THE EMPIRE DISTRICT ELECTRIC COMPANY

2004 Annual Report

Fellow Shareholders,

Earnings for 2004 were — in a word — disappointing. Despite strong customer growth, earnings for the year were $0.86 per share, down from $1.29 per share in 2003. The principal reasons for this poor performance lay in a few key areas: unfavorable weather through most of the year, a drop in off-system sales, higher natural gas prices, and higher operating expenses including costs for health care, non-regulated activities, stock-based compensation, and Sarbanes-Oxley compliance.

Our balance sheet remains solid, with an equity to total capitalization ratio in the 48 percent range, and we continue to focus upon those things that will ensure long-term success. We are working to mitigate our exposure to fuel prices. We are investing in rate base infrastructure to meet the needs of our growing service area. And, we are continuously improving operational efficiencies.

In December we signed a 20-year agreement with PPM Energy to purchase the power generated at their 150 megawatt Elk River Windfarm, currently under construction in Butler County, Kansas. We believe wind energy offers important benefits to our customers and shareholders. It does not require fossil fuels, it is environmentally friendly, and its cost basis is favorable thanks to recent technological advances and the extension of the federal production tax credits for renewable energy. Delivery of power is scheduled to begin late in 2005. We expect Elk River to supply roughly 10 percent of our energy needs beginning in 2006, or about 550,000 megawatt hours annually.

A class action complaint seeking to stop any development or operation of industrial wind generation facilities in the area was filed in U.S. District Court on January 24, 2005, by the Flint Hills Tallgrass Prairie Heritage Foundation. PPM Energy and Empire were among the defendants named in the suit. This complaint was dismissed with prejudice by the Court on February 11, 2005. On March 9, 2005, the plaintiffs filed their notice of appeal. We continue to believe the case is without merit and will defend it vigorously.

Also in 2004 we capitalized on soft market conditions to purchase, at substantial savings, a 155 megawatt Siemens Westinghouse V84.3A2 Econopac combustion turbine that we expect to bring online in April 2007. The unit features high efficiency, economical operation, and low emissions, thus providing our customers with another source of cost-effective and environmentally responsible peaking energy. We'll see additional cost efficiencies by installing the unit at our existing Riverton site, where fewer infrastructure additions need to be made.

The turbine will be engineered to allow for expansion into a combined cycle generating unit, which would increase efficiency even further. We are configuring the facilities to allow space for that possibility should we decide to pursue this kind of operation in the future.

We filed for a rate increase in Missouri on April 30, 2004, asking for an annual increase of 14.8 percent. On March 10, 2005, the Missouri Public Service Commission granted an annual increase in base rates of about 10 percent effective March 27, 2005. The Commission also allowed a three-year, refundable Interim Energy Charge and a return on equity (ROE) of 11.0 percent. Their ruling brings us some much needed relief in what we view as a constructive order. It allows us to more accurately recoup our fuel and purchased power expenses and provides an opportunity to earn at a level where we believe we can access lower-cost capital as we build for the future.

As a result of the Missouri rate order, Standard & Poor's affirmed our BBB corporate credit rating on March 14, 2005, removing the "CreditWatch with negative implications" tag we had been under since September 2004. Their rating for Empire is now BBB with a "stable" outlook.

We filed in Arkansas on July 14, 2004, for a 22.1 percent increase. Any new rates we receive in Arkansas will become effective in the second quarter of 2005.

Of all our activities in 2004, perhaps none will have a greater long-term impact on operations than the installation of the Geospatial Information System and Outage Management System (GIS/OMS). GIS/OMS uses geographical positioning technology to allow more precise control over our system. For example, it helps us identify the point of failure in a power outage so that we can quickly determine which work crew can best respond. We look forward to fully realizing new efficiencies as a result of this technology.

I am pleased to tell you that we are in compliance with the Sarbanes-Oxley Act and likewise continue to meet the governance requirements of the Securities and Exchange Commission and the New York Stock Exchange. Related activity in the coming year will consist mainly of ensuring that new procedures are properly integrated into our systems.

As we move through 2005, we will continue to be guided by our key business strategies. We believe these strategies provide the long-term solution for serving our customers and building shareholder value. We will remain unwavering in our focus upon them.

Two new members joined our Board of Directors in 2004. Elected at our 2004 Annual Shareholders Meeting was Mr. Allan Thoms. Allan is a consultant with Wilk & Associates/LECG of San Francisco, which provides regulatory advocacy services to state regulatory commissions. He holds a Bachelor of Arts in Business from Parsons College, Fairfield, Iowa, an LLB from the College of Law at the University of Iowa, and accreditation from the University of Wisconsin Graduate School of Banking. Mr. Thoms is the former Chairman of the Iowa Utilities Board, the public utility regulator in Iowa.

Mr. Bill D. Helton was appointed as a Class III Director of the Company effective August 1, 2004. Bill is a retired Chairman and CEO of New Century Energies of Denver, and holds a Bachelor of Science degree in Electrical Engineering from Texas Tech University. He will stand for election at our Annual Shareholders' Meeting on April 28, 2005.

As we welcome our newest Board members, we say good-bye to two men who together represent 64 years with Empire. In January 2005, Mr. Robert L. Lamb stepped down from the Board after 50 years of service. Bob began his career with us in 1955 as an electrical engineer. He joined our Board in 1978 and served as President of Empire from 1982 until 1997. Bob provided strong leadership through a period of profound change in our industry. His impact on the Company and our entire service area has been lasting and far reaching.

We also are losing the expertise of Mr. Melvin F. (Nick) Chubb, Jr. who has announced that he will retire from the Board in April. A retired Senior Vice President of Eagle-Picher Industries, Inc. and retired Lieutenant General of the United States Air Force, Nick has been a Board member since 1991. He has served our Company with that dedication so characteristic of a former military man.

We thank these men for their contributions and wish them much happiness and good health.

Nominated to replace Nick on the Board is Mr. Kenneth R. Allen. Ken is Vice President and Treasurer of Texas Industries, Inc., of Dallas. He holds a Bachelor of Arts degree in Economics from the University of Arkansas and a Masters in Management from Northwestern University. He will stand for election at our April shareholders' meeting.

Finally, let me say a few words about my co-workers. In 2004, they attained a new level of excellence by setting a safety record of 1.5 million man-hours worked without a lost-time injury. This makes calendar year 2004 the first time in our 95-year history that we have worked lost-time injury free, an achievement that points to the skill and care Empire employees bring with them as they go about their work day.

On their behalf and my own, I thank you once again for choosing to invest in Empire. We will continue working hard to strengthen that investment.

Bill Gipson

William L. Gipson
President and Chief Executive Officer

Our Mission

- To be a respected supplier of energy and related services
- To know our customers and exceed their expectations
- To provide increasing value to our shareholders
- To create a safe, challenging, and satisfying work environment
- To be responsible stewards of our environment

Our Key Business Strategies

- Assure appropriate corporate governance
- Actively manage weather-related risks
- Improve financial performance
- Implement productivity enhancements/new technologies
- Actively manage fuel procurement and associated risk
- Determine long-term capacity and energy solutions
- Assure environmental/security compliance
- Influence/adapt to structural changes in the industry

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

EXECUTIVE SUMMARY

The Empire District Electric Company is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. We also provide water service to three towns in Missouri and have investments in some non-regulated businesses including fiber optics, Internet access, close-tolerance custom manufacturing and customer information system software services through our wholly owned subsidiary, EDE Holdings, Inc. In 2004, 93.0% of our gross operating revenues were provided from the sale of electricity, 0.4% from the sale of water and 6.6% from our non-regulated businesses.

The primary drivers of our electric operating revenues in any period are: (1) weather, (2) rates we can charge our customers, (3) customer growth, (4) the ability (or inability due to the lack of a fuel adjustment provision in Missouri) to recover increases in fuel costs in rates and (5) general economic conditions. Weather affects the demand for electricity for our regulated business. Very hot summers and very cold winters increase 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 general economic conditions. The utility commissions in the states in which we operate, as well as the FERC, set the rates at which we can charge our customers. In order to offset expenses, we depend on our ability to receive adequate and timely rate relief. We continue to assess the need for rate relief in all of the jurisdictions we serve and file for such relief when necessary. Customer growth, which is the growth in the number of customers, contributes to the demand for electricity. We expect our annual customer growth to be approximately 1.6% over the next several years. We define sales growth to be growth in kWh sales excluding the impact of weather. The primary drivers of 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, (3) employee pension and health care costs, (4) taxes and (5) 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 and purchased power, we have entered into long and short-term agreements to purchase coal and natural gas for our energy supply and 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 predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in our fuel expense and improve predictability. We have purchased, and will install at our Riverton facility, a Siemens V84.3A2 combustion turbine with a summer rated capacity of 155 megawatts to be operational in 2007 to meet additional capacity requirements due to anticipated customer growth.

On December 10, 2004, we entered into a 20-year contract with PPM Energy, to purchase the energy generated at the proposed Elk River Windfarm which will be located in Butler County, Kansas. We expect that the amount and percentage of electricity we generate by natural gas will decrease in 2006 and in the immediate future thereafter due to this contract. We anticipate purchasing approximately 550,000 megawatt-hours of energy, or 10% of our annual needs, from the project beginning in December 2005. We anticipate the cost of this contract to also be offset by purchasing less higher-priced power from other suppliers or by displacing on-system generation. We believe this project is a significant step in assuring that our shareholders and customers benefit from a balanced mix of generation options. With the improvements made in wind generation technology and the extension of the production tax credits, wind energy provides price stability, is environmentally friendly and is economical for our customers.

For the twelve months ended December 31, 2004, basic and diluted earnings per weighted average share of common stock were $0.86 as compared to $1.29 for the twelve months ended December 31, 2003.

The following reconciliation of earnings per share between 2003 and 2004 is a non-GAAP presentation. We believe this information is useful in understanding the fluctuation in earnings per share between the prior and current year. The reconciliation presents the after tax impact of significant items and components of the statement of operations on a per share basis before the impact of additional stock issuances which is presented separately. Earnings per share for the years ended December 31, 2003 and 2004 shown in the reconciliation are presented on a GAAP basis and are the same as the amounts included in the statements of income. 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 — 2003	**$ 1.29**
Revenues	
On-System — Electric	$ 0.11
Off-System — Electric	(0.12)
Non-Regulated	0.02
Water	0.00
Expenses	
Fuel	(0.34)
Purchased power	0.21
Regulated — other (excluding employee health care expense)	(0.06)
Regulated — other (employee health care expense only)	(0.03)
Non — Regulated expenses	(0.05)
Maintenance and repairs	(0.02)
Depreciation and amortization	(0.06)
Other taxes	(0.05)
Interest charges	0.06
Other income and deductions	0.00
Dilutive effect of additional shares	(0.10)
Earnings Per Share — 2004	**$ 0.86**

Fourth Quarter Results

Revenues for the fourth quarter of 2004 were $74.3 million compared to $73.0 million in the fourth quarter of 2003. The increase in revenues was primarily driven by customer growth. Earnings for the fourth quarter of 2004 were $2.0 million, or $0.08 per share, compared to fourth quarter 2003 earnings of $4.8 million, or $0.21 per share. While an increase in revenues for the fourth quarter of 2004 contributed an estimated $0.04 per share in the fourth quarter of 2004 as compared to the fourth quarter of 2003, due to customer growth, increases in total fuel and purchased power costs reduced earnings per share by an estimated $0.08 per share. Also negatively impacting earnings were increases in health care expense, depreciation, property taxes and losses from our non-regulated business units.

RESULTS OF OPERATIONS

The following discussion analyzes significant changes in the results of operations for 2004, compared to 2003, and for 2003, compared to 2002.

Electric Operating Revenues and Kilowatt-Hour Sales

Electric operating revenues comprised approximately 93% of our total operating revenues during 2004. Of these total electric operating revenues, approximately 41% were from residential customers, 31% from commercial customers, 17% from industrial customers, 4.5% from wholesale on-system customers, 2% from wholesale off-system transactions and 4.5% from miscellaneous sources, primarily transmission services. The breakdown of our customer classes has not significantly changed from 2003 or 2002.

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

	kWh Sales (in millions)					
	2004	2003	% Change*	2003	2002	% Change*
Residential	1,703.9	1,728.3	(1.4)%	1,728.3	1,726.5	0.1%
Commercial	1,417.3	1,386.8	2.2	1,386.8	1,378.2	0.6
Industrial	1,085.4	1,058.7	2.5	1,058.7	1,027.4	3.0
Wholesale On-System	305.7	308.6	(0.9)	308.6	323.1	(4.5)
Other***	108.0	103.9	4.2	103.9	102.8	1.1
Total On-System	4,620.3	4,586.3	0.7	4,586.3	4,558.0	0.6

	Operating Revenues (in millions)					
	2004	2003	% Change*	2003	2002**	% Change*
Residential	$124.4	$125.2	(0.6)%	$125.2	$119.5	4.7%
Commercial	92.4	90.6	2.0	90.6	85.5	5.9
Industrial	51.9	50.6	2.4	50.6	46.8	8.3
Wholesale On-System	13.6	12.4	9.4	12.4	11.9	4.8
Other***	7.5	7.3	3.2	7.3	6.8	7.3
Total On-System	$289.8	$286.1	1.3	$286.1	$270.5	5.8

* Percentage changes are based on actual kWhs and revenues and may not agree to the rounded amounts shown in this table.

** Revenues exclude amounts collected under the Interim Energy Charge during 2002 and refunded to customers during the first quarter of 2003. See discussion below.

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

On-System Electric Transactions

KWh sales for our on-system customers increased slightly during 2004 primarily due to continued sales growth. Revenues for our on-system customers increased approximately $3.7 million, with an estimated $1.8 million of this increase attributed to the Oklahoma and FERC rate increases discussed below. Continued sales growth contributed an estimated $8.5 million to revenues during 2004, offset by an estimated $6.4 million negative effect from weather. Our customer growth was 1.7% in 2004 and 1.6% in both 2003 and 2002. We expect our annual customer growth to be approximately 1.6% over the next several years.

Residential kWh sales and revenues, which are more weather sensitive than the other sales classes, decreased in 2004 due primarily to milder temperatures, which had a negative effect on sales, during the first, third and fourth quarters of 2004 as compared to the same periods in 2003. Commercial sales and revenues and industrial sales and revenues, which are not particularly weather sensitive, increased during 2004 primarily due to the continued sales growth discussed above. Industrial sales also benefited from the addition of two new oil pipeline pumping stations on our system that became fully operational in June 2003. In addition, industrial revenues, as well as residential and commercial revenues, were favorably impacted by the August 2003 Oklahoma rate increase.

On-system wholesale kWh sales decreased slightly while revenues associated with these FERC-regulated sales increased as a result of the FERC rate increase that became effective May 1, 2003 and 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. The decrease in kWh sales was mainly due to the change in customer status in June 2003 of an on-system wholesale customer/aggregator, comprising three of our on-system wholesale accounts, which elected to go off-system and purchase power from us at market-based rates. Revenues received from these accounts, which comprised 5–6% of our on-system wholesale sales and revenues, but less than one-half percent of our total on-system sales and revenues in 2002, are now included in our off-system revenues.

KWh sales for our on-system customers increased slightly during 2003 as compared to 2002, primarily due to continued sales growth. Colder temperatures during the first quarter of 2003 as compared to milder temperatures during the same period in 2002 had a positive effect on sales with a new all-time winter peak of 987 megawatts being established on January 23, 2003, replacing the previous winter peak of 941 megawatts established in December 2000. However, the increase in first quarter sales was offset by unfavorable weather in the second, third and fourth quarters of 2003 notwithstanding setting a new summer peak demand of 1,041 megawatts on August 25, 2003. Despite only a slight increase in kWh sales, revenues from our on-system customers increased approximately $15.6 million, with an estimated $13 million of this increase attributed to the Missouri, Oklahoma and FERC rate increases discussed below with the remainder attributed to continued sales growth. This continued sales growth contributed an estimated $7 million to revenues during 2003 offset by an estimated $5 million negative effect from weather.

Notwithstanding the new summer peak demand, the slight increases in residential and commercial kWh sales in 2003 were due primarily to the continued sales growth discussed above. Industrial sales and revenues, which are not particularly weather sensitive, increased during 2003 mainly due to increased sales resulting from the addition of the two new oil pipeline pumping stations on our system in June 2003. Also contributing to the increase were increased sales during the first quarter of 2003 because of better economic conditions as compared to the first quarter of 2002 when our service territory experienced a general slowdown in economic activity. In addition, industrial revenues, as well as residential and commercial revenues, were favorably impacted by the December 2002 Missouri rate increase and, to a lesser extent, the August 2003 Oklahoma rate increase.

On-system wholesale kWh sales decreased due mainly to the change in customer status in June 2003 of the on-system wholesale customer/aggregator which elected to go off-system and purchase power from us at market-based rates. Overall revenues associated with these FERC-regulated sales increased as a result of the FERC rate increase that became effective May 1, 2003 and as a result of the fuel adjustment clause applicable to such sales.

Rate Matters

The following table sets forth information regarding electric and water rate increases granted during the four year period ended December 31, 2004 affecting the revenue comparisons discussed above:

Jurisdiction	Date Requested	Annual Increase Granted	Percent Increase Granted	Date Effective
Missouri — Electric	November 3, 2000	$17,100,000	8.40%	October 2, 2001
Missouri — Electric	March 8, 2002	11,000,000	4.97%	December 1, 2002
Missouri — Electric	April 30, 2004	25,705,500	9.96%	March 27, 2005
Missouri — Water	May 15, 2002	358,000	33.70%	December 23, 2002
Kansas — Electric	December 28, 2001	2,539,000	17.87%	July 1, 2002
FERC — Electric	March 17, 2003	1,672,000	14.00%	May 1, 2003
Oklahoma — Electric	March 4, 2003	766,500	10.99%	August 1, 2003

The 2001 Missouri order approved an annual Interim Energy Charge, or IEC, of approximately $19.6 million effective October 1, 2001 and expiring two years later which was collected subject to refund (with interest). The 2002 Missouri electric order called for us to refund all funds collected under the IEC, with interest, by March 15, 2003. The refunds were made in the first quarter of 2003 and did not have a material impact on our earnings in any of the years from 2001 through 2003.

On March 4, 2003, we filed a request with the Oklahoma Corporation Commission for an annual increase in base rates for our Oklahoma electric customers in the amount of $954,540, or 12.97%. On August 1, 2003 a Unanimous Stipulation and Agreement was approved by the Oklahoma Corporation Commission providing an annual increase in rates for our Oklahoma customers of approximately $766,500, or 10.99%, effective for bills rendered on or after August 1, 2003. This reflects a rate of return on equity (ROE) of 11.27%.

On March 17, 2003, we filed a request with the FERC for an annual increase in base rates for our on-system wholesale electric customers in the amount of $1,672,000, or 14.0%. This increase was approved by the FERC on April 25, 2003 with the new rates becoming effective May 1, 2003.

On April 30, 2004, we filed a request with the Missouri Public Service Commission (MPSC) for an annual increase in base rates for our Missouri electric customers in the amount of $38,282,294, or 14.82%. As part of the filing, we asked the Commission to consider, in addition to a traditional ratemaking approach, two options that would allow us to recover our actual fuel and purchased power expenses: an IEC, subject to refund, similar to the one approved in our 2001 case, or a fuel adjustment clause, that would reflect actual fuel prices. We subsequently abandoned our request for a fuel adjustment clause due to Missouri statutes not providing for such clauses but retained our request for the IEC, subject to refund. We also asked for a ROE of 11.65% and an annual increase in Missouri depreciation expense of approximately $10 million.

On May 20, 2004, we filed a request with the MPSC to implement the proposed IEC no later than June 15, 2004. However, the MPSC denied this request on August 12, 2004. On September 20, 2004, the Staff of the MPSC filed direct testimony in response to our initial April 2004 filing recommending an IEC be adopted for a period of 24 months, due to the extreme volatility currently exhibited by natural gas prices. We completed two weeks of evidentiary hearings during December 2004. Items that were covered during the hearings were: ROE, depreciation, base fuel and purchased power costs and the term and amount of an IEC. On February 22, 2005, we, the Office of Public Counsel (OPC) and two intervenors filed a Nonunanimous Stipulation and Agreement Regarding Fuel and Purchased Power Expense establishing a three-year refundable IEC which became unanimous by operation of Commission rule on March 1, 2005.

Prior to the hearings, we were able to settle several miscellaneous issues with other parties to the case. On December 22, 2004, we, the MPSC Staff, the OPC and two intervenors filed a unanimous Stipulation and Agreement as to Certain Issues with the MPSC settling several of these issues. One of the issues we were able to agree on was a change in the recognition of pension costs. See “Notes to Consolidated Financial Statements — Note 1 — Pensions” and “Note 8 — Retirement Benefits — Pensions.”

The MPSC issued a final order on March 10, 2005 approving an annual increase in base rates of approximately $25.7 million, or 9.96%, effective March 27, 2005. The order granted us a return on equity of 11%, an increase in depreciation rates and an increase in base rates for fuel and purchased power at $24.68/MWH. 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 is $0.0021 per kilowatt hour of customer usage. The recent extraordinarily high natural gas prices and extreme volatility of natural gas led the MPSC to allow forecasted fuel costs to be used rather than the traditional historical costs in determining the fuel portion of the rate increase. At the end of two years, the excess money collected from customers, if any, above $10 million of the greater of the actual and prudently incurred costs or the base cost of fuel and purchased power set in rates, will be refunded to the customers with interest equal to the current prime rate at that time. At the end of the three year term of the IEC all excess money collected from customers, if any, of the greater of the actual and prudently incurred costs or the base cost of fuel and purchased power set in rates, will be refunded to the customers with interest equal to the current prime rate at that time.

On July 14, 2004, we filed a request with the Arkansas Public Service Commission for an annual increase in base rates for our Arkansas electric customers in the amount of $1,428,225, or 22.1%. Any new rates approved as a result of this request are not expected to be effective until the second quarter of 2005.

On March 2, 2005, we notified the Kansas Corporation Commission of our intent to file an application requesting a change in base rates for our Kansas electric customers. We plan to file this application in the second quarter of 2005.

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

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. The following table sets forth information regarding these sales and related expenses for the applicable periods ended December 31,:

(in millions)	2004	2003	2002
Revenues	$10.8	$15.3	$21.9
Expenses	6.3	9.8	13.4
Net Revenue	$ 4.5	$ 5.5	$ 8.5

The decrease in revenues less expenses in 2004 as compared to 2003 and in 2003 as compared to 2002 resulted primarily from the non-renewal of short-term contracts for firm energy that ran from January 2002 through June 2003. We sold this energy in the wholesale market when it was not required to meet our own customers' needs during that period. See "— Competition" below. These expenses are included in our discussion of purchased power costs below.

Operating Revenue Deductions

During 2004, total operating expenses increased approximately $9.9 million (3.8%) compared to 2003. Total fuel costs increased approximately $12.1 million (23.1%) during 2004 offset by a decrease in purchased power costs of approximately $7.4 million (12.2%), resulting in a net increase of $4.7 million for fuel and purchased power. The increase in fuel costs was primarily due to increased generation by both our coal fired and gas fired units during 2004 (an estimated $7.9 million) and lower volumes of hedged natural gas in 2004 as compared to 2003 combined with higher prices for the unhedged portion of the natural gas that we burned in our gas-fired units (an estimated $5.1 million). The decrease in purchased power costs primarily reflected a shift from serving our energy needs with purchased power to generating our own power reflecting that it was more economical to run our own generating units during 2004 than to purchase power. The decrease in purchased power costs also reflects the non-renewal of the short-term contracts for firm energy that ran from January 2002 through June 2003. Despite the overall increase in fuel costs due to increased generation and higher costs, the positive effect of our gas hedging program reduced fuel cost by $11.5 million in 2004 and $9.4 million in 2003, in each case as compared to buying all natural gas requirements on the spot market. Given the current market conditions, we don't expect the results of our gas hedging program to reduce our 2005 fuel costs by amounts comparable to the 2004 and 2003 reductions. See "Hedging Activities" under "Critical Accounting Policies" for information on future hedging activity. We also expect fuel costs to increase in 2005 due to changes in delivered prices resulting from the expiration of our long-term coal and freight contracts. A long-term contract with a subsidiary of Peabody Holding Company, Inc. for the supply of low sulfur Western coal (Powder River Basin) at the Asbury and Riverton Plants expired in December 2004. We signed a new, three-year contract with Peabody on December 15, 2004 that covers approximately 100% of our anticipated 2005 Western coal requirements, approximately 67% of our anticipated 2006 Western coal requirements and approximately 33% of our anticipated Western coal requirements for 2007. We also currently have a contract with Union Pacific Railroad Company and The Kansas City Southern Railway Company which provides for transportation of the Powder River Basin coal which will expire at the end of June 2005. In 2004 we accepted a binding proposal and are in the process of finalizing contractual terms and conditions on a new transportation contract. We expect that, beginning in July 2005, this coal will be delivered under the new transportation contract. The delivered price of coal under the new contracts is expected to be higher than the 2004 price during the first and second quarters of 2005, but we expect the delivered price increase to be substantially mitigated beginning in the third quarter of 2005 due to a combination of our new coal supply and coal transportation contracts. We also expect changes in gas prices to contribute to variances in fuel costs, partially offset by the impact of our hedging program.

Regulated — other operating expenses increased approximately $3.2 million (6.5%) during 2004 as compared to 2003 primarily due to a $1.2 million increase in employee health care costs, an approximate $0.8 million increase in stock compensation costs, a $0.9 million increase in customer accounts expense, of which $0.4 million was a first quarter 2004 addition to bad debt expense, a $0.5 million increase in steam power operating expenses at the Asbury and Riverton plants and a $0.5 million increase in general administrative expense due primarily to $0.6 million associated with Sarbanes-Oxley compliance. These increases were partially offset by a $0.7 million decrease in transmission and distribution expense, a $0.6 million decrease in professional service expenses and a $0.5 million decrease in employee pension expense. Based on the performance of our pension plan assets through January 1, 2003, we were required under the Employee Retirement Income Security Act of 1974 (ERISA) to fund approximately $0.3 million in 2004 in order to maintain minimum funding levels and contributed this $0.3 million to our pension plan in the first quarter of 2004. Based on the performance of our pension plan assets through December 31, 2004, we expect there will be no contribution required under ERISA in order to maintain minimum funding levels in 2005. This could change, however, based on actual investment performance, any future pension plan funding and finalization of actuarial assumptions. No minimum pension liability was required to be recorded as of December 31, 2003 or 2004. No significant changes are expected for our post-retirement benefits in 2005 as compared to 2004. See Note 8 of "Notes to Consolidated Financial Statements" for further discussion regarding our pension and post-retirement benefit plans.

Non-regulated operating expense for all periods presented is discussed below under "—Non-regulated Items".

Maintenance and repairs expense increased approximately $0.9 million (4.4%) during 2004 as compared to 2003 primarily due to the $1.0 million insurance deductible recorded to expense in the first quarter of 2004 related to the maintenance on the Energy Center's Unit No. 2 which experienced a rotating blade failure on January 7, 2004 (which caused damage throughout the machine) and to the second and third quarter maintenance costs related to repairs at the Energy Center not subject to insurance recovery. Also contributing to this increase was a $0.8 million increase in transmission and distribution maintenance and a $0.7 million increase in maintenance costs for the SLCC as compared to the prior year due mainly to a $1.8 million true-up credit (our share of the credit as 60% owners of the SLCC) received from Siemens Westinghouse in June 2003 related to our maintenance contract for the period July 2002 through June 2003 for the SLCC. These increases were partially offset by a $1.4 million decrease in maintenance costs for our coal-fired units during 2004 as compared to the prior year, reflecting the maintenance outages during the second quarter of 2003 when the Iatan Plant underwent a planned boiler outage, the Riverton Plant's Unit No. 7 had a 12-day scheduled spring maintenance outage and Unit No. 8 had an extended maintenance outage that ran from February 14, 2003 until May 14, 2003.

Depreciation and amortization expense increased approximately $2.1 million (7.4%) during 2004 due to increased plant in service. Total provision for income taxes decreased approximately $4.7 million (29.8%) during 2004 due primarily to lower taxable income. Our effective federal and state income tax rate for 2004 was 34.1% as compared to 34.5% for 2003. See Note 9 of "Notes to Consolidated Financial Statements" for additional information regarding income taxes. Other taxes increased $1.9 million (11.6%) during 2004 due mainly to increased property taxes reflecting our additions to plant in service and increased city taxes in the first quarter of 2004 as compared to the first quarter of 2003 when we had a decrease in city taxes resulting from the refund of the IEC in the first quarter of 2003.

During 2003, total operating expenses increased approximately $15.0 million (6.0%) compared to 2002. Total fuel costs increased approximately $2.6 million (5.2%) during 2003 offset by a decrease in purchased power costs of approximately $2.6 million (4.1%) making total combined fuel and purchased power costs in 2003 virtually the same as in 2002. The increase in total fuel costs reflects a $1 million payment in the fourth quarter of 2003, expensed as additional fuel costs in the third quarter of 2003, pursuant to a settlement with Enron of a fuel contract dispute, a $0.7 million unfavorable coal inventory adjustment in August 2003 and increased generation by our coal-fired units, reflecting the non-renewal of short-term contracts for firm energy discussed above. Despite the effectiveness of our natural gas procurement program, increased natural gas prices during 2003 led to a 16.6 % increase in our average cost of gas as compared to 2002. See Note 14 — "Risk Management and Derivative Financial Instruments" of "Notes to Consolidated Financial Statements" for information on the over hedged and qualified portions of our hedging activities. The decrease in purchased power costs primarily reflects a shift from serving our energy needs with purchased power to generating our own power, reflecting that it was more economical to run our own generating units during the third and fourth quarters of 2003 than to purchase power. This decrease in purchased power costs also reflects the decrease in off-system sales due to the non-renewal of the short-term contracts for firm energy discussed above.

Regulated — other operating expenses increased approximately $6.7 million (15.5%) during 2003 as compared to 2002. This increase was primarily due to an increase of $5.6 million in employee pension expense due primarily to a decline in the value of invested funds. Expenses relating to our employee health care plan contributed $0.6

million to the increase in regulated — other operating expenses while increases in insurance premiums added $0.4 million.

There were no expenses during 2003 relating to the terminated merger with Aquila, Inc. as compared with $1.5 million during 2002. Expenses related to the terminated merger in 2002 were primarily the result of expenses related to severance benefits incurred under our Change in Control Severance Pay Plan in the first quarter of 2002. These expenses are shown on the Other line in our Consolidated Statement of Income under the heading "Operating revenue deductions".

Maintenance and repairs expense decreased approximately $4.5 million (18.3%) during 2003 as compared to 2002. Maintenance and repairs expense for the State Line and Energy Center units decreased approximately $6.1 million partially offset by an approximate $1.3 million increase in maintenance and repairs at our Riverton Plant reflecting a scheduled five-year maintenance outage for Unit No. 8 in the first and second quarters of 2003 as well as to make necessary repairs to a high-pressure cylinder. The decrease in maintenance and repairs expense for the State Line Combined Cycle Unit reflects, in part, the $1.8 million true-up credit received from Siemens Westinghouse discussed above as well as estimated monthly credits we have been accruing since July 2003. Monthly payments on this contract had been based on an assumption of 250 equivalent starts per unit each year. Actual starts during the twelve month period ended June 30, 2003, however, were significantly less than originally estimated resulting in the June 2003 true-up credit. We expensed maintenance costs and accrued a credit based on a combination of starts and actual monthly usage hours for the contract year ended June 30, 2004. As of December 31, 2003, we had accrued $0.9 million in estimated credits. A $0.5 million payment during the third quarter of 2002, per contract terms, to Westar Generating, Inc. (WGI) for maintenance expense related to our usage of the existing Unit No. 2 turbine prior to WGI's 40% joint ownership of the State Line Combined Cycle Unit also contributed to the decreased maintenance expense in 2003. Lower payments during the first half of 2003 on our long-term operating plant maintenance contracts for outage services on Units No. 1 and No. 2 at the Energy Center and State Line Unit No. 1 as compared to the first half of 2002 when we were making additional payments of approximately $1.1 million also contributed to the decrease. Lastly, renegotiated terms for the Energy Center units and State Line Unit No. 1 contract for outage services reduced maintenance costs during 2003 by $0.5 million.

Depreciation and amortization expense increased approximately $2.6 million (10.0%) during 2003 due to increased plant in service. Total provision for income taxes increased approximately $2.4 million (17.6%) during 2003 due primarily to higher taxable income. Our effective federal and state income tax rate for 2003 was 34.5% as compared to 34.3% for 2002. See Note 9 of "Notes to Consolidated Financial Statements" for additional information regarding income taxes.

Non-regulated Items

We began investing in non-regulated businesses in 1996. Our non-regulated businesses, which we operate through our wholly-owned subsidiary EDE Holdings, Inc., include leasing of fiber optics cable and equipment (which we are also using in our own operations), Internet access, close-tolerance custom manufacturing and customer information system software services. On January, 31, 2005, we sold our 100% interest in Southwest Energy Training, a company that offers technical training to the utility industry. This divestiture will not have a material impact on our balance sheets or statements of income in future periods. We evaluated our non-regulated businesses for impairment at December 31, 2004, and determined that no impairment exists based on our forecast of future net cash flows. Failure to achieve forecasted cash flows could result in an impairment in the future.

During 2004, total non-regulated operating revenue increased approximately $0.7 million (3.5%) while total non-regulated operating expense increased approximately $1.8 million (8.6%) as compared with 2003. The increase in revenues was mainly due to the activities of our fiber optics business and Fast Freedom, an Internet provider we own a 100% interest in. The increase in expenses was due mainly to MAPP, which we own a 50.01% interest in, and Conversant, Inc., a software company that we own a 100% interest in which began business in early 2002. Conversant markets Customer Watch, an Internet-based customer information system software, and began contributing revenues in the fourth quarter of 2003.

During 2003, total non-regulated operating revenue increased approximately $10.6 million while total non-regulated operating expense increased approximately $9.2 million as compared with 2002. The significant increases during 2003 were primarily due to the inclusion of a full year of MAPP operating revenues and expenses as compared to the prior year results which reflected the acquisition of our 50.01% interest in MAPP in July 2002. The increase in expenses was also due to the activities of Conversant, Inc.

Our non-regulated businesses generated a $1.8 million net loss in 2004 as compared to a $1.4 million net loss in 2003 and a $1.5 million net loss in 2002.

Nonoperating Items

Total allowance for funds used during construction (AFUDC) decreased $0.1 million in 2004 and $0.3 million in 2003 due to lower levels of construction. See Note 1 of "Notes to Consolidated Financial Statements".

Total interest charges on long-term debt decreased $1.4 million (5.4%) in 2004 as compared to 2003 primarily reflecting the refinancing we accomplished in 2003 by calling higher interest debt issues and replacing them with debt issues at lower interest rates. See "— Liquidity and Capital Resources" for further information. Total interest charges on long-term debt increased $1.1 million (4.4%) in 2003 as compared to 2002 primarily reflecting the effects of the sale of $50.0 million of 7.05% senior notes on December 23, 2002, the sale of the $98 million of 4.5% senior notes in June 2003 and the redemption of the $100 million of senior notes in November 2003. Commercial paper interest decreased $0.6 million during 2004 as compared to 2003, reflecting decreased usage of short-term debt.

Other Comprehensive Income

The change in the fair value of the effective portion of our open gas contracts 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 as the net change in unrealized gain or loss. 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 comprehensive income are reclassified to fuel, or interest expense, in the periods in which they are actually realized or no longer qualify for hedge accounting.

The following table sets forth the net-of-tax increase/(decrease) and the change in the fair market value (FMV) of our open contracts in Other Comprehensive Income for the years presented (in millions).

	2004	2003	2002
Natural gas contracts settled(1)	$(11.5)	$ (9.4)	$ 0.3
Interest rate contracts settled	0.0	(2.4)	0.0
Total contracts settled	$(11.5)	$(11.8)	$ 0.3
Change in FMV of open contracts for natural gas	$ 4.2	$ 10.4	$12.9
Change in FMV of open contracts for interest rates	0.0	2.4	0.0
Total change in FMV of open contracts	$ 4.2	$ 12.8	$12.9
Taxes — natural gas	$ 2.8	$ (0.4)	$ (5.0)
Taxes — interest rates	0.0	0.0	0.0
Total taxes	$ 2.8	$ (0.4)	$ (5.0)
Total change in OCI — net of tax	$ (4.5)	$ 0.6	$ 8.2

(1) Reflected in fuel expense

Our average cost for our open financial hedges increased from $3.695/Dth at December 31, 2003 to $4.795/Dth at December 31, 2004.

We had entered into an interest rate derivative contract in May 2003 to hedge against the risk of a rise in interest rates impacting our 4.5% Senior Notes due 2013 prior to their issuance on June 17, 2003. Costs associated with the interest rate derivative (primarily due to interest rate fluctuations) amounted to approximately $2.7 million and have been capitalized as a regulatory asset and are being amortized over the life of the 2013 Notes, along with the $9.1 million redemption premium paid on the redemption of the $100 million aggregate principal amount of our 7.70% Senior Notes due 2004. The $60 million 30-year interest rate derivative contract that we had entered into on May 16, 2003 to hedge against the risk of a rise in interest rates impacting our 6.7% Senior Notes due 2033 prior to their issuance on November 3, 2003, expired on October 29, 2003 with a gain of $5.1 million. This amount was recorded as a regulatory liability and is being amortized against interest expense over the 30 year life of the debt issue we had hedged. See Note 6 — Long Term Debt under "Notes to Consolidated Financial Statements". We had no interest rate derivative contracts in 2002 or 2004.

Competition

Federal regulation has promoted and is expected to continue to promote competition in the wholesale electric utility industry. However, none of the states in our service territory has legislation that could require competitive retail pricing to be put into effect. The Arkansas Legislature passed a bill in April 1999 that called for deregulation of the state's electricity industry as early as January 2002. However, a law was passed in February 2003 repealing retail deregulation in the state of Arkansas.

We, and most other electric utilities with interstate transmission facilities, have placed our facilities under 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 (SPP), a regional reliability coordinator of the North American Electric Reliability Council and FERC approved Regional Transmission Organization (RTO). Effective September 1, 2002, we began taking Network Integration Transmission Service under the SPP's Open Access Transmission Tariff. This provides a cost-effective way for us to participate in a broader market of generation resources with the possibility of lower transmission costs. This tariff provides for a zonal rate structure, whereby transmission customers within the same zone pay a pro-rata share, in the form of a reservation charge, for the use of the facilities for each transmission owner that serves them. Currently, all revenues collected within a zone are allocated back to the transmission owner serving the zone. To the extent that we are allocated revenues and charges to serve our on-system wholesale and retail power customers, only the difference, if any, is recorded. Revenues received from off-system transmission customers are reflected in electric operating revenues and the related charges expensed.

Prior to the time we began taking Network Integration Transmission Service under the SPP's Open Access Transmission Tariff, we had an agreement with Kansas City Power & Light (KCP&L) for transmission service from the Iatan plant. We believed we had the right to terminate the service under the older Iatan transmission agreement, whereas KCP&L contended that we did not. While we were working to resolve this dispute, we ceased scheduling service from KCP&L but continued to accrue (but not pay) the monthly amount we had paid under the original contract terms. We reached a settlement with KCP&L to pay approximately $0.8 million which was the amount that had accrued since October 2002 and was paid in August 2003, and to continue the service agreement with KCP&L through March 2004, at which time we were released from the original agreement. The additional cost for continuing the service agreement through March 2004 was approximately $0.7 million, which was paid in monthly installments.

In December 1999, the FERC issued Order No. 2000 which encourages the development of RTOs. RTOs are designed to independently control the wholesale transmission services of the utilities in their regions thereby facilitating open and more competitive bulk power markets. On October 15, 2003, the SPP announced it had filed with the FERC seeking formal recognition as an RTO in accordance with FERC Order 2000 and on February 10, 2004, the FERC approved the SPP RTO with conditions. Upon completion of the conditions, the SPP would gain status and FERC acceptance as an RTO. On October 4, 2004, the FERC granted RTO status to the SPP and ordered the SPP to resolve rate "pancaking" (accumulation of multiple access charges) concerns and assure the independence of its proposed market monitor as conditions of the decision. FERC also ordered SPP to finalize a joint operating agreement with Midwest Independent Transmission System Operator, Inc. (MISO). These conditions have been addressed and the SPP is now operating as an RTO.

In October 2003, we filed a notice of intent with the SPP for the right to withdraw from the SPP effective October 31, 2004 because of uncertainty surrounding the treatment from the states regarding RTO participation and cost recoveries. Such withdrawal requires approval from the FERC. We retained the option, however, to rescind such notice on or before October 31, 2004 and remain a member of the SPP, which we did on October 25, 2004. At the same time, we filed a new notice of intent with the SPP for the right to withdraw from the SPP effective October 31, 2005. We will be seeking authorization from Missouri, Kansas and Arkansas to participate in and transfer functional control of our transmission facilities to the SPP RTO should we decide to remain a member. As part of the applications to the aforementioned states, a formal independent SPP RTO Cost Benefit Analysis (CBA) will be submitted. It is anticipated that the completion of the CBA will be finalized by or before April 2005. We are unable to quantify the potential impact of membership in the RTO on our future financial position, results of operation or cash flows at this time, but will continue to evaluate the situation and make a decision whether or not to discontinue membership with the SPP.

In November 2003, FERC issued its Final Rule, Order 2004, with subsequent follow-up Orders regarding electric and natural gas industry Code of Conduct requirements for natural gas and electric transmission service providers and their affiliates. Such Orders are closely related to Order 889 standards of conduct for electric transmission providers and management of Open Access Same Time Information Systems (OASIS) for the power industry. In February 2004, we made an Informational Filing to FERC in response to Order 2004 describing our existing waiver, issued in May 1997, of Order 889 requirements and requesting the continuation of such waiver for Order 2004 requirements. In its April 2004 Order, FERC addressed existing 889 waivers/exemptions and affirmed that such existing waivers/exemptions would continue. If in the future, FERC determines that a waiver of Orders 889 or 2004 is not appropriate for us, then we will be required to separate our bulk power retail sales and purchase functions from our transmission operations functions as well as implement formal code of conduct training and OASIS practices.

In July 2004, FERC issued an order regarding new testing standards for assessing market power by entities that have wholesale market-based rates 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. Failure to show a lack of market power would result in the inability for a utility to continue to charge such market-based rates. Our filing has been submitted and followed by subsequent informational data filings to the FERC. On March 3, 2005, the FERC issued an order commencing an investigation to determine if we have market power within our control area based on our failure to meet one of FERC's wholesale market share screens. We are required to file a response within 60 days. Even if the FERC does find we have market power within our control area, it will not have a material impact on our financial position because we currently have no market-price based wholesale customers within our control area. The outcome of FERC rulings for all utilities is pending.

Approximately 4.5% of our electric operating revenues are derived from sales to on-system wholesale customers, the type of customer for which the FERC is already requiring wheeling, or the use, for a fee, of transmission facilities owned by one company or system to move electrical power for another company or system. Our two largest on-system wholesale customers accounted for 92% of our wholesale business in 2004. We have contracts with these customers that run through the first quarter of 2008.

LIQUIDITY AND CAPITAL RESOURCES

Our net cash provided by operations was higher in 2004 as compared to 2003 due to the repayment in 2003 of a previously accumulated IEC. Investments were lower due to decreased construction. Our primary sources of cash flow during 2004 were $74.4 million in internally generated funds and $13.4 million in proceeds from the issuance of common stock, primarily related to our Dividend Reinvestment and Stock Purchase Plan. Our primary uses of cash during 2004 were $41.9 million in capital expenditures, $13.3 million in short-term debt repayments and $32.6 million in dividend payments.

Our capital expenditures are expected to increase during 2005-2007 due to the purchase and expected installation of a Siemens V84.3A2 combustion turbine with an expected capacity of 155 megawatts at our Riverton Plant to meet additional capacity requirements. This unit is expected to be operational in 2007. Our future construction expenditures include approximately $16.9 million in 2005, $13.5 million in 2006 and $14.1 million in 2007 for the purchase and installation of this turbine.

A detailed discussion on cash flow activity follows.

Cash Provided by Operating Activities

Our net cash flows provided by operating activities increased $4.6 million during 2004 as compared to 2003 primarily due to the refunding of $18.7 million to our Missouri electric customers in the first quarter of 2003 (the amount of the IEC, with interest, collected between October 2001 and December 2002). Other major factors positively impacting cash flows provided by operating activities during 2004 as compared to 2003 were a $2.4 million increase due to changes in accounts payable and accrued liabilities, a $2.7 million increase in depreciation and amortization due to increased plant in service and a $1.0 million increase due to changes in prepaid expenses and deferred charges. Negatively impacting cash provided by operating activities were a $7.6 million decrease in net income, a $6.0 million decrease due to higher accounts receivable and accrued unbilled revenues, a $4.0 million decrease in deferred income taxes associated with lower net income and a $3.8 million decrease due to changes in cash used for fuel, materials and supplies.

Our net cash flows provided by operating activities decreased $3.3 million during 2003 as compared to 2002 primarily due to the refunding of the $18.7 million to our Missouri electric customers in the first quarter of 2003. This outflow of cash in 2003 was partially offset by a $3.9 million increase in net income, a $6.9 million increase due to changes in accounts receivable and accrued unbilled revenues and a $3.3 million increase in depreciation and amortization due to increased plant in service during 2003. Also positively impacting cash flows provided by operating activities were (1) a deferred income tax increase of $3.2 million during 2003 as compared to 2002 primarily due to deferred taxes related to an additional first year depreciation tax allowance recorded for financial statement purposes primarily for our FT8 peaking units and the deduction for tax purposes of the loss on reacquired debt (unamortized issuance costs and discounts on the redeemed first mortgage bonds) and (2) a change from pension income of $3.6 million in 2002 to pension expense of $3.9 million in 2003 primarily due to a decline in the value of invested funds.

We do not expect a significant change in our cash flows from operating activities as a result of our 20-year contract with PPM Energy for the purchase of approximately 550,000 megawatt-hours of energy annually from the proposed Elk River Windfarm beginning in December 2005. We expect that the amount and percentage of electricity we generate by natural gas will decrease in 2006 and in the immediate future thereafter due to this contract. We anticipate the cost of this contract to also be offset by purchasing less higher-priced power from other suppliers or by displacing on-system generation.

Capital Requirements and Investing Activities

Our net cash flows used in investing activities decreased $24.0 million during 2004 as compared to 2003, primarily reflecting the completion of the two FT8 peaking units at the Empire Energy Center in April 2003.

Our net cash flows used in investing activities decreased $11.0 million during 2003 as compared to 2002, primarily reflecting completion of the two FT8 peaking units at the Empire Energy Center.

Our capital expenditures totaled approximately $41.9 million, $65.9 million, and $76.9 million in 2004, 2003 and 2002, respectively. These capital expenditures include AFUDC, increases in capitalized software costs, capital expenditures to retire assets and benefits from salvage.

A breakdown of these capital expenditures for 2004, 2003 and 2002 is as follows:

	Capital Expenditures		
(in millions)	**2004**	**2003**	**2002**
Distribution and transmission system additions	$26.6	$27.7	$25.5
FT8 peaking units — Energy Center	—	20.8	31.7
Combustion turbine — Riverton	2.3	—	—
May 2003 tornado damage	0.7	6.7	—
Other Storms	0.6	—	—
Additions and replacements — Asbury	1.8	1.0	3.0
Additions and replacements — Riverton, Iatan and Ozark Beach	1.3	1.2	2.2
Additions and replacements — Energy Center	1.2	—	—
Additions and replacements — State Line Combined Cycle Unit	0.4	—	2.0
Additions and replacements — State Line Unit 1	0.6	—	—
System mapping project	1.7	2.2	1.3
Fiber optics (non-regulated)	1.5	2.1	2.0
Other non-regulated capital expenditures	0.8	2.1	3.9
Transportation	1.0	0.2	0.7
Computer Services projects	0.1	0.3	0.8
Combustor inspection — State Line Unit 1	—	—	1.8
Other	1.4	0.5	0.8
Retirements and salvage (net)	(0.1)	1.1	1.2
Total	**$41.9**	**$65.9**	**$76.9**

Approximately 99%, 58% and 63% of the cash requirements for capital expenditures for 2004, 2003 and 2002, respectively, were satisfied with internally generated funds (net cash 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 unsecured Senior Notes discussed below.

On July 17, 2002 our subsidiary, EDE Holdings, Inc., together with other investors, acquired the assets of the Precision Products Department of Eagle Picher Technologies, LLC. The acquisition was accomplished through the creation of a newly formed limited liability company, Mid-America Precision Products, LLC (MAPP). EDE Holdings, Inc. acquired a controlling 50.01% interest in MAPP through a cash investment of $0.65 million and, as of December 31, 2003, was the guarantor for 50.01% of a $2.4 million long-term note payable and a $0.75 million revolving short-term credit facility. Although our ownership interest in MAPP remained at 50.01%, as of January 1, 2004, our guaranty was lowered to 25%. However, as part of curing MAPP's violation of certain financial covenants at December 31, 2004, MAPP's loan covenants have been revised and, as of January 1, 2005, EDE Holdings, Inc, is again the guarantor of 50.01% of the remaining $2.7 million long-term note payable and the $0.85 million revolving short-term credit facility, of which $0.8 million was outstanding.

We estimate that our capital expenditures will total approximately $69.3 million in 2005, $86.0 million in 2006 and $88.4 million in 2007. Of these amounts, we anticipate that we will spend approximately $26.5 million, $26.9 million and $27.4 million in 2005, 2006 and 2007, respectively, for additions to our distribution system to meet projected increases in customer demand. These capital expenditure estimates also include approximately $16.9 million in 2005, $13.5 million in 2006 and $14.1 million in 2007 for the purchase and installation of a Siemens V84.3A2 combustion turbine at our Riverton Plant with an expected capacity of 155 megawatts which is scheduled to be operational in 2007 to meet additional capacity requirements.

We estimate that internally generated funds will provide 69% of the funds required in 2005 for capital expenditures. As in the past, we intend to utilize short-term debt or the proceeds of sales of long-term debt 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 any additional amounts needed 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 used in financing activities increased $27.8 million to $33.0 million during 2004 as compared to 2003, primarily due to the borrowing and repayment of short-term debt (commercial paper), the payment of dividends on an increased number of shares of our common stock, partially offset by proceeds from stock issuances, and by the lack of issuances and redemptions of securities consummated in 2003 as described below.

Our net cash flows provided by financing activities decreased $12.0 million during 2003 as compared to 2002 resulting in a $5.3 million use of cash during 2003. Our net cash flows provided by financing activities in 2003 were primarily affected by issuances of common stock, senior notes and trust preferred securities and redemptions and repayments of senior notes and first mortgage bonds, each of which is described in detail below. Also increasing net cash flows provided by financing activities for 2003 was the receipt of $5.1 million from a realized gain resulting from an interest rate derivative, which was partially offset by a loss of $2.7 million on a similar interest rate derivative.

On May 22, 2002, we sold to the public in an underwritten offering 2,500,000 shares of newly issued common stock for $51.9 million. The net proceeds of approximately $49.4 million were used to repay $37.5 million of our First Mortgage Bonds, 7.50% Series due July 1, 2002 and to repay short-term debt.

On December 23, 2002, we sold to the public in an underwritten offering $50 million aggregate principal amount of our unsecured Senior Notes, 7.05% Series due 2022, which mature on December 15, 2022. The net proceeds of approximately $48.6 million were added to our general funds and used to repay short-term debt.

On June 17, 2003, we sold to the public in an underwritten offering, $98 million aggregate principal amount of our unsecured Senior Notes, 4.5% Series due 2013, for net proceeds of approximately $96.6 million. We used the net proceeds from this issuance, along with short-term debt, to redeem all $100 million aggregate principal amount of our Senior Notes, 7.70% Series due 2004 for approximately $109.8 million, including interest. We had entered into an interest rate derivative contract in May 2003 to hedge against the risk of a rise in interest rates impacting the 2013 Notes prior to their issuance. Costs associated with the interest rate derivative (primarily due to interest rate fluctuations) amounted to approximately $2.7 million and were capitalized as a regulatory asset and are being amortized over the life of the 2013 Notes, along with the $9.1 million redemption premium paid on the Senior Notes, 7.70% Series due 2004.

On November 3, 2003, we issued $62.0 million aggregate principal amount of Senior Notes, 6.70% Series due 2033 for net proceeds of approximately $61.0 million. We used the proceeds from this issuance, along with short-term debt, to redeem three separate series of our outstanding first mortgage bonds: (1) all $2.25 million aggregate principal amount of our First Mortgage Bonds, 9¾% Series due 2020 for approximately $2.4 million, including interest; (2) all $13.1 million aggregate principal amount of our First Mortgage Bonds, 7¼% Series due 2028 for approximately $13.7 million, including interest; and (3) all $45.0 million aggregate principal amount of our First Mortgage Bonds, 7% Series due 2023 for approximately $46.8 million, including interest. The $1.7 million aggregate redemption premiums paid in connection with the redemption of these first mortgage bonds, together with $1.1 million of remaining unamortized issuance costs and discounts on the redeemed first mortgage bonds, were recorded as a regulatory asset and are being amortized as interest expense over the life of the 2033 Notes. On May 16, 2003, we entered into an interest rate derivative contract with an outside counterparty to hedge against the risk of a rise in interest rates impacting the 2033 Notes prior to their issue. Upon issuance of the 2033 Notes, the realized gain of $5.1 million from the derivative contract was recorded as a regulatory liability and is being amortized over the life of the 2033 Notes as a reduction of interest expense.

We “marked-to-market” the fair market value of these contracts at the end of each accounting period and included the change in value in Other Comprehensive Income until they were reclassified as a regulatory asset upon issuance of the 2013 Notes in June 2003 and a regulatory liability upon issuance of the 2033 Notes in November 2003.

On December 17, 2003, we sold to the public in an underwritten offering, 2,000,000 newly issued shares of our common stock for $42.3 million. The net proceeds of approximately $40.3 million were used to repay short-term debt and for other general corporate purposes. On January 8, 2004, we sold an additional 300,000 shares to cover the underwriters’ over-allotments for approximately $6.1 million. The proceeds were added to our general funds.

During 2004 and 2003 we also issued $7.3 million and $6.9 million, respectively, in common stock pursuant to our stock plans, primarily through our employee stock purchase and dividend reinvestment plans.

We have an effective shelf registration statement with the SEC under which approximately $89 million of our common stock, unsecured debt securities, preference stock and first mortgage bonds remain available for issuance.

On October 22, 2004, we extended our $100 million unsecured revolving credit facility until May 31, 2006. Borrowings 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. The 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 the Trust Preferred Securities or the related 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, amortization and certain other non-cash charges) 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 would result in an event of default under the credit facility and would prohibit us from borrowing funds thereunder. We are in compliance with these ratios as of December 31, 2004. This credit facility is also subject to cross-default if we default on excess of $5,000,000 in the aggregate of our other indebtedness. There were no borrowings outstanding under this revolver as of December 31, 2004.

Short-term commercial paper outstanding and notes payable averaged $1.4 million and $42.8 million daily during 2004 and 2003, respectively, with the highest month-end balances in each year being $8.5 million and $74.4 million, respectively. Our commercial paper borrowings decreased to zero at December 31, 2004 compared to $13 million at December 31, 2003.

Restrictions in our mortgage bond indenture could affect our liquidity. The Mortgage contains a requirement that for new first mortgage bonds to be issued, our net earnings (as defined in the Mortgage) for any twelve consecutive months within the fifteen months preceding issuance must be two times the annual interest requirements (as defined in the 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, 2004 would permit us to issue approximately $172.2 million of new first mortgage bonds based on this test with an assumed interest rate of 7.0%. In addition to the interest coverage requirement, the Mortgage provides that new bonds must be issued against, among other things, retired bonds or 60% of net property additions. At December 31, 2004, we had retired bonds and net property additions which would enable the issuance of at least $401.0 million principal amount of bonds if the annual interest requirements are met. We are in compliance with all restrictive covenants of the Mortgage.

The Mortgage and the Restated Articles contain certain dividend restrictions. The most restrictive of these is contained in the 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 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, 2004, our level of retained earnings did not prevent us from issuing dividends. In addition, under certain circumstances (including defaults thereunder), 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.

As of December 31, 2004, the ratings for our securities were as follows:

	Moody's	Standard & Poor's
First Mortgage Bonds	Baa1	A–
First Mortgage Bonds — Pollution Control Series	Aaa	AAA
Senior Notes	Baa2	BBB–
Commercial Paper	P-2	A-2
Trust Preferred Securities	Baa3	BB+

On July 22, 2004, Standard & Poor's notified us that they had upgraded their rating on our first mortgage bonds from BBB to A−. On September 28, 2004, Standard & Poor's notified us that they had placed that rating on credit watch with negative implications reflecting, "prospects for erosion of Empire's pressured financial condition if recent testimony by the MPSC staff in Empire's pending general rate case is ultimately endorsed by the MPSC." On March 14, 2005, Standard & Poor's affirmed its 'BBB/A-2' corporate credit rating on us and removed the rating from credit watch with negative implications. The outlook is now stable reflecting the MPSC's rate case decision on March 10, 2005 that exceeded expectation and supports our credit quality. Moody's currently has a negative rating outlook on Empire. These ratings indicate the agencies' assessment of our ability to pay interest, distributions, dividends and principal on these securities. The lower the rating the higher our financing costs will be when our securities are sold. Ratings below investment grade (Baa3 or above for Moody's and BBB- or above for Standard & Poor's) may also impair our ability to issue short-term debt, commercial paper or other securities or make the marketing of such securities more difficult.

CONTRACTUAL OBLIGATIONS

Set forth below is information summarizing our contractual obligations as of December 31, 2004. Not included in these amounts are expected obligations associated with the installation of the new combustion turbine at Riverton, the wind energy agreement, postretirement benefit funding or any future pension funding commitments. These items are discussed in "Executive Summary", "Liquidity and Capital Resources" and "Notes to Consolidated Financial Statements — Note 8 — Retirement Benefits."

	Payments Due by Period (in millions)				
Contractual Obligations	**Total**	**Less than 1 Year**	**1–3 Years**	**3–5 Years**	**More than 5 Years**
Long-Term Debt (w/o discount)	$ 358.1	$ 10.0	$ —	$ 20.0	$328.1
Note Payable to Securitization Trust	50.0	—	—	—	50.0
Interest on Long-Term Debt	430.7	26.2	51.9	51.4	301.2
Capital Lease Obligations	0.4	0.3	0.1	—	—
Operating Lease Obligations	2.7	0.6	1.2	0.9	—
Purchase Obligations*	253.5	52.7	71.9	56.6	72.3
Open Purchase Orders	32.8	11.2	20.4	1.2	—
Other Long-Term Liabilities**	3.0	0.5	2.5	—	—
Total Contractual Obligations	$1,131.2	$101.5	$148.0	$130.1	$751.6

* includes fuel and purchased power contracts.

** Other Long-term Liabilities primarily represents 100% of the long-term debt issued by Mid-America Precision Products, LLC. As of December 31, 2004, EDE Holdings, Inc. was the 25% guarantor of a $2.7 million note included in this total amount. On January 1, 2005, the guarantee was increased to 50.01%.

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.

CRITICAL ACCOUNTING POLICIES

Set forth below are certain accounting policies that are considered by management to be critical and to possibly involve significant risk, which means that they 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. Our pension expense or benefit includes amortization of previously unrecognized net gains or losses. The amortized amount represents the average of gains and losses over the prior five years, with this amount being amortized over five years. In compliance with FAS 87, additional gain or expense may be recognized when our unrecognized gain or loss exceeds 10% of our pension benefit obligation or fair value of plan assets. In addition, we record a liability when the accumulated benefit obligation of the plan exceeds the fair value of the plan assets. Our policy is consistent with the provisions of SFAS 87, "Employers' Accounting for Pensions".

In our most recently approved 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 except that unrecognized actuarial gains or losses will now be amortized over a 10 year period. In accordance with the rate order, we will prospectively calculate the value of plan assets using the Market Related Value method (as defined in SFAS 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 GAAP did not meet the FAS 71 requirements for treatment as a regulatory asset or liability. As a result, we have continued to account for pension expense or benefits in accordance with SFAS 87, using the previously mentioned amortization formula for recognizing net gains or losses. We now expect future pension expense or benefits will be fully recovered or recognized in rates charged to customers.

Risks and uncertainties affecting the application of this 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. Based on the performance of our pension plan assets through January 1, 2003, we were required under the Employee Retirement Income Security Act of 1974 (ERISA) to fund approximately $0.3 million in 2004 in order to maintain minimum funding levels and contributed this $0.3 million to our pension plan in the first quarter of 2004. No minimum pension liability was required to be recorded as of December 31, 2003 or December 31, 2004. 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.

Postretirement Benefits. We recognize expense related to 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 postretirement expense or benefit includes amortization of previously unrecognized net gains or losses. The amortized amount represents the average of gains and losses over the prior five years, with this amount being amortized over five years. Additional gain or expense may be recognized when our unrecognized gain or loss exceeds 10% of our postretirement benefit obligation or fair value of plan assets. Our policy is consistent with the provisions of SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions". Factors that could result in additional postretirement expense include: a lower discount rate than estimated, higher compensation rate and medical cost rate increases, lower return on plan assets, and longer retirement periods.

Risks and uncertainties affecting the application of this 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 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 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.

As of March 4, 2005, approximately 61% of our anticipated volume of natural gas usage for the remainder of the year 2005 is hedged at an average price of $4.795 per Dekatherm (Dth). In addition, approximately 40% of our anticipated volume of natural gas usage for the year 2006 is hedged at an average price of $4.760 per Dth, approximately 37% of our anticipated volume of natural gas usage for the year 2007 is hedged at an average price of $4.526 per Dth, approximately 21% of our anticipated volume of natural gas usage for the year 2008 is hedged at an average price of $4.569 per Dth and approximately 40% of our anticipated volume of natural gas usage for the years 2009–2011 is hedged at an average price of $4.522 per Dth.

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 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.

Regulatory Assets and Liabilities. In accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation", our financial statements reflect ratemaking policies prescribed by the regulatory commissions having jurisdiction over us (FERC and four states).

Certain expenses and credits, normally recognized as incurred, are deferred as assets and liabilities on the balance sheet until the time they are recovered from or refunded to customers. This is consistent with the provisions of SFAS No. 71. We have recorded certain regulatory assets which are expected to result in future revenues as these costs are recovered through the ratemaking process. 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, 2004, we have recorded $52.1 million in regulatory assets and $30.2 million in income taxes, gain on interest rate derivatives and costs of removal as regulatory liabilities. See Note 3 of "Notes to Consolidated Financial Statements" 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 and the 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 that has been provided to customers but not billed. Risks and uncertainties affecting the application of this accounting policy include: projecting customer energy usage and estimating the impact of weather and other factors that affect usage (such as line losses) for the unbilled period.

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 2004, 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, 2004 is $1.5 million.

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.

RECENTLY ISSUED ACCOUNTING STANDARDS

See "Notes to Consolidated Financial Statements — Note 1 — Recently Issued and Proposed Accounting Standards."

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 may include 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 14 of "Notes to Consolidated Financial Statements" 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. We manage our interest rate exposure by limiting our variable-rate exposure (applicable only to commercial paper) to a certain percentage of total capitalization, as set by policy, and by monitoring the effects of market changes in interest rates. See Notes 6 and 7 of "Notes to Consolidated Financial Statements" for further information.

If market interest rates average 1% more in 2005 than in 2004, our interest expense would increase, and income before taxes would decrease by less than $100,000. This amount has been determined by considering the impact of the hypothetical interest rates on our highest month-end commercial paper balance for 2004. There was no outstanding commercial paper as of December 31, 2004. 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 have entered into a three-year contract for the purchase of coal in order to manage our exposure to fuel prices. See Note 11 of our Financial Statements for further information. We satisfied 70.5% of our 2004 fuel supply need through coal. Approximately 90% of our 2004 coal supply was Western coal. Our new three-year coal contract satisfies approximately 100% of our anticipated 2005 requirements, approximately 67% of our 2006 requirements and approximately 33% of our anticipated requirements for 2007 for our Asbury and Riverton Western coal needs. 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 March 4, 2005, 61%, or 4.25 million Dths's, of our anticipated volume of natural gas usage for the remainder of year 2005 is hedged. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies — Hedging Activities" for further information.

Based on our expected natural gas purchases for 2005, if average natural gas prices should increase 10% more in 2005 than the price at December 31, 2004, our fuel expense would increase, and income before taxes would decrease by approximately $2.1 million based on our 2005 financial hedge positions.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have completed an integrated audit of Empire District Electric Company's 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income and comprehensive income, of common shareholders' equity, and of cash flows present fairly, in all material respects, the financial position of Empire District Electric Company and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes 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. We believe that our audits provide a reasonable basis for our opinion.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control — Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
St. Louis, Missouri
March 10, 2005

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, 2004. Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

MANAGEMENT CERTIFICATIONS

William L. Gipson, President and Chief Executive Officer of The Empire District Electric Company, and Gregory A. Knapp, Vice President — Finance and Chief Financial Officer of The Empire District Electric Company, have issued the certifications required by Sections 302 of The Sarbanes-Oxley Act of 2002 and applicable SEC regulations with respect to the Company's Annual Report on Form 10-K, including the financial statements provided in this Report. Among other matters required to be included in those certifications, Mr. Gipson and Mr. Knapp have each certified that, to the best of his knowledge, the financial statements, and other financial information included in the Annual Report on Form 10-K, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented. See Exhibit 31 to the Company's Annual Report on Form 10-K for the complete Section 302 Certifications.

In addition, because our common stock is listed on the NYSE, Mr. Gipson, 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. The CEO's Annual 303A.12 Certification for 2004 was filed with the NYSE on May 7, 2004. Our Chief Executive Officer intends to timely provide the NYSE with the CEO's Annual Certification for 2005.

THE EMPIRE DISTRICT ELECTRIC COMPANY

CONSOLIDATED BALANCE SHEETS

	December 31, 2004	December 31, 2003
Assets		
Plant and property, at original cost: (Note 2)		
Electric	$1,221,384,998	$1,191,445,355
Water	9,201,314	8,801,483
Non-regulated	23,668,864	21,105,515
Construction work in progress	8,653,720	5,840,870
	1,262,908,896	1,227,193,223
Accumulated depreciation and amortization	405,873,917	379,235,073
	857,034,979	847,958,150
Current assets:		
Cash and cash equivalents	12,593,369	13,108,197
Accounts receivable — trade, net of allowance of $248,000 and $702,000, respectively	20,052,892	21,946,990
Accrued unbilled revenues	7,599,964	7,784,403
Accounts receivable — other (Note 15)	12,874,123	9,243,073
Fuel, materials and supplies	32,044,113	29,179,937
Unrealized gain in fair value of derivative contracts (Note 14)	2,867,550	11,631,350
Prepaid expenses	1,952,236	2,240,748
	89,984,247	95,134,698
Noncurrent assets and deferred charges:		
Regulatory assets (Note 3)	52,127,262	55,977,495
Unamortized debt issuance costs	5,881,384	6,289,783
Unrealized gain in fair value of derivative contracts (Note 14)	4,142,900	567,000
Prepaid pension asset (Note 8)	13,973,827	16,532,132
Other	4,393,939	2,631,587
	80,519,312	81,997,997
Total Assets	$1,027,538,538	$1,025,090,845

(Continued)

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

THE EMPIRE DISTRICT ELECTRIC COMPANY

CONSOLIDATED BALANCE SHEETS (continued)

	December 31, 2004	December 31, 2003
Capitalization and Liabilities		
Common stock, $1 par value, 100,000,000 shares authorized, 25,695,972 and 24,975,604 shares issued and outstanding, respectively	$ 25,695,972	$ 24,975,604
Capital in excess of par value	321,632,092	306,727,950
Retained earnings	29,078,105	39,848,572
Accumulated other comprehensive income, net of income tax (Note 14)	2,774,221	7,272,705
Total common stockholders' equity	379,180,390	378,824,831
Long-term debt (Note 6):		
Note payable to securitization trust	50,000,000	50,000,000
Obligations under capital lease	122,570	297,655
First mortgage bonds and secured debt	140,363,500	150,692,450
Unsecured debt	209,430,556	209,402,515
Total long-term debt	399,916,626	410,392,620
Total long-term debt and common stockholders' equity	779,097,016	789,217,451
Current liabilities:		
Accounts payable and accrued liabilities	36,926,520	34,102,261
Current maturities of long-term debt	10,462,211	429,140
Obligations under capital lease	239,684	205,556
Commercial paper	—	13,000,000
Customer deposits	5,724,211	5,251,359
Interest accrued	2,700,402	2,836,241
Unrealized loss in fair value of derivative contracts (Note 14)	1,030,100	583,140
Taxes accrued	1,411,355	1,389,389
	58,494,483	57,797,086
Commitments and contingencies (Note 11)		
Noncurrent liabilities and deferred credits:		
Regulatory liabilities (Note 3)	30,225,020	31,686,523
Deferred income taxes (Note 9)	133,403,329	125,065,620
Unamortized investment tax credits	5,041,000	5,581,000
Postretirement benefits other than pensions (Note 8)	8,248,004	8,088,674
Unrealized loss in fair value of derivative contracts (Note 14)	1,505,800	80,350
Minority interest	705,326	1,159,953
Other	10,818,560	6,414,188
	189,947,039	178,076,308
Total Capitalization and Liabilities	$1,027,538,538	$1,025,090,845

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,		
	2004	2003	2002
Operating revenues:			
Electric	$302,590,345	$303,261,146	$294,571,794
Water	1,369,316	1,388,832	1,075,671
Non-regulated (Note 12)	21,579,975	20,854,918	10,255,530
	325,539,636	325,504,896	305,902,995
Operating revenue deductions:			
Fuel	64,440,543	52,337,362	49,755,465
Purchased power	52,845,618	60,208,746	62,765,107
Regulated — other (Note 16)	52,962,362	49,752,972	43,064,291
Non-regulated (Note 12)	22,972,582	21,160,154	11,911,021
Other	—	—	1,524,355
Maintenance and repairs	20,793,630	19,923,408	24,395,974
Depreciation and amortization	30,797,854	28,688,480	26,084,430
Provision for income taxes	11,054,035	15,751,999	13,390,001
Other taxes	18,133,136	16,247,256	16,175,446
	273,999,760	264,070,377	249,066,090
Operating income	51,539,876	61,434,519	56,836,905
Other income and (deductions):			
Allowance for equity funds used during construction	121,673	—	—
Interest income	205,178	57,011	87,336
Benefit (provision) for other income taxes	(245,965)	250,000	80,000
Minority interest	308,107	(353,634)	(142,463)
Other — non-operating income	67,016	52,857	115,955
Other — non-operating expense	(969,098)	(860,398)	(882,509)
	(513,089)	(854,164)	(741,681)
Interest charges:			
Long-term debt — other	24,640,812	26,044,688	24,957,961
Note payable to securitization trust (Note 1)	4,250,000	—	—
Trust preferred distributions by subsidiary holding solely parent debentures (Note 1)	—	4,250,000	4,250,000
Allowance for borrowed funds used during construction	(98,055)	(282,268)	(570,808)
Other	386,496	1,117,628	1,933,953
	29,179,253	31,130,048	30,571,106
Net income	$ 21,847,534	$ 29,450,307	$ 25,524,118
Weighted average number of common shares outstanding — basic	25,467,740	22,845,952	21,433,889
Weighted average number of common shares outstanding — diluted	25,520,963	22,853,105	21,437,710
Earnings per weighted average share of common stock — basic	$ 0.86	$ 1.29	$ 1.19
Earnings per weighted average share of common stock — diluted	$ 0.86	$ 1.29	$ 1.19
Dividends per share of common stock	$ 1.28	$ 1.28	$ 1.28

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

THE EMPIRE DISTRICT ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year ended December 31,		
	2004	2003	2002
Net income	$ 21,847,534	$ 29,450,307	$25,524,118
Reclassification adjustments for (gains) / losses included in net income or reclassified to regulatory asset or liability	(11,471,020)	(11,752,251)	337,660
Change in fair value of open derivative contracts for period	4,215,400	12,767,151	12,928,110
Income taxes	2,757,136	(385,662)	(5,040,993)
Net change in unrealized (gain)/loss on derivative contracts	(4,498,484)	629,238	8,224,777
Comprehensive income	$ 17,349,050	$ 30,079,545	$33,748,895

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

THE EMPIRE DISTRICT ELECTRIC COMPANY

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY

	Year ended December 31,		
	2004	2003	2002
Common stock, $1 par value:			
Balance, beginning of year	$ 24,975,604	$ 22,567,179	$ 19,759,598
Stock/stock units issued through:			
Public offering	300,000	2,000,000	2,500,000
Stock purchase and reinvestment plans	420,368	408,425	307,581
Balance, end of year	$ 25,695,972	$ 24,975,604	$ 22,567,179
Capital in excess of par value:			
Balance, beginning of year	$306,727,950	$260,559,197	$208,223,200
Excess of net proceeds over par value of stock issued:			
Public offering	5,632,346	38,370,600	46,857,626
Stock purchase and reinvestment plans	9,271,796	7,798,153	5,478,371
Balance, end of year	$321,632,092	$306,727,950	$260,559,197
Retained earnings:			
Balance, beginning of year	$ 39,848,572	$ 39,544,819	$ 41,906,483
Net income	21,847,534	29,450,307	25,524,118
	61,696,106	68,995,126	67,430,601
Less common stock dividends declared	32,618,001	29,146,554	27,885,782
Balance, end of year	$ 29,078,105	$ 39,848,572	$ 39,544,819
Accumulated other comprehensive income (loss):			
Balance, beginning of year	$ 7,272,705	$ 6,643,467	$ (1,581,310)
Reclassification adjustment for (gains)/losses included in net income	(11,471,020)	(11,752,251)	337,660
Change in fair value of open derivative contracts for period	4,215,400	12,767,151	12,928,110
Income taxes	2,757,136	(385,662)	(5,040,993)
Balance, end of year	$ 2,774,221	$ 7,272,705	$ 6,643,467

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,		
	2004	2003	2002
Operating activities			
Net income	$ 21,847,534	$ 29,450,307	$ 25,524,118
Adjustments to reconcile net income to cash flows:			
Depreciation and amortization	35,259,579	32,556,221	29,301,526
Pension expense/(income)	3,005,548	3,858,417	(3,581,781)
Deferred income taxes, net	11,440,001	15,392,000	12,180,000
Investment tax credit, net	(540,000)	(550,000)	(550,000)
Allowance for equity funds used during construction	(121,673)	—	—
Issuance of common stock and stock options for incentive plans	2,231,023	1,300,305	1,195,752
Unrealized (gain)/loss on derivatives	161,790	1,157,850	(1,238,940)
Cash flows impacted by changes in:			
Accounts receivable and accrued unbilled revenues	(1,909,613)	4,127,022	(2,745,282)
Fuel, materials and supplies	(1,738,892)	2,047,510	(2,098,946)
Prepaid expenses and deferred charges	11,233	(1,016,909)	559,689
Accounts payable and accrued liabilities	1,974,238	(467,384)	(1,238,517)
Customer deposits, interest and taxes accrued	358,979	(465,000)	(507,261)
Other liabilities and other deferred credits	2,420,083	1,171,651	436,818
Accumulated provision — rate refunds	—	(18,718,679)	15,875,234
Net cash provided by operating activities	74,399,830	69,843,311	73,112,410
Investing activities			
Capital expenditures — regulated	(39,191,831)	(61,997,311)	(72,805,389)
Capital expenditures and other investments — non-regulated	(2,700,283)	(3,908,397)	(4,071,514)
Net cash (used in) investing activities	(41,892,114)	(65,905,708)	(76,876,903)
Financing activities			
Proceeds from interest rate derivative	—	5,099,325	—
Payment of interest rate derivatives	—	(2,683,000)	—
Proceeds from issuance of Senior Notes	—	160,000,000	50,000,000
Proceeds from issuance of common stock	13,393,487	47,250,514	53,947,826
Long-term debt issuance costs	—	(1,695,567)	(1,574,401)
Redemption of senior notes	—	(100,058,000)	—
Redemption of First Mortgage Bonds	—	(60,326,000)	(37,578,000)
Premium paid on extinguished debt	—	(10,818,793)	—
Discount on issuance of senior notes	—	(809,580)	—
Dividends	(32,618,001)	(29,146,554)	(27,885,782)
Net (repayments) proceeds from short-term borrowings	(13,275,263)	(12,230,673)	(30,034,096)
Net (repayments) proceeds from non-regulated notes payable	(368,384)	303,245	23,389
Other	(154,383)	(153,550)	(135,491)
Net cash (used in) provided by financing activities	(33,022,544)	(5,268,633)	6,763,445
Net (decrease)/increase in cash and cash equivalents	(514,828)	(1,331,030)	2,998,952
Cash and cash equivalents, beginning of year	13,108,197	14,439,227	11,440,275
Cash and cash equivalents, end of year	$ 12,593,369	$ 13,108,197	$ 14,439,227

Interest paid was $27,473,000, $30,935,000, and $30,943,000 for the years ended December 31, 2004, 2003, and 2002, respectively. Income taxes paid were $1,506,000, $0, and $1,767,000 for the years ended December 31, 2004, 2003, and 2002, respectively. Net income taxes paid in 2003 of $0 were due to payments offset by a refund of federal income tax of $750,000.

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

The Empire District Electric Company, headquartered in Joplin, Missouri, is primarily a regulated electric utility engaged in the generation, purchase, transmission, distribution and sale of electricity. Empire also provides regulated water utility service to three towns in Missouri. Currently, the regulated utility accounts for about 98% of consolidated assets and 93% of consolidated revenues. The utility portions of the 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). Empire also has a wholly-owned non-regulated subsidiary, EDE Holdings, Inc. Through the non-regulated subsidiary, as of December 31, 2004, we leased capacity on our fiber optics network, provided Internet access, performed close-tolerance custom manufacturing (Mid America Precision Products, LLC (MAPP)) and licensed customer information system software services. For discussion of the activities of our non-regulated operations and non-regulated results of operations, see Note 12. 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 2004 were derived as follows: residential 41%, commercial 31%, industrial 17%, wholesale on-system 4.5%, wholesale off-system 2% and other 4.5%. Our electric revenues for 2004 by jurisdiction were as follows: Missouri 88.7%, Kansas 5.6%, Arkansas 2.5%, and Oklahoma 3.2%. These percentages have not significantly changed from 2003 and 2002. Following is a description of the Company's significant accounting policies:

Basis of Presentation

The consolidated financial statements include the accounts of The Empire District Electric Company (EDEC), and the consolidated financial statements of our wholly-owned non-regulated subsidiary, EDE Holdings, Inc. (EDE Holdings) and its subsidiaries. The consolidated entity is referred to throughout as "we" or the "Company". On December 31, 2003 we deconsolidated the Empire District Electric Trust I in 2003 as required by Financial Accounting Standards Board (FASB) Interpretation No. 46-R (FIN 46-R).

Reclassifications

Certain prior year amounts have been reclassified to conform to the current year presentation. These reclassifications had no impact on the statements of income.

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, certain expenses and credits, normally recognized as incurred, are deferred as assets and liabilities on the balance sheet until the time they are recognized when recovered from or refunded to customers. As such, we have recorded certain regulatory assets which are expected to result in future revenues as these costs are recovered through the ratemaking process. 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. As of December 31, 2004, all of our regulatory assets are earning a current return except for approximately \$9.3 million related to unamortized premiums and related costs for debt reacquired, and \$2.9 million related to certain postretirement benefit costs. All of these costs were incurred prior to our 2004 rate case filings. These costs were allowed in rates in our latest Missouri rate case which was approved March 10, 2005, effective March 27, 2005. Since cost recovery of debt related costs has historically been allowed in rate cases in our other jurisdictions, we expect them to be approved in our other jurisdictions as well. Postretirement benefit costs were also allowed in rates in our recently approved Missouri rate case. We believe it is probable these assets will also be afforded similar treatment by other state regulators. In addition, $2.3 million and $4.9 million of loss and gain, respectively, remaining from interest rate derivative transactions were also incurred prior to our 2004 rate case filings, and were included in the recently approved Missouri rate case. We believe it is probable they will also be included in our rate base in other states.

We continually assess the recoverability of our regulatory assets. 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.

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 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 electric services provided between the last bill date and the period end date. We also accrue a liability for the related taxes at the end of each period.

Customer information software service revenues from certain of our non-regulated operations are recognized in accordance with Statement of Position (SOP) 97-2, Software Revenue Recognition as issued by the Accounting Standards Executive Committee of the American Institute of Certified Public Accountants (ACSEC) and related authoritative literature. Software revenue is recognized under SOP 97-2 based on the terms and conditions of each contract. Other non-regulated revenues are recognized when the manufactured products ship to the customer or when the internet or other service has been provided.

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 is charged to accumulated depreciation. 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 latest Missouri rate case approved March 10, 2005, effective March 27, 2005, we will begin accruing cost of removal in depreciation rates for mass property (includes transmission, distribution and general plant assets) effective 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, 2004, and 2003, the amount of accrued cost of removal was $17.6 million and $17.9 million, respectively. We adjust this amount to reflect 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 non-regulated businesses are computed at straight-line rates over the estimated useful life of the properties.

The table below summarizes the total provision for depreciation and depreciation rates, both capitalized and expensed for the years ended December 31,:

	2004	2003	2002
Provision for depreciation			
Regulated	$30,821,724	$28,916,777	$27,157,945
Non-regulated	971,997	840,338	535,611
Total	$31,793,721	$29,757,115	$27,693,556
Annual depreciation rates			
Regulated	2.6%	2.5%	2.5%
Non-regulated	5.8%	5.6%	4.1%
Total	2.5%	2.5%	2.5%

The table below sets forth the average depreciation rate for each class of assets, which have been consistently applied for all periods presented:

Annual Weighted Average Depreciation Rate	
Electric fixed assets:	
Production plant	2.5%
Transmission plant	1.6%
Distribution plant	2.8%
General plant	5.7%
Water	3.0%

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 (preferred and common stockholders' equity) 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 FERC, we utilized aggregate rates (on a before-tax basis) of 6.9% for 2004, 1.4% for 2003 and 2.4% for 2002, compounded semiannually, in determining AFUDC.

Asset Impairments

We periodically 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 there is impairment, 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. We performed this analysis at December 31, 2004 and 2003 and believe that no impairments exist at those dates, including assets related to our non-regulated operations. Failure to achieve forecasted cash flows could result in an impairment in the future.

Derivatives

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 nonhedging 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.

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 unlikely that a forecasted transaction will occur; or (4) management determines that designation of the derivative as a hedge instrument is no longer appropriate. (See Note 14.)

Pensions

Our pension expense or benefit includes amortization of previously unrecognized net gains or losses. The amortized amount represents the average of gains and loses over the prior five years, with this amount being amortized over five years. In compliance with SFAS 87, "Employer's Accounting for Pensions", additional gain or expense may be recognized when our unrecognized gain or loss exceeds 10% of our pension benefit obligation or fair value of plan assets. In addition, we record a liability when the accumulated benefit obligation of the plan exceeds the fair value of the plan assets.

In our most recently approved 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 except that unrecognized actuarial gains or losses will now be amortized over a 10 year period. In accordance with the rate order, we will prospectively calculate the value of plan assets using the Market Related Value method (as defined in SFAS 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 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, we have continued to account for pension expense or benefits in accordance with SFAS 87, using the previously mentioned amortization formula for recognizing net gains or losses. We now expect future pension expense or benefits will be fully recovered or recognized in rates charged to customers.

Postretirement Benefits

We recognize expense related to 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. The amortized amount represents the average of gains and losses over the prior five years with this amount being amortized over five years. Additional gain or expense may be recognized when our unrecognized gain or loss exceeds 10% of our postretirement benefit obligation or fair value of plan assets. In addition, in the third quarter, we adopted FASB staff position No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003". (See "Recently Issued and Proposed Accounting Standards" below and Note 8 for more discussion.)

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. 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. (See Note 11 for more detailed information on litigation exposure).

Franchise Taxes

Franchise taxes are collected for and remitted to their respective cities and are included in operating revenues and other taxes in the Consolidated Statements of Income. Franchise taxes of $5,422,000, $5,142,000 and $5,464,000 were recorded for each of the years ended December 31, 2004, 2003 and 2002, 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 accounts payable. At December 31, 2004 and 2003, these amounts were $9,957,370 and $10,232,633, respectively.

Income Taxes

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

Investment tax credits utilized in prior years were deferred and are being amortized over the useful lives of the properties to which they relate. Remaining unamortized investment tax credits are being amortized over lives ranging from 26.5 to 50.0 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 is 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. The weighted average number of common shares outstanding used to compute basic earnings per share for the 2004, 2003 and 2002 periods were 25,467,740, 22,845,952, and 21,433,889, respectively. Additional dilutive shares for the 2004, 2003 and 2002 periods were 53,223, 7,153, and 3,821, respectively. 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, 2004, we had several stock-based compensation plans, which are described in more detail in Note 4. 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 recognize 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. (See further discussion in "Recently Issued and Proposed Accounting Standards" below and Note 4.)

Asset Retirement Obligations

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). 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.

Upon adoption of FAS 143 on January 1, 2003, we 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. 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. These liabilities 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. Upon adoption of this statement in the first quarter of 2003, we recorded a non-recurring discounted liability and a regulatory asset of approximately $630,000 because we expect to recover these costs of removal in electric rates either through depreciation accruals or direct expenses. This liability will be accreted over the period up to the estimated settlement date. The balances at the end of 2004 and 2003 were approximately $690,000 and $656,000, respectively. Also, we reclassified 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 had no impact on results of operations. As of December 31, 2004 and 2003, the accrual for cost of removal was $17.6 million and $17.9 million, respectively.

Recently Issued and Proposed Accounting Standards

In June 2004, the FASB issued an exposure draft on a proposed interpretation of SFAS No. 143, (FAS 143) "Accounting for Obligations Associated with the Retirement of Long-Lived Assets". Under the interpretation, a legal obligation to perform an asset retirement activity that is conditional on a future event is within the scope of FAS 143. Accordingly, an entity would be required to recognize a liability for the fair value of an asset retirement obligation that is conditional on a future event if the liability's fair value can be estimated reasonably. We are evaluating the effects of the proposed interpretation and cannot currently predict what effect its adoption will have on our financial condition and results of operation. This proposed interpretation, as currently drafted, would be effective for us no later than December 31, 2005.

In January 2004, FASB Staff Position No. 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" was issued. Our postemployment medical plan provides prescription drug coverage for Medicare-eligible retirees. Our accumulated postretirement benefit obligation (APBO) and net cost recognized for other postemployment benefits (OPEB) now reflect 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. This subsidy has caused a decrease of $6.0 million in the APBO which will be recognized as an actuarial gain and amortized through the FAS 106 post-retirement expense. We elected to defer recognition of the effects of the Act until the earlier of the issuance of final accounting guidance or a significant modification of the plan. FASB Staff Position No. 106-2, "Accounting and Disclosure Requirements Related to the

Medicare Prescription Drug, Improvement and Modernization Act of 2003", was issued in May 2004 and called for the subsidy to be generally accounted for in the first annual or interim period starting after June 15, 2004. We believe that our plan provides prescription drug benefits that are "actuarially equivalent" to the prescription drug benefits provided under Medicare and will apply for certification in 2005. As a result, we adopted FASB Staff Position No. 106-2 in the third quarter of 2004, and applied it retroactively, using a measurement date of December 31, 2003. As a result, we recorded a $0.48 million credit to our FAS 106 post-retirement expense retroactive to January 1, 2004. This resulted in a reduction to our FAS 106 cost of $0.7 million in 2004.

In December 2004, the FASB issued Statement of Financial Accounting Standards No. 123 (revised 2004) "Share-Based Payments" (FAS 123R). The statement requires companies to record stock option expense in their financial statements based on a fair value methodology beginning no later than the first fiscal quarter beginning after June 15, 2005. During 2002, we adopted FAS 148, "Accounting for Stock-Based Compensation — Transition and Disclosure — an Amendment of SFAS 123" (FAS 148) and elected to adopt the accounting provisions of FAS 123 "Accounting for Stock-Based Compensation" (FAS 123). Under FAS 123, we currently recognize 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 do not expect to early adopt the provisions of FAS 123R, and do not expect it to have a material impact on our financial statements upon adoption.

In April 2003, the FASB issued SFAS No. 149 (FAS 149), "Amendment of Statement 133 on Derivative Instruments and Hedging Activities". FAS 149 amends and clarifies the accounting guidance on (1) derivative instruments (including certain derivative instruments embedded in other contracts) and (2) hedging activities that fall within the scope of FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133). FAS 149 is effective (1) for contracts entered into or modified after June 30, 2003, with certain exceptions, and (2) for hedging relationships designated after June 30, 2003. The adoption of FAS 149 did not have a material impact on our financial condition and results of operations.

In May 2003, the FASB issued SFAS No. 150 (FAS 150), "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity". This statement requires that (1) financial instruments issued in the form of mandatorily redeemable shares, (2) financial instruments that, at inception, represent an obligation to repurchase the issuer's shares or are an obligation indexed to the price of the company's shares, and (3) financial instruments that embody an unconditional obligation, or a conditional obligation for an instrument other than an outstanding share, that the issuer must or may settle by issuing a variable number of equity shares, be classified as liabilities if, at inception, the monetary value is based on (1) a fixed amount, (2) variations in something other than the fair value of the issuer's shares or (3) variations inversely related to the fair value of the issuer's shares. We adopted the required provisions of FAS 150 on July 1, 2003 and the adoption did not materially impact our financial statements.

The FASB issued FASB Interpretation No. 46-R, "Consolidation of Variable Interest Entities" (FIN No. 46-R), in December 2003, which addressed the requirements for consolidating certain variable interest entities. FIN No. 46-R applied immediately to variable interest entities created after January 31, 2003. FIN No. 46-R applies to all other variable interest entities as of March 31, 2004, or, in the case of special purpose entities, December 31, 2003. Empire District Trust I, a securitization trust subsidiary of Empire created in March 2001, was consolidated within our financial statements prior to the adoption of FIN No. 46-R. As a result of the application of FIN No. 46-R, we have deconsolidated this securitization trust as of December 31, 2003. Amounts of $50 million owed to this securitization trust were recorded within the Consolidated Balance Sheet at December 31, 2004 and 2003.

In July 2003, the Emerging Issues Task Force (EITF) reached a consensus on EITF Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments that are Subject to FASB Statement No. 133, 'Accounting for Derivative Instruments and Hedging Activities,' and Not 'Held for Trading Purposes' as defined in EITF Issue No. 02-3 'Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities'," (EITF 03-11) which was ratified by the FASB in August 2003 and was effective for the Company on October 1, 2003. The EITF concluded that determining whether realized gains and losses on physically settled derivative contracts not "held for trading purposes" should be reported in the income statement on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. The adoption of EITF 03-11 did not have an impact on our Consolidated Statements of Income.

In December 2003, the FASB issued SFAS No. 132 (revised) to improve financial statement disclosures for defined benefit plans. The standard requires more details about plan assets, benefit obligations, cash flows, benefit costs and other relevant information. SFAS No. 132 (revised) became effective for fiscal years ending after December 15, 2003. See Note 8 — Retirement Benefits for further information.

2. Property, Plant and Equipment

	As of December 31,	
(In thousands)	**2004**	**2003**
Electric plant:		
Production	$ 501,678	$ 501,076
Transmission	173,233	170,276
Distribution	481,179	459,096
General	54,788	51,707
Electric plant	1,210,878	1,182,155
Less accumulated depreciation and amortization	398,191	373,128
Electric plant net of depreciation and amortization	812,687	809,027
Construction work in progress	8,567	5,598
Electric plant	821,254	814,625
Electric plant and property — other (Net of depreciation and amortization)	10,469	9,256
Water plant	9,201	8,801
Less accumulated depreciation and amortization	2,579	2,503
Water plant net of depreciation and amortization	6,622	6,298
Construction work in progress	21	2
Net water plant	6,643	6,300
Non-regulated:		
Fiber	16,742	15,069
Non-regulated property	6,927	6,036
Less accumulated depreciation and amortization	5,065	3,569
Non-regulated net of depreciation and amortization	18,604	17,536
Construction work in progress	65	241
Net non-regulated property	18,669	17,777
Net plant and property	$ 857,035	$ 847,958

3. Regulatory Matters

Rate Increases

The following table sets forth information regarding electric and water rate increases granted during the four year period ended December 31, 2004:

Jurisdiction	Date Requested	Annual Increase Granted	Percent Increase Granted	Date Effective
Missouri — Electric	November 3, 2000	$17,100,000	8.40%	October 2, 2001
Missouri — Electric	March 8, 2002	11,000,000	4.97%	December 1, 2002
Missouri — Electric	April 30, 2004	25,705,500	9.96%	March 27, 2005
Missouri — Water	May 15, 2002	358,000	33.70%	December 23, 2002
Kansas — Electric	December 28, 2001	2,539,000	17.87%	July 1, 2002
FERC — Electric	March 17, 2003	1,672,000	14.00%	May 1, 2003
Oklahoma — Electric	March 4, 2003	766,500	10.99%	August 1, 2003

The 2001 Missouri electric order approved an annual Interim Energy Charge, or IEC, of approximately $19.6 million effective October 1, 2001 and expiring two years later, which was collected subject to refund (with interest). The 2002 Missouri electric order called for us to refund all funds collected under the IEC, with interest, by March 15, 2003. The refunds were made in the first quarter of 2003 and did not have a material impact on our earnings in any of the years from 2001 through 2003.

On March 4, 2003, we filed a request with the OCC for an annual increase in base rates for our Oklahoma electric customers in the amount of $954,540, or 12.97%. On August 1, 2003, a Unanimous Stipulation and Agreement was approved by the OCC providing an annual increase in rates for our Oklahoma customers of approximately $766,500 or 10.99%, effective for bills rendered on or after August 1, 2003. This reflects a rate of return on equity (ROE) of 11.27%.

On March 17, 2003, we filed a request with the FERC for an annual increase in base rates for our on-system wholesale electric customers in the amount of $1,672,000, or 14.0%. This increase was approved by the FERC on April 25, 2003, with the new rates becoming effective May 1, 2003.

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%. As part of the filing, we asked the MPSC to consider, in addition to a traditional ratemaking approach, two options that would allow us to recover our actual fuel and purchased power expenses: an IEC, subject to refund, similar to the one approved in our 2001 case, or a fuel adjustment clause, that would reflect actual fuel prices. We subsequently abandoned our request for a fuel adjustment clause due to Missouri statutes not providing for such clauses but retained our request for the IEC, subject to refund. We also asked for a return on equity (ROE) of 11.65% and an annual increase in Missouri depreciation expense of approximately $10 million.

On May 20, 2004, we filed a request with the MPSC to implement the proposed IEC no later than June 15, 2004. However, the MPSC denied this request on August 12, 2004. On September 20, 2004, the Staff of the MPSC filed direct testimony in response to our initial April 2004 filing recommending an IEC be adopted for a period of 24 months, due to the extreme volatility currently exhibited by natural gas prices. We completed two weeks of evidentiary hearings during December 2004. Items that were covered during the hearings were: ROE, depreciation, base fuel and purchased power costs and the term and amount of an IEC. On February 22, 2005, we, the Office of Public Counsel (OPC) and two intervenors filed a Nonunanimous Stipulation and Agreement Regarding Fuel and Purchased Power Expense establishing a three year refundable IEC, which became unanimous by operation of Commission rule on March 1, 2005.

Prior to the hearings, we were able to settle several miscellaneous issues with other parties to the case. On December 22, 2004, we, the MPSC Staff, the OPC and two intervenors filed a unanimous Stipulation and Agreement as to Certain Issues with the MPSC settling several of these issues. One of the issues we were able to agree on was a change in the recognition of pension costs. See Note 1 — "Pensions" and Note 8 — "Retirement Benefits — Pensions."

The MPSC issued a final order on March 10, 2005 approving an annual increase in base rates of approximately $25.7 million, or 9.96%, effective March 27, 2005. The order granted us a return on equity of 11%, an increase in depreciation rates and an increase in base rates for fuel and purchased power at $24.68/MWH. 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 is $0.0021 per kilowatt hour of customer usage. The recent extraordinarily high natural gas prices and extreme volatility of natural gas led the MPSC to allow forecasted fuel costs to be used rather than the traditional historical costs in determining the fuel portion of the rate increase. At the end of two years, the excess money collected from customers, if any, above $10 million of the greater of the actual and prudently incurred costs or the base cost of fuel and purchased power set in rates, will be refunded to the customers with interest equal to the current prime rate at that time. At the end of the three year term of the IEC all excess money collected from customers, if any, of the greater of the actual and prudently incurred costs or the base cost of fuel and purchased power set in rates, will be refunded to the customers with interest equal to the current prime rate at that time.

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%. Any new rates approved as a result of this request are not expected to be effective until the second quarter of 2005.

On March 2, 2005, we notified the Kansas Corporation Commission of our intent to file an application requesting a change in base rates for our Kansas electric customers. We plan to file this application in the second quarter of 2005.

Rate Matters

In accordance with FAS No. 71, we currently have deferred approximately $1,227,000 of expense related to rate cases under other non-current assets and deferred charges. $1,092,000 is directly related to the current Missouri rate case. We amortize this amount over varying periods upon the completion of the specific case. As of December 31, 2004 the full amount of the expense related to the current Missouri case is unamortized. Based on past history, we expect this expense to be recovered in rates.

Regulatory Assets and Liabilities

We have recorded the following regulatory assets and regulatory liabilities. 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 new debt issue, which currently ranges from 9 to 28 years.

	December 31, 2004	December 31, 2003
Regulatory assets		
Income taxes	$27,627,645	$29,001,556
Unamortized loss on reacquired debt	17,322,028	18,635,756
Unamortized loss on interest rate derivative	2,258,192	2,526,491
Asbury five-year maintenance	1,182,198	1,747,067
Other postretirement benefits (Note 8)	3,177,574	3,583,860
Asset retirement obligation	559,625	482,765
Total regulatory assets	$52,127,262	$55,977,495
Regulatory liabilities		
Income taxes	$ 7,694,694	$ 8,723,449
Unamortized gain on interest rate derivative	4,901,018	5,070,995
Costs of removal	17,629,308	17,892,079
Total regulatory liabilities	$30,225,020	$31,686,523

Deregulation

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.

Federal regulation has promoted and is expected to continue to promote competition in the wholesale electric utility industry. However, none of the states in our service territory has legislation that could require competitive retail pricing to be put into effect. The Arkansas Legislature passed a bill in April 1999 that called for deregulation of the state's electricity industry as early as January 2002. However, a law was passed in February 2003 repealing deregulation in the state of Arkansas.

Regional Transmission Organization

In December 1999, the FERC issued Order No. 2000 which encourages the development of regional transmission organizations (RTOs). RTOs are designed to independently control the wholesale transmission services of the utilities in their regions thereby facilitating open and more competitive bulk power markets. On October 15, 2003, the Southwest Power Pool (SPP) announced it had filed with the FERC seeking formal recognition as an RTO in accordance with FERC Order 2000, and on February 10, 2004, the FERC approved the SPP RTO with conditions. Upon completion of the conditions, the SPP would gain status and FERC acceptance as an RTO. On October 4, 2004, the FERC granted RTO status to the SPP and ordered the SPP to resolve rate "pancaking" (accumulation of multiple access charges) concerns and assure the independence of its proposed market monitor as conditions of the decision. FERC also ordered SPP to finalize a joint operating agreement with Midwest Independent Transmission System Operator, Inc. (MISO). These conditions have been addressed and the SPP is now operating as an RTO.

We are a member of the SPP. In October 2003, we filed a notice of intent with the SPP for the right to withdraw from the SPP effective October 31, 2004 because of uncertainty surrounding the treatment from the states regarding RTO participation and cost recoveries. Such withdrawal requires approval from the FERC. We retained the option, however, to rescind such notice on or before October 31, 2004 and remain a member of the SPP, which we did on October 25, 2004. At the same time, we filed a new notice of intent with the SPP for the right to withdraw from the SPP effective October 31, 2005. We will be seeking authorization from Missouri, Kansas and Arkansas to participate in and transfer functional control of our transmission facilities to the SPP RTO should we decide to remain a member. As part of the applications to the aforementioned states, a formal independent SPP RTO Cost Benefit Analysis (CBA) will be submitted. It is anticipated that the completion of the CBA will be finalized by or before April 2005. We are unable to quantify the potential impact of membership in the RTO on our future financial position, results of operation or cash flows at this time, but will continue to evaluate the situation and make a decision whether or not to discontinue membership with the SPP.

4. Common Stock

New Issuances

On December 17, 2003, we sold 2,000,000 shares of our common stock in an underwritten public offering for $21.15 per share. On January 8, 2004, we sold an additional 300,000 shares to cover the underwriters' over-allotments. The December sale resulted in proceeds of approximately $40,275,000, net of issuance costs of $2,025,000. The January sales resulted in proceeds of approximately $6,075,000 net of issuance costs.

On May 22, 2002, we sold 2,500,000 shares of our common stock in an underwritten public offering for $20.75 per share. This sale resulted in proceeds of approximately $49,433,000, net of issuance costs of $2,442,000.

Stock-Based Awards and Programs

We have several stock based awards and programs, which are described below. 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". Under FAS 123, we recognize 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. This applies to our employee stock purchase plan and our stock incentive plan.

Stock compensation expense relative to all of our stock based awards and programs was approximately $2.1 million, $1.1 million, and $1.0 million in 2004, 2003, and 2002, respectively.

Employee Stock Purchase Plan

Our Employee Stock Purchase Plan 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. There are 100,953 shares available for issuance in this plan.

	2004	2003	2002
Subscriptions outstanding at December 31	44,901	38,400	40,574
Maximum subscription price	$ 18.00	$ 19.03	$ 17.91
Shares of stock issued	37,105	40,121	43,696
Stock issuance price	$ 18.02	$ 17.91	$ 17.73

Stock Incentive Plan

Our 1996 Incentive Plan (the Stock Incentive Plan) provides for the grant of up to 650,000 shares of common stock through January 2006. The 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 number of shares issued to directors in lieu of fees were:

2004	2003	2002
6,537	6,623	5,071

The terms and conditions of any option or stock grant are determined by the Board of Directors' Compensation Committee, within the provisions of the Stock Incentive Plan. The other components of this Stock Incentive Plan are described below. At December 31, 2004, there were 610,547 shares available for issuance under this plan.

Stock Incentive Plan — Restricted Stock Awards

During February 2002 and February 2001, awards of restricted stock were made to qualified employees under the Stock Incentive Plan. For grants made to date, the restrictions typically lapse and the shares are issuable to employees who continue in service with us three years from the date of grant. For employees whose service is terminated by death, retirement, disability, or under certain circumstances following a change in control of the Company prior to the restrictions lapsing, the shares are issuable immediately upon such termination. For other terminations, the grant is forfeited. No restricted shares were granted in 2004 or 2003 nor are any expected to be granted in future periods.

	2004	2003	2002
Restricted shares awarded	—	—	2,669
Common stock issued upon vesting of restricted shares	223	138	2,881

Stock Incentive Plan — Performance-Based Restricted Stock Awards

Beginning in 2002, performance-based restricted stock awards were 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.

	2004	2003	2002
Performance-based stock awards granted	26,200	30,200	37,800

Stock Incentive Plan — 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 were also issued to the recipients of the stock options under which dividend equivalents will be accumulated for the three-year period until the option becomes exercisable and will then be converted to restricted shares of our common stock based on the fair market value of the shares on the date converted. Such restricted shares vest on the eighth anniversary of the grant of the dividend equivalent award or, if earlier, upon exercise of the related option in full. The restricted shares are subject to forfeiture if the related option terminates without having been exercised in full prior to the vesting of these shares.

Presented below is a summary of stock option plan activity for the years shown:

	2004		2003		2002	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Outstanding, beginning of year	118,900	$19.83	69,700	$20.95	—	—
Granted	54,200	$21.79	49,200	$18.25	69,700	$20.95
Exercised	—	—	—	—	—	—
Forfeited	—	—	—	—	—	—
Outstanding, end of year	173,100	$20.45	118,900	$19.83	69,700	$20.95
Exercisable, end of year	—	—	—	—	—	—

The range of exercise prices for the options outstanding at December 31, 2004 was $18.25 to $21.79. The weighted-average remaining contractual life of outstanding options at December 31, 2004 and 2003 was 8.1 years and 8.6 years, respectively. 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 Expanded Black-Scholes option-pricing model with the following assumptions:

	2004	2003	2002
Expected life of option	10 years	10 years	10 years
Risk-free interest rate	3.96%	4.07%	4.85%
Expected volatility of Empire stock	18.80%	26.40%	21.60%
Expected dividend yield on Empire stock(1)	0.00%	0.00%	0.00%
Fair value of each option granted during year	$4.78	$4.99	$5.05

(1) Reflects the existence of dividend equivalents.

Stock Unit Plan for Directors

Our Stock Unit Plan for directors (Stock Unit Plan) provides a stock-based retirement 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 retirement benefits in the form of common stock units. The Stock Unit Plan also provides directors the opportunity to convert previously earned cash retirement benefits to common stock units. As of December 31, 2004, all eligible Directors who had benefits under the prior cash retirement plan have converted their cash retirement benefits to common stock units.

A total of 200,000 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 upon retirement by the Director. 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' retirement benefits as the Directors provide services. At December 31, 2004 there were 58,528 shares accrued to Directors' accounts and 164,266 shares available for issuance under this plan.

	2004	2003	2002
Units granted for service	13,798	7,099	6,466
Units granted for dividends	3,511	3,748	3,879
Units redeemed for common stock	18,663	8,914	8,158

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, 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, 2004 there were 186,091 shares available to be issued.

	2004	2003	2002
Shares contributed	40,741	41,878	40,026

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. Our indenture of mortgage and deed of trust governing our first mortgage bonds restricts our ability to pay dividends on our common stock. In addition, under certain circumstances (including defaults thereunder), 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.

5. Preferred and Preference Stock

We have 2,500,000 shares of preference stock authorized, including 500,000 shares of Series A Participating Preference Stock, none of which have been issued. We have 5,000,000 shares of $10.00 par value cumulative preferred stock authorized. There was no preferred stock issued and outstanding at December 31, 2004 or 2003.

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 25,637,443 and 24,915,722 Rights outstanding at December 31, 2004 and 2003, respectively.

In addition, upon the occurrence of a merger or other business combination, or an event of the type referred to in the preceding paragraph, holders of the Rights, other than an Acquiring Person, will be entitled, upon exercise of a Right, to receive either our common stock or common stock of the Acquiring Person having a value equal to two times the exercise price of the Right. Any time after an Acquiring Person acquires 10% or more (but less than 50%) of our outstanding common stock, our Board of Directors may, at their option, exchange part or all of the Rights (other than Rights held by the Acquiring Person) for our common stock on a one-for-one basis.

6. Long-Term Debt

At December 31, 2004 and 2003 the balance of long-term debt outstanding was as follows:

	2004	2003
Note payable to securitization trust[1]	$ 50,000,000	$ 50,000,000
First mortgage bonds:		
7.60% Series due 2005	10,000,000	10,000,000
8⅛% Series due 2009	20,000,000	20,000,000
6½% Series due 2010	50,000,000	50,000,000
7.20% Series due 2016	25,000,000	25,000,000
7¾% Series due 2025[2]	30,000,000	30,000,000
5.3% Pollution Control Series due 2013[3]	8,000,000	8,000,000
5.2% Pollution Control Series due 2013[3]	5,200,000	5,200,000
	148,200,000	148,200,000
Senior Notes, 7.05% Series due 2022[3]	49,942,000	49,942,000
Senior Notes, 4½% Series due 2013[4]	98,000,000	98,000,000
Senior Notes, 6.70% Series due 2033[4]	62,000,000	62,000,000
Long-term debt — Mid-America Precision Products[5]	2,732,895	3,076,824
Long-term debt — Fast Freedom[5]	275,355	299,809
Obligations under capital lease	362,254	503,211
Less unamortized net discount	(893,983)	(994,528)
	410,618,521	411,027,316
Less current obligations of long-term debt	(10,462,211)	(429,140)
Less current obligations under capital lease	(239,684)	(205,556)
Total long-term debt	$399,916,626	$410,392,620

(1) Represented by our Junior Subordinated Debentures, 8 1/2% Series due 2031.

(2) We may redeem some or all of the notes at any time on or after June 1, 2005 at 100% of their principal amount plus a premium, plus accrued and unpaid interest to the redemption date. The premium at June 1, 2005 is 3.875% and will decline ratably to zero at June 1, 2015.

(3) 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.

(4) 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.

(5) EDE Holdings is the guarantor of 50.01% (25% at December 31, 2004) of a $2.7 million secured long-term note payable of Mid-America Precision Products (MAPP). Although our guarantee had been lowered to 25% at January 1, 2004, MAPP's loan covenants have been revised as part of curing their violation of certain financial covenants at December 31, 2004. As a result of these revisions, as of January 1, 2005, we are once again a 50.01% guarantor. Fast Freedom is a wholly-owned subsidiary of EDE holdings and is the resulting company of the merger of Transaeris and Joplin.com. The February 2003 purchase of Joplin.com was partially financed through long-term notes payable to the previous owners. The 2004 current obligations of these notes are included in the current obligations of long-term debt.

On March 1, 2001, Empire District Electric Trust I (Trust) issued 2,000,000 shares of its 8½% Trust Preferred Securities (liquidation amount $25 per preferred security) in a public underwritten offering. Holders of the trust preferred securities are entitled to receive distributions at an annual rate of 8½% of the $25 per share liquidation amount. Quarterly payments of dividends by the trust, as well as payments of principal, are made from cash received from corresponding payments made by us on $50,000,000 aggregate principal amount of 8½% Junior Subordinated Debentures due March 1, 2031, issued by us to the trust and held by the trust as assets. Interest payments on the debentures are tax deductible by us. We have effectively guaranteed the payments due on the outstanding trust preferred securities. The Junior Subordinated Debentures are shown as "Note payable to securitization trust" on our balance sheet. In connection with the deconsolidation, we recorded our $1,550,000 investment in the Trust and a corresponding note payable to the Trust for the investment.

As discussed above, at January 1, 2005, EDE Holdings is the guarantor for 50.01% of a $2.7 million note issued by Mid-America Precision Products (MAPP). This is fully consolidated in our balance sheet as EDE Holdings owns 50.01% of MAPP. EDE Holdings also guarantees 50.01% of MAPP's revolving short-term credit facility of $0.85 million, of which $0.8 million is outstanding at year end and consolidated within our financial statements. We have no other guarantees.

The principal amount of all series of first mortgage bonds outstanding at any one time is limited by terms of the mortgage to $1,000,000,000. Substantially all of The Empire District Electric Company's property, plant and equipment is subject to the lien of the mortgage. The indenture governing our first mortgage bonds contains a requirement that for new first mortgage bonds to be issued, our net earnings (as defined in the mortgage) for any twelve consecutive months within the 15 months preceding issuance must be two times the annual interest requirements (as defined in the 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, 2004 would permit us to issue $172.2 million of new first mortgage bonds based on this test, with an assumed interest rate of 7%. In addition to the interest coverage requirement, the mortgage provides that new bonds must be issued against, among other things, retired bonds or 60% of net property additions. At December 31, 2004, we had retired bonds and net property additions which would enable the issuance of at least $401.1 million principal amount of bonds if the annual interest requirements are met. We are in compliance with all restrictive covenants of our first mortgage bonds debt agreements.

On December 23, 2002, we sold to the public in an underwritten offering $50 million aggregate principal amount of our unsecured Senior Notes, 7.05% Series due 2022 which mature on December 15, 2022. The net proceeds of approximately $48.6 million were added to our general funds and used to repay short-term debt.

On June 17, 2003, we sold to the public in an underwritten offering, $98 million aggregate principal amount of our unsecured Senior Notes, 4.5% Series due 2013, for net proceeds of approximately $96.6 million. We used the net proceeds from this issuance, along with short-term debt, to redeem all $100 million aggregate principal amount of our Senior Notes, 7.70% Series due 2004 for approximately $109.8 million, including interest. We had entered into an interest rate derivative contract in May 2003 to hedge against the risk of a rise in interest rates impacting the 2013 Notes prior to their issuance. Costs associated with the interest rate derivative (primarily due to interest rate fluctuations) amounted to approximately $2.7 million and were capitalized as a regulatory asset and are being amortized over the life of the 2013 Notes, along with the $9.1 million redemption premium paid on the Senior Notes, 7.70% Series due 2004.

On November 3, 2003, we issued $62.0 million aggregate principal amount of Senior Notes, 6.70% Series due 2033 for net proceeds of approximately $61.0 million. We used the proceeds from this issuance, along with short-term debt, to redeem three separate series of our outstanding first mortgage bonds: (1) all $2.25 million aggregate principal amount of our First Mortgage Bonds, 9¾% Series due 2020 for approximately $2.4 million, including interest; (2) all $13.1 million aggregate principal amount of our First Mortgage Bonds, 7¼% Series due 2028 for approximately $13.7 million, including interest; and (3) all $45.0 million aggregate principal amount of our First Mortgage Bonds, 7% Series due 2023 for approximately $46.8 million, including interest. The $1.7 million aggregate redemption premiums paid in connection with the redemption of these first mortgage bonds, together with $1.1 million of remaining unamortized issuance costs and discounts on the redeemed first mortgage bonds, were recorded as a regulatory asset and are being amortized as interest expense over the life of the 2033 Notes. On May 16, 2003, we entered into an interest rate derivative contract with an outside counterparty to hedge against the risk of a rise in interest rates impacting the 2033 Notes prior to their issue. Upon issuance of the 2033 Notes, the realized gain of $5.1 million from the derivative contract was recorded as a regulatory liability and is being amortized over the life of the debt to reduce interest expense.

The carrying amount of our total debt exclusive of capital leases was $411,150,250 and $411,518,633 at December 31, 2004 and 2003, respectively, and its fair market value was estimated to be approximately $425,235,358 and $421,074,341, respectively. 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.

Payments Due by Period (in millions)

Long-Term Debt Payout Schedule (Excluding Unamortized Discount)	Total	Less than 1 Year	1–3 Years	3–5 Years	More than 5 Years
Note payable to securitization trust	$ 50.0	$ —	$ —	$ —	$ 50.0
Regulated entity debt obligations	358.1	10.0	—	20.0	328.1
Capital lease obligations	0.4	0.3	0.1	—	—
Non-regulated debt obligations	3.0	0.5	2.5	—	—
Total long-term debt obligations	$411.5	$10.8	$2.6	$20.0	$378.1
Less current obligations and unamortized discount	11.6				
Total long-term debt	$399.9				

7. Short-term Borrowings

Short-term commercial paper outstanding and notes payable averaged $1,423,497 and $42,842,666 daily during 2004 and 2003 respectively, with the highest month-end balances being $8,500,000 and $74,350,000, respectively. The weighted average interest rates during 2004 and 2003 was 1.4% in each period. The weighted average interest rates of borrowings outstanding at December 31, 2003 were 1.4%. At December 31, 2004, we had no commercial paper outstanding.

On October 22, 2004, we extended our $100 million unsecured revolving credit facility until May 31, 2006. Borrowings 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. The 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, amortization and certain other non-cash charges) 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, 2004, we are in compliance with these ratios. This credit facility is also subject to cross-default if we default on in excess of $5,000,000 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, 2004 and 2003.

8. Retirement Benefits

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. Plan assets consist of common stocks, United States government obligations, federal agency bonds, corporate bonds and commingled trust funds.

We expect there will be no contribution required under ERISA in order to maintain minimum funding levels in 2005. This could change, however, based on actual investment performance, any future pension plan funding and finalization of actuarial assumptions. At December 31, 2004, there was no minimum pension liability required to be recorded.

Our pension expense or benefit includes amortization of previously unrecognized actuarial net gains or losses. Through 2004, the amortized amount represents the average of gains and losses over the prior five years, with this amount being amortized over five years subject to minimum amortization requirements in accordance with the provisions of SFAS 87, "Employers' Accounting for Pensions" (FAS 87). Pursuant to the 2004 Missouri rate case, approved March 10, 2005, these gains or losses will be amortized over a 10 year period. Also, in accordance with the rate order, we will prospectively calculate the value of plan assets using the Market Related Value method (as defined in FAS 87). This is a change from the policy approved in our 2002 order. As a result of the approved order, we expect our future pension expense to be fully recovered or recognized in rates charged to customers.

Risks and uncertainties affecting the application of this 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.

Our expected benefit payments from our pension trust, (in millions) are as follows:

2005	$ 5.5
2006	$ 5.8
2007	$ 6.0
2008	$ 6.3
2009	$ 7.0
2010–2014	$37.0

The following table sets forth the plan's projected benefit obligation, the fair value of the plan's assets and its funded status:

Reconciliation of Projected Benefit Obligations:

	2004	2003	2002
Benefit obligation at beginning of year	$ 97,958,815	$87,474,547	$78,291,337
Service cost	2,758,833	2,518,954	2,190,415
Interest cost	6,146,270	5,827,520	5,601,019
Plan amendments	—	503,251	—
Net actuarial loss	12,281,639	6,750,127	6,401,833
Benefits and expenses paid	(5,434,468)	(5,115,584)	(5,010,057)
Benefit obligation at end of year	$113,711,089	$97,958,815	$87,474,547

***Reconciliation of Fair Value of Plan Assets*:**

	2004	2003	2002
Fair value of plan assets at beginning of year	$90,311,661	$78,217,601	$92,138,446
Actual return on plan assets gain/(loss)	10,681,237	17,209,644	(8,910,788)
Employer contribution	342,348	—	—
Benefits paid	(5,434,468)	(5,115,584)	(5,010,057)
Fair value of plan assets at end of year	$95,900,778	$90,311,661	$78,217,601

Reconciliation of Funded Status:

	2004	2003	2002
Fair value of plan assets	$ 95,900,778	$ 90,311,661	$ 78,217,601
Projected Benefit obligations	(113,711,089)	(97,958,815)	(87,474,547)
Funded status	(17,810,311)	(7,647,154)	(9,256,946)
Unrecognized prior service cost	2,619,681	3,175,355	3,227,779
Unrecognized net actuarial loss	29,164,457	21,003,931	26,314,821
Prepaid pension cost	$ 13,973,827	$ 16,532,132	$ 20,285,654

At December 31, 2004, our accumulated benefit obligation was $94,850,123 and our plan asset value was $95,900,778. Therefore, a minimum pension liability has not been recorded.

Net Periodic Pension Benefit Cost/(Income)

Our net periodic benefit cost/(income), (related to the application of FAS 87), net of tax, as a percentage of net income for 2004, 2003 and 2002, was 6.80%, 6.59% and (6.87%), respectively.

Net periodic benefit pension cost/(income), some of which is capitalized as a component of labor cost, for 2004, 2003 and 2002, is comprised of the following components:

	2004	2003	2002
Service cost — benefits earned during the period	$ 2,758,833	$ 2,518,954	$ 2,190,415
Interest cost on projected benefit obligation	6,146,270	5,827,520	5,601,019
Expected return on plan assets	(7,455,120)	(6,422,995)	(8,048,645)
Amortization of:			
Prior service cost	555,674	555,675	519,431
Actuarial (gain)/loss	894,996	1,274,368	(3,352,843)
Unrecognized transition (asset)	—	—	(491,158)
Net periodic pension cost/(income)	$ 2,900,653	$ 3,753,522	$(3,581,781)

Assumptions used to determine Year End Benefit Obligation

Measurement date	12/31/2004	12/31/2003
Weighted average discount rate	5.75%	6.25%
Rate of increase in compensation levels	4.25%	4.25%

Assumptions used to determine Net Periodic Pension Benefit Cost/(Income)

Measurement date	01/01/2004	01/01/2003
Discount rate	6.25%	6.75%
Expected return on plan assets	8.50%	8.50%
Rate of compensation increase	4.25%	4.25%

The expected long-term rate of return assumption was based on historical returns and adjusted to estimate the potential range of returns for the current asset allocation.

Allocation of Plan Assets

	% of Fair Value as of December 31,	
	2004	2003
Actual:		
Equity securities	69%	70%
Debt securities	31%	30%
Other	0%	0%
Total	100%	100%
Target Range:		
Equity securities	60% – 70%	60% – 70%
Debt securities	30% – 40%	30% – 40%
Other	0%	0%
Total	100%	100%

We utilize fair value in determining the market-related values for the different classes of our pension plan assets.

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 on a quarterly basis by the Company's Investment Committee.

Permissible Investments

Listed below are the investment vehicles specifically permitted:

Equity

- Common Stocks
- Preferred Stocks
- Convertible Preferred Stocks
- Convertible Bonds
- Covered Options

Fixed Income

- Bonds
- GICs, BICs
- 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

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:

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

Other Postretirement Benefits

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

Effective January 1, 1993, we adopted SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" (FAS 106), which requires recognition of these benefits on an accrual basis during the active service period of the employees. We elected to amortize our transition obligation (approximately $21,700,000) related to FAS 106 over a twenty-year period. Prior to adoption of FAS 106, we recognized the cost of such postretirement benefits on a pay-as-you-go (i.e., cash) basis. The states of Missouri, Kansas, Oklahoma and Arkansas authorize the recovery of FAS 106 costs through rates.

In accordance with rate orders, we established two separate trusts in 1994, one for those retirees who were subject to a collectively bargained agreement and the other for all other retirees, to fund retiree healthcare and life insurance benefits.

In addition, we adopted FASB Staff Position No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003", in the third quarter of 2004.We applied it retroactively, using a measurement date of December 31, 2003. Our postemployment medical plan provides prescription drug coverage for Medicare-eligible retirees. Our accumulated postretirement benefit obligation (APBO) and net cost recognized for other postemployment benefits (OPEB) now reflect the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The provisions of the Act provide 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. We have determined that our plan provides benefits that are actuarially equivalent to the benefits provided under Medicare and will apply for certification in 2005. This adoption resulted in a reduction to our FAS 106 cost of $0.7 million in 2004.

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, 2004, we expect to be required to fund approximately $6 million in 2005. Assets in these trusts amounted to approximately $33.1 million at December 31, 2004, $27.9 million at December 31, 2003 and $21.5 million at December 31, 2002.

Our estimated benefit payments from trust assets (in millions) are as follows:

2005	$ 2.0
2006	$ 2.0
2007	$ 2.1
2008	$ 2.3
2009	$ 2.5
2010–2014	$15.0

Risks and uncertainties affecting the application of this accounting policy include: future rate of return on plan assets, interest rates used in valuing benefit obligations (i.e. discount rates), health care cost trend rates, Medicare prescription drug costs and demographic assumptions (i.e. mortality and retirement rates).

The following table sets forth the plan's benefit obligation, the fair value of the plan's assets and its funded status:

Reconciliation of Benefit Obligation:

	2004	2003	2002
Benefit obligation at beginning of year	$58,285,354	$53,800,550	$42,315,384
Service cost	1,518,200	1,083,133	1,141,158
Interest cost	2,990,434	3,405,784	3,095,057
Amendments[1]	—	(8,533,544)	—
Actuarial (gain)/loss[3]	(756,655)	10,379,025	9,029,864
Plan participants contributions	518,842	416,828	342,480
Benefits paid	(2,194,883)	(2,266,422)	(2,123,393)
Benefit obligation at end of year	$60,361,292	$58,285,354	$53,800,550

Reconciliation of Fair Value of Plan Assets:

	2004	2003	2002
Fair value of plan assets at beginning of year	$27,901,287	$21,494,115	$18,596,087
Employer contributions	4,555,877	5,355,417	5,233,834
Actual return on plan assets	2,215,066	2,894,866	(586,872)
Benefits paid	(2,085,985)	(2,259,939)	(2,091,414)
Plan participants contributions	518,842	416,828	342,480
Fair value of plan assets at end of year	$33,105,087	$27,901,287	$21,494,115

Reconciliation of Funded Status:

	2004	2003	2002
Fair value of plan assets	$ 33,105,087	$ 27,901,287	$ 21,494,115
Benefit obligations	(60,361,292)	(58,285,354)	(53,800,550)
Funded status	(27,256,205)	(30,384,067)	(32,306,435)
Unrecognized transition obligation	8,672,123	9,756,140	10,840,157
Unrecognized prior service cost	(7,924,005)	(8,533,544)	—
Unrecognized net actuarial loss	18,276,081	21,042,234	16,915,842
Accrued postretirement benefit cost	$ (8,232,006)	$ (8,119,237)	$ (4,550,436)

Postretirement benefit cost, a portion of which has been capitalized for 2004, 2003 and 2002, is as follows:

Net Periodic Postretirement Benefit Cost:

	2004	2003	2002
Service cost on benefits earned during the year	$ 1,518,200	$ 1,083,133	$ 1,141,158
Interest cost on projected benefit obligation	2,990,434	3,405,784	3,095,057
Expected return on assets	(1,959,192)	(1,611,614)	(1,350,634)
Amortization of unrecognized transition obligation	1,084,017	1,084,017	1,084,017
Amortization of prior service cost	(609,539)	—	—
Amortization of actuarial loss	1,742,484	1,585,129	896,316
Recognition of substantive plan	—	3,292,328	—
Net periodic postretirement benefit cost before regulatory asset recognition[4]	4,766,404	8,838,777	4,865,914
Recognition of regulatory asset for previously unrecorded benefit costs[2]	—	(3,292,328)	—
Net periodic postretirement benefit cost	$ 4,766,404	$ 5,546,449	$ 4,865,914

(1) 2003 reflects changes in our drug plan to increase the co-pay of the participants.

(2) Accrued postretirement benefit cost at December 31, 2003 increased by $3.3 million related to an adjustment to recognize incremental substantive plan (as defined in FAS 106) benefit costs identified in 2004. A corresponding regulatory asset was recorded for this amount and is being afforded rate recovery in Missouri, effective with our latest Missouri rate case, approved March 10, 2005. We believe it is probable that these costs will also be afforded rate recovery in our other jurisdictions consistent with past practice. The value of this asset at December 31, 2004 is $2,918,430.

(3) 2004 reflects the effect of the Medicare Act subsidy which resulted in a decrease of $6.0 million in the APBO for the past service cost. This was recognized as an actuarial gain and will be amortized through the FAS 106 postretirement expense.

(4) Total 2004 cost reflects the impact of the Medicare Act subsidy on the net periodic postretirement benefit cost as follows:

Amortization of actuarial loss	$(195,635)
Service cost	(152,422)
Interest cost	(315,206)

Assumptions used to determine Year End Benefit Obligation

Measurement date	12/31/2004	12/31/2003
Weighted average discount rate	5.75%	6.25%
Rate of compensation increase	5.00%	5.00%

Assumptions used to determine Net Periodic Benefit Cost

Measurement date	01/01/2004	01/01/2003
Discount rate	6.25%	6.75%
Expected return on plan assets (after tax)	6.80%	6.80%
Rate of compensation increase	5.00%	5.00%

The expected long-term rate of return assumption was based on historical returns and adjusted to estimate the potential range of returns for the current asset allocation.

The assumed 2004 cost trend rate used to measure the expected cost of healthcare benefits and benefit obligation is 9.5%. Each trend rate decreases 0.50% through 2014 to an ultimate rate of 5% for 2014 and subsequent years.

The effect of a 1% increase in each future year's assumed healthcare cost trend rate would increase the current service and interest cost from $4.8 million to $5.8 million and the accumulated postretirement benefit obligation from $60.4 million to $68.9 million. The effect of a 1% decrease in each future year's assumed healthcare cost trend rate would decrease the current service and interest cost from $4.8 million to $4.1 million and the accumulated benefit obligation from $60.4 million to $53.4 million.

Allocation of Plan Assets

	% of Fair Value as of December 31,	
Actual:	**2004**	**2003**
Cash equivalent	11%	11%
Fixed income	40%	40%
Equities	49%	47%
Other	0%	2%
Total	100%	100%
Target Range:		
Cash equivalent	0%	0% – 10%
Fixed income	40% – 60%	40% – 60%
Equities	40% – 60%	40% – 60%
Other	0%	0%
Total	100%	100%

We utilize fair value in determining the market-related values for the different classes of our postretirement plan assets.

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 on a quarterly basis by the Company's Investment Committee.

Permissible Investments:

Listed below are the investment vehicles specifically permitted:

Equity

- Common Stocks
- Preferred Stocks

Fixed Income

- Bonds
- Cash-Equivalent Securities with a maturity of one year or less
- Bonds
- Money Market Funds

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

Those investments prohibited by the Investment Committee are:

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

9. Income Taxes

The provision for income taxes is different from the amount of income tax determined by applying the statutory income tax rate to income before income taxes as a result of the following differences:

	2004	2003	2002
Computed "expected" federal provision	$11,600,000	$15,730,000	$13,590,000
State taxes, net of federal effect	1,030,000	1,380,000	1,190,000
Adjustment to taxes resulting from:			
Investment tax credit Amortization	(540,000)	(550,000)	(550,000)
Other	(790,000)	(1,058,001)	(920,000)
Actual provision for income taxes	$11,300,000	$15,501,999	$13,310,000

Income tax expense components for the years shown are as follows:

	2004	2003	2002
Taxes currently (receivable)/payable included in operating revenue deductions:			
Federal	$ 890,000	$ 120,000	$ 1,590,000
State	(365,000)	790,000	170,000
Included in "other — net"	(125,000)	(250,000)	(80,000)
	400,000	660,000	1,680,000
Deferred taxes:			
Depreciation and amortization differences	13,122,000	17,106,000	11,479,000
Loss on reacquired debt	(350,000)	4,318,000	(169,000)
Pension & postretirement benefits	(1,537,000)	(1,493,000)	559,000
Other	(78,964)	(1,140,000)	(964,000)
Asbury five-year maintenance	(201,000)	(259,000)	902,000
Software development costs	114,000	(70,000)	(190,000)
Alternative minimum tax credit	—	(1,600,000)	—
Hedging transactions	—	(1,470,000)	—
Included in "other — net"	370,965	—	563,000
	11,440,001	15,392,000	12,180,000
Deferred investment tax credits, net	(540,001)	(550,001)	(550,000)
Total income tax expense	$11,300,000	$15,501,999	$13,310,000

Total income tax expense is shown on more than one tax line on the income statement.

Under SFAS No. 109, "Accounting for Income Taxes" (FAS 109), temporary differences gave rise to deferred tax assets and deferred tax liabilities at December 31, 2004 and 2003 as follows:

	Balances as of December 31,			
	2004		2003	
	Deferred Tax Assets	Deferred Tax Liabilities	Deferred Tax Assets	Deferred Tax Liabilities
Noncurrent				
Depreciation and other property related	$12,681,303	$143,529,004	$13,451,962	$131,885,372
Unamortized investment tax credits	3,102,781	—	3,435,155	—
Miscellaneous book/tax recognition differences	8,551,328	14,209,737	7,985,726	18,053,091
Total deferred taxes	$24,335,412	$157,738,741	$24,872,843	$149,938,463

The net of the deferred tax assets and liabilities above are presented as deferred income taxes under non current liabilities on the balance sheet.

10. Commonly Owned Facilities

We own a 12% undivided interest in the Iatan Power Plant, a coal-fired, 670-megawatt generating unit near Weston, Missouri. Kansas City Power & Light and Aquila own 70% and 18%, respectively, of the Unit. We are entitled to 12% of the available capacity and are obligated for that percentage of costs included in the corresponding operating expense classifications in the Statement of Income. At December 31, 2004 and 2003, our property, plant and equipment accounts included the cost of our ownership interest in the plant of $49,197,000 and $48,915,000, respectively, and accumulated depreciation of $34,510,000 and $33,259,000, respectively. Expenditures recorded for our portion of ownership were $6,786,000 and $7,319,000 for 2004 and 2003, respectively, excluding depreciation expenses.

On July 26, 1999, we and Westar Generating, Inc. (“WGI”), a subsidiary of Westar Energy, Inc., entered into agreements for the construction, ownership and operation 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, 2004 and 2003, our property, plant and equipment accounts include the cost of our ownership interest in the unit of $153,334,000 and $153,243,000, respectively, and accumulated depreciation of $18,108,000 and $13,847,000, respectively. Expenditures recorded for our portion of ownership were $34,886,000 and $24,700,000 for 2004 and 2003, respectively, excluding depreciation.

11. Commitments and Contingencies

We are a party to various claims and legal proceedings arising out of the normal course of our business. Management regularly analyzes this information, and has provided accruals for any liabilities, in accordance with the guidelines 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. Under these contracts, the natural gas supplies are divided into firm physical commitments and options that are used to hedge future purchases. The firm physical gas commitments, which represent normal purchases and sales, and transportation commitments total $19.4 million for 2005, $23.0 million for 2006 through 2007, $23.3 million for 2008 through 2009 and $65.6 million for 2010 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. The minimum requirements are $17.1 million for 2005, $16.5 million for 2006 through 2007, and $0.9 million for 2008 through 2009.

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 $87.7 million through May 31, 2010.

On December 10, 2004, we entered into a 20-year contract with PPM Energy, to purchase the energy generated at the proposed 150-megawatt Elk River Windfarm located in Butler County, Kansas. We anticipate purchasing approximately 550,000 megawatt-hours of energy annually from the project beginning in December 2005. We will not own any portion of the windfarm. Costs for energy purchased under this agreement will be expensed as incurred. On January 24, 2005, Flint Hills Tallgrass Prairie Heritage Foundation, Inc. filed a purported class action complaint in the United States District Court (the Court) seeking to halt the development or operation of industrial wind turbine electric power generation facilities within the Flint Hills Tallgrass Prairie Ecosystem. This complaint was dismissed with prejudice by the Court on February 11, 2005. A notice of appeal has been filed.

Environmental Matters

We are subject to various federal, state, and local laws and regulations with respect to air and water quality as well as other environmental matters. We believe that our operations are in compliance with present laws and regulations.

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). When a plant becomes an affected unit for a particular emission, it locks in the then current emission standards. 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.

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. 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 allowances.

In 2004, our Asbury, Riverton and Iatan plants burned a blend of low sulfur Western coal (Powder River Basin) and higher sulfur local coal or burned 100% low sulfur Western coal. In addition, tire derived fuel (TDF) was 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 and the Energy Center Units 3 and 4 are gas-fired facilities and do not receive SO2 allowances. Annual allowance requirements for the State Line Plant and the Energy Center Units 3 and 4, which are not expected to exceed 20 allowances per year, will be transferred from our inventoried bank of allowances. Based on current operations, the combined actual SO2 allowance need for all affected plant facilities is approximately equal to the number of allowances awarded to us annually by the EPA. As of December 31, 2004, we currently have 48,000 banked allowances.

On July 14, 2004, we filed an application with the Missouri Public Service Commission seeking an order authorizing us to implement a plan for the management, sale, exchange, transfer or other disposition of our SO2 emission allowances. Subsequently, we, the Missouri Public Service Commission Staff (Staff) and the Office of Public Counsel (OPC) engaged in discussions to determine an agreeable manner for us to implement an SO2

Allowance Management Policy (SAMP). As a result of these discussions, the parties entered into a Unanimous Stipulation and Agreement on January 18, 2005, stating that we should be granted authority by the Commission to manage our SO2 allowance inventory in accordance with the terms in our SAMP document, which would provide us the authority to swap banked allowances for future vintage allowances and/or monetary value and, in extreme market conditions, provides us with the authority to sell SO2 allowances outright for monetary value. On March 1, 2005, the Missouri Public Service Commission approved the Stipulation and Agreement to become effective March 11, 2005.

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 2004, approximately 9,550 tons of TDF were burned.

In April 2000 the MDNR promulgated a final rule addressing the ozone moderate non-attainment classification of the St. Louis area. The final regulation, known as the Missouri NOx Rule, set a maximum NOx emission rate of 0.25 lbs/mmBtu for Eastern Missouri and a maximum NOx emission rate of 0.35 lbs/mmBtu for Western Missouri. The Iatan, Asbury, State Line and Energy Center facilities are affected by the Western Missouri regulation. In April 2003 the MDNR approved amendments to the Missouri NOx Rule. Included were amendments to delay the effective date of the rule until May 1, 2004 and to establish a NOx emission limit of 0.68 lbs/mmBtu for plants burning tire derived fuel with a minimum annual burn of 100,000 passenger tire equivalents. The Asbury Plant qualified for the 0.68 lbs/mmBtu emission rate. All of our plants currently meet the required emission limits and additional NOx controls are not required.

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 facilities are in compliance with applicable regulations and have received discharge permits and subsequent renewals as required. The Energy Center permit was revised in 2004. The Riverton Plant is affected by final regulations for Cooling Water Intake Structures issued under the CWA 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. The costs associated with compliance with these regulations are not expected to be material.

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 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 Power Plants. We submitted the required renewal application for the Asbury Title V permit in 2004 and will operate under the existing permit until the MDNR issues the renewed permit. A Compliance Assurance Monitoring (CAM) plan is expected to be required by the renewed permit. We estimate that the capital costs associated with the CAM plan will not exceed $2 million.

In mid-December 2003, the EPA issued proposed regulations with respect to SO2, NOx and mercury emissions from coal-fired power plants in a proposed rulemaking known as the Clean Air Interstate Rule (CAIR). The final CAIR was issued by the EPA on March 10, 2005 and will affect 28 states, including Missouri, where our Asbury plant is located, but excluding Kansas, where our Riverton plant is located. Also in mid-December 2003, the EPA issued proposed regulations for mercury emissions by power plants under the requirements of the 1990 Amendments. These proposed regulations are currently expected to be finalized in March 2005. It is possible that we may need to make some expenditures as early as 2005 in order to meet a proposed December 15, 2007 requirement for anticipated mercury reduction requirements under the proposed clean air mercury regulations. The CAIR was issued, and the clean air mercury regulations are expected to be issued, as a result of delays and setbacks in the legislative process for the President's Clear Skies Act legislation, which would have imposed different restrictions on SO2, NOx and mercury emissions. The CAIR is not directed to specific generation units, but instead, requires the state of Missouri to develop a State Implementation Plan (SIP) within the next 18 months in order to comply with specific NOx and SO2 state-wide annual budgets. Until that plan is finalized, we cannot determine the required emission rate of NOx and SO2 for the Asbury or Iatan plants. Also, the SIP will likely include an allowance trading program for NOx and SO2 that could provide compliance without additional capital expenditures. Until the proposed mercury regulations are finalized and additional testing for mercury emissions is completed at Iatan, Asbury and Riverton, we cannot determine if additional investments are required. It is possible that compliance with the proposed mercury regulations will not require additional capital expenditures. However, we expect that pollution control equipment required at the Iatan plant by 2015 may include a Selective Catalytic Reduction (SCR) system and a Flue Gas Desulphurization (FGD) system and a Bag House, with our share of the capital cost estimated at $30 million. We expect that pollution control equipment needed at the Asbury plant by 2015 may include a SCR, a FGD and a Bag House at an estimated capital cost of $80 million.

12. Non-regulated Businesses

On July 17, 2002, EDE Holdings, Inc., together with other investors, acquired the assets of the Precision Products Department of Eagle Picher Technologies, LLC, a manufacturer of close-tolerance metal products whose customers are in the aerospace, electronics, telecommunications, and machinery industries. The acquisition was accomplished through the creation of a newly formed, non-regulated limited liability company, Mid-America Precision Products (MAPP). EDE Holdings acquired a controlling 50.01% interest in this newly formed company through a cash investment of $650,000. As of January 1, 2005, EDE Holdings is also the 50.01% guarantor of a $2.7 million long-term note payable and a $0.8 million revolving short-term credit facility. The acquisition was accounted for using the purchase method of accounting in accordance with SFAS No. 141, "Business Combinations" (FAS 141). Current assets were valued based on the carrying value at July 17, 2002. The property, plant and equipment was valued through a third party appraisal. The change in non-regulated revenues, expenses and minority interest for the year ended December 31, 2003 compared to the year ended December 31, 2002, reflect a full year's results of this acquisition.

In the first half of 2003, we began amortizing the accumulated costs for our Conversant software and the value of the customer list obtained with our purchase of Joplin.com. This amortization was $237,000 and $171,000 in 2004 and 2003, respectively.

The table below presents information about the reported revenues, operating income, net income, capital expenditures, total assets and minority interests of our non-regulated businesses.

	For the year ended December 31, (000's)					
	2004		2003		2002	
	Non-Regulated	Total Company	Non-Regulated	Total Company	Non-Regulated	Total Company
Statement of Income Information						
Revenues*	$21,935	$325,540	$21,218	$325,505	$10,256	$305,903
Operating income (loss)	(1,760)	51,540	(936)	61,435	(1,373)	56,837
Net income (loss)	(1,833)	21,848	(1,393)	29,450	(1,489)	25,524
Minority interest	308	308	(354)	(354)	(142)	(142)
Capital Expenditures	2,700	41,892	3,908	65,906	4,072	76,827

	As of December 31, (000's)					
	2004		2003		2002	
	Non-Regulated	Total Company	Non-Regulated	Total Company	Non-Regulated	Total Company
Balance Sheet Information						
Total assets	$25,561	$1,027,539	$24,439	$1,025,091	$22,211	$991,034
Minority interest	(705)	(705)	(1,160)	(1,160)	(806)	(806)

* Non-Regulated numbers include revenues received from the regulated business that are eliminated in consolidation.

13. Selected Quarterly Information (Unaudited)

The following is a summary of previously reported and adjusted quarterly results for 2004 and reported quarterly results for 2003. We adopted FASB Staff Position No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003", in the third quarter of 2004. and applied it retroactively, using a measurement date as of December 31, 2003. The effect of this adoption on our total net periodic postretirement benefit cost was $0.7 million for the year. The first and second quarterly results originally reported, did not include the after tax effect on earnings of $0.1 million per quarter.

	Quarters			
	As revised First	As revised Second	Third	Fourth
	(dollars in thousands except per share amounts)			
2004:				
Operating revenues	$77,232	$77,303	$96,741	$74,264
Operating income	9,005	9,558	23,673	9,304
Net income	1,578	2,078	16,235	1,957
Basic earnings per share	0.06	0.08	0.64	0.08
Diluted earnings per share	0.06	0.08	0.63	0.08

	Quarters			
	First	Second	Third	Fourth
	(dollars in thousands except per share amounts)			
2003:				
Operating revenues	$76,906	$74,603	$101,029	$72,967
Operating income	13,806	10,997	24,156	12,376
Net income	5,645	2,662	16,298	4,845
Basic and diluted earnings per share	$ 0.25	$ 0.12	$ 0.71	$ 0.21

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

14. Risk Management and Derivative Financial Instruments

We utilize derivatives to manage our natural gas commodity market risk to help manage our exposure resulting from purchasing natural gas, to be used as fuel, on the volatile spot market and to manage certain interest rate exposure.

As of December 31, 2004 and 2003, we have recorded the following assets and liabilities representing the fair value of qualifying derivative financial instruments held as of that date and subject to the reporting requirements of FAS 133.

	2004	2003
Current assets	$2,867,500	$11,631,350
Noncurrent assets	4,142,900	567,000
Current liabilities	1,030,100	583,140
Noncurrent liabilities	1,505,800	80,350

A $2,774,221 net of tax, unrealized gain representing the fair market value of these contracts is recognized as Accumulated Other Comprehensive Income in the capitalization section of the balance sheet. The tax effect of $1,700,329 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, 2005 and ending on September 30, 2011. At the end of each determination period, any gain or loss for that period related to the instrument will be reclassified to fuel expense.

In the first quarter of 2003, we began recording unrealized gains/(losses) on the overhedged portion of our gas hedging activities in “Fuel” under the Operating Revenue Deductions section of our income statements 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. We had previously recorded such gains/(losses), which were not material in the prior periods ended December 31, 2002, in “Other — non-operating income” under the Other Income and Deductions section.

The following table sets forth “mark-to-market” pre-tax gains/(losses) from the overhedged portion of our hedging activities and the actual pre-tax gains/(losses) from the qualified portion of our hedging activities for settled contracts included in “Fuel” (in millions):

	December 31, 2004	December 31, 2003
Overhedged Portion	$ 0.7	$0.9
Qualified Portion	$11.5	$9.4

The table above does not include a $5.1 million realized gain from an interest rate derivative contract in November 2003 or a $2.7 million realized loss from an interest rate derivative contract in June 2003. The benefit and cost of these transactions are recorded as interest expense as amortized. See Note 6 “Long-Term Debt” for information on our hedging of interest rate exposures.

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 and normal sales (NPNS). We have instituted a process to determine if any future executed contracts that otherwise qualify for the NPNS exception contain a price adjustment feature and will account for these contracts accordingly.

15. Accounts Receivable — Other

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

	December 31, 2004	December 31, 2003
Accounts receivable — other		
Accounts receivable for meter loops, meter bases, line extensions, highway projects, etc.	$ 1.9	$1.9
Accounts receivable for insurance reimbursement for Energy Center(1)	1.9	—
Accounts receivable for non-regulated subsidiary companies(2)	3.1	1.7
Accounts receivable from Westar Generating, Inc. for commonly-owned facility	0.5	0.5
Taxes receivable — overpayment of estimated income taxes	4.2	3.2
Accounts receivable for true-up on maintenance contracts(3)	1.2	1.0
Other	0.1	0.9
Total Accounts receivable — other	$12.9	$9.2

(1) The $1.9 million accounts receivable for insurance reimbursement for Energy Center relates to $4.1 million of total expenses for repairs to our Unit No. 2 combustion turbine at Energy Center, less our $1.0 million deductible which was expensed in the first quarter of 2004 and $1.2 million of insurance reimbursement received as of December 31, 2004. Subsequent to December 31, 2004, we have received an additional $0.6 million of the $1.9 million receivable. Based on discussion with our insurer, we expect the remaining $1.3 million to be reimbursed by our insurer.

(2) The increase to $3.1 million in accounts receivable of our non-regulated subsidiary companies is due mainly to increased trade receivables for Mid-America Precision Products, LLC (MAPP).

(3) The $1.2 million in accounts receivable for true-up on maintenance contracts represents $0.2 million remaining of the $3.2 million gross amount of a true-up credit from Siemens Westinghouse in September 2004 related to our maintenance contract entered into in July 2001 for State Line Combined Cycle Unit (SLCC) and $1.0 million of quarterly estimated credits accrued in the last 6 months of 2004. 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, 2004. At both December 31, 2004 and 2003 we had accrued $0.4 million.

16. 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 (in millions) for all periods presented:

	2004	2003	2002
Transmission and distribution expense	$ 7.4	$ 8.1	$ 8.7
Power operation expense (other than fuel)	10.0	9.2	8.8
Customer accounts & assistance expense	7.1	6.7	6.8
Employee pension expense (income)	3.0	3.5	(2.1)
Employee healthcare plan	8.0	6.8	6.3
General office supplies and expense	7.7	6.3	6.0
Administrative and general expense	8.2	8.1	7.0
Allowance for uncollectible accounts	1.5	1.0	1.2
Miscellaneous expense	0.1	0.1	0.4
Total	$53.0	$49.8	$43.1

SELECTED FINANCIAL DATA

(Dollars in thousands, except per share amounts)

	2004	2003	2002	2001	2000
Operating revenues	**$ 325,540**	$ 325,505	$ 305,903	$ 265,821	$ 261,691
Operating income	**$ 51,540**	$ 61,435	$ 56,837	$ 43,212	$ 45,862
Total allowance for funds used during construction	**$ 220**	$ 282	$ 571	$ 3,611	$ 5,775
Net income	**$ 21,848**	$ 29,450	$ 25,524	$ 10,403	$ 23,617
Weighted average number of common shares outstanding — basic	**25,467,740**	22,845,952	21,433,889	17,777,449	17,503,665
Basic and diluted earnings per share	**$ 0.86**	$ 1.29	$ 1.19	$ 0.59	$ 1.35
Cash dividends per share	**$ 1.28**	$ 1.28	$ 1.28	$ 1.28	$ 1.28
Common dividends paid as a percentage of net income	**149.3%**	99.0%	109.3%	217.4%	94.9%
Allowance for funds used during construction as a percentage of net income	**1.0%**	1.0%	2.2%	34.7%	24.5%
Book value per common share outstanding at end of year	**$ 14.76**	$ 15.17	$ 14.59	$ 13.64	$ 13.62
Capitalization:					
Common equity	**$ 379,180**	$ 378,825	$ 329,315	$ 268,308	$ 240,153
Long-term debt	**$ 399,917**	$ 410,393	$ 410,998	$ 358,615	$ 325,644
Ratio of earnings to fixed charges	**2.12x**	2.44x	2.25x	1.31x	2.25x
Total assets*	**$ 1,027,539**	$ 1,025,091	$ 991,034	$ 904,087	$ 852,369
Plant in service at original cost	**$ 1,254,255**	$ 1,221,352	$ 1,125,460	$ 1,080,100	$ 928,561
Capital expenditures (inc. AFUDC)	**$ 41,892**	$ 65,906	$ 76,877	$ 77,316	$ 131,824

* 2000 through 2003 have been reclassified to present cost of asset removal accruals as a regulatory liability. See Note 1 to the Consolidated Financial Statements.

ELECTRIC OPERATING STATISTICS[1]

	2004	2003	2002	2001	2000
Electric Operating Revenues (000s):					
Residential	**$ 124,394**	$ 125,197	$ 126,088	$ 110,584	$ 108,572
Commercial	**92,407**	90,577	91,065	82,237	77,601
Industrial	**51,861**	50,643	50,155	44,509	42,711
Public authorities	**7,441**	7,210	7,099	6,311	5,927
Wholesale on-system	**13,614**	12,440	11,868	12,911	11,738
Miscellaneous	**6,168**	6,618	6,987	5,583	4,546
Total system	**295,885**	292,685	293,262	262,135	251,095
Wholesale off-system	**7,010**	10,849	17,185	3,898	7,842
Less Provision for IEC Refunds	**—**	—	15,875	2,843	—
Total electric operating revenues[2]	**302,895**	303,534	294,572	263,190	258,937
Electricity generated and purchased (000s of kWh):					
Steam	**2,409,002**	2,287,352	2,143,323	1,969,412	2,193,847
Hydro	**63,036**	58,118	45,430	53,635	51,132
Combustion turbine	**1,009,259**	816,343	943,924	790,993	455,678
Total generated	**3,481,297**	3,161,813	3,132,677	2,814,040	2,700,657
Purchased	**1,726,994**	2,112,879	2,520,421	2,092,955	2,255,076
Total generated and purchased	**5,208,291**	5,274,692	5,653,098	4,906,995	4,955,733
Interchange (net)	**100**	91	(69)	(264)	145
Total system input	**5,208,391**	5,274,783	5,653,029	4,906,731	4,955,878
Maximum hourly system demand (Kw)	**1,014,000**	1,041,000	987,000	1,001,000	993,000
Owned capacity (end of period) (Kw)	**1,102,000**	1,102,000	1,004,000	1,007,000	878,000
Annual load factor (%)	**55.98**	54.28	56.88	54.75	55.12
Electric sales (000s of kWh):					
Residential	**1,703,858**	1,728,315	1,726,449	1,681,085	1,660,928
Commercial	**1,417,307**	1,386,806	1,378,165	1,375,620	1,333,310
Industrial	**1,085,380**	1,058,730	1,027,446	1,004,899	1,015,779
Public authorities	**106,416**	102,338	101,188	100,125	96,403
Wholesale on-system	**305,711**	308,574	323,103	322,336	309,633
Total system	**4,618,672**	4,584,763	4,556,352	4,484,065	4,416,053
Wholesale off-system	**236,232**	324,622	735,154	105,975	161,293
Total electric sales	**4,854,904**	4,909,385	5,291,506	4,590,040	4,577,346
Company use (000s of kWh)	**10,087**	10,093	9,960	10,134	8,714
KWh Losses (000s of kWh)	**343,400**	355,305	351,563	306,557	369,818
Total system input	**5,208,391**	5,274,783	5,653,029	4,906,731	4,955,878
Customers (average number of monthly bills rendered):					
Residential	**132,172**	129,878	127,681	125,996	123,618
Commercial	**23,256**	23,077	22,858	22,670	22,504
Industrial	**357**	362	349	337	345
Public authorities	**1,766**	1,716	1,690	1,645	1,674
Wholesale on-system	**4**	5	7	7	7
Total system	**157,555**	155,038	152,585	150,655	148,148
Wholesale off-system	**16**	17	16	7	6
Total	**157,571**	155,055	152,601	150,662	148,154
Average annual sales per residential customer (kWh)	**12,891**	13,307	13,522	13,342	13,436
Average annual revenue per residential customer	**$ 941.15**	$ 963.96	$ 936.21	$ 869.72	$ 878.29
Average residential revenue per kWh	**7.30¢**	7.24¢	6.92¢	6.52¢	6.54¢
Average commercial revenue per kWh	**6.52¢**	6.53¢	6.21¢	5.91¢	5.82¢
Average industrial revenue per kWh	**4.78¢**	4.78¢	4.55¢	4.35¢	4.20¢

(1) See Selected Financial Data for additional financial information regarding Empire.

(2) Before intercompany eliminations.

Directors

Kenneth R. Allen [(1)]
Vice President and Treasurer
Texas Industries, Inc.
Dallas, Texas
(Age 47, Nominated on October 28, 2004)

Melvin F. (Nick) Chubb, Jr. [(2)]
Retired Senior Vice President
Eagle-Picher Industries, Inc.
Cincinnati, Ohio
(Age 71, Director since 1991)

William L. Gipson
President and Chief Executive Officer
The Empire District Electric Company
(Age 48, Director since 2002)

Ross C. Hartley
Co-Founder and Director
NIC Inc.
Overland Park, Kansas
(Age 57, Director since 1988)

Bill D. Helton
Retired Chairman and Chief Executive Officer
New Century Energies
Denver, Colorado
(Age 66, Director since 2004)

D. Randy Laney
Partner
Investlinc Group
Lowell, Arkansas
(Age 50, Director since 2003)

Dr. Julio S. Leon
President
Missouri Southern State University
Joplin, Missouri
(Age 66, Director since 2001)

Myron W. McKinney
Chairman of the Board of Directors
Retired President and Chief Executive Officer
The Empire District Electric Company
Joplin, Missouri
(Age 60, Director since 1991)

B. Thomas Mueller
Founder and President
SALOV North America Corporation
Hackensack, New Jersey
(Age 57, Director since 2003)

Mary McCleary Posner
President and Principal
Posner McCleary Inc.
Columbia, Missouri
(Age 65, Director since 1991)

Allan T. Thoms
Consultant
Wilk & Associates/LECG
San Francisco, California
(Age 66, Director since 2004)

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(1) Nominated for election April 28, 2005
(2) Retiring effective April 28, 2005

Committees of the Board

Audit Committee — Chubb, Hartley, Laney, Mueller, Posner
Compensation Committee — Helton, Laney, Leon, Posner
Executive Committee — Gipson, Helton, Leon, McKinney
Nominating/Corporate Governance Committee — Chubb, Leon, Mueller, Thoms
Retirement Committee —Hartley, Helton, McKinney, Thoms
Ad Hoc Generation Planning Committee — Helton, Laney, McKinney, Thoms

Officers

William L. Gipson
President and Chief Executive Officer
(Age 48, 24 years of service)

Bradley P. Beecher
Vice President — Energy Supply
(Age 39, 15 years of service)

Ronald F. Gatz
Vice President — Strategic Development
(Age 54, 4 years of service)

David W. Gibson
Vice President — Regulatory and General Services
(Age 59, 25 years of service)

Gregory A. Knapp
Vice President — Finance and Chief Financial Officer
(Age 53, 25 years of service)

Michael E. Palmer
Vice President — Commercial Operations
(Age 48, 18 years of service)

Janet S. Watson
Secretary-Treasurer
(Age 52, 10 years of service)

Darryl L. Coit
Controller, Assistant Secretary and Assistant Treasurer
(Age 55, 34 years of service)

Annual Meeting
The annual meeting of shareholders will be held Thursday, April 28, 2005, at 10:30 a.m., CDT, at the Holiday Inn, 3615 South Range Line, Joplin, Missouri.

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Registrar, Transfer Agent, and Dividend Agent
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Shareowner Services
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St. Paul, Minnesota 55164-0854
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(651) 450-4144 (for the hearing impaired) (TDD)
(651) 450-4064 (outside the United States)
www.shareowneronline.com (for registered shareholders)
www.wellsfargo.com/shareownerservices (for general inquiries)

Stock Trading
Empire stock is listed on the New York Stock Exchange under the following ticker symbols:

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

Stock Prices and Dividends

2004 Quarter	*High*	*Low*	*Dividend Paid*
First	23.48	21.38	$0.32
Second	22.99	19.48	$0.32
Third	20.87	19.53	$0.32
Fourth	23.00	20.25	$0.32

2003 Quarter	*High*	*Low*	*Dividend Paid*
First	19.71	17.00	$0.32
Second	22.20	17.67	$0.32
Third	22.26	20.80	$0.32
Fourth	22.45	21.00	$0.32

Credit Rating

	Moody's	*Standard & Poor's*
First Mortgage Bonds	Baa1	A-
First Mortgage Bonds - Pollution Control Series	Aaa	AAA
Commercial Paper	P-2	A-2
Senior Unsecured Notes	Baa2	BBB-
Trust Preferred	Baa3	BB+

Direct Registration
Empire is a participant in the Direct Registration System ("DRS"). This system allows us to issue shares to our registered shareholders in a book-entry form called Direct Registration. All transfers or issuances of shares will be issued in Direct Registration unless a stock certificate is specifically requested.

Dividend Reinvestment and Stock Purchase Plan
The Dividend Reinvestment and Stock Purchase Plan offers a variety of convenient, low-cost services for current shareholders. It is designed for long-term investors who wish to invest and build their share ownership over time. All registered holders of Empire common stock can participate in the Plan. If you are a beneficial owner of shares in a brokerage account and wish to reinvest your dividends, you can request that your shares become registered or make arrangements with your broker or nominee to participate on your behalf. The Plan offers a 3% discount on the purchase of shares with reinvested dividends. Optional features (applicable to registered holders only) include:

- Additional cash purchases, as often as weekly, with $50 minimum per transaction up to $125,000 per year;
- Automatic deduction from your bank account for additional cash purchases;
- Safekeeping of your certificates;
- Participation in the Plan with full, partial, or no reinvestment of dividends;
- Sale of shares through the Plan.

The Plan Administrator may be contacted as follows to request a prospectus describing the Plan, an enrollment form or to make an optional cash investment:

Wells Fargo Bank, N.A.
Shareowner Services
P.O. Box 64856
St. Paul, Minnesota 55164-0856
(800) 468-9716 (toll free in the United States)
(651) 450-4144 (for the hearing impaired) (TDD)
(651) 450-4064 (outside the United States)
www.shareowneronline.com (for registered shareholders)
www.wellsfargo.com/shareownerservices (for general inquiries)

Financial Report – Form 10-K
Copies of this report and the Annual Report on Form 10-K, including financial statements as filed with the Securities and Exchange Commission, are available without charge upon written request to Janet S. Watson, The Empire District Electric Company, P.O. Box 127, Joplin, Missouri 64802-0127. Both reports may also be accessed via our website, www.empiredistrict.com. This report is not intended to induce any securities' sale or purchase.

Inquiries
Investor, shareholder, and financial information is also available from:

The Empire District Electric Company
Janet S. Watson, Secretary-Treasurer
P.O. Box 127
Joplin, Missouri 64802-0127
Telephone (417) 625-5108
Investor.relations@empiredistrict.com

Internet
We invite you to learn more about our Company by connecting with us at *www.empiredistrict.com.*

EMPIRE

SERVICES YOU COUNT ON

www.empiredistrict.com

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P.O. Box 127
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