Annual Report 2007

The Empire District Electric Company

Fellow Shareholders,

In 2007 we continued to make progress as we set in place major components of the business plan designed to take us into 2010 and beyond. We are adding capacity to meet the projected growth of our customers' demand for power and diversifying our energy supply. We are installing technologies that will allow us to produce cleaner energy. We are positioning ourselves to use our own generation to replace energy that we currently supply through a purchased power contract expiring in 2010.

But even as we held our focus on our long-term goals, we dealt with the effects of some short-term challenges in an otherwise good year. Asbury's five-year turbine inspection and three atypical events—the two worst ice storms in our 98-year history and an unexpected extension of the outage at Asbury—increased our costs by approximately $17.6 million, giving significant negative impact to earnings per share.

Earnings per share for 2007 were $1.09, down from $1.39 in 2006. Of this amount, electric operations contributed $1.04, down from $1.45 in 2006; gas operations contributed $0.035, up from $(0.03); and the segment designated as "other" contributed $0.015, up from $(0.03).

Mother Nature's wrath times two, plus an extended outage. Mother Nature hit us twice in 2007 and hit hard. Major ice storms struck first in January, then again in December. At the height of the January storm, more than half our customers had lost power. The December storm, slightly less intense, left nearly 40 percent without electricity. In both cases, the damage occurred throughout our often rural, 10,000-square-mile territory, further complicating recovery efforts.

A 10-week scheduled outage at the Asbury Plant was prolonged by roughly eight weeks when a generator undergoing five-year maintenance failed inspection in December. During the outage, we were required to use less cost-effective generation and purchased power. This helped drive an increase in our 2007 fuel and purchased power costs of about 19.3 percent over 2006 levels. Because the outage extended into the new year, it will impact expenses for the first quarter of 2008.

So we heaved a sigh of relief when Asbury made its much anticipated return to service on February 10, 2008. The facility is once again giving fine generation performance, our system is fully restored from the ravages of Mother Nature, and three events that helped make 2007 a year that tested our mettle have moved into the annals of Empire history.

Solid accomplishments for the long term. The aforementioned challenges, though considerable, were short-term in nature. Our successes in executing key initiatives, on the other hand, should serve us well for years to come:

- The new Riverton Unit 12 combustion turbine was placed in service in April after two years of construction. Completed on schedule and under budget, it gives us 150 megawatts of new capacity.
- Construction of two new generating facilities continued toward a 2010 completion date. We hold ownership shares of 7.5 percent in the 665-megawatt Plum Point Energy Station and 12 percent in the 850-megawatt Iatan 2 Generating Station. Both are scheduled to be online in 2010. Plum Point construction is being managed by Dynegy; Kansas City Power & Light Company is directing the Iatan 2 project.
- We signed a new 20-year contract with Cloud County Wind Farm, LLC. We will begin receiving power pursuant to the terms of the contract in late 2008. The energy purchased under the new contract, when coupled with the energy we purchase under our existing contract with Elk River Windfarm, LLC, will represent about 15 percent of our energy needs by 2009. These contracts, we believe, decrease our exposure to natural gas, provide a hedge against any future global warming legislation, and help us give our customers lower, more stable rates.
- We completed installation of the Asbury Selective Catalytic Reduction (SCR) unit. The SCR removes about 90 percent of nitrogen oxide emissions from Asbury's generation. With its completion, we have one environmental upgrade task, the Iatan 1 project, remaining on our current to-do list.
- We continued a financing program that allowed us to maintain a debt to equity ratio of approximately 1:1.

Forging ahead. By September 1, 2008, we expect to receive a decision on a Missouri rate case filed in October 2007. We are seeking to recover costs, including expenses for Riverton Unit 12, capital expenditures associated with the Asbury SCR construction, and capital expenditures and expenses related to the ice storms. We have requested an increase in base rates of $34.7 million, or 10.1 percent. We also have requested authorization to implement a fuel adjustment clause for our Missouri territory.

As we continue building the infrastructure we need long term, we anticipate capital expenditures for 2008 to be virtually the same as 2007 levels, then to drop approximately 36 percent for 2009 and 2010. We expect to continue our long-term financing plan utilizing a combination of internally generated funds, short-term debt, and the proceeds of sales of long-term debt and/or common stock.

Board elects Laney vice chairman. At its January 2008 meeting, our Board of Directors elected Mr. Randy Laney to be Vice Chairman of the Board effective May 1, 2008.

Our Chairman, Mr. Myron McKinney, has chosen not to run for reelection in 2009. The election of Mr. Laney as Vice Chairman will allow for a seamless transition as Mr. McKinney retires from the Board.

Mr. Laney, of Farmington, Arkansas, is Vice Chairman of the Investlinc Group. He was co-founder and Chairman of Mercari Technologies of Fayetteville and co-founder and partner in Bentonville Associates Ventures. An attorney, he formerly served as Vice President of Finance and Treasurer of Wal-Mart Stores. He has served on our Board since 2003.

Mr. McKinney assumed chairmanship of the Board on May 1, 2002, after serving on the Board of Directors since 1991. Having first joined Empire in 1972, he was elected President and CEO in 1997 and retired from that post in April 2002.

National recognition for excellence. Early in 2008, Empire received the Edison Electric Institute's 2007 Emergency Recovery Award in recognition of our work to restore power after the January 2007 ice storm. At the award presentation, Empire employees were lauded for "persevering through the harshest of conditions." Indeed, the efforts of my fellow employees and the outside crews who assisted them during the disaster and its aftermath were nothing short of heroic. They well deserve this tribute to their skill, dedication, and tenacity.

An organization for utility shareholder interests. I encourage all Empire shareholders to join the Missouri Utility Shareholders Association (MUSA), a nonpartisan organization created to represent the collective interests of its utility shareholder members. MUSA members are interested in promoting and protecting their investments by taking an active role in issues that affect the electric and gas utility industries in Missouri.

Membership is free. For more information, contact MUSA at (573) 634-8678.

Managing for the long term. Carrying the load of a major building program is, and will continue to be, difficult. But we believe we are well prepared to confront the coming challenges. We will continue to stick to our core businesses. We will seek regulatory treatment that allows timely recovery of our investment. We will optimize our operations by relentlessly focusing on cost management, accountability, and safety. We will work to maintain our 1:1 debt to equity ratio.

I remain confident that our investment in the future will reap rewards for our shareholders, our customers, and our employees.

On behalf of the Board of Directors and my fellow employees, I thank you for your support, your confidence, and your investment in our company.

Bill Gipson

Bill Gipson
President and Chief Executive Officer
March 14, 2008

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, 2007 or

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

For the transition period from to .

Commission file number: 1-3368

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

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

Registrant's telephone number: (417) 625-5100
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock ($1 par value)	New York Stock Exchange
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 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, 2007, was approximately $681,302,040.

As of February 15 2008, 33,652,155 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 24, 2008	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:

- 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;
- weather, business and economic conditions and other factors which may impact sales volumes and customer growth;
- operation of our electric generation facilities and electric and gas transmission and distribution systems;
- 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 estimates;
- legislation;
- regulation, including environmental regulation (such as NOx, SO2 and CO2 regulation);
- competition, including the implementation of the 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;
- other circumstances affecting anticipated rates, revenues and costs;
- the timing of accretion estimates, and integration costs relating to, completed and contemplated acquisitions and the performance of acquired businesses;
- matters such as the effect of changes in credit ratings on the availability and our cost of funds;
- 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; and
- our exposure to the credit risk of our hedging counterparties.

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 formed to hold the Missouri Gas assets acquired from Aquila, Inc. on June 1, 2006. EDG provides natural gas distribution to communities in northwest, north central and west central Missouri. Our other segment consists of our non-regulated businesses, primarily our fiber optics business. In 2007, 87.1% of our gross operating revenues were provided from sales from our electric segment (including 0.4% from the sale of water), 12.2% from our gas segment, and 0.7% from our other segment.

The territory served by our electric operations embraces an area of about 10,000 square miles with a population of over 450,000. The service territory is 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 2007 retail electric revenues, approximately 89.0% came from Missouri customers, 5.5% from Kansas customers, 2.8% from Oklahoma customers and 2.7% from Arkansas customers.

We supply electric service at retail to 121 incorporated communities 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 64% of our electric operating revenues in 2007 were derived from incorporated communities with franchises having at least ten years remaining and approximately 6% 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 2007 were derived as follows: residential 41.1%, commercial 30.4%, industrial 15.9%, wholesale on-system 4.3%, wholesale off-system 4.6% and other 3.7%. Our largest single on-system wholesale customer is the city of Monett, Missouri, which in 2007 accounted for approximately 3% of electric revenues. No single retail customer accounted for more than 2% of electric revenues in 2007.

Our gas operations serve customers in northwest, north central and west central Missouri. The principal utility properties consist of approximately 87 miles of transmission mains and approximately 1,110 miles of distribution mains. We provide natural gas distribution to 44 communities and 269 transportation customers. Our gas operating revenues in 2007 were derived as follows: residential 65.5%, commercial 27.7%, industrial 1.2% and other 5.6%. No single retail customer accounted for more than 2% of gas revenues in 2007. 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-seven 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 other segment consists of our non-regulated businesses, primarily a 100% interest in Empire District Industries, Inc., a subsidiary for our fiber optics business. We sold our controlling 52% interest in Mid-America Precision Products (MAPP) on August 31, 2006, a company that specialized in close-tolerance custom manufacturing for the aerospace, electronics, telecommunications and machinery industries. In December 2006, we sold our 100% interest in Conversant, Inc., a software company that marketed Customer Watch, an Internet-based customer information system software. On September 28, 2007, we sold our 100% interest in Fast Freedom, Inc., an Internet service provider.

Electric Generating Facilities and Capacity

At December 31, 2007, our generating plants consisted of:

Plant	*Capacity (megawatts)	Primary Fuel
Asbury	210	Coal
Riverton	286	Coal and Natural Gas
Iatan (12% ownership)	78**	Coal
State Line Combined Cycle (60% ownership)	300**	Natural Gas
Empire Energy Center	269	Natural Gas
State Line Unit No. 1	96	Natural Gas
Ozark Beach	16	Hydro
Total	1,255	

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

** The 78 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). On February 1, 2007, the SPP RTO launched its energy imbalance services market (EIS). With the implementation of the SPP RTO EIS market and transmission expansion plans of the SPP RTO, we anticipate that our continued participation in the SPP will provide long-term benefits to our customers and other stakeholders. Although our experience to date in the EIS market is limited, we believe we have received benefits through our participation to date. Our active participation and assessment of EIS market benefits continues.

In general, the SPP RTO EIS market is providing 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 serve the native load.

We will continue to actively engage with the SPP RTO, other members of the SPP and staffs of our state commissions to evaluate the impact and value of EIS market participation. 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.

On March 14, 2006, we entered into contracts to add 100 megawatts of power to our system. This power will come from the Plum Point Energy Station, 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 2010. Initially we will own, through an undivided interest, 50 megawatts of the project's capacity for approximately $86.5 million in direct costs, excluding allowance for funds used during construction (AFUDC). We also have a long-term (30 year) purchased power agreement for an additional 50 megawatts of capacity and have the option to convert the 50 megawatts covered by the purchased power agreement into an ownership interest in 2015. We spent $46.4 million through December 31, 2007 and anticipate spending an additional $26.3 million in 2008, $9.1 million in 2009 and $5.0 million in 2010 for construction expenses (excluding AFUDC) related to our 50 megawatt ownership share of Plum Point Unit 1.

On February 4, 2005, we filed an application with the Missouri Public Service Commission (MPSC) seeking approval of an Experimental Regulatory Plan (Plan) concerning our possible participation in a new 800–850 MW coal-fired unit (Iatan 2) 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, or other baseload generation options. Our application also sought a certificate of convenience and necessity to participate in Iatan 2, if necessary, and in connection therewith, obtain approval that is intended to provide adequate assurance to potential investors to make financial options available to us concerning our potential investment in Iatan 2. On July 18, 2005, we filed a Stipulation and Agreement (Agreement) regarding our Plan with the MPSC for its consideration and approval conditioned upon our participation in Iatan 2. The Agreement contains conditions related to our infrastructure investments, including Iatan 2, environmental investments in Iatan 1, the 150 MW V84.3A2 combustion turbine at our Riverton Plant and the installation of Selective Catalytic Reduction (SCR) equipment at the Asbury coal-fired plant. 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. The MPSC issued an order on August 2, 2005 approving the Agreement with an effective date of August 12, 2005.

In relation to the Plan, we entered into an agreement with KCP&L on June 13, 2006 to purchase an undivided ownership interest in the proposed coal-fired Iatan 2. We will own 12%, or approximately 100 megawatts, of the 850-megawatt unit. Construction began in the spring of 2006 with completion scheduled for 2010. On December 12, 2006, KCP&L announced that the total estimated construction budget for Iatan 2, originally reported to be approximately $1.34 billion, had increased to a range of approximately $1.53 billion to $1.67 billion due to increases in estimated costs for labor, materials and equipment and also reflecting other market conditions. KCP&L, which will own 54.7% of the unit, announced their expected share of the total construction costs, originally reported to be approximately $733 million, would actually range from approximately $837 million to $914 million, due to the increase in estimated costs. Accordingly, our share of the Iatan 2 construction costs will increase from approximately $160.8 million to a range of approximately $183.6 million to $200.5 million. These estimated construction expenditures exclude AFUDC.

Our current capital expenditures budget, discussed below, includes $72.4 million in 2008, $43.8 million in 2009 and $33.1 million in 2010 for our share of Iatan 2, excluding AFUDC. At December 31, 2007, we have recorded approximately $54.6 million in construction expenditures on this project. As of January 10, 2008, KCP&L stated it had approximately 94% of the total budgeted direct construction cost of Iatan 2 under firm contract and the project was on schedule to meet its targeted completion in 2010.

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 is required for Iatan 1. According to KCP&L, approximately 97% of the total budgeted direct construction costs for the Iatan 1 environmental upgrades are under firm contract as of January 10, 2008. Our share of the environmental upgrade costs at

Iatan 1 is estimated at $46 million, excluding AFUDC, and will be expended between 2006 and fourth quarter 2009. At December 31, 2007, we have spent approximately $16.0 million on this project.

Due to increased customer growth we installed, at our Riverton facility, a Siemens V84.3A2 combustion turbine, Unit 12, with a summer rated capacity of 150 megawatts to allow us to meet the SPP's 12% minimum capacity margin requirement and increased our Riverton Plant's total generating capacity to 286 megawatts. The total cost for Unit 12, which began commercial operation as of April 10, 2007, was $39.5 million, excluding AFUDC.

In June 2007, we entered into a purchased power agreement with Cloud County Windfarm, LLC, owned by Horizon Wind Energy, Houston, Texas. This agreement provides for a 20-year term commencing with the commercial operation date, which is expected to be during December 2008. We will begin taking delivery of the energy at that time. Under the agreement, we will purchase all of the output from the approximately 105-megawatt Phase 1 Meridian Wind Farm to be located in Cloud County, Kansas.

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, with which we have contracted to purchase approximately 900,000 megawatt-hours of energy per year, 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
2007	162	1255	1417
2008	169***	1255	1424
2009	174***	1257	1431
**2010	62***	1407	1469
**2011	62***	1407	1469

* Contract years begin June 1 and run through May 31 of the following year.

** The contract years 2010 and 2011 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 5 megawatts for the Cloud County Windfarm, LLC.

The charges for capacity purchases under the Westar contract referred to above during calendar year 2007 amounted to approximately $16.2 million. Minimum charges for capacity purchases under the Westar contract total approximately $48.6 million for the period June 1, 2007 through May 31, 2010.

The maximum hourly demand on our system reached a record high of 1,173 megawatts on August 15, 2007. Our previous record peak of 1,159 megawatts was established on July 19, 2006. A new maximum hourly winter demand of 1,059 megawatts was set on February 16, 2007. Our previous winter peak of 1,034 megawatts was established on January 31, 2007.

Gas Facilities

We acquired the Missouri natural gas distribution operations of Aquila, Inc. on June 1, 2006. At December 31, 2007, our principal gas utility properties consisted of approximately 87 miles of transmission mains and approximately 1,110 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

In June 2007, we acquired 10,000 MMBtus per day of firm transportation from Cheyenne Plains Pipeline Company to enhance our Rocky Mountain supply position so that up to 75% of our natural gas purchases going forward could come from the Rocky Mountain gas area. We were able to fill our storage with Rocky Mountain gas supplies that were significantly less expensive during the summer of 2007 than the gas supplies produced in the mid-continent region. Cheyenne Plains interconnects with all of the interstate pipelines listed above that feed our market area. Through this effort we were able to reduce costs for our gas customers.

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 have expanded our supplier base in 2007 and will continue to do so to enhance supply reliability as well as provide for increased price competition.

The maximum daily flow on our system for 2007 was a volume of 68,381 mcfs on February 15, 2007.

Construction Program

Total property additions (including construction work in progress), excluding AFUDC, for the three years ended December 31, 2007, amounted to $376.5 million and retirements during the same period amounted to $30.4 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 $187.6 million in 2007 and for the next three years are estimated for planning purposes to be as follows:

	Estimated Capital Expenditures (amounts in millions)			
	2008	2009	2010	Total
New electric generating facilities:				
Iatan 2	$ 72.4	$ 43.8	$ 33.1	$149.3
Plum Point Energy Station	26.3	9.1	5.0	40.4
Other — combustion turbine — 2011	0.2	4.8	17.0	22.0
Additions to existing electric generating facilities:				
Environmental upgrades — Asbury Plant	2.0	0.3	0.1	2.4
Environmental upgrades — Iatan 1	26.7	1.4	0.3	28.4
Other	9.2	5.3	4.4	18.9
Electric transmission facilities	11.9	6.5	8.9	27.3
Electric distribution system additions	34.9	42.0	45.8	122.7
Non-regulated additions	1.0	1.0	1.0	3.0
General and other additions	2.4	3.1	2.9	8.4
Gas system additions	2.3	3.9	2.5	8.7
Total	$189.3	$121.2	$121.0	$431.5

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. The primary costs included in new electric generating facilities are for Iatan 2, the Plum Point Energy Station and a new combustion turbine scheduled to be in service in 2011 at a still-to-be-determined site. The primary costs included in additions to existing electric generating facilities include environmental upgrades at Iatan 1.

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 by mid-2010. The plan is driven by the continued growth in our service area and the expiration of a major purchase power contract in 2010.

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 equipment delivery schedules, changes in customer requirements, construction delays, 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 2007, 58.9% of our total system input, based on kilowatt-hours generated, was supplied by our steam and combustion turbine generation units, 1.2% was supplied by our hydro generation, and we purchased the remaining 39.9%. Coal supplied approximately 58.6% of the total fuel requirements for our generating units in 2007 based on kilowatt-hours generated. The remainder was supplied by natural gas (41.1%), tire-derived fuel (TDF) (0.2%), which is produced from discarded passenger car tires, and fuel oil (0.1%). The amount and percentage of electricity generated by coal decreased in 2007 as compared to 2006 primarily due to an extended maintenance outage at the Asbury plant in the fourth quarter of 2007. The amount and percentage of electricity generated by natural gas increased in 2007 as compared to 2006 as did the energy we purchased on the spot market to supplement the purchased power from our long-term Westar contract and Elk River Windfarm, LLC contract. We 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 offset the cost of this contract by purchasing less higher-priced power from other suppliers or by displacing on-system generation. We sell the renewable energy credits to third parties to further reduce our costs.

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 2007, Asbury burned a coal blend consisting of approximately 84.1% Western coal (Powder River Basin) and 15.9% blend coal on a tonnage basis. Our average coal inventory target at Asbury is approximately 45 days. As of December 31, 2007, we had sufficient coal on hand to supply anticipated requirements at Asbury for 104–115 days, as compared to 79–83 days as of December 31, 2006, depending on the actual blend ratio within this range. This increase in inventory is due to Asbury being on an extended outage beginning on September 21, 2007 and extending to February 10, 2008. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Executive Summary — 2007 Activities."

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 2007, Riverton Units 7 and 8 burned an estimated blend of approximately 78.8% Western coal (Powder River Basin) and 21.2% petroleum coke on a tonnage basis. Our average coal inventory target at Riverton is approximately 45 days. As of December 31, 2007, we had approximately 37,280 tons of Western coal and approximately 11,265 tons of blend fuel (petroleum coke and local coal) at Riverton. 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, 2007 to run 37 days on both units as compared to 36 days as of December 31, 2006. Riverton receives its Western inventory from coal transported by train to the Asbury Plant which is then transported by truck to Riverton. Therefore, the lower inventory at Riverton as of December 31, 2007, is offset by the larger inventory at the Asbury Plant which we expect to realign throughout the course of 2008.

We have secured 93% of our anticipated coal requirements for 2008, 61% for 2009 and 48% for 2010 through a combination of contracts with Peabody Coal Sales, Peabody Coal Trade, Arch Coal Sales, Rio Tinto, Oxbow Carbon and Minerals (petroleum coke) and coal stored in inventory. We plan to fulfill the remaining 7% of our 2008 coal requirements through spot purchases. 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. The overall delivered price of coal is expected to be slightly higher in 2008 than in 2007 as oil prices and other market factors increase the cost of mining. Due to the extended Asbury maintenance outage, we have issued force majeure notices to our Western coal suppliers and to the railroads suspending Western coal shipments during the outage. This relieves us of our contractual obligations to receive shipments of coal to the extent caused by the Asbury outage.

In 2007, we sold our steel unit train set, which we had previously leased to another utility. We currently lease one aluminum unit train on a full time basis and a second set is leased on an interim basis. These trains deliver Western coal to the Asbury Plant.

Unit No. 1 at the Iatan Plant is a coal-fired generating unit which is jointly-owned by KCP&L (70%), Aquila (18%) and us (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 substantially all of Iatan's requirements for 2008 and approximately 40% for 2009 and 2010. The coal is transported by rail under a contract with BNSF, 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 as needed. During 2007, essentially all of the Energy Center generation came from natural gas. Based on kilowatt hours generated, State Line Unit 1 fuel consumption during 2007 was 97.8% natural gas with the remainder being oil. Our targeted oil inventory at the Energy Center facility permits eight days of full load operation on Units No. 1, 2, 3 and 4. As of December 31, 2007, we have oil inventories sufficient for approximately 2 days of full load operation for these units at the Energy Center and 5 days of full load operation for State Line Unit No. 1.

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. In 2002, we signed a precedent agreement with Williams Natural Gas Company (now Southern Star Central), which provides additional transportation capability for 20 years. 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 expense and gain predictability.

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	2007	2006	2005
Coal — Iatan	$ 0.978	$0.793	$0.786
Coal — Asbury	1.432	1.402	1.322
Coal — Riverton	1.548	1.458	1.391
Natural Gas	7.050	7.276	7.208
Oil	14.870	6.551	5.893

Our weighted cost of fuel burned per kilowatt-hour generated was 3.2197 cents in 2007, 2.6502 cents in 2006 and 2.8912 cents in 2005.

Gas Segment

In June 2007, we acquired 10,000 MMBtus per day of firm transportation from Cheyenne Plains Pipeline Company to enhance our Rocky Mountain supply position so that up to 75% of our natural gas purchases going forward could come from the Rocky Mountain gas area. We were able to fill our storage with Rocky Mountain gas supplies that were significantly less expensive during the summer of 2007 than the gas supplies produced in the mid-continent region. Cheyenne Plains interconnects with all of the interstate pipelines listed below that feed our market area. Through this effort we were able to reduce costs for our gas customers.

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 have expanded our supplier base in 2007 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 transportation and other miscellaneous costs, per mcf of gas used in our gas operations:

Service Area	Name of Pipeline	2007	2006
South	Southern Star Central Gas Pipeline	$8.2967	$8.6513
North	Panhandle Eastern Pipe Line Company	7.9568	8.9693
Northwest	ANR Pipeline Company	7.0551	7.5771
	Weighted average cost	$8.0534	$8.5857

Employees

At December 31, 2007, we had 733 full-time employees, including 55 employees of EDG. 334 of the EDE employees are members of Local 1474 of The International Brotherhood of Electrical Workers (IBEW), while 28 of the EDG employees are members of Local 814 of the IBEW and 8 EDG employees are members of Local 695 of the IBEW. Locals 814 and 695 of the IBEW both ratified a new three-year contract with EDG effective at the June 1, 2006 closing. 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.

ELECTRIC OPERATING STATISTICS[1]

	2007	2006	2005	2004	2003
Electric Operating Revenues (000's):					
Residential	**$ 174,584**	$ 159,381	$ 149,176	$ 124,394	$ 125,197
Commercial	**129,035**	115,059	106,093	92,407	90,577
Industrial	**67,712**	64,820	59,593	51,861	50,643
Public authorities[2]	**9,933**	8,892	8,464	7,441	7,210
Wholesale on-system	**18,444**	17,561	16,582	13,614	12,440
Miscellaneous	**5,826**	4,706	4,934	6,168	6,618
Total system	**405,534**	370,419	344,842	295,885	292,685
Wholesale off-system	**19,627**	12,234	14,139	7,010	10,849
Total electric operating revenues[3]	**425,161**	382,653	358,981	302,895	303,534
Electricity generated and purchased (000's of kWh):					
Steam	**2,074,323**	2,589,360	2,446,528	2,409,002	2,287,352
Hydro	**71,360**	22,673	62,325	63,036	58,118
Combustion turbine	**1,427,298**	955,856	1,453,297	1,009,259	816,343
Total generated	**3,572,981**	3,567,889	3,962,150	3,481,297	3,161,813
Purchased	**2,373,282**	2,065,991	1,684,657	1,726,994	2,112,879
Total generated and purchased	**5,946,263**	5,633,880	5,646,807	5,208,291	5,274,692
Interchange (net)	**(940)**	(173)	(126)	100	91
Total system input	**5,945,323**	5,633,707	5,646,681	5,208,391	5,274,783
Maximum hourly system demand (Kw)	**1,173,000**	1,159,000	1,087,000	1,014,000	1,041,000
Owned capacity (end of period) (Kw)	**1,255,000**	1,102,000	1,102,000	1,102,000	1,102,000
Annual load factor (%)	**53.39**	52.50	55.59	55.98	54.28
Electric sales (000's of kWh):					
Residential	**1,930,493**	1,898,846	1,881,441	1,703,858	1,728,315
Commercial	**1,610,814**	1,547,077	1,485,034	1,417,307	1,386,806
Industrial	**1,110,328**	1,145,490	1,106,700	1,085,380	1,058,730
Public authorities[2]	**115,109**	111,204	111,245	106,416	102,338
Wholesale on-system	**342,347**	337,658	328,803	305,711	308,574
Total system	**5,109,091**	5,040,275	4,913,223	4,618,672	4,584,763
Wholesale off-system	**459,665**	303,493	353,138	236,232	324,622
Total Electric Sales	**5,568,756**	5,343,768	5,266,361	4,854,904	4,909,385
Company use (000's of kWh)[4]	**9,369**	9,324	10,263	10,087	10,093
kWh losses (000's of kWh)[5]	**367,198**	280,615	370,157	343,400	355,305
Total System Input	**5,945,323**	5,633,707	5,646,781	5,208,391	5,274,783
Customers (average number):					
Residential	**139,840**	137,689	134,724	132,172	129,878
Commercial	**24,330**	24,035	23,684	23,256	23,077
Industrial	**362**	370	365	357	362
Public authorities[2]	**1,927**	1,907	1,837	1,766	1,716
Wholesale on-system	**4**	4	4	4	5
Total System	**166,463**	164,005	160,614	157,555	155,038
Wholesale off-system	**20**	20	17	16	17
Total	**166,483**	164,025	160,631	157,571	155,055
Average annual sales per residential customer (kWh)	**13,805**	13,791	13,965	12,891	13,307
Average annual revenue per residential customer	**$ 1,248**	$ 1,158	$ 1,107	$ 941	$ 964
Average residential revenue per kWh	**9.04¢**	8.39¢	7.93¢	7.30¢	7.24¢
Average commercial revenue per kWh	**8.01¢**	7.44¢	7.14¢	6.52¢	6.53¢
Average industrial revenue per kWh	**6.10¢**	5.66¢	5.38¢	4.78¢	4.78¢

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

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

(3) Before intercompany eliminations.

(4) Includes kWh used by Company and Interdepartmental.

(5) Includes the effect of our 2006 unbilled revenue adjustment. (See Note 1 of "Notes to Consolidated Financial Statements" under Item 8).

GAS OPERATING STATISTICS[1]

	2007	2006[2]
Gas Operating Revenues (000's):		
Residential	**$39,205**	$15,957
Commercial	**16,588**	7,127
Industrial	**752**	356
Public authorities	**373**	161
Miscellaneous	**206**	93
Total retail sales revenues	**57,124**	23,694
Transportation revenues	**2,753**	1,451
Total Gas Operating Revenues	**59,877**	25,145
Gas delivered to customers (000's of mcf sales)[3]		
Residential	**2,835**	1,101
Commercial	**1,304**	559
Industrial	**76**	32
Public authorities	**30**	12
Total retail sales	**4,245**	1,704
Transportation sales (cash outs)	**56**	56
Company use[3]	**2**	—
Mcf losses	**8**	(70)
Total gas operating sales	**4,311**	1,690
Transportation volume	**4,297**	2,150
Total system volume	**8,608**	3,840
Customers (average number):		
Residential	**40,315**	40,673
Commercial	**5,208**	5,399
Industrial	**24**	26
Public authorities	**124**	128
Total retail customers	**45,671**	46,226
Transportation customers	**270**	252
Total gas customers	**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) 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, 2007, 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 12/31/07	Positions With the Company	With the Company Since	Officer Since
William L. Gipson	50	President and Chief Executive Officer (2002), Executive Vice President and Chief Operating Officer (2001), Vice President — Commercial Operations (1997)	1981	1997
Bradley P. Beecher	42	Vice President and Chief Operating Officer — Electric (2006), Vice President — Energy Supply (2001), General Manager -Energy Supply (2001)	2001	2001
Harold Colgin	58	Vice President — Energy Supply (2006), General Manager — Energy Supply (2006), Plant Manager, Asbury Plant (1995)	1972	2006
Ronald F. Gatz	57	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	56	Vice President — Finance and Chief Financial Officer (2002), General Manager — Finance (2002)	2002	2002
Michael E. Palmer	51	Vice President — Commercial Operations (2001), General Manager — Commercial Operations (2001), Director of Commercial Operations (1997)	1986	2001
Kelly S. Walters	42	Vice President — Regulatory and General Services (2006), General Manager — Regulatory and General Services (2005), Director of Regulatory and Planning (2001)	2001	2006
Janet S. Watson	55	Secretary — Treasurer (1995)	1994	1995
Laurie A. Delano	52	Controller, Assistant Secretary and Assistant Treasurer and Principal Accounting Officer (2005), Director of Financial Services (2002)	2002	2005

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, 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 2007, approximately 90% of our electric operating revenues were received from retail customers. Approximately 89.0%, 5.5%, 2.8% and 2.7% of such retail revenues were derived from sales in Missouri, Kansas, Oklahoma and Arkansas, respectively. Sales subject to FERC jurisdiction represented approximately 9% of our electric operating revenues during 2007 with the remaining 1% being from miscellaneous sources.

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 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. On July 14, 2005, Missouri Governor Blunt signed Bill SB 179 which authorizes the MPSC to grant fuel adjustment clauses for utilities in the State of Missouri. The bill became effective January 1, 2006. We do not currently have a fuel adjustment clause in Missouri but have requested the implementation of a fuel adjustment clause as part of our current Missouri rate case.

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, 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. 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 gas purchased, 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.

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 wastes, including their identification, transportation, disposal, record-keeping and reporting, as well as other environmental matters. We believe that our operations are in compliance with present laws and regulations.

Electric Segment

Air. The 1990 Amendments to the Clean Air Act, referred to as the 1990 Amendments, affect the Asbury, Riverton, State Line and Iatan Power Plants and Units 3 and 4 (the FT8 peaking units) at the Empire Energy Center. The 1990 Amendments require affected plants to meet certain emission standards, including maximum emission levels for sulfur dioxide (SO2) and nitrogen oxides (NOx). The Asbury Plant became an affected unit under the 1990 Amendments for SO2 on January 1, 1995 and for NOx as a Group 2 cyclone-fired boiler on January 1, 2000. The Iatan Plant became an affected unit for both SO2 and NOx on January 1, 2000. The Riverton Plant became an affected unit for NOx in November 1996 and for SO2 on January 1, 2000. The State Line Plant became an affected unit for SO2 and NOx on January 1, 2000. Units 3 and 4 at the Empire Energy Center became affected units for both SO2 and NOx in April 2003. The new Riverton Unit 12 became an affected unit in January 2007.

SO2 Emissions. Under the 1990 Amendments, the amount of SO2 an affected unit can emit is regulated. Each existing affected unit has been awarded a specific number of emission allowances, each of which allows the holder to emit one ton of SO2. Utilities covered by the 1990 Amendments must have emission allowances equal to the number of tons of SO2 emitted during a given year by each of their affected units. The annual reconciliation of allowances, which occurs on a facility wide basis, is held each March 1 for the previous calendar year. Allowances may be traded between plants or utilities or "banked" for future use. A market for the trading of emission allowances exists on the Chicago Board of Trade. The Environmental Protection Agency (EPA) withholds annually a percentage of the emission allowances awarded to each affected unit and sells those emission allowances through a direct auction. We receive compensation from the EPA for the sale of these withheld allowances.

Our Asbury, Riverton (other than the gas-fired combustion turbines) and Iatan Plants burn a blend of low sulfur Western coal (Powder River Basin) and higher sulfur blend coal and petroleum coke, or burn 100% low sulfur Western coal. In addition, tire-derived fuel (TDF) is used as a supplemental fuel at the Asbury Plant. The Riverton Plant can also burn natural gas as its primary fuel. The State Line Plant, the Energy Center Units 3 and 4 and Riverton Unit 12 are gas-fired facilities and do not receive SO2 allowances. In the near term, annual allowance requirements for the State Line Plant, the Energy Center Units 3 and 4 and Riverton Unit 12, which are not expected to exceed 20 allowances per year, will be transferred from our inventoried bank of allowances. In 2007, the combined actual SO2 allowance need for all affected plant facilities exceeded the number of allowances awarded to us by the EPA. Although the actual reconciliation of SO2 allowances does not occur until March 1 of each year, we had approximately 24,000 banked SO2 allowances at December 31, 2007 as compared to 31,000 at December 31, 2006. We project that our 2008 emissions will again exceed the number of allowances awarded by the EPA. Based on current SO2 allowance usage projections, we expect to exhaust our banked allowances by the end of 2010.

Once our SO2 allowance bank is exhausted, we will need to purchase additional SO2 allowances or build a scrubber at our Asbury Plant. Based on current and projected SO2 allowance prices and high-level estimated scrubber construction costs ($81 million in 2010 dollars), we expect it will be more economical for us to purchase SO2 allowances than to build a scrubber at the Asbury Plant. We would expect the costs of SO2 allowances to be fully recoverable in our rates. In addition, projected engineering and construction timeframes for a new scrubber make it unfeasible at this time to construct a scrubber by the end of 2010.

On July 14, 2004, we filed an application with the MPSC seeking an order authorizing us to implement a plan for the management, sale, exchange, transfer or other disposition of our SO2 emission allowances issued by the EPA. On 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 swap banked allowances for future vintage allowances and/or monetary value and, in extreme market conditions, to sell SO2 allowances outright for monetary value. The Stipulation and Agreement became effective March 11, 2005, although we have not yet swapped or sold any allowances. Our banked allowances are not assigned a cost value. The allowances are removed from inventory on a FIFO basis.

SO2 emissions will be further regulated as described in the Clean Air Interstate Rule section below.

NOx Emissions. The Asbury, Iatan, State Line, Energy Center and Riverton Plants are each in compliance with the NOx limits applicable to them under the 1990 Amendments as currently operated.

The Asbury Plant received permission from the Missouri Department of Natural Resources (MDNR) to burn TDF at a maximum rate of 2% of total fuel input. During 2007, approximately 2,651 tons of TDF were burned. This is equivalent to 265,100 discarded passenger car tires.

Under the MDNR's Missouri NOx Rule, our Iatan, Asbury, State Line and Energy Center facilities, like other facilities in Western Missouri, are generally subject to a maximum NOx emission rate of 0.35 lbs/MMBtu during the ozone season of May 1 through September 30. However, facilities which burn at least 100,000 passenger tire equivalents of TDF per year, including our Asbury Plant, are subject to a higher NOx emission limit of 0.68 lbs/MMBtu. All of our plants currently meet the required emission limits and additional NOx controls are not required.

NOx is further regulated as described in the Clean Air Interstate Rule below.

Clean Air Interstate Rule (CAIR)

The EPA issued its final CAIR on March 10, 2005. CAIR governs NOx and SO2 emissions from fossil fueled units greater than 25 megawatts and will affect 28 states, including Missouri, where our Asbury, Energy Center, State Line and Iatan Plants are located and Arkansas where the future Plum Point Energy Station will be located. Kansas is not included in CAIR and our Riverton Plant will not be affected.

The CAIR is not directed to specific generation units, but instead, requires the states (including Missouri and Arkansas) to develop State Implementation Plans (SIPs) to comply with specific NOx and SO2 state-wide annual budgets. Missouri and Arkansas finalized their respective regulations and submitted their SIPs to the EPA for approval. The Missouri SIP was approved and became effective on December 14, 2007. We will receive our full allotment of allowances as published in the Missouri CAIR Rule. The Arkansas CAIR SIP has been approved but not finalized. Until the Arkansas SIP is finalized by the EPA, we cannot definitively determine the allowed emissions of ozone season NOx for the Plum Point Energy Station in Arkansas. However, based on the SIP for Missouri and the approved SIP for Arkansas, it appears we will have excess annual and ozone season NOx allowances. 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. Based on current SO2 allowance usage projections, we expect to exhaust our banked allowances by the end of 2010 and will need to purchase additional SO2 allowances or build a scrubber at our Asbury Plant.

In order to help meet anticipated CAIR requirements and to meet air permit requirements for Iatan Unit 2, pollution control equipment is being installed on Iatan Unit 1 which will be completed around the end of 2008. This equipment includes a Selective Catalytic Reduction (SCR) system, a Flue Gas Desulphurization (FGD) system and a baghouse, with our share of the capital cost estimated at $46 million, excluding AFUDC. Of this amount, approximately $3.9 million was incurred in 2006 and $12.1 million in 2007. Approximately $26.7 million in 2008, $1.4 million in 2009 and $0.3 million in 2010 are included in our current capital expenditures budget. This project was also included as part of our Experimental Regulatory Plan approved by the MPSC.

Also to help meet anticipated CAIR requirements, we constructed an SCR at Asbury during the fall of 2007 and placed it in service in early February 2008 at a total cost of approximately $31.0 million (excluding AFUDC), of which $28.1 million was expended through December 31, 2007 with the remainder expended in 2008. This project was also included as part of our Experimental Regulatory Plan approved by the MPSC.

Additional pollution control equipment to comply with CAIR may become economically justified at the Asbury Plant sometime prior to 2015 and may include an FGD scrubber to control SO2 and a baghouse at an estimated capital cost of $100 million.

Clean Air Mercury Rule (CAMR)

On March 15, 2005, the EPA issued the CAMR regulations for mercury emissions by power plants under the requirements of the 1990 Amendments to the Clean Air Act. The new mercury emission limits for Phase 1 were scheduled to go into effect January 1, 2010 and remain in effect until January 1, 2018. Beginning January 1, 2018, more restrictive mercury emission limits were scheduled to go into effect for Phase 2 of CAMR. These regulations were challenged in the U.S. Court of Appeals for the District of Columbia Circuit by a group of states led by New Jersey. On February 8, 2008, the Court of Appeals issued its opinion and vacated the EPA's CAMR regulations. The EPA is required to reconsider the regulation of mercury under Section 112 of the CAA. At this point it is too early to determine the effects of this ruling.

The CAMR was not directed to specific generation units, but instead, required the states (including Missouri, Kansas and Arkansas) to develop SIPs to comply with specific mercury state-wide annual budgets. Missouri, Kansas and Arkansas have finalized their respective regulations and submitted their SIPs to the EPA. The proposed SIPs for all states include allowance trading programs for mercury that could allow compliance without additional capital expenditures.

Based on CAMR, we installed a mercury analyzer at Asbury during late 2007 and scheduled the installation of two mercury analyzers at Riverton during 2008 in order to verify our mercury emissions and to meet the compliance date of January 1, 2009 for mercury analyzers and the Phase 1 mercury emission compliance date of January 1, 2010.

CO2 Emissions

Our coal and gas plants emit carbon dioxide (CO2), a greenhouse gas. Although not currently regulated, increasing public concern and political pressure from local, regional, national and international bodies may result in the passage of new laws mandating limits on greenhouse gas emissions such as CO2. Several bills addressing climate change have been introduced in the U.S. Congress and, in April 2007, the U.S. Supreme Court issued a decision ruling the EPA improperly declined to address CO2 impacts in a rule-making related to new motor vehicle emissions. While this decision is not directly applicable to power plant emissions, the reasoning of the decision could affect other regulatory programs. Various proposals in the U.S. Congress could require us to purchase offsets or allowances for some or all of our CO2 emissions, or otherwise affect us based on the amount of CO2 we generate. The impact on us of any future greenhouse gas regulation will depend in large part on the details of the requirements and the timetable for mandatory compliance.

Water. We operate under the Kansas and Missouri Water Pollution Plans that were implemented in response to the Federal Water Pollution Control Act Amendments of 1972. The Asbury, Iatan, Riverton, Energy Center and State Line plants are in compliance with applicable regulations and have received discharge permits and subsequent renewals as required. The State Line permit was renewed in May 2007. The Energy Center permit was renewed in September 2005 and the Asbury Plant permit was renewed in December 2005.

The Riverton Plant is affected by final regulations for Cooling Water Intake Structures issued under the Clean Water Act Section 316(b) Phase II. The regulations became final on February 16, 2004 and require the submission of a Comprehensive Demonstration Study with the permit renewal in 2008. A Proposal for Information Collection (PIC) has been approved by the Kansas Department of Health and Environment (KDHE). Aquatic sampling commenced in April 2006 in accordance with the PIC and was completed in August 2007. Analysis of the sampling and a summary report will be completed during the first half of 2008. On January 25, 2007, the United States Court of Appeals for the Second Circuit remanded key sections of the EPA's February 16, 2004 regulations. On July 9, 2007, the EPA suspended the regulation and is expected to revise and re-propose the regulation by December 2008. If this occurs, we will monitor the EPA revision process and comment appropriately. Data collection and analysis will continue under the PIC and will be completed as needed to limit increased costs, if any, due to the EPA's suspension and revision of the regulation. The permit renewal application will be prepared and submitted as scheduled following KDHE guidance. Under the initial 316(b) regulations, we did not expect costs associated with compliance to be material. We will assess costs under revised rules when they are complete.

Other. Under Title V of the 1990 Amendments, we must obtain site operating permits for each of our plants from the authorities in the state in which the plant is located. These permits, which are valid for five years, regulate the plant site's total air emissions; including emissions from stacks, individual pieces of equipment, road dust, coal dust and other emissions. We have been issued permits for Asbury, Iatan, Riverton, State Line and the Energy Center Plants. We submitted the required renewal applications for the State Line and Energy Center Title V permits in 2003 and the Asbury Title V permit in 2004 and will operate under the existing permits until the MDNR issues the renewed permits. A Compliance Assurance Monitoring (CAM) plan is required by the renewed permit for Asbury. We estimate that the capital costs associated with the CAM plan will not exceed $2 million.

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 Iatan Unit No. 2 currently under construction. The new permit limits Unit No. 1 to a maximum of 6,600 MMBtu per hour of heat input. The 6,600 MMBtu per hour heat input limit is in effect until the new SCR, scrubber, and baghouse are completed, currently estimated to be late in the fourth quarter of 2008.

Gas Segment

The acquisition of Missouri Gas involved the property transfer of two former manufactured gas plant (MGP) sites previously owned by Aquila, Inc. and its predecessors. Site #1 is listed in the MDNR Registry of Confirmed Abandoned or Uncontrolled Hazardous Waste Disposal Sites in Missouri. Site #2 has received a letter of no further action from the MDNR. A Change of Use request and work plan was approved by the MDNR allowing us to expand our existing service center at Site #1 in Chillicothe, Missouri. This project, which was completed in October 2007, included the removal of all excavated soil and the addition of a new concrete surface replacing the existing gravel at a cost of approximately $0.1 million. We estimate further remediation costs at these two sites to be no more than approximately $0.2 million, based on our best estimate at this time. This estimated liability is recorded under noncurrent liabilities and deferred credits. In our agreement with the MPSC approving the acquisition of Missouri Gas, it was agreed that we could reflect a liability and offsetting regulatory asset not to exceed $260,000 for the acquired sites. The MPSC agreed that up to $260,000 of costs related to the clean up of these MGP sites would be allowed for future rate recovery. Accordingly, we concluded that rate recovery was probable and at the acquisition date, a regulatory asset of $260,000 was recorded as part of the purchase price allocation based on our agreement with the MPSC, and in accordance with Statement of Financial Accounting Standards No. 71 — "Accounting for the Effects of Certain Types of Regulation" (FAS 71).

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 15 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, 2007, would permit us to issue approximately $247.7 million of new first mortgage bonds based on this test at an assumed interest rate of 6.5%. In addition to the interest coverage requirement, the EDE Mortgage provides that new bonds must be issued against, among other things, retired bonds or 60% of net property additions. At December 31, 2007, we had retired bonds and net property additions which would enable the issuance of at least $565.5 million principal amount of bonds if the annual interest requirements are met. As of December 31, 2007, 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.

Our 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. At December 31, 2007, we had property additions of $2.5 million. 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, 2007, this test would not allow us to issue any new first mortgage bonds. However, our current financing plan does not contemplate the need for additional EDG first mortgage bonds.

Our Web Site

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

ITEM 1A. RISK FACTORS

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+
EDE First Mortgage Bonds — Pollution Control Series	AAA	Aaa	AAA
Senior Notes	BBB	Baa2	BB+
Trust Preferred Securities	BBB-	Baa3	BB
Commercial Paper	F2	P-2	A-3
Outlook	Negative	Negative	Stable

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. Currently, our senior unsecured debt rating from Standard & Poor's is BB+ (a non-investment grade rating). In addition, on February 14, 2008, Moody's placed all of our ratings on review for possible downgrade. This action, as well as any actual downgrade of our commercial paper rating from Moody's, 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 higher-cost revolving credit facility.

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 market risk in our fuel procurement strategy and may incur losses from these activities.

We have established a risk management practice of purchasing contracts for future fuel needs to meet underlying customer needs. Within this activity, we may incur losses from these contracts. These losses could have a material adverse effect on our results of operations.

By using physical and financial instruments, we are exposed to credit risk and market risk. Credit risk is the risk that the counterparty might fail to fulfill its obligations under contractual terms. 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.

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, 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.

A combination of increases in customer demand, decreases in output from our power plants and/or the failure of performance by purchased power contract counterparties could have a material adverse effect on our results of operations.

If demand for power increases significantly and rapidly (due to weather or other conditions) and either our power plants do not operate as planned or the parties with which we have contracted to purchase power are not able to, or fail to, deliver that power, we would be forced to purchase power in the spot-market. Those unforeseen costs could have a material adverse effect on our results of operations. See Item 1, "Business — Fuel and Natural Gas Supply", Item 2, "Properties — Electric Segment Facilities" and Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for more information.

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. Weather can also impact the revenues of our natural gas utility business. 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 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. Of the factors driving expenses, fuel and purchased power costs are our largest expense items. Increases in the price of natural gas or the cost of purchased power will result in increases in electric operating expenses. Our existing strategies for mitigating such risks include hedging against changes in natural gas prices and utilizing fuel adjustment mechanisms to recover actual fuel and purchased power expenses.

Such efforts, however, may not offset or permit us to recover all of such increased costs. Therefore, significant increases in electric operating expenses or reductions in electric operating revenues may occur and result in a material adverse effect on our business, financial condition and results of operations.

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. However, this provision only permits the recovery of "prudently incurred" costs. To the extent the MPSC determines that any of our costs were not prudently incurred, we would have to repay any such amounts that we collected from customers as part of an annual reconciliation. 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.

Disruptions in coal deliveries could require us to reduce the output of our coal-fired generating facilities and lead to increases in our fuel and purchased power costs.

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, such as those that occurred in 2005 and 2006, 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 increases in our fuel and purchased power costs and could have a material adverse effect on our business, financial condition and results of operations.

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 generally recover 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, 2007, we owned generating facilities with an aggregate generating capacity of 1,255 megawatts.

Our principal electric baseload generating plant is the Asbury Plant with 210 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 17% of our owned generating capacity and in 2007 accounted for approximately 30% 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. Our Asbury units went off-line September 21, 2007 and were expected to be back on-line during the last week of November, during which time we expected to tie in the SCR being constructed at Asbury. However, on December 7, 2007, during the reassembly of the generator, the unit failed inspection. On December 9, 2007, it was determined that corrective action would be necessary and that the additional work would require the unit to remain on outage an additional 60 days. Asbury went back online on February 10, 2008. The Unit No. 2 turbine is inspected approximately every 35,000 hours of operations and was last inspected during the 2001 outage. As of September 21, 2007, the date the units went off-line to begin the five year maintenance outage, Unit No. 2 had operated approximately 2,489 hours since its last turbine inspection in 2001. When the Asbury Plant is out of service, we typically experience increased purchased power and fuel costs associated with replacement energy.

Our generating plant located at Riverton, Kansas, has two steam-electric generating units with an aggregate generating capacity of 92 megawatts and four gas-fired combustion turbine units 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. Unit No. 7 was taken out of service from October 1, 2005 to November 4, 2005 for its five-year scheduled maintenance outage. Unit No. 8 was taken out of service from February 14, 2003 to May 14, 2003 for its scheduled five-year maintenance outage as well as to make necessary repairs to a high-pressure cylinder. 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. Iatan 1 underwent a planned maintenance and turbine inspection from January 6, 2007 through February 23, 2007. 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. The new permit limits Unit No. 1 to a maximum of 6,600 MMBtu per hour of heat input. This heat input limit allows Unit No. 1 to produce a total of 652 net megawatts, and, as a result, our share decreased from 80 megawatts to 78 megawatts. The 6,600 MMBtu per hour heat input limit is in effect until the new SCR, scrubber, and baghouse are completed, currently estimated to be late in the fourth quarter of 2008. 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 Aquila own 70% and 18%, respectively, of the Unit. KCP&L operates the unit for the joint owners. On June 13, 2006, we entered into an agreement with 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 new 850-megawatt unit to be operated by KCP&L and located at the site of the existing Iatan Generating Station.

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, including two FT8 peaking units installed in 2003, at the Empire Energy Center in Jasper County, Missouri, with an aggregate generating capacity of 269 megawatts. These peaking units operate on natural gas, as well as oil. On January 7, 2004, one of the original combustion turbine peaking units, Unit No. 2, experienced a rotating blade failure. Upon dismantling and inspecting the unit, we found damage to rotating and stationary components in the turbine, as well as anomalies in the generator. We incurred $4.1 million of insurable costs to repair this facility, including a $1 million insurance deductible we expensed in the first quarter of 2004 related to this damage. We received all of the remaining $3.1 million from our insurer as of June 30, 2005. On June 21, 2007, Unit No. 3 was taken out of service due to the failure of an engine bearing. It was returned to service on October 3, 2007.

Our hydroelectric generating plant, located on the White River at Ozark Beach, Missouri, has a generating capacity of 16 megawatts. We replaced two of the four water wheels at our hydroelectric plant in 2003, the third wheel in early 2004 and the fourth and final wheel in March 2005. 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. We expect that the Army Corp of Engineers will not implement the new minimum flow plan until at least 2009, but, at this time, we cannot be sure of the timetable. The Appropriations Act has a provision for the Army Corp of Engineers to provide a one time payment to us for lost energy production. The Appropriations Act requires us, in coordination with our relevant public service commissions and the Southwest Power Administration (SWPA), to determine our economic detriment. The SWPA published their estimate of our damages in the Federal Register on February 5, 2008 with comments open until March 6, 2008. We expect the process for reaching agreement on our economic harm to be completed in 2008 or 2009, but cannot predict the outcome at this time.

At December 31, 2007, our transmission system consisted of approximately 22 miles of 345 kV lines, 434 miles of 161 kV lines, 744 miles of 69 kV lines and 81 miles of 34.5 kV lines. Our distribution system consisted of approximately 6,785 miles of line.

Our electric generation stations are located on land owned in fee. We own a 3% undivided interest as tenant in common with KCP&L and Aquila 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 86 miles of water mains in three communities in Missouri.

Gas Segment Facilities

At December 31, 2007, our principal gas utility properties consisted of approximately 87 miles of transmission mains and approximately 1,110 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 Businesses

Our other segment consists of our non-regulated businesses, primarily a 100% interest in Empire District Industries, Inc., a subsidiary for our fiber optics business. We use the fiber optics cable and equipment in our own operations and also lease it to other entities. We sold our controlling 52% interest in MAPP on August 31, 2006, a company that specialized in close-tolerance custom manufacturing for the aerospace, electronics, telecommunications and machinery industries. In December 2006, we sold our 100% interest in Conversant, Inc., a software company that marketed Customer Watch, an Internet-based customer information system software. On September 28, 2007, we sold our 100% interest in Fast Freedom, Inc., an Internet service provider.

ITEM 3. LEGAL PROCEEDINGS

See description of legal matters set forth in Note 12 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 15, 2007, there were 5,298 record holders and 27,830 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 2007 and 2006 were as follows:

	Price of Common Stock				Dividends Paid Per Share	
	2007		2006			
	High	Low	High	Low	2007	2006
First Quarter	$26.11	$23.07	$23.00	$20.33	$0.32	$0.32
Second Quarter	26.13	21.99	23.05	20.26	0.32	0.32
Third Quarter	24.29	21.09	23.09	20.25	0.32	0.32
Fourth Quarter	24.34	22.22	25.10	22.25	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, 2007, our retained earnings balance was $17.2 million (compared to $22.9 million at December 31, 2006) after paying out $39.0 million in dividends during 2007. If we were to reduce our dividend per share, partially or in whole, it could have an adverse effect on our common stock price.

The EDE Mortgage and the 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 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. As of December 31, 2007, our level of retained earnings did not prevent us from issuing dividends. Absent an amendment to the EDE Mortgage, we may not have sufficient earned surplus to pay our next quarterly dividend at the rate of $0.32 per share. As a result, we have commenced a consent solicitation to amend the EDE Mortgage to increase the earned surplus basket under the EDE Mortgage by $10.75 million. We believe that the consent solicitation, which is scheduled to expire on March 11, 2008, will be successful. However, we can give no assurance that this will be the case.

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, 2007, there were no such restrictions on our ability to pay dividends.

During 2007, 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.

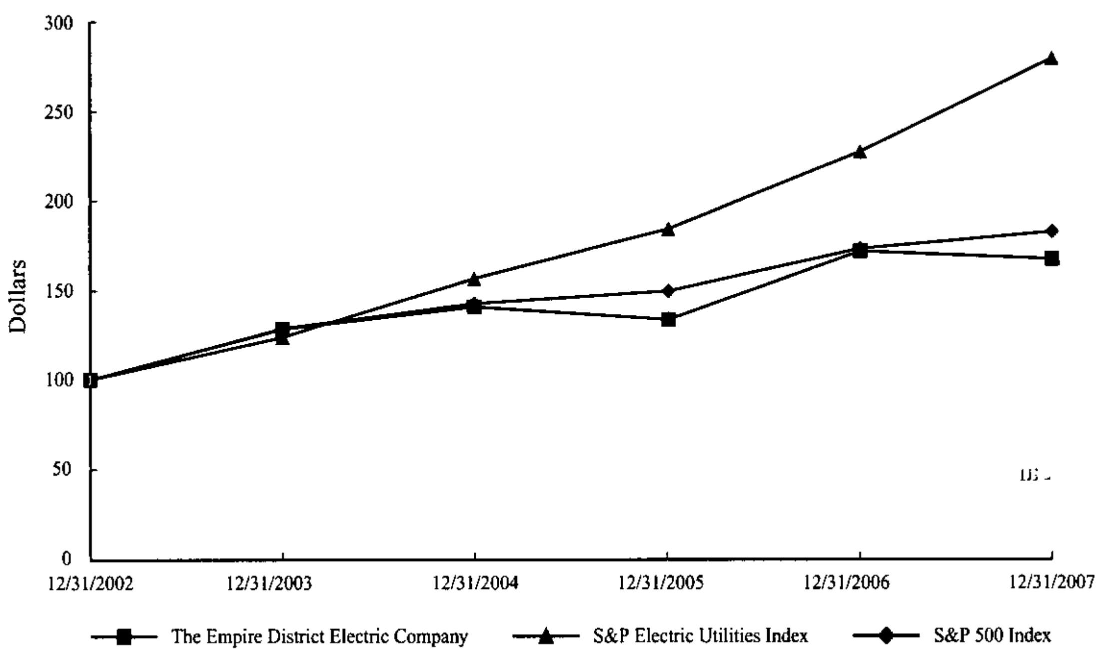
Our shareholders rights plan provides each of the common stockholders one Preference Stock Purchase Right (Right) for each share of common stock owned. One Right enables the holder to acquire one one-hundredth of a share of Series A Participating Preference Stock (or, under certain circumstances, other 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 6 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 5 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 5 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, 2002, 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 TO STOCKHOLDERS
(Assumes $100 investment on 12/31/02)



Total Return Analysis	12/31/2002	12/31/2003	12/31/2004	12/31/2005	12/31/2006	12/31/2007
The Empire District Electric Company	**$100.00**	**$128.30**	**$140.81**	**$133.60**	**$171.63**	**$167.20**
S&P Electric Utilities Index	**$100.00**	**$123.81**	**$156.57**	**$184.16**	**$226.95**	**$279.33**
S&P 500 Index	**$100.00**	**$128.63**	**$142.59**	**$149.58**	**$173.01**	**$182.39**

ITEM 6. SELECTED FINANCIAL DATA

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

	2007	2006[2]	2005	2004	2003
Operating revenues	**$ 490,160**	$ 412,171	$ 362,720	$ 306,354	$ 306,425
Operating income	**$ 65,566**	$ 69,821	$ 53,920	$ 53,212	$ 61,988
Total allowance for funds used during construction	**$ 7,665**	$ 4,255	$ 561	$ 220	$ 282
Income from continuing operations	**$ 33,181**	$ 40,029	$ 24,944	$ 23,542	$ 30,424
Income (loss) from discontinued operations, net of tax	**$ 63**	$ (749)	$ (1,176)	$ (1,694)	$ (974)
Net income	**$ 33,244**	$ 39,280	$ 23,768	$ 21,848	$ 29,450
Weighted average number of common shares outstanding — basic	**30,587**	28,277	25,898	25,468	22,846
Weighted average number of common shares outstanding — diluted	**30,610**	28,296	25,941	25,521	22,853
Earnings from continuing operations per weighted average share of common stock — basic and diluted	**$ 1.09**	$ 1.42	$ 0.96	$ 0.93	$ 1.33
Loss from discontinued operations per weighted average share of common stock — basic and diluted	**$ 0.00**	$ (0.03)	$ (0.04)	$ (0.07)	$ (0.04)
Total earnings per weighted average share of common stock — basic and diluted	**$ 1.09**	$ 1.39	$ 0.92	$ 0.86	$ 1.29
Cash dividends per share	**$ 1.28**	$ 1.28	$ 1.28	$ 1.28	$ 1.28
Common dividends paid as a percentage of net income	**117.2%**	91.8%	139.5%	149.3%	99.0%
Allowance for funds used during construction as a percentage of net income	**23.1%**	10.8%	2.4%	1.0%	1.0%
Book value per common share (actual) outstanding at end of year	**$ 16.04**	$ 15.49	$ 15.08	$ 14.76	$ 15.17
Capitalization:					
Common equity	**$ 539,176**	$ 468,609	$ 393,411	$ 379,180	$ 378,825
Long-term debt	**$ 541,880**	$ 462,398	$ 407,786	$ 397,371	$ 407,445
Ratio of earnings to fixed charges	**1.98x**	2.60x	2.21x	2.12x	2.44x
Total assets[3]	**$1,471,750**	$1,319,142	$1,122,030	$1,027,539	$1,025,091
Plant in service at original cost	**$1,500,640**	$1,374,837	$1,282,123	$1,247,380	$1,215,324
Capital expenditures (including AFUDC)[4]	**$ 195,568**	$ 120,171	$ 73,232	$ 41,045	$ 63,735

(1) All years presented have been adjusted to show continuing operations, reflecting the sale of MAAP and Conversant in 2006 and Fast Freedom in 2007.

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

(3) Total assets at December 31, 2006 increased $30.0 million due to regulatory assets recorded upon adoption of FAS 158. (See Note 4 of "Notes to Consolidated Financial Statements" under Item 8).

(4) 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 formed to hold the Missouri Gas assets acquired from Aquila, Inc. on June 1, 2006. It provides natural gas distribution to customers in 44 communities in northwest, north central and west central Missouri. Our other segment consists of our non-regulated businesses, primarily our fiber optics business. During the twelve months ended December 31, 2007, 87.1% of our gross operating revenues were provided from sales from our electric segment (including 0.4% from the sale of water), 12.2% from the sale of gas and 0.7% from our non-regulated businesses.

In August 2006, we sold our controlling 52% interest in Mid-America Precision Products (MAPP), which specialized in close-tolerance custom manufacturing. In December 2006, we sold our 100% interest in Conversant, Inc., a software company that marketed Customer Watch, an Internet-based customer information system software. On September 28, 2007, we sold our 100% interest in Fast Freedom, Inc., an Internet service provider. For financial reporting purposes, MAPP, Conversant and Fast Freedom, all of which were formerly within our other segment, have been classified as discontinued operations and are not included in our segment information.

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. Weather affects the demand for electricity. 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 1.4% to 1.6% over the next several years. Our electric customer growth for the twelve months ended December 31, 2007 was 1.1%. 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. Fuel and purchased power costs are our largest expense items. Several factors affect these costs, including fuel and purchased power prices, plant outages and weather, which drives customer demand. In order to control the price we pay for fuel for electric generation and purchased power, we have entered into long and short-term agreements to purchase power (including wind energy) and coal and natural gas for our energy supply. We currently engage in hedging activities in an effort to minimize our risk from volatile natural gas prices.

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. However, as part of the unanimous stipulation and agreement filed with the MPSC on March 1, 2006 and approved on April 18, 2006, we have agreed to not file a rate increase request for non-gas costs prior to June 1, 2009. 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 twelve months ended December 31, 2007 was (2.2)%, which we believe was due to higher gas prices and general economic conditions. We expect our annual gas customer growth to be up to 1% over the next several years. We define gas sales growth to be growth in mcf sales excluding the impact of weather. The primary drivers of gas sales growth are customer growth and general economic conditions.

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

Earnings

For the twelve months ended December 31, 2007, basic and diluted earnings per weighted average share of common stock were $1.09 compared to $1.39 for the twelve months ended December 31, 2006. As reflected in the table below, the primary positive drivers were increased electric and gas revenues. This was offset, however, by higher fuel and purchased power costs resulting primarily from the Asbury outage and from higher maintenance and repairs expense resulting from the ice storms discussed below.

The following reconciliation of basic earnings per share between 2006 and 2007 is a non-GAAP presentation. We believe this information is useful in understanding the fluctuation in earnings per share between the prior and current years. The reconciliation presents the after tax impact of significant items and components of the income statement on a per share basis before the impact of additional stock issuances which is presented separately. Earnings per share for the years ended December 31, 2006 and 2007 shown in the reconciliation are presented on a GAAP basis and are the same as the amounts included in the statements of operations. This reconciliation may not be comparable to other companies or more useful than the GAAP presentation included in the statements of operations.

Earnings Per Share — 2006*	**$ 1.39**
Revenues	
Electric on-system	$ 0.77
Electric off-system and other	0.19
Gas	0.78
Water	—
Non-regulated	0.02
Expenses	
Electric fuel	(0.44)
Purchased power	(0.26)
Cost of natural gas sold and transported	(0.50)
Regulated — electric segment	(0.16)
Regulated — gas segment	(0.10)
Non-regulated	(0.01)
Maintenance and repairs	(0.20)
Depreciation and amortization	(0.32)
Other taxes	(0.09)
Interest charges	(0.13)
AFUDC	0.08
Discontinued operations	0.03
Loss on plant disallowance	0.02
Gain on sale of assets	0.03
Change in effective income tax rates	0.08
Other income and deductions	(0.02)
Dilutive effect of additional shares issued	(0.07)
Earnings Per Share — 2007	**$ 1.09**

* 2006 includes the effect of discontinued operations, which was a loss of $0.03.

Fourth Quarter Results

In the fourth quarter of 2007, we experienced a net loss of $0.4 million, or ($0.01) per share compared to fourth quarter 2006 earnings of $8.2 million, or $0.27 per share. Total revenues increased approximately $8.5 million (8.0%) for the fourth quarter of 2007 as compared to the fourth quarter of 2006 primarily due to the Missouri rate increase. However, this was offset by increased operating expenses, including increased fuel and purchased power costs (approximately $17.5 million) primarily relating to the Asbury outage, depreciation expense (approximately $3.5 million) and other operating and maintenance costs (approximately $3.0 million, of which $1.5 million consisted of December ice storm expense).

2007 Activities

Asbury SCR and Maintenance Outage

In order to help meet CAIR requirements, we constructed an SCR at Asbury during the fall of 2007 and placed it in service in early February 2008. This was combined with our five year Asbury maintenance project. Our Asbury units went off-line September 21, 2007 and were expected to be back on-line during the last week of November, during which time we expected to tie in the SCR. However, on December 7, 2007, during the reassembly of the generator, the unit failed inspection. On December 9, 2007 it was determined that corrective action would be necessary and that additional work would require the unit to remain on outage an additional 60 days. The total cost of the SCR project was approximately $31.0 million (excluding AFUDC), of which $28.1 million was expended through December 31, 2007 with the remainder expended in 2008. This project was also included as part of our Experimental Regulatory Plan approved by the MPSC. In addition, as a result of the extended outage at Asbury into the first quarter of 2008, we expect that our earnings for the first quarter will be negatively impacted compared to earnings in the first quarter of 2007. We had to replace the energy that would have been generated by our coal-fired units at the Asbury plant with energy generated at our gas plants and with purchased power. We had originally estimated that this would increase our expenses approximately $7–9 million in the fourth quarter of 2007 as compared to the fourth quarter of 2006 due to the original extended outage. We then estimated that during the additional 60 day outage we would incur approximately $8–10 million in additional replacement energy costs. After assessing the actual cost of the incremental purchased power and gas-fired generation, we estimate the planned outage added incremental expenses for the fourth quarter of approximately $8.7 million. We estimate the extended outage (December 8–December 31, 2007) increased expenses an additional $3.5 million.

2007 Ice Storms

A major winter storm system that brought sleet and freezing rain to a large portion of our service area December 9–11, 2007 left approximately 65,000 (40%) of our electric customers without power. Costs associated with the restoration effort due to this ice storm were approximately $18.6 million, of which approximately $9.2 million was capitalized as additions to our utility plant, approximately $1.5 million was recorded as maintenance expense and approximately $7.9 million was deferred as a regulatory asset, as we believe it is probable that these costs will be recoverable in future electric rate cases.

A major ice storm also struck virtually all areas of our electric service territory January 12–14, 2007 causing substantial damage. Approximately 85,000 (52%) of our electric customers were without power at the height of the storm. Costs associated with the restoration effort due to the ice storm were approximately $30.7 million, of which $19.2 million has been capitalized as additions to our utility plant, approximately $3.9 million recorded as maintenance expense and approximately $7.6 million was deferred as a regulatory asset as we believe it is probable that these costs will be recoverable in future electric rate cases.

Financing

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, EDE issued $80 million principal amount of First Mortgage Bonds, 5.875% Series due 2037. The net proceeds of $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.

Regulatory Matters

On October 1, 2007, we filed a request with the MPSC for an annual increase in base rates for our Missouri electric customers in the amount of $34.7 million, or 10.11%. This request is to allow us to recover our investment in the new 150-megawatt combustion turbine, Unit 12, at our Riverton Plant, capital expenditures associated with the construction of a selective catalytic reduction system at our Asbury Plant, capital expenditures and expenses related to the 2007 ice storms and other changes in our underlying costs. We are also requesting implementation of a fuel adjustment clause in Missouri which would permit the distribution to Missouri customers of changes in fuel and purchased power costs.

On December 29, 2006, the Office of Public Counsel (OPC) and intervenors Praxair, Inc. and Explorer Pipeline Company, filed an application with the MPSC requesting the MPSC grant a rehearing on most of the issues addressed in the December 2006 Missouri rate case order and many of the procedural issues. On December 29, 2006, we also filed an application with the MPSC requesting a rehearing on return on equity, capital structure and energy cost recovery. A decision by the MPSC is pending.

Praxair and Explorer Pipeline filed a Petition for Writ of Review with the Cole County Circuit Court on January 31, 2007. The Circuit Court issued a Writ, but the MPSC moved to have the Writ set aside on the basis that it was issued prematurely. On March 20, 2007, Praxair and Explorer filed a motion in the Circuit Court writ proceeding requesting an immediate stay of the effectiveness of our December 2006 Missouri rate case order and the tariffs filed pursuant thereto. Without an order being issued on the stay motion, pursuant to an agreement of the parties, the Circuit Court set aside the Writ and dismissed the case.

On January 4, 2007, the OPC filed a Petition for Writ of Mandamus with the Missouri Court of Appeals, Western District, seeking to have the order approving tariffs issued by the MPSC on December 29, 2006, set aside. On March 12, 2007, the Court of Appeals issued an order denying the OPC's petition.

On March 19, 2007, the OPC filed a Petition for Writ of Mandamus with the Missouri Supreme Court seeking an order requiring the MPSC to vacate and rescind its December 29, 2006 order approving tariffs and directing the MPSC to provide an effective date for any subsequent tariff approval order that allows at least ten days to prepare and file an application for rehearing. On May 1, 2007, the Missouri Supreme Court issued a preliminary writ directing the MPSC to respond to the OPC's petition. Following briefs and oral argument, on October 30, 2007, the Supreme Court made its preliminary writ peremptory and issued an opinion directing the MPSC to vacate its December 29 order approving tariffs and allow the Public Counsel a reasonable time to prepare and file an application for rehearing. The Court did not examine the lawfulness or reasonableness of the substance of the MPSC's December 29, 2006 order approving tariffs, and considered only the timing of the issuance of the order. The Court also did not consider the underlying tariffed rates which continue in force and in effect. Acting upon this opinion, the MPSC issued an order on December 4, 2007, effective December 14, 2007, vacating the December 29, 2006 order and re-approving the tariffs and the same resulting increase in rates. The OPC and intervenors Praxair, Inc. and Explorer Pipeline Company, filed an application with the MPSC requesting the MPSC grant a rehearing on the December 4, 2007 order. All applications for rehearing remain pending before the MPSC.

We have filed applications for Accounting Authority Orders in Oklahoma and Kansas respecting costs incurred due to the 2007 ice storms.

For additional information, see "Rate Matters" below.

Energy Supply

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. The agreement provides for a 20-year term commencing with the commercial operation date, which is expected to be during December 2008. We will begin taking delivery of the energy at that time. 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 and owned by Cloud County Windfarm, LLC. 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.

As of April 10, 2007, our new Siemens V84.3A2 combustion turbine, Unit 12 at our Riverton plant, began commercial operation. Riverton Unit 12 has a summer rated capacity of 150 megawatts, increasing our Riverton Plant's total generating capacity to 286 megawatts.

Union Agreement

At April 30, 2007, we had 702 full-time employees, including 54 employees of EDG. 326 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.

BPU Contract

In May 2007, we entered into a contract with Kansas City Kansas Board of Public Utilities (BPU) for the sale of energy and capacity for June through September of 2007 and 2008. Capacity revenue will total approximately $1.3 million each year with the energy portion dependent upon the number of hours the contract is utilized by BPU. 2007 revenues from the BPU contract were approximately $1.8 million.

Non-Regulated Businesses

On September 28, 2007, we sold our 100% interest in Fast Freedom, Inc., an Internet service provider. For financial reporting purposes, this business has been classified as a discontinued operation and is not included in our segment information. Our gain on the disposal of Fast Freedom was $0.2 million.

RESULTS OF OPERATIONS

The following discussion analyzes significant changes in the results of operations for the years 2007, 2006 and 2005. The following table represents our results of operations by operating segment for the applicable periods ended December 31:

(in millions)	2007	2006	2005
Income from continuing operations:			
Electric	$31.8	$40.9	$24.9
Gas	1.0	(1.0)	—
Other	0.4	0.1	0.1
Total income from continuing operations	$33.2	$40.0	$25.0
Loss from discontinued operations	—	(0.7)	(1.2)
Net income	$33.2	$39.3	$23.8

Electric Segment

Overview

Our electric segment income from continuing operations for 2007 was $31.8 million as compared to $40.9 million for 2006.

Electric operating revenues comprised approximately 86.7% of our total operating revenues during 2007. Of these total electric operating revenues, approximately 41.1% were from residential customers, 30.4% from commercial customers, 15.9% from industrial customers 4.3% from wholesale on-system customers, 4.6% from wholesale off-system transactions and 3.7% from miscellaneous sources, primarily transmission services. The breakdown of our electric customer classes has not significantly changed from 2006 or 2005.

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

	kWh Sales (in millions)					
Customer Class	**2007**	**2006**	**% Change***	**2006**	**2005**	**% Change***
Residential	1,930.5	1,898.8	1.7%	1,898.8	1,881.5	0.9%
Commercial	1,610.8	1,547.1	4.1	1,547.1	1,485.0	4.2
Industrial	1,110.3	1,145.5	(3.1)	1,145.5	1,106.7	3.5
Wholesale on-system	342.3	337.7	1.4	337.7	328.8	2.7
Other**	116.8	112.7	3.6	112.7	112.9	(0.2)
Total on-system	5,110.7	5,041.8	1.4	5,041.8	4,914.9	2.6

	Operating Revenues (in millions)					
Customer Class	**2007**	**2006**	**% Change***	**2006**	**2005**	**% Change***
Residential	$ 174.6	$ 159.4	9.5%	$ 159.4	$ 149.2	6.8%
Commercial	129.0	115.0	12.1%	115.0	106.1	8.5%
Industrial	67.7	64.8	4.5%	64.8	59.6	8.8%
Wholesale on-system	18.4	17.6	5.0%	17.6	16.6	5.9%
Other**	10.1	9.0	11.8%	9.0	8.5	5.0%
Total on-system	$ 399.8	$ 365.8	9.3%	$ 365.8	$ 340.0	7.6%

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

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

2007 Compared to 2006

Operating Revenues and Kilowatt-Hour Sales

KWh sales for our on-system customers increased approximately 1.4% during 2007 as compared to 2006 primarily due to continued sales growth. Revenues for our on-system customers increased approximately $34.0 million, or 9.3%. The January 2007 Missouri rate increase (discussed below) contributed an estimated $38.3 million in revenues in 2007 while continued sales growth contributed an estimated $8.0 million. Weather and other factors contributed an estimated $2.2 million. These increases were partially offset by the $5.9 million revision to our estimate of unbilled revenues in the third quarter of

2006 and $8.6 million of IEC collected in 2006, neither of which reoccurred in 2007. We expect our annual customer growth to range from approximately 1.4% to 1.6% over the next several years.

Residential and commercial kWh sales and associated revenues increased in 2007 primarily due to sales growth while the associated revenues also increased due to the January 2007 Missouri rate increase. Industrial kWh sales decreased 3.1% primarily due to a pipeline customer running at minimum output during the first quarter of 2007 as well as the revision to our estimate of unbilled revenues in the third quarter of 2006 while the associated revenues increased 4.5%, reflecting the aforementioned rate increase. On-system wholesale kWh sales increased reflecting the continued sales growth discussed above. Revenues associated with these FERC-regulated sales increased more than the kWh sales as a result of the fuel adjustment clause applicable to such sales. This clause permits the distribution to customers of changes in fuel and purchased power costs.

Off-System Electric Transactions

In addition to sales to our own customers, we also sell power to other utilities as available and provide transmission service through our system for transactions between other energy suppliers. See "— Competition" below. The following table sets forth information regarding these sales and related expenses for the years ended December 31:

(in millions)	2007	2006
Revenues	$22.5	$14.4
Expenses	15.8	10.4
Net	$ 6.7	$ 4.0

Revenues less expenses increased during 2007 as compared to 2006 primarily due to sales facilitated by the SPP Energy Imbalance Services (EIS) market that began on February 1, 2007. Sales from this market contributed $8.8 million to our off-system electric revenues during 2007 with $6.2 million of related expense. In addition, sales from the BPU contract contributed approximately $1.8 million to revenues. Total purchase power related expenses are included in our discussion of purchased power costs below.

Operating Revenue Deductions

During 2007, total electric segment operating expenses increased approximately $50.3 million (15.9%) compared to 2006. Total fuel costs increased approximately $19.6 million (20.9%) during 2007 while purchased power costs increased approximately $11.3 million (17.1%), resulting in a total increase of $30.9 million for fuel and purchased power. The increase in fuel costs was primarily due to increased generation by our gas fired units during 2007 as compared to 2006 (an estimated $28.7 million). This increase in gas-fired generation was mainly due to the extended outage at the Asbury plant during the fourth quarter of 2007, the Iatan plant outage during the second quarter of 2007 and the fact that we increased on-system and off-system sales in 2007. The availability of Riverton 12 in the spring of 2007 added additional gas-fired capability that allowed us to sell power into the SPP energy imbalance services market. Lower prices for both the hedged and unhedged natural gas that we burned in our gas-fired units in 2007 reduced fuel prices an estimated $3.6 million. Decreased generation from coal reduced costs approximately $7.3 million (mainly due to the Asbury outage), partially offset by increased coal prices in 2007 which contributed approximately $1.6 million to fuel expense. The increase in purchased power costs primarily reflected our increased purchases on the spot market for replacement energy in the fourth quarter due to the extended Asbury outage and in the second quarter due to the Iatan outage. After assessing the actual cost of the incremental purchased power and gas-fired generation, we estimate the planned Asbury outage added incremental expenses for the fourth quarter of approximately $8.7 million and the extended outage (December 8–December 31, 2007) increased expenses an additional $3.5 million.

Regulated — other operating expenses for our electric segment increased approximately $7.0 million (12.8%) during 2007 as compared to 2006 primarily due to increases of $2.1 million in employee pension expense, $1.3 million in uncollectible accounts, $1.1 million in transmission and distribution expense, $0.6 million in labor and other costs, $0.6 million in customer accounts expense, $0.4 million in regulatory commission expense, $0.4 million in other steam power expense, $0.4 million in injuries and damages and $0.2 million in other power supply expense, partially offset by a $0.2 million decrease in professional services. The increase in pension costs is primarily due to the effects of regulatory accounting. We defer or record pension and other postretirement benefit costs (other than EDG other postretirement benefit costs) if they are more or less, respectively, than those allowed in rates for the Missouri and Kansas portion of pension costs. See Note 4 of "Notes to Consolidated Financial Statements" under Item 8 for further discussion regarding the regulatory treatment of our pension and post-retirement benefit plans.

Maintenance and repairs expense increased approximately $8.5 million (38.7%) during 2007 as compared to 2006 primarily reflecting increases of approximately $7.7 million in distribution maintenance costs, including $3.9 million of incremental costs (and the $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, $0.8 million in transmission distribution maintenance costs and $0.9 million in maintenance costs for our coal-fired units, partially offset by a decrease of approximately $0.8 million in maintenance costs for our gas-fired units. The $0.9 million increase in maintenance costs for our coal-fired units consisted mainly of a $0.5 million increase in maintenance costs at our Iatan Plant related to the 2007 first quarter inspection, a $0.2 million increase in maintenance costs at our Riverton Plant and a $0.1 million increase in maintenance costs at our Asbury Plant. The $0.8 million decrease in maintenance for our gas-fired units consisted mainly of a $0.8 million decrease in maintenance for our SLCC Plant as compared to 2006 expenses related to the spring 2006 SLCC maintenance outage and a $0.4 million decrease in maintenance at our State Line Unit 1 Plant, which had its first major inspection from September 7, 2006 until December 20, 2006, partially offset by a $0.4 million increase in maintenance during 2007 at the Empire Energy Center related to Unit #3 being repaired in the third quarter of 2007. Maintenance expense associated with our five year Asbury maintenance project is not expensed but is deferred as a regulatory asset and amortized over a five year period. A minor true up in December 2007 reclassified some of the January 2007 ice storm costs from maintenance expense to a regulatory asset. See Note 4 of "Notes to Consolidated Financial Statements" under Item 8 for further information regarding our regulatory assets and liabilities.

We recognized a $1.2 million gain in the fourth quarter of 2007 from the sale of our steel unit train set.

Depreciation and amortization expense increased approximately $13.2 million (36.2%) during 2007 primarily due to $10.4 million of regulatory amortization related to the January 2007 Missouri rate order that has been recorded as depreciation expense as well as increased plant in service. Other taxes increased approximately $1.5 million due to increased property taxes reflecting our additions to plant in service and increased municipal franchise taxes.

2006 Compared to 2005

Operating Revenues and Kilowatt-Hour Sales

KWh sales for our on-system customers increased approximately 2.6% during 2006 as compared to 2005 primarily due to continued sales growth. Revenues for our on-system customers increased approximately $25.8 million, or 7.6%. The January 2006 Kansas rate increase, March 2005 Missouri rate increase and May 2005 Arkansas rate increase (discussed below) contributed an estimated $13.8 million to revenues in 2006 while continued sales growth contributed an estimated $6.9 million. Additionally, revisions to our estimate of unbilled revenues contributed $5.9 million to revenues in 2006. Weather and other factors had a negative impact of an estimated $2.8 million despite our setting a new record summer peak of 1,159 megawatts on July 19, 2006. The collected IEC, which was not refunded pursuant to the

December 21, 2006 order from the MPSC, contributed approximately $2.0 million more during 2006. Our customer growth was 2.1% in 2006 compared to 1.9% in 2005.

Residential and commercial kWh sales increased in 2006 primarily due to the strong sales growth and the increase from our revisions to our estimate of unbilled revenues while the associated revenues also increased due to the Missouri, Arkansas and Kansas rate increases. Industrial kWh sales increased 3.5% while revenues increased 8.8%, reflecting the increased sales growth and the aforementioned rate increases. On-system wholesale kWh sales increased reflecting the continued sales growth discussed above. Revenues associated with these FERC-regulated sales increased more than the kWh sales as a result of the fuel adjustment clause applicable to such sales.

Off-System Electric Transactions

In addition to sales to our own customers, we also sell power to other utilities as available and provide transmission service through our system for transactions between other energy suppliers. See "— Competition" below. The following table sets forth information regarding these sales and related expenses for the years ended December 31:

(in millions)	2006	2005
Revenues	$14.4	$16.9
Expenses	10.4	12.0
Net	$ 4.0	$ 4.9

Revenues less expenses decreased during 2006 as compared to 2005 due to decreased market demand resulting from mild weather in the first quarter of 2006 as well as less market demand for gas-fired energy in the third quarter of 2006 as compared to the third quarter of 2005 when there was a shortage of available coal-fired generation on the open market. Companies that normally would have coal-fired energy to sell in the market were not doing so due to coal shortages, pushing demand onto the gas-fired units. The related expenses are included in our discussions of purchased power costs below.

Operating Revenue Deductions

During 2006, total electric segment operating expenses increased approximately $10.1 million (3.3%) compared to 2005. Total fuel costs decreased approximately $18.8 million (16.7%) during 2006 partially offset by increased purchased power costs of approximately $13.6 million (25.8%), resulting in a net decrease of $5.2 million for fuel and purchased power. The decrease in fuel costs was primarily due to decreased generation by our gas fired units during 2006 as compared to 2005 (an estimated $25.6 million), partially offset by higher prices for both hedged and unhedged natural gas that we burned in our gas-fired units in 2006 (an estimated $4.4 million). In addition, in 2005 we recognized a $5 million one-time pre-tax gain from unwinding part of a physical purchase of natural gas for the 2009 through 2011 period as part of our fuel management process. This gain was recognized in the third quarter of 2005 as a decrease to fuel expense. Increased coal costs contributed approximately $2.4 million to total fuel costs in 2006 and increased coal generation added approximately $2.0 million. A decrease in fuel oil generation decreased fuel costs approximately $2.0 million. The increase in purchased power costs primarily reflected our increased purchases from the Elk River Windfarm, LLC and also reflected a February 2006 outage at our Asbury Plant.

Regulated — other operating expenses for our electric segment increased approximately $0.4 million (0.7%) during 2006 as compared to 2005 primarily due to increases of $0.7 million in professional services expense, $0.6 million in general labor costs and $0.5 million in customer assistance expense, partially offset by a $1.5 million decrease in employee health care costs. We began deferring a portion of our pension cost into a regulatory asset effective with the second quarter of 2005, as authorized in our 2005 Missouri rate case. We had deferred approximately $2.4 million as of December 31, 2006. See Note 4 of "Notes to

Consolidated Financial Statements" under Item 8 for further discussion regarding our regulatory treatment of pension and post-retirement benefit plans.

Maintenance and repairs expense increased approximately $1.2 million (5.7%) during 2006 as compared to 2005 primarily reflecting increases of approximately $1.5 million in distribution maintenance costs and $1.4 million in maintenance costs for our gas-fired units, partially offset by a decrease of approximately $1.5 million in maintenance costs for our coal-fired units. The $1.4 million increase in maintenance for our gas-fired units consisted mainly of a $1.5 million increase in maintenance for our SLCC Plant related to the spring 2006 maintenance outage and a $0.4 million increase in maintenance at our State Line Unit 1 Plant, which had its first major inspection from September 7, 2006 until December 20, 2006. These increases were partially offset by a $0.5 million decrease in maintenance during 2006 at the Empire Energy Center related to generator repairs in the second quarter of 2005. The $1.5 million decrease in maintenance costs for our coal-fired units consisted mainly of a $0.9 million decrease in maintenance costs at our Riverton Plant and a $0.5 million decrease in maintenance costs at our Iatan Plant related to 2005 outages. In our 2006 Missouri rate case Stipulation and Agreement as to Certain Issues, approved December 21, 2006, we agreed to a disallowance for regulatory purposes of the Missouri jurisdictional portion of $1 million of our Energy Center Units 3 and 4 costs recorded in plant in service, which would not be afforded rate recovery in Missouri rates. In accordance with FAS 71, we reduced the capitalized value of our Energy Center Units 3 and 4 by recording a charge to expense in 2006 for $0.8 million, which represents the Missouri jurisdictional portion of these capitalized costs.

Depreciation and amortization expense increased approximately $2.6 million (7.6%) during 2006 primarily due to higher depreciation rates that became effective on March 27, 2005 and increased plant in service. Other taxes increased approximately $0.5 million (2.5%) during 2006 due to increased property taxes reflecting our additions to plant in service and increased municipal franchise taxes.

Gas Segment

Operating Revenues and Sales

During 2007, our total natural gas revenues were approximately $59.9 million. Our total natural gas revenues were approximately $25.1 million during 2006 (June 1, 2006 — December 31, 2006). The winter months are high sales months for the natural gas business, whose heating season runs from November to March of each year.

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

Total Gas Delivered to Customers — bcf Sales*

	2007	2006**
Residential	2.83	1.10
Commercial	1.30	0.56
Industrial	0.08	0.03
Public authorities	0.03	0.01
Total retail sales*	4.24	1.70
Transportation sales	4.30	2.23
Total gas operating sales*	8.54	3.93

* Differences could occur due to rounding.

** 2006 bcf sales represent the months of June through December 2006.

Operating Revenues ($ in millions)*

	2007	2006**
Residential	$39.2	$15.9
Commercial	16.6	7.1
Industrial	0.7	0.4
Public authorities	0.4	0.2
Total retail sales revenues	$56.9	$23.6
Transportation revenues	2.8	1.5
Total gas operating revenues	$59.7	$25.1

* Revenues exclude forfeited discounts, reconnect fees, miscellaneous service revenues, etc.

** 2006 revenues represent the months of June through December 2006.

Operating Revenue Deductions

During 2007, EDG's cost of natural gas sold and transported was approximately $37.6 million. The cost of natural gas sold and transported during 2006 (June 1, 2006 — December 31, 2006) was approximately $15.3 million. The cost of natural gas tends to vary with changing sales requirements and unit cost of natural gas purchases. However, due to purchased natural gas cost recovery mechanisms for retail customers, fluctuations in the cost of natural gas have little effect on income. Our Purchased Gas Adjustment (PGA) Clause allows us to recover from our customers, subject to routine regulatory review, the cost of purchased gas supplies, including costs, cost reductions, and related carrying costs associated with the use of financial instruments to hedge the purchase price of natural gas.

Total other operating expenses were approximately $10.2 million during 2007, primarily consisting of approximately $5.7 million of administrative and general expenses, approximately $2.5 million of customer accounts expense (including $1.7 million of uncollectible accounts) and approximately $1.7 million of distribution expense. Total other operating expenses were approximately $5.9 million during 2006 (June 1, 2006 — December 31, 2006) primarily consisting of approximately $4.0 million of administrative and general expenses, approximately $1.0 million of distribution expense and approximately $0.8 million of customer accounts expense (including $0.4 million of uncollectible accounts). EDG had net income of $1.0 million during 2007 and a net loss of $1.0 million during 2006. Approximately $1.2 million in transition costs were paid in 2006 for billing and other transition services. These services ended when they were transitioned to us by November 1, 2006.

Other Segment

Our other segment includes leasing of fiber optics cable and equipment (which we are also using in our own utility operations). See Note 13 of "Notes to Consolidated Financial Statements". The following table represents our results of continuing operations for our remaining non-regulated businesses for the applicable periods ended December 31:

(in millions)	2007	2006	2005
Revenues	$3.7	$2.9	$2.7
Expenses	3.3	2.8	2.6
Net income from continuing operations	$0.4	$0.1	$0.1

Consolidated Company

Income Taxes

Our consolidated provision for income taxes decreased approximately $7.5 million during 2007 as compared to 2006. Our consolidated effective federal and state income tax rate for 2007 was 30.3% as compared to 35.3% for 2006. The decrease in the effective tax rate for 2007 as compared to 2006 was mainly due to decreased income, as well as an increase in equity AFUDC, Medicare Part D tax benefits and increased cost of removal resulting from the January 2007 ice storm.

Our consolidated provision for income taxes increased approximately $9.3 million during 2006 as compared to 2005. Our consolidated effective federal and state income tax rate for 2006 was 35.3% as compared to 33.4% for 2005. The increase in the effective tax rate for 2006 compared to 2005 was mainly due to increased income.

See Note 10 of "Notes to Consolidated Financial Statements" under Item 8 for additional information regarding income taxes.

Nonoperating Items

Total allowance for funds used during construction (AFUDC) increased $3.4 million in 2007 as compared to 2006 and increased $3.7 million in 2006 as compared to 2005 due to higher levels of construction in each period. See Note 1 of "Notes to Consolidated Financial Statements" under Item 8.

Total interest charges on long-term debt increased $5.2 million (19.9%) in 2007 as compared to 2006 reflecting interest on the $80 million principal amount of first mortgage bonds issued March 26, 2007 by EDE, the proceeds of which 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. This increase also reflects interest on the first mortgage bonds issued June 1, 2006 by EDG to fund a portion of our acquisition of the Missouri natural gas distribution operations. Total interest charges on long-term debt increased $2.0 million (8.4%) in 2006 as compared to 2005 reflecting interest on the first mortgage bonds issued June 1, 2006 by EDG. See "— Liquidity and Capital Resources" for further information. Short-term debt interest increased $0.7 million during 2007 as compared to 2006 and increased $2.1 million during 2006 as compared to 2005, reflecting increased usage of short-term debt in each period.

Losses from discontinued operations were approximately $0.7 million and $1.2 million in 2006 and 2005, respectively, which reflected the sales of Fast Freedom in 2007 and MAPP and Conversant in 2006. There was a slight gain from discontinued operations in 2007 of less than $0.1 million.

Other Comprehensive Income

The change in the fair value of the effective portion of our open gas contracts designated as cashflow hedges for our electric business and our interest rate derivative contracts and the gains and losses on contracts settled during the periods being reported, including the tax effect of these items, are reflected in our Consolidated Statement of Comprehensive Income. This net change is recorded as accumulated other comprehensive income in the capitalization section of our balance sheet and does not affect net income or earnings per share. All of these contracts have been designated as cash flow hedges. The unrealized gains and losses accumulated in other comprehensive income are reclassified to fuel, or interest expense, in the periods in which the hedged transaction is actually realized or no longer qualifies for hedge accounting.

The following table sets forth the pre-tax gains/(losses) of our natural gas contracts and interest rate contracts for our electric segment that have settled and been reclassified, the pre-tax change in the fair market value (FMV) of our open contracts and the tax effect in Other Comprehensive Income (OCI) for the presented periods ended December 31:

(in millions)	2007	2006	2005
Natural gas contracts settled[1]	$(1.6)	$ (1.3)	$(4.4)
Interest rate contracts settled	—	—	1.4
Total contracts settled	$(1.6)	$ (1.3)	$(3.0)
Change in FMV of open contracts for natural gas	$ 5.2	$(13.6)	$29.0
Change in FMV of open contracts for interest rates	—	—	(1.4)
Total change in FMV of open contracts	$ 5.2	$(13.6)	$27.6
Taxes — natural gas	$(1.4)	$ 5.7	$(9.3)
Total taxes	$(1.4)	$ 5.7	$(9.3)
Total change in OCI — net of tax	$ 2.2	$ (9.2)	$15.3

(1) Reflected in fuel expense

Our average cost for our open financial natural gas hedges was $5.460/Dth at December 31, 2007, $4.805/Dth at December 31, 2006 and $4.744/Dth at December 31, 2005 for our electric segment.

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.

We had entered into an interest rate derivative contract in May 2005 to hedge against the risk of a rise in interest rates impacting our 5.8% Senior Notes due 2035 prior to their issuance on June 27, 2005. Costs associated with the interest rate derivative (primarily due to interest rate fluctuations) amounted to approximately $1.4 million and were recorded as a regulatory asset and are being amortized over the life of the 2035 Notes. The $1.2 million redemption premium paid in connection with the redemption of the $30 million aggregate principal amount of our First Mortgage Bonds, 7.75% Series due 2025 redeemed in June 2005, together with $2.4 million of remaining unamortized loss on reacquired debt and $0.3 million of unamortized debt expense, were recorded as a regulatory asset and are being amortized as interest expense over the life of the 2035 Notes. See Note 7 of "Notes to Consolidated Financial Statements" under Item 8. We had no interest rate derivative contracts in 2007 or 2006. On February 15, 2008, we unwound 992,000 Dths 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 taxes, which will be recorded in the Statement of Income in the first quarter of 2008.

RATE MATTERS

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

Electric Segment

The following table sets forth information regarding electric and water rate increases since January 1, 2005:

Jurisdiction	Date Requested	Annual Increase Granted	Percent Increase Granted	Date Effective
Missouri — Electric	February 1, 2006	$29,369,397	9.96%	January 1, 2007
Missouri — Water	June 24, 2005	469,000	35.90%	February 4, 2006
Kansas — Electric	April 29, 2005	2,150,000	12.67%	January 4, 2006
Arkansas — Electric	July 14, 2004	595,000	7.66%	May 14, 2005
Missouri — Electric	April 30, 2004	25,705,500	9.96%	March 27, 2005

Missouri

On April 30, 2004, we filed a request with the MPSC for an annual increase in base rates for our Missouri electric customers in the amount of $38,282,294, or 14.82%. On December 22, 2004, we, the MPSC Staff, the Office of the Public Counsel (OPC) and two intervenors filed a unanimous Stipulation and Agreement as to Certain Issues with the MPSC settling several issues. One of the issues we were able to agree on was a change in the recognition of pension costs allowing us to defer the Missouri portion of any costs above or below the amount included in this rate case as a regulatory asset or liability. The amount of pension cost allowed in this rate case was approximately $3.0 million. This stipulation became effective on March 27, 2005 as part of the final Missouri order described below. Therefore, the deferral of these costs began in the second quarter of 2005.

The MPSC issued a final order on March 10, 2005 approving an annual increase in base rates of approximately $25,705,500, or 9.96%, effective March 27, 2005. The order granted us a return on equity of 11%, an increase in base rates for fuel and purchased power at $24.68/MWH and an increase in depreciation rates. The new depreciation rates included a cost of removal component of mass property (transmission, distribution and general plant costs). In addition, the order approved an annual Interim Energy Charge (IEC) of approximately $8.2 million effective March 27, 2005 and expiring three years later. The IEC was $0.002131 per kilowatt hour of customer usage. The MPSC allowed us to use forecasted fuel costs rather than the traditional historical costs in determining the fuel portion of the rate increase. At the end of two years, an assessment would be made of the money collected from customers compared to the greater of the actual and prudently incurred costs or the base cost of fuel and purchased power set in rates. If the excess of the amount collected over the greater of these two amounts was greater than $10 million, the excess over $10 million would be refunded to the customers. The entire excess amount of IEC, not previously refunded, would be refunded at the end of three years, unless the IEC was terminated earlier. Each refund was to include interest at the current prime rate at the time of the refund. The IEC revenues recorded since the inception of the IEC did not recover all the Missouri related fuel and purchased power costs incurred during that period. From inception of the IEC through December 31, 2006, the costs of fuel and purchased power were approximately $22.3 million higher than the total of the costs in our base rates and the IEC recorded during the period, therefore, no provision for refund was recorded.

On February 1, 2006, we filed a request with the MPSC for an annual increase in base rates for our Missouri electric customers in the amount of $29,513,713, or 9.63%. We also requested transition from the IEC from an earlier case to Missouri's new fuel adjustment mechanism. The MPSC issued an order May 2, 2006, however, ruling that we may have the option of requesting that the IEC be terminated, but we may not request the implementation of an energy cost recovery mechanism while the current IEC is effective. The MPSC issued an order on December 21, 2006 granting us an annual increase of $29,369,397 (including regulatory amortization), or 9.96%, with an effective date of January 1, 2007 and eliminating the IEC. Pursuant to this order, the collected IEC was not refunded. The increase included an authorized return on equity of 10.9% and included our fuel and energy costs as a component of base electric rates. Of the increase, approximately $19 million was granted in the form of base rates, with the remainder of approximately $10.4 million granted as regulatory amortization to provide additional cash flow to enhance the financial support for our current generation expansion plan. This regulatory amortization is related to our investment in Iatan 2 and also includes our Riverton V84.3A2 combustion turbine (Unit 12) and the environmental improvements and upgrades at Asbury and Iatan 1. This order also allowed deferral of any other postretirement benefits that are 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 order also approved regulatory treatment of additional liabilities arising from the adoption of FAS 158. We also agreed to write off $1 million of the cost of our Energy Center 2 construction project. The Missouri jurisdictional portion of this agreement resulted in a pre tax write off of $0.8 million in the fourth quarter of 2006.

On December 29, 2006, the Office of Public Counsel (OPC) and intervenors Praxair, Inc. and Explorer Pipeline Company, filed an application with the MPSC requesting the MPSC grant a rehearing on most of the issues addressed in the December 2006 Missouri rate case order and many of the procedural issues. On December 29, 2006, we also filed an application with the MPSC requesting a rehearing on return on equity, capital structure and energy cost recovery. A decision by the MPSC is pending.

Praxair and Explorer Pipeline filed a Petition for Writ of Review with the Cole County Circuit Court on January 31, 2007. The Circuit Court issued a Writ, but the MPSC moved to have the Writ set aside on the basis that it was issued prematurely. On March 20, 2007, Praxair and Explorer filed a motion in the Circuit Court writ proceeding requesting an immediate stay of the effectiveness of our December 2006 Missouri rate case order and the tariffs filed pursuant thereto. Without an order being issued on the stay motion, pursuant to an agreement of the parties, the Circuit Court set aside the Writ and dismissed the case.

On January 4, 2007, the OPC filed a Petition for Writ of Mandamus with the Missouri Court of Appeals, Western District, seeking to have the order approving tariffs issued by the MPSC on December 29, 2006, set aside. On March 12, 2007, the Court of Appeals issued an order denying the OPC's petition.

On March 19, 2007, the OPC filed a Petition for Writ of Mandamus with the Missouri Supreme Court seeking an order requiring the MPSC to vacate and rescind its December 29, 2006 order approving tariffs and directing the MPSC to provide an effective date for any subsequent tariff approval order that allows at least ten days to prepare and file an application for rehearing. On May 1, 2007, the Missouri Supreme Court issued a preliminary writ directing the MPSC to respond to the OPC's petition. Following briefs and oral argument, on October 30, 2007, the Supreme Court made its preliminary writ peremptory and issued an opinion directing the MPSC to vacate its December 29 order approving tariffs and allow the Public Counsel a reasonable time to prepare and file an application for rehearing. The Court did not examine the lawfulness or reasonableness of the substance of the MPSC's December 29, 2006 order approving tariffs, and considered only the timing of the issuance of the order. The Court also did not consider the underlying tariffed rates which continue in force and in effect. Acting upon this opinion, the MPSC issued an order on December 4, 2007, effective December 14, 2007, vacating the December 29, 2006 order and re-approving the tariffs and the same resulting increase in rates. The OPC and intervenors Praxair, Inc. and Explorer Pipeline Company, filed an application with the MPSC requesting the MPSC grant a rehearing on the December 4, 2007 order. All applications for rehearing remain pending before the MPSC.

On October 1, 2007, we filed a request with the MPSC for an annual increase in base rates for our Missouri electric customers in the amount of $34.7 million, or 10.11%. This request is to allow us to recover our investment in the new 150-megawatt combustion turbine, Unit 12, at our Riverton Plant, capital expenditures associated with the construction of a selective catalytic reduction system at our Asbury Plant, capital expenditures and expenses related to the 2007 ice storms and other changes in our underlying costs. We are also requesting implementation of a fuel adjustment clause in Missouri which would permit the distribution to Missouri customers of changes in fuel and purchased power costs.

On June 24, 2005, we filed a request with the MPSC for an annual increase in base rates for our Missouri water customers in the amount of $523,000, or 38%. The MPSC issued a final order on January 31, 2006 approving an annual increase in base rates of approximately $469,000, or 35.9%, effective February 4, 2006.

Arkansas

On July 14, 2004, we filed a request with the APSC for an annual increase in base rates for our Arkansas electric customers in the amount of $1,428,225, or 22.1%. On May 13, 2005, the APSC granted an annual increase in electric rates for our Arkansas customers of approximately $595,000, or 7.66%, effective May 14, 2005.

Kansas

On April 29, 2005, we filed a request with the Kansas Corporation Commission (KCC) for an increase in base rates for our Kansas electric customers in the amount of $4,181,078, or 24.64%. On October 4, 2005, we and the KCC Staff filed a Motion to Approve Joint Stipulated Settlement Agreement (Agreement) with the KCC. The Agreement called for an annual increase in base rates (which includes historical fuel costs) for our Kansas electric customers of approximately $2,150,000, or 12.67%, the implementation of an Energy Cost Adjustment Clause (ECA), a fuel rider that will collect or refund fuel costs in the future that are above or below the fuel costs included in the base rates and the adoption of the same depreciation rates approved by the MPSC in our 2005 Missouri rate case. In addition, we will be allowed to change our recognition of pension costs, deferring the Kansas portion of any costs above or below the amount included in this rate case as a regulatory asset or liability. The KCC approved the Agreement on December 9, 2005 with an effective date of January 4, 2006. Pursuant to the Agreement, we were to seek KCC approval of an explicit hedging program in a separate docket by March 1, 2006. However, we requested and received an extension until April 1, 2006. We made this filing on March 30, 2006. On February 4, 2008, the KCC issued an order denying the request for the approval of our existing natural gas hedging program. All gains or losses related to the financial instruments used to fix the future price of natural gas will be excluded from recovery through the ECA and future base electric rates in Kansas.

We have filed applications for Accounting Authority Orders in Oklahoma and Kansas respecting costs incurred due to the 2007 ice storms.

Gas Segment

On June 1, 2006, The Empire District Gas Company acquired the Missouri natural gas distribution operations of Aquila, Inc. (Missouri Gas). The Missouri Gas properties consist of 44 Missouri communities in northwest, north central and west central Missouri. The rates, excluding the cost of gas, are the same as had been in effect at Aquila, Inc. We agreed in the unanimous stipulation and agreement filed with the MPSC on March 1, 2006 and approved on April 18, 2006, to not file a rate increase request for non-gas costs for a period of 36 months following the closing date of the acquisition. We have also agreed to use Aquila Inc.'s current depreciation rates and were allowed to adopt the pension cost recovery methodology approved in our electric Missouri Rate Case effective March 27, 2005.

A PGA clause is included in our gas rates which allows for the over recovery or under recovery of actual gas costs compared to the cost of gas in the PGA rate. This PGA clause allows us to make rate changes periodically (up to four times) throughout the year in response to weather conditions, natural gas prices and supply demands, rather than in one possibly extreme change per year. The Actual Cost Adjustment (ACA) is a scheduled yearly filing with the MPSC filed between October 15 and November 4 each year. This filing establishes the amount to be recovered from customers for the over/under recovered yearly amounts. A PGA is included in the ACA filing. An optional PGA filing without the ACA can be filed up to three times each year, provided a filing does not occur within 60 days of a previous filing. Our last ACA filing was completed on October 24, 2007.

COMPETITION

Electric Segment

SPP-RTO

On February 1, 2007, the SPP regional transmission organization (RTO) launched its energy imbalance services market (EIS). With the implementation of the SPP RTO EIS market and transmission expansion plans of the SPP RTO, we anticipate that our continued participation in the SPP will provide long-term benefits to our customers and other stakeholders. Although our experience to date in the EIS market is limited, we believe we have received benefits through our participation. Our active participation and assessment of EIS market benefits continues.

In general, the SPP RTO EIS market is providing 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.

We will continue to actively engage with the SPP RTO, other members of the SPP and staffs of our state commissions to evaluate the impact and value of EIS market participation.

On February 16, 2007, the FERC issued a Final Order No. 890, which instituted numerous reforms to its Order 888 open access transmission pro forma tariff (OATT) which was issued in April 1996. The purpose of the Order was (i) to strengthen the OATT to ensure that it better achieves its original purpose of remedying undue discrimination for the provision of transmission service, (ii) to provide greater specificity in the OATT to reduce opportunities for the exercise of undue discrimination, make undue discrimination easier to detect, and facilitate the FERC's enforcement, and (iii) to increase transparency in the rules applicable to planning and use of the transmission system. The FERC's actions required modifications to the SPP and our OATTs as well as regional and local transmission planning processes. We and SPP submitted our respective Order 890 compliance filings of our OATTs on October 11, 2007. Compliance modifications to our OATT filing were not material and we anticipate them being accepted. The SPP proposed modifications to its regional and local area transmission planning processes, pursuant to Order 890, in its December 7, 2007 FERC filing. An issuance from the FERC on our and SPP's filings is pending. In December 2007, the FERC issued Order 890A, reconfirming its February Order 890.

FERC Market Power Order

In April and July 2004, the FERC issued orders regarding new testing standards for assessing market power by entities that have wholesale market-based rate tariffs filed with the FERC. The parameters included in the tests are such that most investor owned electric utilities fail the test within their own control area and are subject to a rebuttable presumption of market power. Entities with wholesale market based rates tariffs are subject to a triennial filing to test for market power and are required to apply the new testing criteria. FERC determination of market power would result in the inability for a utility to continue to charge such market-based rates. In September 2004, we submitted amended and updated market power analyses filings.

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, which could amount to approximately $0.6 million (excluding interest) covering over a thousand hourly energy sales from the period of May 2005 through August 2006 to numerous counterparties external to our system. In response to the order, we filed a Motion For Extension of time and expedited treatment regarding the refund and requested that such refund be delayed until 15 days after the FERC's order on our rehearing request. On September 5, 2006, the FERC granted the Motion For Extension, as requested.

On September 14, 2006, we filed a Request For Rehearing of the FERC's August 15 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. The FERC's decision on the refund is still pending.

On June 21, 2007, the FERC issued a Final Rule related to Market-Based Rates for Wholesales of Electric Energy, Capacity, and Ancillary Services by Public Utilities which directly affects our market power assessment within our service area and Request For Rehearing related to the aforementioned pending potential refund. In reaction to the Final Rule, we were required to modify our Market Based Rate Tariff in the form of a compliance filing to the FERC, which was made on September 17, 2007. The FERC's ruling on our compliance filing is also pending. We have implemented revisions to our wholesale power sales business practices in accordance with the Final Rule.

Other FERC Rulemaking

Also 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. The FERC is seeking comment in the following areas: (i) the role of demand response in the organized markets, (ii) increasing opportunities for long-term power contracts, (iii) strengthening market monitoring and (iv) the responsiveness of RTOs and ISOs to customers and stakeholders.

On January 28, 2008, we made a filing at the FERC related to certain non-rate and ministerial revisions to our currently effective wholesale Open Access Transmission Tariff (OATT), which included the elimination of certain tariff sections that have become moot in light of our membership in the SPP, as well as correction of the formatting of our OATT for consistency with Order No. 614. The FERC's acceptance of the proposed updates to our OATT 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

We used approximately $178.5 million of cash for regulated capital expenditures during 2007. Our primary sources of cash flow for these expenditures during 2007 were $103.5 million in internally generated funds from continuing operations, $79.8 million in gross proceeds from first mortgage bonds and $71.7 million in gross proceeds from the sale of common stock. We also used cash sources to reduce short-term debt by $44.0 million and pay dividends of $39.0 million.

A detailed discussion on cash flow activity follows.

Cash Provided by Operating Activities

Our net cash flows provided by continuing operating activities were $103.5 million during 2007 as compared to $69.2 during 2006. Net income decreased $6.0 million in 2007 but was offset by a $36.1 million positive impact from the effect of adjustments to net income to reconcile to cash flows. This resulted from the positive effects of increased depreciation and amortization, including $10.4 million in regulatory amortization and an increase in deferred taxes primarily resulting from tax deductions allowed as a result of the 2007 ice storms. In addition, cash flows were positively impacted in 2007 as compared to 2006 because of the increase in accounts payable in 2007 compared to the decrease in 2006. Payables associated with fuel costs increased $6.6 million in 2007 while fuel payables decreased by $11.6 million in 2006. The change in prepaid expense and deferred charges resulted in a $9.6 million decrease in cash this year versus 2006. The negative cash flow impact of $15.5 million in cash outlays as a result of the 2007 ice storms, included in deferred charges, that have been deferred as regulatory assets are offset by the net effect of decreases to our regulatory asset accounts. These decreases reflect the recovery of deferred gas costs during the year, as well as changes in our pension and OPEB liabilities. An increase in accounts receivable compared to 2006 had a negative impact on cash flow. This resulted from an increase in unbilled accounts receivable of $6.0 million for our electric segment at December 31, 2007 and an increase in various miscellaneous accounts receivable items.

Our net cash flows provided by operating activities decreased $4.8 million during 2006 as compared to 2005. Cash flows were positively impacted mainly by a $15.5 million increase in net income and a $8.6 million cash flow change in accounts receivable and accrued unbilled revenues. There was also no pension contribution in 2006 as compared to an $11.5 million pension contribution in 2005. These positive impacts were offset mainly by a $28.8 million cash flow change in accounts payable and accrued liabilities and a $6.3 million cash flow change in fuel, materials and supplies. Changes in adjustments to net income for non-cash items were $2.9 million less in 2006 compared to 2005 mainly due to decreases in deferred income taxes.

Capital Requirements and Investing Activities

Our net cash flows used in investing activities decreased $38.4 million during 2007 as compared to 2006, primarily reflecting our acquisition of Missouri Gas in 2006. Partially offsetting this decrease in 2007 were additions to our transmission and distribution systems, construction expenditures for Plum Point Unit 1 and Iatan 2, capital expenditures related to the January and December 2007 ice storms and capital expenditures related to the new SCR at the Asbury Plant. Proceeds from the sale of the unit train added $1.2 million.

Our net cash flows used in investing activities increased $146.7 million during 2006 as compared to 2005, primarily reflecting our acquisition of Missouri Gas, additions to our transmission and distribution systems and construction expenditures for Plum Point Unit 1, Iatan 2 and the new combustion turbine at our Riverton Plant.

Our capital expenditures incurred for continuing operations total approximately $195.5 million, $120.2 million, and $73.2 million in 2007, 2006 and 2005, respectively (excluding the acquisition of Missouri

Gas in 2006). These capital expenditures include AFUDC, capital expenditures to retire assets and benefits from salvage.

A breakdown of these capital expenditures (including AFUDC) for 2007, 2006 and 2005 is as follows:

(in millions)	Capital Expenditures 2007	2006	2005
Distribution and transmission system additions	$ 43.5	$ 44.1	$36.2
New generation — Riverton combustion turbine	3.9	14.0	21.7
New generation — Plum Point Energy Station	29.8	19.6	0.0
New generation — Iatan 2	44.0	12.4	0.0
Storms(1)	26.9	1.2	0.1
Additions and replacements — Asbury	21.7	14.6	4.6
Additions and replacements — Iatan 1	14.2	5.1	0.7
Additions and replacements — Energy Center	0.8	0.5	0.2
Additions and replacements — State Line Combined Cycle Unit, Riverton and Ozark Beach	0.8	0.9	1.8
Additions and replacements — State Line Unit 1	0.5	0.6	2.0
Gas segment additions and replacements	1.8	0.9	0.0
Transportation	0.8	1.9	0.9
Other (including retirements and salvage — net)	1.8	1.8	3.0
Subtotal	$190.5	$117.6	$71.2
Non-regulated capital expenditures (primarily fiber optics)	5.0	2.6	2.0
Subtotal capital expenditures incurred(2)	$195.5	$120.2	$73.2
Less capital expenditures payable(3)	12.1	5.0	2.6
Total cash outlay	$183.4	$115.2	$70.6

(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) Expenditures incurred represent the total cost for work completed for the projects during the year. Discussion of capital expenditures throughout the 10-K is presented on this basis.

(3) The amount of expenditures unpaid at the end of the year and not reflected in the Investing Activities section of the Statement of Cash Flows.

Approximately 36%, 30% and 56% of our cash requirements for capital expenditures for 2007, 2006 (excluding the acquisition of Missouri Gas) and 2005, respectively, were satisfied with internally generated funds (funds provided by operating activities less dividends paid). The remaining amounts of such requirements were satisfied from short-term borrowings and proceeds from our sales of common stock and debt securities discussed below.

We estimate that our capital expenditures will total approximately $189.3 million in 2008, $121.2 million in 2009 and $121.0 million in 2010 (excluding AFUDC). Of these budgeted amounts, we anticipate that we will spend the following amounts over the next three years for the following projects:

Project	2008	2009	2010
Iatan 2	$72.4	$43.8	$33.1
Plum Point Energy Station	26.3	9.1	5.0
Combustion turbine for 2011	0.2	4.8	17.0
Electric distribution system additions	34.9	42.0	45.8
Electric transmission facilities additions	11.9	6.5	8.9
Environmental upgrades — Iatan 1	26.7	1.4	0.3

Construction on the Plum Point Energy Station began in the spring of 2006 with completion scheduled for 2010. Initially we will own, through an undivided interest, 50 megawatts of the project's capacity. We also have a long term purchased power agreement (30 years) for an additional 50 megawatts of the project's capacity and have the option to convert the 50 megawatts covered by the purchased power agreement into an ownership interest in 2015. We are planning a new combustion turbine at a still-to-be-determined site in 2011. See Note 12 of "Notes to Consolidated Financial Statements" under Item 8 for additional information regarding commitments.

Iatan 2 and Plum Point Unit 1 are important components of a long-term, least-cost resource plan to add approximately 200 megawatts of coal-fired generation to our system by mid-2010. The plan is driven by the continued growth in our service area and the expiration of a major purchase power contract in 2010.

We are installing pollution control equipment on Iatan 1 by 2008 which will include a Selective Catalytic Reduction (SCR) system, a Flue Gas Desulphurization (FGD) system and a baghouse, with our share of the capital cost estimated at $46 million (excluding AFUDC). We incurred approximately $12.1 million of this cost in 2007 and $3.9 million in 2006. For additional information, see Item 1, "Business — Environmental Matters."

We estimate that internally generated funds will provide approximately 22% of the funds required in 2008 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 Employee Stock Purchase Plan, our Dividend Reinvestment and Stock Purchase Plan, and our 401(k) Plan and 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.

Financing Activities

Our net cash flows from continuing operations provided by financing activities decreased $76.1 million to $67.0 million during 2007 as compared to $143.1 million in 2006, primarily due to increased repayments of short-term borrowings in 2007.

Our net cash flows from continuing operations provided by financing activities increased $142.3 million to $143.1 million during 2006 as compared to $0.9 million in 2005, primarily due to increased proceeds from the issuance of common stock and EDG first mortgage bonds in 2006.

On June 1, 2006, we used $55 million of privately placed 6.82% First Mortgage Bonds due 2036 issued by EDG to fund a portion of our acquisition of Missouri Gas. We used short-term debt to fund the remainder of the acquisition, which was replaced with common equity on June 21, 2006.

On June 21, 2006, we sold 3,795,000 shares of our common stock, including an additional 495,000 shares to cover the underwriters' over-allotments, in an underwritten public offering for $20.25 per share. The sale resulted in net proceeds of approximately $73.3 million ($76.8 million less issuance costs of $3.5 million). The proceeds were used to pay down short-term debt, including short-term debt used to fund a portion of our acquisition of Missouri Gas.

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.

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.

We have an effective shelf registration statement with the SEC under which approximately $174.2 million of our common stock, unsecured debt securities, preference stock and first mortgage bonds remain available for issuance. Of this amount, $120 million remains available of the original $200 million approved by the MPSC as available for first mortgage bonds. 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 until July 15, 2010. Borrowings (other than through commercial paper) are at the bank's prime commercial rate or LIBOR plus 100 basis points based on our current credit ratings and the pricing schedule in the line of credit facility. On March 14, 2006, we entered into the First Amended and Restated Unsecured Credit Agreement which amends and restates 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 $40.5 million as of February 1, 2008. 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, 2007, 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 were no outstanding borrowings under this agreement at December 31, 2007, however, $33.0 million of the availability thereunder was used at such date to back up our outstanding commercial paper.

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, 2007 would permit us to issue approximately $247.7 million of new first mortgage bonds based on this test with an assumed interest rate of 6.5%. In addition to the interest coverage requirement, the EDE Mortgage provides that new bonds must be issued against, among other things, retired bonds or 60% of net property additions. At December 31, 2007, we had retired bonds and net property additions which would enable the issuance of at least $565.5 million principal amount of bonds if the annual interest requirements are met. As of December 31, 2007, we believe we are in compliance with all restrictive covenants of the EDE Mortgage.

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. At December 31, 2007, we had property additions of $2.5 million. 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, 2007, this test would not allow us to issue any new first mortgage bonds. However, our current financing plan does not contemplate the need for additional EDG 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+
First Mortgage Bonds — Pollution Control Series	AAA	Aaa	AAA
Senior Notes	BBB	Baa2	BB+
Trust Preferred Securities	BBB-	Baa3	BB
Commercial Paper	F2	P-2	A-3
Outlook	Negative	Negative	Stable

On September 22, 2005, Standard & Poor's (S&P), reflecting our announcement of our proposed acquisition of Aquila, Inc.'s Missouri natural gas properties, placed our corporate credit rating on credit watch with negative implications. S&P stated that the acquisition comes in addition to our embarking on a capital spending program that is significantly higher than historical levels and will be partially debt financed. On February 13, 2006, S&P removed our corporate credit rating from credit watch, but placed us on negative outlook. S&P also reduced the rating on our commercial paper from A-2 to A-3 on February 21, 2006. This reduction made it more difficult for us to issue commercial paper and, as a result, our short-term debt during the period from February 21, 2006 to June 30, 2006, was in the form of borrowings under our revolving credit facility. However, beginning on June 30, 2006, we were able to again issue commercial paper at the current rating under a new agreement with Wells Fargo Bank. On May 17, 2006, S&P lowered our long-term corporate credit rating to BBB- from BBB, senior secured debt to BBB+ from A-, senior unsecured debt rating to BB+ from BBB- and affirmed our short-term rating of A-3. S&P's downgrade reflected their view that our financial measures will be constrained over the next several years by fuel and power costs that continue to exceed the level recoverable in rates, and by our higher-than-historical level of capital spending, including the acquisition of Missouri Gas. S&P affirmed our ratings on June 8, 2007 with a stable outlook.

Moody's affirmed our ratings on May 13, 2005 and revised their rating outlook on us from negative to stable. On January 24, 2007, Moody's again affirmed our ratings but changed their rating outlook on us back to negative. The change to a negative rating outlook reflects Moody's view on the longer-term prospects for our ratings given the sizable capital spending program we have committed to through 2010 and the potential for further weakness in our credit metrics that could develop during this time. On February 14, 2008, Moody's placed all of our ratings on review for possible downgrade. Moody's announced that the review will 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. The review will also consider the potential for elevated costs related to our capital spending plan in 2008. This action, as well as any actual downgrade of our commercial paper rating from Moody's, 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 higher-cost revolving credit facility.

On December 19, 2005, Fitch Ratings initiated coverage and assigned ratings (see table above) with a stable rating outlook. Fitch announced that their ratings reflect our low business risk position as a regulated electric utility, a stable service territory and a seemingly improving regulatory environment in Missouri where we receive approximately 89% of our electric revenues. On January 25, 2008, Fitch affirmed our ratings but revised their rating outlook to negative. The change to a negative rating outlook reflects uncertainty surrounding the outcome of our current rate filing and weakness in our projected financial measures relative to Fitch guidelines for the rating category. Recent events leading to the revision were storm damage in December 2007 and the extended outage of the Asbury baseload coal plant following a failed generator inspection.

CONTRACTUAL OBLIGATIONS

Set forth below is information summarizing our contractual obligations as of December 31, 2007. 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 postretirement benefit plans are funded on an ongoing basis to match their corresponding costs, per regulatory requirements and have been estimated for 2007–2011 as noted below. Future pension funding commitments are not expected to be material over the next 5 years and have not been estimated for later years.

	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)	$ 492.5	$ —	$ 70.0	$ —	$ 422.5
Note payable to securitization trust	50.0	—	—	—	50.0
Interest on long-term debt	617.3	34.2	64.3	58.7	460.1
Short-term debt	33.0	33.0	—	—	—
Capital lease obligations	0.8	0.3	0.5	—	—
Operating lease obligations[2]	3.8	1.5	1.1	0.5	0.7
Electric purchase obligations[3]	330.3	74.1	93.8	54.3	108.1
Gas purchase obligations[4]	73.6	11.1	14.1	14.6	33.8
Open purchase orders	37.3	35.1	2.1	0.1	—
Plum Point	53.4	31.4	22.0	—	—
SPP transmission system upgrades	11.7	11.7	—	—	—
Postretirement benefit obligation funding	11.4	2.0	4.5	4.9	—
Other long-term liabilities[5]	4.1	0.1	0.4	0.4	3.2
Total Contractual Obligations[6]	$1,719.2	$234.5	$272.8	$133.5	$1,078.4

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

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

(3) Includes a water usage contract for our SLCC facility, fuel and purchased power contracts and associated transportation costs, as well as purchased power for 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 as required by FIN 48 totaled $0.3 million at December 31, 2007. 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, 2007, our retained earnings balance was $17.2 million, compared to $22.9 million as of December 31, 2006, after paying out $39.0 million in dividends during 2007. A reduction of our dividend per share, partially or in whole, could have an adverse effect on our common stock price.

Our diluted earnings per share were $1.09 for the twelve months ended December 31, 2007 and were $1.39 and $0.92 for the years ended December 31, 2006 and 2005, respectively. Dividends paid per share were $1.28 for the twelve months ended December 31, 2007 and for each of the years ended December 31, 2006 and 2005.

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 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. As of December 31, 2007, our level of earned surplus did not prevent us from issuing dividends. Absent an amendment to the EDE Mortgage, we may not have sufficient earned surplus to pay our next quarterly dividend at the rate of $0.32 per share. As a result, we have commenced a consent solicitation to amend the EDE Mortgage to increase the earned surplus basket under the EDE Mortgage by $10.75 million. We believe that the consent solicitation, which is scheduled to expire on March 11, 2008, will be successful. However, we can give no assurance that this will be the case.

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, 2007, 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 (effective March 27, 2005), 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 calculate the value of plan assets using a market related value method (as allowed by Statement of Financial Accounting Standards No. 87 — "Employers' Accounting for Pensions" (FAS 87)). This is a change from the policy approved in the 2002 order, which allowed us to recover pension costs on an ERISA minimum funding (or cash) basis. Prior to the 2002 order, the MPSC allowed us to recover pension costs consistent with our GAAP policy. We had determined that the difference between the ERISA recovery allowed by the MPSC and our accounting for pension costs under GAPP did not meet the FAS 71 requirements for treatment as a regulatory asset or liability. As a result, we continue to account for pension expense or benefits in accordance with FAS 87, using the previously mentioned amortization formula for recognizing net gains or losses.

The MPSC ruled the 2005 change in the recognition of pension costs would allow 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 most recently approved Kansas Rate Case (effective January 1, 2006), 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 these amounts will be recovered in future rates. The regulatory asset will be reduced by an amount equal to the difference between the regulatory costs and the estimated FAS 87 costs. The difference between this total and the costs being recovered from customers will be deferred as a regulatory asset or liability. We now expect future pension expense or benefits will be fully recovered or recognized in rates charged to our Missouri and Kansas customers, thus lowering our sensitivity to risks and uncertainties.

Our 2006 Missouri rate case order allows us to defer any OPEB 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 September 29, 2006, the FASB issued FASB No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106 and 132R" (FAS 158). FAS 158 is intended to improve financial reporting by requiring 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 or changes in unrestricted net assets of a not-for-profit organization. We adopted FAS 158 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.

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 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 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).

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), while gains and losses from ineffective (overhedged) instruments are recognized as the fair value of the derivative instrument changes.

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. See Note 15 of "Notes to Consolidated Financial Statements" under Item 8 for detailed information regarding our hedging information.

As of February 15, 2008, approximately 88% of our anticipated volume of natural gas usage for our electric operations for the remainder of the year 2008 is hedged, either through physical or financial contracts, at an average price of $6.811 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 five years are hedged at the following average prices per Dth:

Year	% Hedged	Dth Hedged	Average Price
2009	55%	4,696,000	$6.060
2010	34%	3,200,000	$5.561
2011	34%	3,200,000	$5.561
2012	13%	1,200,000	$7.295
2013	13%	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 15, 2008, we have 93% of our expected remaining winter heating season usage (through March 2008) hedged with physical storage, physical forward contracts and financial derivative contracts. The average price of these hedges is $5.488 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 16, 2008, we had 0.4 million Dths in storage on the three pipelines that serve our customers. This represents 21% of our storage capacity. Our long-term hedge positions for gas purchased for resale are still in the development process. 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 SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (FAS 71), our financial statements reflect ratemaking policies prescribed by the regulatory commissions having jurisdiction over us (FERC and four states).

In accordance with FAS 71, we record a regulatory asset for all or part of an incurred cost that would otherwise be charged to expense if the conditions of paragraphs 9a and b of FAS 71 have been met. Additionally, we follow FAS 71 paragraph 11 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, and we believe that the regulatory assets and liabilities we have recorded will be afforded similar treatment. If these items are not afforded similar treatment they will be required to be recognized in our statement of income.

As of December 31, 2007, we have recorded $91.5 million in regulatory assets and $56.8 million in income taxes, gain on interest rate derivatives, pensions and other postretirement benefits and costs of removal as regulatory liabilities. See Note 4 of "Notes to Consolidated Financial Statements" under Item 8 for detailed information regarding our regulatory assets and liabilities.

We continually assess the recoverability of our regulatory assets. Under current accounting standards, regulatory assets and liabilities are eliminated through a charge or credit, respectively, to earnings if and when it is no longer probable that such amounts will be recovered through future revenues.

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 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. 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 2007, we believe that we have accrued liabilities in accordance with the guidelines of Statement of Financial Accounting Standards SFAS 5, "Accounting for Contingencies" (FAS 5) sufficient to meet potential liabilities that could result from these claims. This liability at December 31, 2007 and 2006 was $2.0 million and $1.6 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. We recorded goodwill upon the completion of the 2006 Missouri Gas acquisition of $39.5 million. Goodwill represents the excess of the cost of the acquisition over the fair value of the related net assets at the date of acquisition. In accordance with Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets," goodwill is required to be tested for impairment on an annual basis or whenever events or circumstances indicate possible impairment. Circumstances under which impairment could occur include not realizing anticipated synergies, adverse regulatory treatment or the loss of gas customers. In performing impairment tests, valuation techniques require the use of estimates with regard to discounted future cash flows of operations, involving judgments based on a broad range of information and historical results. If the test indicates impairment has occurred, goodwill would be reduced, adversely impacting earnings. We performed our annual goodwill impairment test as of November 30, 2007 and concluded our goodwill was not impaired.

Risks and uncertainties affecting these assumptions include: management's identification of impairment indicators, changes in business, industry, laws, technology or economic and market conditions, and valuation assumptions and conclusion.

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

Market risk is the exposure to a change in the value of a physical asset or financial instrument, derivative or non-derivative, caused by fluctuations in market variables such as interest rates or commodity prices. We handle our commodity market risk in accordance with our established Energy Risk Management Policy, which typically includes entering into various derivative transactions. We utilize derivatives 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 15 of "Notes to Consolidated Financial Statements" under Item 8 for further information.

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 7 and 8 of "Notes to Consolidated Financial Statements" under Item 8 for further information.

If market interest rates average 1% more in 2008 than in 2007, our interest expense would increase, and income before taxes would decrease by less than $0.4 million. This amount has been determined by considering the impact of the hypothetical interest rates on our highest month-end commercial paper balance for 2007. 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.

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 58.6% of our 2007 generation fuel supply need through coal. Approximately 86% of our 2007 coal supply was Western coal. We have contracts to supply fuel for our coal plants through 2010. These contracts and current inventory satisfy approximately 93% of our anticipated fuel requirements for 2008, 61% for 2009 and 48% for our 2010 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 minimize our risk from 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 expense and improve predictability. We expect that increases in gas prices will be partially offset by realized gains under financial derivative transactions. As of January 25, 2008, 88%, or 6.8 million Dths's, of our anticipated volume of natural gas usage for our electric operations for the remainder of 2008 is hedged. See Note 15 of "Notes to Consolidated Financial Statements" under Item 8 for further information.

Based on our expected natural gas purchases for our electric operations for 2008, if average natural gas prices should increase 10% more in 2008 than the price at December 31, 2007, our natural gas expense would increase, and income before taxes would decrease by approximately $0.9 million based on our December 31, 2007 total hedged positions for the next twelve months.

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 15, 2008, we have 93% of our expected remaining winter heating season usage (through March 2008) hedged with physical storage, physical forward contracts and financial derivative contracts. The average price of these hedges is $5.488 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 16, 2008, we have 0.4 million Dths in storage on the three pipelines that serve our customers. This represents 21% of our storage capacity. Our long-term hedge strategy for our gas segment is still in the development process. 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. Credit risk is the risk of financial loss to the Company if counterparties fail to perform their contractual obligations. 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. 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. Amounts reported as margin deposit liabilities represent funds we hold that result from various trading counterparties exceeding agreed-upon credit exposure thresholds. Amounts reported as margin deposit assets represent funds held on deposit by 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 recorded on our balance sheet at December 31:

(in millions)	2007	2006
Margin deposit assets	$6.3	$2.0
Margin deposit liabilities	$—	$3.9

In addition, we are holding a letter of credit from a counterparty in our favor for $6.5 million as of December 31, 2007.

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.

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. At January 25, 2008, gross credit exposure related to these transactions totaled $22.9 million, reflecting the unrealized gains for contracts carried at fair value.

Subprime Market Risk. We have evaluated our exposure to the current housing subprime risk environment and do not feel it has a significant effect on our business, financial position and results of operations. However, if the credit market continues to deteriorate, we will re-evaluate any effects.

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 accompanying index present fairly, in all material respects, the financial position of The Empire District Electric Company and its subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 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 accompanying index 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, 2007, 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 (which were integrated audits in 2007 and 2006). 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.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for share-based compensation and pension and other post-retirement benefits in fiscal 2006.

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 29, 2008

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
	($-000's)	
Assets		
Plant and property, at original cost:		
Electric	$1,409,217	$1,291,533
Natural gas	54,715	51,936
Water	10,353	10,126
Non-regulated	26,355	21,242
Construction work in progress	167,049	111,918
	1,667,689	1,486,755
Accumulated depreciation and amortization	488,816	456,635
	1,178,873	1,030,120
Current assets:		
Cash and cash equivalents	4,043	12,303
Accounts receivable — trade, net of allowance of $1,140 and $1,179 respectively	38,011	37,053
Accrued unbilled revenues	20,886	14,866
Accounts receivable — other	15,465	13,217
Fuel, material and supplies	49,482	46,613
Unrealized gain in fair value of derivative contracts	2,499	3,819
Prepaid expenses and other	3,308	3,711
Discontinued operations	—	94
	133,694	131,676
Noncurrent assets and deferred charges:		
Regulatory assets	91,460	94,395
Goodwill	39,492	39,323
Unamortized debt issuance costs	6,662	6,044
Unrealized gain in fair value of derivative contracts	17,520	11,812
Other	4,049	4,899
Discontinued operations	—	873
	159,183	157,346
Total assets	$1,471,750	$1,319,142

(Continued)

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

THE EMPIRE DISTRICT ELECTRIC COMPANY

CONSOLIDATED BALANCE SHEETS (Continued)

	December 31, 2007	December 31, 2006
	($-000's)	
Capitalization and liabilities		
Common stock, $1 par value, 100,000,000 shares authorized, 33,605,871 and 30,250,566 shares issued and outstanding, respectively	$ 33,606	$ 30,251
Capital in excess of par value	477,385	406,650
Retained earnings	17,153	22,916
Accumulated other comprehensive income, net of income tax	11,032	8,792
Total common stockholders' equity	539,176	468,609
Long-term debt, (net of current portion)		
Note payable to securitization trust	50,000	50,000
Obligations under capital lease	349	512
First mortgage bonds and secured debt	242,959	163,088
Unsecured debt	248,572	248,798
Total long-term debt	541,880	462,398
Total long-term debt and common stockholders' equity	1,081,056	931,007
Current liabilities:		
Accounts payable and accrued liabilities	79,282	55,288
Current maturities of long-term debt	150	141
Short-term debt	33,040	77,050
Customer deposits	8,414	7,239
Interest accrued	5,147	3,889
Unrealized loss in fair value of derivative contracts	1,611	1,372
Taxes accrued	2,931	2,744
Other current liabilities	328	1,790
Discontinued operations	—	174
	130,903	149,687
Commitments and contingencies (Note 12)		
Noncurrent liabilities and deferred credits:		
Regulatory liabilities	56,783	49,822
Deferred income taxes	165,989	140,838
Unamortized investment tax credits	3,441	3,971
Pension and other postretirement benefit obligations	14,115	26,136
Unrealized loss in fair value of derivative contracts	698	—
Other	18,765	17,496
Discontinued operations	—	185
	259,791	238,448
Total capitalization and liabilities	$1,471,750	$1,319,142

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,		
	2007	2006	2005
	($-000's, except per share amounts)		
Operating revenues:			
Electric	$425,161	$382,653	$358,981
Gas	59,877	25,145	—
Water	1,879	1,843	1,447
Non-regulated	3,243	2,530	2,292
	490,160	412,171	362,720
Operating revenue deductions:			
Fuel — Electric	113,559	93,955	112,755
Purchased power	77,671	66,339	52,720
Cost of natural gas sold and transported	37,626	15,285	—
Non-regulated — other	1,611	1,335	1,592
Regulated — other	71,367	60,092	54,173
Maintenance and repairs	32,059	23,150	20,874
Loss on plant disallowance	—	828	—
Gain on sale of assets	(1,241)	—	—
Depreciation and amortization	52,599	38,392	34,677
Provision for income taxes	14,416	21,947	12,603
Other taxes	24,927	21,027	19,406
	424,594	342,350	308,800
Operating income	65,566	69,821	53,920
Other income and (deductions):			
Allowance for equity funds used during construction	2,923	1,405	306
Interest income	326	389	341
Benefit/(provision) for other income taxes	(28)	16	(20)
Other — non-operating income	147	15	5
Other — non-operating expense	(1,116)	(977)	(957)
	2,252	848	(325)
Interest charges:			
Long-term debt	31,120	25,947	23,931
Note payable to securitization trust	4,250	4,250	4,250
Allowance for borrowed funds used during construction	(4,742)	(2,850)	(255)
Short-term debt	2,940	2,276	195
Other	1,069	1,017	530
	34,637	30,640	28,651
Income from continuing operations	33,181	40,029	24,944
Income (loss) from discontinued operations, net of tax	63	(749)	(1,176)
Net income	$ 33,244	$ 39,280	$ 23,768
Weighted average number of common shares outstanding — basic	30,587	28,277	25,898
Weighted average number of common shares outstanding — diluted	30,610	28,296	25,941
Earnings from continuing operations per weighted average share of common stock — basic and diluted	$ 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	$ 1.09	$ 1.39	$ 0.92
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 OTHER COMPREHENSIVE INCOME

	Year Ended December 31,		
	2007	2006	2005
		($-000's)	
Net income	$33,244	$ 39,280	$23,768
Reclassification adjustments for gains included in net income or reclassified to regulatory asset or liability	(1,610)	(1,320)	(2,964)
Net change in fair value of open derivative contracts for period	5,229	(13,604)	27,617
Income taxes	(1,379)	5,686	(9,397)
Net change in unrealized gain/(loss) on derivative contracts	2,240	(9,238)	15,256
Comprehensive income	$35,484	$ 30,042	$39,024

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

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

	December 31, 2007	December 31, 2006	December 31, 2005
		($-000's)	
Common stock, $1 par value:			
Balance, beginning of year	$ 30,251	$ 26,084	$ 25,696
Stock/stock units issued through:			
Public offering	3,000	3,795	—
Stock purchase and reinvestment plans	355	372	388
Balance, end of year	$ 33,606	$ 30,251	$ 26,084
Capital in excess of par value:			
Balance, beginning of year	$406,650	$329,605	$321,632
Excess of net proceeds over par value of stock issued:			
Public offering	62,779	69,519	—
Stock purchase and reinvestment plans	7,956	7,526	7,973
Balance, end of year	$477,385	$406,650	$329,605
Retained earnings:			
Balance, beginning of year	$ 22,916	$ 19,692	$ 29,078
Cumulative effect of adopting a change in accounting	(54)	—	—
Net income	33,244	39,280	23,768
	56,106	58,972	52,846
Less common stock dividends declared	38,953	36,056	33,154
Balance, end of year	$ 17,153	$ 22,916	$ 19,692
Accumulated other comprehensive income:			
Balance, beginning of year	$ 8,792	$ 18,030	$ 2,774
Reclassification adjustment for gains included in net income	(1,610)	(1,320)	(2,964)
Change in fair value of open derivative contracts for period	5,229	(13,604)	27,617
Income taxes	(1,379)	5,686	(9,397)
Balance, end of year	$ 11,032	$ 8,792	$ 18,030

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,		
	2007	2006	2005
		($-000's)	
Operating activities:			
Net income	$ 33,244	$39,280	$ 23,768
Adjustments to reconcile net income to cash flows:			
Depreciation and amortization	57,317	42,969	39,181
Pension and other postretirement benefit costs	9,490	5,689	6,412
Deferred income taxes and unamortized investment tax credit, net	18,681	845	7,080
Allowance for equity funds used during construction	(2,923)	(1,405)	(306)
Stock compensation expense	2,394	1,887	1,741
Loss on plant disallowance	—	828	—
Non cash gain on derivatives	(893)	(3,380)	(4,564)
Gain on the sale of assets	(1,241)	—	—
Gain on the sale of non-regulated businesses	(161)	(827)	—
Cash flows impacted by changes in:			
Accounts receivable and accrued unbilled revenues	(10,216)	(1,648)	(10,246)
Fuel, materials and supplies	(2,869)	(5,378)	912
Prepaid expenses, other current assets and deferred charges	(13,057)	(3,506)	(3,439)
Accounts payable and accrued liabilities	11,970	(8,235)	20,571
Pension contribution	—	—	(11,500)
Interest, taxes accrued and customer deposits	2,532	1,314	1,807
Other liabilities and other deferred credits	(811)	742	2,531
Net cash provided by operating activities of continuing operations	103,457	69,175	73,948
Net cash provided by operating activities of discontinued operations	208	2,197	223
Total net cash provided by operating activities	103,665	71,372	74,171

(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,		
	2007	2006	2005
		($-000's)	
Investing activities:			
Capital expenditures — regulated	$(178,469)	$(112,577)	$(68,638)
Acquisition of gas operations, net of cash acquired	—	(103,195)	—
Capital expenditures and other investments — non-regulated	(4,924)	(2,632)	(1,941)
Proceeds from the sale of property, plant and equipment	1,250	—	—
Proceeds from the sale of non-regulated businesses	3,240	1,095	—
Net cash used in investing activities of continuing operations	(178,903)	(217,309)	(70,579)
Net cash used in investing activities of discontinued operations	(12)	(366)	(624)
Total net cash used in investing activities	(178,915)	(217,675)	(71,203)
Financing activities:			
Proceeds from first mortgage bonds — electric	79,831	—	—
Proceeds from first mortgage bonds — gas	—	55,000	—
Payment of interest rate derivatives	—	—	(1,386)
Proceeds from issuance of senior notes	—	—	40,000
Proceeds from issuance of common stock, net of issuance costs	71,721	79,326	6,619
Long-term debt issuance costs	(1,078)	(751)	(541)
Redemption of first mortgage bonds	—	—	(40,000)
Premium paid on extinguished debt	—	—	(1,163)
Dividends	(38,953)	(36,056)	(33,154)
Net short-term (repayments) borrowings	(44,010)	46,098	30,952
Other	(452)	(507)	(473)
Net cash provided by financing activities of continuing operations	67,059	143,110	854
Net cash used in financing activities of discontinued operations	(69)	(396)	(410)
Net cash provided by financing activities	66,990	142,714	444
Net (decrease)/increase in cash and cash equivalents	(8,260)	(3,589)	3,412
Cash and cash equivalents, beginning of year	12,303	15,892	12,480
Cash and cash equivalents, end of year	$ 4,043	$ 12,303	$ 15,892

	2007	2006	2005
Supplemental cash flow information:			
Interest paid	$ 35,884	$ 31,258	$ 26,358
Income taxes (received) paid, net of refund	(1,211)	15,107	9,087
Capital lease obligations for purchase of new equipment	—	—	817
Supplementary non-cash financing activities:			
Accrued additions to property, plant and equipment not reported above	$ 12,175	$ 4,963	$ 2,653

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 formed to hold the Missouri Gas assets acquired from Aquila, Inc. on June 1, 2006. It provides natural gas distribution to communities in northwest, north central and west central Missouri. Our other segment consists of our non-regulated businesses, primarily a 100% interest in Empire District Industries Inc, a subsidiary for our fiber optics business. These businesses are held by our other operating segment. See Note 13. In 2007, 87.1% of our gross operating revenues were provided from sales from our electric segment (including 0.4% from the sale of water), 12.2% from sales from our gas segment and 0.7% 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 2007 were derived as follows: residential 41.1%, commercial 30.4%, industrial 15.9%, wholesale on-system 4.3%, wholesale off-system 4.6% and other 3.7%. Our retail electric revenues for 2007 by jurisdiction were as follows: Missouri 89.0%, Kansas 5.5%, Arkansas 2.7%, and Oklahoma 2.8%.

Our gas operations serve approximately 46,000 customers and the 2007 gas operating revenues were derived as follows: residential 65.5%, commercial 27.7%, industrial 1.2%, and other 5.6%.

Following is a description of the Company's significant accounting policies:

Basis of Presentation

The consolidated financial statements include the accounts of EDE, EDG, and EDE Holdings and its subsidiaries. The consolidated entity is referred to throughout as "we" or the "Company". Significant intercompany balances and transactions have been eliminated in consolidation. See Note 13 for additional information regarding our three segments. Certain reclassifications have been made to prior year information to conform to the current year presentation.

Discontinued Operations

In August and December 2006, we sold two of our non-regulated businesses, our controlling 52% interest in Mid-America Precision Products (MAPP) and our 100% interest in Conversant, respectively. MAPP specialized in close-tolerance custom manufacturing for the aerospace, electronics, telecommunications and machinery industries, and was sold to other current owners. We owned 100% of Conversant, a software company that marketed Customer Watch, an internet-based customer information system software. In September 2007, we also sold our 100% interest in Fast Freedom, Inc., an Internet service provider. For financial reporting purposes, these businesses have been classified as discontinued operations and are not included in our segment information.

Accounting for the Effects of Regulation

In accordance with Statement of Financial Accounting Standards SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (FAS 71), 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).

In accordance with FAS 71, we record a regulatory asset for all or part of an incurred cost that would otherwise be charged to expense if the conditions of paragraphs 9a and b of FAS 71 have been met. Additionally, we follow FAS 71 paragraph 11 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 FAS 71 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 FAS 71 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 4 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 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.

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 unbilled estimates are determined based on various assumptions, such as current month load requirements, billing rates by customer classification and loss factors. Changes in those assumptions can significantly affect the estimates of unbilled revenues. During 2006, the Company recorded a $5.9 million increase in electric unbilled revenues as a result of certain changes to the assumptions used in determining estimated unbilled revenues.

Through December 31, 2006 we collected an Interim Energy Charge (IEC) of $0.002131 per kilowatt hour of customer usage authorized by the MPSC. The IEC was designed to recover variable fuel and purchased power costs we incurred subject to a ceiling and floor on the amount recoverable (including realized gains or losses associated with our natural gas hedging program) which are higher than such costs included in the base rates allowed in the 2005 Missouri rate case. This revenue was recorded when service was provided to the customer and subject to refund to the extent collected amounts exceeded variable fuel and purchased power costs. At each balance sheet date, we evaluated the probability that we would be required to refund either a portion or all of the amounts collected under the IEC to ratepayers. No provision for refund was recorded. Effective January 1, 2007 the IEC was terminated as a result of an order issued by the MPSC on December 22, 2006.

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. In this case a gain or loss is recognized upon the disposal of the asset. We recognized a $1.2 million gain from the sale of our unit train in the fourth quarter. Maintenance expenditures and the removal of items not considered units of property are charged to income as incurred.

Until 2002, the depreciation/cost of service methodology utilized by our rate-regulated operations included an estimated cost of dismantling and removing plant from service upon retirement. From January 2002 through March 2005, we suspended accruing the cost of removing plant from service upon retirement through depreciation rates pursuant to the October 2001 Missouri rate case. Pursuant to our Missouri rate case, effective March 27, 2005, we began accruing cost of removal in depreciation rates reclassified for mass property (including transmission, distribution and general plant assets) on April 1, 2005. We reclassified the accrued cost of dismantling and removing plant from service upon retirement, which is not considered an asset retirement obligation under SFAS 143, "Accounting for Obligations Associated with the Retirement of Long-Lived Assets" (FAS 143), from accumulated depreciation to a regulatory liability. At December 31, 2007, and 2006, the amount of accrued cost of removal was $32.0 million and $27.4 million, respectively, for our electric operating segment. We have a similar cost of removal regulatory liability for our gas operating segment. This amount was $3.7 at December 31, 2007 and $4.0 million at December 31, 2006. These amounts are net of our actual cost of removal expenditures.

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 3 for additional details regarding depreciation rates).

In accordance with our December 21, 2006 order from the MPSC, we recorded approximately $10.4 million of regulatory amortization during 2007. 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 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.

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.

Allowance for Funds Used During Construction

As provided in the regulatory Uniform System of Accounts, utility plant is recorded at original cost, including an allowance for funds used during construction 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 7.6% for 2007, 7.2% for 2006 and 7.6% for 2005, 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 4 for additional discussion of our regulatory plan.)

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, 2007. In December 2006 we reduced the capitalized value of our Energy Center Units 3 and 4 by recording a charge to expense for $0.8 million. In our Missouri rate case (ER-2006-0315) Stipulation and Agreement as to Certain Issues, approved December 21, 2006, we agreed to this disallowance for regulatory purposes and recorded the charge to expense, once it was determined it would not be afforded rate recovery in Missouri rates. Until this stipulation was finalized on December 21, 2006, we considered these capitalized costs to be probable of recovery in rates. No other impairments existed at December 31, 2006.

Goodwill

We recorded goodwill of $39.5 million upon the completion of the 2006 Missouri Gas acquisition. Goodwill represents the excess of the cost of the acquisition over the fair value of the related net assets at the date of acquisition. In accordance with Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets," goodwill is required to be tested for impairment on an annual basis or whenever events or circumstances indicate possible impairment. Circumstances under which impairment could occur include not realizing anticipated synergies, adverse regulatory treatment or the loss of gas customers. In performing impairment tests, valuation techniques require the use of estimates with regard to discounted future cash flows of operations, involving judgments based on a broad range of information and historical results. If the test indicates impairment has occurred, goodwill would be reduced, adversely impacting earnings. We performed our annual goodwill impairment test as of November 30, 2007 and concluded our goodwill was not impaired.

Fuel and Purchased Power

Electric Segment

Fuel and purchased power expenses are recorded at the time the fuel is used or the power purchased for our Missouri electric jurisdictions. 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. Similar fuel recovery mechanisms are in place for our Oklahoma, Arkansas and the FERC jurisdictions. In our Kansas jurisdiction, the difference between the costs of fuel used and the cost of fuel recovered from our 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 FAS 71. We buy and sell power through the SPP RTO energy imbalance services market (EIS). We net settle these market transactions on an hourly basis.

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 routine regulatory review, the cost of purchased gas supplies. 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 SFAS 133, "Accounting for Derivative Instruments and Hedging Activities (FAS 133)", 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 other 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.

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 de-designated as a non-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 15).

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 and then 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 FAS 71, 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 expense calculation 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 (effective March 27, 2005), 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 FAS 87). This was a change from the policy approved in our 2002 order, effective December 1, 2002, which allowed us to recover pension costs on an ERISA minimum funding (or cash) basis. Prior to the 2002 order, the MPSC allowed the Company to recover pension costs consistent with our GAAP policy. We had determined that the difference between the ERISA recovery allowed by the MPSC and our accounting for pension costs under GAAP did not meet the FAS 71 requirements for treatment as a regulatory asset or liability. As a result, the Company continued to account for pension expense or benefits in accordance with FAS 87, using the previously mentioned amortization formula for recognizing net gains or losses.

The MPSC ruled the 2005 change in the recognition of pension costs would allow the Company to record the Missouri portion of any costs above the amount included in the 2005 rate case as a regulatory asset or recognize a regulatory liability for costs incurred that are less than those allowed in rates. Therefore, the deferral of these costs began in the second quarter of 2005. In the most recently approved Kansas Rate Case (effective January 1, 2006), 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 order approved April 18, 2006 by 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 related to the acquisition of Missouri Gas have been recorded as regulatory assets, as these amounts will be recovered in future rates. The regulatory asset will be reduced by an amount equal to the difference between the regulatory costs and the estimated FAS 87 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 FAS 71, and recovered over a period of five years.

Other Postretirement Benefits (OPEB)

In our most recent Missouri rate case, effective January 1, 2007, 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 the third quarter of 2004, we adopted FASB staff position No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003". Beginning December 31, 2004, 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.

On December 31, 2006, we adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106 and 132R" (FAS 158). FAS 158 is intended to improve financial reporting by requiring 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. FAS 158 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. Based on the regulatory treatment of pension and OPEB recovery afforded in the Company's jurisdictions, the Company has concluded that the amount of unfunded defined benefit pension and postretirement plan obligations are probable of future rate recovery and are recorded as regulatory assets on the balance sheet rather than as reductions of equity through comprehensive income. (See Note 9).

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 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 12).

Franchise Taxes

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. Franchise taxes of $10.0 million, $7.3 million and $6.4 million were recorded for each of the years ended December 31, 2007, 2006 and 2005, respectively.

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. At December 31, 2007 and 2006, these amounts were $13.2 million and $12.7 million, 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):

	2007	2006
Electric fuel inventory	$16,643	$12,213
Natural gas inventory	5,639	9,184
Materials and supplies	27,200	25,216
Total	$49,482	$46,613

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 10).

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 24 years.

Computations of Earnings Per Share

Basic earnings per share are computed by dividing net income by the weighted average number of common shares outstanding. Diluted earnings per share are computed by dividing net income by the weighted average number of common shares outstanding plus the incremental shares that would have been outstanding under the assumed exercise of dilutive restricted shares and options.

Weighted Average Number Of Shares	2007	2006	2005
Basic	30,586,780	28,276,568	25,898,428
Dilutive shares	23,571	19,827	42,680
Total Dilutive Shares	30,610,351	28,296,395	25,941,108
Antidilutive Shares	**48,903**	**48,903**	**41,115**

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

Stock-Based Compensation

At December 31, 2007, we had several stock-based compensation plans, which are described in more detail in Note 5. During 2002, we adopted SFAS No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure — an Amendment of SFAS 123" (FAS 148), and elected to adopt the accounting provision of FAS 123 "Accounting for Stock-Based Compensation" (FAS 123). Under FAS 123, we recognized compensation expense over the vesting 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. We adopted FAS 123(R) "Share Based Payment" on January 1, 2006 using the modified prospective approach. (See Note 5 — "Common Stock"). The adoption of FAS 123(R) did not have a material impact on our stock compensation expense.

Asset Retirement Obligation

We account and report for legal obligations associated with the retirement or anticipated retirement of tangible long-lived assets in accordance with SFAS No. 143 "Accounting for Obligations Associated with the Retirement of Long-Lived Assets" (FAS 143) and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47). 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 2006 and 2007 are shown below.

(000's)	Liability Balance 12/31/06	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions	Liability Balance at 12/31/07
Asset Retirement Obligation	$3,448	$ —	$ —	$104	$(219)	$3,333

Upon adoption of these standards, 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, 2007, and 2006, our regulatory assets relating to AROs totaled $2.9 million and $3.0 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 FAS 143, from accumulated depreciation to a regulatory liability. This balance sheet reclassification has no impact on results of operations.

Accounting for Uncertainty in Income Taxes

On July 13, 2006, the FASB issued Interpretation No. 48 (FIN 48), which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, "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, or non-U.S. income tax examinations by tax authorities for years before 2003. We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, 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 January 1, 2007 and December 31, 2007, our balance sheet included approximately $219,000 and $328,000, 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.

Recently Issued and Proposed Accounting Standards

On September 15, 2006, the FASB issued FASB No. 157, "Fair Value Measurements" (FAS 157), which provides guidance for using fair value to measure assets and liabilities. FAS 157 also responds to investors' requests for more information about (1) the extent to which companies measure assets and liabilities at fair value, (2) the information used to measure fair value and (3) the effect that fair-value measurements have on earnings. FAS 157 will apply whenever another standard requires (or permits) assets or liabilities to be measured at fair value. This standard does not expand the use of fair value to any new circumstances. FAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. On February 12, 2008 the FASB delayed the effective date of FAS 157 for certain nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The delay is intended to allow the Board and constituents additional time to consider the effect of various implementation issues that have arisen, or that may arise, from the application of FAS 157. We do not expect the pronouncement or the delay to have a material effect on our financial statements.

On February 15, 2007, the FASB issued FASB No. 159, "The Fair-Value Option for Financial Assets and Financial Liabilities — including an amendment of FAS 115" (FAS 159). Under FAS 159, a company may elect to measure eligible financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been elected are reported in earnings at each subsequent reporting date. FAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007. We have not yet completed our review regarding 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.

On April 30, 2007, the FASB issued FASB Staff Position No. 39-1 (FIN 39), an "Amendment of FASB Interpretation No. 39". FIN 39-1 is effective for fiscal years ending after November 15, 2007. It amends paragraph 3 of Interpretation 39 to replace the terms "conditional contracts and exchange contracts" with the term "derivative instruments as defined in FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities". It also amends paragraph 10 of Interpretation 39 to permit a reporting entity to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement that have been offset in accordance with that paragraph. We currently do not apply this offsetting alternative. We are still evaluating this staff position, but do not believe it will have an impact on our financial statements.

On December 1, 2007, the FASB issued SFAS 141(R) "Business Combinations" (FAS 141(R)) and SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51" (FAS 160). FAS 141(R) and FAS 160 are effective for business combinations entered into in fiscal years beginning on or after December 15, 2008. FAS 141 (R) changes the definitions of a business and a business combination, and will result in more transactions recorded as business combinations. Certain acquired contingencies will be recorded initially at fair value on the acquisition date, transactions and restructuring costs generally will be expensed as incurred and in partial acquisitions, companies generally will record 100 percent of the assets and liabilities at fair value, including goodwill. We do not expect these pronouncements to have an effect on our financial statements unless we enter into future business combinations.

2. Acquisition of Missouri Natural Gas Distribution Operations

On September 21, 2005, we announced that we had entered into an Asset Purchase Agreement pursuant to which we agreed to acquire the Missouri natural gas distribution operations of Aquila, Inc. This acquisition was completed by EDG on June 1, 2006. This transaction was subject to the approval of the MPSC, which was obtained, effective May 1, 2006. The total purchase price, including working capital and net plant adjustments but excluding acquisition costs, was $102.5 million. We recorded $39.5 million of goodwill as a result of the acquisition. All of this is expected to be tax deductible.

The components of the purchase price allocation for the Missouri Gas acquisition are shown below. (See Note 7 — "Long-Term Debt", for the information on the purchase price financing). Assets and liabilities are valued at fair value. In the case of property, plant and equipment, fair value is calculated in a manner consistent with the amount recoverable for regulatory treatment.

(in thousands)	Missouri Gas
Purchase Price:	
Cash paid	$102,502
Acquisition costs	2,447
Total	$104,949
Allocation:	
Property, plant and equipment	$ 52,226
Current assets	15,292
Goodwill	39,492
Other assets	11,082
Other liabilities	(13,143)
Total	$104,949

2007 changes to the goodwill reflect minor true-up items primarily relating to accounts receivable and pension adjustments in the first quarter.

The following presents certain consolidated proforma financial information for the years ended December 31, 2006 and 2005, as if our acquisition of Missouri Gas had been completed as of the beginning of 2005. These estimates are based on historical results of the Missouri Gas operations, provided to us by Aquila, Inc., and are unaudited. In addition, they do not include the effects of any financing costs (in thousands).

	2006	2005
Proforma revenues	$441,815	$421,899
Proforma net income from continuing operations	$ 41,586	$ 26,052
Proforma earnings per share from continuing operations — basic and diluted	$ 1.38	$ 0.88

3. Property, Plant and Equipment

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

	December 31, 2007	December 31, 2006
Electric plant		
Production	$ 550,339	$ 511,862
Transmission	191,595	176,978
Distribution	596,245	535,428
General(1)	71,038	67,265
Electric plant	1,409,217	1,291,533
Less accumulated depreciation and amortization	476,657	447,777
Electric plant net of depreciation and amortization	932,560	843,756
Construction work in progress	166,685	110,517
Net electric plant	1,099,245	954,273
Gas plant	54,715	51,936
Less accumulated depreciation and amortization	2,936	919
Gas plant net of accumulated depreciation	51,779	51,017
Construction work in progress	220	1,195
Net gas plant	51,999	52,212
Water plant	10,353	10,126
Less accumulated depreciation and amortization	3,145	2,933
Water plant net of depreciation and amortization	7,208	7,193
Construction work in progress	60	8
Net water plant	7,268	7,201
Other		
Fiber	26,310	21,197
Other non-regulated property	45	45
Less accumulated depreciation and amortization	6,078	5,006
Non-regulated net of depreciation and amortization	20,277	16,236
Construction work in progress	84	198
Net non-regulated property	20,361	16,434
Net plant and property	$1,178,873	$1,030,120

(1) Includes intangible property of $11.6 million as of December 31, 2007, primarily related to capitalized software. Accumulated amortization related to this property in 2007 was $6.9 million.

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):

	2007	2006	2005
Provision for depreciation			
Regulated — Electric and Water	$39,577	$37,174	$34,637
Regulated — Gas	1,967	1,104	—
Non-Regulated	1,077	877	807
Total	42,621	39,155	35,444
Amortization[1]	11,310	777	776
Total	$53,931	$39,932	$36,220

(1) Includes $10.4 million of regulatory amortization granted by the MPSC effective January 1, 2007

	2007	2006	2005
Annual depreciation rates			
Electric	3.0%	3.0%	2.8%
Gas	3.7%	2.1%	—
Other	4.5%	4.4%	4.5%
Total company	3.0%	2.9%	2.9%

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

	2007	2006	2005
Annual Weighted Average Depreciation Rate			
Electric fixed assets:			
Production plant	2.2%	2.2%	2.2%
Transmission plant	2.3%	2.3%	2.2%
Distribution plant	3.6%	3.5%	3.3%
General plant	6.1%	6.1%	6.5%
Water	2.7%	2.8%	2.6%
Gas[1]	3.7%	2.1%	—
Other	4.5%	4.4%	4.5%

(1) The 2006 reflects a 7 month rate. On an annualized basis, the rate is 3.7%.

4. 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.

Electric Segment

The following table sets forth information regarding electric and water rate increases since January 1, 2005:

Jurisdiction	Date Requested	Annual Increase Granted	Percent Increase Granted	Date Effective
Missouri — Electric	February 1, 2006	$29,369,397	9.96%	January 1, 2007
Missouri — Water	June 24, 2005	469,000	35.90%	February 4, 2006
Kansas — Electric	April 29, 2005	2,150,000	12.67%	January 4, 2006
Arkansas — Electric	July 14, 2004	595,000	7.66%	May 14, 2005
Missouri — Electric	April 30, 2004	25,705,500	9.96%	March 27, 2005

Missouri

On April 30, 2004, we filed a request with the MPSC for an annual increase in base rates for our Missouri electric customers in the amount of $38,282,294, or 14.82%. On December 22, 2004, we, the MPSC Staff, the Office of the Public Counsel (OPC) and two intervenors filed a unanimous Stipulation and Agreement as to Certain Issues with the MPSC settling several issues. One of the issues we were able to agree on was a change in the recognition of pension costs allowing us to defer the Missouri portion of any costs above or below the amount included in this rate case as a regulatory asset or liability. The amount of pension cost allowed in this rate case was approximately $3.0 million. This stipulation became effective on March 27, 2005 as part of the final Missouri order described below. Therefore, the deferral of these costs began in the second quarter of 2005.

The MPSC issued a final order on March 10, 2005 approving an annual increase in base rates of approximately $25,705,500, or 9.96%, effective March 27, 2005. The order granted us a return on equity of 11%, an increase in base rates for fuel and purchased power at $24.68/MWH and an increase in depreciation rates. The new depreciation rates included a cost of removal component of mass property (transmission, distribution and general plant costs). In addition, the order approved an annual Interim Energy Charge (IEC) of approximately $8.2 million effective March 27, 2005 and expiring three years later. The IEC was $0.002131 per kilowatt hour of customer usage. The MPSC allowed us to use forecasted fuel costs rather than the traditional historical costs in determining the fuel portion of the rate increase. At the end of two years, an assessment would be made of the money collected from customers compared to the greater of the actual and prudently incurred costs or the base cost of fuel and purchased power set in rates. If the excess of the amount collected over the greater of these two amounts was greater than $10 million, the excess over $10 million would be refunded to the customers. The entire excess amount of IEC, not previously refunded, would be refunded at the end of three years, unless the IEC was terminated earlier. Each refund was to include interest at the current prime rate at the time of the refund. The IEC revenues recorded since the inception of the IEC did not recover all the Missouri related fuel and purchased power costs incurred during that period. From inception of the IEC through December 31, 2006, the costs of fuel and purchased power were approximately $22.3 million higher than the total of the costs in our base rates and the IEC recorded during the period, therefore, no provision for refund was recorded.

On February 1, 2006, we filed a request with the MPSC for an annual increase in base rates for our Missouri electric customers in the amount of $29,513,713, or 9.63%. We also requested transition from the IEC from an earlier case to Missouri's new fuel adjustment mechanism. The MPSC issued an order May 2, 2006, however, ruling that we may have the option of requesting that the IEC be terminated, but we may not request the implementation of an energy cost recovery mechanism while the current IEC is effective. The MPSC issued an order on December 21, 2006 granting us an annual increase of $29,369,397 (including regulatory amortization), or 9.96%, with an effective date of January 1, 2007 and eliminating the IEC. Pursuant to this order, the collected IEC was not refunded. The increase included an authorized return on equity of 10.9% and included our fuel and energy costs as a component of base electric rates. Of the increase, approximately $19 million was granted in the form of base rates, with the remainder of approximately $10.4 million granted as regulatory amortization to provide additional cash flow to enhance the financial support for our current generation expansion plan. This regulatory amortization is related to our investment in Iatan 2 and also includes our Riverton V84.3A2 combustion turbine (Unit 12) and the environmental improvements and upgrades at Asbury and Iatan 1. This order also allowed deferral of any other postretirement benefits that are 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 order also approved regulatory treatment of additional liabilities arising from the adoption of FAS 158. We also agreed to write off $1 million of the cost of our Energy Center 2 construction project. The Missouri jurisdictional portion of this agreement resulted in a pre tax write off of $0.8 million in the fourth quarter of 2006.

On December 29, 2006, the Office of Public Counsel (OPC) and intervenors Praxair, Inc. and Explorer Pipeline Company, filed an application with the MPSC requesting the MPSC grant a rehearing on most of the issues addressed in the December 2006 Missouri rate case order and many of the procedural issues. On December 29, 2006, we also filed an application with the MPSC requesting a rehearing on return on equity, capital structure and energy cost recovery. A decision by the MPSC is pending.

Praxair and Explorer Pipeline filed a Petition for Writ of Review with the Cole County Circuit Court on January 31, 2007. The Circuit Court issued a Writ, but the MPSC moved to have the Writ set aside on the basis that it was issued prematurely. On March 20, 2007, Praxair and Explorer filed a motion in the Circuit Court writ proceeding requesting an immediate stay of the effectiveness of our December 2006 Missouri rate case order and the tariffs filed pursuant thereto. Without an order being issued on the stay motion, pursuant to an agreement of the parties, the Circuit Court set aside the Writ and dismissed the case.

On January 4, 2007, the OPC filed a Petition for Writ of Mandamus with the Missouri Court of Appeals, Western District, seeking to have the order approving tariffs issued by the MPSC on December 29, 2006, set aside. On March 12, 2007, the Court of Appeals issued an order denying the OPC's petition.

On March 19, 2007, the OPC filed a Petition for Writ of Mandamus with the Missouri Supreme Court seeking an order requiring the MPSC to vacate and rescind its December 29, 2006 order approving tariffs and directing the MPSC to provide an effective date for any subsequent tariff approval order that allows at least ten days to prepare and file an application for rehearing. On May 1, 2007, the Missouri Supreme Court issued a preliminary writ directing the MPSC to respond to the OPC's petition. Following briefs and oral argument, on October 30, 2007, the Supreme Court made its preliminary writ peremptory and issued an opinion directing the MPSC to vacate its December 29 order approving tariffs and allow the Public Counsel a reasonable time to prepare and file an application for rehearing. The Court did not examine the lawfulness or reasonableness of the substance of the MPSC's December 29, 2006 order approving tariffs, and considered only the timing of the issuance of the order. The Court also did not consider the underlying tariffed rates which continue in force and in effect. Acting upon this opinion, the MPSC issued an order on December 4, 2007, effective December 14, 2007, vacating the December 29, 2006 order and re-approving the tariffs and the same resulting increase in rates. The OPC and intervenors Praxair, Inc. and Explorer Pipeline Company, filed an application with the MPSC requesting the MPSC grant a rehearing on the December 4, 2007 order. All applications for rehearing remain pending before the MPSC.

On October 1, 2007, we filed a request with the MPSC for an annual increase in base rates for our Missouri electric customers in the amount of $34.7 million, or 10.11%. This request is to allow us to recover our investment in the new 150-megawatt combustion turbine, Unit 12, at our Riverton Plant, capital expenditures associated with the construction of a selective catalytic reduction system at our Asbury Plant, capital expenditures and expenses related to the 2007 ice storms and other changes in our underlying costs. We are also requesting implementation of a fuel adjustment clause in Missouri which would permit the distribution to Missouri customers of changes in fuel and purchased power costs.

On June 24, 2005, we filed a request with the MPSC for an annual increase in base rates for our Missouri water customers in the amount of $523,000, or 38%. The MPSC issued a final order on January 31, 2006 approving an annual increase in base rates of approximately $469,000, or 35.9%, effective February 4, 2006.

Arkansas

On July 14, 2004, we filed a request with the APSC for an annual increase in base rates for our Arkansas electric customers in the amount of $1,428,225, or 22.1%. On May 13, 2005, the APSC granted an annual increase in electric rates for our Arkansas customers of approximately $595,000, or 7.66%, effective May 14, 2005.

Kansas

On April 29, 2005, we filed a request with the Kansas Corporation Commission (KCC) for an increase in base rates for our Kansas electric customers in the amount of $4,181,078, or 24.64%. On October 4, 2005, we and the KCC Staff filed a Motion to Approve Joint Stipulated Settlement Agreement (Agreement) with the KCC. The Agreement called for an annual increase in base rates (which includes historical fuel costs) for our Kansas electric customers of approximately $2,150,000, or 12.67%, the implementation of an Energy Cost Adjustment Clause (ECA), a fuel rider that will collect or refund fuel costs in the future that are above or below the fuel costs included in the base rates and the adoption of the same depreciation rates approved by the MPSC in our 2005 Missouri rate case. In addition, we will be allowed to change our recognition of pension costs, deferring the Kansas portion of any costs above or below the amount included in this rate case as a regulatory asset or liability. The KCC approved the Agreement on December 9, 2005 with an effective date of January 4, 2006. Pursuant to the Agreement, we were to seek KCC approval of an explicit hedging program in a separate docket by March 1, 2006. However, we requested and received an extension until April 1, 2006. We made this filing on March 30, 2006. On February 4, 2008, the KCC issued an order denying the request for the approval of our existing natural gas hedging program. All gains or losses related to the financial instruments used to fix the future price of natural gas will be excluded from recovery through the ECA and future base electric rates in Kansas.

We have filed applications for Accounting Authority Orders in Oklahoma and Kansas respecting costs incurred due to the 2007 ice storms.

Gas Segment

On June 1, 2006, The Empire District Gas Company acquired the Missouri natural gas distribution operations of Aquila, Inc. (Missouri Gas). The Missouri Gas properties consist of 44 Missouri communities in northwest, north central and west central Missouri. The rates, excluding the cost of gas, are the same as had been in effect at Aquila, Inc. We agreed in the unanimous stipulation and agreement filed with the MPSC on March 1, 2006 and approved on April 18, 2006, to not file a rate increase request for non-gas costs for a period of 36 months following the closing date of the acquisition. We have also agreed to use Aquila Inc.'s current depreciation rates and were allowed to adopt the pension cost recovery methodology approved in our electric Missouri Rate Case effective March 27, 2005.

A PGA clause is included in our gas rates which allows for the over recovery or under recovery of actual gas costs compared to the cost of gas in the PGA rate. This PGA clause allows us to make rate changes periodically (up to four times) throughout the year in response to weather conditions, natural gas prices and supply demands, rather than in one possibly extreme change per year. The Actual Cost Adjustment (ACA) is a scheduled yearly filing with the MPSC filed between October 15 and November 4 each year. This filing establishes the amount to be recovered from customers for the over/under recovered yearly amounts. A PGA is included in the ACA filing. An optional PGA filing without the ACA can be filed up to three times each year, provided a filing does not occur within 60 days of a previous filing. Our last ACA filing was completed on October 24, 2007.

Competition

Electric Segment

SPP-RTO

On February 1, 2007, the SPP regional transmission organization (RTO) launched its energy imbalance services market (EIS). With the implementation of the SPP RTO EIS market and transmission expansion plans of the SPP RTO, we anticipate that our continued participation in the SPP will provide long-term benefits to our customers and other stakeholders. Although our experience to date in the EIS market is limited, we believe we have received benefits through our participation. Our active participation and assessment of EIS market benefits continues.

In general, the SPP RTO EIS market is providing 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.

We will continue to actively engage with the SPP RTO, other members of the SPP and staffs of our state commissions to evaluate the impact and value of EIS market participation.

On February 16, 2007, the FERC issued a Final Order No. 890, which instituted numerous reforms to its Order 888 open access transmission pro forma tariff (OATT) which was issued in April 1996. The purpose of the Order was (i) to strengthen the OATT to ensure that it better achieves its original purpose of remedying undue discrimination for the provision of transmission service, (ii) to provide greater specificity in the OATT to reduce opportunities for the exercise of undue discrimination, make undue discrimination easier to detect, and facilitate the FERC's enforcement, and (iii) to increase transparency in the rules applicable to planning and use of the transmission system. The FERC's actions required modifications to the SPP and our OATTs as well as regional and local transmission planning processes. We and SPP submitted our respective Order 890 compliance filings of our OATTs on October 11, 2007.

Compliance modifications to our OATT filing were not material and we anticipate them being accepted. The SPP proposed modifications to its regional and local area transmission planning processes, pursuant to Order 890, in its December 7, 2007 FERC filing. An issuance from the FERC on our and SPP's filings is pending. In December 2007, the FERC issued Order 890A, reconfirming its February Order 890.

The FERC Market Power Order

In April and July 2004, the FERC issued orders regarding new testing standards for assessing market power by entities that have wholesale market-based rate tariffs filed with the FERC. The parameters included in the tests are such that most investor owned electric utilities fail the test within their own control area and are subject to a rebuttable presumption of market power. Entities with wholesale market based rates tariffs are subject to a triennial filing to test for market power and are required to apply the new testing criteria. The FERC determination of market power would result in the inability for a utility to continue to charge such market-based rates. In September 2004, we submitted amended and updated market power analyses filings.

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, which could amount to approximately $0.6 million (excluding interest) covering over a thousand hourly energy sales from the period of May 2005 through August 2006 to numerous counterparties external to our system. In response to the order, we filed a Motion For Extension of time and expedited treatment regarding the refund and requested that such refund be delayed until 15 days after the FERC's order on our rehearing request. On September 5, 2006, the FERC granted the Motion For Extension, as requested.

On September 14, 2006, we filed a Request For Rehearing of the FERC's August 15 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. The FERC's decision on the refund is still pending.

On June 21, 2007, the FERC issued a Final Rule related to Market-Based Rates for Wholesales of Electric Energy, Capacity, and Ancillary Services by Public Utilities which directly affects our market power assessment within our service area and Request For Rehearing related to the aforementioned pending potential refund. In reaction to the Final Rule, we were required to modify our Market Based Rate Tariff in the form of a compliance filing to the FERC, which was made on September 17, 2007. The FERC's ruling on our compliance filing is also pending. We have implemented revisions to our wholesale power sales business practices in accordance with the Final Rule.

Other FERC Rulemaking

Also 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. The FERC is seeking comment in the following areas: (i) the role of demand response in the organized markets, (ii) increasing opportunities for long-term power contracts, (iii) strengthening market monitoring and (iv) the responsiveness of RTOs and ISOs to customers and stakeholders.

On January 28, 2008, we made a filing at the FERC related to certain non-rate and ministerial revisions to our currently effective wholesale Open Access Transmission Tariff (OATT), which included the elimination of certain tariff sections that have become moot in light of our membership in the SPP, as well as correction of the formatting of our OATT for consistency with Order No. 614. The FERC's acceptance of the proposed updates to our OATT 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 FAS No. 71, we currently have deferred approximately $1.0 million of expense related to rate cases under other non-current assets and deferred charges of which $0.3 million is related to the Missouri rate case filed in October 2007, $0.1 million is directly related to the Missouri rate case that was completed in the first quarter of 2005 and $0.3 million for the Missouri rate case completed in 2006. We amortize this amount over varying periods upon the completion of the specific case. As of December 31, 2007, $0.1 million in expense related to the 2006 Kansas rate case completed is unamortized. Based on past history, we expect all these expenses to be recovered in rates.

Regulatory Assets and Liabilities and Other Deferred Credits

We have recorded the following regulatory assets and regulatory liabilities (in thousands).

	December 31, 2007	December 31, 2006
Regulatory Assets		
Income taxes	$30,947	$27,893
Unamortized loss on reacquired debt	14,813	16,136
Unamortized loss on interest rate derivative	2,719	3,035
Asbury five-year maintenance	2,054	—
Pension and other postretirement benefits(1)	22,760	40,145
Ice storm costs	15,518	—
Asset retirement obligations	2,971	3,022
Unrecovered purchase gas costs and Kansas fuel costs(2)	(1,282)	3,024
Other	960	1,140
Total regulatory assets	$91,460	$94,395
Regulatory Liabilities		
Income taxes	11,214	$12,100
Unamortized gain on interest rate derivative	4,391	4,561
Gain on disposition of emission allowances	328	361
Costs of removal	35,724	31,461
Pension and other postretirement benefits(1)	5,126	1,339
Total regulatory liabilities	$56,783	$49,822

(1) The costs associated with our pension and OPEB plans are recovered in rates charged to customers in all of our jurisdictions. To facilitate this recovery, our Missouri regulators have permitted us to use a tracking mechanism to capture the difference between pension and OPEB costs determined in accordance with FAS 87 and FAS 106 and the amount of pension and OPEB costs which are currently part of our rates. Our Kansas regulators also allow similar treatment for pension costs. This difference is recorded as a regulatory asset or liability in accordance with FAS 71. Generally the costs will be recovered or refunded through our future rates granted by our regulators over a period of five years. Also, pursuant to an order reached with the MPSC, (Case No. GO-2006-0205) it was agreed that the effects of pension and OPEB purchase accounting entries related to the Missouri Gas acquisition would be recoverable in future rate proceedings, therefore regulatory assets for these acquisition entries have been recorded in accordance with FAS 71.

Additionally, when we adopted the provisions of FAS No. 158, we concluded that the additional unfunded pension and OPEB obligations required to be recorded on our balance sheet by FAS No. 158 were also probable of future rate recovery based on, among other factors, the FAS 87 and FAS 106 rate recovery mechanisms present in our jurisdictions. Thus a regulatory asset was recorded to offset any charges that would otherwise have been recorded to accumulated other comprehensive income under FAS 158. (See Note 1 regarding pension and OPEB accounting).

Since January 1, 2007, approximately $3.8 million in additional regulatory liabilities and corresponding expense increases have been recognized as a result of this ratemaking treatment. In addition, approximately $0.5 million in pension and other postretirement benefit costs have been recognized since January 1, 2007 to reflect the amortization of the regulatory assets that were recorded at the time of the acquisition of the Aquila, Inc. gas properties.

(2) The tables above include the effects of the PGA clause related to our gas segment and the over or under recovery of Kansas fuel 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 regulatory liability until the balance is recovered from or credited to customers. (See Note 1 regarding fuel costs).

As of December 31, 2007, the costs of all of our regulatory assets are being currently recovered except for approximately $14.2 million of pension and other postretirement costs primarily related to the additional liabilities for future pension and OPEB costs recorded under FAS 158, and $15.5 million of deferred ice storm costs. Since cost recovery of extraordinary storm costs have historically been allowed in rate cases in all of our jurisdictions, we expect them to be approved in future rate case proceedings. The amount and timing of recovery 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 and gain on reacquired debt and the interest rate derivatives are amortized over the life of the related new debt issue, which currently ranges from 6 to 28 years.

5. Common Stock

Recent Issues

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. Effective January 1, 2006, we adopted FAS 123(R) "Share-Based Payment" and applied it to our stock-based awards and programs using the modified prospective approach. We had previously recognized compensation expense over the vesting 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. The adoption of FAS 123(R) did not have a material impact on our financial results, as compared to prior periods.

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):

	2007	2006	2005
Compensation expense	$2,122	$1,670	$1,584
Tax benefit recognized	772	599	566

Stock Incentive Plans

Our 1996 Incentive Plan (the 1996 Stock Incentive Plan) provided for the grant of up to 650,000 shares of common stock through January 2006. The 1996 Stock Incentive Plan permitted grants of stock options and restricted stock to qualified employees and permitted Directors to receive common stock in lieu of cash compensation for service as a Director. 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 to receive common stock in lieu of cash compensation for service as a Director. The terms of the 2006 Incentive Plan are substantially the same as the 1996 Stock Incentive Plan. Awards made prior to 2006 were made under the 1996 Stock Incentive Plan. Awards made on or after January 1, 2006 are made under the 2006 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 2005, 2006 and 2007 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.

For the 2005 grants related to stock incentive plans and performance based restricted stock awards described above, the fair value of these stock awards was determined based on the number of shares granted and the quoted price of our stock on the date of grant of $22.77. Upon adoption of FAS 123(R), the fair value of the estimated shares awarded under the 2006 and 2007 grants were estimated on the date of grant using a lattice-based option valuation model with the assumptions noted in the following table:

	2007	2006
Risk-free interest rate	5.09% to 4.88%	4.60% to 4.54%
Expected volatility of Empire stock	16.6%	15.2%
Expected volatility of peer group stock	18.9%	19.8%
Expected dividend yield on Empire stock	5.55%	5.80%
Expected forfeiture rates	3%	3%
Plan cycle	3 years	3 years
EDE percentile performance	25th	33rd
Fair value percentage	107.73%	108.13%
Grant date	1/31/2007	2/01/2006
Grant date fair value per share	$25.65	$24.04

Non-vested restricted stock awards (based on target number) as of December 31, 2007, 2006 and 2005 and changes during the year ended December 31, 2007, 2006 and 2005 were as follows:

	2007		2006		2005	
	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
Nonvested at January 1,	38,800	$22.25	40,300	$20.76	47,100	$20.32
Granted	17,700	$23.81	13,600	$22.23	12,100	$22.77
Awarded	(7,598)	$21.79	(7,954)	$18.25	(8,815)	$20.95
Not awarded	(5,502)	$ —	(7,146)	$ —	(10,085)	$ —
Nonvested at December 31,	43,400	$23.02	38,800	$22.25	40,300	$20.76

At December 31, 2007, unamortized 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.

The dividend equivalents are accumulated for the three-year period and are converted to shares of our common stock based on the fair market value of the shares on the date converted. To be in compliance with Section 409A of the Internal Revenue Code added by the American Jobs Creation Act of 2004, the dividend equivalent awards were changed to vest and be 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. This modification did not have a material impact on our financial statements.

A summary of option activity under the plan during the year ended December 31, 2007, 2006 and 2005 is presented below:

	2007		2006		2005	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Outstanding at January 1,	135,000	$22.21	142,500	$20.84	173,100	$20.45
Granted	64,200	$23.81	41,700	$22.23	39,100	$22.77
Exercised	(50,000)	$21.79	(49,200)	$18.25	(69,700)	$20.95
Outstanding at December 31,	149,200	$23.04	135,000	$22.21	142,500	$20.84
Exercisable, end of year	4,200	$21.79	—	$ —	—	$ —

The aggregate intrinsic value at December 31, 2007, 2006 and 2005 was approximately $0.0 million, $0.3 million and $0.1 million, respectively. 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 weighted-average remaining contractual life of outstanding options at December 31, 2007, 2006 and 2005 was 7.6, 8.1 and 8.1 years, respectively. As of December 31, 2007, this includes 4,200 shares at the weighted average price of $21.79, which are vested and exercisable. All others are non-vested. As of December 31, 2007, there was $0.3 million of unrecognized compensation expense. The range of exercise prices as of December 31, 2007 was $21.79 — $23.81.

The fair value of the options granted, which is amortized to expense over the option vesting period, has been determined on the date of grant using the methods and assumptions outlined in the table below.

	2007	2006	2005
Stock Options Valuation Methodology	**Black-Scholes**	**Black-Scholes**	**Expanded Black-Scholes**
Weighted average fair value of grants	$2.38	$1.65	$4.38
Risk-free interest rate	4.68%	3.27%	3.63%
Dividend yield[1]	5.33%	6.16%	0%
Expected volatility[2]	16.13%	18.14%	15.51%
Expected life in months	60	60	60
Grant Date	1/31/07	2/1/06	2/3/05

(1) The 2005 grant was valued using an Expanded Black-Scholes method, which included a valuation component for the existence of dividend equivalents, rather than a separate assumption for the dividend equivalents issued under Black-Scholes. In 2006 and 2007, dividend equivalents were separated from the evaluation.

(2) One year historic volatility.

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, 2007, there were 480,812 shares available for issuance in this plan. The adoption of FAS 123(R) did not change the valuation of the options granted under this plan.

	2007	2006	2005
Subscriptions outstanding at December 31,	40,672	38,707	39,391
Maximum subscription price	$ 21.23[1]	$ 20.05	$ 21.03
Shares of stock issued	37,686	39,322	43,133
Stock issuance price	$ 20.05	$ 19.62	$ 18.00

(1) Stock will be issued on the closing date of the purchase period, which runs from June 1, 2007 to May 31, 2008.

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

	2007	2006	2005
Weighted average fair value of grants	$3.40	$3.19	$3.24
Risk-free interest rate	4.98%	5.02%	3.25%
Dividend yield	5.43%	5.75%	5.5%
Expected volatility(1)	18.01%	18.3%	15.38%
Expected life in months	12	12	12
Grant date	6/1/07	6/1/06	6/1/05

(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 provided 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, 2007, there were 97,231 shares accrued to directors' accounts and 356,206 shares available for issuance under this plan.

	2007	2006	2005
Units granted for service	12,702	11,018	9,528
Units granted for dividends	5,147	4,523	3,842
Units redeemed for common stock	3,299	3,119	1,642

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, 2007, there were 52,092 shares available to be issued.

	2007	2006	2005
Shares contributed	47,563	46,123	40,313

Dividends

Holders of our common stock are entitled to dividends, if, as and when declared by our Board of Directors out of funds legally available therefore subject to the prior rights of holders of our outstanding cumulative preferred 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). Also, the EDE Mortgage and our Restated Articles contain certain dividend restrictions. The most restrictive 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 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. As of December 31, 2007, our level of earned surplus did not prevent us from issuing dividends. Absent an amendment to the EDE Mortgage, we may not have sufficient earned surplus to pay our next quarterly dividend at the rate of $0.32 per share. As a result, we have commenced a consent solicitation to amend the EDE Mortgage to increase the earned surplus basket under the EDE Mortgage by $10.75 million. We believe that the consent solicitation, which is scheduled to expire on March 11, 2008, will be successful. However, we can give no assurance that this will be the case.

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, 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, 2007, there were no such restrictions on our ability to pay dividends.

6. 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, 2007 or 2006.

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 33.5 million and 30.2 million Rights outstanding at December 31, 2007 and 2006, 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.

7. Long-Term Debt

At December 31, 2007 and 2006, the balance of long-term debt outstanding was as follows (in thousands):

	2007	2006
Note payable to securitization trust(1)	$ 50,000	$ 50,000
First mortgage bonds (EDE):		
8⅛% Series due 2009	20,000	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	
First mortgage bonds (EDG):		
6.82% Series due 2036(3)	55,000	55,000
	243,200	163,200
Senior Notes, 7.05% Series due 2022(2)	49,289	49,587
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	499	654
Less unamortized net discount	(958)	(902)
	542,030	462,539
Less current obligations of long-term debt	—	—
Less current obligations under capital lease	(150)	(141)
Total long-term debt	$541,880	$462,398

(1) Represented by our Junior Subordinated Debentures, 8½% Series due 2031. We may redeem some or all of the debentures at any time on or after March 1, 2006, 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.

Financing Activities

On June 1, 2006, we used $55 million of privately placed 6.82% First Mortgage Bonds due 2036 issued by EDG to fund a portion of our acquisition of Missouri Gas. We used short-term debt to fund the remainder of the acquisition, which was replaced with common equity on June 21, 2006.

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 an effective shelf registration statement with the SEC under which approximately $174.2 million of our common stock, unsecured debt securities, preference stock and first mortgage bonds remain available for issuance. Of this amount, $120 million remains available of the original $200 million approved by the MPSC as available for first mortgage bonds. 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) are 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, 2007 would permit us to issue approximately $247.7 million of new first mortgage bonds based on this test with an assumed interest rate of 6.5%. In addition to the interest coverage requirement, the EDE Mortgage provides that new bonds must be issued against, among other things, retired bonds or 60% of net property additions. At December 31, 2007, we had retired bonds and net property additions which would enable the issuance of at least $565.5 million principal amount of bonds if the annual interest requirements are met. As of December 31, 2007, we believe we are in compliance with all restrictive covenants of the EDE Mortgage.

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. At December 31, 2007, we had property additions of $2.5 million. 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, 2007, this test would not allow us to issue any new first mortgage bonds. However, our current financing plan does not contemplate the need for additional EDG first mortgage bonds.

The carrying amount of our total debt exclusive of capital leases at December 31, 2007 was $541.5 million compared to a fair market value of approximately $524.0 million. The 2006 carrying amount for total debt exclusive of capital leases approximated its fair market value. 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
2008	$ 151	$ —	$ —	$151
2009	20,174	—	20,000	174
2010	50,170	—	50,000	170
2011	4	—	—	4
2012	—	—	—	—
Thereafter	472,489	50,000	422,489	—
Total long-term debt obligations	$542,988	$50,000	$492,489	$499
Less current obligations and unamortized discount	1,108			
Total long-term debt	$541,880			

8. Short-Term Borrowings

At December 31, 2007, commercial paper comprised $33.0 million of short-term debt. Short-term commercial paper outstanding and notes payable averaged $51.0 million and $39.6 million daily during 2007 and 2006, respectively, with the highest month-end balances being $81.0 million and $77.1 million, respectively. The weighted average interest rates during 2007 and 2006 were 5.76% and 5.74% in each period. The weighted average interest rate of borrowings outstanding at December 31, 2007 was 5.76%,

On July 15, 2005, we entered into a $150 million unsecured revolving credit facility until July 15, 2010. Borrowings (other than through commercial paper) are at the bank's prime commercial rate or LIBOR plus 100 basis points based on our current credit ratings and the pricing schedule in the line of credit facility.

On March 14, 2006, we entered into the First Amended and Restated Unsecured Credit Agreement which amends and restates 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 $40.5 million as of February 1, 2008. 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, 2007, 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 were no outstanding borrowings under this agreement at December 31, 2007, however, $33.0 million of the availability thereunder was used at such date to back up our outstanding commercial paper.

9. Retirement Benefits

We record retirement benefits in accordance with FAS 158 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. All of the benefit plans have been measured as of December 31, 2007, 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.

We expect there to be no contribution required under ERISA to the trust in order to maintain minimum funding levels in 2008. This could change in future years, however, based on actual investment performance, changes in interest rates, any future pension plan funding, reform legislation and finalization of actuarial assumptions.

Expected benefit payments are as follows (in millions):

Year	Payments from Trust
2008	$ 7.0
2009	7.5
2010	7.9
2011	8.4
2012	8.9
2013 – 2017	52.4

Other Postretirement Benefits (OPEB)

We provide certain healthcare and life insurance benefits to eligible retired employees, their dependents and survivors through trusts we have established. Participants generally become eligible for retiree healthcare benefits after reaching age 55 with 5 years of service.

Our funding policy is to contribute annually an amount at least equal to the revenues collected for the amount of postretirement benefit costs allowed in rates. Based on the performance of the trust assets through December 31, 2007, we expect to be required to fund approximately $1.1 million in 2008.

Estimated benefit payments are as follows (in millions):

Year	Payments from Trust	Expected Federal Subsidy
2008	$ 2.4	$0.3
2009	2.7	0.3
2010	2.9	0.3
2011	3.2	0.4
2012	3.4	0.4
2013 – 2017	21.3	2.6

The following tables reflect the effect of the acquisition of the Missouri Gas assets from Aquila, Inc., on June 1, 2006, and set forth the Company's benefit plans' projected benefit obligation, the fair value of the plans' assets and the funded status (in thousands).

Reconciliation of Projected Benefit Obligations:

	Pension		SERP		OPEB	
	2007	2006	2007	2006	2007	2006
Benefit obligation at beginning of year	$ 136,260	$ 123,088	$ 1,889	$ 1,844	$ 63,011	$ 56,674
Service cost	3,492	3,354	50	48	1,705	1,866
Interest cost	8,238	7,368	117	105	3,416	3,425
Amendments	3,832	—	(84)	—	(5,894)	(246)
Net actuarial (gain)/loss	(5,191)	(3,403)	95	(46)	(4,126)	(1,867)
Plan participant's contribution	—	—	—	—	631	685
Benefits and expenses paid	(6,278)	(6,055)	(61)	(62)	(2,545)	(2,545)
Federal subsidy	—	—	—	—	257	205
Acquisition of Missouri gas	—	11,908	—	—	—	4,814
Benefit obligation at end of year	$ 140,353	$ 136,260	$ 2,006	$ 1,889	$ 56,455	$ 63,011

Reconciliation of Fair Value of Plan Assets:

	Pension		SERP		OPEB	
	2007	2006	2007	2006	2007	2006
Fair value of plan assets at beginning of year	$ 126,812	$ 109,276	$ —	$ —	$ 47,727	$ 39,149
Actual return on plan assets — gain	11,405	11,137	—	—	3,323	4,393
Employer contribution	—	—	—	—	3,037	4,958
Benefits paid	(6,278)	(6,055)	—	—	(2,462)	(2,474)
Plan participant's contribution	—	—	—	—	608	661
Federal subsidy	—	—	—	—	247	200
Acquisition of Missouri gas	—	12,454	—	—	—	840
Fair value of plan assets at end of year	$ 131,939	$ 126,812	$ —	$ —	$ 52,480	$ 47,727

Reconciliation of Funded Status:

	Pension		SERP		OPEB	
	2007	2006	2007	2006	2007	2006
Fair value of plan assets	$ 131,939	$ 126,812	$ —	$ —	$ 52,480	$ 47,727
Projected benefit obligations	(140,353)	(136,260)	(2,006)	(1,889)	(56,455)	(63,011)
Funded status	$ (8,414)	$ (9,448)	$(2,006)	$(1,889)	$ (3,975)	$(15,284)

The employee pension plan accumulated benefit obligation at December 31, 2007, and 2006, is presented in the following table (in thousands):

	Pension Benefits		SERP	
	2007	2006	2007	2006
Accumulated benefit obligation	$123,310	$118,633	$1,304	$1,158

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

	Pension		SERP		OPEB	
	2007	2006	2007	2006	2007	2006
Other current liabilities	$ —	$ —	$ 164	$ 61	$ 116	$ 103
Pension and other postretirement benefit obligation	$ 8,414	$ 9,448	$ 1,842	$ 1,828	$ 3,859	$ 15,181

Net periodic benefit pension cost for 2007, 2006 and 2005, some of which is capitalized as a component of labor cost and some of which is deferred as a regulatory asset, is comprised of the following components (in thousands):

Net Periodic Pension Benefit Cost:

	Pension			OPEB		
	2007	2006	2005	2007	2006	2005
Service cost	$ 3,492	$ 3,355	$ 3,472	$ 1,705	$ 1,866	$ 2,070
Interest cost	8,238	7,368	6,685	3,416	3,425	3,312
Expected return on plan assets	(10,300)	(9,512)	(7,701)	(3,398)	(2,781)	(2,368)
Amortization of:						
Unrecognized transition obligation	—	—	—	—	—	1,084
Prior service cost	588	447	494	(1,011)	(461)	(609)
Actuarial loss	2,601	3,174	3,357	1,152	2,398	1,920
Net periodic benefit cost	$ 4,619	$ 4,832	$ 6,307	$ 1,864	$ 4,447	$ 5,409

Net Periodic Pension Benefit Cost:

	SERP 2007	SERP 2006
Service cost	$ 50	$ 48
Interest cost	117	105
Expected return on plan assets	—	—
Amortization of:		
Unrecognized transition obligation	—	—
Prior service cost	(11)	—
Actuarial loss	146	146
Net periodic benefit cost	$302	$299

Our net periodic pension benefit cost, exclusive of capitalized and deferred amounts, net of tax, as a percentage of net income for 2007, 2006 and 2005 was 6.9%, 6.0% and 10.7%, respectively.

Upon adoption of FAS 158 on December 31, 2006, we 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 effect of these entries, including the tax benefit of the Medicare Part D subsidy, are reflected as deferred tax assets and liabilities and regulatory liabilities.

The initial adoption had the following increase or (decrease) effect on our balance sheet accounts at December 31, 2006 (in millions):

Pension and other post-retirement liabilities	$ 15.1
Prepaid pension assets	$(14.9)
Regulatory assets	$ 30.0
Deferred tax assets	$ 17.9
Deferred tax liabilities	$ 11.5
Regulatory liabilities	$ 6.4

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

Regulatory Assets	Beginning Balance 12/31/06	Amount Recognized: Current Year Actuarial (Gain)/ Loss	Amortization of Actuarial Loss	Current Year Prior Service Cost/ (Credit)	Amortization of Prior Service (Cost)/ Credit	Ending Balance 12/31/07
Pension	$24,330	$(6,296)	$(2,601)	$ 3,832	$ (588)	$18,677
SERP	$ 1,270	$ 95	$ (146)	$ (84)	$ 11	$ 1,146
OPEB	$ 4,400	$(4,028)	$(1,152)	$(5,894)	$1,011	$(5,663)

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, 2007, and the subsequent twelve-month period (in thousands):

	Pension Benefits		SERP		OPEB	
	2007	Subsequent Period	2007	Subsequent Period	2007	Subsequent Period
Net actuarial loss	$13,754	$1,615	$1,218	$122	$ 3,997	$ 558
Transition obligation/(asset)	$ —	$ —	$ —	$ —	$ —	$ —
Prior service cost (benefit)	$ 4,923	$ 744	$ (72)	$ (8)	$(9,660)	$(1,010)
Total	$18,677	$2,359	$1,146	$114	$(5,663)	$ (452)

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	
	2007	2006	2007	2006
Discount rate	6.40%	5.90%	6.40%	5.90%
Rate of compensation increase	4.50%	4.25%	4.50%	4.25%

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

	Pension Benefits			OPEB		
	2007	2006	2005	2007	2006	2005
Discount rate	5.90%	5.65%	5.75%	5.90%	5.65%	5.75%
Expected return on plan assets	8.50%	8.50%	8.50%	7.45%	6.80%	6.80%
Rate of compensation increase	4.25%	4.00%	4.25%	4.25%	4.00%	5.00%

To determine the discount rate assumption used in our December 31, 2007 and December 31, 2006 plan obligation estimates, we used an interest rate yield curve that enables companies to make judgments pursuant to Emerging Issues Task Force EITF Topic No. D-36, "Selection of Discount Rates Used for Measuring Defined Benefit Pension Obligations and Obligations of Post Retirement Benefit Plans Other Than Pensions." 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 our pension plan and develop a single-point discount rate matching the plan's payout structure.

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 2007 cost trend rate used to measure the expected cost of healthcare benefits and benefit obligation is 8.50%. Each trend rate decreases 0.50% through 2014 to an ultimate rate of 5.0% in 2014 and subsequent years.

The effect of a 1% increase in each future year's assumed healthcare cost trend rate on the current service and interest cost components of the net periodic benefit cost is $0.5 million, increasing the service and interest cost from $5.1 million to $5.6 million. The effect on the accumulated postretirement benefit obligation is $7.8 million, increasing the obligation from $56.5 million to $64.3 million. The effect of a 1%

decrease in each future year's assumed healthcare cost trend rate for these components is $0.4 million which would decrease the current service and interest cost from $5.1 million to $4.7 million. The effect on the accumulated benefit obligation is $6.8 million, decreasing the obligation from $56.5 million to $49.7 million.

Allocation of Plan Assets

	% of Fair Value as of December 31,			
	2007		2006	
Pension	**Actual**	**Target**	**Actual**	**Target**
Equity securities	71.8%	60% – 80%	70.8%	60% – 80%
Debt securities	28.2%	20% – 40%	29.2%	20% – 40%
Other	0%	0% – 15%	0%	0% – 15%
Total	100%	100%	100%	100%

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 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.

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

Allocation of Plan Assets

	% of Fair Value as of December 31,			
	2007		2006	
OPEB	Actual	Target	Actual	Target
Cash equivalent	3.2%	0% – 10%	3.1%	0% – 10%
Fixed income	40.3%	40% – 60%	41.0%	40% – 60%
Equities	56.5%	40% – 60%	55.9%	40% – 60%
Total	100%	100%	100%	100%

We utilize fair value in determining the market-related values for the different classes of our postretirement 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 the component of the fund used to pay current benefits are liquidity and safety. The primary investment goals for the component of the 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 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.

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

10. Income Taxes

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

	2007	2006	2005
Current income taxes:			
Federal	$(3,788)	$18,410	$ 5,113
State	(540)	2,630	923
Total	(4,328)	21,040	6,036
Deferred income taxes:			
Federal	16,895	1,091	6,280
State	2,407	330	847
Total	19,302	1,421	7,127
Investment tax credit amortization	(530)	(530)	(540)
Income tax from continuing operations	14,444	21,931	12,623
Income tax from discontinued operations	39	(461)	(723)
Total income tax expense	$14,483	$21,470	$11,900

Deferred Income Taxes

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

Deferred Income Taxes	December 31, 2007	2006
Current deferred tax liability (included in other current liabilities)	$ 381	$ 911
Non-current deferred tax liabilities, net	165,989	140,838
Net deferred tax liabilities	$166,370	$141,749

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

Temporary Differences	December 31, 2007	2006
Deferred tax assets:		
Disallowed plant costs	$ 1,218	$ 1,318
Gains on hedging transactions	1,673	1,738
Plant related basis differences	11,881	10,531
Regulated liabilities related to income taxes	4,793	5,730
Pensions and other post-retirement benefits	20,036	24,924
Other	695	702
Total deferred tax assets	$ 40,296	$ 44,943
Deferred tax liabilities:		
Depreciation, amortization and other plant related differences	$145,340	$127,817
Regulated assets related to income	30,947	27,893
Loss on reacquired debt	5,504	6,008
Accumulated other comprehensive income	6,790	5,411
Losses on hedging transactions	1,036	1,157
Pensions and other post-retirement benefits	8,048	16,167
Deferred ice storm expenses	5,912	—
Amortization of intangibles	1,613	533
Other	1,476	1706
Total deferred tax liabilities	206,666	186,692
Net deferred tax liabilities	$166,370	$141,749

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	2007	2006	2005
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	(1.1)	(0.9)	(1.5)
Effect of ratemaking on property related differences	(4.1)	(1.3)	(1.0)
Other	(2.6)	(0.6)	(2.2)
Effective income tax rate	30.3%	35.3%	33.4%

Unrecognized Tax Benefits	Amount
Unrecognized tax benefits — 01/01/07	$219,000
The gross amounts of increases and decreases in unrecognized tax benefits as a result of tax positions taken during the current period	109,000
Unrecognized tax benefits — 12/31/07	$328,000

If unrecognized tax benefits are recognized, the effective tax rate would change from 30.3% to 29.7%. The Company did not recognize any interest or penalties during 2007 related to unrecognized tax benefits in other expenses or on the balance sheet. The Company does not expect any significant changes to our unrecognized tax benefits over the next twelve months.

11. 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, 2007 and 2006, our property, plant and equipment accounts included the cost of our ownership interest in the plant of $49.4 million and $50.5 million, respectively, and accumulated depreciation of $34.0 million and $36.3 million, respectively. Expenditures recorded for our portion of ownership were $8.4 million and $7.5 million for 2007 and 2006, respectively, excluding depreciation expenses. 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. The new permit limits Unit No. 1 to a maximum of 6,600 MMBtu per hour of heat input. This heat input limit allows Unit No. 1 to produce a total of 652 net megawatts and as a result, our share decreased from 80 megawatts to 78 megawatts. The 6,600 MMBtu per hour heat input limit is in effect until the new SCR, Scrubber, and baghouse are completed, currently estimated to be late in the fourth quarter of 2008. 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 Aquila own 70% and 18% respectively, of the Unit. KCP&L operates the unit for the joint owners. 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.

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, 2007 and 2006, our property, plant and equipment accounts include the cost of our ownership interest in the unit of $154.4 million and $154.2 million, respectively, and accumulated depreciation of $31.5 million and $27.0 million, respectively. Expenditures recorded (as operating and maintenance expenses) for our portion of ownership were $68.5 million and $49.3 million for 2007 and 2006, respectively, excluding depreciation.

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

12. 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 of Statement of Financial Accounting Standards SFAS 5, "Accounting for Contingencies" (FAS 5). 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 affect upon our financial condition, or results of operations or cash flows.

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. The firm physical gas and transportation commitments total $47.5 million for 2008, $47.8 million for 2009 through 2010, $46.2 million for 2011 through 2012 and $72.4 million for 2013 and beyond. In the event that this gas cannot be used at our plants, the gas would be liquidated at market price.

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 the extended Asbury maintenance outage, we have issued force majeure notices to our Western coal suppliers and to the railroads suspending Western coal shipments during the outage. This relieves us of our contractual obligations to receive shipments of coal to the extent caused by the Asbury outage. The minimum requirements are $20.9 million for 2008 and $29.3 million for 2009 through 2010.

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 $39.1 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 near Osceola, Arkansas. Construction began in the spring of 2006 with completion scheduled for 2010. We have the option to convert the 50 megawatts covered by the purchased power agreement into an ownership interest in 2015. Commitments under this contract total approximately $48.0 million through June 30, 2015.

We have entered into a 20-year purchased power agreement with Cloud County Windfarm, LLC, owned by Horizon Wind Energy, Houston, Texas to purchase the energy generated at the approximately 105-megawatt Phase 1 Meridian Way Wind Farm to be located in Cloud County, Kansas and a 20-year contract with Elk River Windfarm, LLC, owned by PPM Energy, to purchase the energy generated at the 150-megawatt Elk River Windfarm located in Butler County, Kansas. Although these agreements are considered operating leases under GAAP, payments for these wind agreements are recorded as purchased power expenses, and, because of the contingent nature of these payments, are not included in the operating lease obligations discussed 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. The estimated cost is approximately $86.5 million, excluding AFUDC. In addition, we entered into an agreement with Kansas City Power & Light (KCP&L) on June 13, 2006 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. Construction began in the spring of 2006 with completion scheduled for 2010. We expect our share of the Iatan 2 construction costs will range from approximately $183.6 million to $200.5 million, excluding AFUDC.

Leases

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. The agreement provides for a 20-year term commencing with the commercial operation date, which is expected to be about January 1, 2009. We will begin taking delivery of the energy at that time. 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 to be 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, which was declared commercial on December 15, 2005. 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 wind 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.

We also currently have short-term operating leases for two unit trains to meet coal delivery demands and garage and office facilities for our electric segment and six service center properties for our gas segment. In addition we have a five-year capital lease for telephone equipment.

The gross amount of assets recorded under capital leases total $1.3 million.

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

	Capital Leases
2008	$ 288
2009	288
2010	241
2011	3
Thereafter	—
Total minimum payments	$ 820
Less amount representing maintenance	274
Net minimum lease payments	546
Less amount representing interest	47
Present value of net minimum lease payments	$ 499

	Operating Leases
2008	$1,503
2009	712
2010	372
2011	319
2012	224
Thereafter	674
Total minimum payments	$3,804

Expenses incurred related to operating leases were $1.4 million, $0.9 million and $0.7 million for 2007, 2006, and 2005, respectively. The accumulated amount of amortization for our capital leases was $0.2 million at December 31, 2007.

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 wastes, including their identification, transportation, disposal, record-keeping and reporting, as well as other environmental matters. We believe that our operations are in compliance with present laws and regulations.

Electric Segment

Air. The 1990 Amendments to the Clean Air Act, referred to as the 1990 Amendments, affect the Asbury, Riverton, State Line and Iatan Power Plants and Units 3 and 4 (the FT8 peaking units) at the Empire Energy Center. The 1990 Amendments require affected plants to meet certain emission standards, including maximum emission levels for sulfur dioxide (SO2) and nitrogen oxides (NOx). The Asbury Plant became an affected unit under the 1990 Amendments for SO2 on January 1, 1995 and for NOx as a Group 2 cyclone-fired boiler on January 1, 2000. The Iatan Plant became an affected unit for both SO2 and NOx on January 1, 2000. The Riverton Plant became an affected unit for NOx in November 1996 and for SO2 on January 1, 2000. The State Line Plant became an affected unit for SO2 and NOx on January 1, 2000.

Units 3 and 4 at the Empire Energy Center became affected units for both SO2 and NOx in April 2003. The new Riverton Unit 12 became an affected unit in January 2007.

SO2 Emissions. Under the 1990 Amendments, the amount of SO2 an affected unit can emit is regulated. Each existing affected unit has been awarded a specific number of emission allowances, each of which allows the holder to emit one ton of SO2. Utilities covered by the 1990 Amendments must have emission allowances equal to the number of tons of SO2 emitted during a given year by each of their affected units. The annual reconciliation of allowances, which occurs on a facility wide basis, is held each March 1 for the previous calendar year. Allowances may be traded between plants or utilities or "banked" for future use. A market for the trading of emission allowances exists on the Chicago Board of Trade. The Environmental Protection Agency (EPA) withholds annually a percentage of the emission allowances awarded to each affected unit and sells those emission allowances through a direct auction. We receive compensation from the EPA for the sale of these withheld allowances.

Our Asbury, Riverton (other than the gas-fired combustion turbines) and Iatan Plants burn a blend of low sulfur Western coal (Powder River Basin) and higher sulfur blend coal and petroleum coke, or burn 100% low sulfur Western coal. In addition, tire-derived fuel (TDF) is used as a supplemental fuel at the Asbury Plant. The Riverton Plant can also burn natural gas as its primary fuel. The State Line Plant, the Energy Center Units 3 and 4 and Riverton Unit 12 are gas-fired facilities and do not receive SO2 allowances. In the near term, annual allowance requirements for the State Line Plant, the Energy Center Units 3 and 4 and Riverton Unit 12, which are not expected to exceed 20 allowances per year, will be transferred from our inventoried bank of allowances. In 2007, the combined actual SO2 allowance need for all affected plant facilities exceeded the number of allowances awarded to us by the EPA. Although the actual reconciliation of SO2 allowances does not occur until March 1 of each year, we had approximately 24,000 banked SO2 allowances at December 31, 2007 as compared to 31,000 at December 31, 2006. We project that our 2008 emissions will again exceed the number of allowances awarded by the EPA. Based on current SO2 allowance usage projections, we expect to exhaust our banked allowances by the end of 2010.

Once our SO2 allowance bank is exhausted, we will need to purchase additional SO2 allowances or build a scrubber at our Asbury Plant. Based on current and projected SO2 allowance prices and high-level estimated scrubber construction costs ($81 million in 2010 dollars), we expect it will be more economical for us to purchase SO2 allowances than to build a scrubber at the Asbury Plant. We would expect the costs of SO2 allowances to be fully recoverable in our rates. In addition, projected engineering and construction timeframes for a new scrubber make it unfeasible at this time to construct a scrubber by the end of 2010.

On July 14, 2004, we filed an application with the MPSC seeking an order authorizing us to implement a plan for the management, sale, exchange, transfer or other disposition of our SO2 emission allowances issued by the EPA. On 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 swap banked allowances for future vintage allowances and/or monetary value and, in extreme market conditions, to sell SO2 allowances outright for monetary value. The Stipulation and Agreement became effective March 11, 2005, although we have not yet swapped or sold any allowances. Our banked allowances are not assigned a cost value. The allowances are removed from inventory on a FIFO basis.

SO2 emissions will be further regulated as described in the Clean Air Interstate Rule section below.

NOx Emissions. The Asbury, Iatan, State Line, Energy Center and Riverton Plants are each in compliance with the NOx limits applicable to them under the 1990 Amendments as currently operated.

The Asbury Plant received permission from the Missouri Department of Natural Resources (MDNR) to burn TDF at a maximum rate of 2% of total fuel input. During 2007, approximately 2,651 tons of TDF were burned. This is equivalent to 265,100 discarded passenger car tires.

Under the MDNR's Missouri NOx Rule, our Iatan, Asbury, State Line and Energy Center facilities, like other facilities in Western Missouri, are generally subject to a maximum NOx emission rate of 0.35 lbs/MMBtu during the ozone season of May 1 through September 30. However, facilities which burn at least 100,000 passenger tire equivalents of TDF per year, including our Asbury Plant, are subject to a higher NOx emission limit of 0.68 lbs/MMBtu. All of our plants currently meet the required emission limits and additional NOx controls are not required.

NOx is further regulated as described in the Clean Air Interstate Rule below.

Clean Air Interstate Rule (CAIR)

The EPA issued its final CAIR on March 10, 2005. CAIR governs NOx and SO2 emissions from fossil fueled units greater than 25 megawatts and will affect 28 states, including Missouri, where our Asbury, Energy Center, State Line and Iatan Plants are located and Arkansas where the future Plum Point Energy Station will be located. Kansas is not included in CAIR and our Riverton Plant will not be affected.

The CAIR is not directed to specific generation units, but instead, requires the states (including Missouri and Arkansas) to develop State Implementation Plans (SIPs) to comply with specific NOx and SO2 state-wide annual budgets. Missouri and Arkansas finalized their respective regulations and submitted their SIPs to the EPA for approval. The Missouri SIP was approved and became effective on December 14, 2007. We will receive our full allotment of allowances as published in the Missouri CAIR Rule. The Arkansas CAIR SIP has been approved but not finalized. Until the Arkansas SIP is finalized by the EPA, we cannot definitively determine the allowed emissions of ozone season NOx for the Plum Point Energy Station in Arkansas. However, based on the SIP for Missouri and the approved SIP for Arkansas, it appears we will have excess annual and ozone season NOx allowances. 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. Based on current SO2 allowance usage projections, we expect to exhaust our banked allowances by the end of 2010 and will need to purchase additional SO2 allowances or build a scrubber at our Asbury Plant.

In order to help meet anticipated CAIR requirements and to meet air permit requirements for Iatan Unit 2, pollution control equipment is being installed on Iatan Unit 1 which will be completed around the end of 2008. This equipment includes a Selective Catalytic Reduction (SCR) system, a Flue Gas Desulphurization (FGD) system and a baghouse, with our share of the capital cost estimated at $46 million, excluding AFUDC. Of this amount, approximately $3.9 million was incurred in 2006 and $12.1 million in 2007. Approximately $26.7 million in 2008, $1.4 million in 2009 and $0.3 million in 2010 are included in our current capital expenditures budget. This project was also included as part of our Experimental Regulatory Plan approved by the MPSC.

Also to help meet anticipated CAIR requirements, we constructed an SCR at Asbury during the fall of 2007 and placed it in service in early February 2008 at a total cost of approximately $31.0 million (excluding AFUDC), of which $28.1 million was expended through December 31, 2007 with the remainder expended in 2008. This project was also included as part of our Experimental Regulatory Plan approved by the MPSC.

Additional pollution control equipment to comply with CAIR may become economically justified at the Asbury Plant sometime prior to 2015 and may include an FGD scrubber to control SO2 and a baghouse at an estimated capital cost of $100 million.

Clean Air Mercury Rule (CAMR)

On March 15, 2005, the EPA issued the CAMR regulations for mercury emissions by power plants under the requirements of the 1990 Amendments to the Clean Air Act. The new mercury emission limits for Phase 1 were scheduled to go into effect January 1, 2010 and remain in effect until January 1, 2018. Beginning January 1, 2018, more restrictive mercury emission limits were scheduled to go into effect for Phase 2 of CAMR. These regulations were challenged in the U.S. Court of Appeals for the District of Columbia Circuit by a group of states led by New Jersey. On February 8, 2008, the Court of Appeals issued its opinion and vacated the EPA's CAMR regulations. The EPA is required to reconsider the regulation of mercury under Section 112 of the CAA. At this point it is too early to determine the effects of this ruling.

The CAMR was not directed to specific generation units, but instead, required the states (including Missouri, Kansas and Arkansas) to develop SIPs to comply with specific mercury state-wide annual budgets. Missouri, Kansas and Arkansas have finalized their respective regulations and submitted their SIPs to the EPA. The proposed SIPs for all states include allowance trading programs for mercury that could allow compliance without additional capital expenditures.

Based on CAMR, we installed a mercury analyzer at Asbury during late 2007 and scheduled the installation of two mercury analyzers at Riverton during 2008 in order to verify our mercury emissions and to meet the compliance date of January 1, 2009 for mercury analyzers and the Phase 1 mercury emission compliance date of January 1, 2010.

CO2 Emissions

Our coal and gas plants emit carbon dioxide (CO_2), a greenhouse gas. Although not currently regulated, increasing public concern and political pressure from local, regional, national and international bodies may result in the passage of new laws mandating limits on greenhouse gas emissions such as CO_2. Several bills addressing climate change have been introduced in the U.S. Congress and, in April 2007, the U.S. Supreme Court issued a decision ruling the EPA improperly declined to address CO_2 impacts in a rule-making related to new motor vehicle emissions. While this decision is not directly applicable to power plant emissions, the reasoning of the decision could affect other regulatory programs. Various proposals in the U.S. Congress could require us to purchase offsets or allowances for some or all of our CO_2 emissions, or otherwise affect us based on the amount of CO_2 we generate. The impact on us of any future greenhouse gas regulation will depend in large part on the details of the requirements and the timetable for mandatory compliance.

Water. We operate under the Kansas and Missouri Water Pollution Plans that were implemented in response to the Federal Water Pollution Control Act Amendments of 1972. The Asbury, Iatan, Riverton, Energy Center and State Line plants are in compliance with applicable regulations and have received discharge permits and subsequent renewals as required. The State Line permit was renewed in May 2007. The Energy Center permit was renewed in September 2005 and the Asbury Plant permit was renewed in December 2005.

The Riverton Plant is affected by final regulations for Cooling Water Intake Structures issued under the Clean Water Act Section 316(b) Phase II. The regulations became final on February 16, 2004 and require the submission of a Comprehensive Demonstration Study with the permit renewal in 2008. A Proposal for Information Collection (PIC) has been approved by the Kansas Department of Health and Environment (KDHE). Aquatic sampling commenced in April 2006 in accordance with the PIC and was completed in August 2007. Analysis of the sampling and a summary report will be completed during the first half of 2008. On January 25, 2007, the United States Court of Appeals for the Second Circuit remanded key sections of the EPA's February 16, 2004 regulations. On July 9, 2007, the EPA suspended the regulation and is expected to revise and re-propose the regulation by December 2008. If this occurs, we will monitor the EPA revision process and comment appropriately. Data collection and analysis will continue under the PIC and will be completed as needed to limit increased costs, if any, due to the EPA's suspension and revision of the regulation. The permit renewal application will be prepared and submitted as scheduled following KDHE guidance. Under the initial 316(b) regulations, we did not expect costs associated with compliance to be material. We will assess costs under revised rules when they are complete.

Other. Under Title V of the 1990 Amendments, we must obtain site operating permits for each of our plants from the authorities in the state in which the plant is located. These permits, which are valid for five years, regulate the plant site's total air emissions; including emissions from stacks, individual pieces of equipment, road dust, coal dust and other emissions. We have been issued permits for Asbury, Iatan, Riverton, State Line and the Energy Center Plants. We submitted the required renewal applications for the State Line and Energy Center Title V permits in 2003 and the Asbury Title V permit in 2004 and will operate under the existing permits until the MDNR issues the renewed permits. A Compliance Assurance Monitoring (CAM) plan is required by the renewed permit for Asbury. We estimate that the capital costs associated with the CAM plan will not exceed $2 million.

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 Iatan Unit No. 2 currently under construction. The new permit limits Unit No. 1 to a maximum of 6,600 MMBtu per hour of heat input. The 6,600 MMBtu per hour heat input limit is in effect until the new SCR, scrubber, and baghouse are completed, currently estimated to be late in the fourth quarter of 2008.

Gas Segment

The acquisition of Missouri Gas involved the property transfer of two former manufactured gas plant (MGP) sites previously owned by Aquila, Inc. and its predecessors. Site #1 is listed in the MDNR Registry of Confirmed Abandoned or Uncontrolled Hazardous Waste Disposal Sites in Missouri. Site #2 has received a letter of no further action from the MDNR. A Change of Use request and work plan was approved by the MDNR allowing us to expand our existing service center at Site #1 in Chillicothe, Missouri. This project, which was completed in October 2007, included the removal of all excavated soil and the addition of a new concrete surface replacing the existing gravel at a cost of approximately $0.1 million. We estimate further remediation costs at these two sites to be no more than approximately $0.2 million, based on our best estimate at this time. This estimated liability is recorded under noncurrent liabilities and deferred credits. In our agreement with the MPSC approving the acquisition of Missouri Gas, it was agreed that we could reflect a liability and offsetting regulatory asset not to exceed $260,000 for the acquired sites. The MPSC agreed that up to $260,000 of costs related to the clean up of these MGP sites would be allowed for future rate recovery. Accordingly, we concluded that rate recovery was probable and at the acquisition date, a regulatory asset of $260,000 was recorded as part of the purchase price allocation based on our agreement with the MPSC, and in accordance with Statement of Financial Accounting Standards No. 71 — "Accounting for the Effects of Certain Types of Regulation" (FAS 71).

13. 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 hold the Missouri Gas assets acquired from Aquila, Inc. on June 1, 2006. The other segment consists of our non-regulated businesses, primarily a subsidiary for our fiber optics business.

As discussed in "Note 18 — Discontinued Operations", we sold our controlling 52% interest in MAAP to other current owners on August 31, 2006. MAPP is a company that specialized in close-tolerance custom manufacturing for the aerospace, electronics, telecommunications and machinery industries. We also sold our interest in Conversant, Inc., a software company that marketed Customer Watch, an Internet-based customer information system software. On September 28, 2007, we sold our 100% interest in Fast Freedom, Inc., an Internet service provider. For financial reporting purposes, all of these businesses have been classified as a discontinued operation and are not included in our segment information as shown below (in thousands).

	For the year ended December 31,				
	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 (loss) from continuing operations	31,836	969	376	—	33,181
Capital Expenditures	$ 188,545	$ 2,024	$ 4,999	$ —	$ 195,568

	2006				
	Electric	Gas[2]	Other	Eliminations	Total
Statement of Income Information:					
Revenues	$ 384,496	$ 25,145	$ 2,920	$ (390)	$ 412,171
Depreciation and amortization	36,453	1,065	874	—	38,392
Federal and state income taxes	22,485	(619)	65	—	21,931
Operating income	67,931	1,286	604	—	69,821
Interest income	984	40	—	(635)	389
Interest expense	31,227	2,350	548	(635)	33,490
Income from AFUDC, (debt and equity)	4,190	65	—	—	4,255
Income (loss) from continuing operations	40,931	(959)	57	—	40,029
Capital Expenditures[1]	$ 116,579	$ 996	$ 2,596	$ —	$ 120,171

	2005				
	Electric	Gas	Other	Eliminations	Total
Statement of Income Information:					
Revenues	$ 360,428	$ —	$ 2,665	$ (373)	$ 362,720
Depreciation and amortization	33,873	—	804	—	34,677
Federal and state income taxes	12,574	—	49	—	12,623
Operating income	53,754	—	166	—	53,920
Interest income	427	—	—	(86)	341
Interest expense	28,905	—	87	(86)	28,906
Income from AFUDC, (debt and equity)	561	—	—	—	561
Income (loss) from continuing operations	24,865	—	79	—	24,944
Capital Expenditures	$ 71,237	$ —	$ 1,995	$ —	$ 73,232

(1) Does not include the acquisition of Missouri gas operation.

(2) Represents the months of June through September 2006.

	December 31, 2007				
	Electric	Gas[1]	Other	Eliminations	Total
Balance Sheet Information:					
Total assets	$1,394,997	$120,886	$22,101	$(66,234)	$1,471,750

	December 31, 2006				
	Electric	Gas[1]	Other	Eliminations	Total
Balance Sheet Information:					
Total assets	$1,249,552	$128,589	$21,659	$(80,658)	$1,319,142

(1) Includes goodwill of $39,492 and $39,323 at December 31, 2007 and 2006, respectively.

14. Selected Quarterly Information (Unaudited)

The following is a summary of quarterly results for 2007 and 2006 (dollars in thousands except per share amounts):

Quarterly Results for 2007	Quarters First	Second	Third	Fourth
Operating revenues	$125,650	$107,249	$142,487	$114,774
Operating income	11,913	14,123	31,670	7,860
Income from continuing operations	$ 4,531	$ 5,851	$ 23,200	$ (401)
Income from discontinued operations	(31)	(17)	111	—
Net Income	$ 4,500	$ 5,834	$ 23,311	$ (401)
Basic earnings per share — continuing operations	$ 0.15	$ 0.19	$ 0.76	$ (0.01)
Basic earnings per share — discontinued operations	—	—	—	—
Basic Earning Per Share	$ 0.15	$ 0.19	$ 0.76	$ (0.01)
Diluted earnings per share — continuing operations	$ 0.15	$ 0.19	$ 0.76	$ (0.01)
Diluted earnings per share — discontinued operations	—	—	—	—
Diluted Earnings Per Share	$ 0.15	$ 0.19	$ 0.76	$ (0.01)

Quarterly Results for 2006	Quarters First	Second	Third	Fourth
Operating revenues	$ 83,658	$ 91,413	$130,870	$106,229
Operating income	9,323	15,485	30,454	14,558
Income from continuing operations	$ 2,114	$ 7,486	$ 22,376	$ 8,051
Income from discontinued operations	(502)	(369)	(24)	148
Net Income	$ 1,612	$ 7,117	$ 22,352	$ 8,199
Basic earnings per share — continuing operations	$ 0.08	$ 0.28	$ 0.74	$ 0.27
Basic earnings per share — discontinued operations	(0.02)	(0.01)	—	—
Basic Earning Per Share	$ 0.06	$ 0.27	$ 0.74	$ 0.27
Diluted earnings per share — continuing operations	$ 0.08	$ 0.28	$ 0.74	$ 0.27
Diluted earnings per share — discontinued operations	(0.02)	(0.01)	—	—
Diluted Earnings Per Share	$ 0.06	$ 0.27	$ 0.74	$ 0.27

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.

In the fourth quarter of 2007, we experienced a net loss of $0.4 million, or ($0.01) per share compared to fourth quarter 2006 earnings of $8.2 million, or $0.27 per share. Total revenues increased approximately $8.5 million (8.0%) for the fourth quarter of 2007 as compared to the fourth quarter of 2006 primarily due to the Missouri rate increase. However, this was offset by increased operating expenses, including fuel and purchased power (approximately $17.5 million) primarily relating to an extended outage at our Asbury plant. Depreciation expense increased (approximately $3.4 million), along with other operating and maintenance costs which increased approximately $3.0 million, of which $1.5 million was December ice storm expense.

15. Risk Management and Derivative Financial Instruments

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 and for sale in our natural gas business, on the volatile spot market and to manage certain interest rate exposure.

As of December 31, 2007 and 2006, 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

	Balance Sheet Classification	2007 Fair Value	2006 Fair Value
Derivatives designated as hedging instruments under statement 133			
Natural gas contracts, current electric segment	Current assets	$ 2,435	$ 3,819
Natural gas contracts, non-current electric segment	Non-current assets and deferred charges	17,520	11,812
Derivatives not designated as hedging instruments under statement 133			
Natural gas contracts, current gas segment	Current assets	64	—
Natural gas contracts, non-current gas segment	Non-current assets and deferred charges	—	—
Total derivatives assets		$20,019	$15,631

LIABILITY DERIVATIVES

	Balance Sheet Classification	2007 Fair Value	2006 Fair Value
Derivatives designated as hedging instruments under statement 133			
Natural gas contracts, current electric segment	Current liabilities	$ 1,154	$ 810
Natural gas contracts, non-current electric segment	Non-current liabilities and deferred charges	698	—
Derivatives not designated as hedging instruments under statement 133			
Natural gas contracts, current gas segment	Current liabilities	$ 457	$ 562
Natural gas contracts, non-current gas segment	Non-current liabilities and deferred credits	—	—
Total derivatives liabilities		$ 2,309	$ 1,372

OTHER COMPREHENSIVE INCOME

	Balance Sheet Classification	2007 Fair Value	2006 Fair Value
Current assets — electric segment	Current assets	$ 2,435	$ 3,819
Ineffective non-hedged unrealized gain included in current assets above	Current assets	(281)	—
Unamortized option premiums included in current assets above	Current assets	—	(618)
Non current assets-electric segment	Non-current assets and deferred charges	17,520	11,812
Current liabilities — electric segment	Current liabilities	(1,154)	(810)
Non current liabilities — electric segment	Non-current liabilities and deferred charges	(698)	—
Net fair value of derivatives (before tax) — electric segment		17,822	14,203
Tax effect	Deferred taxes	(6,790)	(5,411)
Other comprehensive income	Capitalization	$11,032	$ 8,792

Electric

An $11.0 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, 2007. The tax effect of $6.8 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, 2008 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, 2007, approximately $1.0 million of unrealized gains are applicable to financial instruments which will settle within the next twelve months.

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 approximate $6 million increase 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.

The following table sets forth the actual pre-tax gains/(losses) 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 Statement 133 Cash Flow Hedging Relationships

	Income Statement Classification of Gain or (Loss) on Derivative	Amount of Gain/ (Loss) Reclassed from OCI into Income (Effective Portion)		Amount of Gain/ (Loss) Recognized in OCI on Derivative (Effective Portion)	
		2007	2006	2007	2006
Commodity contracts — electric segment	Fuel Expense	$1,610	$1,320	$1,610	$1,320
Total Effective — Electric Segment		$1,610	$1,320	$1,610	$1,320

We record unrealized gains/(losses) on the ineffective portion of our gas hedging activities in "Fuel" under the Operating Revenue Deductions section of our statement of operations 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.

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 Statement 133 Cash Flow Hedging Relationships

	Income Statement Classification of Gain/(Loss) on Derivative	Amount of Gain/ (Loss) Recognized in Income on Derivative- (Ineffective)	
		2007	2006
Commodity contracts — electric segment	Fuel Expense	$ —	$(34)
Total Ineffective — Electric Segment		$ —	$(34)

The following table sets forth "mark-to-market" pre-tax gains/(losses) from derivatives not designated as hedging instruments under Statement 133 for the electric segment for each of the years ended December 31, (in thousands):

Derivatives Not Designated as Hedging Instruments Under Statement 133(1)

	Income Statement Classification of Gain/(Loss) on Derivative	Amount of Gain/ (Loss) Recognized in Income on Derivative	
		2007	2006
Commodity contracts — electric segment	Fuel Expense	$281	$ —
Total — Electric Segment		$281	$ —

(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 designated under Statement 133. 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 the fair value accounting of FAS 133 because they are considered to be normal purchases. We have instituted a process 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 15, 2008, 88% of our anticipated volume of natural gas usage for our electric operations for the remainder of year 2008 is hedged, either through physical or financial contracts, at an average price of $6.811 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 six years are hedged at the following average prices per Dth:

Year	% Hedged	Dth Hedged	Average Price
2009	55%	4,696,000	$6.060
2010	34%	3,200,000	$5.561
2011	34%	3,200,000	$5.561
2012	13%	1,200,000	$7.295
2013	13%	1,200,000	$7.295

On February 15, 2008, the Company 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 after tax which will be recorded in the Statement of Income in the first quarter of 2008.

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 15, 2008, we have 93% of our expected remaining winter heating season usage (through March 2008) hedged with physical storage, physical forward contracts and financial derivative contracts. The average price of these hedges is $5.488 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 16, 2008, we had 0.4 million Dths in storage on the three pipelines that serve our customers. This represents 21% of our storage capacity. Our long-term hedge positions for gas purchased for resale are still in the development process. 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 under Statement 133 for the gas segment for the years ended December 31, (in thousands):

Derivatives not designated as hedging instruments under Statement 133

	Balance Sheet Classification of Gain or (Loss) on Derivative	Amount of Gain/(Loss) Recognized on Balance Sheet	
		2007	2006
Commodity contracts — gas segment	Regulatory assets	(1,534)	(1,563)
Total — Gas Segment		(1,534)	(1,563)

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, 2007	December 31, 2006
Accounts receivable for meter loops, meter bases, line extensions, highway projects, etc.	$ 1,197	$ 1,760
Accounts receivable for gas segment(1)	31	1,457
Accounts receivable for non-regulated subsidiary companies	276	2,681
Accounts receivable from Westar Generating, Inc., for commonly-owned facility	932	1,189
Taxes receivable — overpayment of estimated income taxes	5,776	3,055
Accounts receivable for energy trading margin deposit(2)	6,267	1,967
Accounts receivable for true-up on maintenance contracts(3)	824	938
Other	162	170
Total accounts receivable — other	$15,465	$13,217

(1) The December 31, 2006 balance primarily represents a receivable for a contribution in aid of construction for a pipeline replacement project which was paid in 2007.

(2) The accounts receivable for energy trading margin deposit represents the balance in our brokerage account as of December 31, 2007. NYMEX futures contracts are used in our hedging program of natural gas which require posting of margin.

(3) Represents quarterly estimated credits due from Siemens Westinghouse related to our maintenance contract entered into in July 2001 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 as of December 31, 2007.

17. Regulated — Other Operating Expense

The following table sets forth the major components comprising "regulated — other" under "Operating Revenue Deductions" on our consolidated statements of income the years ended (in thousands):

	December 31,		
	2007	2006	2005
Electric transmission and distribution expense	$ 9,465	$ 8,365	$ 8,124
Natural gas transmission and distribution expense	1,755	1,043	—
Power operation expense (other than fuel)	10,417	9,600	9,553
Customer accounts & assistance expense	9,198	8,277	6,967
Employee pension expense(1)	6,553	4,066	3,561
Employee healthcare plan(1)	7,899	7,664	8,687
General office supplies and expense	10,294	7,954	6,792
Administrative and general expense	10,872	10,988	8,564
Allowance for uncollectible accounts	4,673	1,997	1,813
Miscellaneous expense	241	138	112
Total	$71,367	$60,092	$54,173

(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

In August 2006, we sold our controlling 52% interest in MAPP to other current owners. MAPP is a company that specialized in close-tolerance custom manufacturing for the aerospace, electronics, telecommunications and machinery industries. In December 2006, we sold our 100% interest in Conversant, Inc., a software company that marketed Customer Watch, an Internet-based customer information system software. On September 28, 2007, we sold our 100% interest in Fast Freedom, Inc., an Internet service provider. We have reported MAPP, Conversant and Fast Freedom's results as discontinued operations. A summary of the components of losses from discontinued operations for the years ended December 31, 2007, 2006 and 2005 follows (in thousands):

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

2006	MAPP	Conversant	Fast Freedom	Total
Revenues	$ 8,927	$ 1,822	$1,363	$12,112
Expenses	9,295	3,908	1,632	14,835
Losses from discontinued operations before income taxes	(368)	(2,086)	(269)	(2,723)
Gain on disposal	271	555	—	827
Income tax	140	795	102	1,037
Minority interest	177	—	—	177
Income tax — minority interest	(67)	—	—	(67)
Gain (loss) from discontinued operations	$ 153	$ (736)	$ (167)	$ (749)

2005	MAPP	Conversant	Fast Freedom	Total
Revenues	$20,494	$ 1,914	$1,466	$23,874
Expenses	19,779	3,981	1,671	25,431
Earnings (losses) from discontinued operations before income taxes	715	(2,067)	(205)	(1,557)
Income tax	(272)	788	78	594
Minority interest	(344)	—	—	(344)
Income tax — minority interest	131	—	—	131
Gain (loss) from discontinued operations	$ 230	$(1,279)	$ (127)	$(1,176)

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, 2007.

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, 2007.

Audit of Internal Control Over Financial Reporting

The effectiveness of our internal control over financial reporting as of December 31, 2007, 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 2007 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 24, 2008, 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.

Because our common stock is listed on the NYSE, our Chief Executive Officer is required to make a CEO's Annual Certification to the NYSE in accordance with Section 303A.12 of the NYSE Listed Company Manual stating that he is not aware of any violations by us of the NYSE corporate governance listing standards. Our Chief Executive Officer has provided, and intends to continue to timely provide, the NYSE with the CEO's Annual Certificate.

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 24, 2008, 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 24, 2008, 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, 2007:

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	373,902	$22.65	1,663,143
Equity compensation plans not approved by security holders	—	—	—
Total	373,902	$22.65	1,663,143

(1) The weighted average exercise price of $22.65 relates to 39,100 and 4,200 options granted to executive officers in 2005 and 2004, respectively, under the 1996 Stock Incentive Plan, 64,200 and 41,700 options granted to executive officers in 2007 and 2006, respectively, under the 2006 Stock Incentive Plan and 40,672 subscriptions outstanding for our ESPP. The two stock incentive plans had a weighted average exercise price of $23.04 and the ESPP had an exercise price of $21.23. There is no exercise price for 86,800 performance-based stock awards awarded under the 1996 and 2006 Stock Incentive Plans or for 97,230 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 24, 2008, 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 24, 2008, 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 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 Form S-3, File No. 33-56635).

(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 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 year ended December 31, 1994, 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 year ended December 31, 1993, File No. 1-3368).

(h) Twenty-Fifth Supplemental Indenture dated as of November 1, 1994 to Indenture of Mortgage and Deed of Trust (Incorporated by reference to Exhibit 4(p) to Registration Statement No. 33-56635 on Form S-3).

(i) 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 year ended December 31, 1996, File No. 1-3368).

(j) 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).

(k) 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).

(l) Indenture for Unsecured Debt Securities, dated as of September 10, 1999 between Empire and Wells Fargo Bank Minnesota, National Association (Incorporated by reference to Exhibit 4(v) to Registration Statement No. 333-87015 on Form S-3).

(m) 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, 2002, File No. 1-3368).

(n) 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).

(o) 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 June 29, 2003, File No. 1-3368).

(p) 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).

(q). 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 to Current Report on Form 8-K dated June 27, 2005 and filed June 28, 2005, File No. 1-3368).

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

(s) First Amended and Restated Unsecured Credit Agreement, dated as of March 14, 2006, among Empire, UMB Bank, N.A., as arranger and administrative agent, Bank of America, N.A., as syndication agent, and the lenders named therein (Incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K dated March 14, 2006 and filed March 16, 2006, File No. 1-3368).

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

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

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

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

(b) First Amendment to 1996 Stock Incentive Plan. *†

(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. *†

(e) Deferred Compensation Plan for Directors as amended and restated effective January 1, 2008.*†

(f) The Empire District Electric Company Change in Control Severance Pay Plan as amended and restated effective January 1, 2008.*†

(g) Form of Severance Pay Agreement under The Empire District Electric Company Change in Control Severance Pay Plan.*†

(h) The Empire District Electric Company Supplemental Executive Retirement Plan as amended and restated effective January 1, 2008.*†

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

(j) 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 year ended December 31, 2005, File No. 1-3368).†

(k) First Amendment to Stock Unit Plan for Directors.*†

(l) Summary of Annual Incentive Plan.*†

(m) Form of Notice of Award of Dividend Equivalents.*†

(n) Form of Notice of Award of Non-Qualified Stock Options.*†

(o) Form of Notice of Award of Performance-Based Restricted Stock.*†

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

(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, 2007, 2006 and 2005:

	Balance At Beginning Of Period	Additions			Deductions From Reserve		Balance At Close of Period
		Charged To Income	Charged to Other Accounts				
			Description	Amount	Description	Amount	
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
Reserve not shown separately in balance sheet: Injuries and damages reserve (Note A)	$1,592,670	$1,484,529	Property, plant & equipment	$1,484,529	Claims and expenses	$2,556,130	$2,005,598
Year ended **December 31, 2006:**							
Electric reserve deducted from assets: accumulated provision for uncollectible accounts.	$ 561,808	$1,624,200	Recovery of amounts previously written off	$ 932,928	Accounts written off	$2,653,083	$ 465,853
EDG acquisition amount recorded to reserve — Balance as of June 1:	$ 506,505	$ 351,530		$ 140,700		$ 284,011	$ 714,724
Reserve not shown separately in balance sheet: Injuries and damages reserve (Note A)	$1,496,670	$ 984,462	Property, plant & equipment	$ 984,462	Claims and expenses	$1,872,924	$1,592,670
Year ended **December 31, 2005:**							
Reserve deducted from assets: Accumulated provision for uncollectible accounts	$ 284,109	$1,821,444	Recovery of amounts previously written off	$ 806,511	Accounts written off	$2,350,256	$ 561,808
Reserve not shown separately in balance sheet: Injuries and damages reserve (Note A)	$1,546,670	$ 939,399	Property, plant & equipment	$ 939,399	Claims and expenses	$1,928,798	$1,496,670

* 2007 beginning balance combines the 2006 ending balance with the 2006 EDG acquisition amount recorded to reserve ending balance.

Note A: This reserve is provided for workers' compensation, certain postemployment benefits and public liability damages. At December 31, 2007, we carried insurance for workers' compensation claims in excess of $500,000 and for public liability claims in excess of $500,000. The injuries and damages reserve is included on the Balance Sheet in the section "Noncurrent liabilities and deferred credits" in the category "Other".

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: March 3, 2008

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
/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/ MYRON W. MCKINNEY* Myron W. McKinney, Director	
/s/ ROSS C. HARTLEY* Ross C. Hartley, Director	March 3, 2008
/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/ MARY McCLEARY POSNER* Mary McCleary Posner, Director	
/s/ GREGORY A. KNAPP *By (Gregory A. Knapp, As attorney in fact for each of the persons indicated)	

EXHIBIT (12)

Computation of Ratios of Earnings to Fixed Charges

	Year ended December 31,				
	2007	2006	2005	2004	2003
Income before provision for income taxes and fixed charges (Note A)	**$87,152,341**	$99,409,515	$65,781,250	$62,144,879	$76,746,596
Fixed Charges:					
Interest on long-term debt	**$31,120,122**	$25,947,191	$24,059,165	$24,640,812	$26,044,688
Interest on short-term debt	**2,940,317**	2,275,939	195,197	19,854	606,312
Interest on note payable to securitization trust	**4,250,000**	4,250,000	4,250,000	4,250,000	—
Trust preferred distributions by subsidiary holding solely parent debentures	—	—	—	—	4,250,000
Other interest	**1,069,206**	1,029,135	605,492	366,642	511,315
Rental expense representative of an interest factor (Note B)	**4,686,748**	4,798,490	659,844	28,144	28,340
Total fixed charges	**$44,066,393**	$38,300,755	$29,769,698	$29,305,452	$31,440,655
Ratio of earnings to fixed charges	**1.98**	2.60	2.21	2.12	2.44

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).

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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 annual 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 annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual 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 annual 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 annual 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 annual report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this annual report based on such evaluation; and

   d. disclosed in this annual report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter 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 registrant's board of directors (or persons performing the equivalent function):

   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: March 3, 2008

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 annual 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 annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual 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 annual 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 annual 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 annual report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this annual report based on such evaluation; and

   d. disclosed in this annual report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter 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 registrant's board of directors (or persons performing the equivalent function):

   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: March 3, 2008

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, 2007 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: March 3, 2008

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, 2007 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: March 3, 2008

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.

SERVICES YOU COUNT ON

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