1.0	(0.6)	(0.1)
SWPA amortization(3)	(2.8)	(1.5)	—
Unrealized (gain)/loss on derivatives	(1.6)	1.3	0.8
Total fuel and purchased power expense per income statement	$178.9	$200.3	$199.3

(1) Recovered from customers from prior deferral period.

(2) A negative amount indicates costs have been under recovered from customers and a positive amount indicates costs have been over recovered from customers. Missouri amount includes the deferral of additional costs due to construction accounting, which terminated as of June 15, 2011, the effective date of rates for our 2010 Missouri rate case.

(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 changes during 2012 as compared to 2011 and during 2011 as compared to 2010.

(in millions)	2012 vs. 2011	2011 vs. 2010
Employee pension expense	$ 1.4	$ 3.1
Steam power other operating expense[1]	2.0	1.7
Transmission and distribution expense	1.7	2.4
Regulatory commission expense	(0.5)	0.7
Employee health care expense	2.4	0.5
Injuries and damages expense	(0.7)	0.5
Property insurance	0.6	0.3
Other power supply expense	0.1	0.2
Uncollectible accounts	(0.4)	0.2
General labor expense	0.4	(1.6)
Professional services[2]	2.1	(1.2)
Banking fees	(0.6)	—
Other miscellaneous accounts (netted)	0.3	0.6
TOTAL	$ 8.8	$ 7.4

(1) Reflects recognition of expenses of new plants (Iatan and Plum Point) after deferral ended June 15, 2011, the effective date of rates for our 2010 Missouri rate case.

(2) $0.9 million reflects the transfer of expenses from Professional Services in July 2011 to regulatory and capital assets per our 2010 Missouri rate case.

The table below shows maintenance and repairs expense changes during 2012 as compared to 2011 and during 2011 as compared to 2010.

(in millions)	2012 vs. 2011	2011 vs. 2010
Distribution maintenance expense	$(1.1)	$ 2.0
Transmission maintenance expense	(0.3)	(0.1)
Maintenance and repairs expense at the Asbury plant	0.9	(0.1)
Maintenance and repairs expense to SLCC[1]	0.6	1.8
Maintenance and repairs expense at the Iatan plant[2]	(0.8)	1.5
Maintenance and repairs expense at the Plum Point plant	(0.1)	0.7
Maintenance and repairs expense at the Riverton plant — coal units	(0.1)	(1.2)
Maintenance and repairs expense at the Riverton plant — gas units	0.5	(0.3)
Iatan deferred maintenance expense	(0.1)	(0.3)
Other miscellaneous accounts (netted)	(0.1)	0.3
TOTAL	$(0.6)	$ 4.3

(1) 2011 vs. 2010 change mainly due to a transformer failure in December 2011.

(2) 2012 vs. 2011 change mainly due to an outage in 2011.

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.

Depreciation and amortization expense increased approximately $4.3 million (7.9%) during 2011 as compared to 2010. This reflects increased depreciation of $6.3 million due to increased plant in service during 2011 and the effect of ending deferred depreciation related to Iatan 2 as allowed in our regulatory agreements. This increase was partially offset by a decrease in regulatory amortization expense of $0.9 million due to the termination of construction accounting as of June 15, 2011, the effective date of rates for our 2010 Missouri rate case.

Other taxes increased approximately $0.9 million in 2012 and $3.0 million in 2011 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)	2012	2011	% Change	2011	2010	% Change
Residential	2.01	2.56	(21.4)%	2.56	2.68	(4.3)%
Commercial	1.05	1.27	(17.2)	1.27	1.26	0.3
Industrial[1]	0.06	0.10	(42.9)	0.10	0.11	(5.9)
Other[2]	0.02	0.03	(29.5)	0.03	0.03	(0.9)
Total retail sales	3.14	3.96	(20.7)	3.96	4.08	(2.9)
Transportation sales[1]	4.25	4.53	(6.2)	4.53	4.83	(6.2)
Total gas operating sales	7.39	8.49	(13.0)	8.49	8.91	(4.7)

(1) 2012 percentage change reflects the transfer of customers from industrial sales to transportation during the first quarter of 2012. 2011 percentage change reflects three industrial customers switching to transportation during 2011.

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

Gas retail sales decreased 20.7% during 2012 as compared to 2011 reflecting mild weather in 2012 and customer contraction of 0.2%. We expect gas customer growth to be flat during the next several years. 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.

Gas retail sales decreased 2.9% during 2011 as compared to 2010 reflecting both customer contraction of 0.9% and customers switching from sales service retail to transportation. Commercial sales increased slightly during 2011. Industrial sales decreased 5.9% during 2011 due to customer contraction and the transfer of the customers between classes mentioned above.

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

($ in millions)	Operating Revenues and Cost of Gas Sold					
	2012	2011	% Change	2011	2010	% Change
Residential	$24.7	$29.0	(14.7)%	$29.0	$32.3	(10.1)%
Commercial	10.8	12.5	(13.7)	12.5	13.3	(6.2)
Industrial[1]	0.5	0.7	(31.9)	0.7	0.8	(16.0)
Other[2]	0.3	0.3	(23.9)	0.3	0.4	(5.5)
Total retail revenues	$36.3	$42.5	(14.7)	$42.5	$46.8	(9.0)
Other revenues	0.3	0.4	(13.4)	0.4	0.4	7.3
Transportation revenues[1]	3.2	3.5	(7.5)	3.5	3.7	(7.0)
Total gas operating revenues	$39.8	$46.4	(14.2)	$46.4	$50.9	(8.8)
Cost of gas sold	18.6	22.8	(18.1)	22.8	26.6	(14.5)
Gas operating revenues over cost of gas in rates	$21.2	$23.6	(10.4)	$23.6	$24.3	(2.5)

(1) 2012 percentage change reflects the transfer of customers from industrial sales to transportation during the first quarter of 2012. 2011 percentage change reflects three industrial customers switching to transportation during 2011.

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

During 2012, gas segment revenues were approximately $39.8 million as compared to $46.4 million in 2011, a decrease of 14.2%, mainly due to decreased sales resulting from mild weather during 2012. PGA revenue (which represents the cost of gas recovered from our customers) was approximately $18.6 million as compared to $22.8 million in 2011, a decrease of approximately $4.1 million (18.1%), representing a decrease in the cost of gas. Our margin (defined as gas operating revenues less cost of gas in rates) was $2.4 million less in 2012 as compared to 2011.

During 2011, gas segment revenues were approximately $46.4 million as compared to $50.9 million in 2010, a decrease of 8.8%. This decrease was largely driven by a decrease in the PGA that went into effect November 2, 2010. During 2011, our PGA revenue was approximately $22.8 million as compared to $26.6 million in 2010, a decrease of approximately $3.8 million (14.5%), representing a decrease in the cost of gas. Our margin was $0.7 million less in 2011 as compared to 2010.

Our PGA clause 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, 2012, we had 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 compared to unrecovered purchased gas costs of $0.2 million recorded as a current regulatory asset and $1.3 million recorded as a non-current regulatory asset as of December 31, 2011

Operating Revenue Deductions

Total other operating expenses were $8.4 million during 2012 as compared to $8.3 million in 2011, primarily due to a $0.1 million increase in transmission operation expense.

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

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

Total other operating expenses were $8.3 million during 2011 as compared to $9.5 million in 2010, primarily due to a $0.6 million decrease in customer accounts expense (mainly uncollectible accounts), a $0.3 million decrease in rent expense, a $0.2 million decrease in employee pension expense and a $0.2 million decrease in general labor costs.

Depreciation and amortization expense increased approximately $0.5 million (15.2%) during 2011 due to increased depreciation rates resulting from our 2010 Missouri gas rate case.

Our gas segment had net income of $2.7 million in 2011 as compared to $2.6 million in 2010.

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:

	2012	2011	2010
Consolidated provision for income taxes	$34.2	$34.3	$30.5
Consolidated effective federal and state income tax rates	38.0%	38.4%	39.2%

The effective tax rate for 2010 is higher than 2012 and 2011 primarily due to an adjustment made in 2010 as a result of the Patient Protection and Affordable Care Act, which became law on March 23, 2010. This legislation included a provision that removed the non-taxable status, for income tax purposes, of Medicare D subsidies received. Although the elimination of this tax benefit did not take effect until 2013, this change required us to recognize the full accounting impact in our financial statements in the period in which the legislation was enacted. As a result, in the first quarter of 2010, we recorded a one-time non-cash charge of approximately $2.1 million to income taxes to reflect the impact of this change, which increased our effective tax rate in 2010.

As part of an agreement reached in our 2009 Missouri electric rate case, effective September 10, 2010, we agreed to commence an eighteen year amortization of a regulatory asset related to the tax benefits of cost of removal. These tax benefits were flowed through to customers from 1981-2008 and totaled approximately $11.1 million. We recorded the regulatory asset expecting to recover these benefits from customers in future periods. Based on the agreement, we estimated the portion of the amortization period from which we would not receive rate recovery for this item and wrote off approximately $1.2 million in the first quarter of 2010. Amortization resumed during 2011 and the remaining balance as of December 31, 2012 was approximately $9.6 million.

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 2012 as compared to 2011 reflecting the environmental retrofit project at our Asbury plant. AFUDC decreased in 2011 as compared to 2010 reflecting the completion of Iatan 2 and the Plum Point Energy Station in 2010. See Note 1 of "Notes to Consolidated Financial Statements" under Item 8.

($ in millions)	2012	2011	2010
Allowance for equity funds used during construction	$1.1	$0.3	$ 4.5
Allowance for borrowed funds used during construction	0.8	0.2	5.7
Total AFUDC	$1.9	$0.5	$10.2

Total interest charges on long-term and short-term debt for 2012, 2011 and 2010 are shown below. 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 a private placement 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.

The change in long-term debt interest for 2011 as compared to 2010 reflects the redemption of $48.3 million aggregate principal amount of our Senior Notes, 7.05% Series due 2022, which were redeemed on August 27, 2010, and replaced by $50.0 million principal amount 5.20% first mortgage bonds issued August 25, 2010. The changes also reflect the redemption of 6.5% first mortgage bonds on April 1, 2010 and the redemption of our 8.5% trust preferred securities on June 28, 2010, which were replaced by 4.65% first mortgage bonds issued May 28, 2010. The decreases in short-term debt interest for all periods presented primarily reflect lower levels of borrowing.

	Interest Charges ($ in millions)					
	2012	2011	Change	2011	2010	Change
Long-term debt interest	$40.2	$42.6	(5.6)%	$42.6	$41.9	1.5%
Short-term debt interest	0.2	0.1	>100.0	0.1	0.6	(86.3)
Trust preferred securities interest	—	—		—	2.1	(100.0)
Iatan 1 and 2 carrying charges*	0.1	(2.1)	>100.0	(2.1)	(3.2)	31.8
Other interest	1.0	0.9	2.5	0.9	0.9	19.6
Total interest charges	$41.5	$41.5	(0.1)	$41.5	$42.3	(2.0)

* Beginning in the second quarter of 2009, we deferred Iatan 1 carrying charges to reflect construction accounting in accordance with our agreement with the MPSC that allowed deferral of certain costs until the environmental upgrades to Iatan 1 were included in our rate base. We began deferring Iatan 2 carrying charges in the third quarter of 2010. Deferral ended when the plant was placed in rates. Iatan 1 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 continually 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, 2010:

Jurisdiction	Date Requested	Annual Increase Granted	Percent Increase Granted	Date Effective
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
Missouri — Electric	October 29, 2009	$46,800,000	13.40%	September 10, 2010
Kansas — Electric	June 17, 2011	$ 1,250,000	5.20%	January 1, 2012
Kansas — Electric	November 4, 2009	$ 2,800,000	12.40%	July 1, 2010
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
Oklahoma — Electric	March 25, 2010	$ 1,456,979	15.70%	September 1, 2010
Arkansas — Electric	August 19, 2010	$ 2,104,321	19.00%	April 13, 2011
Missouri — Gas	June 5, 2009	$ 2,600,000	4.37%	April 1, 2010

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

COMPETITION AND MARKETS

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 will 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 Integrated Marketplace would replace the existing EIS market described above.

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

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 70% of the funds required in 2013 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 2012	2011	2010
Cash provided by/(used in):			
Operating activities	$ 159.1	$ 134.6	$ 135.9
Investing activities	(136.9)	(105.1)	(111.0)
Financing activities	(24.2)	(34.6)	(20.0)
Net change in cash and cash equivalents	$ (2.0)	$ (5.1)	$ 4.9

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 and the effects of deferred fuel recoveries. The increase or decrease in natural gas prices directly impacts the cost of gas stored in inventory.

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.

2011 compared to 2010. In 2011, our net cash flows provided from operating activities was $134.6 million, a decrease of $1.3 million or 1.0% from 2010. This increase was primarily a result of:

- Changes in net income — $7.6 million.
- Changes in depreciation and amortization, reflecting increased plant in service and fuel deferral amortization — $8.7 million
- Increased deferrals for income taxes, reflecting positive impacts for accelerated tax depreciation and deferring taxability of the 2010 SWPA payment — $18.2 million.
- Lower equity AFUDC — $4.2 million
- Changes in receivables due to lower unbilled revenues, receipt of transmission credits and income tax refunds collected — $21.6 million.
- Changes in accounts payable partially due to lower prices for fuel purchases — $5.9 million.
- Changes in pension and other post retirement benefit costs due to the result of $20.2 million in additional pension contributions compared to 2010 — $(16.7) million.
- Increased natural gas purchases and supplies for new and existing generation plants — $(15.1) million.
- Changes in prepaid expenses and deferred charges mostly reflecting certain regulatory treatment of fuel charges and carrying costs — ($3.6) million.
- Changes reflecting the receipt of SWPA minimum flows payment in 2010 — $(26.6) million.

Capital Requirements and Investing Activities

Our net cash flows used in investing activities increased $31.8 million from 2011 to 2012. 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 decreased $5.9 million from 2010 to 2011. The decrease was primarily the result of a decrease in new generation construction in 2011.

Our capital expenditures totaled approximately $146.3 million, $101.1 million, and $108.2 million in 2012, 2011 and 2010, respectively.

A breakdown of these capital expenditures for 2012, 2011 and 2010 is as follows:

	Capital Expenditures		
(in millions)	2012	2011	2010
Distribution and transmission system additions	$ 63.3	$ 46.5	$ 38.8
Additions and replacements — electric plant	46.7	13.4	7.2
New generation — Iatan 2 and Plum Point Energy Station	0.8	4.5	49.6
Storms	5.0	15.9	0.1
Transportation	3.7	3.9	1.3
Gas segment additions and replacements	3.3	3.9	5.0
Other (including retirements and salvage — net)[1]	20.7	9.2	3.4
Subtotal	$143.5	$ 97.3	$105.4
Non-regulated capital expenditures (primarily fiber optics)	2.8	3.8	2.8
Subtotal capital expenditures incurred[2]	$146.3	$101.1	$108.2
Adjusted for capital expenditures payable[3]	(9.3)	1.4	3.8
Insurance proceeds receivable	—	—	(0.1)
Capital lease, primarily Plum Point unit train	—	—	(2.7)
Total cash outlay	$137.0	$102.5	$109.2

(1) Other includes equity AFUDC of $(1.1) million, $(0.3) million and $(4.5) million for 2012, 2011 and 2010, respectively.

(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 85%, 100% and 75% of our cash requirements for capital expenditures for 2012, 2011 and 2010, respectively, were satisfied internally from operations (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 2013, 2014 and 2015 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	2013	2014	2015	Total
Asbury environmental upgrades	$ 55.8	$ 24.8	$ 12.1	$ 92.7
Riverton Unit 12 combined cycle conversion	15.1	40.4	65.3	120.8
Electric distribution system additions	42.9	38.3	36.3	117.5
Electric transmission facilities	12.1	26.7	36.3	75.1
Other	37.5	35.3	28.1	100.9
Total	$163.4	$165.5	$178.1	$507.0

Our estimated total capital expenditures (excluding AFUDC) for 2016 and 2017 are $107.0 million and $108.2 million, respectively.

We estimate that internally generated funds will provide approximately 70% of the funds required in 2013 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

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.
- We borrowed $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.
- We refinanced $88.0 million of bonds in 2012 which had almost no impact on cash flow.

2011 compared to 2010.

Our net cash flows used in financing activities was $34.6 million in 2011, an increase of $14.6 million as compared to 2010, primarily due to the following:

- A reduction in paid dividends provided $25.3 million of additional cash.
- We repaid $12.0 million in short-term debt in 2012 as compared to repaying $26.5 million in 2011. These activities provided $14.5 million of cash in 2011 compared to 2010.
- Proceeds from the issuance of common stock decreased $(54.4) million as 2010 included proceeds from an equity distribution program.
- We refinanced approximately $150.0 million of bonds and trust preferred securities in total in 2010 which had almost no impact on cash flow.

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 is anticipated to occur on or about May 30, 2013, subject to customary closing conditions. We expect to use the proceeds from the sale of the bonds to redeem all $98.0 million aggregate principal amount of our Senior Notes, 4.50% Series due June 15, 2013 with the remaining proceeds to be used for general corporate purposes. The bonds will be issued under the EDE Mortgage.

Shelf Registration.

We have a $400.0 million shelf registration statement with the SEC, effective February 7, 2011, covering our common stock, unsecured debt securities, preference stock, and first mortgage bonds. We have received regulatory approval for the issuance of securities under this shelf from all four states in our electric service territory, but we may only issue up to $250.0 million of such securities in the form of first mortgage bonds, of which $12.0 million would remain available after giving effect to the $150.0 million of new first mortgage bonds to be issued on or about May 30, 2013. We plan to use proceeds from offerings made pursuant to this shelf to fund capital expenditures, refinancings of existing debt or general corporate needs during the three-year effective period.

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. 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, 2012 would permit us to issue approximately $609.2 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, 2012, we had retired bonds and net property additions which would enable the issuance of at least $776.7 million principal amount of bonds if the annual interest requirements are met. As of December 31, 2012, 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, 2012, this test would allow us to issue approximately $12.8 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*	Baa2	BBB−
EDE First Mortgage Bonds	BBB+	A3	BBB+
Senior Notes	BBB	Baa2	BBB−
Commercial Paper	F3	P-2	A-3
Outlook	Stable	Stable	Stable

* Not rated.

On May 27, 2011 Standard & Poor's revised our rating outlook to stable from positive after the May 2011 tornado. On March 23, 2012, Standard & Poor's reaffirmed our ratings. On May 26, 2011 after the May 2011 tornado, and again on April 25, 2012, Moody's reaffirmed all of our ratings. 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 29, 2012, 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, 2012. 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 2013 – 2017 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)	$ 688.4	$ 98.4	$ —	$ 25.0	$ 565.0
Interest on long-term debt	532.1	34.9	65.7	63.8	367.7
Short-term debt	24.0	24.0	—	—	—
Capital lease obligations	6.9	0.6	1.1	1.1	4.1
Operating lease obligations(2)	4.8	0.8	1.5	1.4	1.1
Electric purchase obligations(3)	508.8	55.3	72.8	59.9	320.8
Gas purchase obligations(4)	36.3	9.4	13.1	9.7	4.1
Open purchase orders	161.8	45.2	33.3	83.3	—
Postretirement benefit obligation funding	20.8	4.9	8.8	7.1	—
Pension benefit funding	63.2	15.6	26.4	21.2	—
Other long-term liabilities(5)	3.3	0.1	0.3	0.3	2.6
TOTAL CONTRACTUAL OBLIGATIONS	$2,050.4	$289.2	$223.0	$272.8	$1,265.4

(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 2013 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.

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. Dividends were paid during all four quarters of 2012. As of December 31, 2012, our retained earnings balance was $47.1 million (compared to $33.7 million at December 31, 2011) after paying out $42.3 million in dividends during 2012.

The following table shows our diluted earnings per share and dividends paid per share for the years ended December 31, 2012, 2011 and 2010:

	2012	2011	2010
Diluted earnings per share	$1.32	$1.31	$1.17
Dividends paid per share	$1.00	$0.64	$1.28

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 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 cost that is 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 we believe 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.

We have rate orders in Missouri, Kansas and Oklahoma that allow us to defer any OPEB cost that is different from those allowed recovery in rate cases. This treatment is similar to treatment afforded pension costs. This includes the use of a market-related value of assets, the amortization of unrecognized gains or losses into expense over ten years and the recognition of regulatory assets and liabilities as described in the immediately preceding paragraph.

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, 2012, we have recorded $250.3 million in regulatory assets and $137.4 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 authorized a fuel adjustment clause for our Missouri customers effective September 1, 2008. A base cost is established in rates. The MPSC established a base cost for the recovery of fuel and purchased power expenses used to supply energy. The fuel adjustment clause 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 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 2012, 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, 2012 and 2011 was $4.2 million and $4.5 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, 2012, 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 likely be mitigated by our current and future regulatory rate design to some extent. Other risks and uncertainties affecting these assumptions include: management's identification of impairment indicators, changes in business, industry, laws, technology and economic conditions. Actual results for the gas reporting unit indicate a slight decline in gas customer growth and demand, but this was anticipated in our assumptions for purposes of the discounted cash flow calculation. Our forecasts anticipate flat customer growth 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 1, 2012 indicated the estimated fair market value of the gas reporting unit to be $5.0 million to $8.0 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 and to help manage our exposure resulting from purchasing most of our natural gas on the volatile spot market for the generation of power for our native-load customers. 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 65.6% of our 2012 generation fuel supply need through coal. This includes the remaining coal used at Riverton as part of its transition to natural gas. Approximately 96% of our 2012 coal supply was Western coal. We have contracts and binding proposals to supply a portion of the fuel for our coal plants through 2015. These contracts satisfy approximately 100% of our anticipated fuel requirements for 2013, 58% for 2014 and 26% for 2015 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, 2012, 58%, or 5.7 million Dths's, of our anticipated volume of natural gas usage for our electric operations for 2013 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 2013, if average natural gas prices should increase 10% more in 2013 than the price at December 31, 2012, our natural gas expenditures would increase by approximately $1.2 million based on our December 31, 2012 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, 2012, we have 1.3 million Dths in storage on the three pipelines that serve our customers. This represents 65% of our storage capacity. We have an additional 0.4 million Dths hedged through financial derivatives and physical contracts.

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 Actual Cost Adjustment (ACA) year at September 1 and illustrates our hedged position as of December 31, 2012 (in thousands). However, due to purchased natural gas cost recovery mechanisms for our retail customers, fluctuations in the cost of natural gas have little effect on income.

Season	Minimum % Hedged	Dth Hedged Financial	Dth Hedged Physical	Dth in Storage	Actual % Hedged
Current	50%	170,000	206,429	1,308,874	80%
Second	Up to 50%	160,000	—	—	2%
Third	Up to 20%	—	—	—	

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, 2012 and December 31, 2011. There were no margin deposit liabilities at these dates.

(in millions)	2012	2011
Margin deposit assets	$4.2	$5.8

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, 2012, 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	$ 6.9
Net unrealized mark-to-market losses for financial natural gas contracts	7.0
Net credit exposure	$13.9

The $7.0 million net unrealized mark-to-market loss for financial natural gas contracts is comprised entirely of $7.0 million of exposure to counterparties of 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, 2012, we have $4.2 million on deposit for NYMEX contract exposure to Empire, of which $3.9 million represents our collateral requirement. If NYMEX gas prices decreased 25% from their December 31, 2012 levels, our collateral requirement would increase $7.2 million. If these prices increased 25%, our collateral requirement would decrease $2.7 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 2013 than in 2012, our interest expense would increase, and income before taxes would decrease by less than $0.6 million. This amount has been determined by considering the impact of the hypothetical interest rates on our highest month-end commercial paper balance for 2012. 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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 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, 2012, based on criteria established in *Internal Control — Integrated Framework* 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 22, 2013

THE EMPIRE DISTRICT ELECTRIC COMPANY

CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2011
	($-000's)	
Assets		
Plant and property, at original cost:		
Electric and water	$2,176,188	$2,074,748
Natural gas	69,851	66,918
Other	37,983	34,984
Construction work in progress	56,347	24,141
	2,340,369	2,200,791
Accumulated depreciation and amortization	682,737	637,139
	1,657,632	1,563,652
Current assets:		
Cash and cash equivalents	3,375	5,408
Restricted cash	4,357	4,357
Accounts receivable — trade, net of allowance of $1,388 and $1,138, respectively	38,874	42,296
Accrued unbilled revenues	23,254	20,326
Accounts receivable — other	13,277	16,269
Fuel, materials and supplies	61,870	62,239
Prepaid expenses and other	21,806	14,629
Unrealized gain in fair value of derivative contracts	96	—
Regulatory assets	6,377	11,839
	173,286	177,363
Noncurrent assets and deferred charges:		
Regulatory assets	243,958	227,807
Goodwill	39,492	39,492
Unamortized debt issuance costs	7,606	9,331
Unrealized gain in fair value of derivative contracts	191	2
Other	4,204	4,188
	295,451	280,820
Total assets	**$2,126,369**	**$2,021,835**

(Continued)

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

THE EMPIRE DISTRICT ELECTRIC COMPANY

CONSOLIDATED BALANCE SHEETS (Continued)

	December 31, 2012	December 31, 2011
	($-000's)	
Capitalization and liabilities		
Common stock, $1 par value, 100,000,000 shares authorized, 42,484,363 and 41,977,725 shares issued and outstanding, respectively	$ 42,484	$ 41,978
Capital in excess of par value	628,199	618,304
Retained earnings	47,115	33,707
Total common stockholders' equity	717,798	693,989
Long-term debt (net of current portion)		
Obligations under capital lease	4,441	4,739
First mortgage bonds and secured debt	487,541	487,948
Unsecured debt	199,644	199,572
Total long-term debt	691,626	692,259
Total long-term debt and common stockholders' equity	1,409,424	1,386,248
Current liabilities:		
Accounts payable and accrued liabilities	66,559	59,307
Current maturities of long-term debt	714	933
Short-term debt	24,000	12,000
Regulatory liabilities	3,089	3,150
Customer deposits	12,001	11,428
Interest accrued	5,902	5,958
Unrealized loss in fair value of derivative contracts	3,403	4,769
Taxes accrued	2,992	2,634
	118,660	100,179
Commitments and contingencies (Note 11)		
Noncurrent liabilities and deferred credits:		
Regulatory liabilities	134,269	125,290
Deferred income taxes	301,967	263,933
Unamortized investment tax credits	18,897	19,226
Pension and other postretirement benefit obligations	120,808	103,371
Unrealized loss in fair value of derivative contracts	3,819	5,081
Other	18,525	18,507
	598,285	535,408
Total capitalization and liabilities	**$2,126,369**	**$2,021,835**

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,		
	2012	2011	2010
	(000's, except per share amounts)		
Operating revenues:			
Electric	$510,653	$524,275	$484,715
Gas	39,849	46,430	50,885
Other	6,595	6,165	5,676
	557,097	576,870	541,276
Operating revenue deductions:			
Fuel and purchased power	178,896	200,256	199,299
Cost of natural gas sold and transported	18,633	22,760	26,614
Regulated operating expenses	94,371	85,442	79,292
Other operating expenses	2,730	2,098	1,950
Maintenance and repairs	40,444	41,041	36,771
Loss on plant disallowance	—	150	—
Depreciation and amortization	60,447	63,537	58,656
Provision for income taxes	34,096	34,071	30,470
Other taxes	31,259	30,581	27,729
	460,876	479,936	460,781
Operating income	96,221	96,934	80,495
Other income and (deductions):			
Allowance for equity funds used during construction	1,147	294	4,538
Interest income	972	555	176
Provision for other income taxes	(63)	(227)	(63)
Other — non-operating expense, net	(1,910)	(1,283)	(1,039)
	146	(661)	3,612
Interest charges:			
Long-term debt	40,192	42,581	41,959
Trust preferred securities	—	—	2,090
Short-term debt	187	86	631
Allowance for borrowed funds used during construction	(781)	(218)	(5,636)
Other	1,088	(1,147)	(2,333)
	40,686	41,302	36,711
Net income	**$ 55,681**	**$ 54,971**	**$ 47,396**
Weighted average number of common shares outstanding — basic	42,257	41,852	40,545
Weighted average number of common shares outstanding — diluted	42,284	41,887	40,580
Total earnings per weighted average share of common stock — basic and diluted	**$ 1.32**	**$ 1.31**	**$ 1.17**
Dividends declared per share of common stock	**$ 1.00**	**$ 0.64**	**$ 1.28**

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

THE EMPIRE DISTRICT ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2012	2011	2010
		($-000's)	
Net income	$55,681	$54,971	$47,396
Reclassification adjustments for loss included in net income or reclassified to regulatory asset or liability	—	—	5,814
Net change in fair market value of open derivative contracts for period	—	—	(6,362)
Income taxes	—	—	209
Comprehensive income	**$55,681**	**$54,971**	**$47,057**

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	Accumulated comprehensive income/(loss)	Total
			($-000's)		
Balance at December 31, 2009	38,112	551,631	10,068	339	600,150
Net income			47,396		47,396
Stock/stock units issued through:					
Public offering	2,871	48,325			51,196
Stock purchase and reinvestment plans	594	10,623			11,217
Dividends declared			(51,996)		(51,996)
Reclassification adjustment for losses included in net income				5,814	5,814
Change in fair value of open derivative contracts for period				(6,362)	(6,362)
Income taxes				209	209
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

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,		
	2012	2011	2010
		($-000's)	
Operating activities:			
Net income	$ 55,681	$ 54,971	$ 47,396
Adjustments to reconcile net income to cash flows from operating activities:			
Depreciation and amortization including regulatory items	71,160	79,751	71,076
Pension and other postretirement benefit costs, net of contributions	1,689	(20,379)	(3,683)
Deferred income taxes and unamortized investment tax credit, net	31,899	45,051	26,880
Allowance for equity funds used during construction	(1,147)	(294)	(4,538)
Stock compensation expense	2,285	2,147	3,478
Non-cash loss on derivatives	4,174	1,187	1,853
Other	(16)	381	—
Cash flows impacted by changes in:			
Accounts receivable and accrued unbilled revenues	(688)	10,342	(11,211)
Fuel, materials and supplies	369	(16,682)	(1,585)
Prepaid expenses, other current assets and deferred charges	(9,238)	(23,163)	(19,606)
Accounts payable and accrued liabilities	(1,297)	(318)	(6,179)
Interest, taxes accrued and customer deposits	875	(980)	1,522
Other liabilities and other deferred credits	3,360	3,172	3,954
SWPA minimum flows payment	—	—	26,564
Accumulated provision — rate refunds	—	(578)	—
Net cash provided by operating activities	159,106	134,608	135,921

(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,		
	2012	2011	2010
		($-000's)	
Investing activities:			
Capital expenditures — regulated	$(134,272)	$ (99,162)	$(106,388)
Capital expenditures and other investments — non-regulated	(2,670)	(3,375)	(2,817)
Restricted cash	(1)	(2,586)	(1,771)
Total net cash used in investing activities	(136,943)	(105,123)	(110,976)
Financing activities:			
Proceeds from first mortgage bonds, net	88,000	—	149,635
Long-term debt issuance costs	(1,074)	—	(1,758)
Proceeds from issuance of common stock, net of issuance costs	8,114	5,884	60,239
Repayment of first mortgage bonds	(88,029)	—	(50,000)
Redemption of trust preferred securities	—	—	(50,000)
Redemption of senior notes	—	—	(48,304)
Net short-term borrowings (repayments)	12,000	(12,000)	(26,500)
Dividends	(42,273)	(26,732)	(51,996)
Other	(934)	(1,754)	(1,356)
Net cash used in financing activities	(24,196)	(34,602)	(20,040)
Net increase (decrease) in cash and cash equivalents	(2,033)	(5,117)	4,905
Cash and cash equivalents, beginning of year	5,408	10,525	5,620
Cash and cash equivalents, end of year	3,375	$ 5,408	$ 10,525

	2012	2011	2010
Supplemental cash flow information:			
Interest paid	$ 38,802	$ 41,088	$ 43,044
Income taxes (refunded) paid, net of refund	(592)	(14,300)	11,264
Supplementary non-cash investing activities:			
Change in accrued additions to property, plant and equipment not reported above	$ 9,345	$ (1,387)	$ (3,846)
Capital lease obligations for purchase of new equipment	—	29	2,696

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

THE EMPIRE DISTRICT ELECTRIC COMPANY

NOTES TO 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 2012 were derived as follows:

Electric segment sales*	91.7%
Gas segment sales	7.1%
Other segment sales	1.2%

* Sales from our electric segment include 0.3% 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 167,900 customers as of December 31, 2012, and the 2012 electric operating revenues were derived as follows:

Customer	% of revenue
Residential	42.2%
Commercial	31.2
Industrial	15.5
Wholesale on-system	3.6
Wholesale off-system	3.1
Miscellaneous sources, primarily public authorities	2.7
Other electric revenues	1.7

Our retail electric revenues for 2012 by jurisdiction were as follows:

Jurisdiction	% of revenue
Missouri	89.3%
Kansas	5.1
Arkansas	2.7
Oklahoma	2.9

Our gas operations serve approximately 44,000 customers as of December 31, 2012, and the 2012 gas operating revenues were derived as follows:

Customer	% of revenue
Residential	62.1%
Commercial	27.1
Industrial	1.2
Other	9.6

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. Certain immaterial reclassifications have been made to prior year information to conform to the current year presentation.

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 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 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).

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.

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 $10.4 million, $11.0 million and $10.6 million were recorded for each of the years ended December 31, 2012, 2011 and 2010, 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, 2012 and 2011 was $5.2 million and $6.6 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).

In accordance with our previous rate orders, we recorded approximately $6.6 million, and $7.5 million of regulatory amortization during 2011, and 2010, respectively. This amortization included in our rates was granted in the Experimental Regulatory Plan approved by the MPSC on August 2, 2005 and terminated on June 15, 2011, as a result of our 2010 Missouri rate case. It provided additional cash flow to enhance the financial support for our generation expansion plan and was related to our investment in Iatan 2 as well as our Riverton V84.3A2 combustion turbine (Riverton Unit 12) and environmental improvement and upgrades at Asbury and Iatan 1. This amortization was included in depreciation and amortization expense and in accumulated depreciation and amortization on the consolidated balance sheet.

As of December 31, 2012 and 2011, we had recorded accrued cost of removal of $77.3 million and $68.6 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, 2012 and 2011 was $6.1 million and $5.0 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 future containment of an 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 initial planning for 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 year, the liabilities for both the ash landfill at the Riverton Power Plant, and PCB contaminants were reevaluated. Changes in the cost estimates and timing resulted in cash flow revisions for these liabilities.

The balances at the end of 2011 and 2012 are shown below.

(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

(000's)	Liability Balance 12/31/10	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions	Liability Balance at 12/31/11
Asset Retirement Obligation	$3,757	$ —	$ —	$187	$ —	$3,944

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, 2012 and 2011, our regulatory assets relating to asset retirement obligations totaled $4.4 million and $3.6 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 5.6% for 2012, 5.2% for 2011 and 7.5% for 2010, compounded semiannually, in determining AFUDC for all of our projects except Iatan 2. 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, 2012 and 2011.

Goodwill

As of December 31, 2012, 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 likely be mitigated by our current and future regulatory rate design to some extent. Other risks and uncertainties affecting these assumptions include: management's identification of impairment indicators, changes in business, industry, laws, technology and economic conditions. Actual results for the gas reporting unit indicate a slight decline in gas customer growth and demand, but this was anticipated in our assumptions for purposes of the discounted cash flow calculation. Our forecasts anticipate flat customer growth 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 2012 indicated the estimated fair market value of the gas reporting unit to be $5.0-$8.0 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, 2012, our Missouri, Kansas and Oklahoma fuel and purchased power costs were over-recovered by $4.0 million, which is reflected as a regulatory liability.

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).

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. PGA factor elements considered 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 volatile spot market and to manage certain interest rate exposure.

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 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. Unrealized gains and losses from cash flow hedges existing prior to the implementation of our fuel adjustment clause were recorded through comprehensive income through September 30, 2010. At December 31, 2010 the remaining hedges, that were entered into prior to the fuel adjustment clause, were de-designated. Given that upon settlement, the realized gain or loss would be recorded as fuel expense and be subject to the fuel adjustment clause, we reclassified the unrealized loss on these hedges from comprehensive income to a regulatory asset.

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 calculated 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.

In the Company's agreement with the MPSC regarding the purchase of Missouri Gas by EDG, the Company was 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 postretirement 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 five years.

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 under funded 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, 2012, 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 $19.7 million and $16.6 million at December 31, 2012 and 2011, 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 and 2011, respectively, were released by all parties in January 2013. The amounts restricted for operating costs, which were $1.8 million at December 31, 2012 and 2011, may increase or decrease based on an annual review.

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):

	2012	2011
Electric fuel inventory	$27,954	$27,431
Natural gas inventory	4,776	6,346
Materials and supplies	29,140	28,462
TOTAL	$61,870	$62,239

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 51 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 2008. At December 31, 2012 and 2011, 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 and performance-based restricted stock are excluded from the calculation of diluted earnings per share if the effect would be antidilutive.

	2012	2011	2010
Weighted Average Number Of Shares			
Basic	42,256,641	41,851,759	40,544,802
Dilutive Securities:			
Performance-based restricted stock awards	14,500	18,222	14,991
Dividend equivalents	6,329	9,585	12,558
Employee stock purchase plan	1,996	3,815	7,170
Stock options	3,160	3,240	—
Time-based restricted stock awards	1,820	807	—
Total dilutive securities	27,805	35,669	34,719
Diluted weighted average number of shares	42,284,446	41,887,428	40,579,521
Antidilutive Shares	128,500	128,500	74,800

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 will not 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,	
	2012	2011
Electric plant		
Production	$1,034,114	$1,023,154
Transmission	251,769	232,390
Distribution	766,026	719,731
General[(1)]	111,963	87,933
Electric plant	2,163,872	2,063,208
Less accumulated depreciation and amortization[(2)]	651,627	610,084
Electric plant net of depreciation and amortization	1,512,245	1,453,124
Construction work in progress	55,957	23,494
Net electric plant	**1,568,202**	**1,476,618**
Gas plant	69,851	66,918
Less accumulated depreciation and amortization	12,940	10,851
Gas plant net of accumulated depreciation	56,911	56,067
Construction work in progress	184	79
Net gas plant	**57,095**	**56,146**
Water plant	12,316	11,540
Less accumulated depreciation and amortization	4,440	4,158
Water plant net of depreciation and amortization	7,876	7,382
Construction work in progress	1	126
Net water plant	**7,877**	**7,508**
Other		
Fiber	37,983	34,984
Less accumulated depreciation and amortization	13,730	12,046
Non-regulated net of depreciation and amortization	24,253	22,938
Construction work in progress	205	442
Net non-regulated property	**24,458**	**23,380**
TOTAL NET PLANT AND PROPERTY	**$1,657,632**	**$1,563,652**

(1) Includes intangible property of $36.4 and $22.1 million as of December 31, 2012 and 2011, respectively, primarily related to capitalized software and investments in facility upgrades owned by other utilities. Accumulated amortization related to this property in 2012 and 2011 was $10.7 and $9.9 million respectively.

(2) Includes regulatory amortization of $37.3 million as of December 31, 2012 and 2011, resulting from our regulatory plan (See Note 3 for additional discussion of our regulatory plan).

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):

	2012	2011	2010
Provision for depreciation			
Regulated — Electric and Water	$57,467	$54,628	$49,254
Regulated — Gas	3,602	3,485	3,046
Non-Regulated	1,538	1,807	1,641
TOTAL	**62,607**	**59,920**	**53,941**
Amortization[(1)]	1,041	7,445	8,347
TOTAL	**$63,648**	**$67,365**	**$62,288**

(1) Includes $6.6 million, and $7.5 million of regulatory amortization for 2011 and 2010, respectively. 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 or our 2010 Missouri rate case.

	2012	2011	2010
Annual depreciation rates			
Electric and water	2.8%	2.7%	2.8%
Gas	5.4%	5.5%	5.1%
Non-Regulated	4.2%	5.4%	5.3%
TOTAL COMPANY	**2.9%**	**2.9%**	**2.9%**

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

	2012	2011	2010
Annual Weighted Average Depreciation Rate			
Electric fixed assets:			
Production plant	2.0%	2.1%	2.0%
Transmission plant	2.4%	2.3%	2.4%
Distribution plant	3.6%	3.6%	3.6%
General plant	5.9%	6.1%	6.2%
Water	2.7%	2.7%	2.7%
Gas	5.4%	5.5%	5.1%
Non-regulated	4.2%	5.4%	5.3%

3. Regulatory Matters

Regulatory Assets and Liabilities and Other Deferred Credits

Tornado

The Missouri Public Service Commission (MPSC) approved a joint settlement agreement allowing us to defer actual incremental operating and maintenance expenses associated with the repair, restoration and rebuilding activities resulting from the tornado which hit our service territory on May 22, 2011. In addition, depreciation related to the capital expenditures will be deferred and a carrying charge will be accrued. These amounts, which were approximately $3.3 million as of December 31, 2012, have been recorded as a regulatory asset.

Construction Accounting

Construction accounting, as approved by the MPSC in our 2005 regulatory plan, permitted the deferral of charges for depreciation, operations and maintenance and carrying costs related to the operation of Iatan 1 and Iatan 2 until they were ultimately included in our rates. Construction accounting was also applied to Plum Point construction costs incurred subsequent to February 28, 2010. All of these deferrals began at the plants' respective in-service dates, and ended when recovery began in rates. All of these deferrals are being amortized over the life of the plants beginning on June 15, 2011, the effective date of rates for our 2010 Missouri rate case. As of December 31, 2012 these deferrals totaled $16.1 million and were recorded as regulatory assets. The regulatory plan also required us to continue to defer the fuel and purchased power expense impacts of Iatan 2, which were approximately $8.2 million as of December 31, 2012 and are recorded in Current and Non-Current Regulatory Liabilities.

As part of a stipulated agreement in our 2009 Kansas rate case, approved by the KCC on June 25, 2010, we also defered depreciation and operating and maintenance expense on both Plum Point and Iatan 2 from their respective in-service dates until the effective date for rates from the next Kansas case, which was January 1, 2012. These deferrals will be recovered over a 4 year period.

Changes

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. Changes to regulatory assets and liabilities regarding their rate base inclusion or amortizable lives from December 31, 2010 to December 31, 2011 are as follows: As a result of our 2010 Missouri rate case, a tracking mechanism has been created to flow the 2010 SWPA payment, net of associated taxes, back to our customers (see Note 9). The Missouri, Kansas and Oklahoma jurisdictional portions of the payment will be amortized over ten years and reflected as a reduction to fuel expense, while the Arkansas jurisdictional portion of the 2010 SWPA payment will be amortized on a straight-line basis over a 50 year period. A tracking mechanism was also created by Missouri related to the Plum Point, Iatan 2 and Iatan Common plant operating expenses. The Missouri tracker is to exclude consumables and SO_2 allowances which are recovered through the fuel adjustment clause. A regulatory asset or liability will be recorded for the difference between the Missouri jurisdictional portion of actual expenses and the annual recovery allowance with a corresponding charge or credit to regulated operating expense.

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

	December 31, 2012	December 31, 2011
Regulatory Assets:		
Under recovered purchased gas costs — gas segment — current	$ 1,689	$ 211
Under recovered electric fuel and purchased power costs — current	1,196	7,513
Other	3,492	4,115
Regulatory assets, current[1]	6,377	11,839
Pension and other postretirement benefits[2]	136,480	121,058
Income taxes	48,759	49,631
Deferred construction accounting costs[3]	16,277	16,717
Unamortized loss on reacquired debt	11,078	10,138
Unsettled derivative losses — electric segment	6,557	7,839
System reliability — vegetation management	8,340	5,908
Storm costs[4]	4,223	4,990
Asset retirement obligation	4,430	3,571
Customer programs	3,916	2,968
Unamortized loss on interest rate derivative	989	1,147
Other	584	1,338
Under recovered purchased gas costs — gas segment	—	1,281
Deferred operating and maintenance expense	2,011	990
Under recovered electric fuel and purchased power costs	314	231
Regulatory assets, long-term	243,958	227,807
TOTAL REGULATORY ASSETS	$250,335	$239,646
Regulatory Liabilities		
SWPA payment for Ozark Beach lost generation	$ 2,774	$ 2,833
Other	315	317
Regulatory liabilities, current[1]	3,089	3,150
Costs of removal	83,368	73,562
SWPA payment for Ozark Beach lost generation	19,467	22,242
Income taxes	11,972	12,337
Deferred construction accounting costs — fuel	8,011	8,156
Unamortized gain on interest rate derivative	3,371	3,541
Pension and other postretirement benefits[5]	2,007	2,939
Over recovered electric fuel and purchased power costs	5,826	2,513
Other	247	—
Regulatory liabilities, long-term	134,269	125,290
TOTAL REGULATORY LIABILITIES	$137,358	$128,440

(1) Reflects over and under recovered costs expected to be returned or recovered as applicable, within the next 12 months in Missouri rates.

(2) Primarily reflects regulatory assets resulting from the unfunded portion of our pension and OPEB liabilities and regulatory accounting for EDG acquisition costs. Approximately $0.5 million in pension and other postretirement benefit costs have been recognized since January 1, 2012 to reflect the amortization of the regulatory assets that were recorded at the time of the EDG acquisition of the Aquila, Inc. gas properties.

(3)

Balances as of December 31, 2012	Deferred Carrying Charges	Deferred O&M	Depreciation	Total
Iatan 1	$2,678	1,339	1,622	$ 5,639
Iatan 2	$3,821	4,155	2,685	$10,661
Plum Point	$ 64	195	158	$ 417
Total				$16,717

Balances as of December 31, 2011	Deferred Carrying Charges	Deferred O&M	Depreciation	Total
Iatan 1	$2,728	1,363	1,652	$ 5,743
Iatan 2	$3,891	4,271	2,728	$10,890
Plum Point	$ 65	239	158	$ 462
Total				$17,095

(4) Reflects ice storm costs incurred in 2007 and costs incurred as a result of the May 2011 tornado.

(5) Includes the effect of costs incurred that are more or less than those allowed in rates for the Missouri (EDE and EDG) and Kansas (EDE) portion of pension and other postretirement benefit costs. Since January 1, 2012, regulatory liabilities and corresponding expenses have been reduced by approximately $0.9 million as a result of ratemaking treatment.

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 or they are earning carrying costs. However, as of December 31, 2012, the costs of all of our regulatory assets are currently being recovered except for approximately $130.3 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 five-year maintenance 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 continually 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, 2010:

Jurisdiction	Date Requested	Annual Increase Granted	Percent Increase Granted	Date Effective
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
Missouri — Electric	October 29, 2009	$46,800,000	13.40%	September 10, 2010
Kansas — Electric	June 17, 2011	$ 1,250,000	5.20%	January 1, 2012
Kansas — Electric	November 4, 2009	$ 2,800,000	12.40%	July 1, 2010
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
Oklahoma — Electric	March 25, 2010	$ 1,456,979	15.70%	September 1, 2010
Arkansas — Electric	August 19, 2010	$ 2,104,321	19.00%	April 13, 2011
Missouri — Gas	June 5, 2009	$ 2,600,000	4.37%	April 1, 2010

Electric Segment

Missouri

2012 Rate Case

On July 6, 2012, we filed a rate increase with the Missouri Public Service Commission (MPSC) for changes in rates for our Missouri electric customers. We are seeking an annual increase in base rate revenues of approximately $30.7 million, or 7.56%, and the continuation of the fuel adjustment clause. After factoring in the fuel adjustment clause revenue of $8.6 million paid by customers during the rate case test year, the impact of the requested annual increase in base rates is approximately $22.1 million, or 5.3%. 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 and new depreciation rates. We are also requesting recovery of a regulatory asset related to the tax benefits of cost of removal, which was approximately $9.6 million at December 31, 2012. We asked the MPSC to implement the $6.2 million portion of the case related to the May 2011 tornado recovery costs and the post-May 2011 cost of service through interim rates. On July 23, 2012, the MPSC suspended the interim rate tariffs and scheduled an evidentiary hearing on September 10, 2012. On October 31, 2012, we received an order rejecting our request for interim tariffs. On February 15, 2013, the MPSC issued an order to delay the procedural schedule, indicating we reached an agreement in principle with the parties to our case. The order also indicated a joint stipulation is anticipated to be filed with the MPSC as early as February 22, 2013, and is still subject to final approval by the MPSC. Details of the stipulation are confidential until it is filed with the MPSC. We do not anticipate the outcome to have a materially negative impact on our financial statements.

The construction costs for our Plum Point Energy Station and Iatan 1 and 2 generating facilities, currently being recovered in rates, are subject to prudency reviews by our regulators. The prudency of these construction costs, as well as other matters previously deferred by the MPSC to future proceedings, were not addressed in our 2010 Missouri rate case, but could be addressed in our current rate proceeding.

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 impacts 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 will 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.

2009 Rate Case

On October 29, 2009, we filed a request with the MPSC for an annual increase in base rates for our Missouri electric customers in the amount of $68.2 million, or 19.6%. This request was primarily designed to allow us to recover capital expenditures associated with environmental upgrades at Iatan 1 and our investment in new generating units at Iatan 2 and the Plum Point Generating Station. As a result of the delay in the Iatan 2 project, however, we agreed to not seek a permanent increase in this rate case for any costs associated with the Iatan 2 unit with the exception of that portion of the Iatan common plant needed to operate Iatan 1.

A stipulated agreement was filed on May 12, 2010, calling for an annual increase of $46.8 million, provided the Plum Point Generating Station met its in-service criteria by August 15, 2010. If the in-service criteria were not met by such date, a base rate increase of $33.1 million was stipulated. The Plum Point Generating Station completed its in-service criteria testing on August 12, 2010, with an in-service date of

August 13, 2010, thus new rates, providing for the full increase of $46.8 million, were effective September 10, 2010. The $46.8 million authorized increase in annual revenues includes $36.8 million in base rate revenue and $10.0 million in regulatory amortization. The regulatory amortization, which is treated as additional book depreciation for rate-making purposes and is reflected in the financial statements, was granted to provide additional cash flow through rates. This regulatory amortization is related to our investments in facilities and environmental upgrades completed during the 2005-2010 construction cycle. As agreed in our regulatory plan, we used construction accounting for our Iatan 2 project. As noted above, regulatory amortization expense of $14.5 million annually and construction accounting terminated as of June 15, 2011 as a result of our 2010 rate case (See Note 3 and Note 11). We also agreed to commence an eighteen year amortization of a deferred asset related to the tax benefits of cost of removal. These tax benefits were flowed through to customers from 1981 to 2008 and totaled approximately $11.1 million. We had previously recorded a regulatory asset expecting to recover these benefits from customers in future periods. We estimated the portion of the amortization period where rate recovery would no longer be probable for this item and wrote off approximately $1.2 million in the first quarter of 2010. Amortization of the remaining regulatory tax asset began during the third quarter of 2011 (See Note 9).

Tornado Recovery

On June 6, 2011, we filed an Accounting Authority Order with the MPSC requesting authorization to defer expenses associated with the tornado and to allow for recovery of the loss of the fixed cost component included in our rates resulting from the lost sales. On June 23, 2011, Praxair, Inc. and Explorer Pipeline Company filed as intervenors with the MPSC, who granted their request on July 6, 2011. On November 15, 2011, following extensive negotiations, the parties filed a joint settlement agreement with the MPSC allowing us to defer actual incremental operating and maintenance expenses associated with the repair, restoration and rebuilding activities resulting from the tornado. In addition, depreciation related to the capital expenditures will be deferred and a carrying charge will be accrued. In the event that an electric rate request is filed in Missouri by June 1, 2013, a ten-year amortization of the deferral will begin. The settlement does not include deferral of the fixed cost component associated with the reduction in customers served by us as a result of the tornado. On November 30, 2011, the MPSC issued an order approving the settlement agreement, effective December 7, 2011. Approximately $3.3 million has been deferred under this agreement.

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.

2009 Rate Case

On November 4, 2009, we filed a request with the KCC for an annual increase in base rates for our Kansas electric customers in the amount of $5.2 million, or 24.6%. This request was primarily to allow us to recover capital expenditures associated with environmental upgrades at Iatan 1 completed in 2009 and at our Asbury plant completed in 2008 and our investment in new generating units at Iatan 2, the Plum Point Generating Station and our Riverton 12 unit that went on line in 2007. A stipulated agreement was filed on May 4, 2010, and approved by the KCC on June 25, 2010, calling for a $2.8 million, or 12.4%, increase in base rates effective July 1, 2010. We agreed to defer depreciation and operating and maintenance expense on both Plum Point and Iatan 2 from their respective in-service dates until the effective date of the rates from the next Kansas case, which was filed on June 17, 2011. We recorded AFUDC on all Plum Point and Iatan 2 capital expenditures incurred after January 31, 2010.

Oklahoma

On March 25, 2010, we requested a capital cost recovery rider (CCRR) at the OCC. The rider was designed to recover the carrying costs on our capital investment for generation, transmission and distribution assets that have been added to the system since our last Oklahoma general rate case (May 2003), as well as investments made on an ongoing basis. As requested, the operation of the CCRR would have increased our operating revenue by approximately $3 million, or approximately 33%, in Oklahoma in a series of three steps to be followed with a general rate case in 2011. On August 30, 2010, we were granted a two-phase Capital Reliability Rider (CRR) by the OCC. The first phase of the rider was put into place for Oklahoma customers for usage on and after September 1, 2010, and resulted in an overall annual base revenue increase of approximately $1.5 million, or 15.7%. In total, the CRR revenue was specifically limited by the OCC to an overall annual revenue increase of $2.6 million, or 27.67% increase. On January 28, 2011 we requested the approval by the OCC of the phase 2 rates of the CRR. We requested an additional $1.1 million, which brought the total annual revenue under the OCC to approximately $2.5 million. On June 30, 2011, we filed a request with the 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 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 removes fuel and purchase power costs from base rates. Fuel and purchase power costs will be listed as a separate line item, identified as the Fuel Adjustment Charge, on customer bills.

Arkansas

On August 19, 2010, we filed a rate increase request with the Arkansas Public Service Commission (APSC) for an annual increase in base rates for our Arkansas electric customers in the amount of $3.2 million, or 27.3%. On February 2, 2011 we entered into a unanimous settlement agreement with the parties involved. The settlement included a general rate increase of $2.1 million, or 19%, and called for the implementation of a new tariff, the Transmission Cost Recovery Rider (TCR) designed to track changes in the cost of transmission charges from the Southwest Power Pool, Inc. The existing Energy Cost Recovery Rider was also modified to include the recovery of the costs associated with certain air quality control materials. The APSC approved the settlement on April 12, 2011 with the new rates effective April 13, 2011.

FERC

On May 18, 2012, we filed with the Federal Energy Regulatory Commission (FERC) proposed revisions to our Open Access Transmission Tariff to implement an annual cost-based transmission formula rate to be effective August 1, 2012. The state of Missouri, the Kansas Corporation Commission, Kansas Electric Power Cooperative Inc. and, as a group, the cities of Monett, Mount Vernon, Lockwood and Chetopa filed motions to intervene and requested the FERC suspend the effective date of the filing for a maximum of five months and set the filing for hearing and settlement procedures. On July 31, 2012, the FERC suspended the rate for five months and set the filing for hearing and settlement procedures. These rates became effective, subject to refund, on January 1, 2013.

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.

Gas Segment

On June 5, 2009, we filed a request with the MPSC for an annual increase in base rates for our Missouri gas customers in the amount of $2.9 million, or 4.9%. In this filing, we requested recovery of the ongoing cost of operating and maintaining our 1,200-mile gas distribution system and a return on equity of 11.3%. On February 24, 2010, the MPSC unanimously approved an agreement among the Office of the Public Counsel (OPC), the MPSC staff and Empire for an increase of $2.6 million. Pursuant to the Agreement, new rates went into effect on April 1, 2010.

COMPETITION AND MARKETS

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: On April 28, 2009, the SPP Regional State Committee (SPP RSC), whose members include state commissioners from our four state commissions, and the SPP Board of Directors (SPP BOD) endorsed a cost benefit report that recommended the SPP RTO move forward with the development of a day-ahead market with unit commitment and co-optimized ancillary services market (Day-Ahead Market or Integrated Marketplace). Implementation of the SPP's Integrated Marketplace is scheduled for March 2014, which will replace the existing EIS market described above. 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. Our implementation preparedness, as well as SPP and its other members, of the Integrated Marketplace is well underway, including the finalization of FERC's Integrated Marketplace compliance requirements for SPP's Open Access Transmission Tariff (OATT). On December 10, 2012, the Arkansas Public Service Commission approved our continued participation in the SPP RTO, which included full participation in the SPP Integrated Market Place. In early 2012, we filed before the Missouri Public Service Commission for our continued participation in the SPP RTO. We expect the case to be scheduled and concluded in mid to late 2013.

SPP Regional Transmission Development: On October 27, 2009, the SPP BOD endorsed a new transmission cost allocation method to replace the existing FERC accepted cost allocation method for new transmission facilities needed to continue to reliably and economically serve SPP customers, including ours, well into the future. On April 19, 2010, SPP filed revisions to its open access transmission pro forma tariff (OATT) to adopt a new highway/byway cost allocation methodology which require SPP BOD approved transmission projects of 300 kV or larger to be funded by the region at 100%, transmission projects between 100 kV and 300 kV to receive 33% regional funding with individual constructing zones to pay 67% of those projects built within the zone. For projects under 100kV, the constructing zones would pay 100% of the cost. On May 17, 2010, we filed a joint protest at the FERC with other SPP members based on our disagreement with the SPP on the allocation percentages and various other issues. On June 17, 2010, the FERC unconditionally approved the new highway/byway cost allocation method. We and other members of the SPP filed a Request for Rehearing on July 19, 2010. On October 20, 2011, the FERC issued its Order on Rehearing denying our request to review various aspects of its June 17, 2010 order. In mid December 2011, we, along with the other SPP member joint protestors, filed a Petition for Review and Motion for Stay of Procedures with the U. S. Court of Appeals for the Eight Circuit. We are concerned with the SPP's authority, pursuant to the FERC order, 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 requested a stay of procedures in order to allow the SPP to complete its efforts to adopt a method satisfactory to us for analyzing the reasonableness of the highway/byway cost allocation approach and an effective remediation process for imbalanced cost allocation. On December 16, 2011, the Eighth Circuit U.S. Court of Appeals granted our petition and stay request. On April 4, 2012, we and the other petitioners filed a status report and motion for voluntary dismissal of the petition. Our decision to dismiss the petition was warranted based on the January 2012 approvals of the SPP Board of Directors (BOD) and Regional State Committee for SPP to implement the review process in 2013. SPP's regional cost allocation review and imbalance analysis is underway with initial results to be presented in mid 2013. On April 5, 2012, the Eighth Circuit granted our motion to dismiss and, on April 10, 2012, amended their judgment of the granting of dismissal to clarify that such dismissal would not preclude us from raising similar concerns of any future FERC order. To date, the SPP's BOD has approved $2.8 billion in highway/byway transmission projects to be constructed by 2022 with an additional $745 million to be approved during the first quarter of 2013. As these projects are constructed, we will be allocated a share of the costs of the projects pursuant to the FERC accepted highway/byway regional cost allocation method. We expect that these operating costs will be material, but that they will be recoverable in future rates.

Other FERC Activity

On June 17, 2010, FERC issued a Notice of Proposed Rulemaking (NOPR) proposing to amend the transmission planning and cost allocation requirements established in Order No. 890 to ensure that FERC-jurisdictional services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential. With respect to transmission planning, FERC said that the proposed rule would: (1) provide that local and regional transmission planning processes account for transmission needs driven by public policy requirements established by state or federal laws or regulations; (2) improve coordination between neighboring transmission planning regions with respect to interregional facilities; and (3) remove from FERC-approved tariffs or agreements a right of first refusal (ROFR) created by those documents that provides an incumbent transmission provider with an undue advantage over a non-incumbent transmission developer. Neither incumbent nor non-incumbent transmission facility developers should, as a result of a FERC-approved tariff or agreement, receive different treatment in a regional transmission planning process, FERC contended. Further, both should share similar benefits and obligations commensurate with that participation, including the right, consistent with state or local laws or regulations, to construct and own a facility that it sponsors in a regional transmission planning process and that is selected for inclusion in the regional transmission plan. With respect to cost allocation, the proposed rule would establish a closer link between transmission planning processes and cost allocation and would require cost allocation methods for intraregional and interregional transmission facilities to satisfy newly established cost allocation principles.

On July 21, 2011, the FERC issued Order No. 1000 (Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities). Order 1000 requires all public utility transmission providers to (among other things) facilitate non-incumbent transmission developer participation in regional transmission planning by removing from FERC-approved tariffs and agreements any language creating a federal ROFR for an incumbent transmission provider to construct transmission facilities selected in a regional transmission plan for cost allocation. On May 17, 2012, the FERC issued Order No. 1000-A setting forth additional clarifications and guidelines for Order 1000 compliance. On October 18, 2012, the FERC issued Order 1000-B, reaffirming its Order 1000 and 1000-A requirements and clarifications. As an incumbent transmission owning member of the SPP RTO, this could directly affect our rights to build transmission facilities within our service territory. A second key element of Order 1000 and Order 1000-A directed transmission providers to develop policy and procedures for interregional transmission coordination and interregional cost allocation. Since we are on the southeastern seam of the SPP, this policy will most likely have a direct impact on our customers, primarily through a potential reduction to our production costs as a result of greater access to lower cost power from within the SPP, and across this seam and the possible reduction because of the cost sharing for new transmission projects. SPP stakeholder processes have commenced to determine the policy and tariff provisions for the compliance filings and we will continue to participate in the SPP processes to understand the impact of Orders 1000, 1000-A and 1000-B 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. A compliance filing by the SPP to address the ROFR requirements was made in November 2012. The compliance filing for the interregional planning and cost allocation requirements of Order 1000 is expected to occur in May 2013. We and the other SPP members will be working on SPP OATT modifications and providing input to SPP related to joint operating agreement modifications needed for Order 1000 compliance.

As a transmission owning member of the SPP RTO, Order 1000 could directly affect our rights to build transmission facilities within our service territory. The second key element of Order 1000 related to policy and procedures for interregional transmission coordination and interregional cost allocation is also significant to us and will most likely have a direct impact to our customers since we are on the southeastern seam of the SPP. Such impacts could be primarily through potential reductions to our production costs as a result of greater access to lower cost power from within the SPP, and across the seams, and the beneficial cost sharing for new interregional type transmission projects. We will continue to participate in the SPP stakeholder processes to understand the impact of Order 1000 on our ability to construct new facilities within our service territory as well as its influence on promoting construction of transmission projects on/near our borders with our neighbors.

On April 23, 2012, we intervened in the SPP's Petition for Review (Case No. 12-1158) of FERC's Orders on Declaratory Order and Rehearing (Docket No. EL11-34-000) on the interpretation of the SPP/MISO Joint Operating Agreement at the United States Court of Appeals for the District of Columbia. We are in agreement with SPP and other SPP members that FERC was incorrect in its determination that MISO's interpretation of the Joint Operating Agreement appropriately enables MISO and Entergy to utilize ours and other SPP members transmission systems to integrate Entergy into the MISO RTO without compensation or consideration of the negative impacts to us and the other SPP members. On June 25, 2012, the SPP interveners made a joint intervention filing at the DC court and a joint brief in October 2012 and reply brief on January 14, 2013. It is in our best interests that the review of the Joint Operating Agreement between SPP and MISO be remanded back to FERC to reevaluate its Orders. 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 increase transmission delivery costs for our Plum Point power station as well as utilize our transmission system without compensation. In late 2012, ITC Holdings and

Entergy announced the sale of transmission assets to ITC and formation of new ITC transmission only companies. Subsequently, ITC, Entergy, and MISO made multiple filings at the FERC for the transfer of ownership of Entergy's transmission facilities as well as full integration into the MISO RTO. We and several other SPP members jointly filed in protest of the filings on January 11, 2013, based on Entergy and MISO's planned utilization of our and the other SPP members' system without mitigation or resolution of the current and expected harm of MISO's interpretation/use of the joint operating agreement to implement the integration. We expect the FERC process to resolve the issues to occur in 2013 as Entergy's planned integration is scheduled for late 2013.

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 $1.8 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, stock options and their related dividend equivalents 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):

	2012	2011	2010
Compensation expense	$1,863	$1,765	$3,193
Tax benefit recognized	649	614	1,160

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 2010, 2011 and 2012 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.

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 2011 and 2012 is presented in the table below:

	December 31, 2012		December 31, 2011	
	Number of shares	Weighted Average Fair Market Value	Number of shares	Weighted Average Fair Market Value
Outstanding at January 1,	3,433	$ 21.84	—	$ —
Granted	—	—	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,	3,300	$20.358	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 2010, 2011 and 2012 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, 2012, 2011 and 2010 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,		
	2012	2011	2010
Risk-free interest rate	0.16% to 0.25%	0.12% to 0.23%	0.30% to 0.62%
Expected volatility of Empire stock	20.6%	23.8%	26.9%
Expected volatility of peer group stock	12.4% to 29.2%	15.7% to 57.4%	21.7% to 82.7%
Expected dividend yield on Empire stock	4.9%	4.7%	6.5%
Expected forfeiture rates	3%	3%	3%
Plan cycle	3 years	3 years	3 years
Fair value percentage	18.0% to 96.0%	51.0% to 75.0%	138.0% to 193.7%
Weighted average fair value per share	$10.94	$13.67	$37.17

Non-vested restricted stock awards (based on target number) as of December 31, 2012, 2011 and 2010 and changes during the year ended December 31, 2012, 2011 and 2010 were as follows:

	2012		2011		2010	
	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,	37,400	$19.28	47,500	$19.86	52,200	$21.57
Granted	10,000	$20.97	10,900	$21.84	13,000	$18.36
Awarded	(7,823)	$18.12	(39,621)	$21.92	(15,104)	$23.81
Awarded in excess of target	—	$ —	18,621	$21.92		
Not awarded	(5,677)	$18.12	—	$ —	(2,596)	$ —
Nonvested at December 31,	33,900	$20.25	37,400	$19.28	47,500	$19.86

At December 31, 2012 and 2011, unrecognized compensation expense related to estimated outstanding awards was $0.1 million and $0.1 million, respectively.

Stock Options

Beginning in 2011, we began issuing time-vested restricted stock in lieu of stock options and dividend equivalents. Stock options were issued with an exercise price equal to the fair market value of the shares on the date of grant, become exercisable after three years and expire ten years after the date granted. Participants' options that are not vested become forfeited when participants leave Empire except for terminations of employment under certain specified circumstances. Dividend equivalent awards were also issued to the recipients of the stock options under which dividend equivalents will be accumulated for the three-year period until the option becomes exercisable. Dividend equivalents cease to be accumulated on the date that a participant leaves Empire, and the accumulated dividend equivalents are forfeited when a participant leaves the Company, except for terminations of employment under certain specified circumstances. There were no stock options or dividend equivalents granted in 2012 or 2011. The fair value per dividend equivalent grant for 2010 and outstanding at December 31, 2012, was $2.92.

The dividend equivalents are accumulated for the three-year period and are converted to shares of common stock based on the fair market value of the shares on the date converted. The dividend equivalent awards vest and are payable in fully vested shares of our common stock on the third anniversary of the grant date (conversion date) or at a change in control and not dependent upon the exercise of the related option.

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, 2012, 2011 and 2010, under a Black-Scholes methodology. The assumptions used in the valuations are shown below:

	Fair Value of Grants Outstanding at December 31,		
	2012	2011	2010
Risk-free interest rate	0.11% to 0.44%	0.12% to 0.72%	0.45% to 2.34%
Dividend yield	4.9%	4.7%	6.5%
Expected volatility	24.0%	25.0%	23.0%
Expected life in months	78	78	78
Market value	$20.38	$21.09	$22.20
Weighted average fair value per option	$1.34	$2.08	$2.02

A summary of option activity under the plan during the years ended December 31, 2012, 2011 and 2010 is presented below:

	2012		2011		2010	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Outstanding at January 1,	190,300	$21.56	267,400	$21.69	232,600	$22.19
Granted	0	$ —	0	$ —	34,800	$18.36
Exercised	27,000	$18.12	77,100	$22.02	—	$ —
Outstanding at December 31,	163,300	$22.13	190,300	$21.56	267,400	$21.69
Exercisable, end of year	128,500	$23.15	128,500	$23.15	149,200	$23.04

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, 2012, 2011 and 2010:

	2012	2011	2010
Aggregate intrinsic value (in millions)	$0.1	$0.2	$0.3
Weighted-average remaining contractual life of outstanding options	3.2 years	5.1 years	6.6 years
Range of exercise prices	$18.36 to $23.81	$18.12 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	$0.2
Recognition period	1 month	1 year	1 – 3 years

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, 2012, there were 195,873 shares available for issuance in this plan.

	2012	2011	2010
Subscriptions outstanding at December 31,	70,850	70,756	71,326
Maximum subscription price	$ 17.95(1)	$ 17.27	$ 16.06
Shares of stock issued	65,919	69,229	66,723
Stock issuance price	$ 17.27	$ 16.06	$ 14.62

(1) Stock will be issued on the closing date of the purchase period, which runs from June 1, 2012 to May 31, 2013.

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

	2012	2011	2010
Weighted average fair value of grants	$ 3.19	$ 3.17	$ 2.28
Risk-free interest rate	0.17%	0.18%	0.35%
Dividend yield	5.00%	2.60%	7.20%
Expected volatility(1)	24.00%	22.00%	17.00%
Expected life in months	12	12	12
Grant date	6/1/12	6/1/11	6/1/10

(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.

A total of 400,000 shares are 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:

	2012	2011
Shares accrued to directors' accounts	143,058	133,956
Shares available for issuance	258,960	280,282

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

	2012	2011	2010
Units accrued for service and dividends	30,426	25,287	33,364
Units redeemed for common stock	21,324	31,243	6,347

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, 2012 and 2011, there were 320,576 and 36,038 shares available to be issued, respectively.

	2012	2011	2010
Shares contributed	65,502	68,523	64,830

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. 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 at $0.25 per share and declared dividends payable on March 15, 2012, June 15, 2012, September 17, 2012 and December 17, 2012. As of December 31, 2012, our retained earnings balance was $47.1 million (compared to $33.7 million at December 31, 2011) after paying out $42.3 million in dividends during 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, 2012 or 2011.

6. Long-Term Debt

At December 31, 2012 and 2011, the balance of long-term debt outstanding was as follows (in thousands):

	2012	2011
First mortgage bonds (EDE):		
7.20% Series due 2016	$ 25,000	$ 25,000
5.3% Pollution Control Series due 2013	—	8,000
5.2% Pollution Control Series due 2013	—	5,200
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
7.0% Series due 2024	—	74,829
3.58% Series due 2027(1)	88,000	—
First mortgage bonds (EDG):		
6.82% Series due 2036(1)	55,000	55,000
	488,000	488,029
Senior Notes, 4.50% Series due 2013(1)	98,000	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	5,155	6,087
Less unamortized net discount	(815)	(924)
	692,340	693,192
Less current obligations of long-term debt	(415)	(641)
Less current obligations under capital lease	(299)	(292)
TOTAL LONG-TERM DEBT	**$691,626**	**$692,259**

(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

2012

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 is anticipated to occur on or about May 30, 2013, subject to customary closing conditions. We expect to use the proceeds from the sale of the bonds to redeem all $98.0 million aggregate principal amount of our Senior Notes, 4.50% Series due June 15, 2013 with the remaining proceeds to be 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 will be 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.

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 to repay short term debt initially used for such purpose). The bonds have been issued under the EDE Mortgage.

2010

On August 25, 2010, we issued $50 million principal amount of 5.20% first mortgage bonds due September 1, 2040. The net proceeds (after payment of expenses) of approximately $49.1 million were used to redeem $48.3 million aggregate principal amount of our Senior Notes, 7.05% Series due 2022 on August 27, 2010.

On May 28, 2010, we issued $100 million principal amount of 4.65% first mortgage bonds due June 1, 2020. The net proceeds (after payment of expenses) of approximately $98.8 million, were used to redeem all 2 million outstanding shares of our 8.5% trust preferred securities, totaling $50 million, on June 28, 2010, and to repay short-term debt which was incurred, in part, to fund the repayment, at maturity, of our 6.5% first mortgage bonds due 2010.

Shelf Registration

We have a $400.0 million shelf registration statement with the SEC, effective February 7, 2011, covering our common stock, unsecured debt securities, preference stock, and first mortgage bonds. We have received regulatory approval for the issuance of securities under this shelf from all four states in our electric service territory, but we may only issue up to $250.0 million of such securities in the form of first mortgage bonds, of which $12.0 million would remain available after giving effect to the $150.0 million of new first mortgage bonds to be issued on or about May 30, 2013. We plan to use proceeds from offerings made pursuant to this shelf to fund capital expenditures, refinancings of existing debt or general corporate needs during the three-year effective period.

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, 2012 would permit us to issue approximately $609.2 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, 2012, we had retired bonds and net property additions which would enable the issuance of at least $776.7 million principal amount of bonds if the annual interest requirements are met. As of December 31, 2012, 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, 2012, this test would allow us to issue approximately $12.8 million principal amount of new first mortgage bonds at an assumed interest rate of 5.5%.

Long-Term Debt Payout Schedule (Excluding Unamortized Discount (in thousands)	Payments Due By Period		
	Total	Regulated Entity Debt Obligations	Capital Lease Obligations
2013	$ 98,714	$ 98,415	$ 299
2014	274	—	274
2015	292	—	292
2016	25,307	25,000	307
2017	325	—	325
Thereafter	568,242	565,000	3,242
Total long-term debt obligations	**693,154**	**$688,415**	**$4,739**
Less current obligations and unamortized discount	1,528		
TOTAL LONG-TERM DEBT	**$691,626**		

7. Short-Term Borrowings

At December 31, 2012, total short-term borrowings consisted of $24.0 million in commercial paper and no borrowings from our line of credit. During 2012 and 2011 our short-term borrowings outstanding averaged (in millions)

	2012	2011
Average borrowings outstanding	$17.8	$ 8.8
Highest month end balance	$55.7	$18.5

The weighted average interest rates and the weighted average interest rate of borrowings outstanding at December 31, 2012 and 2011 were:.

	2012	2011
Weighted average interest rate	1.05%	0.98%
Weighted average interest rate of borrowings outstanding	0.91%	0.85%

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 removes 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. 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 0.25%). 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, 2012, we are in compliance with these ratios. Our total indebtedness is 49.9% of our total capitalization as of December 31, 2012 and our EBITDA is 4.9 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, 2012. However, $24.0 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. 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, 2012, 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. 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 increased $13.7 million and $7.6 million in 2012 and 2011, respectively. This increase was recorded as an increase 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 $15.9 million for 2013. 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 2014, the performance of our pension assets during 2013.

Expected benefit payments are as follows (in millions):

Year	Payments from Trust	Payments from Company Funds
2013	$10.1	$0.3
2014	10.8	0.3
2015	11.5	0.3
2016	12.1	0.3
2017	12.6	0.3
2018 – 2022	71.2	1.6

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.

Our net liability increased $2.2 million and $0.6 million in 2012 and 2011, respectively. The increase was recorded as an increase 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 $4.2 million in 2013.

Estimated benefit payments are as follows (in millions):

Year	Payments from Trust	Expected Federal Subsidy	Payments from Company Funds
2013	$ 2.5	$0.3	$0.1
2014	2.8	0.3	0.2
2015	3.1	0.4	0.2
2016	3.4	0.4	0.2
2017	3.8	0.5	0.2
2018 – 2022	22.7	3.1	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	
	2012	2011	2012	2011	2012	2011
Benefit obligation at beginning of year	$215,088	$186,840	$4,863	$2,895	$83,226	$80,938
Service cost	6,261	5,596	51	93	2,401	2,266
Interest cost	10,258	10,405	263	183	4,037	4,383
Net actuarial (gain)/loss	25,882	20,869	1,511	1,883	6,955	(2,136)
Plan participant's contribution	—	—	—	—	910	863
Benefits and expenses paid	(9,485)	(8,622)	(323)	(191)	(3,156)	(3,261)
Federal subsidy	—	—	—	—	365	173
Benefit obligation at end of year	**$248,004**	**$215,088**	**$6,365**	**$4,863**	**$94,738**	**$83,226**

Reconciliation of Fair Value of Plan Assets:

	Pension		SERP		OPEB	
	2012	2011	2012	2011	2012	2011
Fair value of plan assets at beginning of year	$140,975	$120,353	$—	$—	$58,384	$56,730
Actual return on plan assets — gain/(loss)	17,562	(625)	—	—	7,148	279
Employer contribution	11,123	29,869	—	—	3,970	3,544
Benefits paid	(9,485)	(8,622)	—	—	(3,045)	(3,160)
Plan participant's contribution	—	—	—	—	864	826
Federal subsidy	—	—	—	—	346	165
Fair value of plan assets at end of year	**$160,175**	**$140,975**	**$—**	**$—**	**$67,667**	**$58,384**

Reconciliation of Funded Status:

	Pension		SERP		OPEB	
	2012	2011	2012	2011	2012	2011
Fair value of plan assets	$ 160,175	$ 140,975	$ —	$ —	$ 67,667	$ 58,384
Projected benefit obligations	(248,004)	(215,088)	(6,365)	(4,863)	(94,738)	(83,226)
Funded status	**$ (87,829)**	**$ (74,113)**	**$(6,365)**	**$(4,863)**	**$(27,071)**	**$(24,842)**

The employee pension plan accumulated benefit obligation at December 31, 2012 and 2011 is presented in the following table (in thousands):

	Pension Benefits		SERP	
	2012	2011	2012	2011
Accumulated benefit obligation	$219,659	$191,295	$6,014	$4,670

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

	Pension		SERP		OPEB	
	2012	2011	2012	2011	2012	2011
Accounts Payable and Accrued Liabilities	$ —	$ —	$ 313	$ 311	$ 144	$ 136
Pension and other postretirement benefit obligation	$87,829	$74,113	$6,052	$4,552	$26,927	$24,706

Net periodic benefit pension cost for 2012, 2011 and 2010, 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		
	2012	2011	2010	2012	2011	2010
Service cost	$ 6,261	$ 5,596	$ 4,887	$ 2,401	$ 2,266	$ 2,138
Interest cost	10,258	10,405	10,115	4,037	4,383	4,329
Expected return on plan assets	(12,309)	(11,139)	(9,847)	(4,135)	(4,157)	(3,844)
Amortization of prior service cost(1)	531	532	531	(1,011)	(1,011)	(1,011)
Amortization of actuarial loss(1)	7,935	5,494	3,996	1,661	1,762	1,499
Net periodic benefit cost	**$ 12,676**	**$ 10,888**	**$ 9,682**	**$ 2,953**	**$ 3,243**	**$ 3,111**

Net Periodic Pension Benefit Cost:

	SERP		
	2012	2011	2010
Service cost	$ 51	$ 93	$ 70
Interest cost	263	183	153
Expected return on plan assets	—	—	—
Amortization of prior service cost(1)	(8)	(8)	(8)
Amortization of actuarial loss(1)	389	171	96
Net periodic benefit cost	**$695**	**$439**	**$311**

(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).

		Amount Recognized			
Regulatory Assets	Beginning Balance 12/31/11	Current Year Actuarial Loss	Amortization of Actuarial Loss	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, 2012, and the subsequent twelve-month period (in thousands):

	Pension Benefits		SERP		OPEB	
	2012	Subsequent Period	2012	Subsequent Period	2012	Subsequent Period
Net actuarial loss	$103,838	$10,361	$4,174	$416	$24,917	$ 2,598
Prior service cost (benefit)	1,980	531	(31)	(8)	(4,606)	(1,011)
Total	**$105,818**	**$10,892**	**$4,143**	**$408**	**$20,311**	**$ 1,587**

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	
	2012	2011	2012	2011
Discount rate	4.00%	4.70%	4.11%	4.90%
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		
	2012	2011	2010	2012	2011	2010
Discount rate	4.70%	5.50%	6.00%	4.90%	5.50%	6.00%
Expected return on plan assets	7.90%	8.00%	8.00%	6.65%	7.00%	7.00%
Rate of compensation increase	3.50%	4.50%	4.50%	3.50%	4.50%	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 2012 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	$ 1,285	$ (1,001)
Effect on post-retirement benefit obligation	$14,789	$(11,882)

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 estimated by Wells Fargo Bank, N.A. 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.

The target allocations for plan assets are 60% – 80% equity securities, 20% – 40% debt securities, and 0% – 15% in all other types of investments.

The following fair value hierarchy table presents information about the pension fund assets measured at fair value as of December 31, 2012 and December 31, 2011 (in thousands):

	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 as of December 31, 2011				
	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	$ —	$ 1,787	$ —	$ 1,787	1.2%
Equity securities					
U.S. equity	57,228	—	—	57,228	40.6%
International equity	19,151	—	—	19,151	13.6%
Fixed income					
Common collective trust	—	22,904	—	22,904	16.3%
U.S. corporate debt	—	11,692	—	11,692	8.3%
U.S. government debt	794	—	—	794	0.6%
Other types of investments					
Equity long/short hedge funds	—	—	27,419	27,419	19.4%
	$77,173	$36,383	$27,419	$140,975	100.0%

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

	2012	2011
	Equity long/short hedge funds	Equity long/short hedge funds
Beginning Balance, January 1,	$27,419	$22,338
Actual return on plan assets:		
Relating to assets still held at the reporting date	1,466	(669)
Relating to assets sold during the period	—	—
Purchases	—	5,750
Sales	—	—
Settlements	—	—
Transfers into and (out of) Level 3	—	—
Ending Balance, December 31,	$28,885	$27,419

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, 2012 and December 31, 2011 (in thousands):

	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	$—	67,836	
Accrued interest & dividends				281	0.5%
				$67,667	100%

	Fair Value Measurements as of December 31, 2011				
	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	$ 1,536	$ —	$—	$ 1,536	2.6%
Fixed income					
U.S. government debt	1,839	—	—	1,839	3.1%
U.S. corporate debt	—	17,232	—	17,232	29.5%
Foreign debt	—	1,460	—	1,460	2.5%
Mutual funds — fixed income	2,107	—	—	2,107	3.6%
Equity securities					
U.S. equity	21,080	—	—	21,080	36.1%
International equity	1,784	—	—	1,784	3.1%
Mutual funds — equity	11,075	—	—	11,075	19.0%
	$39,421	$18,692	—	58,113	
Accrued interest & dividends				271	0.5%
				$58,384	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):

	2012	2011	2010
Current income taxes:			
Federal	$ 1,552	$ (8,604)	$ 7,713
State	708	(2,120)	1,057
TOTAL	2,260	(10,724)	8,770
Deferred income taxes:			
Federal	28,210	39,096	17,942
State	4,018	6,297	4,349
TOTAL	32,228	45,393	22,291
Investment tax credit amortization	(329)	(371)	(528)
TOTAL INCOME TAX EXPENSE	**$34,159**	**$ 34,298**	**$30,533**

Deferred Income Taxes

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

Deferred Income Taxes	December 31, 2012	December 31, 2011
Current deferred tax assets, net[1]	$ 13,000	$ 6,688
Non-current deferred tax liabilities, net	301,967	263,933
NET DEFERRED TAX LIABILITIES	**$288,967**	**$257,245**

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

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

Temporary Differences	December 31, 2012	December 31, 2011
Deferred tax assets:		
Net operating loss	$ 13,000	$ 6,688
Disallowed plant costs	1,010	1,097
Gains on hedging transactions	1,389	1,454
Plant related basis differences	21,571	21,044
Regulated liabilities related to income taxes	13,871	13,318
Carry forward of income tax credit	3,722	16,304
Pensions and other post-retirement benefits	693	—
Deferred fuel costs	785	—
Other	1,477	891
Total deferred tax assets	$ 57,518	$ 60,796
Deferred tax liabilities:		
Depreciation, amortization and other plant related differences	$279,604	$253,743
Regulated assets related to income	39,553	40,555
Loss on reacquired debt	4,489	4,288
Pensions and other post-retirement benefits	—	673
Amortization of intangibles	7,009	5,929
Deferred fuel costs	—	2,662
Other	15,830	10,191
Total deferred tax liabilities	346,485	318,041
NET DEFERRED TAX LIABILITIES	**$288,967**	**$257,245**

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	2012	2011	2010
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	(0.4)	(0.4)	(0.7)
Effect of ratemaking on property related differences	(0.2)	0.2	(0.8)
Effect of Medicare part D changes	—	—	2.7
Other	0.5	0.5	(0.1)
EFFECTIVE INCOME TAX RATE	**38.0%**	**38.4%**	**39.2%**

Unrecognized Tax Benefits	2012	2011	2010
Unrecognized tax benefits — January 1,	$—	$ 359,000	$ 906,000
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)	(547,000)
UNRECOGNIZED TAX BENEFITS — December 31,	$—	$ —	$ 359,000

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 running of the statute of limitations on these unrecognized tax benefits on September 15, 2011, there are no unrecognized tax benefits at December 31, 2012 and 2011.

As of December 31, 2012, we have federal and state income tax net operating loss (NOL) carryforwards totaling $27.2 million, which expire in 2031.

We received $17.7 million, of investment tax credits based on our investment in Iatan 2. We utilized less than $0.2 million of these credits when preparing our 2010 tax return as utilization of the credits was limited by alternative minimum tax rules. We expect to utilize approximately $1.8 million of these credits on our 2012 tax return. We expect to use the remaining credits over the 2013 and 2014 tax years. 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.

We received a $26.6 million payment received from the SWPA during 2010 which was deferred and treated as a noncurrent liability for book purposes. We increased our current tax liability by $10.0 million during 2010 in recognition that the $26.6 million payment may be considered taxable income in 2010. An agreement was reached with the IRS in 2011 that allowed us to defer recognition for tax purposes of approximately $26.1 million utilizing "like-kind exchange" rules within the Code. Accordingly, we reduced our current tax liability based on the agreement and will recognize the $26.1 million for tax purposes over more than 50 years.

As part of an agreement reached in our 2009 Missouri electric rate case, effective September 10, 2010, we also agreed to commence an eighteen year amortization of a regulatory asset related to the tax benefits of cost of removal. These tax benefits were flowed through to customers from 1981 – 2008 and totaled approximately $11.1 million. We recorded the regulatory asset expecting to recover these benefits from customers in future periods. Based on the agreement, we estimated the portion of the amortization period from which we would not receive rate recovery for this item and wrote off approximately $1.2 million in the first quarter of 2010. Amortization resumed during 2011 and the remaining balance as of December 31, 2012 was approximately $9.6 million.

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. We expect the extension of bonus depreciation will reduce our tax payments slightly during 2013 and 2014 as the Company will utilize investment tax credits noted above at a slower 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, 2012 and 2011, our property, plant and equipment accounts included the amounts in the following chart (in millions):

Iatan	2012	2011
Cost of ownership in plant in service	$364.1	$362.6
Accumulated Depreciation	$ 83.2	$ 39.6
Expenditures(1)	$ 30.0	$ 31.3

(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, 2012 and 2011, our property, plant and equipment accounts include the amounts in the following chart (in millions):

State Line Combined Cycle Unit	2012	2011
Cost of ownership in plant in service	$164.4	$162.1
Accumulated Depreciation	$ 36.7	$ 32.1
Expenditures(1)	$ 42.7	$ 57.0

(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, 2012 and 2011, our property, plant and equipment accounts included the amounts in the following chart (in millions):

Plum Point Energy Station	2012	2011
Cost of ownership in plant in service	$108.0	$110.1
Accumulated Depreciation	$ 4.9	$ 2.7
Expenditures(1)	$ 7.8	$ 8.5

(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.

On May 22, 2009, a suit was filed in the Circuit Court of Platte County Missouri by several individuals and Class Representatives alleging damages to land, structures, equipment and devastation of crops due to inappropriate management of the levee system around the Iatan Generating Station, of which we are a 12% owner. The parties have reached a settlement in principle and are working on documentation. We do not anticipate the settlement will have a material impact on our results of operations, financial position or liquidity.

A lawsuit was filed in Jasper County Circuit Court (the Court) against us by three of our residential customers, purporting to act on behalf of all Empire customers. These customers were seeking a refund of certain amounts paid for service provided by Empire between January 1, 2007, and December 13, 2007. At all times, we charged the three plaintiffs, and all of our customers, the rates approved by and on file with the MPSC from our 2006 rate case. While the precise circumstances of Empire's 2006 rate case and the approval of Empire's tariffs have not previously been addressed by Missouri's appellate courts, we believe that case law supports the position that the MPSC may not re-determine rates already established and paid without depriving the utility, or a consumer if the rates were originally too low, of its property without due process.

We filed a motion asking the Court to dismiss the case on the basis that the plaintiffs had not stated a valid claim. A hearing on our motion was held April 18, 2012. The Court granted Empire's motion to dismiss, and a judgment was issued by the Court on June 29, 2012, dismissing the case. The plaintiffs filed a Notice of Appeal on July 30, 2012. The Missouri Court of Appeals for the Southern District dismissed the case for failure to properly perfect the appeal. The plaintiffs moved to set aside the dismissal, and the Court of Appeals restored the case to its active docket. The case is now being briefed by the parties.

Coal, Natural Gas and Transportation Contracts

(in millions)	Firm physical gas and transportation contracts	Coal and coal transportation contracts
January 1, 2013 through December 31, 2014	$29.4	$23.6
January 1, 2015 through December 31, 2016	$29.9	$32.1
January 1, 2017 through December 31, 2018	$22.2	$22.7
January 1, 2019 and beyond	$ 8.3	$22.7

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 which entered commercial operation on September 1, 2010. 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 began receiving purchased power under this agreement on September 1, 2010. 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. We will, however, continue to analyze this option during our 2013 IRP process. Commitments under this agreement are approximately $306.7 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 (formerly Horizon Wind Energy), 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 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.

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, 2012.

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

Capital Leases	Capital Leases	Operating Leases
2013	$ 595	$ 788
2014	553	732
2015	553	726
2016	549	721
2017	546	682
Thereafter	4,100	1,131
Total minimum payments	**6,896**	**$4,780**
Less amount representing interest	2,157	
Present value of net minimum lease payments	**$4,739**	

Expenses incurred related to operating leases were $0.9 million, $1.0 million and $0.8 million for 2012, 2011, and 2010, respectively, excluding payments for wind generated purchased power agreements. The accumulated amount of amortization for our capital leases was $1.0 million and $1.0 million at December 31, 2012 and 2011, 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

Air

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) and mercury. In the future they are also likely to include limits on other hazardous pollutants (HAPs) and so-called greenhouse gases (GHG) such as carbon dioxide (CO2) and methane.

Permits

Under the CAA we have obtained, and renewed as necessary, site operating permits, which are valid for five years, for each of our plants.

Compliance Plan

In order to comply with forthcoming environmental regulations, Empire is taking actions to implement its compliance plan and strategy (Compliance Plan). While the Cross State Air Pollution Rule (CSAPR) that was set to take effect on January 1, 2012 was stayed in late December 2011 then vacated in August 2012 by the District of Columbia Circuit Court of Appeals, the Mercury Air Toxics Standard (MATS) was signed by the Environmental Protection Agency (EPA) Administrator on December 16, 2011 and became effective on April 16, 2012. MATS requires compliance by April 2015 (with flexibility for extensions for reliability reasons). Our Compliance Plan largely follows the preferred plan presented in our most recent Integrated Resource Plan. As described above under New Construction, we have begun the installation of 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. Initial construction costs through December 31, 2012 were \$29.0 million for 2012 and \$30.3 million for the project to date, excluding AFUDC. The addition of this air quality control equipment will require the retirement of Asbury Unit 2, an 18 megawatt steam turbine that is currently used for peaking purposes.

In September 2012, we completed the transition of our Riverton Units 7 and 8 from operation on coal 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 2016.

SO2 Emissions

The CAA regulates the amount of SO2 an affected unit can emit. Currently SO2 emissions are regulated by the Title IV Acid Rain Program and the Clean Air Interstate Rule (CAIR). On January 1, 2012, CAIR was to have been replaced by the Cross-State Air Pollution Rule (CSAPR- formerly the Clean Air Transport Rule). But, on December 30, 2011 the District of Columbia Circuit Court of Appeals issued a stay of the CSAPR. On August 21, 2012, following the review of the case challenging the CSAPR, the Court released its decision that the CSAPR will be vacated and CAIR will remain in effect until the EPA develops a valid replacement for CAIR. In addition, on October 5, 2012, the Department of Justice, on behalf of the EPA, requested that the Court of Appeals grant a request for a re-hearing of CSAPR. In the meantime both the Title IV Acid Rain Program and CAIR will remain in effect.

The Mercury Air Toxics Standards (MATS), discussed further below, was signed on December 16, 2011, and will affect SO2 emission rates at our facilities. In addition, the compliance date for the revised SO2 National Ambient Air Quality Standards (NAAQS) is August of 2017; this will also affect SO2 emissions from our facilities. The SO2 NAAQS is discussed in more detail below.

Title IV Acid Rain Program:

Under the Title IV Acid Rain Program, each existing affected unit has been allocated a specific number of emission allowances by the U.S. Environmental Protection Agency (EPA). Each allowance entitles the holder to emit one ton of SO2. Covered utilities, such as Empire, must have emission allowances equal to the number of tons of SO2 emitted during a given year by each of their affected units. Allowances in excess of the annual emissions are banked for future use. In 2012 and 2011, our SO2 emissions exceeded the annual allocations. This deficit was covered by our banked allowances. We estimate our Title IV Acid Rain Program SO2 allowance bank plus annual allocations will be more than our projected emissions through 2016. Long-term compliance with this program will be met by the Compliance Plan detailed above along with possible procurement of additional SO2 allowances. We expect the cost of compliance to be fully recoverable in our rates.

CAIR:

In 2005, the EPA promulgated CAIR under the CAA. 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.

In 2008, the U.S. Court of Appeals for the District of Columbia vacated CAIR and remanded it back to EPA for further consideration, but also stayed its vacatur. As a result, CAIR became effective for NOx on January 1, 2009 and for SO2 on January 1, 2010 and required covered states to develop State Implementation Plans (SIPs) to comply with specific SO2 state-wide annual budgets.

SO2 allowance allocations under the Title IV Acid Rain Program are used for compliance in the CAIR SO2 Program. Beginning in 2010, SO2 allowances were utilized at a 2:1 ratio for our Missouri units. As a result, based on current SO2 allowance usage projections, we expected to have sufficient allowances to take us through 2016.

In order to meet CAIR requirements for SO2 and NOx emissions (NOx is discussed below in more detail) and as a requirement for the air permit for Iatan 2, a Selective Catalytic Reduction system (SCR), a Flue-Gas Desulfurization (FGD) scrubber system and baghouse were installed at our jointly-owned Iatan 1 plant and a SCR was installed at our Asbury plant in 2008. Our jointly-owned Iatan 2 and Plum Point plants were originally constructed with the above technology.

CSAPR- formerly the Clean Air Transport Rule:

On July 6, 2010, the EPA published a proposed CAIR replacement rule entitled the Clean Air Transport Rule (CATR). As proposed and supplemented, the CATR included Missouri and Kansas under both the annual and ozone season for NOx as well as the SO2 program while Arkansas remained in the ozone season NOx program only. The final CATR was released on July 7, 2011 under the name of the CSAPR, and was set to become effective January 1, 2012. However, as mentioned above, the District of Columbia Circuit Court of Appeals vacated CSAPR on August 21, 2012, and the CAIR will be in effect until a valid replacement for CAIR is developed by the EPA. In addition, on October 5, 2012 the EPA petitioned the Court to re-hear the case against CSAPR. When it was published, the final CSAPR required a 73% reduction in SO2 from 2005 levels by 2014. The SO2 allowances allocated under the EPA's Title IV Acid Rain Program cannot be used for compliance with CSAPR but would continue to be used for compliance with the Title IV Acid Rain Program. Therefore, new SO2 allowances would be allocated under CSAPR and retired at one allowance per ton of SO2 emissions emitted. Based on current projections, we would receive more SO2 allowances than would be emitted. Long-term compliance with this Rule will be met by the Compliance Plan detailed above along with possible procurement of additional SO2 allowances. A number of states, including Kansas, various electric utilities and industrial organizations commenced litigation in the District of Columbia Court of Appeals and challenged the CSAPR, resulting in the August 2012 vacatur of the rule. We anticipate compliance costs associated with CAIR or its subsequent replacement to be recoverable in our rates.

Mercury Air Toxics Standard (MATS):

The MATS standard was fully implemented and effective as of April 16, 2012, thus requiring compliance by April 16, 2015 (with flexibility for extensions for reliability reasons). The MATS regulation does not include allowance mechanisms. Rather, it establishes alternative standards for certain pollutants, including SO2 (as a surrogate for hydrogen chloride (HCI)), which must be met to show compliance with hazardous air pollutant limits (see additional discussion in the MATS section below).

SO2 National Ambient Air Quality Standard (NAAQS):

In June 2010, the EPA finalized a new 1-hour SO2 NAAQS which, for areas with no SO2 monitor, originally required modeling to determine attainment and non-attainment areas within each state, but in April 2012, the EPA announced that it is reconsidering this approach. The modeling of emission sources was to have been completed by June 2013 with compliance with the SO2 NAAQS required by August 2017. Because the EPA is reconsidering the compliance determination approach, the compliance time-frame may be pushed back. Draft guidance for 1-hour SO2 NAAQS has been published by the EPA to assist states as they prepare their SIP submissions. The EPA is also planning a rulemaking to address some of the 1-hour SO2 NAAQS implementation program elements. It is likely coal-fired generating units will need scrubbers to be capable of meeting the new 1-hour SO2 NAAQS. In addition, units will be required to include SO2 emissions limits in their Title V permits or execute consent decrees to assure attainment and future compliance.

NOx Emissions

The CAA regulates the amount of NOx an affected unit can emit. As currently operated, each of our affected units is in compliance with the applicable NOx limits. Currently, revised NOx emissions are limited by the CAIR as a result of the vacated CSPAR rule and by ozone NAAQS rules (discussed below) which were established in 1997 and in 2008.

CAIR:

The CAIR required covered states to develop SIPs to comply with specific annual NOx state-wide allowance allocation budgets. Based on existing SIPs, we had excess NOx allowances during 2011 which were banked for future use and will be sufficient for compliance at least through the end of 2016. The CAIR NOx program also was to have been replaced by the CSAPR program January 1, 2012 but because the Court vacated CSAPR, CAIR will remain in effect until the EPA develops a valid replacement for CAIR.

CSAPR:

As published, the CSAPR would have required a 54% reduction in NOx from 2005 levels by 2014. The NOx annual and ozone season allowances that were allocated and banked under CAIR could not be used for compliance under CSAPR. New allowances would have been issued under CSAPR. However, as discussed above, CSPAR was vacated by the District of Columbia Court of Appeals on August 21, 2012. On October 5, 2012, the EPA petitioned for a re-hearing.

Ozone NAAQS:

Ozone, also called ground level smog, is formed by the mixing of NOx and Volatile Organic Compounds (VOCs) in the presence of sunlight. On January 6, 2010, the EPA proposed to lower the primary NAAQS for ozone designed to protect public health to a range between 60 and 70 ppb and to set a separate secondary NAAQS for ozone designed to protect sensitive vegetation and ecosystems.

On September 2, 2011, President Obama ordered the EPA to withdraw proposed air quality standards lowering the 2008 ozone standard pending the CAA 2013 scheduled reconsideration of the ozone NAAQS (the normal 5 year reconsideration period). States will move forward with area designations based on the 2008 75 ppb standard using 2008 – 2010 quality assured monitoring data. Our service territory will be designated as attainment, meaning it will be in compliance with the standard. In the interim, the 1997 ozone NAAQS will remain in effect.

PM NAAQS:

Particulate matter (PM) is the term for particles found in the air which comes from a variety of sources. On June 14, 2012 the US EPA proposed the following actions: 1) to strengthen the annual PM 2.5 (particle size (microns)) NAAQS, also known as fine particulate matter and 2) set a separate 24-hour PM 2.5 standard to improve visibility primarily in urban areas. On December 14, 2012 the EPA revised only the primary annual standard to 12 ug/m^3 and states are required to meet the primary standard in 2020.

Currently, the proposed standards should have no impact on our existing generating fleet because the PM 2.5 ambient monitor results are below the level required by these proposed standards. However, the proposed standards could impact future major modifications/construction projects that require a Prevention of Significant Deterioration (PSD) permit.

Mercury Air Toxics Standard (MATS)

In 2005, the EPA issued the Clean Air Mercury Rule (CAMR) under the CAA. It set limits on mercury emissions by power plants and created a market-based cap and trade system expected to reduce nationwide mercury emissions in two phases. New mercury emission limits for Phase 1 were to go into effect January 1, 2010. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia vacated CAMR. This decision was appealed to the U.S. Supreme Court which denied the appeal on February 23, 2009.

The EPA issued Information Collection Requests (ICR) for determining the National Emission Standards for Hazardous Air Pollutants (NESHAP), including mercury, for coal and oil-fired electric steam generating units on December 24, 2009. The ICRs included our Iatan, Asbury and Riverton plants. All responses to the ICRs were submitted as required. The EPA ICRs were intended for use in developing regulations under Section 112(r) of the CAA maximum achievable emission standards for the control of the emission of hazardous air pollutants (HAPs), including mercury. The EPA proposed the first ever national mercury and air toxics standards (MATS) in March 2011, which became effective April 16, 2012. MATS establishes numerical emission limits to reduce emissions of heavy metals, including mercury (Hg), arsenic, chromium, and nickel, and acid gases, including HCl and hydrogen fluoride (HF). For all existing and new coal-fired electric utility steam generating units (EGUs), the proposed standard will be phased in over three years, and allows states the ability to give facilities a fourth year to comply.

The MATS regulation of HAPs in combination with CSAPR is the driving regulation behind our Compliance Plan and its implementation schedule. We expect compliance costs to be recoverable in our rates.

Greenhouse Gases

Our coal and gas plants, vehicles and other facilities, including EDG (our gas segment), emit CO2 and/or other Greenhouse Gases (GHGs) which are measured in Carbon Dioxide Equivalents (CO2e).

On September 22, 2009, the EPA issued the final Mandatory Reporting of Greenhouse Gases Rule under the CAA which requires power generating and certain other facilities that equal or exceed an emission threshold of 25,000 metric tons of CO2e to report GHGs to the EPA annually commencing in September 2011. EDE and EDG's GHG emissions for 2010 and 2011 have been reported as required to the EPA.

On December 7, 2009, responding to a 2007 U.S. Supreme Court decision that determined that GHGs constitute "air pollutants" under the CAA, the EPA issued its final finding that GHGs threaten both the public health and the public welfare. This "endangerment" finding did not itself trigger any EPA regulations, but was a necessary predicate for the EPA to proceed with regulations to control GHGs. Since that time, a series of rules including the Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule) have been issued by the EPA and several parties have filed petitions with the EPA and lawsuits have been filed challenging these rules. On June 26, 2012, the D.C. Circuit Court issued its opinion in the principal litigation of the EPA GHG rules (Endangerment, the Tailoring Rule, GHG emission standards for light-duty vehicles, and the EPA's rule on reconsideration of the PSD Interpretive Memorandum). The three-judge panel upheld the EPA's interpretation of the Clean Air Act provisions as unambiguously correct. This opinion solidifies the EPA's position that the CAA requires PSD and Title V permits for major emitters of greenhouse gases, such as Empire. Our ongoing projects are currently being evaluated for the projected increase or decrease of CO2e emissions as required by the Tailoring Rule.

As the result of an agreement to settle litigation pending in the U.S. Court of Appeals, on March 27, 2012, the EPA proposed a Carbon Pollution Standard for new power plants. This action is designed to limit the amount of carbon emitted by electric utility generating units. The New Source Performance Standard would require all new power plants to meet a CO2 emissions limit of 1,000 pounds per megawatt hour. This is equal to a coal-fired power plant capturing 50% or more of its emissions. The rule does offer some flexibility but would still require an average of 1,000 pounds per megawatt hour over a 30-year period. It is expected that most new natural gas-fired combined cycles will meet the new standard. The proposed rule would apply only to new fossil-fuel-fired electric utility generating units. The proposal would not apply to existing units including modifications such as changes needed to meet other air pollution standards such as is currently being undertaken by the Asbury facility. Comments for the proposed regulation are currently under consideration by the EPA, and Empire will determine the impact on the Riverton Unit 12 conversion after the final rule is released. Final standards are expected in early 2013. At this time, the regulation does not propose a standard of performance for modifications, and we do not expect the Riverton 12 combined cycle permitting to be affected. Proposed EPA NSPS regulations (through state guidelines) for existing plants are expected in late 2013.

A variety of proposals have been and are likely to continue to be considered by Congress to reduce GHGs. Proposals are also being considered in the House and Senate that would delay, limit or eliminate EPA's authority to regulate GHGs. At this time, it is not possible to predict what legislation, if any, will ultimately emerge from Congress regarding control of GHGs.

Certain states have taken steps to develop cap and trade programs and/or other regulatory systems which may be more stringent than federal requirements. For example, Kansas is a participating member of the Midwestern Greenhouse Gas Reduction Accord (MGGRA), one purpose of which is to develop a market-based cap and trade mechanism to reduce GHG emissions. The MGGRA has announced, however, that it will not issue a CO2e regulatory system pending federal legislative developments. Missouri is not a participant in the MGGRA.

The ultimate cost of any GHG regulations cannot be determined at this time. However, we expect the cost of complying with any such regulations to be recoverable in our rates.

Water Discharges

We operate under the Kansas and Missouri Water Pollution Plans that were implemented in response to the Federal Clean Water Act (CWA). Our plants are in material compliance with applicable regulations and have received 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. The regulations became final on February 16, 2004. In accordance with these regulations, we submitted sampling and summary reports to the Kansas Department of Health and Environment (KDHE) which indicate that the effect of the cooling water intake structure on Empire Lake's aquatic life is insignificant. KCP&L, who operates Iatan Unit 1, submitted the appropriate sampling and summary reports to the Missouri Department of Natural Resources (MDNR).

In 2007 the United States Court of Appeals for the Second Circuit remanded key sections of these CWA regulations to the EPA. As a result, the EPA suspended the regulations and revised and signed a pre-publication proposed regulation on March 28, 2011. The EPA has secured an additional year to finalize the standards for cooling water intake structures under a modified settlement agreement. The EPA is obligated to finalize the rule by July 27, 2013. We will not know the full impact of these rules until they are finalized. If adopted in their present form, we expect regulations of Cooling Water Intake Structures issued by the EPA under the CWA Section 316(b) to have a limited impact at Riverton. The retirement of units 7 and 8 are scheduled in 2016. 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. The EPA has announced its intention to revise its wastewater effluent limitation guidelines under the CWA for coal-fired power plants. The final rule is expected to be published in 2013. 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 the coal ash impoundments are compliant with existing state and federal regulations.

On June 21, 2010, the EPA proposed a new regulation pursuant to the Federal Resource Conservation and Recovery Act (RCRA) governing the management and storage of Coal Combustion Residuals (CCR). In the proposal, the EPA presents 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. The public comment period closed in November 2010. It is anticipated that the final regulation will be published in 2014. We expect compliance with either option as proposed 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 and Riverton Power Plants. 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.

On September 23, 2010 and on November 4, 2010 EPA consultants conducted on-site inspections of our Riverton and Asbury coal ash impoundments, respectively. The consultants performed a visual inspection of the impoundments to assess the structural integrity of the berms surrounding the impoundments, requested documentation related to construction of the impoundments, and reviewed recently completed engineering evaluations of the impoundments and their structural integrity. In response to the inspection comments, the recommended geotechnical studies have been completed and new flow monitoring devices and settlement monuments at both coal ash impoundments have been installed. Final geotechnical engineer report documents for both site impoundments have been received. As a result of the transition from coal to natural gas, initial planning for the closure of the Riverton impoundment is in progress in coordination with the KDHE Bureau of Waste Management. We expect to close it this year. The final design for additional recommendations that will improve safety for slope stability at the Asbury impoundment is under review. The site assessment project has complied with all corrective measures and recommendations made by the EPA in the initial site assessment reports.

Renewable Energy

As previously discussed, we have purchased power agreements with Cloud County Windfarm, LLC, located in Cloud County, Kansas and Elk River Windfarm, LLC, located in Butler County, Kansas. We do not own any portion of either windfarm. More than 15% of the energy we put into the grid comes from these long-term Purchased Power Agreements (PPAs). Through these PPAs, we generate about 900,000 renewable energy certificates (RECs) each year. A REC represents one megawatt-hour of renewable energy that has been delivered into the bulk power grid and "unbundles" the renewable attributes from the associated energy. This unbundling is important because it cannot be determined where the renewable energy is ultimately delivered once it enters the bulk power grid. As a result, RECs provide an avenue for renewable energy tracking and compliance purposes.

Missouri regulations currently require us 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 RECs, at the rate of at least 2% of retail sales in 2012, increasing to at least 15% by 2021. We are currently in compliance with this regulatory requirement. The regulations require that 2% of the renewable energy source must be solar; however, we believe we are exempted from the solar requirement. A challenge to our exemption, brought by two of our customers and Power Source Solar, Inc., was dismissed on May 31, 2011 by the Missouri Western District Court of Appeals. The plaintiffs filed in the Missouri Supreme Court for transfer of the case from the Missouri Western District to the Missouri Supreme Court. The transfer was denied.

Renewable energy standard compliance rules were published by the MPSC on July 7, 2010. Missouri investor-owned utilities and others initiated litigation to challenge these rules. On June 30, 2011, a Cole County Circuit Court judge ruled that portions of the MPSC rules were unlawful and unreasonable, in conflict with Missouri statute and in violation of the Missouri Constitution. Subsequent to that decision, a portion of the appeal was dropped and the entire order was stayed. On December 27, 2011 the judge issued another order identical to the one that was stayed except that the rulings with regard to the constitutionality issue had been omitted. The MPSC appealed this decision and in November of 2012 the court dismissed lawsuits brought against the RES and affirmed the MPSC rules that were finalized in July 2010. 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. In addition, there are several proposals currently before the U.S. Congress to adopt a nationwide RPS.

We have been selling the majority of our RECs and plan to continue to sell all or a portion of them moving forward. As a result of these REC sales, we cannot claim the underlying energy is renewable. Once a REC has been claimed or retired, it cannot be used for any other purpose. At the end of 2012, sufficient RECs, including hydro, were retired to comply with the Missouri and Kansas requirements through the end of November 2012. Additional RECs were retired in January of 2013 to complete the process for 2012. In the future, we will continue to retain a sufficient amount of RECs to meet any current or future requirements.

Gas Segment

The acquisition of Missouri Gas in June 2006 involved the property transfer of two former manufactured gas plant (FMGP) sites previously owned by Aquila, Inc. and its predecessors. Site #1 in Chillicothe, Missouri is listed in the MDNR Registry of Confirmed Abandoned or Uncontrolled Hazardous Waste Disposal Sites in Missouri. No remediation of this site is expected to be required in the near term. We have received a letter stating no further action is required from the MDNR with respect to Site #2 in Marshall, Missouri. We have incurred $0.2 million in remediation costs and estimate further remediation costs at these two FMGP sites to be minimal.

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 subsidiary for 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,				
	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

	2010				
	Electric	Gas	Other	Eliminations	Total
Statement of Income Information:					
Revenues	$484,715	$50,885	$6,268	$(592)	$541,276
Depreciation and amortization	53,983	3,032	1,641	—	58,656
Federal and state income taxes	27,925	1,620	988	—	30,533
Operating income	72,528	6,327	1,640	—	80,495
Interest income	198	403	—	(425)	176
Interest expense	38,798	3,941	33	(425)	42,347
Income from AFUDC (debt and equity)	10,155	19	—	—	10,174
Income from continuing operations	$ 43,187	$ 2,602	$1,607	$ —	$ 47,396
Capital Expenditures	$100,146	$ 5,242	$2,769	$ —	$108,157

	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

	December 31, 2011				
	Electric	Gas(1)	Other	Eliminations	Total
Balance Sheet Information:					
Total assets	$1,931,320	$145,897	$26,038	$(81,420)	$2,021,835

(1) Includes goodwill of $39,492 at December 31, 2012 and 2011.

13. Selected Quarterly Information (Unaudited)

The following is a summary of quarterly results for 2012 and 2011 (dollars in thousands except per share amounts):

	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 Earning Per Share	$ 0.23	$ 0.25	$ 0.60	$ 0.23
Diluted Earnings Per Share	$ 0.23	$ 0.25	$ 0.60	$ 0.23

	Quarters			
Quarterly Results for 2011	First	Second	Third	Fourth
Operating revenues	$150,728	$129,093	$164,284	$132,765
Operating income	$ 21,848	$ 19,134	$ 36,450	$ 19,502
Net Income	$ 11,922	$ 9,175	$ 25,184	$ 8,690
Basic Earning Per Share	$ 0.29	$ 0.22	$ 0.60	$ 0.21
Diluted Earnings Per Share	$ 0.29	$ 0.22	$ 0.60	$ 0.21

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

Earnings for the fourth quarter of 2012 were $9.6 million, or $0.23 per share, as compared to $8.7 million, or $0.21 per share, in the fourth quarter 2011.

14. Risk Management and Derivative Financial Instruments

We engage in hedging activities in an effort to minimize our risk from volatile natural gas prices. 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. 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 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, 2012 and 2011, 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		2012	2011
	Balance Sheet Classification	**Fair Value**	**Fair Value**
Natural gas contracts, gas segment	Current assets	$ 3	$—
	Non-current assets and deferred charges — Other	17	2
Natural gas contracts, electric segment	Current assets	93	—
	Non-current assets and deferred charges — Other	174	
Total derivatives assets		**$287**	**$ 2**

LIABILITY DERIVATIVES

Non-designated as hedging instruments due to regulatory accounting		2012	2011
	Balance Sheet Classification	**Fair Value**	**Fair Value**
Natural gas contracts, gas segment	Current liabilities	$ 104	$ 967
	Non-current liabilities and deferred credits	—	86
Natural gas contracts, electric segment	Current liabilities	3,299	3,802
	Non-current liabilities and deferred credits	3,819	4,995
Total derivatives liabilities		**$7,222**	**$9,850**

Electric

At December 31, 2012, approximately $3.3 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, 2012 and 2011, 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 Loss on Derivative	Amount of Loss Recognized on Balance Sheet	
		2012	2011
Commodity contracts — electric segment	Regulatory assets	$(2,448)	$(6,965)
Total — Electric Segment		**$(2,448)**	**$(6,965)**

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

	Statement of Operations Classification of Loss on Derivative	Amount of Loss Recognized in Income on Derivative	
		2012	2011
Commodity contracts	Fuel and purchased power expense	$(3,985)	$(2,231)
Total — Electric Segment		**$(3,985)**	**$(2,231)**

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, 2012, the following volumes and percentages of our anticipated volume of natural gas usage for our electric operations for 2013 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
2013	58%	2,020,000	3,660,000	$5.15
2014	39%	460,000	3,540,000	$4.74
2015	20%	—	1,910,000	$4.93
2016	10%	—	1,000,000	$4.41
2017	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%

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, 2012 we had 1.3 million Dths in storage on the three pipelines that serve our customers. This represents 65% 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, 2012 (Dth in thousands).

Season	Minimum % Hedged	Dth Hedged Financial	Dth Hedged Physical	Dth in Storage	Actual % Hedged
Current	50%	170,000	206,429	1,308,874	80%
Second	Up to 50%	160,000	—	—	2%
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 2012	Amount of Loss Recognized on Balance Sheet 2011
Commodity contracts	Regulatory assets	$(461)	$(1,916)
Total — Gas Segment		**$(461)**	**$(1,916)**

Contingent Features

Certain of our derivative instruments contain provisions that require our senior unsecured debt to maintain an investment grade credit rating with any relevant credit rating agency. If our debt were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the derivative instruments could request increased collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with the credit-risk-related contingent features that are in a liability position on December 31, 2012 is $2.8 million for which we have posted no collateral in the normal course of business. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2012, we would have been required to post $2.8 million of collateral with one of our counterparties. On December 31, 2012, we had no collateral posted with this counterparty.

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.

The following fair value hierarchy table presents information about our commodity contracts measured at fair value using the market value approach on a recurring basis as of December 31, 2012:

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, 2012				
Derivative assets	$ 287	$ 287	—	—
Derivative liabilities	$(7,222)	$(7,222)	—	—
December 31, 2011				
Derivative assets	$ 2	$ 2	—	—
Derivative liabilities	$(9,850)	$(9,850)	—	—

* The only recurring measurements are derivative related and assets and liabilities are netted together in the table above.

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, 2012 and 2011, was \$688 million and \$688 million, compared to a fair market value of approximately \$747 million and \$752 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, 2012 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,		
	2012	2011	2010
Power operation expense (other than fuel)	\$15,637	\$13,277	\$11,356
Electric transmission and distribution expense	17,083	15,361	12,996
Natural gas transmission and distribution expense	2,443	2,385	2,194
Customer accounts & assistance expense	10,211	10,210	11,618
Employee pension expense(1)	10,180	8,805	5,899
Employee healthcare plan(1)	9,825	7,439	6,930
General office supplies and expense	10,776	10,158	11,584
Administrative and general expense	15,091	14,295	12,896
Bad debt expense	3,038	3,425	3,651
Miscellaneous expense	87	87	168
TOTAL	\$94,371	\$85,442	\$79,292

(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, 2012.

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 issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2012.

Audit of Internal Control Over Financial Reporting

The effectiveness of our internal control over financial reporting as of December 31, 2012, 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 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting other than the changes resulting from a new Enterprise Resource Planning ("ERP") system which replaced certain legacy computer systems. This system became operational October 1, 2012 and materially affected our internal control over financial reporting. In response, we made appropriate changes to internal controls and procedures as expected with a major system implementation. None of the changes resulting from the implementation impair or significantly alter the effectiveness of our internal control over financial reporting. There were no other changes in our internal controls over financial reporting (as defined in Rules 13a-15(f) under the Exchange Act) identified in connection with the evaluation of our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect such controls.

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 April 25, 2013, 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 April 25, 2013, which is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Except as set forth below, information required by this item may be found in our proxy statement for our Annual Meeting of Stockholders to be held April 25, 2013, 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.

Securities Authorized For Issuance Under Equity Compensation Plans

We have four equity compensation plans, all of which have been approved by shareholders, the 1996 Stock Incentive Plan, the 2006 Stock Incentive Plan, the Employee Stock Purchase Plan (ESPP) and the Stock Unit Plan for Directors.

The following table summarizes information about our equity compensation plans as of December 31, 2012:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights.	(b) Weighted-average exercise price of outstanding options, warrants and rights(1)	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders . . .	475,308	$20.87	1,021,739
Equity compensation plans not approved by security holders . . .	—	—	—
TOTAL	475,308	$20.87	1,021,739

(1) The weighted average exercise price of $20.87 relates to 39,100 and 4,200 options granted to executive officers in 2005 and 2004, respectively, under the 1996 Stock Incentive Plan, 34,800, 5,400, 64,200 and 15,600 options granted to executive officers in 2010, 2008, 2007 and 2006, respectively, under the 2006 Stock Incentive Plan and 70,850 subscriptions outstanding for our ESPP. The two stock incentive plans had a weighted average exercise price of $22.13 and the ESPP had an exercise price of $17.95. There is

no exercise price for 67,800 performance-based stock awards and 3,300 time-vested restricted stock awards awarded under the 2006 Stock Incentive Plans or for 143,058 units awarded under the Stock Unit Plan for Directors.

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 April 25, 2013 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 April 25, 2013 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 October 31, 2002 (Incorporated by reference to Exhibit 4(b) to Annual Report on Form 10-K for year ended December 31, 2002, 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) 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).

(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) 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).

(q) 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).

(r) 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).

(s) 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).

(t) 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).

(u) 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).

(v) 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(q) to Annual Report on Form 10-K for the year ended December 31, 2011, File No. 1-3368).

(r) Summary of Compensation of Non-Employee Directors.*†

(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, 2012, filed with the SEC on February 22, 2013, formatted in Extensible Business Reporting Language (XBRL): (i) the Consolidated Statements of Income for 2012, 2011 and 2010, (ii) the Consolidated Balance Sheets at December 31, 2012 and December 31, 2011, (iii) the Consolidated Statements of Cash Flows for 2012, 2011 and 2010, 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, 2012, 2011 and 2010:

		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, 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
Year ended **December 31, 2010**:							
Reserve deducted from assets: accumulated provision for uncollectible accounts.	$1,086,853	$3,607,066	Recovery of amounts previously written off	$ 833,113	Accounts written off	$4,661,796	$ 865,236

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 22, 2013

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 22, 2013

/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

/s/ 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,				
	2012	**2011**	**2010**	**2009**	**2008**
Income before provision for income taxes and fixed charges (Note A) . .	**$137,251,581**	$136,980,092	$125,706,453	$114,457,760	$108,185,260
Fixed Charges:					
Interest on long-term debt .	**$ 40,192,347**	$ 42,580,987	$ 41,958,541	$ 42,084,023	$ 36,040,957
Interest on short-term debt	**187,132**	86,406	630,913	1,124,883	1,853,682
Interest on trust preferred securities	**—**	—	2,089,583	4,250,000	4,250,000
Other interest	**1,087,719**	(1,147,472)	(2,332,530)	(680,863)	1,152,588
Rental expense representative of an interest factor (Note B) .	**5,944,675**	6,190,709	5,430,863	6,501,484	6,040,062
TOTAL FIXED CHARGES	**$ 47,411,873**	$ 47,710,630	$ 47,777,370	$ 53,279,527	$ 49,337,289
Ratio of earnings to fixed charges	**2.89**	2.87	2.63	2.15	2.19

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 22, 2013

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 22, 2013

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, 2012 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 22, 2013

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, 2012 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 22, 2013

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, April 25, 2013, 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) 450-4144 (for the hearing impaired) (TDD)
(651) 450-4064 (outside the United States)
www.shareowneronline.com (for registered shareholders & general inquiries)

Stock Trading

As of December 31, 2012, there were 4,582 common shareholders of record. Empire common stock is listed on the New York Stock Exchange under the ticker symbol EDE.

Stock Prices and Dividends

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

2011	Quarter	High	Low	Dividend Paid
	First	$22.40	$20.70	$0.32
	Second	$23.26	$18.01	$0.32
	Third	$21.12	$18.10	$0.00
	Fourth	$21.40	$18.41	$0.00

Credit Ratings

	Standard & Poor's	Moody's	Fitch
Corporate Credit Rating	BBB-	Baa2	N/R*
First Mortgage Bonds	BBB+	A3	BBB+
Commercial Paper	A-3	P-2	F3
Senior Notes	BBB-	Baa2	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) 450-4144 (for the hearing impaired) (TDD)
(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 Web site, 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, 2012.

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***.

EMPIRE

SERVICES YOU COUNT ON

The Empire District Electric Company

602 S. Joplin Avenue | PO Box 127 | Joplin, MO 64802-0127

www.empiredistrict.com