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MEETING CHALLENGES HEAD ON

THE EMPIRE DISTRICT ELECTRIC COMPANY

2003 Annual Report

PROFILE: Based in Joplin, Missouri, The Empire District Electric Company (NYSE:EDE) is an investor-owned utility providing electric service to approximately 157,000 customers in southwest Missouri, southeast Kansas, northeast Oklahoma, and northwest Arkansas. The Company also provides fiber optic and Internet services, customer information software services, utility industry technical training and has an investment in close-tolerance custom manufacturing. Empire provides water service in three incorporated communities in Missouri. Founded in 1909, Empire has been listed on the New York Stock Exchange since 1946. [illegible] since 1944.

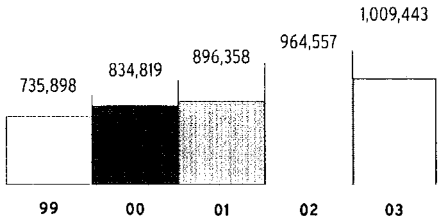
RESPONSE

A STORY OF **SUCCESS** IN A CHANGING INDUSTRY CLIMATE

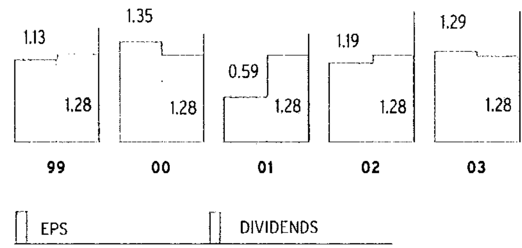
AND

CITIZENSHIP IN THE FACE OF NATURAL DISASTER.

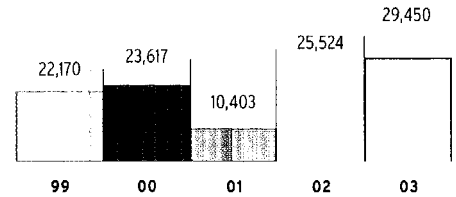
Total Assets
DOLLARS IN THOUSANDS



Earnings & Dividends Paid per Common Share
DOLLARS



Net Income
DOLLARS IN THOUSANDS



2003 Highlights

DECEMBER 31,	2003	2002	CHANGE
Operating Revenues	$ 325,504,896	$ 305,902,995	6.41%
Operating Income	$ 61,434,519	$ 56,836,905	8.09%
Net Income	$ 29,450,307	$ 25,524,118	15.38%
Earnings Per Average Common Share	$ 1.29	$ 1.19	8.40%
Dividends Paid	$ 1.28	$ 1.28	0.00%
Return on Average Common Equity	8.79%	8.55%	2.81%
Book Value Per Share of Common Stock	$ 15.17	$ 14.28	6.23%
Common Shares Outstanding	24,915,722	22,509,230	10.69%
Weighted Average Common Shares Outstanding	22,845,952	21,433,889	6.59%
Number of Common Shareholders of Record (Year end)	6,354	6,541	-2.86%
Total Capital Expenditures (including AFUDC)	$ 65,059,358	$ 77,522,137	-16.08%
Gross Utility Plant	$ 1,200,246,838	$ 1,108,384,516	8.29%
On-System Sales (Thousand kwh)	4,584,763	4,556,352	0.62%
Electric Customers (Year end)	156,681	154,170	1.63%
Total System Capability (Net kw)	1,264	1,166	8.40%
System Peak Demand (Net kw)	1,041	987	5.47%
Degree Days, Heating	3,957	4,183	-5.40%
Degree Days, Cooling	1,537	1,638	-6.17%
Number of Employees (Year end)	824	792	4.04%

TO OUR SHAREHOLDERS

It was a busy year. In 2003, we installed two new peaking units, laid the groundwork for an outage management system, executed a series of financing arrangements, negotiated two rate increases, addressed corporate governance challenges, turned the first profitable quarter from our non-regulated business, set up a new management development program, and repaired major damage inflicted by a series of tornadoes.

We are proud of the results yielded by our efforts. To highlight just a few:

- Our top priority was to improve our financial strength, and we did. We refinanced debt at lower interest rates and issued 2.3 million shares of new common stock. Today our equity to total capitalization ratio stands at about 47%, well in line with what we consider a healthy ratio for our business.
- We wanted to assure our compliance with recently mandated corporate governance reforms, and the Board of Directors moved aggressively to do so. Among other things, they established guidelines for corporate governance, a code of ethics for senior financial officers and me, procedures for reporting accounting or audit-related complaints, and criteria for the independence of directors. All directors except Myron McKinney and me have been declared independent by the Board. Charters are in place for the Audit, Nominating/Corporate Governance, and Compensation Committees.
- EDE Holdings, Inc., the non-regulated arm of our business established in 2001, posted its first profitable period in the fourth quarter of 2003. We believe our non-regulated activities, which form about 2% of our assets, are on schedule to add a small cushion to earnings within the next few years.

Earnings. Earnings per share were $1.29 in 2003, up from $1.19 in 2002. This 8.4% increase largely resulted from increases in our rates, continued customer growth and diligent management of expenses. A full discussion of financial results can be found in the Financial Review section under "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Key Business Strategies for 2004. As we move forward, our business plan remains largely unchanged. Except for the goal of establishing a management development program, which was achieved in 2003, we've retained the key business strategies developed for 2003 and adjusted their focus to reflect 2004 priorities.

Assure appropriate corporate governance. We are on track to meet all new requirements of the New York Stock Exchange, Securities and Exchange Commission, and Sarbanes-Oxley Act by, or prior to, the deadlines.

Diversify weather and Missouri regulatory risk. We will continue to actively pursue acquisition opportunities that balance our seasonality profile and to work with the Missouri Energy Development Association (MEDA) to restore balance to Missouri's regulatory environment. High on MEDA's agenda for 2004 is obtaining a fuel adjustment clause and pre-determination for major construction.

Improve financial performance. While we are pleased with our progress in this area, we are not satisfied. Accordingly, we will continue working to achieve rate relief when justified, reduce volatility in our fuel costs, and gain new efficiencies in our operations.

Implement productivity enhancements/new technologies. Over the past year or so, our system mapping project has laid the groundwork for major productivity gains.

Mapping was completed in early 2004, and we expect to have the related Outage Management System in place by October 2004. Also in the works is a pilot program to analyze automated meter reading alternatives.

Actively manage fuel procurement and associated risk. Although we still need a fuel adjustment clause in Missouri to offset the impact of rising fuel costs, our hedging plan for natural gas is working. We will continue to employ this strategy. On the coal front, we will seek to negotiate and complete contract renewals for coal supply and freight in 2004.

Determine long-term capacity and energy solutions. To meet growing demand, we added, at a cost of $55 million, two 50-megawatt combustion turbines at the Energy Center, and we plan to add another combustion turbine in 2007. For the longer term, we are investigating a wide variety of options, including wind energy alternatives, but have yet to find the right choice for Empire. This issue is important to us and our customers, and we will find the definitive solution.

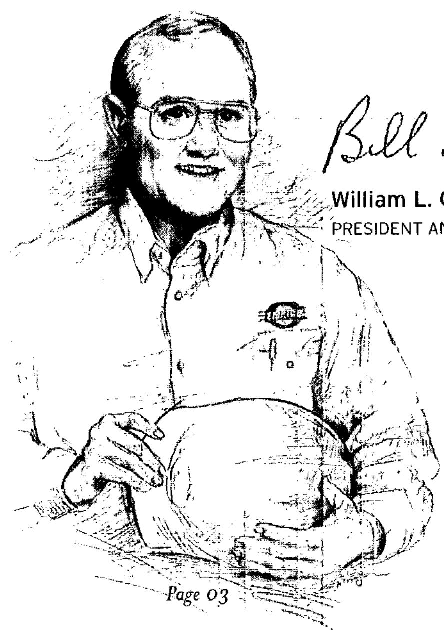
Assure environmental/security compliance. New regulations to govern mercury emissions are expected to be issued in December 2004 and become effective in the 2007-2010 time frame. In 2003, we joined an Electric Power Research Institute collaboration to experiment on mercury removal techniques. This research should provide data that will allow us to make cost-effective decisions to meet the new standards.

Influence/adapt to structural changes in the industry. The Southwest Power Pool (SPP), of which we are a member, received conditional approval for regional transmission organization (RTO) status on February 10, 2004. Due to uncertainties surrounding cost recovery treatment by our regulatory commissions and the uncertainty of costs for the SPP, we gave notice to the SPP of our intention to withdraw membership effective October 31, 2004. This action frees us to consider our RTO options without financial obligation to the SPP beyond that date. We will decide prior to October 31, 2004, to either rescind our withdrawal notice or let it stand.

Transitions. It is with much regret that we announce the retirement of Francis Jeffries, effective April 22, 2004, after 20 years of distinguished service on our Board of Directors. Mr. Jeffries' vast knowledge of our industry and his toughness and zeal for excellence have been invaluable. We thank him for the wise counsel he has provided, and I thank him personally for the mentorship he has given me outside the boardroom. We wish him happiness and good health for the future.

Our theme, "Response," focuses not only on our response to your needs as shareholders but also on our response to a natural disaster of 2003, the series of tornadoes that brought devastation to our area in the course of a single spring night. The importance of this event to you lies not in its damage to our system, which we rebuilt; rather it lies in the evidence of strength, fortitude, and ingenuity our employees displayed under pressure. They erected an entire substation in an unprecedented four days; implemented innovative approaches to material supplies that will shape our response procedures for years to come; and impacted the lives of our customers in ways that will not soon be forgotten. They were tireless and selfless, and I am proud to be their coworker.

On their behalf and my own, I thank you for your investment. My team and I pledge to continue to work with diligence and integrity for a strong Empire.



Bill Gipson

William L. Gipson
PRESIDENT AND CHIEF EXECUTIVE OFFICER

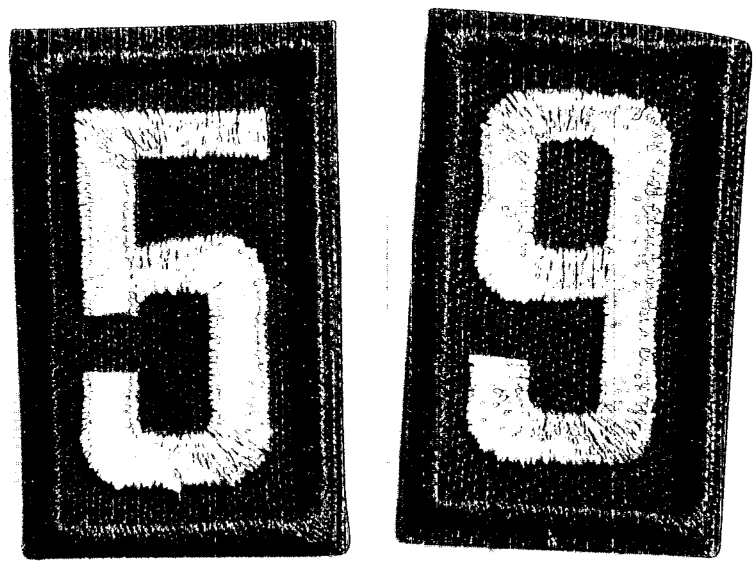
For an electric utility, it's all about response. When the customer flips a switch. When Mother Nature stirs up a storm. When the shareholder looks for value. Sometimes you must be quick and reflexive. Sometimes you must move deliberately. And sometimes you just need to follow your plan.

RESPONSE to STAKEHOLDER NEEDS

Plan. Improve. Serve.

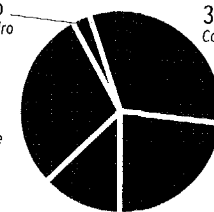
CONSECUTIVE YEARS OF DIVIDENDS

Empire shareholders have been paid dividends, without interruption, every quarter since 1944. It's an accomplishment we're proud of.



A BALANCE OF POWER

Our diverse capacity mix protects against the *pitfalls of relying on a single fuel source.*



WE BEST SERVE OUR SHAREHOLDERS WHEN THE CUSTOMER IS WELL SERVED.

In 2003, we once again shunned the bells and whistles of a complicated approach to follow a basic, common sense plan: Enhance our product, manage our expenses, and serve our customers. In short, our strategy requires continually improving the efficiency of our electric business and, perhaps most importantly, anticipating and responding to our customers' needs. It's been a good plan, and we're happy to share the results.

The balance sheet is strONg. Our ratio of common equity to total capitalization is approximately 47%, up from about 40% in early 2001. Today our short-term debt level is low, our debt is refinanced at a lower cost, and we are well positioned to take advantage of opportunities as they arise.

We arrived at this position of strength by following our plan.

The power is ON. Improving the business means, in part, growing it to meet increasing customer demand for electricity. Our number of customers increased 1.6% in 2003 and a healthy 6.3% over the last five years. We reached a new peak on August 25, 2003, when demand hit 1,041 megawatts, up from a previous high of 1,001 megawatts set in 2001.

We meet our growing demand by maintaining a diverse, low-cost generation portfolio that is overseen by a well-trained, cost-conscious team. In 2003, we added another 100 megawatts of capacity, bringing our total system capability to 1,102 megawatts. We hold an additional 162 megawatts of coal-fired capacity under long-term contract.

Rate relief strategy: Stepping forward and speaking up. We aggressively pursue rate relief when justified, while striving to keep our rates competitive and our working relationship with regulatory authorities strong. In 2003, we received annual rate increases of $0.8 million, or 11.0%, in Oklahoma, and $1.7 million, or 14.0%, for wholesale customers. Since 2001, annual rate relief has totaled $33.5 million.

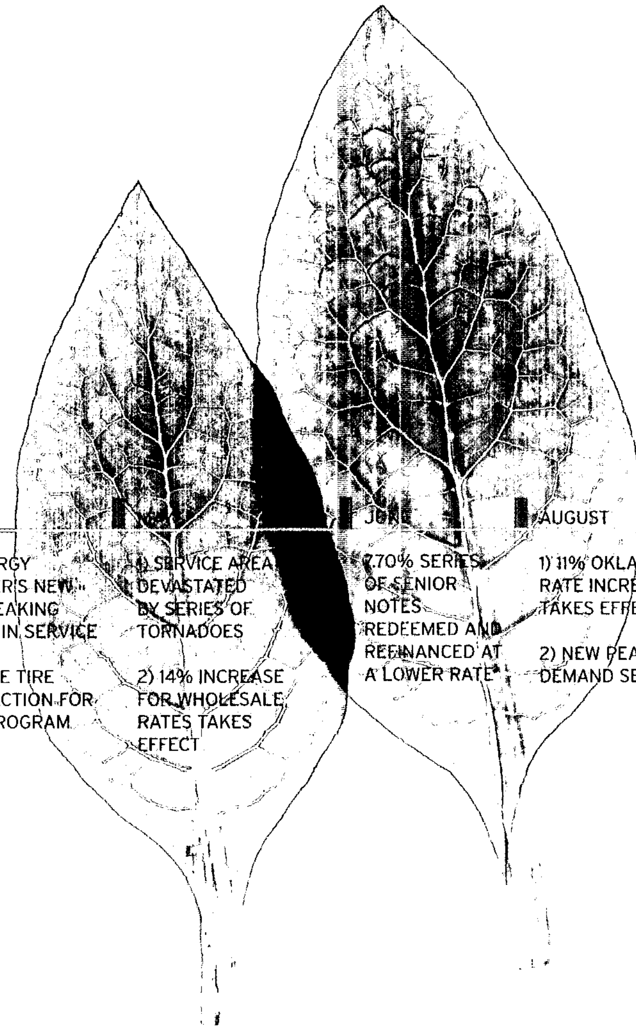
Our rate relief strategy also includes working to achieve balanced regulatory and legislative environments. We are a charter member of the Missouri Energy Development Association (MEDA), an organization formed in late 2002 which serves as an industry voice for energy and water utilities in the state. In 2003, MEDA played a key role in passing initiatives aimed at achieving this balance. Current MEDA initiatives on the legislative front include the authorization of fuel adjustment clauses for electric companies and predetermination for significant capital projects such as new generating facilities. On the regulatory side, MEDA is working for more balanced treatment of return on equity, pension expense, and depreciation. Our Company President and CEO, Bill Gipson, chairs the organization.

Managing the bottom line. Nearly 70% of our regulated operating expenses come from fuel and purchased power, so controlling these costs is crucial to our bottom line. To reduce volatility, we employ a natural gas hedging strategy that incorporates both physical purchases and financial tools. The approach serves us well. Fluctuations in costs in the current

ENVIRONMENTAL AWARDS

In 2003, our trophy box gained three new Missouri awards presented to Empire by Governor Holden: the Pollution Prevention Award, the Recycling Award, and the prestigious Statewide Environmental Excellence Award. The awards recognize the Asbury Plant TDF program, which recycles old tires into fuel for power generation. TDF now comprises 2% of the fuel burned at Asbury.

ASSESSING THE RECENT PAST



FEBRUARY
JOPLIN.COM JOINS THE EMPIRE FAMILY

APRIL
1) ENERGY CENTER'S NEW FT8 PEAKING UNITS IN SERVICE

2) FREE TIRE COLLECTION FOR TDF PROGRAM

MAY
1) SERVICE AREA DEVASTATED BY SERIES OF TORNADOES

2) 14% INCREASE FOR WHOLESALE RATES TAKES EFFECT

JUNE
7.70% SERIES OF SENIOR NOTES REDEEMED AND REFINANCED AT A LOWER RATE

AUGUST
1) 11% OKLAHOMA RATE INCREASE TAKES EFFECT

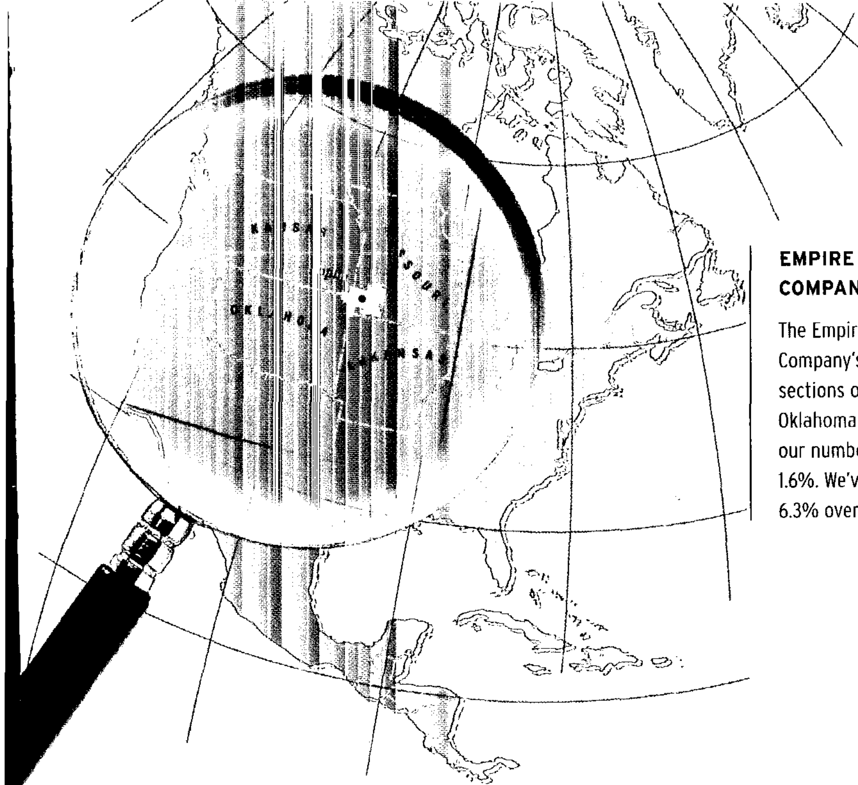
2) NEW PEAK DEMAND SET

OCTOBER
EMPIRE RECEIVES THREE ENVIRONMENTAL AWARDS

NOVEMBER
1) THREE SERIES OF FIRST MORTGAGE BONDS REDEEMED AND REFINANCED AT A LOWER RATE

2) EMPLOYEES CONCLUDE RECORD-SETTING UNITED WAY CAMPAIGN

DECEMBER
NEW COMMON STOCK ISSUED



EMPIRE DISTRICT ELECTRIC COMPANY SERVICE AREA

The Empire District Electric Company's Service Area includes sections of Missouri, Kansas, Oklahoma and Arkansas. In 2003, our number of customers grew 1.6%. We've grown a healthy 6.3% over the last five years.

environment have been minimized, and the resulting improved stability sets a more predictable basis for rate proceedings. In 2003, total fuel and purchased power costs were virtually the same as in 2002. Since 2000, these costs have decreased 8%.

Lowering costs. When drops in interest rates during 2003 offered unique prospects for *cost-cutting, we took advantage by redeeming and refinancing long-term debt, effectively* reducing interest costs on this portion of our debt about 12%. We also renegotiated a bank line of credit, which was extended to two years, and issued new common stock during the year.

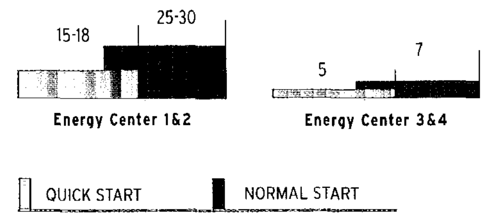
Growing productivity. In 2003, we also saw positive results from our efforts to further improve productivity. Field operation personnel were reduced 10% through attrition over a two-year period while exceptional customer service was maintained.

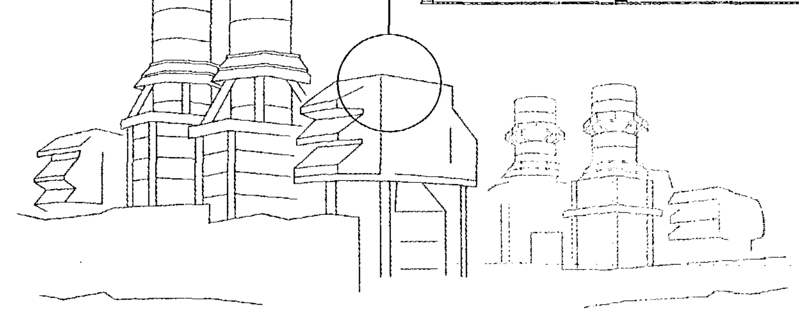
We also posted very positive results at our generating facilities. Employees at Riverton, our oldest facility, achieved 100% availability for two units and 96% for another two. The remaining unit, Unit 8, was off-line from February through mid May for its 5-year maintenance overhaul. After repairs, Unit 8 performed excellently through the remainder of the year. Employees also achieved near-100% availability for all four Energy Center units and for State Line 1.

WHAT IS AN FT8 PEAKING UNIT?

The new Energy Center Units 3 and 4 are FT8 peaking units, simple cycle combustion turbines powered by jet engine technology. Reliability is high, maintenance requirements low, and "dual fuel" capability gives added flexibility of burning either natural gas or oil.

STARTING TIME
IN MINUTES



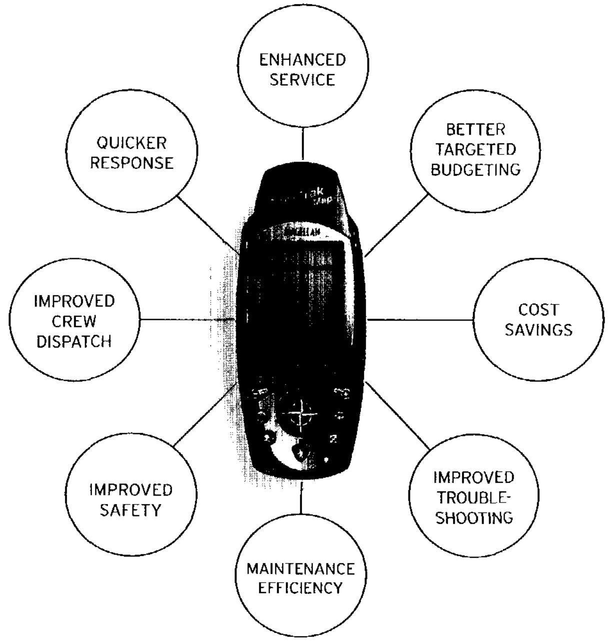


On January 7, 2004, Energy Center Unit 2, a combustion turbine engine, experienced a blade failure when one of the rotating blades broke during operation. We expect our share of the expenses related to the damage to be approximately $1.5 million which includes a $1 million insurance deductible. Because of the new capacity added in 2003, we do not anticipate the problem to impact fuel or purchased power costs.

Efficiencies through technology. In April 2003, we completed construction on Energy Center Units 3 and 4, two 50-megawatt, dual-fuel FT8 peaking units. Our most efficient simple cycle generation, these FT8s use aero-derivative combustion technology to quickly reach full load, allowing fuel economies and prompt response to demand changes.

BENEFITS OF EMPIRE'S NEW GIS/OMS.

The GIS/OMS uses geographical positioning technology to allow dramatic efficiencies in a wide array of operational functions. The GIS/OMS will be completed in 2004.



More ON the way. Our next major gains in productivity are expected to come from a project currently underway, the Geospatial Information System and Outage Management System. The GIS/OMS uses geographical positioning technology to allow dramatic efficiencies in a wide array of operational functions. System mapping was completed in early 2004, and we expect the balance of the project to be in place by late third quarter.

Seizing opportunity. We also look to enhance our competitive position through our small line of non-regulated business held by EDE Holdings, Inc. In 2003, EDEH acquired Joplin.com, a high-speed Internet service provider, and a 6% interest in ETG, a company that makes automated meter reading equipment. Conversant, EDEH's software company, signed its first customer in 2003 and began contributing license revenues in the fourth quarter. In February 2004, Conversant signed a license agreement with its second customer, Energy Services Group, a Massachusetts company providing business processing outsourcing services to the energy industry.

It's all persONal: good corporate citizenship. Most Empire employees are customers and shareholders as well as Company workers, and we live in the communities we serve. So good corporate citizenship for us means taking care of our own. We maintained these responsibilities in 2003. We worked closely with communities to promote economic development, with schools to further educational opportunities, and with charities and social service organizations to assist the less fortunate.

It's all persONal: reaching for green and clean. We're constantly on the lookout for cost-conscious ways to be responsible stewards of the environment. Our TDF (tire-derived fuel) program, which collects discarded tires that are processed and burned for fuel at the Asbury Plant, was honored in 2003 with three statewide environmental awards. And our investigation into supplying future energy needs includes research into renewable energy opportunities.

It's all persONal: being a good employer. We enhance the value of employees by putting heavy emphasis on training. In 2003, our Hollister, Missouri, employees were recognized by the National Safety Council, just the latest bit of evidence of the success of the workplace safety program. And 2003 marked the launch of a new management development program designed to prepare the next generation of leadership.

It all ties back to a clear, basic philosophy: Keep the plan simple and balance the interests of shareholders, customers and employees. In other words, respONd.

RESPONSE

On May 4, 2003, a series of tornadoes ripped through the Empire District.

Empire employees were called to action.

Called "a 50-year to 100-year event" by the National Weather Service, the three supercell storm systems devastated local communities and huge swatches of rural areas. Damage to the Empire system was unprecedented. The storm destroyed two substations and significantly damaged two others. We lost 170 transmission poles, three steel towers, seven-plus miles of transmission line, about 1,400 distribution poles, and nearly 50 miles of distribution line. About 30,000 of our 157,000 customers lost power.

Employees throughout the organization swung into action. Our friends – suppliers, vendors, neighboring utilities – came out in droves to help. By midnight the next day, power had been restored to all but 10,000 customers. **VIRTUALLY ALL WHOSE SERVICE COULD BE RESTORED WERE BACK ON SERVICE WITHIN ONE WEEK.** Here's the story, in our employees' own words.

STORIES OF RESPONSE

May 4, 2003

Rick Stockton | CONSTRUCTION DESIGN

"Someone, I don't remember who, said that if we *really* wanted to move things along, we should bring supplies to the field rather than having the guys come in to get them. So we set up a plan for "roving" storerooms."

-On the innovative approach to supplying field operations personnel.

Eric Jack | LINE OPERATIONS - BOLIVAR

"We used transmission line for distribution — *anything* that worked."

Jeff Kennedy | LINE OPERATIONS, WEBB CITY

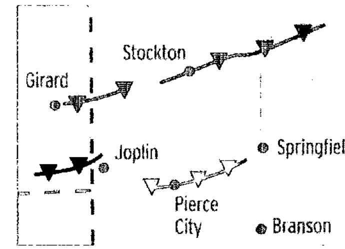
"No one was hurt, and there wasn't much I could do right then. So my wife and kids stayed at my dad's house and I headed in to work. It was pretty much non-stop after that."

-Describing the damage inflicted on his home.

Ryan Kerschen | ENERGY SUPPLY

"I was the *one* guy sitting under the *only* light in the whole town."

-Describing his time on the midnight shift guarding supplies with a small generator for light.



THREE STORM PATHS

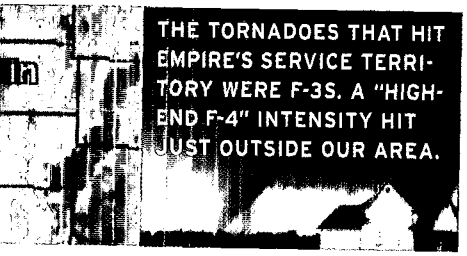
▼ Touched down in southeast Kansas, then crossed into southwest Missouri, delivering devastating damage. It ranged in width from 200 to 300 yards.

▽ Dealt a tragic blow to Pierce City, Missouri, cut a nearly unbroken path for 43 miles. Its width ranged from 100 yards to one-quarter mile, and its damage path extended to one-mile wide.

▼ Left a path approximately 75 miles long, beginning in eastern Kansas, then crossing into Missouri. While in the Stockton, Missouri community, it was estimated to be one half to three quarters of a mile wide.

Jeff Kennedy
LINE OPERATIONS, WEBB CITY

During the recovery, Jeff was part of a line crew working to restore power in southwest Missouri communities.



THE TORNADOES THAT HIT EMPIRE'S SERVICE TERRITORY WERE F-3S. A "HIGH-END F-4" INTENSITY HIT JUST OUTSIDE OUR AREA.

WHAT IS THE F-SCALE?

The F-Scale, or Fujita Scale, measures tornado intensity on a scale of F-0 (winds 40-72 mph) to F-5 (winds of 261-318 mph). F-3s, with winds from 158-206 mph, account for about 6% of all tornadoes.

Larry Myers | LINE OPERATIONS - SARCOXIE

"That first day people sat on the curb and cried while we walked by pulling wire. It was hard to keep going but there wasn't time to think about what had happened. We had to get our feeder hot and get power to those people."

Travis Jones | COMMUNITY RELATIONS - WEST

"It was like a jigsaw puzzle without any corners to help you get started. *Everything* was in pieces."

Visiting Lineman

"And when we *finally* made our way though the mess, a guy was standing on his porch – no house, no trees standing, just that porch – waving and yelling that he was glad to see us. *Man*, I thought, you've lost everything. *How* can you be glad to see us?"

Denny Frieze | SUBSTATION MAINTENANCE - WEST

"*Four* days. Your men have to have a lot of heart to finish a job like that in *four* days."

–On constructing a new substation in record time. The previous fastest time was 7 weeks, 3 days.

Marsha Wallace
ECONOMIC DEVELOPMENT

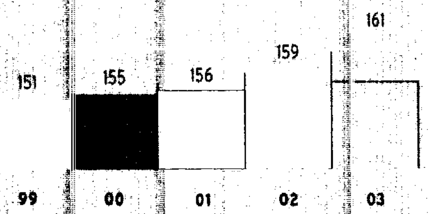
Marsha contributed to the recovery effort in southeast Kansas by coordinating meal deliveries for field personnel.

Marsha Wallace | ECONOMIC DEVELOPMENT

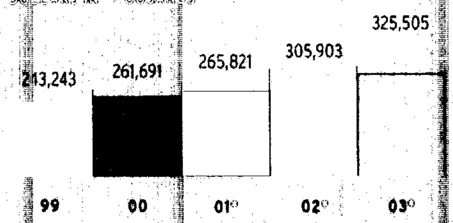
"We brought meals directly to them so they could keep working. Just as importantly, we brought them snacks and cold drinks so they'd stop to rest."

–Explaining how office employees assisted linemen and other field personnel.

Utility Customers (Year End)
THOUSANDS

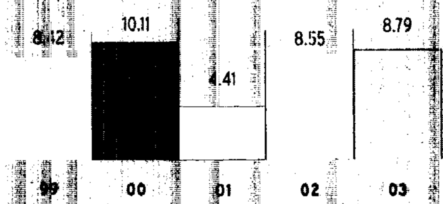


Total Operating Revenues
DOLLARS IN THOUSANDS



* Includes Non-Regulated

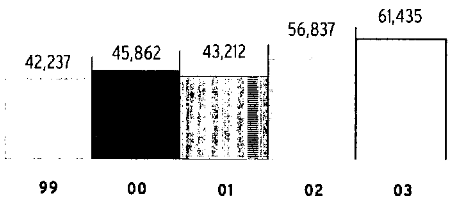
Return on Average Common Equity
PERCENT



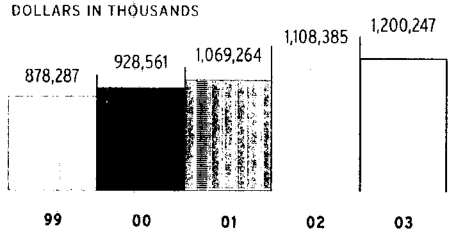
FINANCIAL SECTION

CHARTED DATA
THE EMPIRE DISTRICT ELECTRIC COMPANY

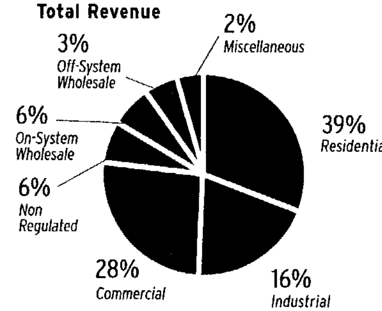
Operating Income
DOLLARS IN THOUSANDS



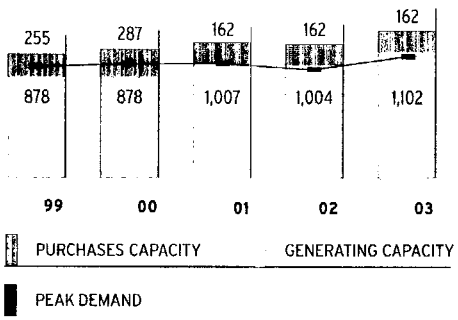
Utility Plant in Service
DOLLARS IN THOUSANDS



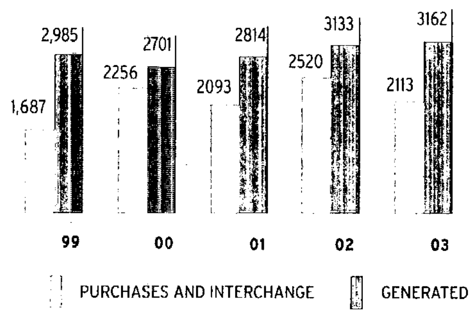
2003 Sources of Total Revenue



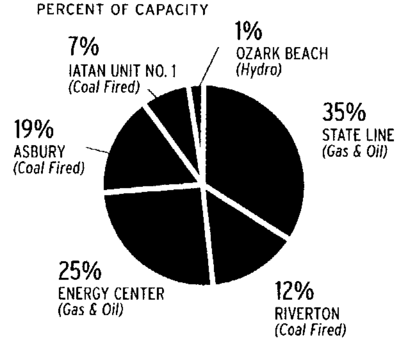
System Capability and Peak Demand
MEGAWATTS



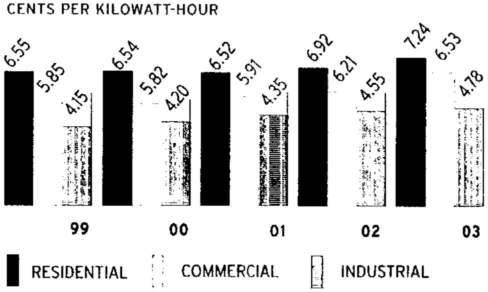
Total System Input (Does not include Hydro)
MILLIONS OF KILOWATT-HOURS



Empire power Plants
PERCENT OF CAPACITY



Average Rates
CENTS PER KILOWATT-HOUR



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 several non-regulated businesses including fiber optics, Internet access, utility industry technical training, close-tolerance custom manufacturing and customer information system software services through our wholly owned subsidiary, EDE Holdings, Inc.

The primary drivers of our electric operating revenues in any period are: (1) weather, (2) rates we can charge our customers, (3) customer growth and (4) 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. 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 contributes to the demand for electricity. We expect our annual customer growth to be approximately 1.5% over the next several years. General economic conditions primarily affect our industrial sales. We experienced better economic conditions in 2003 as compared to 2002, when our service territory experienced a general slowdown in economic activity.

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.

During 2003 we improved our financial strength through rate increases that contributed to our increase in earnings per share to $1.29 in 2003 as compared to $1.19 in 2002 and by taking advantage of lower interest rates to refinance long-term debt, which allowed us to lower our cost of debt as well as our level of short-term debt. Our 2003 results were significantly impacted by the following items. The increase in earnings in 2003 was primarily due to the December 2002 Missouri rate increase, May 2003 FERC rate increase and August 2003 Oklahoma rate increase. Also favorably impacting 2003 earnings was a $4.5 million decrease in maintenance and repairs expense, the absence of $1.5 million in terminated merger expenses as compared to 2002 and continued customer growth. Earnings per share for 2003 were negatively impacted by a $5.6 million net increase in pension expense, a $3.0 million decrease in the net impact (revenues less expenses) of off-system sales and a $2.6 million increase in depreciation and amortization expense. The calculation of our earnings per share for 2003 also gives effect to the sale in underwritten public offerings of 2.0 million shares of our common stock in December 2003 and 2.5 million shares in May 2002. See "– Liquidity and Capital Resources" below.

Basic and diluted earnings per weighted average share of common stock were $1.19 during 2002 compared to $0.59 in 2001. The following pre-tax items positively affected earnings per share: increased revenue from the October 2001 and December 2002 Missouri rate increases, the July 2002 Kansas rate increase, lower fuel and purchased power prices, an increase in off-system sales and decreased depreciation expense pursuant to the Missouri rate order noted above. Also favorably impacting 2002 earnings were cooler temperatures in April and the fourth quarter and warmer temperatures in June and September as compared to the same periods in 2001 and a $1.2 million unrealized gain on derivatives in December 2002. Earnings per share for 2002 were negatively impacted by $1.5 million in terminated merger-expenses as well as planned increased maintenance costs for our combustion turbine and combined cycle units. Earnings per share for 2001 were negatively impacted by the mild weather in the third and fourth quarters, increased natural gas prices and greater use of gas than in the prior year and a one-time non-cash charge of $2.5 million, net of related income taxes, from the write-down of the SLCC construction expenditures. Earnings for 2001 included approximately $2.3 million, after taxes, resulting from the tax benefit occurring because we recognized approximately $6.1 million of merger-related expenses upon the termination of the proposed merger with Aquila, Inc. in January 2001. The calculation of our earnings per share for 2002 also gives effect to the sale in underwritten public offerings of 2.0 million shares of our common stock in December 2001 and 2.5 million shares in May 2002. See "– Liquidity and Capital Resources" below.

RESTATEMENTS

We have restated our consolidated financial statements for the first three quarters of 2003 as a result of a determination we made in January 2004 that an adjustment was necessary to the estimated pension cost that had been recorded throughout 2003 related to the defined benefit pension plan covering substantially all of our employees. This adjustment was based on corrected actuarial information received relative to minimum actuarial loss amortization requirements under generally accepted accounting principles. As a result of this adjustment, we recorded $2.2 million as additional pre tax pension expense for 2003 ($1.4 million, net of tax, or $0.06 per share). The restatement reduced previously reported earnings by $0.02, $0.01 and $0.02 per share for the quarters ended March 31, 2003, June 30, 2003 and September 30, 2003, respectively. See Note 13 of "Notes to Consolidated Financial Statements".

RESULTS OF OPERATIONS

The following discussion analyzes significant changes in the results of operations for 2003, compared to 2002, and for 2002, compared to 2001.

Electric Operating Revenues and Kilowatt-Hour Sales

Electric operating revenues comprised approximately 93% of our total operating revenues during 2003. Of these total electric operating revenues, approximately 41% were from residential customers, 30% from commercial customers, 17% from industrial customers, 4% from wholesale on-system customers, 3.5% 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 2002 or 2001.

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)					
	2003	2002	% Change*	2002	2001	% Change*
Residential	1,728.3	1,726.5	0.1%	1,726.5	1,681.1	2.7%
Commercial	1,386.8	1,378.2	0.6	1,378.2	1,375.6	0.2
Industrial	1,058.7	1,027.4	3.0	1,027.4	1,004.9	2.2
Wholesale On-System	308.6	323.1	(4.5)	323.1	322.3	0.2
Other***	103.9	102.8	1.1	102.8	101.8	1.0
Total On-System	4,586.3	4,558.0	0.6	4,558.0	4,485.7	1.6

	Operating Revenues (in millions)					
	2003	2002**	% Change*	2002	2001**	% Change*
Residential	$ 125.2	$ 119.5	4.7%	$119.5	$109.6	9.1%
Commercial	90.6	85.5	5.9	85.5	81.3	5.2
Industrial	50.6	46.8	8.3	46.8	43.7	7.0
Wholesale On-System	12.4	11.9	4.8	11.9	12.9	(8.1)
Other***	7.3	6.8	7.3	6.8	6.3	7.5
Total On-System	$ 286.1	$ 270.5	5.8	$270.5	$253.8	6.6

* 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 2001 and 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 2003 primarily due to customer 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 for our on-system customers increased approximately $15.6 million, with approximately $13 million of this increase attributed to the Missouri, Oklahoma and FERC rate increases discussed below with the remainder attributed to customer growth. Customer growth contributed approximately $7 million to revenues during 2003 offset by an approximate $5 million negative effect from weather. Our customer growth was 1.63% in 2003, 1.60% in 2002 and 1.13% in 2001. We expect our annual customer growth to be approximately 1.5% over the next several years.

Notwithstanding the new summer peak demand, the slight increases in residential and commercial kWh sales in 2003 were due primarily to the customer 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 two new oil pipeline pumping stations on our system that became fully operational 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 an on-system wholesale customer/aggregator, which comprised 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, but less than one-half percent of our total on-system sales, in both 2002 and 2001, are now included in our off-system sales. This reclassification did not have a material impact on off-system sales. 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. This clause permits the pass through to customers of changes in fuel and purchased power costs.

KWh sales for our on-system customers increased during 2002 as compared to 2001, primarily due to cooler temperatures in April and the fourth quarter of 2002 (during our heating seasons) and warmer temperatures in June and September 2002 (during our air conditioning season). Revenues for our on-system customers increased primarily as a result of the increased sales and the October 2001 Missouri rate increase and, to a lesser extent, the December 2002 Missouri rate increase and the July 2002 Kansas rate increase discussed below. The increases in residential and commercial kWh sales and revenues in 2002 were due primarily to the weather conditions and rate increases discussed above. Industrial sales and revenues increased, reflecting increased sales in April 2002 and during August through November 2002 as compared to the same periods in 2001. Residential, commercial and industrial revenues for 2002 were also favorably impacted by the Missouri and Kansas rate increases.

On-system wholesale kWh sales increased in 2002, reflecting the weather conditions discussed above. Revenues associated with these sales decreased in 2002 as compared to 2001 as a result of the operation of our fuel adjustment clause applicable to these FERC regulated sales.

Rate Matters. The following table sets forth information regarding electric and water rate increases 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 - 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 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.

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 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 of off-system wholesale and transmission services:

	2003	2002	2001
(in millions)			
Revenues	$ 15.3	$ 21.9	$ 7.5
Expenses	9.8	13.4	3.0
Net	$ 5.5	$ 8.5	$ 4.5

The decrease in revenues less expenses in 2003 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.

The increase in revenues during 2002 resulted primarily from the availability of competitively priced power from our SLCC which was placed in service in June 2001 and the term purchases of firm energy during 2002 which, when not required to meet our own customers' needs, could be sold in the wholesale market. See "-Competition" below.

Operating Revenue Deductions.

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 that ran from January 2002 through June 2003. 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. 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. Based on the performance of our pension plan assets through December 31, 2003, we expect to be required under ERISA to fund approximately $0.3 million in 2004 and $0.2 million in 2005 in order to maintain minimum funding levels. No minimum pension liability was required to be recorded as of December 31, 2003. See Note 8 of "Notes to Consolidated Financial Statements" for further discussion of the accounting for our pension plans. 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. We expect pension and health care costs to continue to increase.

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

There were no expenses during 2003 relating to the terminated merger with Aquila, Inc., as compared to $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. See Note 17 of "Notes to Consolidated Financial Statements" for more information on the terminated merger.

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, a $1.8 million true-up credit received from Siemens Westinghouse in June 2003 related to our maintenance contract entered into in July 2001 for the State Line Combined Cycle Unit 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 are now expensing maintenance costs and accruing a credit based on actual monthly usage hours for the contract year ending June 30, 2004. As of December 31, 2003, we have 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 the twelve months ended December 31, 2003 was 34.5% as compared to 34.3% for the twelve months ended December 31, 2002. See Note 9 of "Notes to Consolidated Financial Statements"for additional information regarding income taxes.

During 2002, total operating expenses increased approximately $11.8 million (7.4%) compared to 2001. Total purchased power costs increased by approximately $0.4 million (0.6%) during 2002 although the amount of power purchased increased 20%, reflecting increased demand in the second and third quarters of 2002 and the term purchases of firm energy previously discussed. Purchased power costs reflected lower purchased power prices in 2002 than in 2001. Total fuel costs decreased approximately $5.5 million (9.8%) during 2002 as compared to 2001, resulting in a net decrease in fuel and purchased power costs of $5.1 million. The $5.5 million decrease in total fuel costs primarily reflected lower natural gas prices in 2002 as well as less generation by our gas-fired units due in large part to the term purchases of firm energy. Natural gas costs (on a per MMBtu basis) were lower by 30.5% during 2002 than in 2001. This was a result of a combination of lower commodity prices during 2002 and our natural gas procurement program.

Regulated – other operating expenses increased approximately $6.3 million (17.3%) during 2002 primarily due to increases of $3.9 million in administrative and general expense resulting from increased expense for employee health care and benefit plans and decreased pension income, $1.4 million in transmission expense for the delivery of purchased energy to our system and $1.1 million in other power operation expenses related to a full year of operation of the SLCC. Expenses relating to the terminated merger with Aquila, Inc., were $1.5 million during 2002 as compared to $1.4 million in 2001. Expenses related to the terminated merger in both 2002 and 2001 were primarily the result of expenses related to severance benefits incurred under our Change in Control Severance Pay Plan in the first quarters of those years. See Note 17 of "Notes to Consolidated Financial Statements" under Item 8 for more information on the terminated merger.

Maintenance and repairs expense increased approximately $5.3 million (27.8%) during 2002. Expenditures under long-term maintenance contracts that serve to levelize maintenance costs over time and are reflected in our rates that became effective in October 2001, accounted for $4.5 million of this increase of which $2.9 million was for the maintenance contracts that began in January 2002 for the Energy Center and State Line Unit No. 1 and $1.6 million was for the first full year of these contracts for the SLCC, which commenced operations in June 2001. Maintenance costs associated with a three-week outage to replace the main transformer at the Asbury Plant during the second quarter of 2002 also contributed to this increase.

Depreciation and amortization expense decreased approximately $3.8 million (12.7%) during 2002 due to lower depreciation rates put into effect during the fourth quarter of 2001 as a result of the October 2001 Missouri rate order. Total provision for income taxes increased approximately $11.4 million (732.9%) during 2002 due primarily to higher taxable income and the benefit created by the deductibility of approximately $6.1 million in merger related expenses in the first quarter of 2001 as a result of the termination of the proposed merger with Aquila, Inc. in January 2001. See Note 9 of "Notes to Consolidated Financial Statements" for additional information regarding income taxes. Other taxes increased approximately $2.6 million (19.0%) during 2002 as compared to 2001 primarily due to a reduction in capitalized property taxes related to the SLCC being placed in service in June 2001.

Non-regulated Items

We began investing in non-regulated businesses in 1996 and now lease capacity on our fiber optics network, provide Internet access, offer utility industry technical training, perform close-tolerance custom manufacturing (Mid-America Precision Products, LLC (MAPP)) and license customer information system software services through our wholly owned subsidiary, EDE Holdings, Inc. In December 2002, we sold our monitored security business, E-Watch, to Federal Protection, Inc. of Springfield, Missouri after it did not meet our earnings expectations. This sale did not have a material effect on our financial position, results of operations or cash flows. On February 1, 2003 we purchased Joplin.com, a leading Internet service provider in the Joplin, Missouri area. The purchase was made through Transaeris, a non-regulated subsidiary of EDE Holdings, Inc. We merged Transaeris and Joplin.com into one company named Fast Freedom, Inc. In September, 2003, EDE Holdings, Inc. purchased an approximate 6% interest in ETG, a company that makes automated meter reading equipment. See Item 1, "Business – General" in our December 31, 2003 Annual Report on Form 10-K for further information about these non-regulated businesses.

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 MAPP in July 2002. The increase in expenses was also due to the activities of Conversant, Inc., a software company which began business in early 2002. Conversant markets Customer Watch, the Internet-based customer information system software formerly named Centurion that was developed by our employees. In June 2003, Conversant, Inc. signed a contract with Intermountain Gas Company of Boise, Idaho. A pilot project has been successfully completed and Conversant, Inc. began contributing license revenues in the fourth quarter of 2003. Full implementation is scheduled to be complete by midyear 2004.

Our non-regulated businesses generated a $1.4 million net loss in 2003 as compared to a $1.5 million net loss in 2002. The decreased loss was primarily due to the increased profitability of MAPP partially offsetting the net loss of Conversant.

During 2002, total non-regulated operating revenue increased approximately $8.7 million while total non-regulated operating expense increased approximately $10.4 million compared with 2001. The increase in both revenues and expenses was primarily due to the acquisition of MAPP in July 2002. The increase in expense was also due to the activities of our wholly owned subsidiary, Conversant, Inc.

In 2002, we began recording revenue from our non-regulated business in "Non-regulated" under Operating Revenues and including expense from such business in "Non-regulated" under the Operating Revenue Deductions section of our income statements rather than netting them under "Other – net" in the Other Income and Deductions section, as we had done in prior periods. We have reclassified the non-regulated revenues and expenses for prior periods to conform to the new presentations. Prior period amounts reclassified are not material to the results of operations for those periods.

Nonoperating Items

Total allowance for funds used during construction (AFUDC) decreased $0.3 million in 2003 and $3.0 million in 2002 reflecting the completion of the SLCC in June 2001. See Note 1 of "Notes to Financial Statements".

A one-time write-down of $4.1 million was taken in the third quarter of 2001 for disallowed capital costs related to the construction of the SLCC. These costs were disallowed as part of a stipulated agreement approved by the Missouri Commission in connection with our 2001 rate case and will not be recovered in rates. The net effect on 2001 earnings after considering the tax effect on this write-down was $2.5 million.

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 $98.0 million of 4.5% senior notes on June 17, 2003 and the redemption of all $100 million aggregate principal amount of our Senior Notes, 7.70% Series due 2004 on June 19, 2003. Our sale of $62.0 million of 6.70% Senior Notes for net proceeds of approximately $61.0 million on November 3, 2003 and subsequent redemption of three separate series of higher interest first mortgage bonds aggregating approximately $60.4 million also decreased interest charges slightly. See "- Liquidity and Capital Resources" for further information. Total interest charges on long-term debt decreased $1.4 million (5.4%) in 2002 as compared to 2001 mainly due to the maturing of $37.5 million of our first mortgage bonds in July 2002.

Other Comprehensive Income

The change in the fair value 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 included 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 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, as applicable, in the periods in which they are actually realized or no longer qualify for hedge accounting. We had a net change in unrealized gain of $0.6 million at the end of 2003 as compared to a net change in unrealized gain of $8.2 million at the end of 2002 and a net change in unrealized loss of $1.6 million at the end of 2001, the first year we recorded such contracts.

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 will be 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 expired on October 29, 2003 with a gain of $5.1 million. This amount was recorded as a regulatory liability and will be 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 2001.

During 2002 we settled fuel derivative contracts for losses of $0.3 million. Natural gas prices increased throughout the year resulting in the fair market value (FMV) of our open contracts increasing by $12.9 million. We adjust our Other Comprehensive Income (OCI) to net of taxes for the gains and losses on our open contracts. The increase in the FMV of our contracts in 2002 resulted in an approximate $5 million tax effect. The combined effect of these items resulted in an increase in OCI of $8.2 million, net of taxes, in 2002. During 2003 we settled contracts for gains of $11.8 million, including a $2.4 million gain on interest rate derivatives. Natural gas prices continued to increase in 2003 resulting in the FMV of our open contracts increasing by $12.8 million. The adjustment to OCI for taxes in 2003 was $0.4 million. The combined effect of these items resulted in an increase in OCI of $0.6 million, net of taxes, in 2003.

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 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. 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 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 will be released from the original agreement. The additional cost for continuing the service agreement through March 2004 is approximately $0.7 million payable in monthly installments.

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. The SPP and Midwest Independent Transmission System Operator, Inc. (MISO) agreed in October 2001 to consolidate and form an RTO which was approved by the FERC in December 2001. However, on March 20, 2003, the SPP and MISO announced they had mutually agreed to terminate the consolidation of the organizations. 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. On February 10, 2004 the FERC approved the SPP RTO with conditions that include implementing its independent board and modifying its governance structure, expanding the coverage of SPP's tariff to assure that it is the sole transmission provider, obtaining clear and sufficient authority to exercise day-to-day operational control over appropriate transmission facilities, having an independent market monitor in place, obtaining clear and precise authority to independently and solely determine which project to include in the regional transmission plan and having a seams agreement with MISO on file. Upon completion of the conditions, the SPP would gain status and FERC acceptance as an RTO.

On October 27, 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 recovery; increased risk of additional membership assessment cost allocation due to potential member departures; and anticipated change in the terms and conditions of the SPP tariff and network services. Such withdrawal requires approval from the FERC. We retain the option, however, to rescind such notice on or before October 31, 2004 and remain a member of the SPP. Kansas City Power and Light, Southwestern Power Administration, Westar Energy, Inc., Southwestern Public Service, Grand River Dam Authority and American Electric Power have also filed notices of intent to withdraw. We are unable to quantify the potential impact of membership in an 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 continue membership with the SPP prior to the October 31, 2004 withdrawal notice deadline.

On November 25, 2003, FERC issued its Final Rule, Order 2004, regarding electric and natural gas industry Code of Conduct requirements for transmission service providers. Order 2004 is 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. On February 9, 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. If in the future, FERC determines that a waiver of Orders 889 and 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. As a small utility that does not influence our regional wholesale power market, the benefits of modifying our organization and implementing systems and processes to promote a more efficient and competitive wholesale market do not, in our opinion, appear to exceed the estimated start up costs of between $0.5 million and $1.0 million plus annual recurring costs. FERC's decision is pending as to whether or not our and the other existing Order 889 waivers within the industry will be continued and, if not, when compliance plans would need be implemented and associated costs incurred.

Approximately 4% 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 90% of our wholesale business in 2003. We have contracts with these customers that run through the first quarter of 2008.

LIQUIDITY AND CAPITAL RESOURCES

Cash Provided by Operating Activities

Our net cash flows provided by operating activities decreased $8.9 million during 2003 as compared to 2002 primarily due to the refunding of $18.7 million to our Missouri electric customers, which was the amount of the IEC (with interest) collected between October 2001 and December 2002. We had collected $15.9 million of the IEC, subject to refund, during 2002. 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. Negatively impacting cash provided by operating activities were decreases in accounts payable and accrued liabilities of $4.8 million primarily due to the completion of payments on our FT8 peaking units.

Our net cash flows provided by operating activities increased $40.6 million during 2002 as compared to 2001 primarily due to an increase in net income of $15.1 million as well as the collection of $15.9 million of the IEC as compared to $2.8 million collected in 2001 from our Missouri electric customers. An $11.4 million increase in deferred taxes also contributed to the increased cash flow.

Capital Requirements and Investing Activities

Our net cash flows used in investing activities decreased $11.0 million during 2003 as compared to 2002, 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 $1.9 million during 2002 as compared to 2001, primarily reflecting decreased construction expenditures due mainly to the completion of the SLCC in June 2001.

Our capital expenditures totaled approximately $65.1 million, $77.5 million, and $71.8 million in 2003, 2002 and 2001, respectively. Capital expenditures, as used in this section, include AFUDC. Capital expenditures to retire assets are not included here, but are included in capital expenditures on our Consolidated Statements of Cash Flows.

A breakdown of these capital expenditures for 2003, 2002 and 2001 is as follows:

	Capital Expenditures		
(in millions)	2003	2002	2001
Distribution and transmission system additions	$ 27.7	$25.5	$ 31.2
FT8 peaking units - Energy Center	20.8	31.7	3.5
State Line Combined Cycle Unit	-	2.0	24.7
May tornado damage	6.7	-	-
Additions and replacements - Asbury	1.0	3.0	7.7
Additions and replacements - Riverton, Iatan and Ozark Beach	1.2	2.2	1.1
System mapping project	2.2	1.3	-
Fiber optics (non-regulated)	2.1	2.0	0.8
Other non-regulated capital expenditures	2.1	3.9	-
Computer Services projects	-	0.8	-
Combustor system upgrade - State Line	-	1.8	-
Other	1.3	3.3	2.8
Total	$ 65.1	$77.5	$ 71.8

The amounts in the table for 2001 do not include $9.2 million of capitalized spare parts for the State Line Combined Cycle Plant, ($1.3) million of plant retirements and ($0.3) million in capital leases and utility land transferred to land held for future use.

Approximately 58%, 63% and 20% of the cash requirements for capital expenditures for 2003, 2002 and 2001, respectively, were satisfied internally from operations (with funds provided by operating activities less dividends paid). The remaining amounts of such requirements were satisfied from short-term borrowings and proceeds from our sales of common stock and unsecured Senior Notes discussed below. We had estimated that our capital expenditures would total approximately $50.2 million in 2003. Capital expenditures were higher than expected in 2003, primarily as a result of the May tornado damage and customer growth.

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 percent 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 remains at 50.01%, as of January 1, 2004, our guaranty was lowered to 25%.

We estimate that our capital expenditures will total approximately $32.3 million in 2004, $46.9 million in 2005 and $86.9 million in 2006. Of these amounts, we anticipate that we will spend $16.9 million, $18.9 million and $27.5 million in 2004, 2005 and 2006, respectively, for additions to our distribution system to meet projected increases in customer demand. These capital expenditure estimates also include approximately $4.1 million in 2005 and $24.9 million in 2006 for the purchase and installation of a 50 megawatt simple cycle CT unit which is scheduled to be operational in 2007. As a result of an unexpected event on January 7, 2004 when one of our original combustion turbine peaking units, Energy Center Unit No. 2, experienced a rotating blade failure, our estimated 2004 capital expenditures could increase. Upon dismantling and inspecting the unit, we found damage to rotating and stationary components in the turbine as well as anomalies in the generator. Because of the new capacity added in 2003, we do not expect the problem to materially impact fuel or purchased power costs. We expect our share of the expenses related to the damage to be approximately $1.5 million, including $1 million to meet our insurance deductible.

We estimate that internally generated funds will provide 100% of the funds required in 2004 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 provided by financing activities decreased $6.4 million during 2003 as compared to 2002 and decreased $48.5 million during 2002 as compared to 2001. Our net cash flows provided by financing activities 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 March 1, 2001, the Empire District Electric Trust I issued two million shares of its 8 1/2% Trust Preferred Securities in a public underwritten offering. This sale generated proceeds of $50.0 million and issuance costs of $1.8 million. Holders of the trust preferred securities are entitled to receive distributions at an annual rate of 8 1/2% 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 $50.0 million aggregate principal amount of our 8.5% Junior Subordinated Debentures due March 1, 2031, issued by us to the trust, and held by the trust as assets. Our interest payments on the debentures are tax deductible by us. We have effectively guaranteed the payments due on the outstanding trust preferred securities. The net proceeds of this offering were added to our general funds and were used to repay short-term indebtedness. See the discussion of FIN No. 46-R under "– Recently Issued Accounting Standards" below for further information.

On December 10, 2001, we sold to the public in an underwritten offering 2,012,500 newly issued shares of our common stock for $41.0 million. The net proceeds of approximately $39.0 million from the sale were added to our general funds and used to repay short-term debt.

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 of our unsecured 7.05% Senior Notes 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 of our unsecured 4.5% Senior Notes that mature on June 15, 2013 for net proceeds of approximately $96.6 million. We used the 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, 9-3/4% Series due 2020 for approximately $2.4 million, including interest; (2) all $13.1 million aggregate principal amount of our First Mortgage Bonds, 7-1/4% 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.

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, the underwriters purchased an additional 300,000 shares for approximately $6.1 million to cover over-allotments. The proceeds were added to our general funds.

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, subject to the approval of the Missouri Public Service Commission to mortgage property, first mortgage bonds remain available for issuance.

On April 17, 2003, we closed a two-year renewal of our $100 million unsecured revolving credit facility which was to expire on May 12, 2003. 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) 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 distributions on the Trust Preferred Securities) 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, 2003. This credit facility is also subject to cross-defaul if we default in excess of $5,000,000 in the aggregate on our other indebtedness. There were no borrowings outstanding under this revolver as of December 31, 2003. However, $13 million of the facility as of that date was used to back up our commercial paper and was not available to be borrowed.

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, 2003 would permit us to issue approximately $279.8 million of new first mortgage bonds based on this test with an assumed interest rate of 7.0%, subject to approval of the Missouri Public Service Commission to mortgage property. The Mortgage provides an exception from this earnings requirement in certain instances, relating to the issuance of new first mortgage bonds against first mortgage bonds which have been, or are to be, retired. See Note 6 to "Notes to Financial Statements" for more information on the mortgage bond indenture.

As of December 31, 2003, the ratings for our securities were as follows:

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

Moody's and Standard & Poor's currently have a negative outlook and a stable outlook, respectively, 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 the cost of the securities when they 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 as described above, 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, 2003:

	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	$ -	$ 348.1
Trust Preferred Securities	50.0	-	-	-	50.0
Capital Lease Obligations	0.5	0.2	0.3	-	-
Operating Lease Obligations	0.9	0.6	0.3	-	-
Purchase Obligations*	240.6	42.9	70.5	50.6	76.6
Pension Funding Obligations	0.5	0.3	0.2	-	-
Open Purchase Orders	14.7	8.0	2.7	2.7	1.3
Other Long-Term Liabilities**	3.4	0.4	1.0	2.0	-
Total Contractual Obligations	$ 668.7	$ 52.4	$85.0	$55.3	$476.0

* includes fuel and purchased power contracts and associated transportation costs.

** Other Long-term Liabilities primarily represents 100% of the long-term debt issued by Mid-America Precision Products, LLC. EDE Holdings, Inc., as of December 31, 2003, was the 50.01% quarantor of a $2.4 million note included in this total amount.

The pension funding obligations disclosed in the above table represent our estimated funding obligations in 2004 for the year ending 2003, and 2005 for the year ending 2004.

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 recent Missouri Rate Case, the Commission ruled that we would be allowed to recover pension costs on an ERISA minimum funding (or cash) basis. Previously, the Commission allowed us to recover pension costs consistent with our GAAP policy noted above. We have determined that the difference between the recovery allowed by the Commission and our accounting for pension costs under GAAP does not meet the FAS 71 requirements for regulatory deferral. As a result, we will continue to account for pension expense or benefits in accordance with SFAS 87, using the previously mentioned amortization formula for recognizing net gains or losses. As a result, future pension expense or benefits may not 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 and discount rates. Based on the performance of our pension plan assets through December 31, 2003, we expect to be required under ERISA to fund approximately $0.3 million in 2004 and $0.2 million in 2005 in order to maintain minimum funding levels. These amounts are estimates and may change based on actual investment performance, any future pension plan funding and finalization of actuarial assumptions. Absent a continued recovery in the equity markets, pension expense and cash funding requirements could substantially increase over the next several years. No minimum pension liability was required to be recorded as of December 31, 2003.

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. Additioinal 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".

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, healthcare cost trend rates and discount rates as well as Medicare prescription drug costs.

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. Our policy is consistent with the provisions of SFAS 149, "Accounting for Certain Derivative Instruments and Certain Hedging Activities, An Amendment of SFAS 133" as amended by SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities".

As of February 6, 2004, 64% of our anticipated volume of natural gas usage for the remainder of year 2004 is hedged at an average price of $3.28 per Dekatherm (Dth). In addition, approximately 40% of our anticipated volume of natural gas usage for the year 2005 is hedged at an average price of $4.154 per Dth, approximately 20% of our anticipated volume of natural gas usage for the year 2006 is hedged at an average price of $4.271 per Dth, and approximately 10% of our anticipated volume of natural gas usage for the year 2007 is hedged at an average price of $4.289 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 on contractual commodity commitments, regulatory and political environments and requirements, fair value estimations on longer term contracts, estimating underlying fuel demand and counterparty ability to perform.

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.

As of December 31, 2003, we have recorded $55,977,495 in regulatory assets and $17,600,422 in income taxes, gain on interest rate derivatives and costs of removal as regulatory liabilities. See Note 3 of "Notes to 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 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.

RECENTLY ISSUED ACCOUNTING STANDARDS

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, "Accounting for Obligations Associated with the Retirement of Long-Lived Assets" (FAS 143). This statement establishes standards for accounting and reporting for legal obligations associated with the retirement, or anticipated retirement, of tangible long-lived assets. It requires us to 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 to 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 this standard on January 1, 2003, we have identified future asset retirement obligations associated with the removal of certain river water intake structures and equipment at the Iatan Power Plant in which we have a 12% ownership. We also have a liability for future containment of an ash landfill at the Riverton Power Plant. 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. This liability will be accreted over the period up to the estimated settlement date. The balance at the end of 2003 was approximately $656,000. 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, 2003 and 2002, this reclassification was $3.8 million and $4.9 million, respectively. This estimated liability may be subject to further refinement pending further analysis, including the results of our depreciation study expected to be completed in the first quarter of 2004.

In December 2002, the FASB issued SFAS No. 148 (FAS 148), "Accounting for Stock-Based Compensation-Transition and Disclosure". FAS 148 amends SFAS No. 123, "Accounting for Stock-Based Compensation" (FAS 123), to provide alternative methods of transition when an entity changes from the intrinsic value method to the fair-value method of accounting for stock-based employee compensation. FAS 148 amends the disclosure requirements of FAS 123 to require more prominent and more frequent disclosure about the effects of stock-based compensation by requiring pro forma data to be presented more prominently and in a more user-friendly format in the footnotes to the financial statements. In addition, FAS 148 requires that the information be included in interim as well as annual financial statements. The transition guidance and annual disclosure provisions of FAS 148 are effective for fiscal years ending after December 15, 2002. We have adopted the transition and disclosure provisions of FAS 148 and now recognize compensation expense related to stock option issuances on or subsequent to January 1, 2002 under the fair-value provisions of FAS 123. Any stock compensation expense in prior periods has not been material. We do not have any transition issues and, accordingly, FAS 148 did not have a material impact on our financial condition and results of operations upon adoption.

In April 2003, the FASB issued SFAS No. 149 (FAS 149), "Amendment of Statement 133 on Derivative Instruments and Hedging Activities"(FAS149). 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 (FAS 133), *Accounting for Derivative Instruments and Hedging Activities.* 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, represents an obligation to repurchase the issuer's shares or is 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.

In November 2002, the FASB issued FASB Interpretation No. 45 (FIN 45), "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others, and Interpretation of FASB Statements Nos. 5, 57, and 107 and rescission of FASB Interpretation No. 34". FIN 45 requires: (1) the guarantor of debt to recognize a liability, at the inception of the guarantee, for the fair value of the obligation undertaken in issuing this guarantee, (2) indirect guarantees of debt to be recognized in the financial statements of the guarantor and (3) the guarantor to disclose the background and nature of the guarantee, the maximum potential amount to be paid under the guarantee, the carrying value of the liability associated with the guarantee and any recourse of the guarantor to recover amounts paid under the guarantee from third parties. The disclosure requirement of FIN 45 was effective for our December 31, 2002 financial statements. Other than the current 25% guarantee by our wholly-owned subsidiary, EDE Holdings, Inc., of a $2.4 million note issued by Mid-America Precision Products, LLC (MAPP), we do not have any material commitments within the scope of FIN 45.

The FASB issued FASB Interpretation No. 46 "Consolidation of Variable Interest Entities" in January 2003 and issued its deferral in 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. Variable interest entities are accounted for under FIN No. 46-R, as revised in December 2003. 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 as a note payable to affiliates within the Consolidated Balance Sheet at December 31, 2003. This change in presentation had no impact on our Consolidated Balance Sheet at December 31, 2002 or on our net income.

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 us 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 under "Notes to Consolidated Financial Statements" for further information.

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 significant financing through our issuance of commercial paper. We manage our interest rate exposure by limiting our variable-rate exposure 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 Financial Statements" for further information.

If market interest rates average 1% more in 2004 than in 2003, our interest expense would increase, and income before taxes would decrease by less than $150,000. This amount has been determined by considering the impact of the hypothetical interest rates on our commercial paper balances as of December 31, 2003. 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 long-term contracts 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 72.6% of our 2003 fuel supply need through coal. All of our required 2004 supply of coal has been acquired at fixed prices (including standard adjustments). Future coal supplies will be acquired using a combination of fixed pricing and price hedging strategies. 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 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. As of February 6, 2004, 64% of our anticipated volume of natural gas usage for the remainder of year 2004 is hedged. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies – Hedging Activities" for further information.

If average natural gas prices should increase 10% more in 2004 than in 2003, our fuel expense would increase, and income before taxes would decrease by approximately $2 million.

FORWARD LOOKING STATEMENTS

Certain matters discussed in this annual report are "forward-looking statements" intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. Such statements address or may address future plans, objectives, expectations and events or conditions concerning various matters such as capital expenditures, earnings, pension and other costs, competition, litigation, our construction program, our financing plans, rate and other regulatory matters, liquidity and capital resources, and accounting matters. Forward-looking statements may contain words like "anticipate," "believe," "expect," "project," "objective" or similar expressions to identify them as forward-looking statements. Factors that could cause actual results to differ materially from those currently anticipated in such statements include: the amount, terms and timing of rate relief we seek and related matters; the cost and availability of purchased power and fuel, and the results of our activities (such as hedging) to reduce the volatility of such costs; electric utility restructuring, including ongoing state and federal activities; weather, business and economic conditions and other factors which may impact customer growth; operation of our generation facilities; legislation; regulation, including environmental regulation (such as NOx regulation); competition; the impact of deregulation on off-system sales; changes in accounting requirements; other circumstances affecting anticipated rates, revenues and costs, including pension and post-retirement costs, matters such as the effect of changes in credit ratings on the availability and our cost of funds; the revision of our construction plans and cost estimates; the performance of our non-regulated businesses; the success of efforts to invest in and develop new opportunities; and costs and effects of legal and administrative proceedings, settlements, investigations and claims.

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

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

REPORT OF INDEPENDENT AUDITORS

THE EMPIRE DISTRICT ELECTRIC COMPANY

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

In our opinion, the consolidated financial statements listed in the index appearing under Item 15 present fairly, in all material respects, the financial position of The Empire District Electric Company and its subsidiaries at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit 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.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for asset retirement obligations as of January 1, 2003.

PricewaterhouseCoopers LLP
St. Louis, Missouri
January 30, 2004

CONSOLIDATED BALANCE SHEETS
THE EMPIRE DISTRICT ELECTRIC COMPANY

December 31,	2003	2002
Assets		
Plant and property, at original cost: (Note 2)		
Electric	$ 1,191,445,355	$ 1,099,983,796
Water	8,801,483	8,400,720
Non-regulated	21,105,515	17,075,955
Construction work in progress	5,840,870	41,504,451
	1,227,193,223	1,166,964,922
Accumulated depreciation and amortization	393,321,174	368,016,348
	833,872,049	798,948,574
Current assets:		
Cash and cash equivalents	13,108,197	14,439,227
Accounts receivable - trade, net of allowance of $702,000 and $650,000, respectively	21,946,990	22,022,750
Accrued unbilled revenues	7,784,403	9,543,729
Accounts receivable - other (Note 15)	7,853,684	9,950,909
Fuel, materials and supplies	29,179,937	31,227,447
Unrealized gain in fair value of derivative contracts (Note 14)	11,631,350	7,482,978
Prepaid expenses	2,240,748	1,640,745
	93,745,309	96,307,785
Noncurrent assets and deferred charges:		
Regulatory assets (Note 3)	55,977,495	36,169,683
Unamortized debt issuance costs	6,289,783	6,287,639
Unrealized gain in fair value of derivative contracts (Note 14)	567,000	4,977,500
Other (Notes 1 and 8)	18,991,507	21,866,142
	81,825,785	69,300,964
Total Assets	$1,009,443,143	$ 964,557,323

December 31,	2003	2002
Capitalization and Liabilities		
Common stock, $1 par value, 100,000,000 shares authorized, 24,975,604 and 22,567,179 shares issued and outstanding, respectively	$ 24,975,604	$ 22,567,179
Capital in excess of par value	306,727,950	260,559,197
Retained earnings	39,848,572	39,544,819
Accumulated other comprehensive income net of income tax (Note 14)	7,272,705	6,643,467
Total common stockholders' equity	378,824,831	329,314,662
Long-term debt (Note 6):		
Note payable to securitization trust	50,000,000	-
Company obligated mandatorily redeemable securities of subsidiary *holding solely parent debentures*	-	50,000,000
Obligations under capital lease	297,655	462,618
First mortgage bonds and secured debt	150,692,450	210,602,210
Unsecured debt	209,402,515	149,933,267
Total long-term debt	410,392,620	410,998,095
Total long-term debt and common stockholders' equity	789,217,451	740,312,757
Current liabilities:		
Current maturities of long-term debt	429,140	236,872
Obligations under capital lease	205,556	194,143
Commercial paper	13,000,000	22,541,000
Accounts payable and accrued liabilities	34,102,261	37,259,318
Customer deposits	5,251,359	4,644,105
Interest accrued	2,836,241	3,990,184
Provision for rate refund	-	18,718,679
Unrealized loss in fair value of derivative contracts (Note 14)	583,140	506,268
	56,407,697	88,090,569
Commitments and contingencies (Note 11)		
Noncurrent liabilities and deferred credits:		
Regulatory liabilities (Note 3)	17,600,422	16,717,110
Deferred income taxes	125,065,620	103,144,549
Unamortized investment tax credits	5,581,000	6,131,000
Postretirement benefits other than pensions	8,088,674	4,928,965
Unrealized loss in fair value of derivative contracts (Note 14)	80,350	-
Minority interest	1,159,953	806,319
Other	6,241,976	4,426,054
	163,817,995	136,153,997
Total Capitalization and Liabilities	$ 1,009,443,143	$ 964,557,323

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

CONSOLIDATED STATEMENTS OF INCOME

THE EMPIRE DISTRICT ELECTRIC COMPANY

Year ended December 31,	2003	2002	2001
Operating revenues:			
Electric	$ 303,261,146	$ 294,571,794	$ 263,189,506
Water	1,388,832	1,075,671	1,065,348
Non-regulated (Note 12)	20,854,918	10,255,530	1,566,028
	325,504,896	305,902,995	265,820,882
Operating revenue deductions:			
Operating expenses:			
Fuel	52,337,362	49,755,465	56,523,370
Purchased power	60,208,746	62,765,107	62,383,952
Regulated - other (Note 16)	49,752,972	43,064,291	36,726,181
Non-regulated (Note 12)	21,160,154	11,911,021	1,478,978
Merger related expenses	-	1,524,355	1,391,673
Maintenance and repairs	19,923,408	24,395,974	19,094,735
Depreciation and amortization	28,688,480	26,084,430	29,868,851
Provision for income taxes	15,751,999	13,390,001	1,551,165
Other taxes	16,247,256	16,175,446	13,590,023
	264,070,377	249,066,090	222,608,928
Operating income	61,434,519	56,836,905	43,211,954
Other income and (deductions):			
Allowance for equity funds used during construction	-	-	569,961
Interest income	57,011	87,336	199,447
Loss on plant disallowance	-	-	(4,087,066)
Benefit for other income taxes	250,000	80,000	1,551,165
Minority interest	(353,634)	(142,463)	-
Other – non-operating income	52,857	115,955	205,549
Other – non-operating expense (Note 1)	(860,398)	(882,509)	(1,237,634)
	(854,164)	(741,681)	(2,798,578)
Interest charges:			
Trust preferred distributions by subsidiary holding solely parent debentures	4,250,000	4,250,000	3,541,667
Long-term debt – other	26,044,688	24,957,961	26,384,310
Allowance for borrowed funds used during construction	(282,268)	(570,808)	(3,041,298)
Other	1,117,628	1,933,953	3,125,783
	31,130,048	30,571,106	30,010,462
Net income applicable to common stock	$ 29,450,307	$ 25,524,118	$ 10,402,914
Weighted average number of common shares outstanding	22,845,952	21,433,889	17,777,449
Basic and diluted earnings per weighted average share of common stock	$ 1.29	$ 1.19	$ 0.59
Dividends per share of common stock	$ 1.28	$ 1.28	$ 1.28

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
THE EMPIRE DISTRICT ELECTRIC COMPANY

Year ended December 31,	2003	2002	2001
Net income	$ 29,450,307	$ 25,524,118	$ 10,402,914
Reclassification adjustments for (gains)/losses included in net income	(11,752,251)	337,660	690,400
Change in fair value of open derivative contracts for period	12,767,151	12,928,110	(3,240,900)
Income taxes	(385,662)	(5,040,993)	969,190
Net change in unrealized (gain)/loss on derivative contracts	629,238	8,224,777	(1,581,310)
Comprehensive income	$ 30,079,545	$ 33,748,895	$ 8,821,604

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

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

Year ended December 31,	2003	2002	2001
Common stock, $1 par value:			
Balance, beginning of year	$ 22,567,179	$ 19,759,598	$ 17,596,530
Stock/stock units issued through:			
Public offering	2,000,000	2,500,000	2,012,500
Stock purchase and reinvestment plans	408,425	307,581	150,568
Balance, end of year	$ 24,975,604	$ 22,567,179	$ 19,759,598
Capital in excess of par value:			
Balance, beginning of year	$ 260,559,197	$208,223,200	$168,439,089
Excess of net proceeds over par value of stock issued:			
Public offering	38,370,600	46,857,626	37,023,140
Stock purchase and reinvestment plans	7,798,153	5,478,371	2,760,971
Balance, end of year	$306,727,950	$ 260,559,197	$208,223,200
Retained earnings:			
Balance, beginning of year	$ 39,544,819	$ 41,906,483	$ 54,117,292
Net income	29,450,307	25,524,118	10,402,914
	68,995,126	67,430,601	64,520,206
Less common stock dividends declared	29,146,554	27,885,782	22,613,723
Balance, end of year	$ 39,848,572	$ 39,544,819	$ 41,906,483
Accumulated other comprehensive income (loss):			
Balance, beginning of year	$ 6,643,467	$ (1,581,310)	$ -
Reclassification adjustment for (gains) /losses included in net income	(11,752,251)	337,660	690,400
Change in fair value of open derivative contracts for period	12,767,151	12,928,110	(3,240,900)
Income taxes	(385,662)	(5,040,993)	969,190
Balance, end of year	$ 7,272,705	$ 6,643,467	$ (1,581,310)

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
THE EMPIRE DISTRICT ELECTRIC COMPANY

Year ended December 31,	2003	2002	2001
Operating activities			
Net income	$ 29,450,307	$ 25,524,118	$ 10,402,914
Adjustments to reconcile net income to cash flows:			
Depreciation and amortization	32,556,221	29,301,526	32,855,222
Pension expense / (income)	3,858,417	(3,581,781)	(4,366,247)
Deferred income taxes, net	15,392,000	12,180,000	810,000
Investment tax credit, net	(550,000)	(550,000)	(550,000)
Allowance for equity funds used during construction	-	-	(569,961)
Issuance of common stock and stock options for incentive plans	1,300,305	1,195,752	941,823
Loss on plant disallowance	-	-	4,087,066
Unrealized (gain)/loss on derivatives	1,157,850	(1,238,940)	-
Cash flows impacted by changes in:			
Accounts receivable and accrued unbilled revenues	4,208,711	(2,668,531)	(2,423,368)
Fuel, materials and supplies	2,047,510	(2,098,946)	(5,505,306)
Prepaid expenses and deferred charges	(1,016,909)	559,689	(831,109)
Accounts payable and accrued liabilities	(3,157,057)	1,686,387	(1,261,594)
Customer deposits, interest and taxes accrued	(546,689)	(584,012)	(1,796,926)
Other liabilities and deferred credits	1,171,651	436,818	798,001
Accumulated provision – rate refunds	(18,718,679)	15,875,234	2,843,445
Net cash provided by operating activities	67,153,638	76,037,314	35,433,960
Investing activities			
Capital expenditures – regulated	$ (61,997,311)	$(72,805,389)	$ (78,569,879)
Capital expenditures and other investments – non-regulated	(3,908,397)	(4,071,514)	(792,394)
Allowance for equity funds used during construction	-	-	569,961
Net cash used in investing activities	(65,905,708)	(76,876,903)	(78,792,312)

Year ended December 31,	2003	2002	2001
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	49,179,914	56,465,200	42,964,341
Proceeds from issuance of notes payable to securitization trust	-	-	50,000,000
Long-term debt issuance costs	(1,695,567)	(1,574,401)	(1,884,756)
Redemption of senior notes	(100,058,000)	-	-
Redemption of First Mortgage Bonds	(60,326,000)	(37,578,000)	(176,000)
Premium paid on extinguished debt	(10,818,793)	-	-
Discount on issuance of senior notes	(809,580)	-	-
Common stock issuance costs	(1,929,400)	(2,517,374)	(1,958,985)
Dividends	(29,146,554)	(27,885,782)	(22,613,723)
Net (repayments) proceeds from short-term borrowings	(9,541,000)	(32,959,000)	(14,000,000)
Other	149,695	(112,102)	(22,830)
Net cash (used in) provided by financing activities	(2,578,960)	3,838,541	52,308,047
Net (decrease)/increase in cash and cash equivalents	(1,331,030)	2,998,952	8,949,695
Cash and cash equivalents, beginning of year	14,439,227	11,440,275	2,490,580
Cash and cash equivalents, end of year	$ 13,108,197	$ 14,439,227	$ 11,440,275

Interest paid was $30,935,000, $30,943,000, and $31,705,000 for the years ended December 31, 2003, 2002, and 2001, respectively. Net income taxes paid in 2003 were zero due to a refund of federal income tax of $750,000. Income taxes paid were $1,767,000, and $4,343,000 for the years ended December 31, 2002 and 2001, respectively. Capital lease obligations incurred for the purchase of equipment was $748,000 for the year ended December 31, 2001. There were no capital lease obligations incurred during the years ended December 31, 2003 and 2002.

The accompanying notes are an integral part of these 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 (MoPSC), 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, we lease capacity on our fiber optics network, provide Internet access, offer utility industry technical training, perform close-tolerance custom manufacturing (Mid American Precision Products, LLC (MAPP)) and license customer information system software services. For discussion of the acquisition of certain 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 2003 were derived as follows: residential 41%, commercial 30%, industrial 17%, wholesale on-system 4%, wholesale off-system 3.5% and other 4.5%. Our electric revenues for 2003 by jurisdiction were as follows: Missouri 88.7%, Kansas 5.8%, Arkansas 2.8%, and Oklahoma 2.7%. These percentages have not significantly changed from 2002 and 2001. 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). The consolidated entity is referred to throughout as "we" or the "Company". We have deconsolidated the Empire District Electric Trust I as required by Financial Accounting Standards Board (FASB) Interpretation No. 46-R (FIN 46-R). See further discussion under "Recently Issued Accounting Standards".

Restatements. We have restated our consolidated financial statements for the first three quarters of 2003 as a result of a determination we made in January 2004 that an adjustment was necessary to the estimated pension cost that had been recorded throughout 2003 related to the defined benefit pension plan covering substantially all of our employees. This adjustment was based on corrected actuarial information received relative to minimum actuarial loss amortization requirements under generally accepted accounting principles. As a result of this adjustment, we recorded $2.2 million as additional pre-tax pension expense for 2003 ($1.4 million, net of tax, or $0.06 per share). We filed amended quarterly reports on Form 10-Q/A for each of these quarters. The restatement reduced previously reported earnings by $0.02, $0.01 and $0.02 per share for the quarters ended March 31, 2003, June 30, 2003 and September 30, 2003, respectively. Please reference Footnote 13, which discusses our restated quarterly information.

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

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 MoPSC, the KCC, the OCC, the APSC and the FERC).

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. All of our regulatory assets are earning a current return except for approximately $10.8 million related to premiums and related costs for debt reacquired and $3.3 million related to postretirement benefit cost. All of these costs have been incurred since our latest rate case in each jurisdiction. Cost recovery of debt related costs has historically been allowed in our rate cases. Postretirement benefit costs have also been allowed in rates, pursuant to state statute. We believe it is probable these assets will be afforded similar treatment by our regulators. In addition, our $2.5 million loss and our $5.1 million gain on interest rate derivatives have also been incurred since our latest rate case. Since these items increase and reduce, respectively, our effective interest cost, we believe it is probable they will also be included in our rate base.

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.

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 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 and also 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, which is credited with salvage and charged with removal costs. 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 has included an estimated cost of dismantling and removing plant from service upon retirement. Pursuant to the October 2001 Missouri rate case, we no longer accumulate the future cost of removal through depreciation rates. We classified 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. At December 31, 2003 and 2002, the amount of the reclassification was $3.8 million and $4.9 million, respectively. This amount represents the difference between the amounts estimated and collected through depreciation rates and those actually experienced. We periodically 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:

	2003	2002	2001
Provision for depreciation			
Regulated	$ 28,916,777	$ 27,157,945	$ 31,035,431
Non-regulated	840,338	535,611	413,399
Total	$ 29,757,115	$ 27,693,556	$ 31,448,830
Annual depreciation rates			
Regulated	2.5 %	2.5 %	3.0 %
Non-regulated	5.6 %	4.1 %	3.8 %
Total	2.5 %	2.5 %	3.0 %

The table below sets forth the estimated service life range of our fixed assets:

Service Life Range (years)	Low	High
Electric fixed assets:		
Production plant	25	95
Transmission plant	45	77
Distribution plant	19	50
General plant	7	40
Non-regulated fixed assets	3	40

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 1.4% for 2003, 2.4% for 2002 and 5.6% for 2001, 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, discounted operating cash flows and other operating factors, to determine the impairment amount. In August 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (FAS 144), establishing new standards for accounting and reporting for the impairment or disposal of long-lived assets. We adopted FAS 144 on January 1, 2002. We believe there is no impairment of long-lived assets at December 31, 2003 and 2002.

Derivatives. All derivative instruments primarily related to fuel are designated as hedges and are recognized on the balance sheet with the gains and losses from the effective portion of these instruments deferred in other comprehensive income (in Stockholders' Equity), until the contract settles. Amounts in other comprehensive income are reclassified to earnings in the same period during which the hedged forecasted transaction affects earnings. Gains and losses from the ineffective portion of a hedge are recognized currently in earnings. The Company's policy is consistent with GAAP regarding accounting for derivative instruments and hedging activities. (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. Our policy is consistent with the provisions of SFAS 87. (See Note 8.)

In our most recent Missouri Rate Case, the Commission ruled the Company would be allowed to recover pension costs on an ERISA minimum funding (or cash) basis. Previously, the Commission allowed the Company to recover pension costs consistent with the Company's GAAP policy noted above. The Company has determined that the difference between the recovery allowed by the Commission and the Company's accounting for pension costs under GAAP does not meet the FAS 71 requirements for regulatory deferral. As a result, the Company will continue to account for pension expense or benefits in accordance with SFAS 87, using the previously mentioned amortization formula for recognizing net gains or losses. As a result, future pension expense or benefits may not be fully recovered or recognized in rates charged to customers.

Noncurrent Assets and Deferred Charges -- Other. This line item primarily consists of our prepaid pension cost. (See Note 8.)

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. This policy is consistent with the provisions of SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions". (See Note 8.)

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

Other – non-operating Expense. The components of other non-operating expense primarily include donations and other contributions for civic and community activities.

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.

Franchise Taxes. Franchise taxes are collected for and remitted to their respective cities and are included in other taxes in the Consolidated Statements of Income. Operating revenues also include franchise taxes of $5,142,000, $5,464,000 and $4,850,000 for each of the years ended December 31, 2003, 2002 and 2001, 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 does not include checks issued, but not cleared, which are reflected in accounts payable. At December 31, 2003 and 2002, these amounts were $9,261,768 and $11,689,521, 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 2003, 2002 and 2001 periods were 22,845,952, 21,433,889 and 17,777,449, respectively. Additional dilutive shares for the 2003, 2002 and 2001 periods were 7,153, 3,821 and 8,118, 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, 2003, we had several stock-based compensation plans, which are described in more detail in Note 4. We apply the recognition and fair-value measurement principles of SFAS No. 123, "Accounting for Stock-Based Compensation" (FAS 123), for all stock option and equity instrument issuances on or subsequent to January 1, 2002 and "Accounting for Stock Issued to Employees" (APB 25) and related interpretations for issuances prior to that date. If the fair-value based accounting method under FAS 123 had been used to account for stock-based compensation costs, the effects on 2001 net income and earnings per share would have been immaterial.

Recently Issued Accounting Standards. In June 2001, the Financial Accounting Standards Board issued SFAS No. 143, "Accounting for Obligations Associated with the Retirement of Long-Lived Assets" (FAS 143). This statement established standards for accounting and reporting for legal obligations associated with the retirement or anticipated retirement of tangible long-lived assets. It requires us to 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 to 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 this standard 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. This liability will be accreted over the period up to the estimated settlement date. The balance at the end of 2003 was approximately $656,000. Also we reclassified the accured 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, 2003 and 2002, this reclassification was $3.8 million and $4.9 million, respectively. This estimated liability may be subject to further refinement pending further analysis, including the results of our depreciation study expected to be completed in the first quarter of 2004.

In December 2002, the Financial Accounting Standards Board issued SFAS No. 148 (FAS 148), "Accounting for Stock-Based Compensation-Transition and Disclosure". FAS 148 amends SFAS No. 123, "Accounting for Stock-Based Compensation" (FAS 123), to provide alternative methods of transition when an entity changes from the intrinsic value method to the fair-value method of accounting for stock-based employee compensation. FAS 148 amends the disclosure requirements of FAS 123 to require more prominent and more frequent disclosure about the effects of stock-based compensation by requiring pro forma data to be presented more prominently and in a more user-friendly format in the footnotes to the financial statements. In addition, FAS 148 requires that the information be included in interim as well as annual financial statements. The transition guidance and annual disclosure provisions of FAS 148 are effective for fiscal years ending after December 15, 2002. We have adopted the transition and disclosure provisions of FAS 148 and now recognize compensation expense related to stock option issuances on or subsequent to January 1, 2002 under the fair-value provisions of FAS 123. Any stock compensation expense in prior periods has not been material. We do not have any transition issues and, accordingly, FAS 148 did not have a material impact on our financial condition and results of operations upon adoption.

In April 2003, the Financial Accounting Standard Board (FASB) issued SFAS No. 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (FAS149). 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" (FAS133). 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.

In November 2002, the FASB issued FASB Interpretation No. 45 (FIN 45), "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others, and Interpretation of FASB Statements Nos. 5, 57, and 107 and rescission of FASB Interpretation No. 34". FIN 45 requires: (1) the guarantor of debt to recognize a liability, at the inception of the guarantee, for the fair value of the obligation undertaken in issuing this guarantee, (2) indirect guarantees of debt to be recognized in the financial statements of the guarantor and (3) the guarantor to disclose the background and nature of the guarantee, the maximum potential amount to be paid under the guarantee, the carrying value of the liability associated with the guarantee and any recourse of the guarantor to recover amounts paid under the guarantee from third parties. The disclosure requirement of FIN 45 was effective for the Company's December 31, 2002 financial statements. Other than the 50.01% (reduced to 25% on January 1, 2004) guarantee by our wholly-owned subsidiary, EDE Holdings, Inc., of a $2.4 million note issued by Mid-America Precision Products, LLC (MAPP), we do not have any material commitments within the scope of FIN 45.

The FASB issued FASB Interpretation No. 46 "Consolidation of Variable Interest Entities" in January 2003, and issued its deferral in 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. Variable interest entities are accounted for under FIN No. 46-R, as revised in December 2003. 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, 2003. This change in presentation had no impact on our Consolidated Balance Sheet at December 31, 2003 or our net income.

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)	2003	2002
Electric plant:		
Production	$501,076	$443,665
Transmission	170,276	162,764
Distribution	459,096	435,634
General	51,707	48,721
Electric plant	1,182,155	1,090,784
Less accumulated depreciation and amortization	387,214	363,458
Electric plant net of depreciation and amortization	794,941	727,326
Construction work in progress	5,598	41,388
Net electric plant	800,539	768,714
Net electric plant and property – other	9,256	9,168
Water plant	8,801	8,401
Less accumulated depreciation and amortization	2,503	2,372
Water plant net of depreciation and amortization	6,298	6,029
Construction work in progress	2	–
Net water plant	6,300	6,029
Non-regulated:		
Non-regulated property	21,105	17,076
Less accumulated depreciation and amortization	3,569	2,154
Non-regulated net of depreciation and amortization	17,536	14,922
Construction work in progress	241	116
Net non-regulated property	17,777	15,038
Net plant and property	$833,872	$798,949

3. REGULATORY MATTERS

Rate Increases. The following table sets forth information regarding electric and water rate increases during the three year period ended December 31, 2003:

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 – 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.

On March 4, 2003, we filed a request with the Oklahoma Corporation Commission (OCC) for an annual increase in base rates for our Oklahoma electric customers in the amount of $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 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%. This increase was approved by the FERC on April 25, 2003, with the new rates becoming effective May 1, 2003.

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

Other Rate Matters. A one-time write-down of $4,100,000 was taken in the third quarter of 2001 for disallowed capital costs related to the construction of the State Line Combined Cycle Unit. These costs were disallowed as part of a stipulated agreement approved by the MoPSC in connection with our 2001 rate case and are not recoverable in rates. The net effect on 2001 earnings after considering the tax effect on this write-down was $2,500,000.

In accordance with FAS No. 71, we have deferred approximately $660,000 of expense directly related to Missouri rate cases. We amortize this amount over varying periods. As of December 31, 2003, approximately $373,000 remains unamortized.

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 2 to 30 years.

December 31,	2003	2002
Regulatory assets		
Income taxes	$ 29,001,556	$ 25,915,508
Unamortized loss on reacquired debt	18,635,756	7,293,862
Unamortized loss on interest rate derivative	2,526,491	-
Coal contract restructuring costs	-	249,546
Gas supply realignment costs	-	18,563
Asbury five-year maintenance	1,747,067	2,368,284
Other postretirement benefits (1)	3,583,860	323,920
Asset retirement obligation	482,765	-
Total regulatory assets	$ 55,977,495	$ 36,169,683
Regulatory liabilities		
Income taxes	$ 8,723,449	$ 11,840,810
Unamortized gain on interest rate derivative	5,070,995	-
Costs of removal	3,805,978	4,876,300
Total regulatory liabilities	$ 17,600,422	$ 16,717,110

(1) Please reference Note 8 for discussion regarding other postretirement benefits.

Deregulation. 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 have passed 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.

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. On February 10, 2004, the FERC approved the SPP RTO with conditions that include implementing its independent board and modifying its governance structure, expanding the coverage of SPP's tariff to assure that it is the sole transmission provider, obtaining clear and sufficient authority to exercise day-to-day operational control over appropriate transmission facilities, having an independent market monitor in place, obtaining clear and precise authority to independently and solely determine which project to include in the regional transmission plan and having a seams agreement with Midwest Independent Transmission System Operator (MISO) on file. Upon completion of the conditions, the SPP would gain status and FERC acceptance as an RTO.

We are a member of the SPP. However, on October 27, 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 recovery; increased risk of additional membership assessment cost allocation due to potential member departures; and anticipated change in the terms and conditions of the SPP tariff and network services. Such withdrawal would require approval from the FERC. We retain the option, however, to rescind such notice on or before October 31, 2004 and remain a member of the SPP. Kansas City Power and Light, Southwestern Power Administration, Westar Energy, Inc., Southwestern Public Service, Grand River Dam Authority and American Electric Power have also filed notices of intent to withdraw. We are unable to quantify the potential impact of membership in an 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 continue membership with the SPP prior to the October 31, 2004 withdrawal notice deadline.

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.

On December 10, 2001, we sold 2,012,500 shares of our common stock in an underwritten public offering for $20.37 per share. This sale resulted in proceeds of approximately $38,961,000, net of issuance costs of $2,034,000.

Stock-Based Awards and Programs

Stock Unit Plan for Directors. In 1998, we implemented a stock unit plan for directors (the Director Retirement Plan) to provide 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 Director Retirement Plan also provides directors the opportunity to convert previously earned 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 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 retirement benefit.

	2003	2002	2001
Units granted for service	7,099	6,466	3,569
Units granted for dividends	3,748	3,879	3,404
Units redeemed for common stock	8,914	8,158	-

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.

	2003	2002	2001
Subscriptions outstanding	38,400	40,574	46,419
Maximum subscription price	$19.03	$17.91	$17.73
Shares of stock issued	40,121	43,696	38,328
Stock issuance price	$17.91	$17.73	$17.78

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 matching contributions are made to the plan.

	2003	2002	2001
Shares contributed	41,878	40,086	35,793

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 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 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 components of this Stock Incentive Plan are described below:

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 2003 nor will be granted in future periods.

	2003	2002	2001
Restricted shares awarded	-	2,669	2,835
Restricted shares issued	6,761	7,952	4,648

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.

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

Stock compensation expense relative to the above noted plans was approximately $1.0 million, $1.2 million, and $1.2 million in 2001, 2002, and 2003, respectively.

Stock Incentive Plan – Stock Options. 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.

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 exer-cisable 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:

	2003		2002	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Outstanding, beginning of year	69,700	$20.95	-	-
Granted	49,200	$18.25	69,700	$20.95
Exercised	-	-	-	-
Forfeited	-	-	-	-
Outstanding, end of year	118,900	$19.83	69,700	$20.95
Exercisable, end of year	-	-	-	-

	2003	2002	2001
Compensation expense	$229,634	$127,264	-

The range of exercise prices for the options outstanding at December 31, 2003 was $18.25 to $20.95. The weighted-average remaining contractual life of outstanding options at December 31, 2003 and 2002 was 8.5 years and 9.1 years, respectively. The fair value of the options granted, which is hypothetically amortized to expense over the option vesting period in determining the pro forma impact, has been estimated on the date of grant using the Expanded Black-Scholes option-pricing model with the following assumptions:

	2003	2002
Expected life of option	10 years	10 years
Risk-free interest rate	4.07%	4.85%
Expected volatility of Empire stock	26.4%	21.6%
Expected dividend yield on Empire stock [1]	0.0%	0.0%
Fair value of options granted during year	$4.99	$5.05

(1) Reflects the existence of dividend equivalents.

At December 31, 2003, 2,118,076 shares remain available for issuance under all of the foregoing plans.

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), our Junior Subordinated Debentures, 8-1/2% 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, 2003 or 2002.

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 24,915,722 and 22,509,230 Rights outstanding at December 31, 2003 and 2002, 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, 2003 and 2002 the balance of long-term debt outstanding was as follows:

	2003	2002
Note payable to securitization trust [4]	$ 50,000,000	$ -
Company obligated mandatorily redeemable securities of subsidiary holding solely parent debentures [4]	-	50,000,000
Other:		
First mortgage bonds:		
7.60% Series due 2005	10,000,000	10,000,000
8-1/8% Series due 2009	20,000,000	20,000,000
6-1/2% Series due 2010	50,000,000	50,000,000
7.20% Series due 2016	25,000,000	25,000,000
9-3/4% Series due 2020	-	2,250,000
7% Series due 2023	-	45,000,000
7-3/4% Series due 2025[2]	30,000,000	30,000,000
7-1/4% Series due 2028	-	13,076,000
5.3% Pollution Control Series due 2013 [2]	8,000,000	8,000,000
5.2% Pollution Control Series due 2013 [2]	5,200,000	5,200,000
	$ 148,200,000	$ 208,526,000
Senior Notes, 7.70% Series due 2004	-	100,000,000
Senior Notes, 7.05% Series due 2022 [1][2]	49,942,000	50,000,000
Senior Notes, 4-1/2% Series due 2013 [2]	98,000,000	-
Senior Notes, 6.70% Series due 2033 [2]	62,000,000	-
Long-term debt - Mid-America Precision Products[3]	3,076,824	2,723,389
Long-term debt - Fast Freedom[3]	299,809	-
Obligations under capital lease	503,211	656,761
Less unamortized net discount	(994,528)	(477,040)
	411,027,316	411,429,110
Less current obligations of long-term debt	(429,140)	(236,872)
Less current obligations under capital lease	(205,556)	(194,143)
Total long-term debt	$ 410,392,620	$ 410,998,095

(1) During each twelve-month period ending December 15, we are required to repurchase up to $25,000 in principal amount of the notes of this series per holder per year, upon the death of the holder. We are not required to repurchase more than $1,000,000 in the aggregate in any twelve-month period. At December 31, 2003, we had repurchased $58,000 of the notes related to this requirement.

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

(3) EDE Holdings is the guarantor of 50.01% (reduced to 25% on January 1, 2004) of a $2.4 million secured long-term note payable of Mid-America Precision Products (MAPP). Additional long-term debt includes seller financed notes for equipment purchases. 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 2003 current obligations of these notes are included in the current obligations of long-term debt.

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

On March 1, 2001, Empire District Electric Trust I issued 2,000,000 of its 8.5% Trust Preferred Securities (liquidation amount $25 per preferred security) in a public underwritten offering. This issuance generated proceeds of $50,000,000 and issuance costs of approximately $1.8 million. Holders of the trust preferred securities are entitled to receive distributions at an annual rate of 8-1/2% 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 8-1/2% 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 net proceeds of this offering were added to our general funds and were used to repay short-term indebtedness. The Junior Subordinated Debentures are shown as "Note payable to securitization trust" on our balance sheet. See discussion of FASB Interpretation 46-R, regarding consolidation of variable interest entities under "Recently Issued Accounting Standards"in Note 1.

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, 2003 would permit us to issue $279.8 million of new first mortgage bonds based on this test, with an assumed interest rate of 7%, subject to approval by the Missouri Public Service Commission to mortgage property. The mortgage provides an exception from this earnings requirement in certain instances, relating to the issuance of new first mortgage bonds against first mortgage bonds which have been, or are to be, retired. 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, 2003, we had retired bonds and net property additions which would enable the issuance of at least $341.0 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. The net proceeds of approximately $48.6 million were added to our general funds and were used to repay short-term indebtedness.

On June 17, 2003, we sold to the public in an underwritten offering, $98 million 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, 9-3/4% Series due 2020 for approximately $2.4 million, including interest; (2) all $13.1 million aggregate principal amount of our First Mortgage Bonds, 7-1/4% 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 long-term debt exclusive of capital leases was $410,094,965 and $410,535,477 at December 31, 2003 and 2002, respectively, and its fair market value was estimated to be approximately $417,759,000 and $414,125,000, 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 maturation. 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
Long-term debt	358.1	–	10.0	–	348.1
Capital lease obligations	0.5	0.2	0.3	–	–
Other long-term obligations	3.4	0.4	1.0	2.0	–
Total long-term debt obligations	$ 412.0	$ 0.6	$ 11.3	$ 2.0	$ 398.1
Less current obligations and unamortized discount	1.6				
Total long-term debt	$ 410.4				

7. SHORT-TERM BORROWINGS

Short-term commercial paper outstanding and notes payable averaged $42,842,666 and $46,551,748 daily during 2003 and 2002, respectively, with the highest month-end balances being $74,350,000 and $62,000,000, respectively. The weighted daily average interest rates during 2003 and 2002 were 1.4% and 2.4%, respectively. The weighted average interest rates of borrowings outstanding at December 31, 2003 and 2002 were 1.4% and 2.0%, respectively. At December 31, 2003, we had outstanding commercial paper of $13,000,000 with due dates from January 5, 2004 to January 15, 2004.

On April 17, 2003, we closed a two-year renewal of our $100 million unsecured revolving credit facility which was to expire on May 12, 2003. 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 Trust Preferred Securities) 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 distributions on the Trust Preferred Securities) 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 there under. As of December 31, 2003, we are in compliance with these ratios. This credit facility is also subject to cross-default if we default 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, 2003. However, $13,000,000 of the facility as of that date was used to back up our commercial paper and was not available to be borrowed.

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.

Based on the performance of our pension plan assets through December 31, 2003, we expect to be required under ERISA to fund approximately $0.3 million in 2004 and $0.2 million in 2005 in order to maintain minimum funding levels. These amounts are estimates and will likely change based on actual investment performance, any future pension plan funding and finalization of actuarial assumptions. At December 31, 2003, there was no minimum pension liability required to be recorded.

Our pension expense or benefit includes amortization of previously unrecognized net gains or losses as a result of requirements of the September 20, 2001 MoPSC rate case. 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).

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, healthcare cost trend rates and discount rates, as well as Medicare prescription drug costs.

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

	2003	2002	2001
Reconciliation of Projected Benefit Obligations:			
Benefit obligation at beginning of year	$ 87,474,547	$ 78,291,337	$ 75,217,964
Service cost	2,518,954	2,190,415	2,172,379
Interest cost	5,827,520	5,601,019	5,604,231
Plan amendments	503,251	–	–
Net actuarial loss/(gain)	6,750,127	6,401,833	99,017
Benefits and expenses paid	(5,115,584)	(5,010,057)	(4,802,254)
Benefit obligation at end of year	$ 97,958,815	$ 87,474,547	$ 78,291,337

	2003	2002	2001
Reconciliation of Fair Value of Plan Assets:			
Fair value of plan assets at beginning of year	$ 78,217,601	$ 92,138,446	$ 98,898,066
Actual return on plan assets gain/(loss)	17,209,644	(8,910,788)	(1,957,366)
Benefits paid	(5,115,584)	(5,010,057)	(4,802,254)
Fair value of plan assets at end of year	$ 90,311,661	$ 78,217,601	$ 92,138,446

	2003	2002	2001
Reconciliation of Funded Status:			
Funded status	$ (7,647,154)	$ (9,256,946)	$13,847,109
Unrecognized net assets at January 1, 1986 being amortized over 17 years	–	–	(491,158)
Unrecognized prior service cost	3,175,355	3,227,779	3,747,210
Unrecognized net loss/(gain)	20,273,733	25,584,623	(1,129,486)
Prepaid pension cost	$ 15,801,934	$ 19,555,456	$ 15,973,675

At December 31, 2003, our accumulated benefit obligation was $82,229,530 and our plan asset value was $90,311,661.

Net Periodic Pension Cost/(Income)

Our net periodic benefit cost or (income), (related to the application of FAS 87), net of tax, as a percentage of net income for 2002 and 2003 was (6.49)% and 6.75%, respectively.

Net periodic pension cost/(income) for 2003, 2002 and 2001 is comprised of the following components:

	2003	2002	2001
Service cost - benefits earned during the period	$ 2,518,954	$ 2,190,415	$ 2,172,379
Interest cost on projected benefit obligation	5,827,520	5,601,019	5,604,231
Expected return on plan assets	(6,422,995)	(8,048,645)	(8,672,012)
Net amortization	1,830,043	(3,324,570)	(3,470,845)
Net periodic pension cost/(income)	$ 3,753,522	$ (3,581,781)	$ (4,366,247)

Assumptions used to determine Year End Benefit Obligation		
Measurement date	**12/31/2003**	**12/31/2002**
Weighted average discount rate	6.25%	6.75%
Rate of increase in compensation levels	4.25%	4.25%
Assumptions used to determine Net Periodic Pension Benefit Cost / (Income)		
Measurement date	**01/01/2003**	**01/01/2002**
Discount rate	6.75%	7.25%
Expected return on plan assets	8.50%	9.00%
Rate of compensation increase	4.25%	4.00%

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.

Allocation of Plan Assets	% OF FAIR VALUE AS OF DECEMBER 31,	
Actual:	2003	2002
Equity securities	69.86%	63.64%
Debt securities	30.07%	36.15%
Real estate	0%	0%
Other	.07%	.21%
Total	100.00%	100.00%
Target:		
Equity securities	60% - 70%	60% - 70%
Debt securities	30% - 40%	30% - 40%
Real estate	-0%-	-0%-
Other	-0%-	-0%-
Total	100.00%	100.00%

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 these 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.
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. The Company believes that investment decisions are best made when not restricted by excessive procedure. Therefore, 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	**Fixed Income**
• Common Stocks	• Bonds
• Preferred Stocks	• GICs, BICs
• Convertible Preferred Stocks	• Cash-Equivalent Securities (e.g., U.S. T-Bills, Commercial Paper, etc.)
• Convertible Bonds	• Certificates of Deposit in institutions with FDIC/FSLIC protection
• Covered Options	• 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	• Warrants
• Commodities Futures	• Short Sales
• Securities of Empire District	• Index Options
• Derivatives	

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. 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. Assets in these trusts amounted to approximately $27,900,000 at December 31, 2003, $21,500,000 at December 31, 2002 and $18,600,000 at December 31, 2001.

Postretirement benefits, a portion of which have been capitalized for 2003, 2002 and 2001 included the following components:

Net Periodic Postretirement Benefit Cost:	**2003**	**2002**	**2001**
Service cost on benefits earned during the year	$ 1,083,133	$ 1,141,158	$ 828,316
Interest cost on projected benefit obligation	3,405,784	3,095,057	2,892,691
Expected return on assets	(1,611,614)	(1,350,634)	(1,260,307)
Amortization of unrecognized transition obligation	1,084,017	1,084,017	1,084,017
Amortization of unrecognized net loss	1,585,129	896,316	407,068
Recognition of substantive plan	3,292,328	-	-
Net periodic postretirement benefit cost before regulatory asset recognition	$ 8,838,777	$ 4,865,914	$ 3,951,785
Recognition of regulatory asset for previously unrecorded benefit costs [1]	(3,292,328)	-	-
Net periodic postretirement benefit cost	$ 5,546,449	$ 4,865,914	$ 3,951,785

Reconciliation of Benefit Obligation:	**2003**	**2002**	**2001**
Benefit obligation at beginning of year	$ 53,800,550	$ 42,315,384	$ 37,251,254
Service cost	1,083,133	1,141,158	828,316
Interest cost	3,405,784	3,095,057	2,892,691
Amendments [1]	(8,533,544)	-	-
Actuarial (gain)/loss	10,379,025	9,029,864	2,757,072
Benefits paid	(1,849,594)	(1,780,913)	(1,413,949)
Benefit obligation at end of year	$ 58,285,354	$ 53,800,550	$ 42,315,384

Reconciliation of Fair Value of Plan Assets:	**2003**	**2002**	**2001**
Fair value of plan assets at beginning of year	$ 21,494,115	$ 18,596,087	$ 16,055,828
Employer contributions	5,355,417	5,233,834	3,951,785
Actual return on plan assets	2,894,866	(586,872)	2,423
Benefits paid	(1,843,111)	(1,748,934)	(1,413,949)
Fair value of plan assets at end of year	$ 27,901,287	$ 21,494,115	$ 18,596,087

Reconciliation of Funded Status:	**2003**	**2002**	**2001**
Funded status	$ (30,384,067)	$(32,306,435)	$ (23,719,297)
Unrecognized transition obligation	9,756,140	10,840,157	11,924,174
Unrecognized prior service cost [2]	(8,533,544)		-
Unrecognized net loss	21,042,234	16,915,842	6,870,118
Accrued postretirement benefit cost [2]	$ (8,119,237)	$ (4,550,436)	$ (4,925,005)

(1) Accrued postretirement benefit cost at December 31, 2003 has 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 has been recorded for this amount as we believe it is probable that these costs will be afforded rate recovery consistent with past practice and a state statute.
(2) Reflects changes in our drug plan to increase the co-pay of the participants.

Assumptions used to determine Year End Benefit Obligation		
Measurement date	**12/31/2003**	**12/31/2002**
Weighted average discount rate	6.25%	6.75%

Assumptions used to determine Net Periodic Benefit Cost		
Measurement date	01/01/2003	01/01/2002
Discount rate	6.75%	7.25%
Expected return on plan assets	8.50%	9.00%

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 allocatiion.

Allocation of Plan Assets	% OF FAIR VALUE AS OF DECEMBER 31,	
Actual:	2003	2002
Cash equivalent	10.74%	12.36%
Fixed income	40.18%	48.18%
Equities	46.80%	34.60%
Other	2.28%	4.86%
Total	100.00%	100.00%
Target:		
Cash equivalent	0% - 10%	0% - 10%
Fixed income	40% - 60%	40% - 60%
Equities	40% - 60%	40% - 60%
Other	-0%-	-0%-
Total	100.00%	100.00%

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
- 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

The assumed 2003 cost trend rate used to measure the expected cost of healthcare benefits is 10%. The trend rate decreases through 2013 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 $5,300,000 to $6,700,000 and the accumulated postretirement benefit obligation from $58,300,000 to $70,900,000. 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 $5,300,000 to $4,300,000 and the accumulated benefit obligation from $58,300,000 to $47,900,000.

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:

	2003	2002	2001
Computed "expected" federal provision	$ 15,730,000	$ 13,590,000	$ 3,640,000
State taxes, net of federal effect	1,380,000	1,190,000	125,000
Adjustment to taxes resulting from:			
Merger costs	-	-	(2,320,000)
Investment tax credit amortization	(550,000)	(550,000)	(550,000)
Other	(1,058,001)	(920,000)	(895,000)
Actual provision for income taxes	$ 15,501,999	$ 13,310,000	$ -

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

	2003	2002	2001
Taxes currently (receivable)/payable			
Included in operating revenue deductions:			
Federal	$ 120,000	$ 1,590,000	$ (50,000)
State	790,000	170,000	30,000
Included in "other – net"	(250,000)	(80,000)	(240,000)
	660,000	1,680,000	(260,000)
Deferred taxes:			
Depreciation and amortization differences	17,106,000	11,479,000	2,986,000
Loss on reacquired debt	4,318,000	(169,000)	(203,000)
Pension & postretirement benefits	(1,493,000)	559,000	844,000
Other	(1,140,001)	(964,000)	(1,028,000)
Asbury five-year maintenance	(259,000)	902,000	(100,000)
Software development costs	(70,000)	(190,000)	(252,000)
Alternative minimum tax credit	(1,600,000)	-	-
Hedging transactions	(1,470,000)	-	-
Included in "other – net"	-	563,000	120,000
Disallowed plant addition	-	-	(1,557,000)
	15,391,999	12,180,000	810,000
Deferred investment tax credits, net	(550,000)	(550,000)	(550,000)
Total income tax expense	$ 15,501,999	$ 13,310,000	$ -

Under SFAS No. 109, "Accounting for Income Taxes" (FAS 109), temporary differences gave rise to deferred tax assets and deferred tax liabilities at year end 2003 and 2002 as follows:

	Balances as of December 31,			
	2003		2002	
	Deferred Tax Assets	Deferred Tax Liabilities	Deferred Tax Assets	Deferred Tax Liabilities
Noncurrent				
Depreciation and other property related	$ 13,451,962	$ 131,885,372	$ 11,748,535	$109,531,527
Unamortized investment tax credits	3,435,155	-	3,854,342	-
Miscellaneous book/tax recognition differences	7,985,726	18,053,091	7,198,842	16,414,743
Total deferred taxes	$ 24,872,843	$ 149,938,463	$ 22,801,719	$ 125,946,270

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, 2003 and 2002, our property, plant and equipment accounts included the cost of our ownership interest in the plant of $48,915,000 and $48,338,000, respectively, and accumulated depreciation of $33,259,000 and $32,436,000, respectively.

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"). The State Line Combined Cycle Unit was placed into commercial operation on June 25, 2001. The total cost of the State Line Combined Cycle Unit was approximately $204,000,000, including the one-time non-cash charge of $4,100,000, before related income taxes, that was recorded in the third quarter of 2001 for disallowed capital costs. Our 60% share of this amount was approximately $122,000,000 before considering the contribution of 40% of existing property. After the transfer to WGI on June 15, 2001 of an undivided 40% joint ownership interest in the existing State Line Unit No. 2 and certain other property at book value, our net cash requirement was approximately $108,000,000, excluding AFUDC. We are responsible for the operation and maintenance of the State Line Combined Cycle Unit and for 60% of its costs. The State Line Combined Cycle Unit provides us with approximately 150 megawatts of additional capacity compared to our existing State Line Unit No. 2. At December 31, 2003 and 2002, our property, plant and equipment accounts include the cost of our ownership interest in the unit of $153,243,000 and $153,103,000, respectively, and accumulated depreciation of $13,847,000 and $9,700,000, respectively.

11. COMMITMENTS AND CONTINGENCIES

We are a party to various claims and legal proceedings arising out of the normal course of our business. In the opinion of management, the ultimate outcome of these claims and lawsuits will not 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 and transportation commitments total $6.9 million for 2004, $25.1 million for 2005 through 2006, $14.1 million for 2007 through 2008 and $53.7 million for 2009 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 for 2004, 2005, 2006 and 2007 are $19.5 million, $9.0 million, $3.9 million and $4.0 million, respectively.

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 $104 million through May 31, 2010.

Other. By letters dated October 31, 2002, January 17, 2003 and June 26, 2003, Enron North America Corp. (Enron) and their counsel demanded that we pay Enron $6,113,850 (plus accrued interest at the rate of 6.0%), an amount that Enron claimed it was owed as a result of our early termination of all transactions under the Enfolio Master Firm Purchases/Sale Agreement dated June 1, 2001 between us and Enron, which we disputed. We terminated the agreement effective December 3, 2001 as a result of, among other reasons, the drop in Enron's credit ratings. In October 2003, we reached an agreement with Enron to settle the dispute for payment of $1.0 million. This settlement agreement was approved by the bankruptcy court. On October 27, 2003, Enron signed the settlement agreement, and we paid the $1.0 million on October 29, 2003. We accrued the $1.0 million as a charge to fuel expense in the third quarter of 2003.

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 the new 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. The two new FT8 peaking units 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.

Our Asbury, Riverton and Iatan plants currently burn a blend of low sulfur Western coal (Powder River Basin) and higher sulfur local coal or burn 100% low sulfur Western coal. The State Line Plant and the Energy Center's new FT8 peaking units are gas-fired facilities and do not receive SO2 allowances. However, annual allowance requirements for the State Line Plant and the new FT8 peaking units, which are not expected to exceed 20 allowances per year, will be transferred from our inventoried bank of allowances. We anticipate, based on current operations, that the combined actual SO2 allowance need for all affected plant facilities will not exceed the number of allowances awarded to us annually by the EPA. The excess annual SO2 allowances will be transferred to our inventoried bank of allowances. We currently have 49,000 banked allowances.

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 tire derived fuel (TDF) at a maximum rate of 2% of total fuel input. During 2003, approximately 11,000 tons of TDF were burned. This is equivalent to 1,100,000 discarded passenger car tires.

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 Riverton and State Line Power Plants' National Pollution Discharge Elimination System Permits were issued in 2003.

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.

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 Interstate Air Quality Rule. Also in mid-December 2003, the EPA issued proposed regulations for mercury under the requirements of the 1990 Amendments. Both sets of proposed rules are currently under a public review and comment period and may change before being issued as final regulations in 2004 or early 2005. It is possible that some expenditures may need to begin as early as 2005 in order to meet a proposed December 15, 2007 requirement for mercury reduction in the 1990 Amendments version of the proposed mercury regulations. The proposed Interstate Air Quality Rule would require significant additional reductions in emissions from our power plants, in phases, beginning in 2010. Preliminary estimates of capital costs to meet these requirements cannot be made at this time due to the uncertainty surrounding the final regulations, but could possibly be significant.

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. EDE Holdings is also the 50.01% (reduced to 25% on January 1, 2004) guarantor of a $2.4 million long-term note payable. 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.

In February 2003, we purchased Joplin.com, a leading Internet service provider in the Joplin, Missouri area. The purchase was made through Transaeris, a non-regulated subsidiary of EDE Holdings, Inc. We have merged Transaeris and Joplin.com into one company named Fast Freedom, Inc.

In September 2003, EDE Holdings, Inc. purchased an approximate 6% interest in ETG, a company that makes automated meter reading equipment. This investment is accounted for under the cost method.

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 in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets". This amortization which approximates $0.2 million did not have a material impact on our consolidated financial condition or results of operations.

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, 2003** Non-Regulated	2003** Total Company	2002 Non-Regulated	2002 Total Company
Statement of Income Information				
Revenues	$ 21,217,750*	$ 325,504,896	$ 10,255,530	$305,902,995
Operating income (loss)	$ (936,153)	$ 61,434,519	$ (1,373,252)	$ 56,836,905
Net income (loss)	$ (1,392,660)	$ 29,450,307	$ (1,489,325)	$ 25,524,118
Minority interest	$ 353,634	$ 353,634	$ 142,463	$ 142,463
Capital Expenditures* **	$ 4,153,868	$ 65,059,358	$ 5,917,421	$ 77,522,137

	As of December 31, 2003 Non-Regulated	2003 Total Company	2002 Non-Regulated	2002 Total Company
Balance Sheet Information				
Total assets	$ 24,439,244	$1,009,443,143	$ 22,210,566	$964,557,323
Minority interest	$ 1,159,953	$ 1,159,953	$ 806,319	$ 806,319

* Includes revenues received from the regulated business that are eliminated in consolidation.

** Increases in non-regulated revenues and minority interest for the year ended December 31, 2003 primarily reflect a full year's results of MAPP, a company specializing in close-tolerance custom manufacturing for the aerospace, electronics, telecommunications and machinery industries, which was acquired in July 2002.

*** The capital expenditures for 2002 have been adjusted to include the capital expenditures of all our non-regulated subsidiaries. We previously included only the construction expenditures of our fiber business.

13. SELECTED QUARTERLY INFORMATION (UNAUDITED)

The following is a summary of previously reported and restated quarterly results for 2003 and reported quarterly results for 2002. During January of 2004, we determined that an adjustment was necessary to the estimated pension cost that had been recorded throughout 2003 related to the defined benefit pension plan covering substantially all of our employees. This adjustment was based on corrected actuarial information received relative to minimum actuarial loss amortization requirements under generally accepted accounting principles. As a result of this adjustment, we recorded $2.2 million as additional pre-tax pension expense for 2003 ($1.4 million, net of tax, or $0.06 per share). We filed amended quarterly reports on Form 10-Q/A for each of these quarters. The restatement reduced previously reported earnings by $0.02, $0.01 and $0.02 per share for the quarters ended March 31, 2003, June 30, 2003 and September 30, 2003, respectively.

	Quarters			
	As reported First	As reported Second	As reported Third	Fourth
	(dollars in thousands except per share amounts)			
2003:				
Operating revenues	$ 76,906	$74,603	$ 101,029	$ 72,967
Operating income	14,185	11,236	24,621	12,376
Net income	6,024	2,901	16,763	4,845
Net income applicable to common stock	6,024	2,901	16,763	4,845
Basic and diluted earnings per average share of common stock	$ 0.27	$ 0.13	$ 0.73	$ 0.21

	Quarters			
	As restated First	As restated Second	As restated 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
Net income applicable to common stock	5,645	2,662	16,298	4,845
Basic and diluted earnings per average share of common stock	$ 0.25	$ 0.12	$ 0.71	$ 0.21

	Quarters			
	First	Second	Third	Fourth
	(dollars in thousands except per share amounts)			
2002:				
Operating revenues	$ 65,297	$68,905	$ 99,823	$ 71,878
Operating income	7,644	11,980	26,061	11,152
Net income	(537)	4,027	18,387	3,647
Net income applicable to common stock	(537)	4,027	18,387	3,647
Basic and diluted earnings per average share of common stock	$ (0.03)	$ 0.19	$ 0.82	$ 0.16

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

14. RISK MANAGEMENT AND DERIVATIVE FINANCIAL INSTRUMENTS

On January 1, 2001, we adopted the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133), SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities and Amendment of SFAS 133" (FAS 138) and SFAS No. 149, "Amendment of Statement 133 Derivative Instruments and Hedging Activites" (FAS 149). FAS 133, as amended, requires recognition of all derivatives as either assets or liabilities on the balance sheet measured at fair value. 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.

FAS 133 requires derivatives to be recognized on the balance sheet at their fair value. On the date a derivative contract is entered into, the derivative is designated as (1) a hedge of a forecasted transaction or of the variability of cash flows to be received or paid related to a recognized asset or liability ("cash-flow" hedge); or (2) an instrument that is held for non-hedging purposes (a "non-hedging" instrument). Changes in the fair value of a derivative that is highly effective and designated and qualifies as a cash-flow hedge are recorded in other comprehensive income, until earnings are affected by the variability of cash flows (e.g., when periodic settlements on a variable-rate asset or liability are recorded in earnings). Changes in the fair value of non-hedged derivative instruments are reported in current-period earnings.

We discontinue hedge accounting prospectively when (1) it is determined that the derivative is no longer 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 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.

As of December 31, 2003 and 2002, 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.

	2003	2002
Current assets	$ 11,631,350	$ 7,482,978
Noncurrent assets	567,000	4,977,500
Current liabilities	583,140	506,268
Noncurrent liabilities	80,350	-

A $7,272,705 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 $4,457,465 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, 2004 and ending on July 31, 2007. 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 ineffective (overhedged) portion of our hedging activities in "Fuel" under the Operating Revenue Deductions section of our income statements as allowed by FAS 133 since all of our gas hedging activities are related to stabilizing fuel costs as part of our fuel procurement program and are not speculative ventures. 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. Gains/(losses) from the ineffective (overhedged) portion of our hedging activities included in "Fuel" were $2.2 million (pre-tax) for 2003.

As of December 31, 2002, $1,238,940 of unrealized gains and related taxes of $470,000 relating to non-qualifying hedging instruments had been recognized within Other Income and Deductions in our Statement of Income. These amounts have been reclassified to "Fuel" under the Operating Revenue Deductions section for 2002.

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). None of our NPNS contracts contain a price adjustment feature as contemplated in Derivative Implementation Group Issue No. C20 issued in June 2003 and effective the first fiscal quarter beginning after July 10, 2003. 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):

	2003	2002
Accounts receivable for meter loops, meter bases, line extensions, highway projects, etc.	$ 1.9	$ 2.2
Accounts receivable of our non-regulated subsidiary companies	1.7	3.0
Accounts receivable from Westar Generating, Inc. for commonly-owned facility	0.5	1.5
Taxes receivable - overpayment of estimated income taxes	1.9	2.8
Accounts receivable for true-up on maintenance contracts	1.0	–
Other	0.9	0.5
Total accounts receivable – other	$ 7.9	$ 10.0

The $1.0 million in accounts receivable for true-up on maintenance contracts represents $0.1 million remaining of the $3.0 million gross amount of a true-up credit from Siemens Westinghouse in June 2003 related to our maintenance contract entered into in July 2001 for the State Line Combined Cycle Unit (SLCC) and $0.9 million of quarterly estimated credits accrued in the last 6 months of 2003. 40% 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, 2003.

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:

	2003	2002	2001
Transmission and distribution expense	$ 8.1	$ 8.7	$ 7.8
Power operation expense (other than fuel)	9.2	8.8	6.9
Customer accounts & assistance expense	6.7	6.8	6.1
Other water operating expense	0.1	0.1	0.2
Employee pension expense/(income)	3.5	(2.1)	(2.9)
Employee healthcare plan	6.8	6.3	4.8
General office supplies and expense	6.3	6.0	5.7
Administrative and general expense	8.1	7.0	5.7
Allowance for uncollectible accounts	1.0	1.2	2.0
Miscellaneous expense	–	0.3	0.4
Total	$ 49.8	$ 43.1	$ 36.7

17. MERGER AGREEMENT

We and Aquila (formerly UtiliCorp United, Inc.) entered into an Agreement and Plan of Merger, dated as of May 10, 1999 (the "Merger Agreement"), which provided for a merger of the Company with and into Aquila, with Aquila being the surviving corporation (the "Merger"). Our shareholders approved the proposed merger on September 3, 1999.

Under the terms of the Merger Agreement, either company could terminate the Merger Agreement without penalty if all regulatory approvals were not obtained prior to December 31, 2000. On January 2, 2001, Aquila exercised its right to terminate the Merger Agreement on that basis. Upon termination of the Merger Agreement, approximately $6.1 million of merger-related costs that had not been deductible for income tax purposes became deductible. As a result, we recognized a tax benefit related to such costs of approximately $2.3 million in the first quarter of 2001.

The stockholder approval of the merger effected a change in control under our Change in Control Severance Pay Plan (the "Plan"). Certain key employees, electing voluntary termination, became eligible to receive compensation as specified under the terms of the Plan. The termination of the Merger Agreement did not relieve us of our obligations under the Plan.

As of December 31, 2000, we had incurred approximately $155,000 of obligations to individuals electing voluntary termination under the Plan. Subsequent to that date, we incurred approximately $1,967,000 in additional obligations under the Plan. As of December 31, 2002 approximately $739,000 of the obligations had been paid and $1,383,000 remained. As of December 31, 2003 approximately $727,000 in obligations remain to be paid.

SELECTED FINANCIAL DATA

THE EMPIRE DISTRICT ELECTRIC COMPANY

(Dollars in thousands, except per share amounts)	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
Operating revenues [1]	$ 325,505	$ 305,903	$ 265,821	$ 261,691	$ 243,243	$ 239,858	$ 215,311	$ 205,984	$ 192,838	$ 177,757	$ 168,439
Operating income [1]	$ 61,435	$ 56,837	$ 43,212	$ 45,862	$ 42,237	$ 47,440	$ 40,962	$ 36,652	$ 33,151	$ 32,005	$ 29,291
Total allowance for funds used during construction	$ 282	$ 571	$ 3,611	$ 5,775	$ 1,193	$ 409	$ 1,226	$ 1,420	$ 2,239	$ 1,715	$ 229
Net income	$ 29,450	$ 25,524	$ 10,403	$ 23,617	$ 22,170	$ 28,323	$ 23,793	$ 22,049	$ 19,798 [2]	$ 19,683	$ 15,936
Earnings applicable to common stock	$ 29,450	$ 25,524	$ 10,403	$ 23,617	$ 19,463	$ 25,912	$ 21,377	$ 19,633	$ 17,381 [2]	$ 18,120	$ 15,551
Weighted average number of common shares outstanding	22,845,952	21,433,889	17,777,449	17,503,665	17,237,805	16,932,704	16,599,269	16,015,858	14,730,902	13,734,231	13,415,539
Basic and diluted earnings per weighted average shares outstanding	$ 1.29	$ 1.19	$ 0.59	$ 1.35	$ 1.13	$ 1.53	$ 1.29	$ 1.23	$ 1.18 [2]	$ 1.32	$ 1.16
Cash dividends per common share	$ 1.28	$ 1.28	$ 1.28	$ 1.28	$ 1.28	$ 1.28	$ 1.28	$ 1.28	$ 1.28	$ 1.28	$ 1.28
Common dividends paid as a percentage of earnings applicable to common stock	99.0 %	109.3 %	217.4 %	94.9 %	114.5 %	83.7 %	99.4 %	104.5 %	108.9 %	97.0 %	110.4%
Allowance for funds used during construction as a percentage of earnings applicable to common stock	1.0 %	2.2%	34.7 %	24.5 %	6.2 %	1.6 %	5.7 %	7.2 %	12.9 %	9.5 %	1.5%
Book value per common share outstanding at end of year	$ 15.17	$ 14.59	$ 13.64	$ 13.62	$ 13.44	$ 13.40	$ 13.03	$ 12.93	$ 12.67	$ 12.42	$ 12.33
Capitalization:											
Common equity	$ 378,825	$ 329,315	$ 268,308	$ 240,153	$ 234,188	$ 229,791	$ 219,034	$ 213,091	$ 193,137	$ 173,780	$ 167,861
Preferred stock without mandatory redemption provisions	$ 0	$ 0	$ 0	$ 0	$ 0	$ 32,634	$ 32,902	$ 32,902	$ 32,902	$ 32,902	$ 7,902
Long-term debt	$ 410,393	$ 410,998	$ 358,615	$ 325,644	$ 345,850	$ 246,093	$ 196,385	$ 219,533	$ 194,705	$ 184,977	$ 165,227
Ratio of earnings to fixed charges	2.44	2.25	1.31	2.25	2.77	3.32	3.01	3.11	2.90	3.16	2.73
Ratio of earnings to combined fixed charges and preferred stock dividend requirements	2.44	2.25	1.31	2.25	2.40	2.50	2.50	2.53	2.36	2.70	2.63
Total assets [3]	$ 1,009,443	$ 964,557	$ 896,358	$ 834,819	$ 735,898	$ 653,141	$ 626,465	$ 596,980	$ 557,368	$ 520,213	$ 463,617
Plant in service at original cost [1]	$ 1,221,352	$ 1,125,460	$1,080,100	$ 928,561	$ 878,287	$ 838,883	$ 797,839	$ 717,890	$ 682,609	$ 611,360	$ 576,083
Plant expenditures (including AFUDC) [1]	$ 65,059	$ 77,522	$ 77,316	$ 131,824	$ 70,127	$ 50,899	$ 53,280	$ 59,373	$ 49,217	$ 71,649	$ 42,648

(1) 1998 through 2001 have been restated to reflect non-utility property, revenues and expenses.
(2) Reflects a pre-tax charge of $4,583,000 for certain one time costs associated with the Company's Voluntary Early Retirement Program.
(3) 1999 through 2002 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]

THE EMPIRE DISTRICT ELECTRIC COMPANY

(dolars in thousands, except per share amounts)	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
Electric Operating Revenues (000s):											
Residential	$ 125,197	$ 126,088	$ 110,584	$ 108,572	$ 98,787	$ 100,567	$ 88,636	$ 86,014	$ 81,331	$ 71,977	$ 68,477
Commercial	90,577	91,065	82,237	77,601	73,773	71,810	64,940	61,811	58,430	54,052	50,264
Industrial	50,643	50,155	44,509	42,711	41,030	39,805	37,192	35,213	32,637	31,317	28,880
Public authorities	7,210	7,099	6,311	5,927	5,847	5,559	4,995	4,180	3,745	3,509	3,419
Wholesale on-system	12,440	11,868	12,911	11,738	10,682	10,928	9,730	9,482	8,360	8,173	8,038
Miscellaneous	6,618	6,987	5,583	4,546	3,856	4,006	3,341	3,639	3,345	2,393	2,302
Total system	292,685	293,262	262,135	251,095	233,975	232,675	208,834	200,339	187,848	171,421	161,380
Wholesale off-system	10,849	17,185	3,898	7,842	7,090	6,126	5,473	4,595	4,000	5,391	6,244
Less Provision for IEC Refunds	–	15,875	2,843	–	–	–	–	–	–	–	–
Total electric operating revenues [2]	$ 303,534	$ 294,572	$ 263,190	$ 258,937	$ 241,065	$ 238,801	$ 214,307	$ 204,934	$ 191,848	$ 176,812	$ 167,624
Electricity generated and purchased (000s of kWh):											
Steam	2,287,352	2,143,323	1,969,412	2,193,847	2,378,130	2,228,103	2,372,914	2,231,062	2,374,021	2,495,055	2,322,749
Hydro	58,118	45,430	53,635	51,132	86,349	70,631	77,578	62,860	71,302	83,556	102,673
Combustion turbine	816,343	943,924	790,993	455,678	520,340	439,517	211,872	162,679	170,479	51,358	39,532
Total generated	3,161,813	3,132,677	2,814,040	2,700,657	2,984,819	2,738,251	2,662,364	2,456,601	2,615,802	2,629,969	2,464,954
Purchased	2,112,879	2,520,421	2,092,955	2,255,076	1,686,782	1,970,348	1,839,833	1,968,898	1,540,816	1,394,470	1,443,410
Total generated and purchased	5,274,692	5,653,098	4,906,995	4,955,733	4,671,601	4,708,599	4,502,197	4,425,499	4,156,618	4,024,439	3,908,364
Interchange (net)	91	(69)	(264)	145	(138)	(1,894)	1,018	(1,087)	(5,851)	630	11,266
Total system input	5,274,783	5,653,029	4,906,731	4,955,878	4,671,463	4,706,705	4,503,215	4,424,412	4,150,767	4,025,069	3,919,630
Maximum hourly system demand (Kw)	1,041,000	987,000	1,001,000	993,000	979,000	916,000	876,000	842,000	815,000	741,000	739,000
Owned capacity (end of period) (Kw)	1,102,000	1,004,000	1,007,000	878,000	878,000	878,000	878,000	724,000	737,000	656,500	657,300
Annual load factor (%)	54.28	56.88	54.75	55.12	52.16	55.72	55.38	56.85	55.15	57.32	54.88
Electric sales (000s of kWh):											
Residential	1,728,315	1,726,449	1,681,085	1,660,928	1,509,176	1,548,630	1,429,787	1,440,512	1,350,340	1,264,721	1,248,482
Commercial	1,386,806	1,378,165	1,375,620	1,333,310	1,260,597	1,246,323	1,171,848	1,154,879	1,086,894	1,018,052	950,906
Industrial	1,058,730	1,027,446	1,004,899	1,015,779	988,114	960,783	943,287	923,730	859,017	827,067	760,737
Public authorities	102,338	101,188	100,125	96,403	99,739	98,675	101,122	95,652	90,543	86,463	83,239
Wholesale on-system	308,574	323,103	322,336	309,633	297,614	299,256	273,035	262,330	243,869	234,228	232,815
Total system	4,584,763	4,556,352	4,484,065	4,416,053	4,155,240	4,153,667	3,919,079	3,877,103	3,630,663	3,430,531	3,276,179
Wholesale off-system	324,622	735,154	105,975	161,293	198,234	235,391	253,060	219,814	213,590	304,554	366,729
Total electric sales	4,909,385	5,291,506	4,590,040	4,577,346	4,353,474	4,389,058	4,172,139	4,096,917	3,844,253	3,735,085	3,642,908
Company use (000s of kWh)	10,093	9,960	10,134	8,714	8,583	8,940	9,688	9,584	9,559	9,260	9,117
Lost and unaccounted for (000s of kWh)	355,305	351,563	306,557	369,818	309,406	308,707	321,388	317,911	296,955	280,724	267,605
Total system input	5,274,783	5,653,029	4,906,731	4,955,878	4,671,463	4,706,705	4,503,215	4,424,412	4,150,767	4,025,069	3,919,630
Customers (average number of monthly bills rendered):											
Residential	129,878	127,681	125,996	123,618	121,523	119,265	117,271	115,116	112,605	109,032	105,079
Commercial	23,077	22,858	22,670	22,504	22,206	21,774	21,323	20,758	20,098	19,175	18,447
Industrial	362	349	337	345	350	354	346	346	339	318	283
Public authorities	1,716	1,690	1,645	1,674	1,759	1,739	1,720	1,696	1,637	1,558	1,517
Wholesale on-system	5	7	7	7	7	7	7	7	7	7	7
Total system	155,038	152,585	150,655	148,148	145,845	143,139	140,667	137,923	134,686	130,090	125,333
Wholesale off-system	17	16	7	6	6	6	7	9	6	6	5
Total	155,055	152,601	150,662	148,154	145,851	143,145	140,674	137,932	134,692	130,096	125,338
Average annual sales per residential customer (kWh)	13,307	13,522	13,342	13,436	12,419	12,985	12,192	12,514	11,992	11,600	11,881
Average annual revenue per residential customer	$ 963.96	$ 936.21	$ 869.72	$ 878.29	$ 812.91	$ 843.22	$ 755.82	$ 747.19	$ 722.27	$ 660.14	$ 651.67
Average residential revenue per kWh	7.24¢	6.92¢	6.52¢	6.54¢	6.55¢	6.49¢	6.20¢	5.97¢	6.02¢	5.69¢	5.48¢
Average commercial revenue per kWh	6.53¢	6.21¢	5.91¢	5.82¢	5.85¢	5.76¢	5.54¢	5.35¢	5.38¢	5.31¢	5.29¢
Average industrial revenue per kWh	4.78¢	4.55¢	4.35¢	4.20¢	4.15¢	4.14¢	3.94¢	3.81¢	3.80¢	3.79¢	3.80¢

(1) See Selected Financial Data for additional financial information regarding Empire.
(2) Before intercompany eliminations.

FT8 peaking unit: Simple cycle combustion turbine powered by jet engine technology and used mainly for peaking and quick-start situations.

Capacity: The ability of a generating unit to produce power, typically expressed in kilowatts or megawatts.

Combined cycle: The combination of one or more gas turbines and steam turbines in an electric generation plant. As electricity is produced from the gas turbine, the heat exiting from the unit is routed to a heat-recovery steam generator and used by the steam turbine to produce more electricity. This process increases efficiency.

Combustion turbine (CT): A fuel-fired turbine engine used to drive an electric generator.

Corporate governance: The ways in which rights and responsibilities are shared between various corporate participants, shareholders, Board of Directors and Management.

Federal Energy Regulatory Commission (FERC): The United States agency that regulates interstate electricity and natural gas transactions.

Fuel adjustment clause: A provision in a rate schedule that provides for adjusting the amount of the bill as the cost of fuel varies from a specified base amount per unit.

GIS/OMS: Geospatial Information System and Outage Management System, an electronic map and computerized program for managing service to customers.

Interim Energy Charge (IEC): Effective October 2001 through December 2002, a charge approved by the Missouri Public Service Commission and added to customer bills in Missouri that allowed Empire to collect for fuel and purchased power costs above a base amount and below a ceiling amount, subject to refund.

Kilowatt-hour (kWh): The amount of electrical energy consumed when one thousand watts are used for one hour.

Merger: The combining of two or more organizations.

Non-regulated business: Those aspects of the company's business activities that are not regulated by FERC or state utility commissions.

Peak demand: The greatest amount of electricity supplied at a specific time.

Predetermination: Sometimes called "pre-approval," a regulatory commission's act of ascertaining beforehand, rather than after the project is completed, the prudency of the decision and potentially the portion of expenditures in a capital project that will be allowed into rate base.

Purchased power: Electricity bought by one utility from another producer instead of, or in addition to, generating power on its own.

Regulated business: Those aspects of the company's business that are regulated by FERC or state utility commissions.

Regional transmission organization (RTO): An association designed to control the wholesale transmission services of the utilities in their regions, thereby facilitating open and more competitive markets in bulk power. FERC Order No. 2000 establishes a framework for RTOs and provides economic incentives for utilities to participate in the timely formation of qualified RTOs.

Southwest Power Pool (SPP): A regional reliability coordinator of the North American Electric Reliability Council.

Substation: The place where high voltage power is received and reduced to a voltage level that can be distributed to neighborhoods or other end-users.

Transmission line: The network or system of cables used to move bulk or high voltage electricity from one point to another.

Volt: A measure of the force used to transmit electric power. A kilovolt (kV) equals one thousand volts.

Watt: A measure of the amount of electrical power that is generated or consumed. A kilowatt (kW) equals on thousand watts, a megawatt (mW) equals one million watts, and a gigawatt (gW) equals one billion watts.

Wholesale customer: An entity, such as a municipality or rural electric cooperative, that buys electricity from Empire for the purpose of reselling it to the ultimate customer.

Wholly-owned subsidiary: A separate corporation set up by a parent company and 100 percent owned by the parent corporation.

Vertically integrated electric utility: A company that follows the historically common arrangement of owning its own generating plants, transmission system, and distribution lines to provide all aspects of service.

CORPORATE INFORMATION

THE EMPIRE DISTRICT ELECTRIC COMPANY

Annual Meeting
The annual meeting of shareholders will be held Thursday, April 22, 2004, at 10:30 a.m. at the Holiday Inn, 3615 South Range Line, Joplin, Missouri.

Company Headquarters
The Empire District Electric Company
602 Joplin Street
P.O. Box 127
Joplin, Missouri 64802-0127
Telephone (417) 625-5100

Auditors
PricewaterhouseCoopers LLP
St. Louis, Missouri

Registrar, Transfer Agent, and Dividend Agent
Wells Fargo Bank, N.A.
Shareowner Services
P.O. Box 64854
St. Paul, Minnesota 55164-0854
(800) 468-9716 (toll free in the United States)
(651) 450-4144 (for the hearing impaired) (TDD)
(651) 450-4064 (outside the United States)
www.shareowneronline.com (for registered shareholders)
www.wellsfargo.com/shareownerservices (for general inquiries)

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

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

Stock Prices and Dividends

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

2002 Quarter	High	Low	Dividend Paid
First	21.99	20.28	$0.32
Second	21.78	18.72	$0.32
Third	20.30	15.90	$0.32
Fourth	19.12	15.06	$0.32

Credit Rating

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

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.

DIRECTORS AND OFFICERS

THE EMPIRE DISTRICT ELECTRIC COMPANY

DIRECTORS

Melvin F. (Nick) Chubb, Jr.
Retired Senior Vice President
Eagle-Picher Industries, Inc.
Cincinnati, Ohio
(Age 70, Director since 1991)

William L. Gipson
President and Chief Executive Officer
The Empire District Electric Company
Joplin, Missouri
(Age 47, Director since 2002)

Ross C. Hartley
Co-Founder and Director
NIC Inc.
Overland Park, Kansas
(Age 56, Director since 1988)

Francis E. Jefferies (1)
Retired Chairman
Phoenix Duff & Phelps Corporation
Chicago, Illinois
(Age 73, Director since 1984)

Robert L. Lamb
Retired President
The Empire District Electric Company
Joplin, Missouri
(Age 71, Director since 1978)

D. Randy Laney
Partner
Investlinc Group
Lowell, Arkansas
(Age 49, Director since 2003)

[illegible]
President
Missouri Southern [illegible]
Joplin, Missouri
(Age 65, Director [illegible])

Myron W. McKinney
Chairman of the Board of Directors
Retired President and Chief Executive [illegible]
The Empire District Electric Company
Joplin, Missouri
(Age 59, Director since 1991)

B. Thomas Mueller
Founder and President
SALOV North America Corporation
Hackensack, New Jersey
(Age 56, Director since 2003)

Mary McCleary Posner
President and Principal
Posner McCleary Inc.
Columbia, Missouri
(Age 64, Director since 1991)

Allan T. Thoms (2)
Wilk & Associates/LECG
San Francisco, California
(Age 65, Nominated on March 1, 2004)

(1) Retiring effective April 22, 2004
(2) Nominated for election April 22, 2004

COMMITTEES OF THE BOARD

Audit Committee -
Chubb, Hartley, Jefferies, Laney, Leon, Mu[illegible]
Compensation Committee -
Jefferies, Lamb, Laney, Posner
Executive Committee -
Gipson, Hartley, Lamb, Laney, Leon, McKinney
Nominating/Corporate Governance Committee -
Chubb, Laney, Leon, Mueller
Retirement Committee -
Gipson, Hartley, Lamb, McKinney

OFFICERS

William L. Gipson
President and Chief Executive Officer
(Age 47, 23 years of service)

Bradley P. Beecher
Vice President - Energy Supply
(Age 38, 14 years of service)

Ronald F. Gatz
Vice President - Strategic Development
(Age 53, 3 years of service)

David W. Gibson
Vice President - Regulatory and General Services
(Age 58, 24 years of service)

[illegible]
Vice President - Fina[illegible]
(Age 52, 24 years of service)

Michael E. Palmer
Vice President - Commercial Operations
(Age 47, 17 years of service)

Janet S. Watson
Secretary-Treasurer
(Age 51, 9 years of service)

Darryl L. Coit
Controller, Assistant Secretary and Assistant [illegible]
(Age 54, 33 years of service)

EMPIRE

www.empiredistrict.com

THE EMPIRE DISTRICT ELECTRIC COMPANY 602 Joplin Street | P.O. Box 127 Joplin, Missouri 64802-0127 Telephone (417) 625-5100