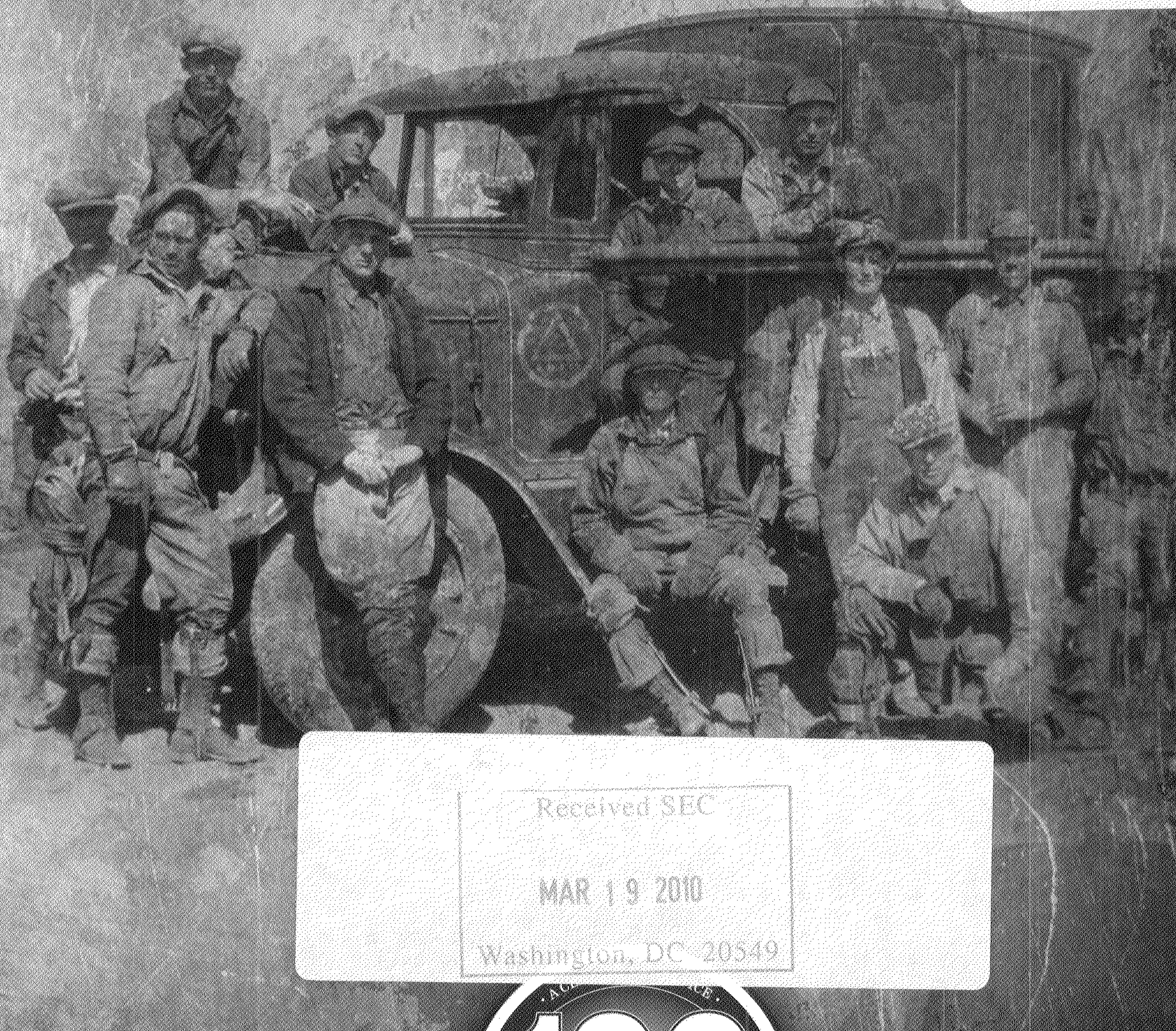
The Empire District Electric Company
2009 Annual Report



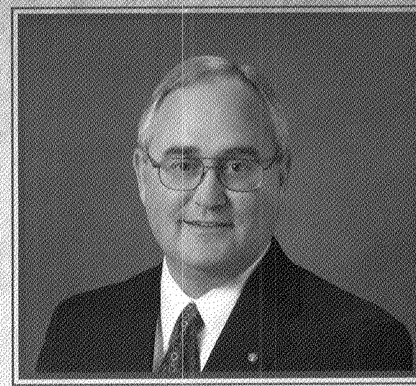
100
EMPIRE DISTRICT ELECTRIC COMPANY
1909 EMPIRE 2009

Financial Highlights

December 31,	2009	2008	Change
Operating Revenues (000)	$497,168	$518,163	-4.1%
Operating Income (000)	$74,495	$71,012	4.9%
Net Income (000)	$41,296	$39,722	4.0%
Earnings Per Weighted Average Common Share (Basic And Diluted)	$1.18	$1.17	0.9%
Dividends Paid Per Share	$1.28	$1.28	0.0%
Return On Common Equity (End Of Period)	6.9%	7.5%	-8.0%
Book Value Per Share Of Common Stock	$15.75	$15.56	1.2%
Common Shares Outstanding (Year End) (000)	38,112	33,982	12.2%
Weighted Average Common Shares Outstanding (Basic)(000)	34,924	33,821	3.3%
Capital Expenditures (Including AFUDC) (000)	$148,804	$206,405	-27.9%
Gross Plant (000)	$2,020,596	$1,870,018	8.1%
On-System Sales (mWh)	4,892,347	5,115,067	-4.4%
On-System Sales (000) (Mcf)	8,543	8,993	-5.0%
Electric Customers (Year End)	168,706	168,280	0.3%
Gas Customers (Year End)	44,899	45,474	-1.3%
Owned System Capability (Net mW)	1,257	1,255	0.2%
System Electric Peak Demand (Net mW)	1,085	1,152	-5.8%
System Gas Peak Demand (Mcf)	70,046	66,005	6.1%
Employees	730	733	-0.4%

Century of

To our shareholders, customers, and employees,



Bill Gipson

This past year, Empire District reached a milestone that is eclipsed by only a few: we celebrated our 100-year anniversary. Your company, which began on October 16, 1909, with just over 2,000 customers, eight megawatts of generation, and about 100 miles of transmission lines, ended its century of service with about 168,000 electric customers served by 1,257 megawatts of generation, 1,282 miles of transmission lines, and 6,857 miles of distribution lines, close to 44,000 natural gas customers, about 4,500 water customers, and roughly 80 customers who receive fiber optic service.

During this past year, we have taken time to look back and examine the accomplishments that have propelled us to this point. We found many references to generation building projects, each one presenting unique opportunities and challenges, and intensely destructive storms and stories of the materials and manpower needed to return our system to service.

There were mentions of operations – from advanced accounting systems and innovative technologies to efficient new facilities – that have been put in place to serve our customers.

But in the end, what we found was a business that is much more than generating plants, poles, wires, gas lines, and other utility infrastructure. Although it is clearly our business to build and maintain facilities to serve our customers, our business is more than kilowatt hours of electricity and cubic feet of natural gas. Our business is people.

This is true of every business, but energy service utilities, especially small, investor-owned utilities like Empire, embody the concept in a special way. The work we do ensures that factories, hospitals, and schools operate, that ballparks are lit for night games, that homes are comfortable. We impact the lives of everyone in the Empire service territory every single day and, when we've done our jobs right, they don't even notice.

It is this role that we play in our communities and our awareness of the responsibilities it entails that form the core values of Empire. We work hard every day to ensure that our customers get reliable, cost-effective energy, that our communities receive the benefits of a good corporate citizen, that our employees enjoy a positive work experience, and that our shareholders receive a good return on an investment of which they are proud.

The lackluster weather in 2009, including a mild winter and the coolest summer in 30 years, combined with the economic slowdown, left us with earnings per share only slightly higher than last year. Our consolidated earnings were $41.3 million, or $1.18 per share, for the year. This compares to 2008 earnings of $39.7 million, or $1.17 a share.

As we move on to the next century of service, one that is sure to bring its own opportunities and challenges, we pause only briefly to reflect. We have work to complete. In the coming months, we will finish our five-year construction plan, including putting the financing in place, and will seek rates to recover our investment. Details are in the next pages.

Service

As they have since their formation, your board of directors and executive management team continue to evolve. Dr. Julio Leon and Mr. Allan Thoms will retire from our board on April 29, 2010, having reached the board's mandatory retirement age.

Dr. Leon, retired president of Missouri Southern State University, has been a board member since 2001. Mr. Thoms, the principal of Allan Thoms Consulting, LLC which provides regulatory advocacy services, has served the Empire board since 2004. Their talents and counsel have made important contributions to Empire during an era of intense industry change. We thank them for their service.

Mr. Herb Schmidt and Mr. James Sullivan have been nominated to fill the board vacancies and will stand for election at the Company's annual meeting of stockholders in April 2010.

Mr. Schmidt is a local civic leader and president of Con-way Truckload. He began his career in the transportation industry with United Parcel Service in operations and industrial engineering. In 1984 he joined CFI (now Con-way Truckload) as director of safety. He has held the positions of vice president of administration, vice president of safety, senior vice president of operations, senior vice president of sales and marketing, and president and chief executive officer. Following the merger of CFI and Con-way, he was named president of the rebranded truckload unit. Mr. Schmidt is a graduate of Missouri Southern State University with a Bachelor of Science degree in political science.

Mr. Sullivan is an independent consultant, advising energy clients on regulatory and strategic issues. He was a member on the Alabama Public Service Commission from 1983 until 2008 where he served as president. He has held various leadership roles with the National Association of Regulatory Utility Commissioners, as well as with the Electric Power Research Institute, the Institute of Nuclear Power Operations, and the National Regulatory Research Institute. He is a member of the Alabama State Bar. Mr. Sullivan holds a Bachelor of Business Administration degree in Banking and Finance from the University of Mississippi and a Master's degree in Banking and Finance and a Juris Doctorate from the University of Alabama.

On February 4, 2010, the board named Mr. Brad Beecher executive vice president and chief operating officer – electric. Brad was elected vice president – energy supply in April 2001 and promoted to vice president and chief operating officer – electric in June 2006. He first joined us at Empire in 1988.

As they have for a century, our legacy and our values will continue to guide us as we face the future. We have an obligation and a commitment to go forward thoughtfully. We take this duty seriously as we constantly strive to fulfill our mission to be a respected supplier of energy and services.

Bill Gipson

Bill Gipson
President and Chief Executive Officer
February 19, 2010

Our centennial anniversary in 2009 provided an opportunity to reflect on the accomplishments of the past 100 years, but we remain focused on the future.

In 2005, Empire began work on the largest comprehensive construction cycle in our history. The five-year regulatory plan developed in cooperation with the Missouri Public Service Commission, the Office of Public Counsel, the Missouri Department of Natural Resources, and others, focused on additions and improvements to our system that ensure our continued ability to deliver to our customers safe, reliable electricity through the least-cost option. Two areas are the primary focus of the plan – environmental upgrades and additions to our generation capacity.

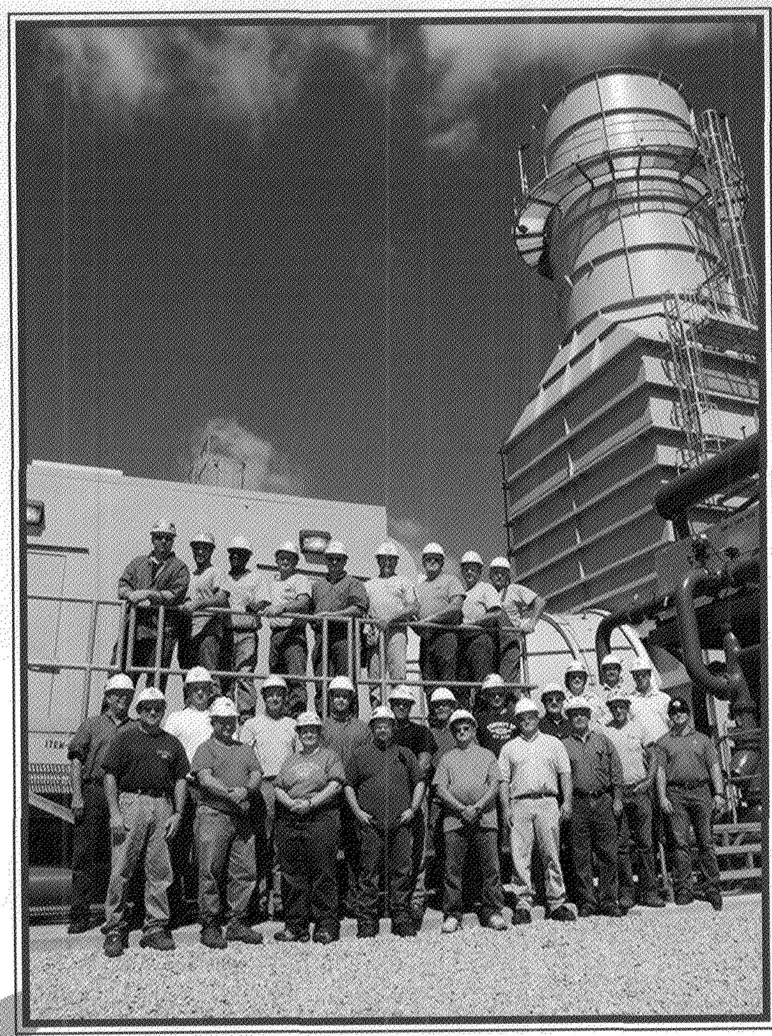
A selective catalytic reduction (SCR) system was completed in December 2007 at the Asbury Power Plant. The $31 million project reduces nitrogen oxide emissions by approximately 90 percent, allowing Asbury to meet environmental standards. Iatan 1 also received environmental upgrades that were completed in early 2009. These additions included an SCR, a flue gas desulphurization system, and a baghouse installation. Our investment for the projects at Iatan 1 totaled $60 million.

Constructed at our Riverton Power Plant site and online in April 2007, natural-gas fired Riverton 12 provides 155 megawatts of generating capacity for our system. This $49 million investment provides necessary support to our entire system during peak-demand conditions. The construction of Iatan 2 is the final piece in this five-year plan. Empire is a joint owner in this new 850-megawatt, coal-fired generating unit located adjacent to Iatan 1, near Kansas City, Missouri. Our 12 percent ownership share will provide our customers with approximately 100 megawatts of generating capacity. Although not included in the original regulatory plan, our investment in Plum Point Generating Station also plays an important role in our long-term, least-cost option resource plan.

Today, we are working toward completion of this incredibly ambitious project that will ultimately add 355 megawatts of capacity to our system and ensure a balanced mix of energy resources to serve our customers. Our focus remains on executing this plan.

Plants

As stated earlier, in 2009, environmental upgrades to Iatan 1 were completed, and the plant was returned to service. The 708-megawatt plant is operated by Kansas City Power & Light (KCP&L) with Empire owning 12 percent, or about 85 megawatts. Work continued on the two remaining construction projects, Plum Point and Iatan 2, both coal-fired base load units.



The Riverton Team
Natural gas-fired Riverton Unit 12 brought 155 megawatts to our system. Online since 2007, it was the first completed project of our current construction cycle.

Service

Scheduled for completion in summer 2010, Plum Point Generating Station will provide 100 megawatts of coal-fired generation. Empire owns 50 megawatts and will receive another 50 megawatts through a purchased power contract. *Photo courtesy of Aerial Innovations of Tennessee, Inc.*

Plum Point, located near Osceola, Arkansas, remains on budget. Slated for completion in summer 2010, the 665-megawatt facility will provide Empire with an ownership share of 50 megawatts, or 7.5 percent. We will also purchase an additional 50 megawatts through a purchased power agreement. Our ownership investment in the project is estimated at about $88 million. Plum Point achieved a major milestone on January 20, 2010, when managing partner, Dynegy, Inc., reported first fire at the plant. This important step indicates great progress at the construction site.

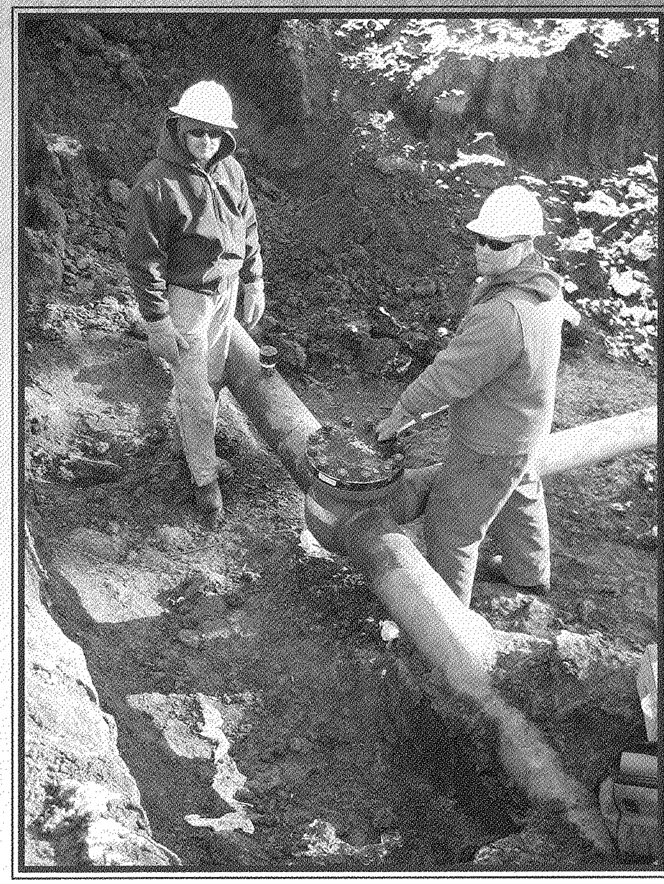
Work also continues at Iatan 2. Citing construction delays and unusually cold weather, the operator and construction manager, KCP&L, announced on January 13, 2010, a revised in-service date. Iatan 2 was expected to be in service late summer 2010; however, that has now been shifted two months into the fall of 2010. KCP&L reported no expected material increase in the estimated construction cost due to this change. Our total investment in Iatan 2 will be approximately $218-230 million, excluding AFUDC and property taxes.

Rate Cases

In the rate case for our natural gas customers that was filed in June 2009, we have entered into a Stipulated Agreement which was approved by the Missouri Public Service Commission. The new rates are designed to produce an increase in annual revenues of $2.6 million, or 4.39 percent. The Agreement calls for new rates to go into effect on April 1, 2010.

Increases in electric rates were requested in our Missouri and Kansas jurisdictions in 2009. In October, we filed a request for higher rates with the Missouri Public Service Commission. Our Missouri request is seeking an annual revenue increase of approximately $68.2 million, or about 19.6 percent. The new rates we have requested are designed to begin to recover costs associated with the major investments we have made on our system, including environmental upgrades at Iatan 1 and new generating units at Plum Point and Iatan 2, plus the annual costs associated with these units. Due to the delay in the in-service date, we do not anticipate recovering costs associated with Iatan 2 in this Missouri case. We anticipate filing a rate case at the conclusion of this case to recover the Iatan 2 costs.

In Kansas, we filed a request for higher rates with the Kansas Corporation Commission in November. We are asking for an annual increase in revenues of approximately $5.2 million, or about 24.6 percent. The Kansas rates we have requested will recover costs associated with environmental upgrades at Iatan 1 and Asbury and the costs associated with our new generating units, Riverton Unit 12, Iatan 2, and Plum Point. This request also includes recovery of operating and maintenance costs associated with these units. We anticipate rates for Kansas will go into effect by mid-July.



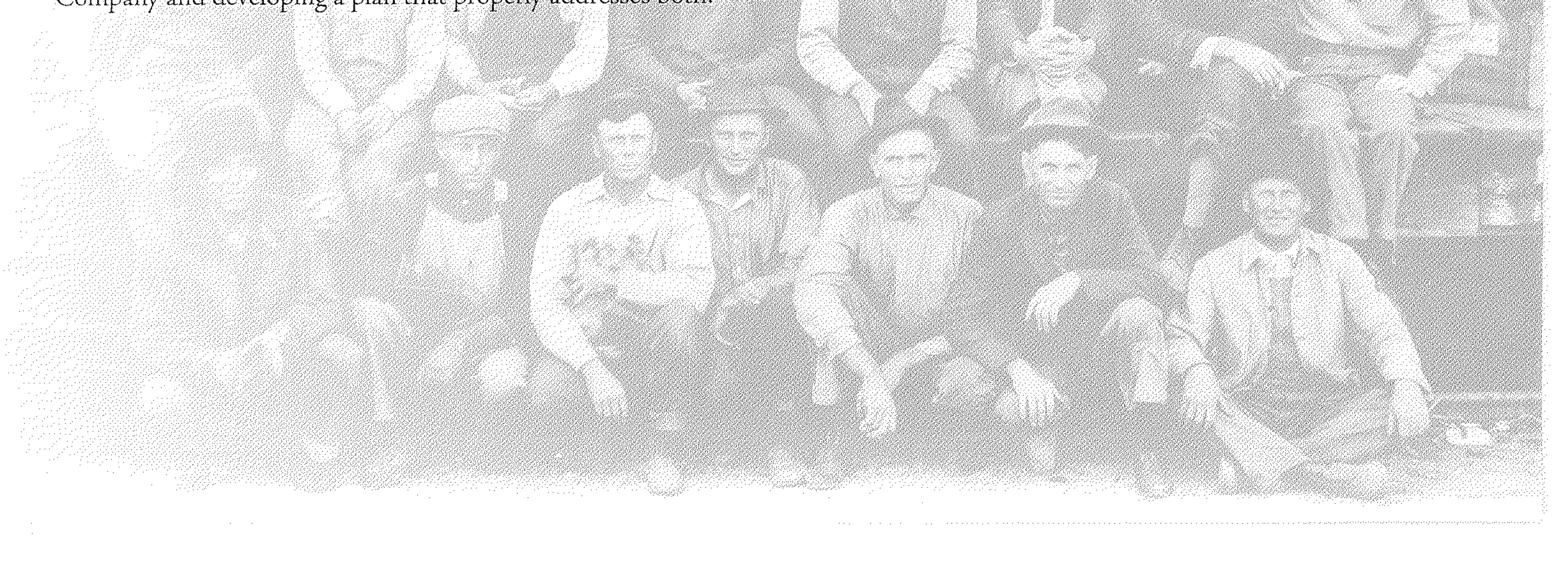
Ron and Jeff, Gas Operations
New gas rates requested for spring 2010 will allow us to recover costs associated with operating and maintaining our 1,200-mile gas distribution system.

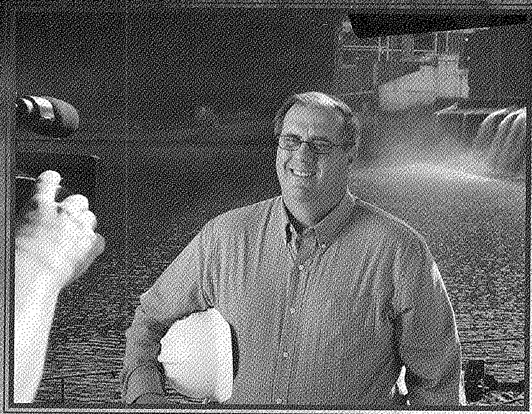
Financing

The key to completing the largest comprehensive construction cycle in our history and remaining a fiscally strong company is proper financing. Despite extremely challenging capital market conditions, we were able to do this successfully in 2009. Funds used to repay short-term debt were raised through the sale of $75 million of first mortgage bonds. We also added a $50 million line of revolving credit, and began an equity distribution program with an aggregate price offering of up to $120 million. By the end of 2009, net proceeds from the equity distribution program had brought in approximately $66.7 million.

By bringing Plum Point and Iatan 2 into service in 2010, we will complete the final piece of our five-year plan. Concurrently, we will continue to finance the remaining capital to complete this work. The rate case already under review in Kansas will allow us to begin recovering the costs associated with our investment. The Missouri case now underway will allow us to begin recovery of our investment at Plum Point.

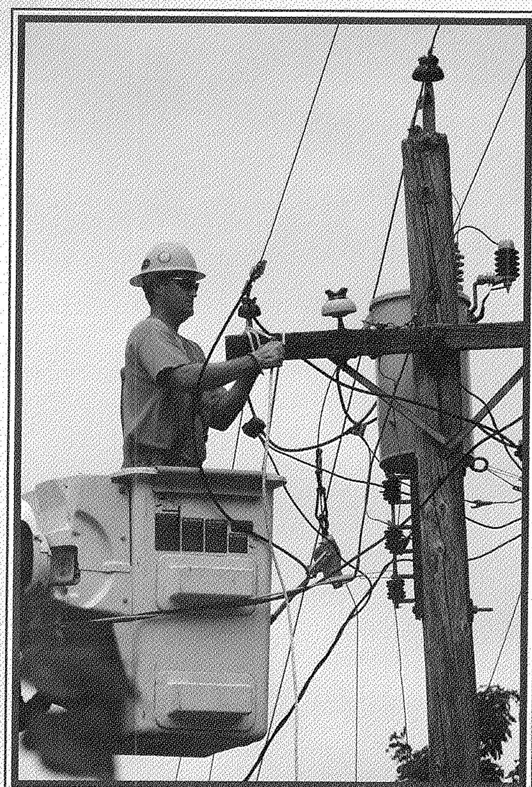
However, we will not pause long to reflect on this accomplishment. The nuts and bolts of providing reliable, efficient energy at a reasonable cost require much forethought. We will move forward by determining future needs of both our customers and our Company and developing a plan that properly addresses both.





Tom, Energy Supply
The "Power the Future" 2009 media campaign educated customers about energy efficiency and our balanced mix of generation resources.

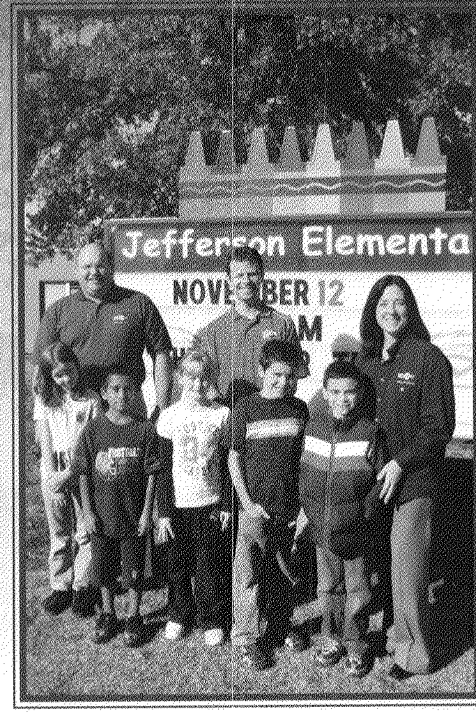
Eric, Meter/Service Truck; Tiffany, Call Center; Jason, Meter Reading; Sherri, Customer Service; Max, Connection/Location Services
A 2009 customer survey showed that 91 percent of customers are satisfied with Empire and nearly 25 percent know an Empire employee.



Jeff, Line Operations
Employees worked around the clock to restore service after a May 8 wind storm broke poles, uprooted trees, and knocked out power to nearly half our customers.

Wind provided about 15 percent of the energy Empire delivered to the grid during 2009. Empire sells the majority of the Renewable Energy Certificates associated with this energy while the underlying non-renewable electricity is delivered to Empire's retail customers. Actual renewable energy delivered to Empire's customers during 2009 was just over one percent of total net system input.

Becky, Credit and Collections; Danny, Safety and Environmental Services; Jackie, Human Resources; Martha, Property Accounting; Todd, Planning and Regulatory
In 2009, the Joplin Tri-State Business Journal recognized Empire as one of the best places to work.



Rick, Commercial Operations (back left), and Janice, Billing Services (back right), with Jefferson principal and students
In 2009, Empire was recognized for its commitment to the business/education partnership it has with Jefferson Elementary School in Joplin. The partnership has spanned over two decades.

Ozark Area 100-year Anniversary Picnic
Employees, retirees, and their families celebrated our centennial anniversary with food, fun, and friendship during picnics.

Service

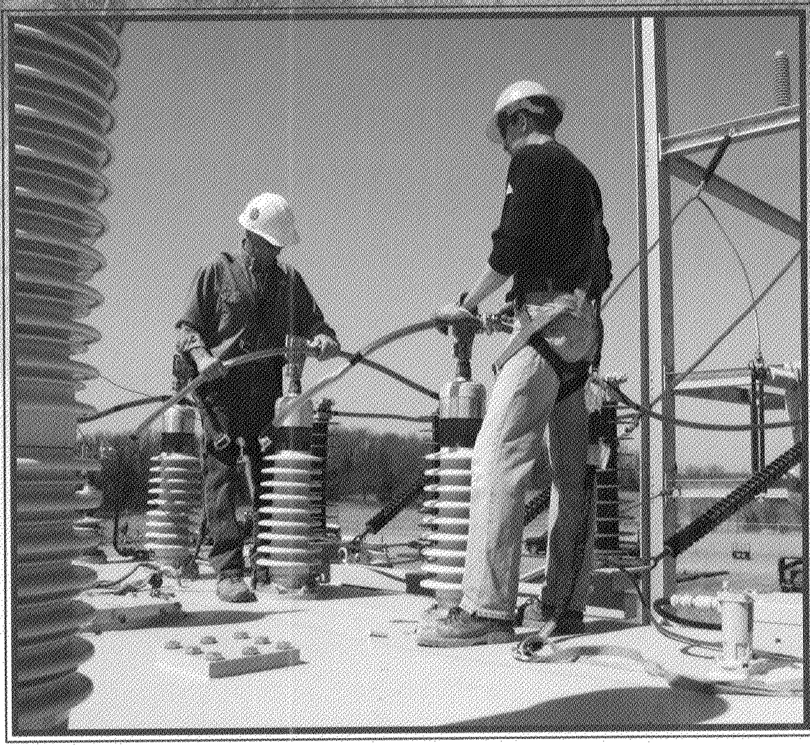
Kelly, Industrial and Commercial Energy Services (3rd from left), and Sherry, Planning and Regulatory (3rd from right)
The first home constructed to meet Empire's ENERGY STAR® New Homes standards was dedicated in October 2009. On average, ENERGY STAR homes result in annual energy savings of 20-30 percent.

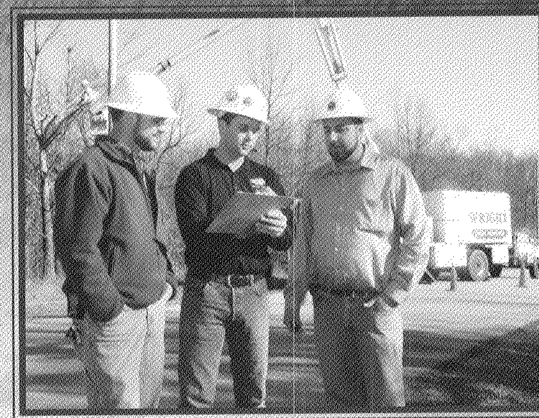
Rick and Justin, Energy Supply
The Energy Center won a 2009 Best Practices Award from Combined Cycle Journal for its new database systems that assist with maintenance procedures and troubleshooting issues.

Green-e certified renewable energy certificates, donated by Empire to the Wildcat Glades Conservation & Audubon Center in 2009, provide offsets for 100 percent of the energy used each year by the Joplin nature center. The energy is generated by the Elk River Wind Farm.

Our new utility arboretum in Ozark, Missouri, shows living examples of proper tree selection and placement to avoid power line problems while preserving the health and beauty of the landscape. In late 2009, work began on an arboretum in Joplin that will be dedicated in 2010.

Century of





Rob, Scott, and Jason, Vegetation Management
Empire's vegetation management program is designed to maintain the integrity and functionality of our lines by controlling the growth of invasive trees and brush. The environmentally sound process enhances biodiversity and promotes native plants and grasses.

Clyde and Rusty, Substation Maintenance
To meet the growing energy needs of our customers, new substations have been added in the Pierce City and Ozark areas.

Front row, left to right: *Brad Beecher, Bill Gipson, Greg Knapp*
Back row: *Laurie Delano, Ron Gatz, Kelly Walters, Mike Palmer, Harold Colgin, Jan Watson*

Officers[1]

William L. Gipson
President and Chief Executive Officer
(Age 53, 28 years of service)

Bradley P. Beecher
Executive Vice President and Chief Operating Officer – Elect
(Age 44, 20 years of service)

Harold R. Colgin
Vice President – Energy Supply
(Age 60, 38 years of service)

Ronald F. Gatz
Vice President and Chief Operating Officer – Gas
(Age 59, 8 years of service)

Gregory A. Knapp
Vice President – Finance and Chief Financial Officer
(Age 58, 30 years of service)

Michael E. Palmer
Vice President – Commercial Operations
(Age 53, 23 years of service)

Kelly S. Walters
Vice President – Regulatory and Services
(Age 44, 17 years of service)

Laurie A. Delano
Controller, Assistant Secretary and Assistant Treasurer
(Age 54, 19 years of service)

Janet S. Watson
Secretary-Treasurer
(Age 57, 15 years of service)

Committees of the Board

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

Compensation Committee – Allen (Chair), Helton, Laney, Leon, Portney

Nominating/Corporate Governance Committee – Allen, Laney, Leon (Chair), Mueller, Thoms

Retirement Committee – Hartley (Chair), Helton, Lind, Thoms

Strategic Projects Committee – Helton (Chair), Laney, Portney, Thoms

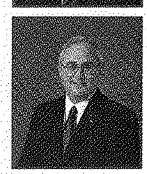
Executive Committee – Gipson (Chair), Hartley, Leon, Mueller

1 Ages and years of service shown as of March 1, 2010.
2 Audit Committee Financial Expert.

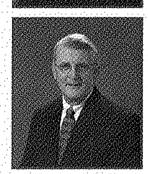
Directors[1]

Kenneth R. Allen
Vice President – Finance and Chief Financial Officer
Texas Industries, Inc.
Dallas, Texas
(Age 52, Director since 2005)

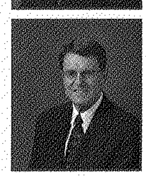
William L. Gipson
President and Chief Executive Officer
The Empire District Electric Company
(Age 53, Director since 2002)



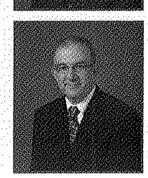
Ross C. Hartley
Co-Founder and Director
NIC, Inc.
Teton Village, Wyoming
(Age 62, Director since 1988)



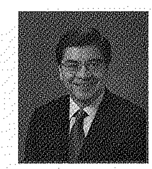
Bill D. Helton
Retired Chairman and Chief Executive Officer
New Century Energies
Amarillo, Texas
(Age 71, Director since 2004)



D. Randy Laney
Chairman of the Board of Directors
The Empire District Electric Company
Farmington, Arkansas
(Age 55, Director since 2003)



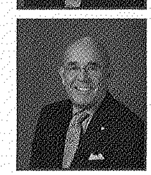
Dr. Julio S. Leon
Retired President
Missouri Southern State University
Joplin, Missouri
(Age 71, Director since 2001)



Bonnie Lind
Senior Vice President, Chief Financial Officer, and Treasurer
Neenah Paper, Inc.
Alpharetta, Georgia
(Age 51, Director since 2009)

B. Thomas Mueller
Founder and President
SALOV North America Corporation
Montclair, New Jersey
(Age 62, Director since 2003)

Dr. Paul Portney
Dean of Eller College of Management
University of Arizona
Tucson, Arizona
(Age 64, Director since 2009)



Allan T. Thoms
Principal
Allan Thoms Consulting, LLC
Cedar Rapids, Iowa
(Age 71, Director since 2004)

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2009 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	**44-0236370**
(State of Incorporation)	(I.R.S. Employer Identification No.)
602 S. Joplin Avenue, Joplin, Missouri	**64801**
(Address of principal executive offices)	(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
Preference Stock Purchase Rights	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, 2009, was approximately $566,092,888.

As of February 5, 2010, 38,300,730 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 29, 2010	Part of Item 10 of Part III All of Item 11 of Part III Part of Item 12 of Part III All of Item 13 of Part III All of Item 14 of Part III

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FORWARD LOOKING STATEMENTS

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

- weather, business and economic conditions and other factors which may impact sales volumes and customer growth;
- the amount, terms and timing of rate relief we seek and related matters;
- 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;
- 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 results of prudency and similar reviews by regulators of costs we incur, including capital expenditures;
- operation of our electric generation facilities and electric and gas transmission and distribution systems, including the performance of our joint owners;
- the costs and other impacts resulting from natural disasters, such as tornados and ice storms;
- the periodic revision of our construction and capital expenditure plans and cost and timing estimates;
- legislation;
- regulation, including environmental regulation (such as NOx, SO2 and CO2 regulation);
- competition, including the regional SPP energy imbalance market;
- electric utility restructuring, including ongoing federal activities and potential state activities;
- the impact of electric deregulation on off-system sales;
- changes in accounting requirements;
- 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;
- matters such as the effect of changes in credit ratings on the availability and our 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;

- interruptions or changes in our coal delivery, gas transportation or storage agreements or arrangements;
- the success of efforts to invest in and develop new opportunities;
- costs and effects of legal and administrative proceedings, settlements, investigations and claims;
- our exposure to the credit risk of our hedging counterparties; 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. In 2009, 87.5% of our gross operating revenues were provided from sales from our electric segment (including 0.4% from the sale of water), 11.5% from our gas segment, and 1.0% from our other segment.

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. Of our total 2009 retail electric revenues, approximately 89.1% came from Missouri customers, 5.1% from Kansas customers, 3.0% from Oklahoma customers and 2.8% from Arkansas customers.

We supply electric service at retail to 121 incorporated communities as of December 31, 2009, 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 157,000. We operate under franchises having original terms of twenty years or longer in virtually all of the incorporated communities. Approximately 53% of our electric operating revenues in 2009 were derived from incorporated communities with franchises having at least ten years remaining and approximately 17% 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 electric operating revenues in 2009 were derived as follows:

Residential	41.6%
Commercial	31.4
Industrial	15.2
Wholesale on-system	4.2
Wholesale off-system	3.3
Miscellaneous sources*	2.7
Other electric revenues	1.6

* primarily public authorities

Our largest single on-system wholesale customer is the city of Monett, Missouri, which in 2009 accounted for approximately 3% of electric revenues. No single retail customer accounted for more than 2% of electric revenues in 2009.

Our gas operations serve customers in northwest, north central and west central Missouri. We provide natural gas distribution to 44 communities and 310 transportation customers as of December 31, 2009. 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-four 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 2009 were derived as follows:

Residential	63.1%
Commercial	27.1
Industrial	3.6
Other	6.2

No single retail customer accounted for more than 4% of gas revenues in 2009.

Our other segment consists of our fiber optics business. As of December 31, 2009, we have 89 fiber customers.

Electric Generating Facilities and Capacity

At December 31, 2009, our generating plants consisted of:

Plant	*Capacity (megawatts)	Primary Fuel
Asbury	207	Coal
Riverton	286	Coal and Natural Gas
Iatan I (12% ownership)	85**	Coal
State Line Combined Cycle (60% ownership)	300**	Natural Gas
Empire Energy Center	267	Natural Gas
State Line Unit No. 1	96	Natural Gas
Ozark Beach	16	Hydro
Total	1,257	

* Based on summer rating conditions as utilized by Southwest Power Pool.

** The 85 and 300 megawatts of Iatan and State Line Combined Cycle, respectively, reflect 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. We have contracted with Westar Energy for the purchase of 162 megawatts of capacity and energy through May 31, 2010 and have contracted to add 50 megawatts of purchased power beginning in 2010 from the Plum Point Energy Station discussed below. The amount of capacity purchased under such contracts supplements our on-system capacity and contributes to meeting our current expectations of future power needs.

In order to replace the 162 megawatts of capacity and energy from Westar Energy that is expiring May 31, 2010, we entered into contracts to add 200 megawatts of power to our system. This energy is to come from two new plants that are scheduled to be operational in 2010, with 100 megawatts from the new Plum Point Energy Station and 100 megawatts from the new Iatan 2 generating facility, each of which is described below. Due to the expected in-service delays of Plum Point and Iatan 2, however, we have arranged for sufficient alternative transmission and generating capacity to meet our expected needs for May 2010 through July 2010. The incremental costs associated with this alternative will not have a material impact on our earnings and will be subject to our fuel adjustment mechanism.

The Plum Point Energy Station is a new 665-megawatt, coal-fired generating facility which is being built near Osceola, Arkansas. Construction began in the spring of 2006 with completion scheduled for summer 2010. Initially we will own, through an undivided interest, 50 megawatts of the project's capacity for approximately $88.0 million in direct expenditures, excluding allowance for funds used during construction (AFUDC). We spent $83.8 million through December 31, 2009 and anticipate spending an additional $3.6 million in 2010 for construction expenses related to our 50 megawatt ownership share of Plum Point Unit 1. All of our actual and estimated construction expenditures exclude AFUDC and property taxes unless specified otherwise. We also have a long-term (30 year) purchased power agreement for an additional 50 megawatts of capacity and have the option to purchase an undivided ownership interest in the 50 megawatts covered by the purchased power agreement in 2015. During the third quarter of 2009, we entered into a 15 year capital lease for 54 railcars for our Plum Point plant.

We also purchased an undivided ownership interest in the coal-fired Iatan 2 generating facility to be operated by Kansas City Power & Light Company (KCP&L) and located at the site of the existing Iatan Generating Station (Iatan 1) near Weston, Missouri. We will own 12%, or approximately 100 megawatts, of the 850-megawatt unit. Construction began in the spring of 2006 with completion scheduled for the fall of 2010. Our share of the Iatan 2 construction expenditures is expected to be in a range of approximately $218 million to $230 million, excluding AFUDC and property taxes. As a requirement for the air permit for Iatan 2, and to help meet requirements of the Clean Air Interstate Rule (CAIR), additional emission control equipment was installed on Iatan 1. Our share of the Iatan 1 environmental costs was $54.0 million through December 31, 2009. KCP&L reported the equipment met regulatory in-service criteria as of April 19, 2009 and it is currently in service.

Our current capital expenditures budget, discussed below, includes $37.3 million in 2010 and $5.9 million in 2011 for our share of Iatan 2. At December 31, 2009, we have recorded approximately $192.0 million in construction expenditures on the Iatan 2 project. Of this amount, approximately $22.9 million of property expenditures common to both Iatan 1 and Iatan 2 were in service as of December 31, 2009.

Iatan 2 and Plum Point Unit 1 are important components of a long-term, least-cost resource plan to add approximately 200 megawatts of new coal-fired generation to our system in 2010. The plan is driven by the continued growth in our service area and the expiration of the Westar Energy purchased power contract described above. The Missouri Public Service Commission (MPSC) issued an order on August 2, 2005 approving a Stipulation and Agreement (Agreement) with an effective date of August 12, 2005 regarding our Experimental Regulatory Plan (Plan). The Agreement contains conditions related to some of the infrastructure investments discussed above, including Iatan 2, and environmental investments in Iatan 1, as well as the 150 MW combustion turbine at our Riverton Plant and the installation of Selective Catalytic Reduction (SCR) equipment at the Asbury coal-fired plant. The Riverton Plant combustion turbine and the Asbury SCR equipment were included in our 2007 Missouri rate case and are now in our Missouri rate base. The other parties to the Agreement include the Missouri Department of Natural Resources, the MPSC Staff, two of our industrial customers and the Office of the Public Counsel. We were also granted a certificate of convenience and necessity to participate in Iatan 2, and in connection therewith, obtained approval intended to provide adequate assurance to potential investors to make financial options available to us concerning our investment in Iatan 2.

We have a 20-year purchased power agreement with Cloud County Windfarm, LLC, owned by Horizon Wind Energy, Houston, Texas to purchase all of the output from the approximately 105-megawatt Phase 1 Meridian Wind Farm located in Cloud County, Kansas. The windfarm was declared commercial on

December 15, 2008. We also have a 20-year contract with Elk River Windfarm, LLC to purchase approximately 550,000 megawatt-hours of energy per year. The windfarm was declared commercial on December 15, 2005. 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 contract years (which run from June 1 to May 31 of the following year). 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."

Contract* Year	Purchased Power Commitment***	Anticipated Owned Capacity	Total Megawatts
2009	177	1257	1434
**2010	****106	1407	1513
**2011	65	1407	1472
**2012	65	1407	1472
**2013	65	1407	1472

* The Westar contract years begin June 1 and run through May 31 of the following year. This contract ends May 31, 2010.

** The contract years 2010 through 2013 assume 50 megawatts of purchased power capacity from Plum Point Unit 1, 50 megawatts of owned capacity from Plum Point Unit 1 and 100 megawatts of owned capacity from Iatan 2.

*** Includes an estimated 7 megawatts for the Elk River Windfarm, LLC and 8 megawatts for the Cloud County Windfarm, LLC.

****The contract year 2010 assumes an additional 41 megawatts of purchased power capacity through a contract with Merrill Lynch to address the expected in-service delays of Plum Point and Iatan 2.

The charges for capacity purchases under the Westar contract referred to above during calendar year 2009 amounted to approximately $16.2 million. Minimum charges for capacity purchases under the Westar contract total approximately $16.2 million for the period June 1, 2009 through May 31, 2010.

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 1,173 megawatts was set on August 15, 2007. Our previous summer record peak of 1,159 megawatts was established on July 19, 2006.

Gas Facilities

At December 31, 2009, our principal gas utility properties consisted of approximately 87 miles of transmission mains and approximately 1,118 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 73,271 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), excluding AFUDC, for the three years ended December 31, 2009, amounted to $527.1 million and retirements during the same period amounted to $39.6 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 $140.8 million in 2009 and for the next three years are estimated for planning purposes to be as follows:

	Estimated Capital Expenditures (amounts in millions)			
	2010	2011	2012	Total
New electric generating facilities:				
Iatan 2	$ 37.3	$ 5.9	$ —	$ 43.2
Plum Point Energy Station	3.6	—	—	3.6
Facilities study	—	—	3.0	3.0
Additions to existing electric generating facilities:				
Environmental upgrades — Asbury	4.4	0.1	—	4.5
Other	11.0	13.9	11.8	36.7
Electric transmission facilities	9.7	9.1	7.7	26.5
Electric distribution system additions	36.0	40.1	40.1	116.2
Non-regulated additions	2.9	1.5	1.5	5.9
General and other additions	3.8	15.2	4.4	23.4
Gas system additions	2.2	4.0	2.0	8.2
Total	$110.9	$89.8	$70.5	$271.2

Construction expenditures for new generating facilities and additions to our transmission and distribution systems to meet projected increases in customer demand constitute the majority of the projected capital expenditures for the three-year period listed above.

A new combustion turbine previously scheduled to be installed by the summer of 2011 is currently delayed until 2015 as our generation regulation needs are being met through a combination of our existing units and the SPP energy imbalance market.

Estimated capital expenditures are reviewed and adjusted for, among other things, revised estimates of future capacity needs, the cost of funds necessary for construction 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

In 2009, 55.1% of our total system input, based on kilowatt-hours generated, was supplied by our steam and combustion turbine generation units, 1.3% was supplied by our hydro generation, and we purchased the remaining 43.6%. Approximately 69.8% of the total fuel requirements for our generating units in 2009 (based on kilowatt-hours generated) were supplied by coal and approximately 29.8% supplied by natural gas with fuel oil and tire-derived fuel (TDF), which is produced from discarded passenger car tires, providing the remainder. The amount and percentage of electricity generated by natural gas decreased in 2009 as compared to 2008 while the amount of energy we purchased increased, primarily reflecting that it was more economical to purchase power during this period than to produce gas-fired generation and reflecting increased purchases of power under our two contracts with windfarms. We offset the cost of these contracts by purchasing less higher-priced power from other suppliers or by displacing on-system generation.

Our Asbury Plant is fueled primarily by coal with oil being used as start-up fuel and TDF being used as a supplement fuel. In 2009, Asbury burned a coal blend consisting of approximately 86.8% Western coal (Powder River Basin) and 13.2% blend coal on a tonnage basis. Our average coal inventory target at Asbury is approximately 60 days. As of December 31, 2009, we had sufficient coal on hand to supply anticipated requirements at Asbury for up to 95 days, as compared to 96-97 days as of December 31, 2008, depending on the actual blend ratio within this range.

Our Riverton Plant fuel requirements are primarily met by coal with the remainder supplied by natural gas, petroleum coke and oil. We installed a Siemens V84.3A2 gas combustion turbine (Unit 12) at our Riverton plant in 2007. Riverton Unit 12 and three other smaller units are fueled by natural gas. During 2009, Riverton Units 7 and 8 burned an estimated blend of approximately 82.1% Western coal (Powder River Basin) and 17.9% petroleum coke on a tonnage basis. Our average coal inventory target at Riverton is approximately 60 days. Riverton Unit 7 requires a minimum amount of blend fuel to operate, while Riverton Unit 8 can burn 100% Western coal or a mix of Western and blend fuel. Based on these assumptions, we had sufficient coal as of December 31, 2009 to run 36 days on both units as compared to 43 days as of December 31, 2008.

We have secured 98% of our anticipated coal requirements for 2010, 59% for 2011, 28% for 2012 and 30% for 2013 through a combination of contracts and binding proposals. All of the Western coal is shipped to the Asbury Plant by rail, a distance of approximately 800 miles, under a five-year contract with the Burlington Northern and Santa Fe Railway Company (BNSF) and the Kansas City Southern Railway Company which expires on June 29, 2010. We are currently in the process of selecting a vendor to provide future rail service. The overall delivered price of coal is expected to be slightly higher in 2010 than in 2009 due to increased market costs. Riverton receives its Western inventory from the coal transported by train to the Asbury Plant which is then transported by truck to Riverton.

We currently lease one aluminum unit train on a full time basis and a second set is leased on an interim basis to deliver Western coal to the Asbury Plant. During the third quarter of 2009, we entered into a 15 year lease agreement for 54 railcars for our Plum Point plant, which is scheduled to be completed in the summer of 2010.

Unit 1 at the Iatan Plant is a coal-fired generating unit which is jointly-owned by KCP&L, a subsidiary of Great Plains Energy, Inc. and us, with our share of ownership being 12%. KCP&L is the operator of this plant and is responsible for arranging its fuel supply. KCP&L has secured contracts for low sulfur Western coal in quantities sufficient to meet 95% of Iatan's requirements for 2010 and approximately 40% for 2011, 40% for 2012, 40% for 2013 and 25% for 2014. The coal is transported by rail under a contract with BNSF Railway, which expires on December 31, 2010.

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 2009, Energy Center generation was 99.8% natural gas with the remainder being fuel oil, and essentially all of the State Line Unit 1 generation came from natural gas. As of December 31, 2009, 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 original expiration dates of July 31, 2016, 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.

We have signed an agreement with Southern Star to purchase one million Dths of firm gas storage service capacity for a period of five years beginning in April 2011. The reservation charge for this storage capacity is approximately $1.1 million annually. This storage capacity will enable 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	2009	2008	2007
Coal — Iatan	$ 1.186	$ 1.070	$ 0.978
Coal — Asbury	1.763	1.577	1.432
Coal — Riverton	1.768	1.724	1.548
Natural Gas	7.376	6.909	7.050
Oil	14.318	16.721	14.870

Our weighted average cost of fuel burned per kilowatt-hour generated was 3.1698 cents in 2009, 3.1307 cents in 2008 and 3.2197 cents in 2007.

Gas Segment

In June 2007, we acquired 10,000 MMBtus per day of firm transportation from Cheyenne Plains Pipeline Company so that up to 75% of our natural gas purchases going forward could come 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 expanded our supplier base in 2008 and will continue to do so 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	2009	2008	2007
South	Southern Star Central Gas Pipeline	$7.8475	$8.9898	$8.2967
North	Panhandle Eastern Pipe Line Company	7.4055	8.3207	7.9568
Northwest	ANR Pipeline Company	7.1160	8.0716	7.0551
	Weighted average cost	$7.6395	$8.6964	$8.0534

Employees

At December 31, 2009, we had 730 full-time employees, including 54 employees of EDG. 328 of the EDE employees are members of Local 1474 of The International Brotherhood of Electrical Workers (IBEW). On May 9, 2007, the Local 1474 IBEW voted to ratify a new five-year agreement effective retroactively to November 1, 2006, the expiration date of the last contract. At December 31, 2008, 26 of the EDG employees were members of Local 814 of the IBEW and 8 EDG employees were members of Local 695 of the IBEW. Effective January 1, 2009, both of these locals were merged into Local 1464 of the IBEW, of which 36 EDG employees were members at December 31, 2009. Local 814 of the IBEW and Local 695 of the IBEW had both previously ratified a three-year contract with EDG which expired on May 31, 2009. In June 2009, Local 1464 of the IBEW ratified a new four-year agreement with EDG effective June 1, 2009.

ELECTRIC OPERATING STATISTICS[1]

	2009	2008	2007	2006	2005
Electric Operating Revenues (000's):					
Residential	**$ 180,404**	$ 179,293	$ 174,584	$ 159,381	$ 149,176
Commercial	**135,800**	132,888	129,035	115,059	106,093
Industrial	**65,983**	67,353	67,712	64,820	59,593
Public authorities[2]	**11,411**	10,876	9,933	8,892	8,464
Wholesale on-system	**18,199**	19,229	18,444	17,561	16,582
Miscellaneous[3]	**6,814**	6,976	5,703	4,605	4,833
Interdepartmental	**178**	154	123	101	101
Total system	**418,789**	416,769	405,534	370,419	344,842
Wholesale off-system	**14,344**	29,697	19,627	12,234	14,139
Total electric operating revenues[4]	**433,133**	446,466	425,161	382,653	358,981
Electricity generated and purchased (000's of kWh):					
Steam	**2,259,304**	2,228,716	2,074,323	2,589,360	2,446,528
Hydro	**76,733**	32,601	71,360	22,673	62,325
Combustion turbine	**926,934**	1,480,729	1,427,298	955,856	1,453,297
Total generated	**3,262,971**	3,742,046	3,572,981	3,567,889	3,962,150
Purchased	**2,516,702**	2,440,246	2,373,282	2,065,991	1,684,657
Total generated and purchased	**5,779,673**	6,182,292	5,946,263	5,633,880	5,646,807
Interchange (net)	**(568)**	(436)	(940)	(173)	(126)
Total system input	**5,779,105**	6,181,856	5,945,323	5,633,707	5,646,681
Maximum hourly system demand (Kw)	**1,085,000**	1,152,000	1,173,000	1,159,000	1,087,000
Owned capacity (end of period) (Kw)	**1,257,000**	1,255,000	1,255,000	1,102,000	1,102,000
Annual load factor (%)	**55.38**	54.29	53.39	52.50	55.59
Electric sales (000's of kWh):					
Residential	**1,866,473**	1,952,869	1,930,493	1,898,846	1,881,441
Commercial	**1,579,832**	1,622,048	1,610,814	1,547,077	1,485,034
Industrial	**992,165**	1,073,250	1,110,328	1,145,490	1,106,700
Public authorities[2]	**121,816**	122,375	115,109	111,204	111,245
Wholesale on-system	**332,061**	344,525	342,347	337,658	328,803
Total system	**4,892,347**	5,115,067	5,109,091	5,040,275	4,913,223
Wholesale off-system	**515,899**	688,203	459,665	303,493	353,138
Total Electric Sales	**5,408,246**	5,803,270	5,568,756	5,343,768	5,266,361
Company use (000's of kWh)[5]	**9,088**	9,209	9,369	9,324	10,263
kWh losses (000's of kWh)	**361,771**	369,377	367,198	280,615	370,157
Total System Input	**5,779,105**	6,181,856	5,945,323	5,633,707	5,646,781
Customers (average number):					
Residential	**141,206**	140,791	139,840	137,689	134,724
Commercial	**24,412**	24,532	24,330	24,035	23,684
Industrial	**355**	361	362	370	365
Public authorities[2]	**1,995**	1,935	1,927	1,907	1,837
Wholesale on-system	**4**	4	4	4	4
Total System	**167,972**	167,623	166,463	164,005	160,614
Wholesale off-system	**19**	22	20	20	17
Total	**167,991**	167,645	166,483	164,025	160,631
Average annual sales per residential customer (kWh)	**13,218**	13,871	13,805	13,791	13,965
Average annual revenue per residential customer	**$ 1,278**	$ 1,273	$ 1,248	$ 1,158	$ 1,107
Average residential revenue per kWh	**9.67¢**	9.18¢	9.04¢	8.39¢	7.93¢
Average commercial revenue per kWh	**8.60¢**	8.19¢	8.01¢	7.44¢	7.14¢
Average industrial revenue per kWh	**6.65¢**	6.28¢	6.10¢	5.66¢	5.38¢

(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) Includes kWh used by Company and Interdepartmental.

GAS OPERATING STATISTICS[1]

	2009	2008	2007	2006[2]
Gas Operating Revenues (000's):				
Residential	**$36,176**	$39,639	$39,205	$15,957
Commercial	**15,552**	17,416	16,588	7,127
Industrial	**2,066**	5,069	752	356
Public authorities	**365**	416	373	161
Total retail sales revenues	**54,159**	62,540	56,918	23,601
Miscellaneous[3]	**221**	231	206	93
Transportation revenues	**2,934**	2,667	2,753	1,451
Total Gas Operating Revenues	**57,314**	65,438	59,877	25,145
Maximum Daily Flow (mcf)	**70,046**	66,005	68,379	60,890
Gas delivered to customers (000's of mcf sales)[4]				
Residential	**2,687**	2,949	2,835	1,101
Commercial	**1,278**	1,397	1,304	559
Industrial	**218**	553	76	32
Public authorities	**30**	35	30	12
Total retail sales	**4,213**	4,934	4,245	1,704
Transportation sales	**4,330**	4,059	4,300	2,150
Total gas operating and transportation sales	**8,543**	8,993	8,545	3,854
Company use[4]	**3**	4	2	—
Transportation sales (cash outs)	**—**	—	56	56
Mcf losses	**36**	140	8	(70)
Total system sales	**8,582**	9,137	8,611	3,840
Customers (average number):				
Residential	**38,621**	39,159	40,315	40,673
Commercial	**5,038**	5,119	5,208	5,399
Industrial	**25**	26	24	26
Public authorities	**131**	127	124	128
Total retail customers	**43,815**	44,431	45,671	46,226
Transportation customers	**296**	272	270	252
Total gas customers	**44,111**	44,703	45,941	46,478

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

(2) 2006 revenues and mcf sales represent the months of June through December 2006.

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

(4) 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, 2009, positions held and effective date 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 12/31/09	Positions With the Company	With the Company Since	Officer Since
William L. Gipson	52	President and Chief Executive Officer (2002), Executive Vice President and Chief Operating Officer (2001), Vice President — Commercial Operations (1997)	1981	1997
Bradley P. Beecher[(1)]	44	Executive Vice President and Chief Operating Officer — Electric (2010), Vice President and Chief Operating Officer — Electric (2006), Vice President — Energy Supply (2001), General Manager — Energy Supply (2001)	2001	2001
Harold Colgin	60	Vice President — Energy Supply (2006), General Manager — Energy Supply (2006), Plant Manager, Asbury Plant (1995)	1972	2006
Ronald F. Gatz	59	Vice President and Chief Operating Officer — Gas (2006), Vice President — Strategic Development (2002), Vice President — Nonregulated Services (2001), General Manager — Nonregulated Services (2001)	2001	2001
Gregory A. Knapp[(2)]	58	Vice President — Finance and Chief Financial Officer (2002), General Manager — Finance (2002)	2002	2002
Michael E. Palmer	53	Vice President — Commercial Operations (2001), General Manager — Commercial Operations (2001), Director of Commercial Operations (1997)	1986	2001
Kelly S. Walters[(3)]	44	Vice President — Regulatory and Services (2006), General Manager — Regulatory and General Services (2005), Director of Regulatory and Planning (2001)	2001	2006
Janet S. Watson	57	Secretary — Treasurer (1995)	1994	1995
Laurie A. Delano[(4)]	54	Controller, Assistant Secretary and Assistant Treasurer and Principal Accounting Officer (2005), Director of Financial Services (2002)	2002	2005

(1) Bradley P. Beecher was previously with Empire from 1988 to 1999 and held the positions of Director of Production Planning and Administration (1993) and Director of Strategic Planning (1995). During the period from 1999 to 2001, Mr. Beecher served as the Associate Director of Marketing and Strategic Planning for the Energy Engineering and Construction Division of Black & Veatch.

(2) Gregory A. Knapp was previously with Empire from 1978 to 2000 and held the position of Controller and Assistant Treasurer (1983). During the period from 2000 to 2002, Mr. Knapp served as Controller for the Missouri Department of Transportation.

(3) Kelly S. Walters was previously with Empire from 1988 to 1998 and held the position of Director of Internal Auditing (1997 - 1998). Prior to rejoining Empire, she was Director of Financial Services of Crowder College.

(4) Laurie A. Delano was previously with Empire from 1979 to 1991 and held the position of Director of Internal Auditing (1983-1991). Immediately prior to rejoining Empire, she was with Lozier Corporation, a store fixture manufacturing company, from 1997 to 2002, where she served as Plant Controller.

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 2009, approximately 90.9% of our electric operating revenues was received from retail customers. Sales subject to FERC jurisdiction represented approximately 8.0% of our electric operating revenues during 2009 with the remaining 1.1% being from miscellaneous sources. The percentage of retail revenues derived from each state follows:

Missouri	89.1%
Kansas	5.1
Oklahoma	3.0
Arkansas	2.8

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 without the need for a general rate proceeding. Fuel adjustment clauses are presently applicable to our retail electric sales in Missouri (effective September 1, 2008), Oklahoma and Kansas (effective January 1, 2006) 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, 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 to the consolidated financial statements 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 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, 2009, would permit us to issue approximately $239.9 million of new first mortgage bonds based on this test at an assumed interest rate of 7.0%. 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, 2009, we had retired bonds and net property additions which would enable the issuance of at least $644.8 million principal amount of bonds if the annual interest requirements are met. As of December 31, 2009, we believe 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 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, 2009, this test would not allow us to issue new first mortgage bonds.

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 Officer, 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.

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+	Baa1	BBB+
Senior Notes	BBB	Baa2	BBB-
Trust Preferred Securities	BB+	Baa3	BB
Commercial Paper	F2	P-2	A-3
Outlook	Negative	Negative	Stable

* Not rated.

The ratings indicate the agencies' assessment of our ability to pay interest, distributions and principal on 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 facility, which may result in higher costs.

We cannot assure 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 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 (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 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.

We depend upon regular deliveries of coal as fuel for our Riverton, Asbury and Iatan plants, and as fuel for the facility which supplies us with purchased power under our contract with Westar Energy. 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 higher-cost 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.

With the addition of the Missouri fuel adjustment mechanism effective September 1, 2008, we now have a fuel cost recovery mechanism in all of our jurisdictions, which significantly reduces our net income exposure to the impact of the risks discussed above. 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 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 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.

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 increases in our 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 unable to predict the impact on our operating results from the regulatory activities of any of these agencies. 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; operating limitations that may be imposed by equipment conditions, environmental or other regulatory requirements; fuel supply or fuel transportation reductions or interruptions; transmission scheduling constraints; and catastrophic events such as fires, explosions, severe weather or other similar occurrences.

We have implemented training, preventive maintenance and other programs, but there is no assurance that these programs will prevent or minimize future breakdowns, outages or failures of our generation facilities. 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.

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

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

General market declines in 2008 and early 2009, resulting in part from the sub-prime mortgage issues, have generally reduced access to the capital markets. We estimate our capital expenditures to be $110.9 million in 2010. Although we believe it is unlikely we will have difficulty accessing the markets for the capital needed to complete these projects, financing costs could fluctuate. Market conditions in 2008 negatively impacted the return on our pension plan and Other Postretirement Benefits (OPEB) assets in 2008. Our net pension and OPEB liability increased $68.7 million in 2008. The market recovered in 2009, however our costs also increased, resulting in a $0.7 million increase in our 2009 net pension and OPEB liability. We expect to be required to fund approximately $15.2 million in 2010 for pension and OPEB liabilities. Future market declines could result in increased pension and OPEB liabilities and funding obligations.

The cost and schedule of construction projects may materially change.

We have entered into an agreement to purchase an undivided interest in 50 megawatts (7.5% ownership interest) of the Plum Point Energy Station's new 665-megawatt, coal-fired generating facility, scheduled for completion in the summer of 2010. We have also entered into an agreement with KCP&L to purchase an undivided ownership interest in the coal-fired Iatan 2 generating facility, scheduled for completion in the fall of 2010. We will own 12%, or approximately 100 megawatts, of the 850-megawatt unit.

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 currently planned, the scope and timing of projects may change, and other events beyond our control, including the failure of one or more of the generation plant co-owners to pay their share of construction, operations and maintenance costs, may occur that may materially affect the schedule, budget, cost and performance of these projects. To the extent the completion of these 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.

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 future air emission standards (such as those limiting emission levels of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) and, potentially, carbon dioxide (CO_2)) 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Electric Segment Facilities

At December 31, 2009, we owned generating facilities with an aggregate generating capacity of 1,257 megawatts.

Our principal electric baseload generating plant is the Asbury Plant with 207 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 16% of our owned generating capacity and in 2009 accounted for approximately 41.2% of the energy generated by us. Routine plant maintenance, during which the entire plant is taken out of service, is scheduled once each year, normally for approximately four weeks in the spring. Approximately every fifth year, the maintenance outage is scheduled to be extended to a total of six weeks to permit inspection of the Unit No. 1 turbine. The last such outage took place in the fall of 2007. The Unit No. 2 turbine is inspected approximately every 35,000 hours of operations and was last inspected in 2001. As of December 31, 2009, Unit No. 2 has operated approximately 2,862 hours since its last turbine inspection in 2001. 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.

Our generating plant located at Riverton, Kansas, has two steam-electric generating units (Units 7 and 8) with an aggregate generating capacity of 92 megawatts and four gas-fired combustion turbine units (Units 9, 10, 11 and 12) with an aggregate generating capacity of 194 megawatts. The steam-electric generating units burn coal as a primary fuel and have the capability of burning natural gas. We installed a Siemens V84.3A2 combustion turbine (Unit 12) at our Riverton plant in 2007 with a summer rated capacity of 150 megawatts. It began commercial operation on April 10, 2007.

We own a 12% undivided interest in the coal-fired Unit No. 1 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. A new air permit was issued for the Iatan Generating Station on January 31, 2006. The new permit covers the entire Iatan Generating Station and includes the existing Unit No. 1 and Unit No. 2, currently under construction. Iatan 1 began a planned major maintenance outage on October 18, 2008 which included activities ranging from a turbine upgrade and generator rewind to the tie-in of the new air quality control systems. Once all the outage work was complete, start-up and commissioning activities began in late January. In early February, vibration issues with the upgraded high pressure turbine were encountered requiring the turbine to be shipped off-site for repairs, delaying the unit's return to service until the second quarter of 2009. KCP&L reported the emission control equipment had met regulatory in-service criteria as of April 19, 2009 and it is currently in service. We are entitled to 12% of the unit's available capacity, currently 85 megawatts, and are obligated to pay for that percentage of the operating costs of the unit. KCP&L operates the unit for the joint owners.

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 96 megawatts and a Combined Cycle Unit with generating capacity of 500 megawatts of which we are entitled to 60%, or 300 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 stipulations. 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. Unit No. 1 had its first major inspection from September 7, 2006 until December 20, 2006.

We have four combustion turbine peaking units at the Empire Energy Center in Jasper County, Missouri, with an aggregate generating capacity of 267 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 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 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 requires the Southwest Power Administration (SWPA), in coordination with us and our relevant public service commissions, to determine our economic detriment.

The SWPA published its Final Determination Report on January 23, 2009 documenting the procedure they intended to use to calculate the present value of the future lifetime replacement cost of the electrical energy and capacity lost due to the White River Minimum Flows project at Ozark Beach. The actual hydropower compensation values were to be calculated using the method presented in the Final Determination and current values for the specified parameters based on the official implementation date. Assuming a January 1, 2011 date of implementation for the White River Minimum Flows project and November 2008 values for the specified parameters, the SWPA's determination at that time resulted in a present value for the estimated future lifetime replacement costs of the electrical energy and capacity at Ozark Beach of $41.3 million. On June 8, 2009, the SWPA published a draft addendum to its January 2009 Final Determination Report documenting proposed changes to the SWPA's methodology, including the inclusion of an additional discount rate source to be used by the SWPA in determination of the present value of the losses. Assuming a January 1, 2011 date of implementation for the White River Minimum Flows project and current values for the specified parameters, the SWPA's Draft Addendum to its Final Determination results in a present value of $22.3 million for the estimated future lifetime replacement costs of the electrical energy and capacity at Ozark Beach. We and the MPSC have provided comments on the new methodology included in the draft addendum but cannot predict the final outcome. Originally, the Appropriations Act had a provision for the Army Corp of Engineers to provide a one time payment to us for lost energy production. This provision was revised in October 2009 to allow the SWPA to pay for damages through a special disbursement account. Under the revised law, payments must be made annually by SWPA in an amount of at least $5 million until the total damages are reimbursed.

At December 31, 2009, our transmission system consisted of approximately 22 miles of 345 kV lines, 434 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 6,905 miles of line.

Our electric generation stations 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 87 miles of water mains in three communities in Missouri.

Gas Segment Facilities

At December 31, 2009, our principal gas utility properties consisted of approximately 87 miles of transmission mains and approximately 1,118 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 non-regulated business, the 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. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

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. On February 5, 2010, there were 5,044 record holders and 31,905 individual participants in security position listings. The high and low sale 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 of 2009 and 2008 were as follows:

	Price of Common Stock				Dividends Paid Per Share	
	2009		2008			
	High	Low	High	Low	2009	2008
First Quarter	$18.51	$11.92	$23.29	$19.33	$0.32	$0.32
Second Quarter	16.66	14.19	21.88	18.30	0.32	0.32
Third Quarter	19.00	16.44	23.48	18.37	0.32	0.32
Fourth Quarter	19.36	17.78	21.60	14.90	0.32	0.32

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. As of December 31, 2009, our retained earnings balance was $10.1 million (compared to $13.6 million at December 31, 2008) after paying out $44.8 million in dividends during 2009. A reduction of our dividend per share, partially or in whole, could have an adverse effect on our common stock price. On February 4, 2010, the Board of Directors declared a quarterly dividend of $0.32 per share on common stock payable March 15, 2010 to holders of record as of March 1, 2010.

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 March 11, 2008, we amended the EDE Mortgage in order to provide us with more flexibility to pay dividends to our shareholders by increasing the basket available to pay dividends by

$10.75 million, as described above. As of December 31, 2009, this restriction did not prevent us from issuing dividends.

In addition, under certain circumstances, our Junior Subordinated Debentures, 8½% Series due 2031, reflected as a note payable to securitization trust on our balance sheet, held by Empire District Electric Trust I, an unconsolidated securitization trust subsidiary, may also restrict our ability to pay dividends on our common stock. These restrictions apply if: (1) we have knowledge that an event has occurred that would constitute an event of default under the indenture governing these junior subordinated debentures and we have not taken reasonable steps to cure the event, (2) we are in default with respect to payment of any obligations under our guarantee relating to the underlying preferred securities, or (3) we have deferred interest payments on the Junior Subordinated Debentures, 8½% Series due 2031 or given notice of a deferral of interest payments. As of December 31, 2009, there were no such restrictions on our ability to pay dividends.

During 2009, no purchases of our common stock were made by or on behalf of us.

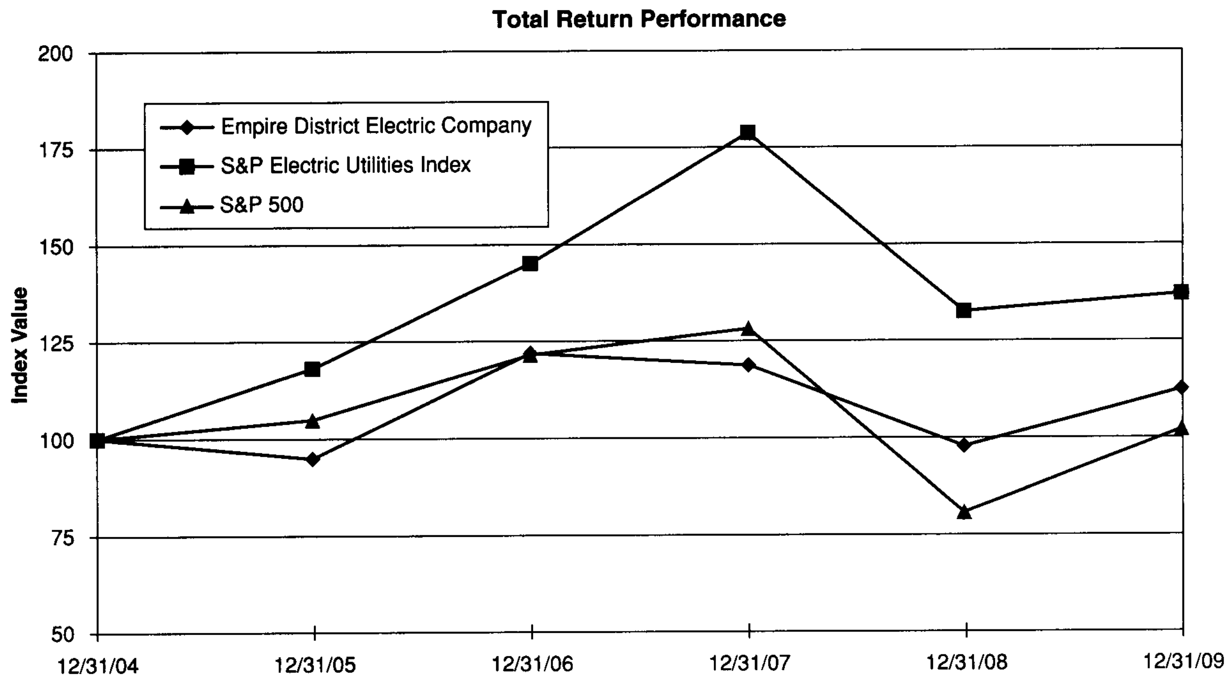
Participants in our Dividend Reinvestment and Stock Purchase Plan may acquire, at a 3% discount, newly issued common shares with reinvested dividends. Participants may also purchase, at an averaged market price, newly issued common shares with optional cash payments on a weekly basis, subject to certain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

Our shareholders rights plan, which expires July 25, 2010, provides each of the common stockholders one Preference Stock Purchase Right (Right) for each share of common stock owned. One Right enables the holder to acquire one one-hundredth of a share of Series A Participating Preference Stock (or, under certain circumstances, other securities) at a price of $75 per one-hundredth of a share, subject to adjustment. The rights (other than those held by an acquiring person or group (Acquiring Person)) will be exercisable only if an Acquiring Person acquires 10% or more of our common stock or if certain other events occur. 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, 2004, 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 Analysis	12/31/2004	12/31/2005	12/31/2006	12/31/2007	12/31/2008	12/31/2009
The Empire District Electric Company	$100.00	$ 94.87	$121.87	$118.68	$ 97.76	$112.38
S&P Electric Utilities Index	$100.00	$118.05	$145.11	$178.67	$132.50	$136.98
S&P 500 Index	$100.00	$104.91	$121.48	$128.16	$ 80.74	$102.11

ITEM 6. SELECTED FINANCIAL DATA

(in thousands, except per share amounts)[1]

	2009	2008	2007	2006[2]	2005
Operating revenues	**$ 497,168**	$ 518,163	$ 490,160	$ 412,171	$ 362,720
Operating income	**$ 74,495**	$ 71,012	$ 65,566	$ 69,821	$ 53,920
Total allowance for funds used during construction	**$ 14,133**	$ 12,518	$ 7,665	$ 4,255	$ 561
Income from continuing operations	**$ 41,296**	$ 39,722	$ 33,181	$ 40,029	$ 24,944
Income (loss) from discontinued operations, net of tax	**$ —**	$ —	$ 63	$ (749)	$ (1,176)
Net income	**$ 41,296**	$ 39,722	$ 33,244	$ 39,280	$ 23,768
Weighted average number of common shares outstanding — basic	**34,924**	33,821	30,587	28,277	25,898
Weighted average number of common shares outstanding — diluted	**34,956**	33,860	30,610	28,296	25,941
Earnings from continuing operations per weighted average share of common stock — basic and diluted	**$ 1.18**	$ 1.17	$ 1.09	$ 1.42	$ 0.96
Loss from discontinued operations per weighted average share of common stock — basic and diluted	**$ —**	$ —	$ 0.00	$ (0.03)	$ (0.04)
Total earnings per weighted average share of common stock — basic and diluted	**$ 1.18**	$ 1.17	$ 1.09	$ 1.39	$ 0.92
Cash dividends per share	**$ 1.28**	$ 1.28	$ 1.28	$ 1.28	$ 1.28
Common dividends paid as a percentage of net income	**108.5%**	109.0%	117.2%	91.8%	139.5%
Allowance for funds used during construction as a percentage of net income	**34.2%**	31.5%	23.1%	10.8%	2.4%
Book value per common share (actual) outstanding at end of year	**$ 15.75**	$ 15.56	$ 16.04	$ 15.49	$ 15.08
Capitalization:					
Common equity	**$ 600,150**	$ 528,872	$ 539,176	$ 468,609	$ 393,411
Long-term debt	**$ 640,156**	$ 611,567	$ 541,880	$ 462,398	$ 407,786
Ratio of earnings to fixed charges	**2.15x**	2.19x	2.08x	2.60x	2.21x
Total assets	**$1,839,846**	$1,713,846	$1,473,074	$1,319,142	$1,122,030
Plant in service at original cost	**$1,718,584**	$1,586,152	$1,506,234	$1,380,431	$1,287,717
Capital expenditures (including AFUDC)[3]	**$ 148,804**	$ 206,405	$ 195,568	$ 120,171	$ 73,232

(1) 2006 through 2005 have been adjusted to show continuing operations, reflecting the sale of MAPP and Conversant in 2006 and Fast Freedom in 2007.

(2) Includes EDG data for the months of June through December 2006.

(3) 2006 capital expenditures do not include $103.2 million for the acquisition of the Missouri Gas operations.

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

EXECUTIVE SUMMARY

We operate our businesses as three segments: electric, gas and other. The Empire District Electric Company (EDE) 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. It provides natural gas distribution to customers in 44 communities in northwest, north central and west central Missouri. Our other segment consists of our fiber optics business. During the year ended December 31, 2009, 87.5% of our gross operating revenues were provided from sales from our electric segment (including 0.4% from the sale of water), 11.5% from the sale of gas and 1.0% from our other segment.

Electric Segment

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 (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. Of the factors driving revenues, weather has the greatest short-term effect on the demand for electricity for our regulated business. Very hot summers and very cold winters increase electric demand, while mild weather reduces demand. Residential and commercial sales are impacted more by weather than industrial sales, which are mostly affected by business needs for electricity and by general economic conditions. Customer growth, which is the growth in the number of customers, contributes to the demand for electricity. We expect our annual electric customer growth to range from approximately 1.1% to 1.5% over the next several years. Our electric customer growth for the year ended December 31, 2009 was 0.3%. 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 and general economic conditions.

The primary drivers of our electric operating expenses in any period are: (1) fuel and purchased power expense, (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. Historically, fuel and purchased power costs were the expense items that had the most significant impact on our net income. In our 2007 rate case, the Missouri Public Service Commission (MPSC) authorized a fuel adjustment clause for our Missouri customers effective September 1, 2008. The MPSC established a base rate for the recovery of fuel and purchased power expenses used to supply energy. The clause permits the distribution to customers of 95% of the changes in fuel and purchased power costs above or below the base. With the addition of the Missouri fuel adjustment mechanism, we now have a fuel cost recovery mechanism in all of our jurisdictions, which will significantly reduce 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, (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 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 gas segment customer contraction for the year ended December 31, 2009 was 1.3%, which we believe was due to depressed economic conditions. The rate of gas customer contraction is expected to level out during the next three years and begin modest growth after 2012. 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, 2009, basic and diluted earnings per weighted average share of common stock were $1.18 compared to $1.17 for the year ended December 31, 2008. Third quarter 2009 weather was the coolest summer in the past 30 years, which affected both customer demand and generation needs. The resulting lower revenues were the primary driver for lower earnings in 2009 as compared to 2008. Lower fuel and purchased power costs, however, mostly offset the decrease in revenues.

The table below sets forth a reconciliation of basic and diluted earnings per share between 2008 and 2009, which reconciliation 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 operations on a per share basis before the impact of additional stock issuances.

We believe this presentation is useful to investors because the statement of operations 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 operations. We also note that this presentation does not purport to be an alternative to earnings per share determined in accordance with GAAP as a measure of operating performance or any other measure of financial performance presented in accordance with GAAP. Management compensates for the limitations of using non-GAAP financial measures by using them to supplement GAAP results to provide a more complete understanding of the factors and trends affecting the business than GAAP results alone.

Earnings Per Share — 2008	**$ 1.17**
Revenues	
Electric on-system	$ 0.04
Electric off-system and other	(0.30)
Gas	(0.16)
Water	0.00
Other	0.01
Expenses	
Electric fuel and purchased power	0.43
Cost of natural gas sold and transported	0.14
Regulated — electric segment	(0.02)
Regulated — gas segment	0.00
Other segment	0.00
Maintenance and repairs	(0.09)
Depreciation and amortization	0.04
Other taxes	(0.01)
Interest charges	(0.07)
AFUDC	0.03
Change in effective income tax rates	0.00
Other income and deductions	(0.01)
Dilutive effect of additional shares issued	(0.02)
Earnings Per Share — 2009	**$ 1.18**

Fourth Quarter Results

Earnings for the fourth quarter of 2009 were $7.9 million, or $0.22 per share, as compared to $7.7 million, or $0.23 per share, in the fourth quarter 2008. Total revenues decreased approximately $10.4 million (7.9%) for the fourth quarter of 2009 as compared to the fourth quarter of 2008 primarily due to milder weather in October and November of 2009 as compared to 2008. Mostly offsetting the decrease in revenues were decreased fuel and purchased power costs and decreased natural gas costs.

2009 Activities

Regulatory Matters

On November 4, 2009, we filed a request with the Kansas Corporation Commission (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 is 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. We anticipate new rates will go into effect in July 2010.

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 is primarily 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. We are currently in discussions about procedures to be used in this case, including the timing of the consideration and rate recovery of our investments in the three generating facilities and other expenditures. Due to the expected in-service delay of Iatan 2, however, we do not anticipate recovering Iatan 2 costs in this Missouri rate case. We anticipate filing a rate case at the conclusion of this case to recover the Iatan 2 costs.

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%. We have entered into a Stipulated Agreement, which was approved by the MPSC, for an increase of $2.6 million. Pursuant to the Agreement, new rates will go into effect on April 1, 2010.

All pending applications for rehearing in our 2006 Missouri electric rate case were denied by the MPSC on November 20, 2008. On December 15, 2008, the Office of the Public Counsel (OPC) filed a Petition for Writ of Review with the Cole County Circuit Court regarding the MPSC's decisions in our 2006 rate case. Praxair and Explorer Pipeline filed a Petition for Writ of Review on December 19, 2008. These actions were consolidated into one proceeding. Briefs were filed by all parties and oral arguments were held on June 2, 2009. The Cole County Circuit Court issued a ruling on December 8, 2009, affirming the MPSC's order. OPC, Praxair and Explorer Pipeline have filed appeals with the Western District Court of Appeals.

On May 13, 2009, the OPC filed a petition in the Jasper County Circuit Court seeking refunds with regard to utility rates for electric service paid by our customers during the period of January 1, 2007 to December 13, 2007. During this period, we charged the rates set forth in the tariffs which were approved by, and are on file with, the MPSC. We filed a motion to dismiss, or, in the alternative, motion for more definitive statement. On September 3, 2009, the Jasper County Circuit Court dismissed the petition with prejudice. On October 7, 2009, the OPC appealed the Jasper County Circuit Court decision to the Missouri Court of Appeals — Southern District. The initial brief was filed by the OPC on January 11, 2010. We filed a responsive brief on February 5, 2010.

The MPSC issued an order on July 30, 2008 in response to a request filed with the MPSC on October 1, 2007 for an annual increase in base rates for our Missouri electric customers. This order granted an annual increase in revenues for our Missouri electric customers in the amount of $22.0 million, or 6.7%, based on a 10.8% return on equity. The new rates went into effect August 23, 2008. The OPC and intervenors Praxair, Inc. and Explorer Pipeline Company filed applications for rehearing with the MPSC regarding this order. On August 12, 2008, the MPSC issued its Order Granting Expedited Treatment and Approving Compliance Tariff Sheets, effective August 23, 2008, in which the MPSC approved our tariff sheets containing our base rates for service rendered on and after August 23, 2008, and approved our fuel adjustment clause tariff sheets effective September 1, 2008. On September 3, 2008, the MPSC denied all pending applications for rehearing.

On October 2, 2008, the OPC and intervenors Praxair, Inc. and Explorer Pipeline Company filed Petitions for Writ of Review with the Cole County Circuit Court. These actions were consolidated into one proceeding, briefs were filed and the Cole County Circuit Court heard oral arguments on September 29, 2009. The Cole County Circuit Court issued a ruling on December 31, 2009, affirming the Commission's Report and Order. OPC, Praxair and Explorer Pipeline have filed appeals with the Western District Court of Appeals.

For additional information, see "Rate Matters" below.

Financings

During the fourth quarter of 2009, we issued and sold 2,115,149 shares of our common stock, pursuant to our equity distribution agreement with UBS Securities LLC (UBS), at an average price per share of $18.51, resulting in proceeds to us of approximately $37.9 million (after payment of approximately $1.2 million in commissions to the sales agent). Since inception of the program, in the aggregate, we have issued and sold 3,767,909 shares pursuant to the program, resulting in net proceeds to us of approximately $66.7 million. Sales of the shares pursuant to the equity distribution agreement will be made at market prices or as otherwise agreed with UBS. Under the terms of the program agreement, we may also sell shares to UBS as principal for UBS' own account at a price agreed upon at the time of sale. On

October 22, 2009, we amended the equity distribution agreement to increase the aggregate offering amount under the program from $60 million to $120 million.

On March 27, 2009, we issued $75 million principal amount of 7% first mortgage bonds due April 1, 2024. The net proceeds (after payment of expenses) of approximately $72.6 million, were used to repay short-term debt incurred, in part, to fund our current construction program.

On January 26, 2010, we entered into the Second Amended and Restated Unsecured Credit Agreement (Credit Agreement) which amends and restates our Amended and Restated Unsecured Credit Agreement dated March 14, 2006. This agreement extends the termination date of the revolving credit facility from July 15, 2010 to January 26, 2013. In addition, the pricing and fees under the Credit Agreement were amended. Interest on borrowings under the Credit Agreement 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 Credit Agreement. As of the date hereof, and based on our current credit ratings, the LIBOR margin under the facility increased from 0.80% to 2.70%. A facility fee is payable quarterly on the full amount of the commitments under the Credit Agreement and a usage fee is payable on the full amount of the commitments under the Credit Agreement for any period in which we have drawn less than 33% of the total revolving commitments under the Credit Agreement, in each case based on our current credit ratings. In addition, upon entering into the Credit Agreement, we paid an upfront fee to the revolving credit banks of $900,000 in the aggregate. The aggregate amount of the revolving commitments remained unchanged at $150 million and there were no other material changes to the terms of the Credit Agreement.

On March 11, 2009, we entered into a $50 million unsecured credit agreement. This agreement provides for $50 million of revolving loans to be available to us for working capital, general corporate purposes and to back-up our use of commercial paper and terminates on July 15, 2010. This credit agreement is in addition to, and has substantially identical covenants and terms as (other than pricing), our Second Amended and Restated Unsecured Credit Agreement dated January 26, 2010. There were no borrowings under the new agreement at December 31, 2009.

Regulatory Plan

On April 19, 2009, we began recording deferred carrying charges associated with environmental upgrades recently completed at our Iatan 1 facility in accordance with our regulatory plan. We deferred $2.7 million in 2009. Construction accounting, for purposes of the regulatory plan, allows us to defer certain charges as regulatory assets, including depreciation and carrying costs, related to operation of the facilities until the facilities are ultimately included in our rate base. The amounts deferred, which began at the in-service date for Iatan 1 and will also be deferred for Iatan 2 at its in-service date, will then be amortized over the life of the plants once they are in our rate base. The regulatory plan covers the 150 megawatt V84.3A2 combustion turbine (Unit 12) that began commercial operation on April 10, 2007 at our Riverton plant, the environmental upgrades at Asbury, which were completed in 2008, environmental upgrades at Iatan 1 and the construction of the Iatan 2 facilities. See Note 3 of "Notes to Consolidated Financial Statements".

Iatan 2

On June 13, 2006, we announced we had entered into an agreement with Kansas City Power & Light (KCP&L) to purchase an undivided ownership interest in the coal-fired Iatan 2 generating facility. We will own 12%, or approximately 100 megawatts, of the 850-megawatt unit. Early in the third quarter of 2009, KCP&L announced its efforts to produce a cost and schedule reforecast primarily to address on-going productivity issues that were negatively impacting the original schedule and reported the anticipated in-service date for Iatan 2 to be late summer of 2010. Based on a late summer in-service date, we expected base rates reflecting our investment to be in effect in late 2010 as we filed a request with the MPSC on October 29, 2009, for an annual increase in base rates for our Missouri electric customers in the amount of $68.2 million, or 19.6%, as discussed above. However, on January 13, 2010, KCP&L announced that, due to construction delays and unusually cold weather, it currently anticipates that the in-service date of Iatan 2 will shift approximately two months into the fall of 2010. KCP&L also announced that, as the Iatan 2 project moves into the startup phase, it has commenced a cost and schedule reforecast process for Iatan 2. KCP&L notes that the results will be disclosed when the process is completed, which it currently projects to be in the second half of the first quarter of 2010. Additionally, KCP&L also stated that it presently believes there will be no material increase in the estimated construction cost range of Iatan 2. As a result of this delay in the project, we expect that the timing of receipt of the increase in base rates associated with Iatan 2 will be delayed.

SLCC Generator Failure

On July 3, 2009, the generator on State Line Unit 2-1, one of the combustion turbines at SLCC, failed during operation. Unit 2-1 represents about 150 megawatts of the 500 megawatts rated output of SLCC, of which we are entitled to 60%, or 300 megawatts. The remainder of SLCC was undamaged and continued to operate as normal. The cost to replace the turbine was in excess of the $1.5 million insurance deductible on the unit. We expect to recover all the costs from insurance proceeds in excess of the $1.5 million deductible. The unplanned outage did not have a material financial impact. Unit 2-1 returned to service in October 2009.

Energy Center Engine Failure

On September 28, 2009, we experienced a failure on Energy Center Unit 3, Engine A. The unit returned to 100% operation on December 23, 2009. This unplanned outage did not have a material financial impact, as almost all of the expenditures were capital replacements and our insurance covered all costs greater than our $500,000 deductible.

2009 Storm Damage

A major wind storm caused substantial damage to our electric service territory on May 8, 2009. Approximately 83,000 of our electric customers were without power at the height of the storm. Incremental costs associated with the restoration effort due to the wind storm were approximately $6.0 million, of which $5.3 million was capitalized as additions to our utility plant and approximately $0.7 million was maintenance expense that was deferred as a regulatory asset as we believe it is probable that these costs will be recoverable in future electric rate cases.

Ozark Beach Plant

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 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 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 requires the Southwest Power Administration (SWPA), in coordination with us and our relevant public service commissions, to determine our economic detriment.

The SWPA published its Final Determination Report on January 23, 2009 documenting the procedure they intended to use to calculate the present value of the future lifetime replacement cost of the electrical energy and capacity lost due to the White River Minimum Flows project at Ozark Beach. The actual hydropower compensation values were to be calculated using the method presented in the Final Determination and current values for the specified parameters based on the official implementation date. Assuming a January 1, 2011 date of implementation for the White River Minimum Flows project and November 2008 values for the specified parameters, the SWPA's determination at that time resulted in a present value for the estimated future lifetime replacement costs of the electrical energy and capacity at Ozark Beach of $41.3 million. On June 8, 2009, the SWPA published a draft addendum to its January 2009 Final Determination Report documenting proposed changes to the SWPA's methodology, including the inclusion of an additional discount rate source to be used by the SWPA in determination of the present value of the losses. Assuming a January 1, 2011 date of implementation for the White River Minimum Flows project and current values for the specified parameters, the SWPA's Draft Addendum to its Final Determination results in a present value of $22.3 million for the estimated future lifetime replacement costs of the electrical energy and capacity at Ozark Beach. We and the MPSC have provided comments on the new methodology included in the draft addendum but cannot predict the final outcome. Originally, the Appropriations Act had a provision for the Army Corp of Engineers to provide a one time payment to us for lost energy production. This provision was revised in October 2009 to allow the SWPA to pay for damages through a special disbursement account. Under the revised law, payments must be made annually by SWPA in an amount of at least $5 million until the total damages are reimbursed.

Gas Storage Contract

We have signed an agreement with Southern Star to purchase one million Dths of firm gas storage service capacity for a period of five years beginning in April 2011. The reservation charge for this storage capacity is approximately $1.1 million annually. This storage capacity will enable us to better manage our natural gas commodity and transportation needs for our electric segment

Iatan 2 Coal Investment Tax Credits

We are currently working with KCP&L to enter into an agreement with the IRS to receive our share of the $125 million in advanced coal investment tax credits granted Iatan 2, of which our share amounts to approximately $17.7 million. We cannot predict the timing of the receipt of the credit. However, it would have no significant income statement impact as the credit, which would reduce our tax payments, would flow to our customers over the life of the plant.

RESULTS OF OPERATIONS

The following discussion analyzes significant changes in the results of operations for the years 2009, 2008 and 2007.

The following table represents our results of operations by operating segment for the applicable periods ended December 31:

(in millions)	2009	2008	2007
Income from continuing operations:			
Electric	$39.1	$37.4	$31.8
Gas	0.9	1.7	1.0
Other	1.3	0.6	0.4
Income from continuing operations	$41.3	$39.7	$33.2
Income (loss) from discontinued operations	—	—	0.0
Net income	**$41.3**	**$39.7**	**$33.2**

Electric Segment

Overview

Our electric segment income for 2009 was $39.1 million as compared to $37.4 million for 2008.

Electric operating revenues comprised approximately 87.5% of our total operating revenues during 2009. Of these total electric operating revenues, approximately 41.6% were from residential customers, 31.4% from commercial customers, 15.2% from industrial customers, 4.2% from wholesale on-system customers, 3.3% from wholesale off-system transactions, 2.7% from miscellaneous sources, primarily public authorities and 1.6% from other electric revenues. The percentage of revenues provided from our wholesale off-system transactions has decreased during 2009 as compared to 2008 primarily due to decreased market demand resulting from milder weather in 2009 and general economic conditions.

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

	kWh Sales (in millions)					
Customer Class	**2009**	**2008**	**% Change***	**2008**	**2007**	**% Change***
Residential	1,866.5	1,952.9	(4.4)%	1,952.9	1,930.5	1.2%
Commercial	1,579.8	1,622.0	(2.6)	1,622.0	1,610.8	0.7
Industrial	992.2	1,073.3	(7.6)	1,073.3	1,110.3	(3.3)
Wholesale on-system	332.0	344.5	(3.6)	344.5	342.3	0.6
Other**	123.4	123.8	(0.3)	123.8	116.8	6.0
Total on-system sales	4,893.9	5,116.5	(4.3)	5,116.5	5,110.7	0.1
Off-system	515.9	688.2	(25.0)	688.2	459.7	49.7
Total KWh Sales	5,409.8	5,804.7	(6.8)	5,804.7	5,570.4	4.2

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

** Other kWh sales include street lighting, other public authorities and interdepartmental usage.

	Electric Segment Operating Revenues (in millions)					
Customer Class	**2009**	**2008**	**% Change***	**2008**	**2007**	**% Change***
Residential	$180.4	$179.3	0.6%	$179.3	$174.6	2.7%
Commercial	135.8	132.9	2.2	132.9	129.0	3.0
Industrial	66.0	67.4	(2.0)	67.4	67.7	(0.5)
Wholesale on-system	18.2	19.2	(5.4)	19.2	18.4	4.3
Other**	11.6	11.0	5.1	11.0	10.1	9.7
Total on-system revenues	412.0	409.8	0.5	409.8	399.8	2.5
Off-system	14.3	29.7	(51.7)	29.7	19.6	51.3
Total revenues from KWh sales	426.3	439.5	(3.0)	439.5	419.4	4.8
Miscellaneous revenues***	6.8	7.0	(2.3)	7.0	5.7	22.3
Total electric operating revenues	$433.1	$446.5	(3.0)	$446.5	$425.1	5.0
Water revenues	1.8	1.7	(1.0)	1.7	1.9	(5.1)
Total Electric Segment Operating Revenues	$434.9	$448.2	(3.0)	$448.2	$427.0	5.0

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

** Other operating revenues include street lighting, other public authorities and interdepartmental usage.

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

The following table sets forth revenues and expenses relating to off-system transactions (including through the Southwest Power Pool (SPP) energy imbalance services (EIS) market) for the years ended December 31:

(in millions)	Off-System Electric Transactions		
	2009	2008	2007
Energy Imbalance revenues	$ 6.2	$13.1	$ 8.8
Other revenues	8.1	16.6	10.8
Total off-system revenues	14.3	29.7	19.6
Energy Imbalance expenses	4.8	9.3	6.2
Other expenses	7.0	12.2	7.8
Total off-system expenses	11.8	21.5	14.0
Net	$ 2.5	$ 8.2	$ 5.6

2009 Compared to 2008

On-System Operating Revenues and Kilowatt-Hour Sales

KWh sales for our on-system customers decreased approximately 4.3% during 2009 as compared to 2008 with the associated revenues increasing approximately $2.2 million (0.5%). Weather and other related factors decreased revenues an estimated $20.3 million. Total cooling degree days (the cumulative number of degrees that the average temperature for each day during that period was above 65° F) for 2009 were 12.3% less than 2008 and 18.7% less than the 30-year average. 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 2009 were 4.0% less than 2008 and 0.5% less than the 30-year average. Rate changes, primarily the August 2008 Missouri rate increase (discussed below), contributed an estimated $21.9 million to revenues while continued sales growth contributed an estimated $0.6 million. We expect our annual customer growth to range from approximately 1.1% to 1.5% over the next several years.

Residential and commercial kWh sales decreased in 2009 primarily due to mild weather during the year. The related revenues increased during 2009 primarily due to the August 2008 Missouri rate increase and continued sales growth. Industrial kWh sales decreased 7.6% mainly due to a slowdown created by economic uncertainty while the associated revenues decreased 2.0%, reflecting the economic conditions, partially offset by the Missouri rate increase. On-system wholesale kWh sales and revenues decreased reflecting the general economic conditions and mild weather.

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 now included as a component of the fuel adjustment clause in our Missouri, Kansas and Oklahoma jurisdictions 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.

Revenues and related expenses were less during 2009 as compared to 2008 primarily due to decreased market demand and lower gas prices that made it more economical for utilities to generate their own power rather than purchase it. Total purchased power related expenses are included in our discussion of purchased power costs below.

Miscellaneous Revenues

Our miscellaneous revenues were $6.8 million during 2009 as compared to $7.0 million during 2008. These revenues are comprised mainly of transmission revenues, late payment fees and renewable energy credit sales.

Operating Revenue Deductions

During 2009, total electric segment operating expenses decreased approximately $17.3 million (4.5%) compared to 2008.

Total fuel and purchased power expenses decreased approximately $22.1 million (10.8%) during 2009 as compared to 2008. 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 2009 and 2008.

(in millions)	2009	2008
Actual fuel and purchased power expenditures	$182.1	$204.1
Kansas regulatory adjustments*	0.5	(0.5)
Missouri fuel adjustment deferral*	(2.0)	0.2
Missouri fuel adjustment recovery**	1.7	
Unrealized (gain)/loss on derivatives	(0.3)	0.3
Total fuel and purchased power expense per income statement	$182.0	$204.1

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

** Currently being recovered from customers from prior deferral period.

The overall fuel and purchased power expense decrease primarily reflects the effect of decreased market demand resulting from mild weather in 2009, as well as the effects of an extended outage at the Asbury plant lasting from the fourth quarter of 2007 into the first quarter of 2008 during which time we relied on purchased power as well as our gas-fired units to replace our coal-fired generation. The decrease in fuel costs also includes the effect of decreased off-system sales.

Summarized in the table below are our estimated cost and volume changes in the components of fuel and purchased power expenses when compared to 2008. This table incorporates all the changes mentioned above. As shown below, the largest impacts on fuel and purchased power costs were lower purchased power and natural gas prices and decreased generation by our gas-fired units.

(in millions)	2008 to 2009 change
Coal (cost)	$ 3.8
Natural gas (cost)	2.3
Purchased power (cost)	(10.1)
Coal generation volume	(0.6)
Natural gas generation volume	(23.1)
Purchased power spot purchase volume	3.0
Natural gas — gain on unwind of positions	2.1
Other (including fuel adjustments)	0.5
TOTAL	$(22.1)

Regulated operating expenses increased approximately $1.0 million (1.6%) during 2009 as compared to 2008 primarily due to increases of $1.5 million in professional services, $1.2 million in other steam power expense, $0.8 million in general labor costs and $0.6 million in customer accounts expenses (mainly increased banking fees). These increases were partially offset by decreases of $1.3 million in employee health care expense, $1.1 million in injuries and damages expense, $0.4 million in pension expense and $0.3 million in regulatory commission expense. We were able to defer an additional $0.6 million in other steam power expense related to Iatan 1 operating costs in accordance with our agreement with the MPSC that allows deferral of certain costs until the environmental upgrades to Iatan 1 are included in our rate base.

Maintenance and repairs expense increased approximately $4.5 million (16.4%) during 2009 primarily due to increases of approximately $3.8 million in distribution maintenance costs (including $2.5 million of ice storm related amortization), $1.2 million in maintenance and repairs expense at the Asbury plant, $0.3 million in maintenance and repairs expense to the SLCC mainly due to a maintenance outage in the first quarter of 2009, $0.1 million in maintenance and repairs expense to the Riverton gas units and $0.1 million in maintenance and repairs expense to State Line Unit No. 1. These increases were partially offset by decreases of $0.6 million in maintenance and repairs expense at the Iatan plant which experienced an outage in the fourth quarter of 2008 and $0.4 million in maintenance and repairs expense to the coal units at the Riverton plant.

Depreciation and amortization expense decreased approximately $2.3 million (4.5%) during 2009 primarily due to reduced regulatory amortization resulting from the Missouri rate case that went into effect August 23, 2008. Other taxes increased approximately $0.8 million due to increased property tax reflecting our additions to plant in service and increased municipal franchise taxes.

2008 Compared to 2007

On-System Operating Revenues and Kilowatt-Hour Sales

KWh sales for our on-system customers increased approximately 0.1% during 2008 as compared to 2007 primarily due to continued sales growth. Revenues for our on-system customers increased approximately $10.0 million, or 2.5%. Rate changes, primarily the August 2008 Missouri rate increase (discussed below), contributed an estimated $8.9 million to revenues while continued sales growth contributed an estimated $3.9 million. Weather and other related factors decreased revenues an estimated $2.8 million.

Residential and commercial kWh sales increased in 2008 primarily due to continued sales growth while the associated revenues also increased due to the August 2008 Missouri rate increase. Industrial kWh sales decreased 3.3% mainly due to a slowdown created by economic uncertainty while the associated revenues decreased 0.5%, reflecting the economic conditions, partially offset by the Missouri rate increase. On-system wholesale kWh sales increased reflecting the continued sales growth discussed above.

Off-System Electric Transactions

Off-system revenues increased during 2008 as compared to 2007 primarily due to sales facilitated by the EIS market that began on February 1, 2007. Total purchased power related expenses are included in our discussion of purchased power costs below.

Miscellaneous Revenues

Our miscellaneous revenues were $7.0 million during 2008 as compared to $5.7 million during 2007. These revenues are comprised mainly of transmission revenues, late payment fees and renewable energy credit sales.

Operating Revenue Deductions

During 2008, total electric segment operating expenses increased approximately $17.0 million (4.6%) compared to 2007.

Total fuel and purchased power expenses increased approximately $12.8 million (6.7%) during 2008 as compared to 2007. 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 2008 and 2007.

(in millions)	2008	2007
Actual fuel and purchased power expenditures	$204.1	$191.0
Kansas regulatory adjustments*	(0.5)	0.2
Missouri regulatory adjustments*	0.2	—
Unrealized loss on derivatives	0.3	—
Total fuel and purchased power expense per income statement	$204.1	$191.2

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

The overall fuel and purchased power increase included the effect of increased costs for off-system sales of $7.6 million and the effect of replacement power for the Asbury and Riverton 8 outages in both years. After assessing the actual cost of the incremental purchased power and gas-fired generation, we estimate the extended outage at Asbury increased our expenses by an additional $5.8 million in the first quarter of 2008 (January 1 - February 10, 2008). This compares to the impact of the 5-year planned maintenance outage in 2007 which we estimated added additional expenses of approximately $8.7 million and the extended outage (December 8 - December 31, 2007) which increased expenses an additional $3.5 million.

Summarized in the table below are our estimated cost and volume changes in the components of fuel and purchased power costs when compared to 2007. This table incorporates all the changes mentioned above. As shown below, the largest impact on fuel and purchased power costs was increased costs for both purchased power and coal, offset by decreases in natural gas prices and the effect of the unwinding of future physical natural gas positions in February 2008.

(in millions)	2007 to 2008 change
Purchased power (cost)	$ 9.6
Coal (cost)	4.0
Natural gas (cost)	(1.3)
Coal generation volume	2.5
Purchased power spot purchase volume	0.4
Natural gas generation volume	(0.2)
Natural gas — gain on unwind of positions	(2.1)
Other	(0.1)
TOTAL	$12.8

Regulated operating expenses increased approximately $0.8 million (1.4%) during 2008 as compared to 2007 primarily due to increases of $1.4 million in transmission and distribution expense, $0.8 million in other steam power expense, $0.6 million in injuries and damages expense, $0.4 million in other power expense and $0.1 million in director and stockholder expense. These increases were partially offset by decreases of $0.9 million in uncollectible accounts expense, $0.7 million in employee pension expense, $0.7 million in employee health care expense and $0.2 million in professional services.

Maintenance and repairs expense decreased approximately $2.9 million (9.6%) during 2008 mainly due to decreases of approximately $4.2 million in distribution maintenance costs as compared to 2007. In 2007 we incurred $3.9 million of incremental costs (and $1.2 million non-incremental tree trimming and labor costs in the first quarter of 2007) related to the January 2007 ice storm and $1.5 million of incremental costs related to the December 2007 ice storm. In 2008 we began amortizing this cost and recognized $1.4 million in maintenance costs. Also contributing to the decrease during 2008 was a $0.5 million decrease in maintenance and repairs expense at the Asbury plant as compared to the same period in 2007 when there was an extended outage during the fourth quarter, and a $0.4 million decrease in maintenance expense at the Energy Center plant compared to 2007 when there was a bearing failure in Unit #3 in the second quarter of 2007. These decreases were partially offset by a $0.7 million increase in maintenance and repairs expense at the SLCC plant due to the extended spring maintenance outage in the second quarter of 2008, a $0.7 million increase in maintenance and repairs expense at the Riverton plant due to the extended outage on Unit 8 to repair damage to high pressure blades discovered during Riverton's scheduled maintenance outage in May 2008, a $0.5 million increase in transmission expense and a $0.1 million increase in maintenance costs for the Riverton gas-fired units.

We recognized a $1.2 million gain in the fourth quarter of 2007 from the sale of our unit train set. We recognized no corresponding gains in 2008.

Depreciation and amortization expense increased approximately $0.7 million (1.3%) mainly due to a $2.9 million increase in depreciation expense due to increased plant in service partially offset by a $2.3 million decrease in the amount of regulatory amortization related to the 2008 Missouri electric rate order that is recorded as depreciation expense. Other taxes increased approximately $0.4 million due to increased property taxes reflecting our additions to plant in service and increased municipal franchise taxes.

Gas Segment

Gas Operating Revenues and Sales

The following tables detail our natural gas sales and revenues for the periods ended December 31:

	Total Gas Delivered to Customers					
(bcf sales)	2009	2008	% Change	2008	2007	% Change
Residential	2.69	2.95	(8.9)%	2.95	2.83	4.0%
Commercial	1.27	1.40	(8.6)	1.40	1.30	7.2
Industrial*	0.22	0.55	(60.5)	0.55	0.08	628.3
Other**	0.03	0.03	(13.3)	0.03	0.03	20.5
Total retail sales	4.21	4.93	(14.6)	4.93	4.24	16.3
Transportation sales*	4.33	4.06	6.7	4.06	4.30	(5.6)
Total gas operating sales	8.54	8.99	(5.0)	8.99	8.54	5.3

($ in millions)	Operating Revenues and Cost of Gas Sold 2009	2008	% Change	2008	2007	% Change
Residential	$36.2	$39.6	(8.7)%	$39.6	$39.2	1.1%
Commercial	15.5	17.4	(10.7)	17.4	16.6	5.0
Industrial*	2.1	5.1	(59.3)	5.1	0.7	574.4
Other**	0.4	0.4	(12.8)	0.4	0.4	17.6
Total retail revenues	$54.2	$62.5	(13.4)	$62.5	$56.9	9.9
Other revenues	0.2	0.2	(2.1)	0.2	0.2	0.5
Transportation revenues*	2.9	2.7	10.0	2.7	2.8	(3.1)
Total gas operating revenues	$57.3	$65.4	(12.4)	$65.4	$59.9	9.3
Cost of gas sold	35.6	42.6	(16.5)	42.6	37.6	13.3
Gas operating revenues over cost of gas in rates	$21.7	$22.8	(4.8)	$22.8	$22.3	2.5

* Percentage change reflects the transfer of a customer from transportation to industrial sales in April 2008 and back to transportation in April 2009 and two customers switching from industrial sales to transportation in October 2009 after an eight-month suspension.

** Other includes other public authorities and interdepartmental usage.

2009 Compared to 2008

Operating Revenues and bcf Sales

Gas retail sales decreased 14.6% during 2009 as compared to 2008 reflecting milder weather, the switching of customers between industrial sales and transportation (see footnote above) and the effect of our gas segment customer contraction of 1.3% in 2009. We believe this contraction was due to depressed economic conditions. We estimate that the rate of gas customer contraction will level out during the next three years and begin modest growth after 2012. Residential and commercial sales decreased during 2009 primarily due to the milder weather as well as customer contraction. Heating degree days were 9.7% lower than 2008 and 3.9% lower than the 30-year average. Industrial sales decreased during 2009 due to the transfer of customers between classes mentioned above.

During 2009, gas segment revenues were approximately $57.3 million as compared to $65.4 million in 2008, a decrease of 12.4%. This decrease was largely driven by the decrease in residential and industrial sales as well as PGA revenue. During 2009, our PGA revenue (which represents the cost of gas recovered from our customers) was approximately $35.6 million as compared to $42.6 million in 2008, a decrease of approximately $7.0 million. This decrease was largely driven by the decrease in sales and decreases in the PGAs that went into effect May 15, 2009 and November 13, 2009.

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, 2009, we had unrecovered purchased gas costs of $0.4 million recorded as a current regulatory asset and over recovered purchased gas costs of $1.9 million recorded as a regulatory liability.

Operating Revenue Deductions

Total other operating expenses were $10.3 million during 2009 as compared to $10.0 million in 2008, mainly due to a $0.2 million increase in distribution operation expense and a $0.1 million increase in general labor costs. Our gas segment had net income of $0.9 million in 2009 as compared to $1.7 million in 2008.

2008 Compared to 2007

Operating Revenues and bcf Sales

Gas retail sales increased 16.3%, primarily due to an increase in industrial sales as compared to 2007 and colder weather. Residential and commercial sales increased during 2008 as compared to 2007 primarily due to colder weather. Heating degree days were 13.5% higher than 2007. Industrial sales increased during 2008 due to the transfer of one large volume interruptible customer from transportation to sales service and the addition of two new large volume interruptible customers. These increases offset the effect of our gas segment customer contraction of 1.5% in 2008. We believe this contraction was due to higher gas prices and general economic conditions.

During 2008, gas segment revenues were approximately $65.4 million as compared to $59.9 million in 2007, an increase of 9.3%, reflecting the higher sales and higher gas costs. During 2008, our PGA revenue (which represents the cost of gas recovered from our customers) was approximately $42.6 million as compared to $37.6 million in 2007, an increase of approximately $5.0 million. This increase was largely driven by the increase in the industrial sales and the effect of higher sales due to weather.

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, 2008, we had unrecovered purchased gas costs of $5.6 million recorded as a regulatory asset.

Operating Revenue Deductions

Total other operating expenses were $10.0 million during 2008 as compared to $10.2 million in 2007, a decrease of $0.2 million. This decrease was mainly due to a $0.8 million decrease in uncollectible accounts, and a $0.6 million decrease in administrative and general expenses, partially offset by a $0.9 million increase in customer accounts expense and a $0.2 million increase in distribution expense. Our gas segment had net income of $1.7 million in 2008 as compared to $1.0 million in 2007.

Other Segment

Our other segment consists of our non-regulated business, the leasing of fiber optics cable and equipment (which we are also using in our own utility operations). See Note 12 of "Notes to Consolidated Financial Statements". The following table represents the results for our other segment for the applicable periods ended December 31:

(in millions)	2009	2008	2007
Revenues	$5.5	$5.0	$3.7
Expenses	4.2	4.4	3.3
Net income from continuing operations	$1.3	$0.6	$0.4

Consolidated Company

Income Taxes

Our consolidated provision for income taxes increased approximately $0.4 million during 2009 as compared to 2008 primarily due to increased income. Our consolidated provision for income taxes increased approximately $4.7 million during 2008 as compared to 2007 due to rates for 2009 and 2008 being higher as compared to 2007, primarily due to lower tax benefits received from cost of plant retirement expenditures. Our cost of retirement expenditures was unusually high in 2007 due to the ice storms we experienced. These reduced benefits were partially offset by an increase in the tax effects of equity AFUDC.

The following table shows our consolidated effective federal and state income tax rates for the applicable periods ended December 31:

	2009	2008	2007
Consolidated effective federal and state income tax rates	32.5%	32.5%	30.3%

See Note 9 of "Notes to Consolidated Financial Statements" under Item 8 for additional information regarding income taxes.

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 2009 as compared to 2008 and in 2008 as compared to 2007 due to higher levels of construction in each period. See Note 1 of "Notes to Consolidated Financial Statements" under Item 8.

($ in millions)	2009	2008	2007
Allowance for equity funds used during construction	$ 6.2	$ 5.9	$2.9
Allowance for borrowed funds used during construction	7.9	6.6	4.8
Total AFUDC	$14.1	$12.5	$7.7

Total interest charges on long-term and short-term debt for 2009, 2008 and 2007 are shown below. The increases in long-term debt interest for 2009 reflect the interest on the $75 million principal amount of first mortgage bonds we issued March 27, 2009. The increases in long-term debt interest for 2009 and 2008, as compared to 2007, also reflect the $90 million principal amount of first mortgage bonds we issued May 16, 2008. The increase in long-term debt interest for 2008 as compared to 2007 also reflects a full year of interest on the $80 million principal amount of first mortgage bonds we issued on March 26, 2007. The decreases in short-term debt interest primarily reflect lower cost of borrowing.

	Interest Charges ($ in millions)					
	2009	2008	Change	2008	2007	Change
Long-term debt interest	$42.1	$36.0	16.8%	$36.0	$31.1	15.8%
Short-term debt interest	1.1	1.9	(39.3)	1.9	2.9	(37.0)
Note payable to securitization trust interest	4.3	4.3	0.0	4.3	4.3	0.0
Iatan 1 deferral*	(1.3)	—	—	—	—	—
Other interest	0.6	1.1	(42.5)	1.1	1.1	7.8
Total interest charges	$46.8	$43.3	8.0	$43.3	$39.4	9.9

* Beginning in the second quarter of 2009, we are able to defer Iatan 1 carrying charges in accordance with our agreement with the MPSC that allows deferral of certain costs until the environmental upgrades to Iatan 1 are included in our rate base.

RATE MATTERS

We continually assess the need for rate relief in all of the jurisdictions we serve and file for such relief when necessary. In addition to the information set forth below, see Note 3 of "Notes to Consolidated Financial Statements" under Item 8.

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 regulatory 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, regulatory amortization and retirement of utility plant and write-off's as authorized 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 between the time we incur costs and the time when we can start recovering the costs through rates. See Note 2 of "Notes to Consolidated Financial Statements" under Item 8 for the amounts recorded for regulatory amortization.

Electric Segment

The following table sets forth information regarding electric and water rate increases since January 1, 2007:

Jurisdiction	Date Requested	Annual Increase Granted	Percent Increase Granted	ROE	Date Effective
Missouri — Electric	October 1, 2007	$22,040,395	6.70%	10.8%	August 23, 2008
Missouri — Electric	February 1, 2006	$29,369,397	9.96%	10.9%	January 1, 2007

Missouri

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 is primarily 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. We are currently in discussions about procedures to be used in this case, including the timing of the consideration and rate recovery of our investments in the three generating facilities and other expenditures. Due to the expected in-service delay of Iatan 2, however, we do not anticipate recovering Iatan 2 costs in this Missouri rate case. We anticipate filing a rate case at the conclusion of this case to recover the Iatan 2 costs.

2007 Rate Case

The MPSC issued an order on July 30, 2008 in response to a request filed with the MPSC on October 1, 2007 for an annual increase in base rates for our Missouri electric customers. This order granted an annual increase in revenues for our Missouri electric customers in the amount of $22.0 million, or 6.7%, based on a 10.8% return on equity. The new rates went into effect August 23, 2008.

The order contains two components. The first component provides an addition to base rates of approximately $27.7 million. This increase in base rates was partially offset by a $5.7 million reduction to regulatory amortization, which is the second component to support certain credit metrics of the overall change in revenue authorized by the MPSC. Regulatory amortization provides us additional cash through rates during the current construction cycle. This construction, which is part of our long-range plan to ensure reliability, includes the facilities at the Riverton Power Plant and Iatan 2 Power Plant, as well as environmental improvements at the Asbury Power Plant and at Iatan 1. The regulatory amortization is now approximately $4.5 million annually and is recorded as depreciation expense.

The MPSC also authorized a fuel adjustment clause for our Missouri customers effective September 1, 2008. The MPSC established a base cost for the recovery of fuel and purchased power expenses used to supply energy. The clause permits the distribution to customers of 95% of the changes in fuel and purchased power costs 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, the off-system sales margin flows back to the customer. Rates related to the recovery of fuel and purchased power costs will be modified twice a year subject to the review and approval by the MPSC. In accordance with accounting guidance for regulated activities, 95% of the difference between the actual cost 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 a 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. On April 1, 2009, we filed proposed rate schedules with the MPSC requesting an increase of $1.9 million in revenues for the under recovered fuel costs recognized for the six month period ended February 28, 2009. This increase in revenue was approved by the MPSC on May 21, 2009, became effective June 1, 2009 and is billed through our fuel adjustment clause. On October 1, 2009, we filed proposed rate schedules with the MPSC requesting a decrease of $0.8 million in revenues for the over recovered fuel and purchased power costs recognized for the six month period ended August 31, 2009.

The MPSC order in the rate case approved a Stipulation and Agreement providing for the recovery of deferred expenses of approximately $14.2 million over a five year period for the 2007 ice storms. In addition, the MPSC order required the implementation of a two-way tracking mechanism for recovery of the costs relating to the new MPSC rules on infrastructure inspection and vegetation management. The mechanism authorized by the MPSC creates a regulatory liability in any year we spend less than the target amount, which has been set at $8.6 million for our Missouri jurisdiction, and a regulatory asset if we spend more than the target amount. Any regulatory asset and liability amounts created using the tracking mechanism will then be netted against each other and taken into account in our next rate case. The MPSC also approved Stipulations and Agreements providing for the continuation of the pension and other post-retirement employee benefits tracking mechanism established in our 2006 and 2007 Missouri rate orders.

The MPSC issued its Report and Order on July 30, 2008, effective August 9, 2008. The OPC and intervenors Praxair, Inc. and Explorer Pipeline Company filed applications for rehearing with the MPSC regarding this order. On August 12, 2008, the MPSC issued its Order Granting Expedited Treatment and Approving Compliance Tariff Sheets, effective August 23, 2008, in which the MPSC approved our tariff sheets containing our base rates for service rendered on and after August 23, 2008, and approved our fuel adjustment clause tariff sheets effective September 1, 2008. On September 3, 2008, the MPSC denied all pending applications for rehearing.

On October 2, 2008, the OPC and intervenors Praxair, Inc. and Explorer Pipeline Company filed Petitions for Writ of Review with the Cole County Circuit Court. These actions were consolidated into one proceeding, briefs were filed and the Cole County Circuit Court heard oral arguments on September 29, 2009. The Cole County Circuit Court issued a ruling on December 31, 2009, affirming the Commission's Report and Order. OPC, Praxair and Explorer Pipeline have filed appeals with the Western District Court of Appeals.

2006 Rate Case

All pending applications for rehearing in our Missouri 2006 rate case were denied by the MPSC on November 20, 2008. On December 15, 2008, the OPC filed a Petition for Writ of Review with the Cole County Circuit Court regarding the MPSC's decisions in our 2006 rate case. Praxair and Explorer Pipeline filed a Petition for Writ of Review on December 19, 2008. These actions were consolidated into one proceeding. Briefs were filed by all parties and oral arguments were held on June 2, 2009. The Cole County Circuit Court issued a ruling on December 8, 2009, affirming the MPSC's order. OPC, Praxair and Explorer Pipeline have filed appeals with the Western District Court of Appeals.

On May 13, 2009, the OPC filed a petition in the Jasper County Circuit Court seeking refunds with regard to utility rates for electric service paid by our customers during the period of January 1, 2007 to December 13, 2007. During this period, we charged the rates set forth in the tariffs which were approved by, and are on file with, the MPSC. We filed a motion to dismiss, or, in the alternative, motion for more definitive statement. On September 3, 2009, the Jasper County Circuit Court dismissed the petition with prejudice. On October 7, 2009, the OPC appealed the Jasper County Circuit Court decision to the Missouri Court of Appeals — Southern District. The initial brief was filed by the OPC on January 11, 2010. We filed a responsive brief on February 5, 2010.

Kansas

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 is 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. We anticipate new rates will go into effect in July 2010.

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%. We have entered into a Stipulated Agreement, which was approved by the MPSC, for an increase of $2.6 million. Pursuant to the Agreement, new rates will go into effect on April 1, 2010.

COMPETITION

Electric Segment

SPP-RTO

Energy Imbalance Services: On February 1, 2007, the Southwest Power Pool (SPP) regional transmission organization (RTO) launched its energy imbalance services market (EIS). In general, the SPP RTO EIS market 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 and its members have been evaluating the costs and benefits on expanding the EIS market into a full day ahead energy market with a co-optimized ancillary services market, which will include the consolidation of all SPP balancing authorities, including ours, into a single SPP balancing authority. 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) and implement the complete Day-Ahead Market as soon as practical, which is anticipated in late 2013 or early 2014. As part of the Day-Ahead Market, 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 us, which is expected to provide operational and economic benefits for us and our customers. The implementation of the Day-Ahead Market will replace the existing EIS market, which to date has, and is expected to continue to, provide benefits for our customers.

SPP Regional Transmission Development: On August 15, 2008, the SPP filed with the FERC proposed revisions to its open access transmission pro forma tariff (OATT) to establish a process for including a "balanced portfolio" of economic transmission upgrades in the annual SPP Transmission Expansion Plan. The cost of such upgrades will be recovered through a regional rate allocated to SPP members based on their load ratio share within SPP's market area of the balanced portfolio's cost. On October 16, 2008, the FERC accepted the balanced portfolio approach, which sets forth the selection process of a group of projects and regional cost allocation rules based on projected benefits and allocated costs over a ten year period. The plan will be balanced if the portfolio is cost beneficial for each zone, including ours, within the SPP. A balanced portfolio could include projects below the 345 kv level (which is the bright line voltage level for projects to be included in the portfolio) to increase benefits to a particular zone to achieve balance of benefits and costs over the ten year study period. On April 28, 2009, the SPP RSC and the SPP BOD approved the first set of balanced portfolio extra high voltage transmission projects to be constructed within the SPP region. The transmission expansion projects, totaling over $700 million, include projects in Missouri, Kansas, Arkansas, Oklahoma, Nebraska and Texas. We anticipate this set of transmission expansion projects will provide long term benefits to our customers yet expect our share of the net allocated costs to be immaterial. Also on April 28, 2009, the SPP RSC and BOD approved a new report that recommends restructuring of the SPP's regional planning processes, which would establish an integrated planning process for reliability, transmission service and economic transmission projects, based on a new set of planning principles that focus on the construction of a more robust transmission system large enough in both scale and geography to provide flexibility to meet SPP members' and customers' future needs. We will actively participate in the development of these new processes as well as cost allocation and recovery issues with members, prospective customers and the state commission representatives to the SPP RSC. 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. The new cost allocation method will be filed at the FERC in the second quarter of 2010. We continue to evaluate the cost and benefit impacts and our position on the new cost allocation method to determine whether it will provide sufficient long term benefits to our customers or require modifications through the FERC approval process.

FERC Market Power Order

On March 3, 2005, the FERC issued an order commencing an investigation to determine if we had market power within our control area based on our failure to meet one of the FERC's wholesale market share screens. We filed responses to that order in May and June 2005 and in early January 2006. On August 15, 2006, the FERC issued its order accepting Empire's proposed mitigation to become effective May 16, 2005, subject to a further compliance filing as directed in the order. Relying on a series of orders issued since March 17, 2006 in other proceedings, the FERC rejected our tariff language and directed us to file revisions to our market-based tariff to provide that service under the tariff applies only to sales outside our control area. The FERC directed us to make refunds, with interest, by September 15, 2006, covering over 1,000 hourly energy sales since May 16, 2005 to numerous counterparties external to our system for wholesale sales made at market prices above the cost based prices permitted under the mitigation proposal accepted by the FERC. The refund obligation applied to certain wholesale power sales made "inside" our service area at market based rates, even though consumption of the energy occurred outside our service area.

On September 14, 2006, we filed a Request For Rehearing of the FERC's August 15, 2006 order regarding the refund and market power mitigation we had proposed. We requested a rehearing and a waiver of the refund requirement in its entirety. On April 25, 2008, the FERC issued an Order that rejected our Request For Rehearing, required a Compliance Filing of our market based rate tariff and ordered refunds with interest. We made our Compliance Filing and issued refunds totaling $340,608, including interest, on May 27, 2008. We also filed an informational refund report with the FERC on June 26, 2008.

As a result of the FERC's requirement for us to issue the aforementioned refunds and our belief that the FERC erred in its orders, on June 30, 2008 we initiated a Petition For Review of the FERC's orders on our market based rate refunds in the United States Court of Appeals for the District of Columbia Circuit (DC Circuit). We requested and received approval for a consolidation of our Petition with a similar petition by Westar Energy. On June 12, 2009, the DC Circuit denied our and Westar's Petition for FERC to review its Order requiring the refunds to be made, concluding our efforts to recover the refunds paid.

As part of our market based pricing authority, we are required to conduct a market power analysis within our service territory and within the SPP RTO region every three years. We filed our triennial market power analysis with the FERC on July 30, 2009, concluding there were no material changes to our market position. As a result, we do not anticipate any changes to our existing market based rate authority. The FERC's acceptance of our filing is pending.

Other FERC Activity

On June 21, 2007, the FERC issued an Advance Notice of Proposed Rulemaking (ANOPR) on potential reforms to improve operations in organized wholesale power markets, such as the SPP RTO in which we participate. On October 16, 2008, the FERC issued its Final Order on Wholesale Competition in Regions with Organized Electric Markets. The Final Order will affect us as it directly affects the SPP RTO. The Final Order addresses four key areas for amending its regulations in Wholesale Competition for RTOs and Independent System Operators (ISOs): (1) demand response and market pricing during periods of operating reserve shortage; (2) long-term power contracting; (3) market monitoring policies; and (4) the responsiveness of RTOs and ISOs to stakeholders and customers. We continue to be involved in the SPP RTO and our state commission discussions on compliance of these new rules.

On May 21, 2009, the FERC issued an order clarifying that, going forward, small public utilities that have been granted waiver of Order No. 889 (Open Access Same Time Information Systems (OASIS) requirement) and the Standards of Conduct for transmission operations, which includes us, are required to submit a notification filing if there has been a material change in facts that may affect the basis on which a public utility's waiver was premised. The Standards of Conduct generally govern the communications between our day to day transmission operations personnel and our day to day wholesale marketing and sales personnel. We submitted our filing on July 13, 2009 in which we believe continuation of our waiver, issued in 1997 and reaffirmed in 2004, is appropriate and reasonable. Based on the May 21, 2009 order, it is possible that the FERC will revoke our waiver which would impact communication between our transmission and wholesale marketing and sales functions and operations within our organization. As part of our filing, we sought a twelve month extension in order to comply with the Standard of Conduct requirements in the event the FERC determined that revoking our waiver was appropriate. The FERC's decision on this and other Standard of Conduct waiver filings is pending.

Gas Segment

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

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, including through our existing shelf registration statement, 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 only a portion of the funds required in 2010 for our budgeted capital expenditures (as discussed in "Capital Requirements and Investing Activities" below). Although our working capital was negative as of December 31, 2009, we believe the amounts available to us under our credit facilities and the issuance of debt and equity securities together with this 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

	Fiscal Year		
(in millions)	**2009**	**2008**	**2007**
Cash provided by (used in):			
Operating activities	$ 129.6	$ 93.0	$ 103.5
Investing activities	(154.7)	(211.8)	(178.9)
Financing activities	28.0	117.5	67.0
Net change in cash and cash equivalents from continuing operations	2.9	(1.3)	(8.4)
Discontinued operations	—	—	0.1
Net change in cash and cash equivalents	$ 2.9	$ (1.3)	$ (8.3)

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 in natural gas prices directly impacts the cost of gas stored in inventory.

2009 compared to 2008. In 2009, our net cash flow provided from operating activities was $129.6 million, an increase of $36.6 million or 39.3% from 2008. This increase was primarily a result of:

- Draw down of the commodity risk management margin accounts through settlement of hedged positions.
- Decreased cash payments for income taxes, reflecting positive affects for accelerated tax depreciation.
- Changes in depreciation and amortization, reflecting collection of deferred ice storm costs from customers.
- Changes in the levels of accounts receivable and inventory, primarily from lower gas prices.

2008 compared to 2007. In 2008, our net cash flow provided from operating activities was $93.0 million, a decrease of $10.5 million or 10% from 2007. The decrease was primarily a result of:

- Cash outlays for the December 2007 ice storms, paid in 2008.
- Higher cash payments for taxes, reflecting the casualty loss deduction in 2007 for two major ice storms.
- Positive working capital impacts resulting from decreased cash for inventory purchases, lower natural gas costs and changes in customer receivables and payments.

These decreases were offset by higher net income and changes in levels of accounts payable.

Capital Requirements and Investing Activities

Our net cash flows used in investing activities decreased $57.1 million from 2009 to 2008. The 2008 capital expenditures reflect cash outlays for the December 2007 ice storm. These expenditures were incurred in 2007 but paid in the first quarter of 2008. In addition, expenditures for new generation and distribution and transmission system additions were lower in 2009 than in 2008.

Our net cash flows used in investing activities increased $32.8 million during 2008 as compared to 2007, primarily reflecting our construction expenditures for Plum Point Unit 1 and Iatan 2.

Our capital costs incurred for continuing operations totaled approximately $148.8 million, $206.4 million, and $195.5 million in 2009, 2008 and 2007, respectively.

A breakdown of these capital costs (including AFUDC) for 2009, 2008 and 2007 is as follows:

	Capital Expenditures		
(in millions)	**2009**	**2008**	**2007**
Distribution and transmission system additions	$ 33.7	$ 46.8	$ 43.5
New generation — Riverton combustion turbine	—	—	3.9
New generation — Plum Point Energy Station	16.3	30.9	29.8
New generation — Iatan 2	66.2	82.6	44.0
Storms[1]	6.4	4.3	26.9
Additions and replacements — Asbury	0.3	6.0	21.7
Additions and replacements — Iatan 1	13.6	32.3	14.2
Additions and replacements — State Line Combined Cycle Unit, Riverton, Energy Center, State Line Unit 1 and Ozark Beach	8.9	1.9	2.1
Gas segment additions and replacements	2.1	1.9	1.8
Transportation	1.4	1.2	0.8
Other (including retirements and salvage — net)[1][2]	(1.4)	(3.6)	1.8
Subtotal	$147.5	$204.3	$190.5
Non-regulated capital expenditures (primarily fiber optics)	1.3	2.1	5.0
Subtotal capital expenditures incurred[3]	$148.8	$206.4	$195.5
Less capital expenditures payable[4]	(3.8)	(6.9)	12.1
Insurance proceeds receivable	5.6	—	—
Capital lease, primarily Plum Point unit train	(2.9)	—	—
Total cash outlay	$155.3	$213.3	$183.4

(1) For 2007, storm costs of $17.8 million and Other of $1.4 million, which relate to the cost of removal, are specifically related to capital expenditures associated with the January 2007 ice storm. $9.2 million of capitalized storm costs are related to the December 2007 ice storm.

(2) Other includes equity AFUDC of $(6.2) million, $(5.9) million and $(2.9) million for 2009, 2008 and 2007, respectively. 2009 and 2008 also include proceeds from sale of property of $0.5 million and $1.5 million, respectively.

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

(4) Represents the change in unpaid capital expenditures at the end of the year and not reflected in the Investing Activities section of the Statement of Cash Flows.

Approximately 55%, 23% and 36% of our cash requirements for capital expenditures for 2009, 2008 and 2007, respectively, were satisfied with internally generated funds. 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.

We estimate that our capital expenditures will total approximately $110.9 million in 2010, $89.8 million in 2011 and $70.5 million in 2012 (excluding AFUDC). See Item 1, "Business —

Construction Program." Of these budgeted amounts, we anticipate that we will spend the following amounts over the next three years for the following projects:

Project	2010	2011	2012
Iatan 2	$ 37.3	$ 5.9	$ —
Plum Point Energy Station	3.6	—	—
Electric distribution system additions	36.0	40.1	40.1
Electric transmission facilities additions	9.7	9.1	7.7
Environmental upgrades — Asbury	4.4	0.1	—
Other	19.9	34.6	22.7
Total	$110.9	$89.8	$70.5

We estimate that internally generated funds will provide approximately 64% of the funds required in 2010 for our budgeted capital expenditures. We intend to utilize a combination of short-term debt, the proceeds of sales of long-term debt and/or common stock (including common stock sold under our equity distribution agreement discussed below, as well as under our Employee Stock Purchase Plan, our Dividend Reinvestment and Stock Purchase Plan, and our 401(k) Plan and our ESOP) to finance additional amounts needed beyond those provided by operating activities for such capital expenditures. We will continue to utilize short-term debt as needed to support normal operations or other temporary requirements. 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

Our net cash flows provided by financing activities decreased $89.5 million to $28.0 million during 2009 as compared to $117.5 million in 2008, primarily due to repayments of short-term borrowings in 2009, as well as increased cash flows from operations and lower capital expenditures.

Our net cash flows from continuing operations provided by financing activities increased $50.4 million to $117.5 million during 2008 as compared to $67.0 million in 2007, primarily due to the issuance of first mortgage bonds and increased usage of short-term borrowings in 2008.

On February 25, 2009, we entered into an equity distribution agreement with UBS Securities LLC (UBS). Under the terms of the agreement, as amended, we may offer and sell shares of our common stock, par value $1.00 per share, having an aggregate offering amount of up to $120 million from time to time through UBS, as sales agent. We intend to use the net proceeds from this equity distribution program to repay short-term debt and for general corporate purposes, including to fund our current construction program. During the fourth quarter of 2009, we issued and sold 2,115,149 shares of our common stock, pursuant to this program, at an average price per share of $18.51, resulting in proceeds to us of approximately $37.9 million (after payment of approximately $1.2 million in commissions to the sales agent). Since inception of the program, in the aggregate, we have issued and sold 3,767,909 shares pursuant to the program, resulting in net proceeds to us of approximately $66.7 million. Sales of the shares pursuant to the equity distribution agreement will be made at market prices or as otherwise agreed with UBS. Under the terms of the program agreement, we may also sell shares to UBS as principal for UBS' own account at a price agreed upon at the time of sale.

On March 27, 2009, we issued $75 million principal amount of 7% first mortgage bonds due April 1, 2024. The net proceeds (after payment of expenses) of approximately $72.6 million were used to repay short-term debt incurred, in part, to fund our current construction program.

On May 16, 2008, we issued $90 million principal amount of first mortgage bonds. The net proceeds of approximately $89.4 million, less $0.4 million of legal and other financing fees, were added to our general funds and used primarily to pay down short-term indebtedness incurred, in part, as a result of our on-going construction program.

On December 12, 2007, we sold 3,000,000 shares of our common stock in an underwritten public offering for $23.00 per share. The sale resulted in net proceeds of approximately $65.8 million ($69.0 million less issuance costs of $3.2 million). The proceeds were added to our general funds and used to pay down short-term indebtedness incurred, in part, as a result of our on-going construction program.

On March 26, 2007, we issued $80 million principal amount of first mortgage bonds. The net proceeds of approximately $79.1 million, less $0.4 million of legal and other financing fees, were added to our general funds and used to pay down short-term indebtedness incurred, in part, as a result of our on-going construction program.

We have a $400 million shelf registration statement with the SEC, which became effective on August 15, 2008, covering our common stock, unsecured debt securities, preference stock, first mortgage bonds and trust preferred securities. As of December 31, 2009, in addition to amounts remaining under the equity distribution program described above, $205 million remains available for issuance under this shelf registration statement. Of the original $400 million, $250 million was available for first mortgage bonds with $175 million remaining available after the issuance of $75 million in first mortgage bonds on March 27, 2009. We plan to use a portion of the proceeds from issuances under this shelf to fund a portion of the capital expenditures for our new generation projects.

On July 15, 2005, we entered into a $150 million unsecured revolving credit facility which was scheduled to terminate on July 15, 2010. On March 14, 2006, we entered into the First Amended and Restated Unsecured Credit Agreement which amended and restated the $150 million unsecured revolving credit facility. The principal amount of the credit facility was increased to $226 million, with the additional $76 million allocated to support a letter of credit issued in connection with our participation in the Plum Point Energy Station project. This extra $76 million of availability reduces over a four year period in line with the amount of construction expenditures we owe for Plum Point Unit 1 and was $8.5 million as of February 1, 2010. On January 26, 2010, we entered into the Second Amended and Restated Unsecured Credit Agreement which amended and restated this facility again. This agreement extends the termination date of the revolving credit facility from July 15, 2010 to January 26, 2013. 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 increased from 0.80% to 2.70%. A facility fee is payable quarterly on the full amount of the commitments under the facility and a usage fee is payable on the full amount of the commitments under the facility for any period in which we have drawn less than 33% of the total revolving commitments under the facility, in each case based on our current credit ratings. In addition, upon entering into the amended and restated facility, we paid an upfront fee to the revolving credit banks of $900,000 in the aggregate. The aggregate amount of the revolving commitments remained unchanged at $150 million and 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 (which does not include our note payable to the securitization trust) 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 (which includes interest on the note payable to the securitization trust) 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, 2009, we are in compliance with these ratios. 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 was $32.0 million of outstanding borrowings under this agreement at December 31, 2009 and an additional $18.5 million was used to back up our outstanding commercial paper.

On March 11, 2009, we entered into a $50 million unsecured credit agreement. This agreement provides for $50 million of revolving loans to be available to us for working capital, general corporate purposes and to back-up our use of commercial paper and terminates on July 15, 2010. This credit agreement is in addition to, and has substantially identical covenants and terms as (other than pricing), our Second Amended and Restated Unsecured Credit Agreement dated January 26, 2010 discussed above. There were no borrowings under this agreement at December 31, 2009.

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, 2009 would permit us to issue approximately $239.9 million of new first mortgage bonds based on this test with an assumed interest rate of 7.0%. 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, 2009, we had retired bonds and net property additions which would enable the issuance of at least $644.8 million principal amount of bonds if the annual interest requirements are met. As of December 31, 2009, we are in compliance with all restrictive covenants of the EDE Mortgage.

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, 2009, these tests would not allow us to issue new first mortgage bonds.

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-
First Mortgage Bonds	BBB+	Baa1	BBB+
Senior Notes	BBB	Baa2	BBB-
Trust Preferred Securities	BB+	Baa3	BB
Commercial Paper	F2	P-2	A-3
Outlook	Negative	Negative	Stable

* Not rated.

On November 5, 2008, Standard & Poor's raised our senior unsecured debt rating from BB+ (a non-investment grade rating) to BBB- as a result of a reevaluation of the application of their notching criteria for U. S. investment-grade investor-owned utility operating company unsecured debt to better reflect the relatively strong recovery prospects of creditors in this sector. As a result, the senior unsecured debt of most utilities will now be rated the same as the corporate credit rating almost uniformly, even when a considerable amount of secured debt is outstanding.

On February 14, 2008, Moody's placed all of our ratings on review for possible downgrade. Moody's announced that the review would consider the cumulative impact that certain negative events, including severe weather and operational disruptions in 2007 and 2008, have had on our cash flow and overall financial flexibility at the current rating level as well as consider the potential for elevated costs related to our capital spending plan in 2008. On May 12, 2008, Moody's affirmed our ratings with a negative outlook.

On January 25, 2008, Fitch affirmed our ratings but revised their rating outlook to negative. At the time of the change, the negative rating outlook reflected uncertainty surrounding the outcome of our Missouri rate filing and weakness in our projected financial measures relative to Fitch guidelines. Events leading to the revision were storm damage incurred in December 2007 and the extended Asbury coal plant outage we experienced last winter. On January 22, 2010, Fitch Ratings downgraded our trust preferred securities from BBB- to BB+ as a result of Fitch's recently revised guidelines for rating preferred stock and hybrid securities issued by companies in all sectors. The new guidelines typically resulted in downgrades of one notch for many deferrable instruments that are currently performing. The new guidelines also provide guidance on how Fitch will rate and notch hybrids and preferred securities at different stages in the"life cycle" of an instrument. All of the affected instruments are performing and were downgraded by a single notch; Fitch does not currently have reason to expect that deferral or loss absorption will be activated.

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, 2009. Not included in these amounts are expected obligations associated with our share of the Iatan 2 construction and Iatan 1 environmental construction additions for which we have not yet been billed. 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 2010-2014 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)	$ 639.0	$ 50.6	$ 1.3	111.6	$ 475.5
Note payable to securitization trust	50.0	—	—	—	50.0
Interest on long-term debt	669.8	41.2	80.7	73.0	474.9
Short-term debt	50.5	50.5	—	—	—
Capital lease obligations	4.6	0.7	0.6	0.6	2.7
Operating lease obligations[2]	8.2	1.2	1.9	1.7	3.4
Electric purchase obligations[3]	275.9	72.5	85.4	51.5	66.5
Gas purchase obligations[4]	60.6	11.6	15.2	13.9	19.9
Open purchase orders	33.2	33.1	0.1	—	—
Plum Point	3.6	3.6	—	—	—
Postretirement benefit obligation funding	17.9	3.4	7.3	7.2	—
Pension benefit funding	57.5	12.0	21.6	23.9	—
Other long-term liabilities[5]	3.7	0.1	0.3	0.3	3.0
TOTAL CONTRACTUAL OBLIGATIONS[6]	$1,874.5	$280.5	$214.4	$283.7	$1,095.9

(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 2010 through 2015 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 owed to City Utilities of Springfield, Missouri of $11,000 per month over 30 years.

(6) Our estimate of uncertain tax liabilities totaled $0.9 million at December 31, 2009. Due to the uncertainties surrounding this estimate, we cannot reasonably estimate the timing of potential payments, if any, and have not included any in the table above.

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). As of December 31, 2009, our retained earnings balance was $10.1 million, compared to $13.6 million as of December 31, 2008, after paying out $44.8 million in dividends during 2009. A reduction of our dividend per share, partially or in whole, could have an adverse effect on our common stock price. On February 4, 2010, the Board of Directors declared a quarterly dividend of $0.32 per share on common stock payable March 15, 2010 to holders of record as of March 1, 2010.

Our diluted earnings per share were $1.18 for the year ended December 31, 2009 and were $1.17 and $1.09 for the years ended December 31, 2008 and 2007, respectively. Dividends paid per share were $1.28 for the year ended December 31, 2009 and for each of the years ended December 31, 2008 and 2007.

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 March 11, 2008, we amended the EDE Mortgage in order to provide us with more flexibility to pay dividends to our shareholders by increasing the basket available to pay dividends by $10.75 million, as described above. As of December 31, 2009, this restriction did not prevent us from issuing dividends.

In addition, under certain circumstances, our Junior Subordinated Debentures, 8½% Series due 2031, reflected as a note payable to securitization trust on our balance sheet, held by Empire District Electric Trust I, an unconsolidated securitization trust subsidiary, may also restrict our ability to pay dividends on our common stock. These restrictions apply if: (1) we have knowledge that an event has occurred that would constitute an event of default under the indenture governing these junior subordinated debentures and we have not taken reasonable steps to cure the event, (2) we are in default with respect to payment of any obligations under our guarantee relating to the underlying preferred securities, or (3) we have deferred interest payments on the Junior Subordinated Debentures, 8½% Series due 2031 or given notice of a deferral of interest payments. As of December 31, 2009, there were no such restrictions on our ability to pay dividends.

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 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 (effective January 1, 2005) and OPEB benefits (effective January 1, 2007) unrecognized net gains or losses as of the measurement date are amortized into actuarial expense over ten years.

In our 2005 electric Missouri Rate Case the MPSC ruled that we would be allowed to recover pension costs consistent with our GAAP policy noted above. In accordance with the rate order, we prospectively calculated 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.

The MPSC ruling also allowed us to record the Missouri portion of any costs above or below the amount included in rates as a regulatory asset or liability, respectively. Therefore, the deferral of these costs began in the second quarter of 2005. In our 2006 Kansas Rate Case, the KCC also ruled that we would be allowed to change our recognition of pension costs, deferring the Kansas portion of any costs above or below the amount included in our rate case as a regulatory asset or liability. 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 will be 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 will be 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 now expect future pension expense or benefits are probable of full recovery in rates charged to our Missouri and Kansas customers, thus lowering our sensitivity to accounting risks and uncertainties.

Our 2006 Missouri rate case order allows us to defer any OPEB cost that is different from those allowed recovery in this rate case. This treatment is similar to treatment afforded pension costs in our March 2005 rate case. 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.

On December 31, 2006, we adopted the ASC guidance on defined benefit plans disclosure which requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity. We adopted the guidance for the fiscal year ended December 31, 2006. Based on the regulatory treatment of pension and OPEB recovery afforded in our jurisdictions, we have concluded that the amount of unfunded defined benefit pension and postretirement plan obligations will be recorded as regulatory assets on our balance sheet rather than as reductions of equity through comprehensive income.

Our 2008 Missouri rate case order approved Stipulations providing for the continuation of the pension and other post-retirement employee benefits tracking mechanism established in our 2006 and 2007 Missouri rate cases. Our funding policy is to contribute annually an amount at least equal to the actuarial cost of pension and postretirement benefits. We expect to be required to fund approximately $12.0 million to our pension plan and $3.2 million for OPEB benefits in 2010. (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.

Hedging Activities. We currently engage in hedging activities in an effort to minimize our risk from volatile natural gas prices. We enter into 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 expense 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 gains and losses from effective instruments deferred in other comprehensive income (in stockholders' equity) or a regulatory asset or liability for instruments entered into after September 1, 2008, while gains and losses from ineffective (overhedged) instruments are recognized as the fair value of the derivative instrument changes. With the addition of the Missouri fuel adjustment mechanism effective September 1, 2008, we now have a fuel cost recovery mechanism in all of our jurisdictions, which significantly reduces the impact of fluctuating fuel costs on our net income.

Risks and uncertainties affecting the application of this accounting policy 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 in our Consolidated Statement of Income and then deferred to a regulatory asset or liability, given it is probable of recovery through our fuel adjustment mechanism. See Note 14 of "Notes to Consolidated Financial Statements" under Item 8 for detailed information regarding our hedging information.

As of February 5, 2010, approximately 77% of our anticipated volume of natural gas usage for our electric operations for the year 2010 is hedged, either through physical or financial contracts, at an average price of $6.322 per Dekatherm (Dth). In addition, the following volumes and percentages of our anticipated volume of natural gas usage for our electric operations for the next three years are hedged at the following average prices per Dth:

Year	% Hedged	Dth Hedged	Average Price
2011	71%	5,115,000	$5.840
2012	40%	3,085,000	$7.016
2013	17%	1,200,000	$7.295

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. As of February 5, 2010, we have 91% of our expected remaining winter heating season usage (through March 2010) hedged with physical storage, physical forward contracts and financial derivative contracts. The average price of these hedges is $3.948 per Dth. 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 February 7, 2010, we had 0.7 million Dths in storage on the three pipelines that serve our customers. This represents 33% of our storage capacity. We have an additional 0.6 million Dths hedged through financial derivatives and physical contracts. Our long-term hedge strategy is to mitigate price volatility for our customers by hedging a minimum of 50% of current year, up to 50% of second year and up to 20% of third year expected gas usage by the beginning of the Actual Cost Adjustment (ACA) year at September 1. A 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.

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, 2009, we have recorded $169.0 million in regulatory assets and $87.5 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 and the ability to recover costs.

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.

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 2009, 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, 2009 and 2008 was $3.1 million and $3.5 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, 2009, 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. We believe it is unlikely that a change to one of these key assumptions, by itself, would be sufficient to impact the estimated fair value determined in our discounted cash flow calculation enough to result in an impairment charge. However, if significant negative changes occurred to multiple 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 recent 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 the customer contraction will minimize in the near future and return to positive customer growth within the next few 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 November 30, 2009 indicated the estimated fair market value of the gas reporting unit to be 10-15% higher than its carrying value at that time. While we believe the assumptions utilized in our analysis were reasonable, significant adverse developments in future periods could negatively impact goodwill impairment considerations, which could adversely impact earnings.

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 Recently Issued and Proposed Accounting Standards under Note 1 of "Notes to Consolidated Financial Statements" under Item 8.

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 often are 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 69.8% of our 2009 generation fuel supply need through coal. Approximately 88% of our 2009 coal supply was Western coal. We have contracts to supply a portion of the fuel for our coal plants through 2013. These contracts satisfy approximately 98% of our anticipated fuel requirements for 2010, 59% for 2011, 28% for 2012 and 30% for our 2013 requirements for our Asbury and Riverton 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 February 5, 2010, 77%, or 6.5 million Dths's, of our anticipated volume of natural gas usage for our electric operations for 2010 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 2010, if average natural gas prices should increase 10% more in 2010 than the price at December 31, 2009, our natural gas expenditures would increase by approximately $1.0 million based on our December 31, 2009 total hedged positions for the next twelve months. However, such an increase would be probable of recovery through fuel adjustment mechanisms. With the addition of the Missouri fuel adjustment mechanism effective September 1, 2008, we now have a fuel cost recovery mechanism 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 February 7, 2010, we have 0.7 million Dths in storage on the three pipelines that serve our customers. This represents 33% of our storage capacity. We have an additional 0.6 million Dths hedged through financial derivatives and physical contracts. Our long-term hedge strategy is to mitigate price volatility for our customers by hedging a minimum of 50% of the current year, up to 50% of the second year and up to 20% of third year expected gas usage by the beginning of the ACA year at September 1. 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.

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 (Unaudited)" 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 various trading counterparties that resulted from us exceeding agreed-upon credit limits established by the counterparties. The following table depicts our margin deposit assets and margin deposit liabilities at December 31, 2009 and December 31, 2008:

(in millions)	2009	2008
Margin deposit assets	$2.9	$10.7

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, 2009, 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	$ 8.4
Net unrealized mark-to-market gains for financial natural gas contracts	(0.4)
Net credit exposure	$ 8.0

The $0.4 million net unrealized mark-to-market gain for financial natural gas contracts is comprised of $4.3 million of exposure to counterparties of Empire for unrealized losses and $4.7 million of exposure to Empire of unrealized gains, of which $4.5 million is from a single counterparty. We are holding no collateral from this counterparty since we are below the $10 million mark-to-market collateral threshold in our agreement with this counterparty. As noted above, we have $2.9 million on deposit for NYMEX counterparty exposure to Empire, of which $2.4 million represents our collateral requirement. If NYMEX gas prices decreased 25% from their December 31, 2009 levels, our collateral requirement would increase $2.4 million. If these prices increased 25%, our collateral requirement would decrease $3.4 million and our counterparties would be required to post $0.5 million in 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 2010 than in 2009, our interest expense would increase, and income before taxes would decrease by less than \$0.3 million. This amount has been determined by considering the impact of the hypothetical interest rates on our highest month-end commercial paper balance for 2009. 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 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, 2009, 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 19, 2010

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	($-000's)	
Assets		
Plant and property, at original cost:		
Electric	$1,619,949	$1,490,829
Natural gas	58,180	56,282
Water	10,891	10,560
Other	29,564	28,481
Construction work in progress	302,012	289,460
	2,020,596	1,875,612
Accumulated depreciation and amortization	561,586	527,245
	1,459,010	1,348,367
Current assets:		
Cash and cash equivalents	5,620	2,754
Accounts receivable — trade, net of allowance of $1,087 and $1,265, respectively	36,136	39,487
Accrued unbilled revenues	23,717	25,170
Accounts receivable — other	21,417	19,353
Fuel, material and supplies	43,973	48,608
Unrealized gain in fair value of derivative contracts	2,782	2,395
Prepaid expenses and other	4,438	5,675
Regulatory assets	772	2,033
	138,855	145,475
Noncurrent assets and deferred charges:		
Regulatory assets	168,254	162,026
Goodwill	39,492	39,492
Unamortized debt issuance costs	10,638	9,133
Unrealized gain in fair value of derivative contracts	2,525	6,434
Deferred investment tax credits	17,713	—
Other	3,359	2,919
	241,981	220,004
Total assets	$1,839,846	$1,713,846

(Continued)

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

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	($-000's)	
Capitalization and liabilities		
Common stock, $1 par value, 100,000,000 shares authorized, 38,112,280 and 33,981,579 shares issued and outstanding, respectively	$ 38,112	$ 33,982
Capital in excess of par value	551,631	483,443
Retained earnings	10,068	13,579
Accumulated comprehensive income/(loss), net of income taxes	339	(2,132)
Total common stockholders' equity	600,150	528,872
Long-term debt (net of current portion)		
Note payable to securitization trust	50,000	50,000
Obligations under capital lease	2,563	174
First mortgage bonds and secured debt	339,643	312,953
Unsecured debt	247,950	248,440
Total long-term debt	640,156	611,567
Total long-term debt and common stockholders' equity	1,240,306	1,140,439
Current liabilities:		
Accounts payable and accrued liabilities	67,406	69,502
Current maturities of long-term debt	51,021	20,160
Short-term debt	50,500	102,000
Customer deposits	10,394	9,577
Interest accrued	5,698	5,921
Fair value of derivative contracts	4,337	12,276
Taxes accrued	3,386	3,174
	192,742	222,610
Commitments and contingencies (Note 11)		
Noncurrent liabilities and deferred credits:		
Regulatory liabilities	87,533	66,585
Deferred income taxes	194,315	173,511
Unamortized investment tax credits	20,125	2,917
Pension and other postretirement benefit obligations	84,240	83,151
Fair value of derivative contracts	426	3,302
Other	20,159	21,331
	406,798	350,797
Total capitalization and liabilities	$1,839,846	$1,713,846

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,		
	2009	2008	2007
	($-000's, except per share amounts)		
Operating revenues:			
Electric	$433,133	$446,466	$425,161
Gas	57,314	65,438	59,877
Water	1,764	1,782	1,879
Other	4,957	4,477	3,243
	497,168	518,163	490,160
Operating revenue deductions:			
Fuel and purchased power	182,028	204,058	191,230
Cost of natural gas sold and transported	35,601	42,630	37,626
Regulated operating expenses	73,086	71,918	71,367
Other operating expenses	1,801	1,889	1,611
Maintenance and repairs	33,012	28,549	32,059
Gain on sale of assets	—	—	(1,241)
Depreciation and amortization	51,494	53,562	52,599
Provision for income taxes	19,571	19,128	14,416
Other taxes	26,080	25,417	24,927
	422,673	447,151	424,594
Operating income	74,495	71,012	65,566
Other income and (deductions):			
Allowance for equity funds used during construction	6,209	5,929	2,923
Interest income	217	1,057	326
Benefit/(provision) for other income taxes	(311)	2	(28)
Other — non-operating expense, net	(460)	(1,569)	(969)
	5,655	5,419	2,252
Interest charges:			
Long-term debt	42,084	36,041	31,120
Note payable to securitization trust	4,250	4,250	4,250
Short-term debt	1,125	1,854	2,940
Allowance for borrowed funds used during construction	(7,924)	(6,589)	(4,742)
Other	(681)	1,153	1,069
	38,854	36,709	34,637
Income from continuing operations	41,296	39,722	33,181
Income from discontinued operations, net of tax	—	—	63
Net income	$ 41,296	$ 39,722	$ 33,244
Weighted average number of common shares outstanding — basic	34,924	33,821	30,587
Weighted average number of common shares outstanding — diluted	34,956	33,860	30,610
Earnings from continuing operations per weighted average share of common stock — basic and diluted	$ 1.18	$ 1.17	$ 1.09
Earnings from discontinued operations per weighted average share of common stock — basic and diluted	—	—	0.00
Total earnings per weighted average share of common stock — basic and diluted	$ 1.18	$ 1.17	$ 1.09
Dividends declared per share of common stock	$ 1.28	$ 1.28	$ 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,		
	2009	2008	2007
		($-000's)	
Net income	$41,296	$ 39,722	$33,244
Reclassification adjustments for (gain)/loss included in net income or reclassified to regulatory asset or liability	13,568	(3,872)	(1,610)
Net change in fair market value of open derivative contracts for period	(9,576)	(17,394)	5,229
Income taxes	(1,521)	8,102	(1,379)
Comprehensive income	$43,767	$ 26,558	$35,484

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, 2006	$30,251	$406,650	$ 22,916	$ 8,792	$468,609
Net income			33,244		33,244
Stock/stock units issued through:					
Public offering	3,000	62,779			65,779
Stock purchase and reinvestment plans	355	7,956			8,311
Dividends declared			(38,953)		(38,953)
Cumulative effect of adopting a change in accounting			(54)		(54)
Reclassification adjustment for gains included in net income				(1,610)	(1,610)
Change in fair value of open derivative contracts for period				5,229	5,229
Income taxes				(1,379)	(1,379)
Balance at December 31, 2007	33,606	477,385	17,153	11,032	539,176
Net income			39,722		39,722
Stock/stock units issued through:					
Stock purchase and reinvestment plans	376	6,058			6,434
Dividends declared			(43,296)		(43,296)
Reclassification adjustment for gains included in net income				(3,872)	(3,872)
Change in fair value of open derivative contracts for period				(17,394)	(17,394)
Income taxes				8,102	8,102
Balance at December 31, 2008	33,982	483,443	13,579	(2,132)	528,872
Net income			41,296		41,296
Stock/stock units issued through:					
Public offering	3,664	60,825			64,489
Stock purchase and reinvestment plans	466	7,363			7,829
Dividends declared			(44,807)		(44,807)
Reclassification adjustment for losses included in net income				13,568	13,568
Change in fair value of open derivative contracts for period				(9,576)	(9,576)
Income taxes				(1,521)	(1,521)
Balance at December 31, 2009	$38,112	$551,631	$ 10,068	$ 339	$600,150

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,		
	2009	2008	2007
		($-000's)	
Operating activities:			
Net income	$ 41,296	$ 39,722	$ 33,244
Adjustments to reconcile net income to cash flows from operating activities:			
Depreciation and amortization	62,247	59,066	57,317
Pension and other postretirement benefit costs	4,096	8,282	9,490
Deferred income taxes and unamortized investment tax credit, net	15,324	8,580	18,681
Allowance for equity funds used during construction	(6,209)	(5,929)	(2,923)
Stock compensation expense	2,616	2,169	2,394
Non cash (gain)/loss on derivatives	10,350	(39)	(893)
Gain on the sale of assets	(457)	—	(1,402)
Impairment of other non-operating investment	—	556	—
Cash flows impacted by changes in:			
Accounts receivable and accrued unbilled revenues	2,989	(10,938)	(10,216)
Fuel, materials and supplies	4,635	(4,720)	(2,869)
Prepaid expenses, other current assets and deferred charges	(7,464)	(2,683)	(13,057)
Accounts payable and accrued liabilities	(1,305)	(4,905)	11,970
Interest, taxes accrued and customer deposits	806	2,234	2,532
Other liabilities and other deferred credits	699	1,597	(811)
Net cash provided by operating activities of continuing operations	129,623	92,992	103,457
Net cash provided by operating activities of discontinued operations	—	—	208
Total net cash provided by operating activities	129,623	92,992	103,665

(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,		
	2009	2008	2007
		($-000's)	
Investing activities:			
Capital expenditures — regulated	$(154,016)	$(211,311)	$(178,469)
Capital expenditures and other investments — non-regulated	(1,239)	(1,969)	(4,924)
Proceeds from the sale of property, plant and equipment	544	1,538	1,250
Proceeds from the sale of other segment businesses	—	—	3,240
Net cash used in investing activities of continuing operations	(154,711)	(211,742)	(178,903)
Net cash used in investing activities of discontinued operations	—	—	(12)
Total net cash used in investing activities	(154,711)	(211,742)	(178,915)
Financing activities:			
Proceeds from first mortgage bonds — electric	75,000	89,950	79,831
Proceeds from issuance of common stock, net of issuance costs	70,271	5,385	71,721
Long-term debt issuance costs	(2,397)	(3,168)	(1,078)
Net short-term borrowings (repayments)	(51,500)	68,960	(44,010)
Repayment of first mortgage bonds	(20,025)	—	—
Dividends	(44,807)	(43,296)	(38,953)
Proceeds from issuance of notes payable	2,470	—	—
Other	(1,058)	(370)	(452)
Net cash provided by financing activities of continuing operations	27,954	117,461	67,059
Net cash used in financing activities of discontinued operations	—	—	(69)
Net cash provided by financing activities	27,954	117,461	66,990
Net decrease in cash and cash equivalents	2,866	(1,289)	(8,260)
Cash and cash equivalents, beginning of year	2,754	4,043	12,303
Cash and cash equivalents, end of year	$ 5,620	$ 2,754	$ 4,043

	2009	2008	2007
Supplemental cash flow information:			
Interest paid	$ 45,730	$ 40,384	$ 35,884
Income taxes paid (received), net of refund	3,246	8,706	(1,211)
Supplementary non-cash investing activities:			
Change in accrued additions to property, plant and equipment not reported above	$ (3,833)	$ (6,895)	$ 12,175
Capital lease obligations for purchase of new equipment	2,946	—	—

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. It provides natural gas distribution to communities in northwest, north central and west central Missouri. Our other segment consists of a 100% interest in Empire District Industries Inc (EDI), which holds our fiber optics business. See Note 12. In 2009, 87.5% of our gross operating revenues were provided from sales from our electric segment (including 0.4% from the sale of water), 11.5% from sales from our gas segment and 1.0% from our other segment.

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 revenues in 2009 were derived as follows: residential 41.6%, commercial 31.4%, industrial 15.2%, wholesale on-system 4.2%, wholesale off-system 3.3%, miscellaneous sources, primarily public authorities, 2.7% and other electric revenues 1.6%. Our retail electric revenues for 2009 by jurisdiction were as follows: Missouri 89.1%, Kansas 5.1%, Arkansas 2.8%, and Oklahoma 3.0%.

Our gas operations serve approximately 45,000 customers and the 2009 gas operating revenues were derived as follows: residential 63.1%, commercial 27.1%, industrial 3.6%, and other 6.2%.

Basis of Presentation

The consolidated financial statements include the accounts of EDE, EDG, and EDI. The consolidated entity is referred to throughout as "we" or the "Company". Significant 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. Subsequent events were evaluated through February 19, 2010, the date these financial statements were issued.

Discontinued Operations

In September 2007, we sold our 100% interest in Fast Freedom, Inc., an Internet service provider. For financial reporting purposes, this business has been classified as discontinued operations and is not included in our segment information.

Accounting for the Effects of Regulation

In accordance with 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. We recorded estimated unbilled revenue of $23.7 million and $25.2 million as of December 31, 2009 and 2008, respectively.

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 $10.2 million, $10.2 million and $10.0 million were recorded for each of the years ended December 31, 2009, 2008 and 2007, respectively.

Property, Plant & Equipment

The costs of additions to utility property and replacements for retired property units are capitalized. Costs include labor, material and an allocation of general and administrative costs, plus 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. In 2007, we recognized a $1.2 million pre-tax gain from the sale of our unit train. 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 is 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, 2009 and 2008 was $9.7 million and $10.5 million, respectively.

As of December 31, 2009 and 2008, we had recorded accrued cost of removal of $49.8 million and $40.1 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. From January 2002 through March 2005, we suspended accruing the cost of removing plant from service upon retirement through depreciation rates pursuant to our 2001 Missouri rate case. Pursuant to our 2005 Missouri rate order, we again began accruing cost of removal in depreciation rates for mass property (including transmission, distribution and general plant assets) on April 1, 2005. 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, 2009 and 2008 was $3.3 million and $3.6 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 future asset retirement obligations associated with the 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 liability for future containment of an ash landfill at the Riverton Power Plant along with a liability for future asset retirement obligations associated with the removal of asbestos located at the Riverton and Asbury Plants. 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 liabilities 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 5.0% 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.

The balances at the end of 2008 and 2009 are shown below.

(000's)	Liability Balance 12/31/08	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions	Liability Balance at 12/31/09
Asset Retirement Obligation	$3,468	$ —	$ —	$139	$ —	$3,607

(000's)	Liability Balance 12/31/07	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions	Liability Balance at 12/31/08
Asset Retirement Obligation	$3,333	$ —	$ —	$135	$ —	$3,468

Upon adoption of the standards on the retirement of long lived assets and conditional asset retirement obligations, we recorded a non-recurring discounted liability and a 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, 2009 and 2008, our regulatory assets relating to asset retirement obligations totaled $3.3 million and $3.1 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.

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 businesses 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 2006 and 2008 rate orders from the MPSC, we recorded approximately $4.5 million and $8.2 million of regulatory amortization during 2009 and 2008, respectively. This amortization included in our rates was granted in the Experimental Regulatory Plan approved by the MPSC on August 2, 2005. It provides additional cash flow to enhance the financial support for our current generation expansion plan. It is related to our investment in Iatan 2 and also includes our Riverton V84.3A2 combustion turbine (Riverton Unit 12) and environmental improvement and upgrades at Asbury and Iatan 1. This amortization is included as depreciation and amortization expense and in accumulated depreciation and amortization on the consolidated balance sheet.

Allowance for Funds Used During Construction

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

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

In accordance with the methodology prescribed by the FERC, we utilized aggregate rates (on a before-tax basis) of 7.0% for 2009, 7.8% for 2008 and 7.7% for 2007, compounded semiannually, in determining AFUDC for all of our projects except Iatan 2. The specific Iatan 2 AFUDC rate is a result of our Experimental Regulatory Plan approved by the MPSC on August 2, 2005. 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.)

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. The allowance for doubtful accounts at December 31, 2009 and 2008 was $1.1 million and $1.3 million, respectively.

Asset Impairments

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 several criteria, including but not limited to revenue trends, undiscounted forecasted cash flows and other operating factors, to determine the impairment amount. None of our assets were impaired as of December 31, 2009 and 2008.

Goodwill

As of December 31, 2009, 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. We believe it is unlikely that a change to one of these key assumptions, by itself, would be sufficient to impact the estimated fair value determined in our discounted cash flow calculation enough to result in an impairment charge. However, if significant negative changes occurred to multiple 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 recent 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 the customer contraction will minimize in the near future and return to positive customer growth within the next few 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 November 30, 2009 indicated the estimated fair market value of the gas reporting unit to be 10-15% higher than its carrying value at that time. While we believe the assumptions utilized in our analysis were reasonable, significant adverse developments in future periods could negatively impact goodwill impairment considerations, which could adversely impact earnings.

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.

The MPSC authorized a fuel adjustment clause (FAC) for our Missouri customers effective September 1, 2008. The MPSC established a base cost for the recovery of fuel and purchased power expenses used to supply energy. 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 all of the off-system sales margin flows back to the customer. Rates related to the fuel adjustment clause will be 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 the FERC jurisdictions. We buy and sell power through the SPP RTO energy imbalance services market (EIS). We net settle these market transactions on an hourly basis.

At December 31, 2009, our Missouri fuel and purchased power costs were under-recovered by $0.1 million, which is reflected as a regulatory asset.

We receive Renewable Energy Credits (REC) in conjunction with our purchased power agreements with Elk River Windfarm LLC and Cloud County Windfarm, LLC. These credits are considered inventory and are recorded at zero cost (See Note 11).

Effective March 1, 2005, the MPSC approved a Stipulation and Agreement 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. The banked allowances are recorded at zero cost. The allowances are removed from inventory on a FIFO basis. We consider used allowances 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). Changes in the fair value of a derivative that is highly effective and designated and qualifies as a cash-flow hedge are recorded in comprehensive income until earnings are affected by the variability of cash flows (e.g., when periodic settlements on a variable-rate asset or liability are recorded in earnings). Changes in the fair value of non-hedged derivative instruments and any ineffective portion of a qualified hedge are reported in current-period earnings in fuel expense. Effective September 1, 2008, in conjunction with the implementation of the Missouri fuel adjustment clause in the July 2008 MPSC rate order, the unrealized losses or gains from new derivatives used to hedge our fuel costs will be 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. Unrealized gains and losses from cash flow hedges existing at September 1, 2008 will continue to be recorded through comprehensive income. Once settled, the realized gain or loss will be recorded as fuel expense and be subject to the fuel adjustment clause.

We discontinue hedge accounting prospectively when (1) it is determined that the derivative is no longer highly effective in offsetting changes in cash flows of a hedged item (including forecasted transactions); (2) the derivative expires or is sold, terminated, or exercised; (3) the derivative is no longer designated as a hedging instrument because it is less than probable that a forecasted transaction will occur; or (4) management determines that designation of the derivative as a hedge instrument is no longer appropriate (See Note 14).

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 income.

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 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 (effective January 1, 2005) and OPEB benefits (effective January 1, 2007), unrecognized net gains or losses as of the measurement date are amortized into actuarial expense over ten years.

Pensions

In our 2005 electric Missouri rate case, the MPSC ruled the Company would be allowed to recover pension costs consistent with our GAAP policy noted above. In accordance with the rate order, 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 portion of any costs above or below the amount included in rates as a regulatory asset or liability, respectively. Therefore, the deferral of these costs began in the second quarter of 2005. In our 2006 Kansas rate case, the KCC also ruled that the Company would be allowed to change the recognition of pension costs, deferring the Kansas portion of any costs above or below the amount included in the rate case as a regulatory asset or liability.

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 will be 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 will be 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)

In our 2006 Missouri rate case, the MPSC approved 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. During 2008, the MPSC approved Stipulations and Agreements providing for the continuation of the pension and other postretirement employee benefits tracking mechanism established in our 2006 and 2007 Missouri rate orders (See Note 3). This treatment will allow for future rate recovery of the obligations and as such, we record them 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, 2009, the balance of other noncurrent liabilities is primarily comprised of accruals for self insurance and customer advances for construction.

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 $14.1 million and $16.1 million at December 31, 2009 and 2008, respectively.

Fuel, Material and Supplies

Fuel, material 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):

	2009	2008
Electric fuel inventory	$15,885	$16,430
Natural gas inventory	5,404	8,911
Materials and supplies	22,684	23,267
TOTAL	$43,973	$48,608

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. Remaining unamortized investment tax credits are being amortized over remaining lives of approximately 21 years.

The Company is working with Kansas City Power & Light to enter into an agreement with the IRS to receive our share of the $125 million in advanced coal investment tax credits granted to the Iatan 2 facility. Our share amounts to approximately $17.7 million. We cannot predict the timing of the receipt of the credit; however, it will have no significant income statement impact as the credit, which will reduce our tax payments, will flow to our customers over the life of the plant. The credit, which will ultimately reduce our tax liability, has been recorded on the balance sheet under deferred charges and deferred credits.

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 2005. We adopted the provisions of this guidance on January 1, 2007. As a result of the implementation of this guidance, we recognized approximately $54,000 of additional liability for unrecognized tax benefits, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings. At December 31, 2009 and 2008, our balance sheet included approximately $0.9 million and $2.2 million, respectively, of unrecognized tax benefits which would affect our effective tax rate if recognized. 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 time-vested restricted stock are excluded from the calculation of diluted earnings per share if the effect would be antidilutive.

	2009	2008	2007
Weighted Average Number Of Shares			
Basic	34,923,526	33,820,750	30,586,780
Dilutive Securities:			
Performance-based restricted stock awards	20,513	23,680	18,997
Dividend equivalents	12,122	10,981	—
Employee stock purchase plan	103	4,637	3,840
Stock options			734
Total dilutive securities	32,738	39,298	23,571
Diluted weighted average number of shares	34,956,264	33,860,048	30,610,351
Antidilutive Shares	**117,178**	**—**	**48,903**

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 recognized compensation expense over the requisite service period of all stock-based compensation awards issued subsequent to January 1, 2002 based upon the fair-value of the award as of the date of issuance (See Note 4).

Recently Issued and Proposed Accounting Standards

Codification: In June 2009, the FASB issued an accounting pronouncement amending "Generally Accepted Accounting Principles". This pronouncement is effective for periods ending after September 15, 2009. The amendment identifies the sources of accounting principles, and establishes the FASB Accounting Standards Codification (Codification) as the only source of authoritative accounting principles recognized by the FASB. This pronouncement is not intended to change generally accepted accounting principles. We adopted this pronouncement on September 15, 2009. As a result of this adoption, the Financial Accounting Standards previously listed as FASBs have been replaced with the new standards references. This change did not change the underlying principles and, therefore, had no effect on our financial statements.

Fair Value: We adopted new accounting guidance on fair value measurements and disclosures on January 1, 2008. This guidance defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. This guidance applies to other accounting pronouncements that require or permit fair value measurements. The guidance contains a scope exception for leases and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement. The adoption of this guidance for financial assets and financial liabilities did not have a material impact on our consolidated financial position, results of operations and cash flows. The guidance was amended to delay the effective date for all nonfinancial assets and nonfinancial liabilities to fiscal years beginning after November 15, 2008. We adopted this portion of the guidance on January 1, 2009. The adoption of the guidance for nonfinancial assets and nonfinancial liabilities did not have an effect on our consolidated financial position, results of operations or cash flows. (See Note 15).

In April 2009, the FASB amended the fair value measurements and disclosures guidance to provide additional guidance for estimating fair value in accordance with the fair value measurements guidance, when the volume and level of activity for an asset or liability has decreased significantly. This guidance also addresses identifying circumstances that indicate a transaction is not orderly. The amendment was effective as of June 30, 2009. The adoption of the amendment did not have any effect on our results of operations, financial position or liquidity.

In April 2009, the FASB also amended the financial instruments disclosure guidance, to require disclosures about fair value of financial instruments in interim financial statements, in addition to the annual financial statements as already required by the accounting guidance. Adoption is required for interim periods ending after June 15, 2009. As the amendment provides only disclosure requirements, the application of this standard will not have a material impact on our results of operations, financial position or liquidity.

In September 2009, the FASB amended the accounting guidance for fair value measurements and disclosures. The amendment was issued because some investments, such as some hedge funds and private equity funds, do not have a readily determinable fair value. This amendment allows the investor to use net asset value per share (NAV) as a practical expedient to fair value so long as the NAV has been calculated in a manner consistent with generally accepted accounting principles for investment companies. This amendment is effective for periods ending after December 15, 2009. The adoption of the amendment will not have any effect on our results of operations, financial position or liquidity.

In January 2010, the FASB amended the fair value measurements and disclosures guidance to require additional disclosures about fair value measurements. The revised guidance will require new disclosures about the transfers in and out of Level 1 and 2 measurements, including descriptions of the reasons for the transfers. Additionally, the reconciliation of Level 3 measurements will now require separate presentation of sales, issuances and settlements. This guidance for the Level 1 and 2 measurements will be effective for periods beginning after December 15, 2009. The guidance on the Level 3 measurements will be effective for periods beginning after December 15, 2010. We do not expect the adoption of this guidance to have any effect on our results of operations, financial position or liquidity.

Derivatives: In April 2008, the FASB amended the guidance for derivatives and hedging to enhance the disclosure framework. We adopted this amendment on January 1, 2009. (See Note 14 below).

Subsequent events: In May 2009, the FASB issued accounting guidance covering subsequent events. This guidance is effective for periods ending after June 15, 2009 and requires the disclosure of the date through which an entity has evaluated subsequent events, and whether that date represents the date the financial statements were issued or were available to be issued. We adopted this guidance upon its issuance by the FASB. The adoption of this guidance did not have a material effect on our financial statement disclosures.

Defined benefit plans: In December 2008, the FASB amended the defined benefit plans' disclosure guidance. The amendment requires additional disclosures related to pension and other postretirement benefit plan assets. The amendment is effective as of December 31, 2009 and requires disclosure of the fair value of each major category of plan asset of a defined benefit pension or postretirement plan. In addition, employers are required to disclose information enabling users to understand investment policies and strategies, assess the inputs and valuation techniques used to develop fair value measurements, and to disclose any significant concentrations of risks within plan assets. The adoption of this amendment did not have a material effect on our results of operations, financial position or liquidity (See Note 8 below).

Impairment: In April 2009, the FASB amended the debt and equity securities — subsequent measurement guidance to change the other-than-temporary impairment guidance in existing Generally Accepted Accounting Principles (GAAP) for debt securities. The amendment provides for improved presentation and disclosure of other-than-temporary impairments of debt securities in the financial statements. This guidance was effective as of June 30, 2009. The adoption of this amendment did not have a material effect on our results of operations, financial position or liquidity.

Consolidation: In June 2009, the FASB amended the accounting guidance for transfers and servicing. This amendment is effective for annual periods beginning after November 15, 2009. The amendment removes qualifying special-purpose entities (QSPE) from GAAP. Additionally, the requirements for derecognizing financial assets have been changed, and additional disclosures about a transferor's continuing involvement in transferred financial assets will be required. We do not expect the adoption of this amendment to have a material effect on our financial statements.

In June 2009, the FASB also amended the accounting guidance for consolidations. This amendment is effective for annual periods beginning after November 15, 2009. The amendment requires an entity to complete a qualitative analysis when determining who must consolidate a variable interest entity. Additionally, the amendment requires additional disclosures, and an ongoing reassessment of who must consolidate a variable interest entity. We are evaluating the impact of the adoption of this standard; however, we do not expect the adoption of this standard to have a material impact on our financial statements.

2. Property, Plant and Equipment

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

	December 31, 2009	December 31, 2008
Electric plant		
Production	$ 690,768	$ 594,711
Transmission	203,436	197,450
Distribution	651,657	625,919
General[(1)]	74,088	72,749
Electric plant	1,619,949	1,490,829
Less accumulated depreciation and amortization	542,226	511,750
Electric plant net of depreciation and amortization	1,077,723	979,079
Construction work in progress	301,534	289,108
Net electric plant	1,379,257	1,268,187
Gas plant	58,180	56,282
Less accumulated depreciation and amortization	6,854	4,599
Gas plant net of accumulated depreciation	51,326	51,683
Construction work in progress	436	291
Net gas plant	51,762	51,974
Water plant	10,891	10,560
Less accumulated depreciation and amortization	3,664	3,396
Water plant net of depreciation and amortization	7,227	7,164
Construction work in progress	5	56
Net water plant	7,232	7,220
Other		
Fiber	29,564	28,481
Less accumulated depreciation and amortization	8,842	7,500
Non-regulated net of depreciation and amortization	20,722	20,981
Construction work in progress	37	5
Net non-regulated property	20,759	20,986
TOTAL NET PLANT AND PROPERTY	$1,459,010	$1,348,367

(1) Includes intangible property of $12.1 and $11.9 million as of December 31, 2009 and 2008, respectively, primarily related to capitalized software. Accumulated amortization related to this property in 2009 and 2008 was $8.5 and $7.8 million respectively.

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

	2009	2008	2007
Provision for depreciation			
Regulated — Electric and Water	$44,973	$42,389	$39,577
Regulated — Gas	2,072	2,016	1,967
Non-Regulated	1,443	1,319	1,077
TOTAL	48,488	45,724	42,621
Amortization(1)	5,159	9,132	11,310
TOTAL	$53,647	$54,856	$53,931

(1) Includes $4.5 million, $8.2 million, and $10.4 million of regulatory amortization for 2009, 2008 and 2007, respectively. This was granted by the MPSC effective January 1, 2007 and updated August 23, 2008.

Annual depreciation rates			
Electric and water	2.9%	3.0%	3.0%
Gas	3.7%	3.7%	3.7%
Non-Regulated	5.0%	4.8%	4.5%
TOTAL COMPANY	3.0%	3.0%	3.0%

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

	2009	2008	2007
Annual Weighted Average Depreciation Rate			
Electric fixed assets:			
Production plant	2.2%	2.2%	2.2%
Transmission plant	2.4%	2.3%	2.3%
Distribution plant	3.6%	3.6%	3.6%
General plant	6.1%	6.2%	6.1%
Water	2.7%	2.8%	2.7%
Gas	3.7%	3.7%	3.7%
Non-regulated	5.0%	4.8%	4.5%

3. Regulatory Matters

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 regulatory 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, regulatory amortization and retirement of utility plant and write-off's as authorized 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 between the time we incur costs and the time when we can start recovering the costs through rates. See Note 2 for a discussion of regulatory amortization.

Electric Segment

The following table sets forth information regarding electric and water rate increases since January 1, 2007:

Jurisdiction	Date Requested	Annual Increase Granted	Percent Increase Granted	ROE	Date Effective
Missouri — Electric	October 1, 2007	$22,040,395	6.70%	10.8%	August 23, 2008
Missouri — Electric	February 1, 2006	$29,369,397	9.96%	10.9%	January 1, 2007

Missouri

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 is primarily 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. We are currently in discussions about procedures to be used in this case, including the timing of the consideration and rate recovery of our investments in the three generating facilities and other expenditures. Due to the expected in-service delay of Iatan 2, however, we do not anticipate recovering Iatan 2 costs in this Missouri rate case. We anticipate filing a rate case at the conclusion of this case to recover the Iatan 2 costs.

2007 Rate Case

The MPSC issued an order on July 30, 2008 in response to a request filed with the MPSC on October 1, 2007 for an annual increase in base rates for our Missouri electric customers. This order granted an annual increase in revenues for our Missouri electric customers in the amount of $22.0 million, or 6.7%, based on a 10.8% return on equity. The new rates went into effect August 23, 2008.

The order contains two components. The first component provides an addition to base rates of approximately $27.7 million. This increase in base rates was partially offset by a $5.7 million reduction to regulatory amortization, which is the second component to support certain credit metrics of the overall change in revenue authorized by the MPSC. Regulatory amortization provides us additional cash through rates during the current construction cycle. This construction, which is part of our long-range plan to ensure reliability, includes the facilities at the Riverton Power Plant and Iatan 2 Power Plant, as well as environmental improvements at the Asbury Power Plant and at Iatan 1. The regulatory amortization is now approximately $4.5 million annually and is recorded as depreciation expense.

The MPSC also authorized a fuel adjustment clause for our Missouri customers effective September 1, 2008. The MPSC established a base cost for the recovery of fuel and purchased power expenses used to supply energy. The clause permits the distribution to customers of 95% of the changes in fuel and purchased power costs 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, the off-system sales margin flows back to the customer. Rates related to the recovery of fuel and purchased power costs will be modified twice a year subject to the review and approval by the MPSC. In accordance with accounting guidance for regulated activities, 95% of the difference between the actual cost 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 a 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. On April 1, 2009, we filed proposed rate schedules with the MPSC requesting an increase of $1.9 million in revenues for the under recovered fuel costs recognized for the six month period ended February 28, 2009. This increase in revenue was approved by the MPSC on May 21, 2009, became effective June 1, 2009 and is billed through our fuel adjustment clause. On October 1, 2009, we filed proposed rate schedules with the MPSC requesting a decrease of $0.8 million in revenues for the over recovered fuel and purchased power costs recognized for the six month period ended August 31, 2009.

The MPSC order in the rate case approved a Stipulation and Agreement providing for the recovery of deferred expenses of approximately $14.2 million over a five year period for the 2007 ice storms. In addition, the MPSC order required the implementation of a two-way tracking mechanism for recovery of the costs relating to the new MPSC rules on infrastructure inspection and vegetation management. The mechanism authorized by the MPSC creates a regulatory liability in any year we spend less than the target amount, which has been set at $8.6 million for our Missouri jurisdiction, and a regulatory asset if we spend more than the target amount. Any regulatory asset and liability amounts created using the tracking mechanism will then be netted against each other and taken into account in our next rate case. The MPSC also approved Stipulations and Agreements providing for the continuation of the pension and other post-retirement employee benefits tracking mechanism established in our 2006 and 2007 Missouri rate orders.

The MPSC issued its Report and Order on July 30, 2008, effective August 9, 2008. The OPC and intervenors Praxair, Inc. and Explorer Pipeline Company filed applications for rehearing with the MPSC regarding this order. On August 12, 2008, the MPSC issued its Order Granting Expedited Treatment and Approving Compliance Tariff Sheets, effective August 23, 2008, in which the MPSC approved our tariff sheets containing our base rates for service rendered on and after August 23, 2008, and approved our fuel adjustment clause tariff sheets effective September 1, 2008. On September 3, 2008, the MPSC denied all pending applications for rehearing.

On October 2, 2008, the OPC and intervenors Praxair, Inc. and Explorer Pipeline Company filed Petitions for Writ of Review with the Cole County Circuit Court. These actions were consolidated into one proceeding, briefs were filed and the Cole County Circuit Court heard oral arguments on September 29, 2009. The Cole County Circuit Court issued a ruling on December 31, 2009, affirming the Commission's Report and Order. OPC, Praxair and Explorer Pipeline have filed appeals with the Western District Court of Appeals.

2006 Rate Case

All pending applications for rehearing in our Missouri 2006 rate case were denied by the MPSC on November 20, 2008. On December 15, 2008, the OPC filed a Petition for Writ of Review with the Cole County Circuit Court regarding the MPSC's decisions in our 2006 rate case. Praxair and Explorer Pipeline filed a Petition for Writ of Review on December 19, 2008. These actions were consolidated into one proceeding. Briefs were filed by all parties and oral arguments were held on June 2, 2009. The Cole County Circuit Court issued a ruling on December 8, 2009, affirming the MPSC's order. OPC, Praxair and Explorer Pipeline have filed appeals with the Western District Court of Appeals.

On May 13, 2009, the OPC filed a petition in the Jasper County Circuit Court seeking refunds with regard to utility rates for electric service paid by our customers during the period of January 1, 2007 to December 13, 2007. During this period, we charged the rates set forth in the tariffs which were approved by, and are on file with, the MPSC. We filed a motion to dismiss, or, in the alternative, motion for more definitive statement. On September 3, 2009, the Jasper County Circuit Court dismissed the petition with prejudice. On October 7, 2009, the OPC appealed the Jasper County Circuit Court decision to the Missouri Court of Appeals — Southern District. The initial brief was filed by the OPC on January 11, 2010. We filed a response brief on February 5, 2010.

Kansas

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 is 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. We anticipate new rates will go into effect in July 2010.

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%. We have entered into a Stipulated Agreement, which was approved by the MPSC, for an increase of $2.6 million. Pursuant to the Agreement, new rates will go into effect on April 1, 2010.

COMPETITION

Electric Segment

SPP-RTO

Energy Imbalance Services: On February 1, 2007, the Southwest Power Pool (SPP) regional transmission organization (RTO) launched its energy imbalance services market (EIS). In general, the SPP RTO EIS market 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 and its members have been evaluating the costs and benefits on expanding the EIS market into a full day ahead energy market with a co-optimized ancillary services market, which will include the consolidation of all SPP balancing authorities, including ours, into a single SPP balancing authority. 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) and implement the complete Day-Ahead Market as soon as practical, which is anticipated in late 2013 or early 2014. As part of the Day-Ahead Market, 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 us, which is expected to provide operational and economic benefits for us and our customers. The implementation of the Day-Ahead Market will replace the existing EIS market, which to date has, and is expected to continue to, provide benefits for our customers.

SPP Regional Transmission Development: On August 15, 2008, the SPP filed with the FERC proposed revisions to its open access transmission pro forma tariff (OATT) to establish a process for including a "balanced portfolio" of economic transmission upgrades in the annual SPP Transmission Expansion Plan. The cost of such upgrades will be recovered through a regional rate allocated to SPP members based on their load ratio share within SPP's market area of the balanced portfolio's cost. On October 16, 2008, the FERC accepted the balanced portfolio approach, which sets forth the selection process of a group of projects and regional cost allocation rules based on projected benefits and allocated costs over a ten year period. The plan will be balanced if the portfolio is cost beneficial for each zone, including ours, within the SPP. A balanced portfolio could include projects below the 345 kv level (which is the bright line voltage level for projects to be included in the portfolio) to increase benefits to a particular zone to achieve balance of benefits and costs over the ten year study period. On April 28, 2009, the SPP RSC and the SPP BOD approved the first set of balanced portfolio extra high voltage transmission projects to be constructed within the SPP region. The transmission expansion projects, totaling over $700 million, include projects in Missouri, Kansas, Arkansas, Oklahoma, Nebraska and Texas. We anticipate this set of transmission expansion projects will provide long term benefits to our customers yet expect our share of the net allocated costs to be immaterial. Also on April 28, 2009, the SPP RSC and BOD approved a new report that recommends restructuring of the SPP's regional planning processes, which would establish an integrated planning process for reliability, transmission service and economic transmission projects, based on a new set of planning principles that focus on the construction of a more robust transmission system large enough in both scale and geography to provide flexibility to meet SPP members' and customers' future needs. We will actively participate in the development of these new processes as well as cost allocation and recovery issues with members, prospective customers and the state commission representatives to the SPP RSC. 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. The new cost allocation method will be filed at the FERC in the second quarter of 2010. We continue to evaluate the cost and benefit impacts and our position on the new cost allocation method to determine whether it will provide sufficient long term benefits to our customers or require modifications through the FERC approval process.

FERC Market Power Order

On March 3, 2005, the FERC issued an order commencing an investigation to determine if we had market power within our control area based on our failure to meet one of the FERC's wholesale market share screens. We filed responses to that order in May and June 2005 and in early January 2006. On August 15, 2006, the FERC issued its order accepting Empire's proposed mitigation to become effective May 16, 2005, subject to a further compliance filing as directed in the order. Relying on a series of orders issued since March 17, 2006 in other proceedings, the FERC rejected our tariff language and directed us to file revisions to our market-based tariff to provide that service under the tariff applies only to sales outside our control area. The FERC directed us to make refunds, with interest, by September 15, 2006, covering over 1,000 hourly energy sales since May 16, 2005 to numerous counterparties external to our system for wholesale sales made at market prices above the cost based prices permitted under the mitigation proposal accepted by the FERC. The refund obligation applied to certain wholesale power sales made "inside" our service area at market based rates, even though consumption of the energy occurred outside our service area.

On September 14, 2006, we filed a Request For Rehearing of the FERC's August 15, 2006 order regarding the refund and market power mitigation we had proposed. We requested a rehearing and a waiver of the refund requirement in its entirety. On April 25, 2008, the FERC issued an Order that rejected our Request For Rehearing, required a Compliance Filing of our market based rate tariff and ordered refunds with interest. We made our Compliance Filing and issued refunds totaling $340,608, including interest, on May 27, 2008. We also filed an informational refund report with the FERC on June 26, 2008.

As a result of the FERC's requirement for us to issue the aforementioned refunds and our belief that the FERC erred in its orders, on June 30, 2008 we initiated a Petition For Review of the FERC's orders on our market based rate refunds in the United States Court of Appeals for the District of Columbia Circuit (DC Circuit). We requested and received approval for a consolidation of our Petition with a similar petition by Westar Energy. On June 12, 2009, the DC Circuit denied our and Westar's Petition for FERC to review its Order requiring the refunds to be made, concluding our efforts to recover the refunds paid.

As part of our market based pricing authority, we are required to conduct a market power analysis within our service territory and within the SPP RTO region every three years. We filed our triennial market power analysis with the FERC on July 30, 2009, concluding there were no material changes to our market position. As a result, we do not anticipate any changes to our existing market based rate authority. The FERC's acceptance of our filing is pending.

Other FERC Activity

On June 21, 2007, the FERC issued an Advance Notice of Proposed Rulemaking (ANOPR) on potential reforms to improve operations in organized wholesale power markets, such as the SPP RTO in which we participate. On October 16, 2008, the FERC issued its Final Order on Wholesale Competition in Regions with Organized Electric Markets. The Final Order will affect us as it directly affects the SPP RTO. The Final Order addresses four key areas for amending its regulations in Wholesale Competition for RTOs and Independent System Operators (ISOs): (1) demand response and market pricing during periods of operating reserve shortage; (2) long-term power contracting; (3) market monitoring policies; and (4) the responsiveness of RTOs and ISOs to stakeholders and customers. We continue to be involved in the SPP RTO and our state commission discussions on compliance of these new rules.

On May 21, 2009, the FERC issued an order clarifying that, going forward, small public utilities that have been granted waiver of Order No. 889 (Open Access Same Time Information Systems (OASIS) requirement) and the Standards of Conduct for transmission operations, which includes us, are required to submit a notification filing if there has been a material change in facts that may affect the basis on which a public utility's waiver was premised. The Standards of Conduct generally govern the communications between our day to day transmission operations personnel and our day to day wholesale marketing and sales personnel. We submitted our filing on July 13, 2009 in which we believe continuation of our waiver, issued in 1997 and reaffirmed in 2004, is appropriate and reasonable. Based on the May 21, 2009 order, it is possible that the FERC will revoke our waiver which would impact communication between our transmission and wholesale marketing and sales functions and operations within our organization. As part of our filing, we sought a twelve month extension in order to comply with the Standard of Conduct requirements in the event the FERC determined that revoking our waiver was appropriate. The FERC's decision on this and other Standard of Conduct waiver filings is pending.

Gas Segment

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

Other — Rate Matters

In accordance with ASC guidance on regulated operations, we currently have deferred approximately $0.7 million of expense related to rate cases under other non-current assets and deferred charges of which $0.2 million is related to the 2007 Missouri rate case, $0.2 million is related to the Missouri electric case filed October 29, 2009 and $0.2 million is related to the Missouri gas rate case filed June 5, 2009. 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.

Regulatory Assets and Liabilities and Other Deferred Credits

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

	December 31, 2009	December 31, 2008
Regulatory Assets:		
Unrecovered purchased gas costs — gas segment — current	$ 434	$ 1,791
Unrecovered electric fuel and purchased power costs — current	338	242
Regulatory assets, current[1]	772	$ 2,033
Pension and other postretirement benefits[2]	81,171	84,926
Income taxes	49,230	34,515
Storm costs[3]	11,673	14,704
Unamortized loss on reacquired debt	12,167	13,490
Unamortized loss on interest rate derivative	2,091	2,405
Asbury five-year maintenance	1,401	1,855
Deferred Iatan construction accounting costs[4]	2,732	—
Asset retirement obligation	3,264	3,118
Unrecovered electric fuel and purchased power costs	662	
Unrecovered purchased gas costs — gas segment	—	3,787
Unsettled derivative losses — electric segment	335	1,218
Customer programs	1,255	591
System reliability — vegetation management	1,636	654
Other	637	763
Regulatory assets, long-term	168,254	162,026
TOTAL REGULATORY ASSETS	$169,026	$164,059
Regulatory Liabilities		
Costs of removal	$ 53,083	$ 43,713
Income taxes	20,678	11,126
Unamortized gain on interest rate derivative	4,051	4,221
Pension and other postretirement benefits[5]	6,415	7,042
Over recovered electric fuel and purchased power costs[6]	1,344	228
Over recovered purchased gas costs — gas segment	1,874	
Other	88	255
TOTAL REGULATORY LIABILITIES	$ 87,533	$ 66,585

(1) Reflects under recovered costs currently being recovered 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, 2009 to reflect the amortization of the regulatory assets that were recorded at the time of the acquisition of the Aquila, Inc. gas properties.

(3) Primarily reflects ice storm costs incurred in 2007 but also includes deferred wind storm costs of $0.7 million incurred in May 2009. Consistent with recent rate case treatment, we expect to recover wind storm costs over a five year period commencing when rates go into effect.

(4) Includes $0.8 million of deferred depreciation costs and $1.9 million in carrying costs related to construction accounting for Iatan 1 discussed below.

(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 costs and the Missouri EDE portion of other postretirement benefit costs. Since January 1, 2009, regulatory liabilities and corresponding expenses have been reduced by approximately $0.5 million as a result of ratemaking treatment.

(6) Primarily consists of Missouri over recovered fuel and purchased power costs for the current accumulation period September 2009 through February 2010.

On April 19, 2009, we began recording deferred Iatan construction accounting costs associated with our share of the environmental upgrades recently completed at our Iatan 1 facility subsequent to the in-service date in accordance with our regulatory plan. The effect of these deferred costs, which include depreciation and a deferred carrying charge, is reflected in regulated operating expenses, depreciation and in other interest on the statement of operations. Construction accounting, for purposes of the regulatory plan, is specific to Iatan 1 and Iatan 2 construction and allows us to defer certain charges as regulatory assets, including depreciation and carrying costs, related to operation of the facilities until the facilities are ultimately included in our rate base. The amounts deferred, which began at the in-service date for Iatan 1 and will also be deferred for Iatan 2 at its in-service date, will then be amortized over the life of the plants once they are in our rate base. The regulatory plan covers the 150 megawatt V84.3A2 combustion turbine (Unit 12) that began commercial operation on April 10, 2007 at our Riverton plant, the environmental upgrades at Asbury, which were completed in 2008, environmental upgrades at Iatan 1 and the construction of the Iatan 2 facilities.

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, 2009, the costs of all of our regulatory assets are currently being recovered except for the deferred Iatan costs discussed above, deferred wind storm costs incurred in May of 2009, and approximately $74.8 million of pension and other postretirement costs primarily related to the additional 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 4 to 26 years. The unrecovered fuel costs are generally recovered within a year following their recognition. Ice 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.

4. Common Stock

Recent Issues

On February 25, 2009, we entered into an equity distribution agreement with UBS Securities LLC (UBS). Under the terms of the agreement, as amended, we may offer and sell shares of our common stock, par value $1.00 per share, having an aggregate offering amount of up to $120 million from time to time through UBS, as sales agent. We intend to use the net proceeds from this equity distribution program to repay short-term debt and for general corporate purposes, including to fund our current construction program. During the fourth quarter of 2009, we issued and sold 2,115,149 shares of our common stock, pursuant to this program, at an average price per share of $18.51, resulting in proceeds to us of approximately $37.9 million (after payment of approximately $1.2 million in commissions to the sales agent). Since the inception of this program, in the aggregate, we have issued and sold 3,767,909 shares pursuant to the program, resulting in net proceeds to us of approximately $66.7 million.

Sales of the shares pursuant to the equity distribution agreement will be made at market prices or as otherwise agreed with UBS. Under the terms of the program agreement, we may also sell shares to UBS as principal for UBS' own account at a price agreed upon at the time of sale.

On December 12, 2007, we sold 3,000,000 shares of our common stock in an underwritten public offering for $23.00 per share. The sale resulted in net proceeds of approximately $65.8 million ($69.0 million less issuance costs of $3.2 million). The proceeds were used to pay down short-term debt incurred, in part, as a result of our ongoing construction program.

Stock Based Compensation

We have several stock-based awards and programs, which are described below. Performance based restricted stock awards, 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):

	2009	2008	2007
Compensation expense	$2,292	$1,841	$2,122
Tax benefit recognized	819	659	772

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 2008 and 2009 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.

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 2007, 2008 and 2009 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, 2009 and 2008 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,		
	2009	2008	2007
Risk-free interest rate	0.47% to 1.08%	0.37% to 0.66%	4.5% to 5.09%
Expected volatility of Empire stock	28.8%	26.6%	15.2% to 16.6%
Expected volatility of peer group stock	22.1% to 80.9%	20.5% to 68.7%	18.9% to 19.8%
Expected dividend yield on Empire stock	7.6%	6.4%	5.6% to 5.8%
Expected forfeiture rates	3%	3%	3%
Plan cycle	3 years	3 years	3 years
Fair value percentage	87.0% to 132.0%	99.0% to 124.0%	107.7% to 108.1%
Weighted average fair value per share	$21.00	$19.23	$23.02

Non-vested restricted stock awards (based on target number) as of December 31, 2009, 2008 and 2007 and changes during the year ended December 31, 2009, 2008 and 2007 were as follows:

	2009		2008		2007	
	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,	52,300	$22.64	43,400	$23.02	38,800	$22.25
Granted	13,500	$18.12	21,000	$21.92	17,700	$23.81
Awarded	(12,394)	$22.23	(6,486)	$22.77	(7,598)	$21.79
Not awarded	(1,206)	$ —	(5,614)	$ —	(5,502)	$ —
Nonvested at December 31,	52,200	$21.57	52,300	$22.64	43,400	$23.02

At December 31, 2009 and 2008, unrecognized compensation expense related to estimated outstanding awards was $0.4 million.

Stock Options

Stock options are 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 are 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. The fair value per dividend equivalent grants for 2009, 2008 and 2007 outstanding at December 31, 2009, were $3.75, $3.82 and $3.84, respectively.

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. As per Section 409A of the Internal Revenue Code, added by the American Jobs Creation Act of 2004, 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, 2009 and 2008, under a Black-Scholes methodology. The assumptions used in the valuations are shown below:

	Fair Value of Grants Outstanding at December 31,		
	2009	2008	2007
Risk-free interest rate	1.11% to 2.98%	0.85% to 1.70%	3.3% to 4.7%
Dividend yield	7.6%	6.4%	5.3% to 6.2%
Expected volatility	24.0%	24.0%	15.5% to 18.1%
Expected life in months	78	78	60
Market value	$18.73	$17.60	n/a
Weighted average fair value per option	$0.97	$0.78	$2.71

A summary of option activity under the plan during the year ended December 31, 2009, 2008 and 2007 is presented below:

	2009		2008		2007	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Outstanding at January 1,	205,600	$22.73	149,200	$23.04	135,000	$22.21
Granted	27,000	$18.12	56,400	$21.92	64,200	$23.81
Exercised	—	$ —	—	$ —	(50,000)	$21.79
Outstanding at December 31,	232,600	$22.19	205,600	$22.73	149,200	$23.04
Exercisable, end of year	85,000	$22.46	43,300	$22.67	4,200	$21.79

The aggregate intrinsic value at December 31, 2009, 2008 and 2007 was immaterial. 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 range of exercise prices for the options outstanding at December 31, 2009 was $18.12 to $23.81. The weighted-average remaining contractual life of outstanding options at December 31, 2009, 2008 and 2007 was 6.6, 7.1 and 7.6 years, respectively. As of December 31, 2009, this includes 85,000 shares at the weighted average price of $22.46, which are vested and exercisable. All others are non-vested. As of December 31, 2009 and 2008, there was $0.2 and $0.3 million, respectively, of unrecognized compensation expense related to non-vested options and related dividend equivalents granted under the plan.

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, 2009, there were 397,744 shares available for issuance in this plan.

	2009	2008	2007
Subscriptions outstanding at December 31,	68,591	48,413	40,672
Maximum subscription price	$ 14.62(1)	$ 18.57	$ 21.23
Shares of stock issued	44,265	38,803	37,686
Stock issuance price	$ 14.10	$ 18.61	$ 20.05

(1) Stock will be issued on the closing date of the purchase period, which runs from June 1, 2009 to May 31, 2010.

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

	2009	2008	2007
Weighted average fair value of grants	$ 3.26	$ 3.46	$ 3.40
Risk-free interest rate	0.48%	2.17%	4.98%
Dividend yield	7.90%	6.20%	5.43%
Expected volatility(1)	40.00%	26.00%	18.01%
Expected life in months	12	12	12
Grant date	6/1/09	6/2/08	6/1/07

(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. At December 31, 2009 and 2008, there were 112,895 and 114,725 shares accrued to directors' accounts, respectively; and 317,870 and 352,722 shares available for issuance under this plan, respectively.

	2009	2008	2007
Units accrued for service and dividends	33,024	20,979	17,849
Units redeemed for common stock	34,853	3,484	3,299

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, 2009 and 2008, there were 169,431 and 242,839 shares available to be issued, respectively.

	2009	2008	2007
Shares contributed	73,408	59,253	47,563

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. As of December 31, 2009, our retained earnings balance was $10.1 million, compared to $13.6 million at December 31, 2008 after paying out $44.8 million in dividends during 2009. A reduction of our dividend per share, partially or in whole, could have an adverse effect on our common stock price. On February 4, 2010, the Board of Directors declared a quarterly dividend of $0.32 per share on common stock payable March 15, 2010 to holders of record as of March 1, 2010.

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 March 11, 2008, we amended the EDE Mortgage in order to provide us with more flexibility to pay dividends to our shareholders by increasing the basket available to pay dividends by $10.75 million, as described above. As of December 31, 2009, this restriction did not prevent us from issuing dividends.

In addition, under certain circumstances, our Junior Subordinated Debentures, 8½% Series due 2031, reflected as a note payable to securitization trust on our balance sheet, held by Empire District Electric Trust I, an unconsolidated securitization trust subsidiary, may also restrict our ability to pay dividends on our common stock. These restrictions apply if: (1) we have knowledge that an event has occurred that would constitute an event of default under the indenture governing these junior subordinated debentures and we have not taken reasonable steps to cure the event, (2) we are in default with respect to payments of any obligations under our guarantee relating to the underlying preferred securities, or (3) we have deferred interest payments on the Junior Subordinated Debentures, 8½% Series due 2031 or given notice of a deferral of interest payments. As of December 31, 2009, there were no such restrictions on our ability to pay dividends.

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, 2009 or 2008.

Preference Stock Purchase Rights

Our shareholder rights plan provides each of the common stockholders one Preference Stock Purchase Right (Right) for each share of common stock owned. Each Right enables the holder to acquire one one-hundredth of a share of Series A Participating Preference Stock (or, under certain circumstances, other securities) at a price of $75 per one one-hundredth share, subject to adjustment. The Rights (other than those held by an acquiring person or group (Acquiring Person)), which expire July 25, 2010, will be exercisable only if an Acquiring Person acquires 10% or more of our common stock or if certain other events occur. The Rights may be redeemed by us in whole, but not in part, for $0.01 per Right, prior to 10 days after the first public announcement of the acquisition of 10% or more of our common stock by an Acquiring Person. We had 38.0 million and 33.9 million Rights outstanding at December 31, 2009 and 2008, respectively.

In addition, upon the occurrence of a merger or other business combination, or an event of the type referred to in the preceding paragraph, holders of the Rights, other than an Acquiring Person, will be entitled, upon exercise of a Right, to receive either our common stock or common stock of the Acquiring

Person having a value equal to two times the exercise price of the Right. Any time after an Acquiring Person acquires 10% or more (but less than 50%) of our outstanding common stock, our Board of Directors may, at their option, exchange part or all of the Rights (other than Rights held by the Acquiring Person) for our common stock on a one-for-one basis.

6. Long-Term Debt

At December 31, 2009 and 2008, the balance of long-term debt outstanding was as follows (in thousands):

	2009	2008
Note payable to securitization trust(1)	$ 50,000	$ 50,000
First mortgage bonds (EDE):		
8⅛% Series due 2009	—	20,000
6½% Series due 2010	50,000	50,000
7.20% Series due 2016	25,000	25,000
5.3% Pollution Control Series due 2013(2)	8,000	8,000
5.2% Pollution Control Series due 2013(2)	5,200	5,200
5.875% Series due 2037(3)	80,000	80,000
6.375% Series due 2018(3)	90,000	90,000
7.0% Series due 2024(4)	74,975	—
First mortgage bonds (EDG):		
6.82% Series due 2036(3)	55,000	55,000
	388,175	333,200
Senior Notes, 7.05% Series due 2022(2)	48,522	49,084
Senior Notes, 4½% Series due 2013(3)	98,000	98,000
Senior Notes, 6.70% Series due 2033(3)	62,000	62,000
Senior Notes, 5.80% Series due 2035(3)	40,000	40,000
Other	5,254	334
Less unamortized net discount	(774)	(891)
	691,177	631,727
Less current obligations of long-term debt	(50,587)	(20,000)
Less current obligations under capital lease	(434)	(160)
Total long-term debt	$640,156	$611,567

(1) Represented by our Junior Subordinated Debentures, 8½% Series due 2031. We may redeem some or all of the debentures at any time at 100% of their principal amount plus accrued and unpaid interest to the redemption date.

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

(3) 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.

(4) We may redeem some or all of the bonds at any time on or after April 1, 2012, at 100% of the principal amount of the bonds plus accrued and unpaid interest to the redemption date.

Debt Financing Activities

On March 27, 2009, we issued $75 million principal amount of 7% first mortgage bonds due April 1, 2024. The net proceeds (after payment of expenses) of approximately $72.6 million were used to repay short-term debt incurred, in part, to fund our current construction program.

On May 16, 2008, we issued $90 million principal amount of first mortgage bonds. The net proceeds of approximately $89.4 million, less $0.4 million of legal and other financing fees, were added to our general funds and used primarily to pay down short-term indebtedness incurred, in part, as a result of our on-going construction program.

On March 26, 2007, we issued $80 million principal amount of first mortgage bonds. The net proceeds of approximately $79.1 million, less $0.4 million of legal and other financing fees, were added to our general funds and used to pay down short-term indebtedness incurred, in part, as a result of our on-going construction program.

We have a $400 million shelf registration statement with the SEC, which became effective on August 15, 2008, covering our common stock, unsecured debt securities, preference stock, first mortgage bonds and trust preferred securities. We have received regulatory approval in all four of our state jurisdictions. Of the $400 million, $250 million is available for first mortgage bonds with $175 million remaining available after the issuance of $75 million in first mortgage bonds on March 27, 2009. We plan to use a portion of the proceeds from issuances under this shelf to fund a portion of the capital expenditures for our new generation projects.

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 twelve months ended December 31, 2009 would permit us to issue approximately $239.9 million of new first mortgage bonds based on this test with an assumed interest rate of 7.0%. 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, 2009, we had retired bonds and net property additions which would enable the issuance of at least $644.8 million principal amount of bonds if the annual interest requirements are met. As of December 31, 2009, we are in compliance with all restrictive covenants of the EDE Mortgage.

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, 2009, these tests would not allow us to issue new first mortgage bonds.

The carrying amount of our total debt exclusive of capital leases at December 31, 2009 was $688 million compared to a fair market value of approximately $695 million. The carrying amount of our total debt exclusive of capital leases as of December 31, 2008 was $631.4 million, compared to a fair value of approximately $563.8 million. These estimates were based on 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 year-end or that will be realizable in the future.

Long-Term Debt Payout Schedule (Excluding Unamortized Discount (in thousands)	Payments Due By Period			
	Total	Note Payable to Securitization Trust	Regulated Entity Debt Obligations	Capital Lease Obligations
2010	$ 51,021	$ —	$ 50,587	$ 434
2011	763	—	613	150
2012	795	—	641	154
2013	111,780	—	111,616	164
2014	131	—	—	131
Thereafter	527,461	50,000	475,497	1,964
Total long-term debt obligations	691,951	$50,000	$638,954	$2,997
Less current obligations and unamortized discount	51,795			
Total long-term debt	$640,156			

7. Short-Term Borrowings

At December 31, 2009, total short-term borrowings consisted of $18.5 million in commercial paper and $32 million in borrowings from our line of credit. Short-term borrowings outstanding averaged $68.9 million and $47.7 million daily during 2009 and 2008, respectively, with the highest month-end balances being $123.0 million and $102.0 million, respectively. The weighted average interest rates during 2009 and 2008 were 1.63% and 3.89% in each period. The weighted average interest rate of borrowings outstanding at December 31, 2009 and 2008 was 1.05% and 2.96%, respectively.

On March 11 2009, we entered into a $50 million unsecured credit agreement. This agreement provides for $50 million of revolving loans to be available to us for working capital, general corporate purposes and to back-up our use of commercial paper and terminates on July 15, 2010. This credit agreement is in addition to, and has substantially identical covenants and terms as (other than pricing), our Second Amended and Restated Unsecured Credit Agreement dated January 26, 2010 discussed below. There were no borrowings under this agreement at December 31, 2009.

On July 15, 2005, we entered into a $150 million unsecured revolving credit facility which was scheduled to terminate on July 15, 2010. On March 14, 2006, we entered into the First Amended and Restated Unsecured Credit Agreement which amended and restated the $150 million unsecured revolving credit facility. The principal amount of the credit facility was increased to $226 million, with the additional $76 million allocated to support a letter of credit issued in connection with our participation in the Plum Point Energy Station project. This extra $76 million of availability reduces over a four year period in line with the amount of construction expenditures we owe for Plum Point Unit 1 and was $8.5 million as of February 1, 2010. On January 26, 2010, we entered into the Second Amended and Restated Unsecured Credit Agreement which amended and restated this facility again. This agreement extends the termination date of the revolving credit facility from July 15, 2010 to January 26, 2013. 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 increased from 0.80% to 2.70%. A facility fee is payable quarterly on the full amount of the commitments under the facility and a usage fee is payable on the full amount of the commitments under the facility for any period in which we have drawn less than 33% of the total revolving commitments under the facility, in each case based on our current credit ratings. In addition, upon entering into the amended and restated facility, we paid an upfront fee to the revolving credit banks of $900,000 in the aggregate. The aggregate amount of the revolving commitments remained unchanged at $150 million and there were no other material changes to the terms of the facility. The unallocated credit facility is used for working capital, general corporate purposes and to back-up our use of commercial paper. This facility requires our total indebtedness (which does not include our note payable to the securitization trust) 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 (which includes interest on the note payable to the securitization trust) 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, 2009, we are in compliance with these ratios. 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 was $32.0 million of outstanding borrowings under this agreement at December 31, 2009 and an additional $18.5 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 that the unfunded amount of these plans will be afforded rate recovery. The tax effects of these entries, including the tax benefit of the Medicare Part D subsidy, 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, 2009, 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 minimum funding requirements of ERISA. 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.

The general market declines experienced through 2008 negatively impacted the performance of our pension assets. As a result our net pension liability increased $53.2 million in 2008. The market recovered in 2009, however our cost also increased. As a result, our net pension liability increased an additional $0.3 million in 2009. 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. We expect future pension funding commitments to increase to at least the level of our accrued cost, as required by our regulator. Our contribution is estimated at $12.0 million for 2010. For 2011, we will also be required to fund at least our accrued cost. The actual minimum funding requirements will be determined based on the results of the actuarial valuations and, in the case of 2011, the performance of our pension assets during 2010.

Expected benefit payments are as follows (in millions):

Year	Payments from Trust	Payments from Company Funds
2010	$ 7.8	$0.06
2011	8.3	0.06
2012	8.9	0.07
2013	9.5	0.08
2014	10.2	0.09
2015 – 2019	$60.1	$0.71

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.

The market declines experienced through 2008 also impacted our OPEB asset performance. Our net liability increased $15.5 million in 2008. The market recovered in 2009, however our costs also increased, resulting in a $0.4 million increase in our 2009 net liability. 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 $3.2 million in 2010.

Estimated benefit payments are as follows (in millions):

Year	Payments from Trust	Expected Federal Subsidy	Payments from Company Funds
2010	$ 2.6	$0.3	$0.1
2011	2.9	0.3	0.1
2012	3.2	0.4	0.1
2013	3.5	0.4	0.1
2014	3.8	0.4	0.2
2015 – 2019	$23.2	$2.8	$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	
	2009	2008	2009	2008	2009	2008
Benefit obligation at beginning of year	$154,377	$140,353	$2,337	$2,006	$61,950	$56,455
Service cost	4,612	3,568	61	57	1,830	1,651
Interest cost	9,876	9,048	148	137	3,907	3,617
Net actuarial (gain)/loss	8,092	8,223	92	200	3,881	2,150
Plan participant's contribution	—	—	—	—	832	782
Benefits and expenses paid	(7,902)	(6,815)	(63)	(63)	(2,885)	(2,980)
Federal subsidy	—	—	—	—	396	275
Benefit obligation at end of year	$169,055	$154,377	$2,575	$2,337	$69,911	$61,950

Reconciliation of Fair Value of Plan Assets:

	Pension		SERP		OPEB	
	2009	2008	2009	2008	2009	2008
Fair value of plan assets at beginning of year	$ 92,730	$131,939	$ —	$ —	$42,483	$52,480
Actual return on plan assets — gain/(loss)	19,748	(32,394)	—	—	6,799	(9,240)
Employer contribution	2,500	—	—	—	2,333	1,032
Benefits paid	(7,902)	(6,815)	—	—	(2,753)	(2,858)
Plan participant's contribution	—	—	—	—	803	753
Federal subsidy	—	—	—	—	371	316
Fair value of plan assets at end of year	$107,076	$ 92,730	$ —	$ —	$50,036	$42,483

Reconciliation of Funded Status:

	Pension		SERP		OPEB	
	2009	2008	2009	2008	2009	2008
Fair value of plan assets	$ 107,076	$ 92,730	$ —	$ —	$ 50,036	$ 42,483
Projected benefit obligations	(169,055)	(154,377)	(2,575)	(2,337)	(69,911)	(61,950)
Funded status	$ (61,979)	$ (61,647)	$(2,575)	$(2,337)	$(19,875)	$(19,467)

The employee pension plan accumulated benefit obligation at December 31, 2009 and 2008 is presented in the following table (in thousands):

	Pension Benefits		SERP	
	2009	2008	2009	2008
Accumulated benefit obligation	$146,826	$135,296	$1,864	$1,570

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

	Pension		SERP		OPEB	
	2009	2008	2009	2008	2009	2008
Other current liabilities	$ —	$ —	$ 62	$ 165	$ 127	$ 135
Pension and other postretirement benefit obligation	$61,979	$61,647	$2,513	$2,172	$19,748	$19,332

Net periodic benefit pension cost for 2009, 2008 and 2007, 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		
	2009	2008	2007	2009	2008	2007
Service cost	$ 4,612	$ 3,568	$ 3,492	$ 1,830	$ 1,651	$ 1,705
Interest cost	9,876	9,048	8,238	3,907	3,617	3,416
Expected return on plan assets	(10,379)	(10,729)	(10,300)	(3,843)	(3,750)	(3,398)
Amortization of prior service cost(1)	604	744	588	(1,011)	(1,011)	(1,011)
Amortization of actuarial loss(1)	3,182	1,693	2,601	869	511	1,152
Net periodic benefit cost	$ 7,895	$ 4,324	$ 4,619	$ 1,752	$ 1,018	$ 1,864

Net Periodic Pension Benefit Cost:

	SERP		
	2009	2008	2007
Service cost	$ 61	$ 57	$ 50
Interest cost	148	137	117
Expected return on plan assets	—	—	—
Amortization of prior service cost(1)	(8)	(8)	(11)
Amortization of actuarial loss(1)	103	132	146
Net periodic benefit cost	$304	$318	$302

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

Our net periodic pension benefit cost, exclusive of capitalized and deferred amounts, net of tax, as a percentage of net income for 2009, 2008 and 2007 was 9.8%, 5.9% and 6.9%, respectively.

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

		Amount Recognized			
Regulatory Assets	Beginning Balance 12/31/08	Current Year Actuarial (Gain)/Loss	Amortization of Actuarial Loss	Amortization of Prior Service (Cost)/Credit	Ending Balance 12/31/09
Pension	$67,586	(1,276)	(3,182)	(604)	$62,524
SERP	$ 1,221	92	(103)	8	$ 1,218
OPEB	$ 9,978	926	(869)	1,011	$11,046

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, 2009, and the subsequent twelve-month period (in thousands):

	Pension Benefits		SERP		OPEB	
	2009	Subsequent Period	2009	Subsequent Period	2009	Subsequent Period
Net actuarial loss	$58,948	$4,134	$1,274	$127	$18,684	$ 1,377
Prior service cost (benefit)	3,576	532	(56)	(8)	(7,638)	(1,011)
Total	$62,524	$4,666	$1,218	$119	$11,046	$ 366

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	
	2009	2008	2009	2008
Discount rate	6.00%	6.30%	6.00%	6.30%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%

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

	Pension Benefits			OPEB		
	2009	2008	2007	2009	2008	2007
Discount rate	6.30%	6.40%	5.90%	6.30%	6.40%	5.90%
Expected return on plan assets	8.50%	8.50%	8.50%	7.45%	7.45%	7.45%
Rate of compensation increase	4.50%	4.50%	4.25%	4.50%	4.50%	4.25%

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 2009 cost trend rate used to measure the expected cost of healthcare benefits and benefit obligation is 8.0%. Each trend rate decreases 0.50% through 2015 to an ultimate rate of 5.0% in 2015 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	798	(648)
Effect on post-retirement benefit obligation	8,405	(6,926)

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.

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, 2009 (in thousands):

	Fair Value Measurements as of December 31, 2009				
	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	$ —	$ 965	$ —	$ 965	0.9%
Equity securities					
U.S. equity	40,069	—	—	40,069	37.4%
International equity	13,053	—	—	13,053	12.2%
Fixed income	—	29,474	—	29,474	27.5%
Other types of investments					
Equity long/short hedge funds	—	—	23,515	23,515	22.0%
	$53,122	$30,439	$23,515	$107,076	100.0%

	Fair Value Measurements as of December 31, 2008				
	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	$ —	$ 925	$ —	$ 925	1.0%
Equity securities					
U.S. equity	31,222	—	—	31,222	33.7%
International equity	9,671	—	—	9,671	10.4%
Fixed income	—	34,743	—	34,743	37.5%
Other types of investments					
Equity long/short hedge funds	—	—	16,169	16,169	17.4%
	$40,893	$35,668	$16,169	$92,730	100.0%

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

	2009	2008
	Equity long/short hedge funds	Equity long/short hedge funds
Beginning Balance, January 1,	$16,169	$20,455
Actual return on plan assets:		
Relating to assets still held at the reporting date	2,346	(4,286)
Relating to assets sold during the period	—	—
Purchases, sales and settlements, net	5,000	—
Transfers into and (out of) Level 3	—	—
Ending Balance, December 31,	$23,515	$16,169

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, 2009:

	Fair Value Measurements as of December 31, 2009				
	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 & equivalents	$ 1,179	$ —	$ —	$ 1,179	2.4%
Fixed income					
U.S. government issues	—	9,307	—	9,307	18.6%
U.S. corporate issues	—	12,969	—	12,969	25.9%
Foreign issues	—	429	—	429	0.9%
Mutual funds — fixed income	145	—	—	145	0.3%
Equity securities					
U.S. common stocks	15,243	—	—	15,243	30.5%
Foreign Stocks	335	—	—	335	0.7%
Mutual funds — equity	10,170	—	—	10,170	20.3%
	27,072	22,705	—	49,777	
Accrued interest & dividends				259	0.4%
				$50,036	100%

	Fair Value Measurements as of December 31, 2008				
	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 & equivalents	$ 909	$ —	$ —	$ 909	2.1%
Fixed income					
U.S. government issues	—	14,121	—	14,121	33.2%
U.S. corporate issues	—	5,432	—	5,432	12.8%
Foreign issues	—	412	—	412	1.0%
Mutual funds — fixed income	191	—	—	191	0.5%
Equity securities					
U.S. common stocks	13,060	—	—	13,060	30.7%
Foreign Stocks	183	—	—	183	0.4%
Mutual funds — equity	7,611	—	—	7,611	18.0%
	21,954	19,965	—	41,919	
Accrued interest & dividends				564	1.3%
				42,483	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):

	2009	2008	2007
Current income taxes:			
Federal	$ 3,987	$12,067	$(3,788)
State	572	1,667	(540)
Total	4,559	13,734	(4,328)
Deferred income taxes:			
Federal	13,854	5,179	16,895
State	1,973	738	2,407
Total	15,827	5,917	19,302
Investment tax credit amortization	(504)	(525)	(530)
Income tax from continuing operations	19,882	19,126	14,444
Income tax from discontinued operations	—	—	39
Total income tax expense	$19,882	$19,126	$14,483

Deferred Income Taxes

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

Deferred Income Taxes	December 31, 2009	December 31, 2008
Non-current deferred tax liabilities, net	194,315	173,511
Net deferred tax liabilities	$194,315	$173,511

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

Temporary Differences	December 31, 2009	December 31, 2008
Deferred tax assets:		
Disallowed plant costs	$ 1,217	$ 1,127
Gains on hedging transactions	1,583	1,647
Plant related basis differences	19,130	14,617
Regulated liabilities related to income taxes	14,297	4,017
Pensions and other post-retirement benefits	14,558	15,027
Other	2,301	2,008
Total deferred tax assets	$ 53,086	$ 38,443
Deferred tax liabilities:		
Depreciation, amortization and other plant related differences	$191,930	$158,142
Regulated assets related to income	38,327	34,515
Loss on reacquired debt	4,496	5,000
Accumulated comprehensive income	929	1,114
Losses on hedging transactions	836	956
Deferred ice storm expenses	4,448	5,602
Deferred fuel costs	—	2,136
Amortization of intangibles	3,773	2,693
Other	2,662	1,796
Total deferred tax liabilities	247,401	211,954
Net deferred tax liabilities	$194,315	$173,511

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	2009	2008	2007
Federal statutory income tax rate	35.0%	35.0%	35.0%
Increase in income tax rate resulting from:			
State income tax (net of federal benefit)	3.1	3.1	3.1
Investment tax credit amortization	(0.8)	(0.9)	(1.1)
Effect of ratemaking on property related differences	(3.6)	(3.5)	(4.1)
Other	(1.2)	(1.2)	(2.6)
Effective income tax rate	32.5%	32.5%	30.3%

Unrecognized Tax Benefits	2009	2008	2007
Unrecognized tax benefits — January 1,	$ 2,176,000	$ 328,000	$219,000
The gross amounts of increases in unrecognized tax benefits taken during prior periods	—	1,957,000	109,000
The gross amounts of decreases in unrecognized tax benefits taken during the period relating to positions accepted by taxing authorities	—	(109,000)	—
Reductions to unrecognized tax benefits as a result of a lapse of the applicable statute of limitations	(1,270,000)	—	—
Unrecognized tax benefits — December 31,	$ 906,000	$2,176,000	$328,000

If unrecognized tax benefits are recognized, the effective tax rate would change from 32.5% to 32.1% based on recognizing approximately $0.3 million of unrecognized benefits. The Company recognized interest or penalties of $(0.1) million and $0.2 million during 2009 and 2008 respectively, related to unrecognized tax benefits in other expenses and on the balance sheet. The Company does not expect any significant changes to our unrecognized tax benefits over the next twelve months.

10. Commonly Owned Facilities

We own a 12% undivided interest in the coal-fired Unit No. 1 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, 2009 and 2008, our property, plant and equipment accounts included the amounts in the following chart (in millions):

Iatan	2009	2008
Cost of ownership in plant in service	$134.6	$50.1
Accumulated Depreciation	$ 36.6	$34.7
Expenditures[(1)]	$ 9.9	$ 9.2

(1) Operating and maintenance expenditures excluding depreciation expense.

We are entitled to 12% of the unit's available capacity and are obligated to pay for that percentage of the operating costs of the unit. KCP&L and KCP&L Greater Missouri Operations Co. (formerly Aquila) own 70% and 18% respectively, of the Unit. KCP&L operates the unit for the joint owners. In 2009 we added $54.0 million to plant in service associated with Iatan I environmental upgrades. On June 13, 2006, we entered into an agreement with KCP&L to purchase a 12% undivided ownership interest in the new coal-fired Iatan 2. During 2009 we placed in service approximately $22.9 million of common property expenditures associated with this construction project. See Note 11 for discussion regarding joint ownership in power plants under construction.

We and Westar Generating, Inc, ("WGI"), a subsidiary of Westar Energy, Inc., share joint ownership of a 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, 2009 and 2008, our property, plant and equipment accounts include the amounts in the following chart (in millions):

State Line Combined Cycle Unit	2009	2008
Cost of ownership in plant in service	$164.0	$159.0
Accumulated Depreciation	$ 40.1	$ 35.7
Expenditures(1)	$ 41.9	$ 68.8

(1) Operating and maintenance expenditures excluding depreciation expense.

All of the dollar amounts listed above represents our ownership share of costs. Each participant must provide their own financing.

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 Plaintiff crops due to inappropriate management of the levee system around Iatan, of which we are a 12% owner. No procedural schedule has been established and we are unable to predict the outcome of the law suit.

Coal, Natural Gas and Transportation Contracts

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 as follows (in millions):

Firm physical gas and transportation contracts	
January 1, 2010 through December 31, 2010	$45.4
January 1, 2011 through December 31, 2012	61.7
January 1, 2013 through December 31, 2014	36.9
January 1, 2015 and beyond	39.2

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. Due to damage incurred in March 2009 to our Asbury rail car unloading facility, we issued Force Majeure notices to our western coal suppliers and to the railroads, suspending western coal shipments. This relieved us of our contractual obligations to receive shipments of coal until the railroad unloading facility was repaired and put back in service May 13, 2009. The minimum requirements for our coal and coal transportation contracts are as follows (in millions):

Coal and coal transportation contracts	
January 1, 2010 through December 31, 2010	$24.8
January 1, 2011 through December 31, 2012	16.1
January 1, 2013 through December 31, 2014	5.0
January 1, 2015 and beyond	—

Purchased Power

We currently supplement our on-system generating capacity with purchases of capacity and energy from other utilities 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.

We have contracted with Westar Energy for the purchase of capacity and energy through May 31, 2010. Commitments under this contract total approximately $6.7 million through May 31, 2010.

We also have a long term (30 year) agreement for the purchase of capacity from the Plum Point Energy Station, a new 665-megawatt, coal-fired generating facility which is being built by Dynegy near Osceola, Arkansas. Construction began in the spring of 2006 and Dynegy reports that substantial completion is scheduled for summer 2010. We have the option to purchase an undivided ownership interest in the 50 megawatts covered by the purchased power agreement in 2015. Commitments under this contract total approximately $48.0 million through June 30, 2015. Due to the expected in-service delays of Plum Point and Iatan 2, we have arranged for sufficient alternative transmission and generating capacity to meet our expected needs for May 2010 through July 2010. The incremental costs associated with this alternative will not have a material impact on our earnings and will be subject to our fuel adjustment mechanism.

On June 25, 2007, we entered into a 20-year purchased power agreement with Cloud County Windfarm, LLC, owned by Horizon Wind Energy, Houston, Texas. Pursuant to the terms of the agreement, we will purchase all of the output from 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.

On December 10, 2004, we entered into a 20-year contract with Elk River Windfarm, LLC to purchase the energy generated at the 150-megawatt Elk River Windfarm located in Butler County, Kansas. We have contracted to purchase approximately 550,000 megawatt-hours of energy per year, or approximately 10% of our annual supply under the contract. We do not own any portion of the windfarm. Payments for wind energy from the Elk River Windfarm are contingent upon output of the facility. Annual payments can run 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 March 14, 2006, we entered into contracts to purchase an undivided interest in 50 megawatts of the Plum Point Energy Station's new 665-megawatt, coal-fired generating facility which is being built near Osceola, Arkansas. Construction began in the spring of 2006 with completion scheduled for summer 2010. Initially we will own, through an undivided interest, 50 megawatts of the project's capacity for approximately $88.0 million in direct expenditures, excluding allowance for funds used during construction (AFUDC). We spent $83.8 million through December 31, 2009 and anticipate spending an additional $3.6 million in 2010 for construction expenses related to our 50 megawatt ownership share of Plum Point Unit 1. All of our actual and estimated construction expenditures exclude AFUDC and property taxes, unless specified otherwise. We also have a long-term (30 year) purchased power agreement for an additional 50 megawatts of capacity and have the option to purchase an undivided ownership interest in the 50 megawatts covered by the purchased power agreement in 2015.

On June 13, 2006, we announced we had entered into an agreement with Kansas City Power & Light (KCP&L) to purchase an undivided ownership interest in the coal-fired Iatan 2 generating facility. We will own 12%, or approximately 100 megawatts, of the 850-megawatt unit. On January 13, 2010, KCP&L announced that, due to construction delays and unusually cold weather, it currently anticipates that the in-service date of Iatan 2 will shift approximately two months from the previous schedule into the fall of 2010. KCP&L also announced that, as the Iatan 2 project moves into the startup phase, it has commenced a cost and schedule reforecast process for Iatan 2. KCP&L notes that the results will be disclosed when the process is completed, which it currently projects to be in the second half of the first quarter of 2010. Additionally, KCP&L also stated that it presently believes there will be no material increase in the estimated construction cost range of Iatan 2.

Our share of the Iatan 2 construction expenditures is expected to be in a range of approximately $218 million to $230 million. Our share of the Iatan 2 costs through December 31, 2009 was $192.0 million. As a requirement for the air permit for Iatan 2, and to help meet requirements of the Clean Air Interstate Rule (CAIR), additional emission control equipment was installed on Iatan 1. Our share of the Iatan 1 environmental costs was $54.0 million through December 31, 2009. KCP&L reported the equipment had met regulatory in-service criteria as of April 19, 2009 and it is currently in service.

Based on a late summer in-service date, we expected base rates reflecting our investments to be in effect in late 2010 as we filed a request with the MPSC on October 29, 2009, for an annual increase in base rates for our Missouri electric customers in the amount of $68.2 million, or 19.6%. This request is primarily 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. We are currently in discussions about procedures to be used in this case, including the timing of the consideration and rate recovery of our investments in the three generating facilities and other expenditures. As a result of the delay in the project, we expect that the timing of receipt of the increase in base rates associated with Iatan 2 will be delayed.

We also filed a request with the Kansas Corporation Commission (KCC) on November 4, 2009 for an annual increase in base rates for our Kansas electric customers in the amount of $5.2 million, or 24.6%, primarily to allow us to recover capital expenditures associated with these investments. See Note 3 for additional discussion of our rate cases.

A new combustion turbine previously scheduled to be installed by the summer of 2011 will be delayed until 2014 as our generation regulation needs are being met through a combination of our existing units and the SPP energy imbalance market.

Leases

We have purchased power agreements with Cloud County Wind Farm and Elk River Wind Farm, 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 six service center properties related to our gas segment. In addition, we have capital leases for certain office equipment and a unit train for our Plum Point generating facility.

The gross amount of assets recorded under capital leases total $4.2 million at December 31, 2009.

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

Capital Leases	
2010	$ 698
2011	320
2012	315
2013	315
2014	274
Thereafter	2,737
Total minimum payments	4,659
Less amount representing maintenance	80
Net minimum lease payments	4,579
Less amount representing interest	1,582
Present value of net minimum lease payments	$2,997

Operating Leases	
2010	$1,189
2011	1,021
2012	915
2013	845
2014	815
Thereafter	3,410
Total minimum payments	$8,195

Expenses incurred related to operating leases were $1.4 million, $1.5 million and $1.4 million for 2009, 2008, and 2007, respectively, excluding payments for wind generated purchased power agreements. The accumulated amount of amortization for our capital leases was $0.4 million and $0.3 million at December 31, 2009 and 2008, 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 estimate compliance costs for any new requirements, we expect them 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, and nitrogen oxides (NOx). In the future they are also likely to include limits on emissions of mercury, and so-called greenhouse gases (GHG) such as carbon dioxide and methane.

Permits

Under the CAA we have obtained site operating permits, which are valid for five years, for each of our plants. We expect to receive renewed permits for the Asbury, State Line and Energy Center plants early in 2010.

The CAA also requires a permit, and if necessary installation of pollution control equipment, when making a major modification or a change in operation if such modification or change is likely to cause a significant net increase in regulated emissions. In May 2008, KCPL received a Federal grand jury subpoena under the CAA requesting documents relating to capital projects at Iatan 1. We own 12% of Iatan 1. We were informed by KCPL in September 2009 that the US Department of Justice does not intend to bring charges under the CAA in connection with repair work, maintenance or modifications at Iatan Unit 1.

SO2 Emissions

The CAA regulates the amount of SO2 an affected unit can emit through, among other things, a cap and trade program. Each existing affected unit has been allocated a specific number of emission allowances by the U.S. Environmental Protection Agency (EPA), each of which allows 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 2009, our SO2 emissions exceeded the annual allocations. This deficit was covered by our banked allowances. When our SO2 allowance bank is exhausted, currently estimated to be mid-2011, we will need to purchase additional SO2 allowances or build a Flue Gas Desulphurization (FGD) scrubber system at our Asbury Plant. Based on current and projected SO2 allowance prices and high-level estimated FGD scrubber construction costs ($81 million in 2010 dollars), it will likely be more economical for us to purchase SO2 allowances than to build a scrubber at the Asbury Plant. If we were to purchase SO2 allowances, we would expect their cost to be fully recoverable in our rates.

NOx Emissions

The CAA regulates the amount of NOx an affected unit can emit. Each of our affected units is in compliance with the NOx limits applicable to it as currently operated.

On January 6, 2010, the EPA proposed to lower the primary National Ambient Air Quality Standard (NAAQS) for ozone designed to protect public health and to set a secondary NAAQS for ozone designed to protect sensitive vegetation and ecosystems. The EPA intends to issue final standards by August 31, 2010. Once final standards are set, states will be required to develop State Implementation Plans (SIPs) which reflect these standards. Ozone, also called ground level smog, is formed by the mixing of NOx and Volatile Organic Compounds in the presence of sunlight.

Clean Air Interstate Rule (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 NOx in 28 states, including Missouri, where our Asbury, Energy Center, State Line and Iatan Units No. 1 and No. 2 are located and Arkansas where the Plum Point Energy Station is being constructed. Kansas is not included in CAIR and our Riverton Plant is not affected.

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.

The CAIR requires covered states (including Missouri and Arkansas) to develop SIPs to comply with specific NOx and SO2 state-wide annual budgets. Missouri and Arkansas have approved SIPs and, based on these SIPs, we believe we will have excess NOx allowances for 2010 which will be banked for future use. However, SO2 allowances must be utilized at a 2:1 ratio for our Missouri units as compared to our non-CAIR Kansas units beginning in 2010. As a result, based on current SO2 allowance usage projections, we expect to exhaust our banked allowances by mid-2011 and, as discussed above, will need to purchase additional SO2 allowances or build a scrubber at our Asbury Plant.

In order to meet CAIR requirements for Iatan 1 and to meet air permit requirements for Iatan 2, pollution control equipment has been installed on Iatan 1, including a Selective Catalytic Reduction system (SCR), FGD scrubber system and baghouse. Installation was completed in April 2009 at a cost to us of approximately $54 million excluding AFUDC. Also to meet CAIR requirements, we constructed an SCR at Asbury at a total cost of approximately $31 million excluding AFUDC.

The EPA has announced that proposed revisions to CAIR will be published in May 2010 with the final regulations expected 12-14 months after the proposal. It is not possible at this time to predict what the new requirements will be or their impact on our operations.

Mercury

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 has not issued guidance to the states regarding the vacated regulation nor recommended future actions. However, the EPA has undertaken to develop emissions standards for hazardous air pollutants including mercury from power plants under Section 112 of the CAA (maximum achievable emission standards), and indicated it intends to issue a proposed rule by March 16, 2011 and a final rule by November 16, 2011.

Based on CAMR, we installed a mercury analyzer at Asbury and installed two mercury analyzers at Riverton in 2008 in order to meet the previous monitoring compliance date of January 1, 2009 and the Phase 1 mercury emission compliance date of January 1, 2010. We continue to operate the mercury analyzers at Riverton and Asbury in accordance with the appropriate state environmental regulator's guidance.

CO2 Emissions

Our coal and gas plants, vehicles and other facilities, including EDG (our gas segment), emit carbon dioxide (CO2) and/or other greenhouse gases (GHG) 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, including EDG that equal or exceed an emission threshold of 25,000 metric tons of CO2e to report GHGs to the EPA annually. The first record keeping year is 2010 with initial reporting due in March 2011. We will report our GHG emissions as required to the EPA in 2011. In addition, on September 30, 2009, the EPA issued the proposed "Prevention of Significant Deterioration and Title V Greenhouse Gases Tailoring Rule" (Tailoring Rule) that would regulate GHG emissions from emitting sources that equal or exceed a threshold of 25,000 short tons of CO2e annually. The EPA proposes to issue the final regulation in March 2010. The EPA indicated that Title V operating permits be the vehicle for regulation for existing facilities with appropriate language inserted into the permits at renewal. New units and major modifications to existing units would be regulated under the current Prevention of Significant Deterioration provisions of the CAA. On December 7, 2009, responding to a 2007 US 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 does not itself trigger any EPA regulations, but is a necessary predicate for the EPA to proceed with the Tailoring Rule or other efforts to control GHGs.

LItigation aimed at controlling GHG emissions has increased. For example, recently the U.S. Court of Appeals for the Second Circuit and the U.S. Court of Appeals for the Fifth Circuit have ruled that certain public and private parties can pursue claims that GHG emissions constitute a public nuisance and can seek to recover alleged related damages.

Several proposed pieces of legislation regulating emission of GHGs, including cap and trade systems, are under consideration by Congress with no consensus achieved to date. It is unclear what effect, if any, final federal legislation will have on the EPA's ability to regulate GHG emissions from stationary sources.

Certain states have taken steps to develop cap and trade programs and/or other regulatory systems which may be more stringent than any federal regulations. 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.

Although there can be no guarantee and the ultimate cost of any GHG regulations can not be determined at this time, we would 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 Plant is 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. 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 is expected to revise and re-propose the regulations by mid-2010. Under the initial regulations, we did not expect costs associated with compliance to be material. We will reassess costs after the revised rules are complete.

Ash Ponds

We own and maintain coal ash ponds located at our Riverton and Asbury Power Plants. Additionally, we own a 12 percent interest in a coal ash pond at the Iatan Generating Station. The EPA has announced its intention to revise its wastewater effluent limitation guidelines under the CWA for coal-fired power plants before 2012. Once the new guidelines are issued, the EPA and states would incorporate the new standards into wastewater discharge permits, including permits for coal ash ponds. We do not have sufficient information at this time to estimate additional costs that any new standards would impose on our operations. In April and May 2009, we received Information Collection Requests from the EPA regarding our ash ponds, and have responded to such requests. All of the ash ponds are compliant with existing state and federal regulations.

The EPA has announced its intention to propose new regulations pursuant to the Federal Resource Conservation and Recovery Act governing the management and storage of coal ash wastes, and to determine whether to designate coal ash as a non-hazardous solid waste or as a hazardous waste. If the EPA designates it as a hazardous waste, coal ash would become subject to a variety of hazardous waste regulations and the cost of handling, transporting, storing and disposing of the material would increase. We cannot predict with certainty the impact of any final EPA regulations on our financial position, liquidity or results of operations at this time.

Renewable Energy

On November 4, 2008, Missouri voters approved the Clean Energy Initiative (Proposition C). This initiative requires Empire and other investor-owned utilities in Missouri to generate or purchase electricity from renewable energy sources, such as solar, wind, biomass and hydro power, at the rate of at least 2% in retail sales by 2011, increasing to at least 15% by 2021. Kansas established a renewables portfolio standard (RPS) in May 2009. Also, there are currently proposals before the U.S. Congress to adopt a national RPS which could be more strict than the Missouri or Kansas RPS.

The Kansas Corporation Commission will issue regulations to implement its RPS by May 2010. At least 25 other states have adopted RPS programs that mandate some form of renewable generation. Some of these RPS programs incorporate a trading system in which utilities are allowed to buy and sell renewable energy certificates (RECs) in order to comply. Additionally, RECs are utilized by many companies in "green" marketing efforts. REC prices are driven by various market forces. We have been selling RECs and plan to continue to sell all or a portion of the RECs associated with our contracts with

Elk River Windfarm, LLC and Cloud County Windfarm, LLC. With respect to the energy underlying the RECs that we sell, we may not claim that we are purchasing renewable energy for any purpose, including for purposes of complying with the new Missouri requirements. Over time, we expect to retain some of the renewable allowances associated with these contracts to meet Missouri's RPS. Revenues from REC sales for 2009, 2008 and 2007 were $1.7 million, $1.8 million, and $0.9 million respectively.

Gas Segment

The acquisition of our natural gas distribution assets in June 2006 involved the potential future remediation of two former manufactured gas plant (MGP) sites. 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 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.

As discussed in "Note 18 — Discontinued Operations", on September 28, 2007, we sold our 100% interest in Fast Freedom, Inc., an Internet service provider. For financial reporting purposes, it has been classified as a discontinued operation and is not included in our segment information as shown below (in thousands).

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

	For the year ended December 31				
	2009				
	Electric	Gas	Other	Eliminations	Total
Statement of Income Information:					
Revenues	$ 434,897	$ 57,314	$ 5,562	$ (605)	$ 497,168
Depreciation and amortization	48,036	2,015	1,443	—	51,494
Federal and state income taxes	18,484	572	826	—	19,882
Operating income	68,414	4,634	1,447	—	74,495
Interest income	225	403	—	(411)	217
Interest expense	43,173	3,959	57	(411)	46,778
Income from AFUDC (debt and equity)	14,131	2	—	—	14,133
Income from continuing operations	$ 39,078	$ 874	$ 1,344	$ —	$ 41,296
Capital Expenditures	$ 145,287	$ 2,256	$ 1,261	$ —	$ 148,804

	2008				
	Electric	Gas	Other	Eliminations	Total
Statement of Income Information:					
Revenues	$ 448,248	$ 65,438	$ 5,005	$ (528)	$518,163
Depreciation and amortization	50,305	1,940	1,317	—	53,562
Federal and state income taxes	17,764	987	375	—	19,126
Operating income	64,426	5,420	1,166	—	71,012
Interest income	1,162	390	—	(495)	1,057
Interest expense	39,627	3,962	204	(495)	43,298
Income from AFUDC (debt and equity)	12,508	10	—	—	12,518
Income from continuing operations	$ 37,436	$ 1,677	$ 609	$ —	$ 39,722
Capital Expenditures	$ 202,295	$ 2,139	$ 1,952	$ —	$206,386

	2007				
	Electric	Gas	Other	Eliminations	Total
Statement of Income Information:					
Revenues	$ 427,039	$ 59,877	$ 3,681	$ (437)	$ 490,160
Depreciation and amortization	49,637	1,889	1,073	—	52,599
Federal and state income taxes	13,590	572	282	—	14,444
Operating income	60,222	4,688	656	—	65,566
Interest income	562	375	—	(611)	326
Interest expense	35,782	3,957	251	(611)	39,379
Income from AFUDC (debt and equity)	7,648	17	—	—	7,665
Income from continuing operations	31,836	969	376	—	33,181
Capital Expenditures	$ 188,545	$ 2,024	$ 4,999	$ —	$ 195,568

	December 31, 2009				
	Electric	Gas(1)	Other	Eliminations	Total
Balance Sheet Information:					
Total assets	$1,759,415	$134,355	$21,907	$(75,831)	$1,839,846

	December 31, 2008				
	Electric	Gas(1)	Other	Eliminations	Total
Balance Sheet Information:					
Total assets	$1,621,502	$138,788	$22,186	$(68,630)	$1,713,846

(1) Includes goodwill of $39,492 at December 31, 2009 and 2008.

13. Selected Quarterly Information (Unaudited)

The following is a summary of quarterly results for 2009 and 2008 (dollars in thousands except per share amounts):

	Quarters			
Quarterly Results for 2009	First	Second	Third	Fourth
Operating revenues	$136,015	$112,230	$128,053	$120,870
Operating income	$ 18,655	$ 16,027	$ 23,677	$ 16,136
Net Income	$ 10,913	$ 7,627	$ 14,829	$ 7,927
Basic Earning Per Share	$ 0.32	$ 0.22	$ 0.43	$ 0.22
Diluted Earnings Per Share	$ 0.32	$ 0.22	$ 0.43	$ 0.22

	Quarters			
Quarterly Results for 2008	First	Second	Third	Fourth
Operating revenues	$136,946	$111,280	$138,685	$131,253
Operating income	14,559	12,326	28,019	16,108
Net Income	$ 6,990	$ 4,817	$ 20,180	$ 7,735
Basic Earning Per Share	$ 0.21	$ 0.14	$ 0.60	$ 0.23
Diluted Earnings Per Share	$ 0.21	$ 0.14	$ 0.59	$ 0.23

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 2009 were $7.9 million, or $0.22 per share, as compared to $7.7 million, or $0.23 per share, in the fourth quarter 2008. Total revenues decreased approximately $10.4 million (7.9%) for the fourth quarter of 2009 as compared to the fourth quarter of 2008 primarily due to milder weather in October and November of 2009 as compared to the same period in 2008. Mostly offsetting the decrease in revenues were decreased fuel and purchased power costs and decreased natural gas costs.

14. Risk Management and Derivative Financial Instruments

We currently engage in hedging activities in an effort to minimize our risk from volatile natural gas prices. We enter into 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 expense 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 gains and losses deferred in other comprehensive income (in stockholders' equity) for effective instruments related to our electric segment, entered into prior to September 1, 2008. All other instruments are deferred as a regulatory asset or liability, due to our fuel recovery mechanism, effective September 1, 2008 for our electric segment, and for our gas segment.

For instruments entered into prior to September 1, 2008, we record unrealized gains/(losses) on the ineffective portion of our gas hedging activities in "Fuel and purchased power" under the operating revenue deductions section of our Statement of Income since all of our gas hedging activities are related to stabilizing fuel costs as part of our fuel procurement program and are not speculative activities. 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.

As of December 31, 2009 and 2008, 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

		2009	2008
Derivatives designated as hedging instruments	**Balance Sheet Classification**	**Fair Value**	**Fair Value**
Natural gas contracts, electric segment	Current assets	$2,233	$1,214
	Non-current assets and deferred charges	2,438	6,208
Derivatives not designated as hedging instruments due to regulatory accounting			
Natural gas contracts, gas segment	Current assets	410	1,177
	Non-current assets and deferred charges	—	226
Natural gas contracts, electric segment	Current assets	139	4
	Non-current assets and deferred charges	87	—
Total derivatives assets		$5,307	$8,829

LIABILITY DERIVATIVES

Derivatives designated as hedging instruments	Balance Sheet Classification	2009 Fair Value	2008 Fair Value
Natural gas contracts, electric segment	Current liabilities	$4,123	$ 6,254
	Non-current liabilities and deferred credits	—	3,282
Derivatives not designated as hedging instruments due to regulatory accounting			
Natural gas contracts, gas segment	Current liabilities	214	4,474
	Non-current liabilities and deferred credits	—	20
Natural gas contracts, electric segment	Current liabilities	—	1,548
	Non-current liabilities and deferred credits	426	—
Total derivatives liabilities		$4,763	$15,578

Electric

A $0.3 million net of tax, unrealized gain representing the fair market value of our electric segment derivative contracts treated as cash flow hedges is recognized as Accumulated Other Comprehensive Income in the capitalization section of the balance sheet as of December 31, 2009. The tax effect of $0.2 million on this gain is included in deferred taxes. These amounts will be adjusted cumulatively on a monthly basis during the determination periods, beginning January 1, 2010 and ending on September 30, 2011. At the end of each determination period, or if cash flow hedge treatment is discontinued, any gain or loss for that period related to the instrument will be reclassified to fuel expense. As of December 31, 2009, approximately $1.9 million of unrealized losses are applicable to financial instruments which will settle within the next twelve months. Effective September 1, 2008, in conjunction with the implementation of the Missouri fuel adjustment clause in the July 2008 MPSC rate order, the unrealized losses or gains from new cash flow hedges are recorded in regulatory assets or liabilities. This is in accordance with ASC guidance on accounting for 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 at September 1, 2008 will continue to be recorded through comprehensive income. Once settled, the realized gain or loss will be recorded as fuel expense and be subject to the fuel adjustment clause.

The following tables set forth the actual pre-tax gains/(losses) and the mark to market effect of unsettled positions from the qualified portion of our hedging activities for settled contracts for the electric segment for each of the years ended December 31, (in thousands):

Derivatives in Cash Flow Hedging Relationships — Electric Segment

	Income Statement Classification of Gain/(Loss) on Derivative	Amount of Gain/(Loss) Reclassed from OCI into Income (Effective Portion) 2009	2008
Commodity contracts	Fuel and purchased power expense . . .	$(13,568)	$3,872
Total Effective — Electric Segment . . .		$(13,568)	$3,872

Derivatives in Cash Flow Hedging Relationships — Electric Segment

	Statement of Comprehensive Income	Amount of Gain/(Loss) Recognized in OCI on Derivative (Effective Portion) 2009	2008
Commodity contracts	Fuel and purchased power expense . . .	$9,576	$(17,394)
Total Effective — Electric Segment . . .		$9,576	$(17,394)

The following table sets forth "mark-to-market" pre-tax gains/(losses) from the ineffective portion of our hedging activities for the electric segment for each of the years ended December 31, (in thousands):

Derivatives in Cash Flow Hedging Relationships — Electric Segment

	Statement of Income Classification of Gain/(Loss) on Derivative	Amount of Gain/(Loss) Recognized in Income on Derivative- (Ineffective Portion) 2009	2008
Commodity contracts	Fuel and purchased power expense .	$ —	$32
Total Ineffective — Electric Segment . . .		$ —	$32

In accordance with the Missouri fuel adjustment clause discussed above, the recoverable portion of any gain or loss is recorded in a regulatory asset or liability account. The following tables set forth "mark-to-market" pre-tax gains/ (losses) from derivatives not designated as hedging instruments for the electric segment for each of the years ended December 31, (in thousands):

Derivatives Not Designated as Hedging Instruments — Due to Regulatory Accounting Electric Segment

	Balance Sheet Classification of Gain/(Loss) on Derivative	Amount of Gain/(Loss) Recognized on Balance Sheet 2009	2008
Commodity contracts — electric segment	Regulatory (assets)/liabilities	$1,192	$(1,215)
Total — Electric Segment . . .		$1,192	$(1,215)

Derivatives Not Designated as Hedging Instruments — Due to Regulatory Accounting Electric Segment[(1)]

	Statement of Operations Classification of Gain/(Loss) on Derivative	Amount of Gain/(Loss) Recognized in Income on Derivative 2009	2008
Commodity contracts	Fuel and purchased power expense	$ (2,249)	$ (329)
Total — Electric Segment		$ (2,249)	$ (329)

(1) All of our gas hedging activities are related to stabilizing fuel costs as part of our fuel procurement program and are not speculative activities. If conditions change, such as a planned unit outage, we may need to de-designate and/or unwind some of our previous derivatives. In this instance, these derivatives would be classified into the category above.

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 are not derivatives because they are considered to be normal purchases. We have a process in place to determine if any future executed contracts that otherwise qualify for the normal purchases exception contain a price adjustment feature and will account for these contracts accordingly.

As of February 5, 2010, 77% of our anticipated volume of natural gas usage for our electric operations for the year 2010 is hedged, either through physical (3.5 million Dths) or financial contracts (3.0 million Dths), at an average price of $6.322 per Dekatherm (Dth). In addition, the following volumes and percentages of our anticipated volume of natural gas usage for our electric operations for the next three years are hedged at the following average prices per Dth:

Year	% Hedged	Dth Hedged	Average Price
2011[(1)]	71%	5,115,000	$5.840
2012[(1)]	40%	3,085,000	$7.016
2013	17%	1,200,000	$7.295

(1) 2.0 million Dth and 1.4 million Dth of the anticipated volume of natural gas usage for 2011 and 2012, respectively, are hedged through financial derivative contracts.

We utilize the following procurement guidelines for our electric segment: current year up to 100% of expected gas usage, first year minimum of 60%, second year minimum of 40%, third year minimum of 20% and fourth year minimum of 10%, subject to a maximum of 80% of the expected gas usage in any one year.

On February 15, 2008, we unwound 992,000 Dth of physical gas contracts originally scheduled for delivery in July and August of 2010 and 2011. This transaction resulted in a gain of approximately $1.3 million after tax which was recorded as a reduction to fuel and purchased power expense in the Statement of Income in the first quarter of 2008. We believe it is probable that we will take physical delivery under the remaining physical gas forward contracts.

As of June 30, 2007, we elected to change our valuation of natural gas derivatives (financial hedges) for financial reporting purposes to a new methodology which is more closely related to an independent market valuation. For accounting purposes, this change is considered a change in estimate. To reflect the change, an increase of approximately $6 million was recorded to the fair value of derivatives and $3.7 million, net of tax, was recorded to other comprehensive income at June 30, 2007. This change had no impact on the income statement.

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. As of February 5, 2010, we have 91% of our expected remaining winter heating season usage (through March 2010) hedged with physical storage, physical forward contracts and financial derivative contracts. The average price of these hedges is $3.948 per Dth. 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 February 7, 2010, we had 0.70 million Dths in storage on the three pipelines that serve our customers. This represents 33% of our storage capacity. We have an additional 0.6 million Dth hedged through financial derivatives and physical contracts. Our long-term hedge strategy is to mitigate price volatility for our customers by hedging a minimum of 50% of current year, up to 50% of second year and up to 20% of third year expected gas usage by the beginning of the Actual Cost Adjustment (ACA) year at September 1. 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):

Derivatives Not Designated as Hedging Instruments Due to Regulatory Accounting — Gas Segment

	Balance Sheet Classification of Gain or (Loss) on Derivative	Amount of Gain/(Loss) Recognized on Balance Sheet 2009	2008
Commodity contracts	Regulatory (assets)/liabilities	$(671)	$(8,939)
Total — Gas Segment		$(671)	$(8,939)

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, 2009 is $2.4 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, 2009, we would have been required to post $0.4 million of collateral with one of our counterparties. On December 31, 2009, 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 provided by a third party that are derived principally from or corroborated by observable market data by correlation. Our Level 3 fair value measurements consist of both quoted price inputs and unobservable quoted inputs provided by a third party.

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 derivative assets measured at fair value using the market value approach on a recurring basis as of December 31, 2009:

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, 2009				
Net derivative assets/(liabilities)*	$ 544	$ 544	—	—
December 31, 2008				
Net derivative assets/(liabilities)*	$(6,749)	$(14,117)	$1,160	$6,208

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

The following tables present the net fair value on a recurring basis using significant unobservable inputs (Level 3) during the twelve months ended December 31, 2009 and 2008 (in thousands):

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)

($ in 000's)	2009 Net Derivatives[1]	2008 Net Derivatives[1]
Beginning Balance, January 1,	$ 6,208	$11,961
Total gains or losses (realized/unrealized)		
Included in earnings (or changes in net assets)	—	—
Included in comprehensive income	(1,738)	(5,753)
Purchases, issuances, and settlements, net	—	—
Transfers in and/or out of Level 3	(4,470)	—
Ending Balance, December 31,	$ —	$ 6,208
Changes in unrealized Gains (Losses) relating to assets still held at reporting date	$ 1,738	$ 5,753

(1) Net derivatives at December 31, 2009 and 2008 included zero and $6.2 million in derivative assets and no derivative liabilities, respectively.

16. Accounts Receivable — Other

The following table sets forth the major components comprising "accounts receivable — other" on our consolidated balance sheet (in thousands):

	December 31, 2009	December 31, 2008
Accounts receivable for meter loops, meter bases, line extensions, highway projects, etc.	$ 2,812	$ 803
Accounts receivable for gas segment	37	76
Accounts receivable for non-regulated subsidiary companies	454	287
Accounts receivable from Westar Generating, Inc., for commonly-owned facility	817	1,673
Taxes receivable — overpayment of estimated income taxes	3,191	4,503
Accounts receivable for energy trading margin deposit[1]	2,914	10,768
Accounts receivable for true-up on maintenance contracts[2]	1,831	1,138
Accounts receivable for insurance proceeds for SLCC generator failure[3]	9,270	—
Other	91	105
Total Accounts Receivable — Other	$21,417	$19,353

(1) The accounts receivable for energy trading margin deposit represents the balance in our brokerage account. NYMEX futures contracts are used in our hedging program of natural gas which require posting of margin.

(2) Represents quarterly estimated credits due from Siemens Westinghouse related to our maintenance contract for State Line Combined Cycle Unit (SLCC). Forty percent of this credit belongs to Westar Generating, Inc., the owner of 40% of the SLCC, and has been recorded in accounts payable.

(3) Represents the insurance proceeds for the failure of the State Line Combined Cycle Unit 2-1 generator. Forty percent of these proceeds belong to Westar Generating, Inc., and is recorded in accounts payable.

17. 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,		
	2009	2008	2007
Electric transmission and distribution expense	$11,063	$10,891	$ 9,465
Natural gas transmission and distribution expense	2,161	1,995	1,755
Power operation expense (other than fuel)	12,315	11,671	10,417
Customer accounts & assistance expense	10,597	10,166	9,198
Employee pension expense[(1)]	5,557	5,892	6,553
Employee healthcare plan[(1)]	5,908	7,136	7,899
General office supplies and expense	10,070	9,330	10,294
Administrative and general expense	12,211	11,728	10,872
Bad debt expense	3,125	2,944	4,673
Miscellaneous expense	79	165	241
Total	$73,086	$71,918	$71,367

(1) Does not include capitalized portion of costs, but reflects the GAAP expensed cost plus or minus costs deferred to a regulatory asset or recognized as a regulatory liability for Missouri and Kansas jurisdictions.

18. Discontinued Operations

On September 28, 2007, we sold our 100% interest in Fast Freedom, Inc., an Internet service provider. We have reported its results as discontinued operations. A summary of the components of losses from discontinued operations for the year ended December 31, 2007 follows (in thousands):

2007	Fast Freedom
Revenues	$ 905
Expenses	1,063
Losses from discontinued operations before income taxes	(158)
Gain on disposal	161
Income tax	60
Gain from Discontinued Operations	$ 63

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, 2009.

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, 2009.

Audit of Internal Control Over Financial Reporting

The effectiveness of our internal control over financial reporting as of December 31, 2009, 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 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Except as set forth below, the information required by this Item may be found in our proxy statement for our Annual Meeting of Stockholders to be held April 29, 2010, 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 29, 2010, 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 29, 2010, 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, 2009:

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	518,486	$20.47	1,330,680
Equity compensation plans not approved by security holders	—	—	—
TOTAL	518,486	$20.47	1,330,680

(1) The weighted average exercise price of $20.47 relates to 39,100 and 4,200 options granted to executive officers in 2005 and 2004, respectively, under the 1996 Stock Incentive Plan, 27,000, 56,400, 64,200 and 41,700 options granted to executive officers in 2009, 2008, 2007 and 2006, respectively, under the 2006 Stock Incentive Plan and 68,591 subscriptions outstanding for our ESPP. The two stock incentive plans had a weighted average exercise price of $22.19 and the ESPP had an exercise price of $14.62. There is no exercise price for 104,400 performance-based stock awards awarded under the 2006 Stock Incentive Plans or for 112,895 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 29, 2010 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 29, 2010 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-Second Supplemental Indenture dated as of November 1, 1993 to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4(k) to Annual Report on Form 10-K for the year ended December 31, 1993, File No. 1-3368).

(f) Twenty-Third Supplemental Indenture dated as of November 1, 1993 to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4(l) to Annual Report on Form 10-K for the year ended December 31, 1993, File No. 1-3368).

(g) 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).

(h) 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).

(i) Twenty-Ninth Supplemental Indenture dated as of April 1, 1998 to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4 to Form 10-Q for quarter ended March 31, 1998, File No. 1-3368).

(j) 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).

(k) 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).

(l) 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).

(m) Thirty-Fourth Supplemental Indenture, dated as of March 27, 2009, to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated March 27, 2009 and filed March 30, 2009, File No. 1-3368).

(n) 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).

(o) Securities Resolution No. 2, dated as of February 22, 2001, of Empire under the Indenture for Unsecured Debt Securities (Incorporated by reference to Exhibit 4(s) to Annual Report on Form 10-K for the year ended December 31, 2000, File No. 1-3368).

(p) Securities Resolution No. 3, dated as of December 18, 2002, of Empire under the Indenture for Unsecured Debt Securities (Incorporated by reference to Exhibit 4(s) to Annual Report on Form 10-K for year ended December 31, 2002, File No. 1-3368).

(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) Rights Agreement dated as of April 27, 2000 between Empire and Wells Fargo Bank, N.A. (as successor to Chase Mellon Shareholder Services LLC) (Incorporated by reference to Exhibit 4 to Quarterly Report on Form 10-Q for the quarter ended March 31, 2000, File No. 1-3368).

(u) Bond Purchase Agreement dated June 1, 2006 among The Empire District Gas Company and the purchasers party thereto (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated June 1, 2006 and filed June 6, 2006, File No. 1-3368).

(v) Indenture of Mortgage and Deed of Trust dated as of June 1, 2006 by The Empire District Gas Company, as Grantor, to Spencer R. Thomson, Deed of Trust Trustee for the Benefit of The Bank of New York Trust Company, N.A., Bond Trustee, as Grantee (Incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K dated June 1, 2006 and filed June 6, 2006, File No. 1-3368).

(w) First Supplemental Indenture of Mortgage and Deed of Trust dated as of June 1, 2006 by The Empire District Gas Company, as Grantor, to Spencer R. Thomson, Deed of Trust Trustee for the Benefit of The Bank of New York Trust Company, N.A., Bond Trustee, as Grantee (Incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K dated June 1, 2006 and filed June 6, 2006, File No. 1-3368).

(10)(a) 1996 Stock Incentive Plan (Incorporated by reference to Exhibit 4.1 to Form S-8, File No. 33-64639).†

(b) First Amendment to 1996 Stock Incentive Plan. (Incorporated by reference to Exhibit 10(b) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(c) 2006 Stock Incentive Plan (Incorporated by reference to Exhibit 4(u) to Form S-8, File No. 333-130075).†

(d) First Amendment to 2006 Stock Incentive Plan. (Incorporated by reference to Exhibit 10(d) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(e) Second Amendment to 2006 Stock Incentive Plan (Incorporated by reference to Exhibit 10(e) to Annual Report on Form 10-K for the year ended December 31, 2008, File No. 1-3368).†

(f) Deferred Compensation Plan for Directors as amended and restated effective January 1, 2008. (Incorporated by reference to Exhibit 10(e) to Annual Report on Form 10-K for the year ended December 31, 2007). †

(g) The Empire District Electric Company Change in Control Severance Pay Plan as amended and restated effective January 1, 2008. (Incorporated by reference to Exhibit 10(f) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(h) Form of Severance Pay Agreement under The Empire District Electric Company Change in Control Severance Pay Plan. (Incorporated by reference to Exhibit 10(g) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(i) The Empire District Electric Company Supplemental Executive Retirement Plan as amended and restated effective January 1, 2008. (Incorporated by reference to Exhibit 10(h) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(j) Retirement Plan for Directors as amended August 1, 1998 (Incorporated by reference to Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 1998, File No. 1-3368).†

(k) Stock Unit Plan for Directors of The Empire District Electric Company (Incorporated by reference to Exhibit 10(i) to Annual Report on Form 10-K for the year ended December 31, 2005, File No. 1-3368).†

(l) First Amendment to Stock Unit Plan for Directors. (Incorporated by reference to Exhibit 10(k) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(m) Summary of Annual Incentive Plan. (Incorporated by reference to Exhibit 10(l) to Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-3368).†

(n) Form of Notice of Award of Dividend Equivalents. (Incorporated by reference to Exhibit 10(n) to Annual Report on Form 10-K for the year ended December 31, 2008, File No. 1-3368)†

(o) Form of Notice of Award of Non-Qualified Stock Options. (Incorporated by reference to Exhibit 10(o) to Annual Report on Form 10-K for the year ended December 31, 2008, File No. 1-3368).†

(p) Form of Notice of Award of Performance-Based Restricted Stock. (Incorporated by reference to Exhibit 10(p) to Annual Report on Form 10-K for the year ended December 31, 2008, File No. 1-3368).†

(q) Summary of Compensation of Non-Employee Directors. (Incorporated by reference to Exhibit 10(q) to Annual Report on Form 10-K for the year ended December 31, 2008, File No. 1-3368).†

(r) 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).†

(s) Equity Distribution Agreement dated February 25, 2009 between The Empire District Electric Company and UBS Securities LLC (Incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K dated February 25, 2009 and filed February 26, 2009, File No. 1-3368).

(t) Amendment No. 1, dated October 22, 2009 to the Equity Distribution Agreement dated February 25, 2009 between The Empire District Electric Company and UBS Securities LLC (Incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K dated October 22, 2009 and filed October 22, 2009, File No. 1-3368).

(u) Unsecured Credit Agreement dated as of March 11, 2009, 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 March 11, 2009 and filed March 12, 2009, File No. 1-3368).

(v) Second Amended and Restated Unsecured Credit Agreement dated as of January 26, 2010, 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 26, 2010 and filed January 27, 2010, 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.*~

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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.

~ 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, 2009, 2008 and 2007:

	Balance At Beginning Of Period	Additions: Charged To Income	Additions: Charged to Other Accounts: Description	Additions: Charged to Other Accounts: Amount	Deductions From Reserve: Description	Deductions From Reserve: Amount	Balance At Close of Period
Year ended **December 31, 2009**:							
Reserve deducted from assets: accumulated provision for uncollectible accounts.	$1,265,421	$3,109,679	Recovery of amounts previously written off	$1,531,820	Accounts written off	$4,820,067	$1,086,853
Year ended **December 31, 2008**:							
Reserve deducted from assets: accumulated provision for uncollectible accounts.	$1,140,955	$2,903,922	Recovery of amounts previously written off	$1,877,576	Accounts written off	$4,657,032	$1,265,421
Year ended **December 31, 2007**:							
Reserve deducted from assets: accumulated provision for uncollectible accounts.	$1,180,577	$4,661,439	Recovery of amounts previously written off	$1,203,544	Accounts written off	$5,904,605	$1,140,955

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 19, 2010

By /s/ WILLIAM L. GIPSON

William L. Gipson, 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 19, 2010

/s/ WILLIAM L. GIPSON

William L. Gipson, President,
Chief Executive Officer, Director
(Principal Executive Officer)

/s/ GREGORY A. KNAPP

Gregory A. Knapp, Vice President-Finance
(Principal Financial Officer)

/s/ LAURIE A. DELANO

Laurie A. Delano, Controller, Assistant
Secretary and Assistant Treasurer
(Principal Accounting Officer)

/s/ DR. JULIO S. LEON*

Dr. Julio S. Leon, Director

/s/ KENNETH R. ALLEN*

Kenneth R. Allen, Director

/s/ PAUL R. PORTNEY*

Paul R. Portney, Director

/s/ ROSS C. HARTLEY*

Ross C. Hartley, Director

/s/ D. RANDY LANEY*

D. Randy Laney, Director

/s/ BILL D. HELTON*

Bill D. Helton, Director

/s/ B. THOMAS MUELLER*

B. Thomas Mueller, Director

/s/ ALLAN T. THOMS*

Allan T. Thoms, Director

/s/ BONNIE C. LIND*

Bonnie C. Lind, Director

/s/ GREGORY A. KNAPP

*By (Gregory A. Knapp, As attorney in fact for
each of the persons indicated)

Computation of Ratios of Earnings to Fixed Charges

	Year ended December 31,				
	2009	**2008**	**2007**	**2006**	**2005**
Income before provision for income taxes and fixed charges (Note A)	**$114,457,760**	$108,185,260	$91,690,922	$99,409,515	$65,781,250
Fixed Charges:					
Interest on long-term debt	**$ 42,084,023**	$ 36,040,957	$31,120,122	$25,947,191	$24,059,165
Interest on short-term debt	**1,124,883**	1,853,682	2,940,317	2,275,939	195,197
Interest on note payable to securitization trust	**4,250,000**	4,250,000	4,250,000	4,250,000	4,250,000
Other interest	**(680,863)**	1,152,588	1,069,206	1,029,135	605,492
Rental expense representative of an interest factor (Note B)	**6,501,484**	6,040,062	4,686,748	4,798,490	659,844
Total fixed charges	**$ 53,279,527**	$ 49,337,289	$44,066,393	$38,300,755	$29,769,698
Ratio of earnings to fixed charges	**2.15**	2.19	2.08	2.60	2.21

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, minority interest 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, William L. Gipson, 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 19, 2010

By: /s/ William L. Gipson

Name: William L. Gipson
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, Gregory A. Knapp, 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 19, 2010

By: /s/ Gregory A. Knapp

Name: Gregory A. Knapp
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, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), William L. Gipson, 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/ William L. Gipson

Name: William L. Gipson
Title: President and Chief Executive Officer

Date: February 19, 2010

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, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Gregory A. Knapp, 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/ Gregory A. Knapp

Name: Gregory A. Knapp
Title: Vice President — Finance and Chief Financial Officer

Date: February 19, 2010

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 29, 2010, at 10:30 a.m., CDT, at the Memorial Hall, 212 West 8th Street, 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)
www.wellsfargo.com/shareownerservices (for general inquiries)

Stock Trading
As of December 31, 2009, there were 5,060 common shareholders of record. Empire stock is listed on the New York Stock Exchange under the following ticker symbols:

EDE	Common Stock
EDE PrD	Trust Preferred Securities of Empire District Electric Trust I

Stock Prices and Dividends

2009	Quarter	High	Low	Dividend Paid
	First	$18.51	$11.92	$0.32
	Second	$16.66	$14.19	$0.32
	Third	$19.00	$16.44	$0.32
	Fourth	$19.36	$17.78	$0.32

2008	Quarter	High	Low	Dividend Paid
	First	$23.29	$19.33	$0.32
	Second	$21.88	$18.30	$0.32
	Third	$23.48	$18.37	$0.32
	Fourth	$21.60	$14.90	$0.32

Credit Ratings

	Standard & Poor's	Moody's	Fitch
Corporate Credit Rating	BBB-	Baa2	N/R*
First Mortgage Bonds	BBB+	Baa1	BBB+
Commercial Paper	A-3	P-2	F2
Senior Notes	BBB-	Baa2	BBB
Trust Preferred Securities	BB	Baa3	BB+
Outlook	Stable	Negative	Negative

*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.
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St. Paul, Minnesota 55164-0856
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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, 2009.

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

www.empiredistrict.com

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