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True Blue

The Empire District Electric Company
2002 Annual Report to Shareholders


EMPIRE

True Blue

THE EMPIRE APPROACH

"True Blue is not so much an idealism as it is the belief that treating people right is just good business. It sets a high standard, one that Empire employees continually strive to meet. Their degree of success has been admirable."

Based in Joplin, Missouri, **The Empire District Electric Company** (NYSE:EDE) is an investor-owned utility providing electric service to approximately 154,000 customers in southwest Missouri, southeast Kansas, northeast Oklahoma, and northwest Arkansas. The Company also provides fiber optic and Internet services and has an investment in close-tolerance custom manufacturing. Empire provides water service in three incorporated communities in Missouri.

Founded in 1909, Empire is headquartered in Joplin, Missouri, and has been listed on the New York Stock Exchange since 1946. Empire has paid dividends continuously since 1944.

Financial Highlights

December 31,	*2002*	*2001*	*Change*
Operating Revenues	$ 305,903,000	$ 265,821,000	15.1%
Operating Income	$ 56,068,000	$ 43,212,000	29.8%
Net Income	$ 25,524,000	$ 10,403,000	145.4%
Earnings Per Average Common Share	$ 1.19	$ 0.59	101.7%
Dividends Paid	$ 1.28	$ 1.28	0.00%
Return on Common Equity	7.75%	3.88%	99.7%
Book Value Per Share of Common Stock	$ 14.28	$ 13.64	4.7%
Common Shares Outstanding	22,509,230	19,703,837	14.2%
Weighted Average Common Shares Outstanding	21,433,889	17,777,449	20.6%
Number of Common Shareholders (Year end)	25,988	23,701	9.7%
Total Construction Expenditures (including AFUDC)	$ 73,579,000	$ 77,316,000	-4.8%
Gross Plant	$1,108,045,000	$1,069,176,000	3.6%
On-System Sales (Mwh)	4,556,352	4,484,065	1.6%
Electric Customers (Year end)	154,170	151,734	1.6%
Total System Capability (Net MW)	1,166	1,169	-0.3%
System Peak Demand (Net MW)	987	1,001	-1.4%
Degree Days, Heating	4,183	3,704	12.9%
Degree Days, Cooling	1,638	1,628	0.6%

William L. Gipson
President and Chief Executive Officer

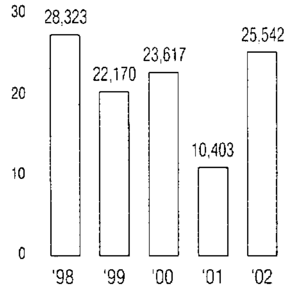
To Our Shareholders,

Your employees at Empire worked hard for you in 2002, and the following pages will show you the activities and achievements that have made your company a stronger one than a year ago.

Earnings for the year were $1.19 per share, which compares to $0.59 per share for 2001. Excluding all non-recurring charges, earnings were $1.24 per share compared to $0.66 for the prior year. A full discussion of financial results can be found in the Financial Review section of this report under "Management's Discussion and Analysis of Financial Condition and Results of Operations."

We're proud of what we achieved last year. As always, though, there's more work to be done. Our plan is in place; our sleeves are rolled up. Empire's activities in 2003 will be guided by the following key business strategies:

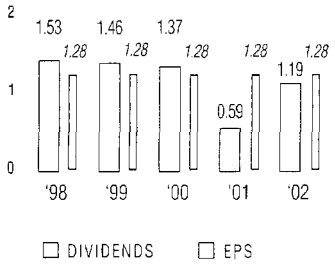
Net Income
Dollars in Thousands



Improve financial strength. Much was achieved in this area in 2002. Much is left to be done. We met a major goal by bringing our equity ratio to a respectable 44 percent. Nevertheless, Empire was one of many utilities that saw our credit ratings downgraded during the year. Our objective now is to improve our ratings, an ambitious goal for today's environment. We will focus our efforts on achieving this objective.

Diversify regulatory and weather risk. Two main factors beyond our direct control affect earnings – regulatory agencies and weather. To foster a more positive regulatory climate in Missouri, where we, in 2002, derived about 88 percent of our retail electric revenues, we've joined with other utilities to form the Missouri Energy Development Association. This group will work to ensure that regulators, legislators, the media, and

Earnings & Dividends Paid Per Common Share
Excluding merger related expenses



the general public get the information they need to make the best decisions on issues affecting your Empire investment. We had some success on the seasonality issue last year. In December, a smaller differential between summer and winter rates became effective as a result of our Missouri rate case settlement. The change is small, however, and we still have work to do.

Another way to minimize the negative impact from these elements is to add non-electric revenue sources. In 2001, we launched EDE Holdings, Inc., to build our line of non-regulated business, and through it we made small acquisitions in 2002 and early 2003. We're progressing toward a goal of adding a 5-10 percent cushion of earnings from EDE Holdings within 3-5 years. Our strategy here is cautious and conservative, and it will not change Empire's basic nature as a utility.

Assure appropriate corporate governance. Many of the reforms set forth in the Sarbanes-Oxley Act of 2002 and those proposed or enacted by the Securities and Exchange Commission (SEC) and the New York Stock Exchange (NYSE) reflect practices that Empire has long followed. Where a change or further implementation is necessary, we are prepared to meet all timelines for reform approved by the SEC and NYSE.

Actively manage fuel procurement and associated risk. We operate largely without benefit of fuel adjustment clauses, and fuel and purchased power make up a very large portion of our costs, historically comprising half or more of total electric expenses. This means that fluctuations in these costs can significantly impact earnings. Our procurement strategy has been very successful in leveling natural gas costs for us, and our coal costs have remained fairly steady. We will continue to employ this same strategy.

Implement productivity enhancements/new technologies. We are currently installing new Geospatial Information and Outage Management Systems. The technologies contained in these systems will transform the way we do business with our customers and will do so while keeping our rates competitive. We expect to complete the project by late 2003 or early 2004.

Determine long-term capacity and energy solution. We will bring new FT8 peaking units online at the Energy Center in the spring of 2003. This expansion should fill our capacity needs until about 2007. For the longer term, we are evaluating a number of energy supply options. We will carefully watch legislative, regulatory, and financial market issues as we weigh our next move.

Assure environmental/security compliance. One uncertainty for 2003 and beyond lies with the outcome of emissions legislation. We support sensible legislation that affords us the opportunity to protect the environment without imposing unduly burdensome costs. We understand that we safeguard our shareholders' assets by staying in compliance with state and federal regulations. We will continue to diligently meet this responsibility as new legislation and regulations are put in place.

Influence/comply with structural changes in the industry. In addition to environmental and security legislation, we are following other developments that affect our shareholders' investment, the most prominent of which lately is the redesign of wholesale markets. We will remain engaged in these issues and work to influence their outcomes.

Redesign management development/succession planning. Preparation of leaders for our future is essential. In 2003, we will place high priority on upgrading our program to prepare the next generation of Empire leaders.

Transitions. Mr. Roy E. Mayes and Mr. R. Dwain Hammons retired from our Board of Directors in 2002, and Mr. Jack R. Herschend has announced that he will not stand for re-election to the Board in 2003. These men have given generously of their time and talents and have provided us with invaluable counsel and leadership. They will be missed.

Newly appointed to our Board is Mr. B. Thomas Mueller, founder and President of SALOV North America Corporation, Hackensack, New Jersey. Mr. Mueller will stand for election at this year's shareholders' meeting. Also standing for election will be Mr. D. Randy Laney, co-founder and Chairman of Mercari Technologies of Fayetteville, Arkansas, and co-founder and partner in Bentonville Associates Ventures of Lowell, Arkansas.

On the management side, my colleague and predecessor Mr. Myron W. McKinney retired as Empire's President and Chief Executive Officer last April after more than 34 years of service to your Company. He was named Chairman of the Board of Directors effective May 1, 2002. We are fortunate to retain the benefit of his expertise and experience.

Mr. C.A. (Tony) Stark, Vice President – General Services, also retired in 2002 after 22 years with us. We thank him for his contributions to our organization and wish him good health and happiness.

We've chosen the theme *"True Blue"* for this year's report. It's as apt a description of the Empire approach as I've seen. True Blue is not so much an idealism as it is the belief that treating people right is just good business. It sets a high standard, one that Empire employees continually strive to meet. Their degree of success has been admirable.

My co-workers and I pledge to continue our commitment to shareholders and customers and to preserve and nurture an Empire that is hard working, honest, and dedicated to excellence. We thank you for your investment.

Bill Gipson

William L. Gipson
President and Chief Executive Officer

True Blue

SECTION 1

Empire has been serving the heart of the nation with electric power since 1909 and paying dividends to investors every quarter since 1944. That's 93 years of service and 232 consecutive quarters of dividends.

☐ **Duane Zerr**, **Bill Kelley** and **Bruce Andrews** lead the skilled team at our Riverton Power Plant. Riverton's 2002 forced outage rate of less than 3 percent handily beat the 5 percent national average.

True Blue is honesty.

It's Reliability.

True Blue means working to add shareholder value. Always. Amid the turmoil that marked our industry in 2002, Empire stuck to the approach that's been working for years — *we developed a common-sense business plan and followed it.*

Our number one goal was to improve our financial strength. We had begun 2001 in a weakened financial state, and throughout that year we reset the building blocks of our organization. In 2002, we continued the process of shoring up our foundation. We ended the year once again on solid ground. Our success came primarily through tackling the key financial factors that drive our core electric business.

Controlling fuel prices. Fuel and purchased power typically make up about half of our electric operating expenses, so volatility in fuel prices, particularly natural gas, can bring significant unpredictability to our bottom line. To help stabilize natural gas expenses, we follow a strategy that incorporates both physical purchases and financial tools. Under this approach, we hedge future natural gas needs over time under predetermined guidelines, but do not engage in any speculative trading.

It's working for us. Fuel and purchased power costs fell 13.8 percent in 2002. Our strategy allows us to more prudently manage our business and should establish a more predictable basis for fuel costs in future rate case proceedings.

Pursuing rate relief. Regulatory solutions play a crucial role in our financial strength. We aggressively seek regulatory rate relief whenever such relief is justified.

Our assertive approach has been effective because we temper it in two ways. We stay committed to balancing reasonable rates of return for shareholders with fair rates for our customers, and we strive for good working relationships with regulatory authorities. During 2002, we were granted approximately $14 million in annual rate relief. Over the past two years, that amount has totaled nearly $31 million.

2002 KEY ACTIVITIES

PUTTING BALANCE BACK INTO OUR BALANCE SHEET

Successes in 2002 included improvements in our equity to total capitalization ratio and our overall financial strength.

Recent financing activities played a key role in our achievement.

□ We initiated a new $100 million, six-bank syndicate, 370-day revolving credit facility in May which does not contain rating agency default triggers.

□ On May 22, we sold 2.5 million shares of newly issued common stock in an underwritten public offering. Net proceeds of $49.4 million were used to repay outstanding debt, including the retirement of $37.5 million in long-term debt.

□ On December 23, we sold to the public, in an underwritten offering, $50 million aggregate principal amount of our 7.05% Senior Notes due 2022. Net proceeds of approximately $48.6 million were added to our general funds and were used to repay short-term debt.

These activities over the past two years also contributed.

Over the past two years:

□ We finalized rate cases with new rates totaling about $31 million over the old rates.

□ We obtained regulatory approval for the Interim Energy Charge (IEC), effective October 2001 through December 2002, which protected both customers and shareholders by allowing us to recover prudently incurred actual fuel and purchased power costs.

□ We implemented a natural gas procurement strategy that is designed to protect the company and our customers from price volatility. Successes in reducing and stabilizing fuel and purchased power costs allowed us to refund IEC moneys to customers in March 2003.

□ We strategically reduced field operations personnel by 10%.

HIGHLIGHTS OF THE 2002 RATE CASE ACTIVITY

□ Missouri Electric general case, an $11 million annual increase, or 4.97 percent, granted effective December 1

□ Missouri Water general case, a $358,000 annual increase, or 33.7 percent, granted effective December 23

□ Kansas Electric general case, a $2.5 million annual increase, or 17.9 percent, granted effective July 1

Further explanation of Company activities in 2002 can be found in the Financial Review section of this report under "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Taking a proactive approach. Because regulatory authorities and legislative issues present unique challenges for our industry, Empire joined with Missouri's other investor-owned electric and natural gas companies in October 2002 to create the Missouri Energy Development Association (MEDA). Based in Jefferson City, Missouri, MEDA will serve as an industry voice on legislative and regulatory issues. Empire President and CEO Bill Gipson is Chairman of MEDA's Board of Directors.

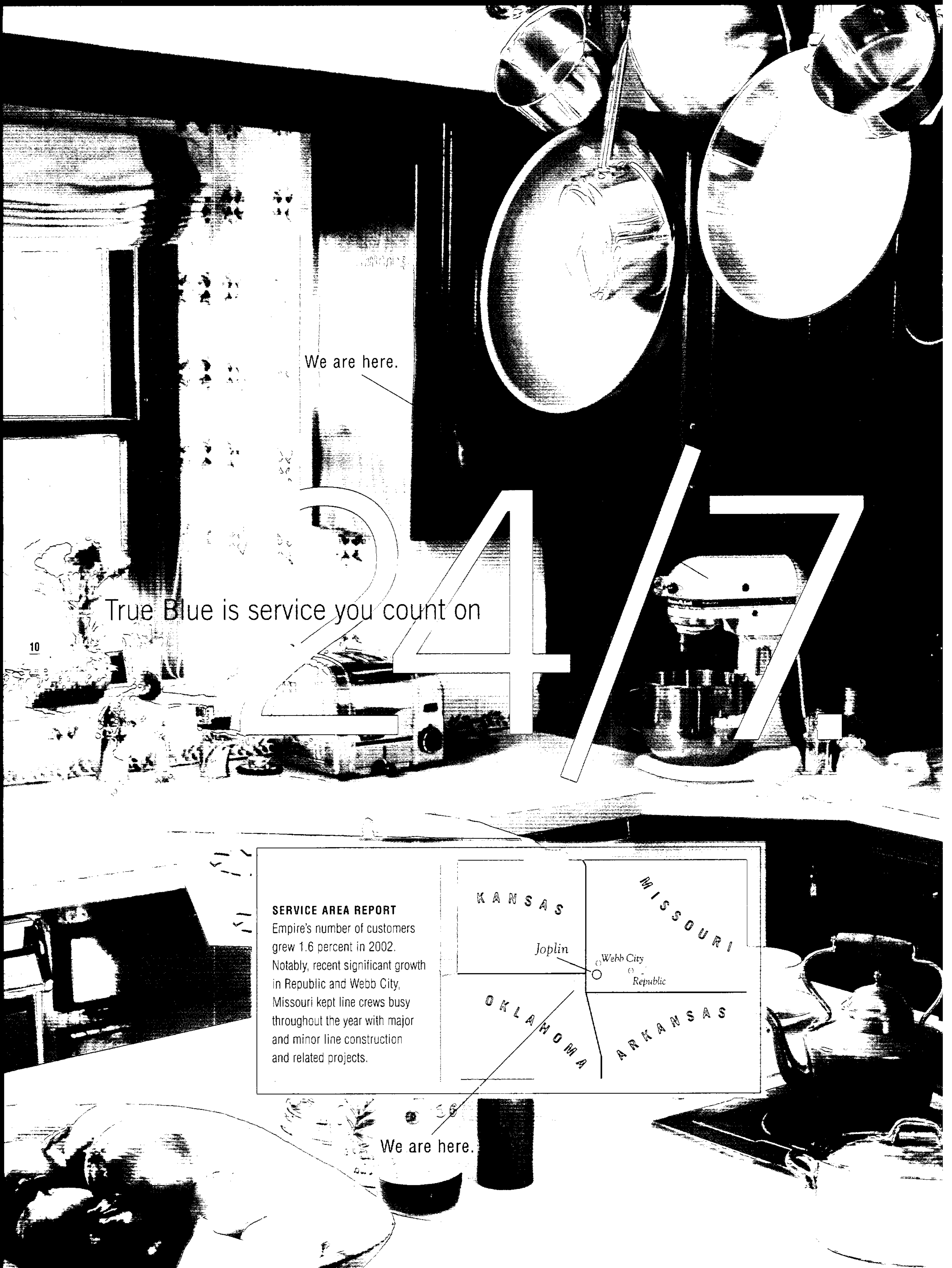
Being proactive sometimes means facing setbacks head on. One of our biggest disappointments last year came when Standard & Poor's downgraded its ratings of our First Mortgage Bonds from A- to BBB and of our unsecured debt from BBB+ to BBB-. At the same time, the outlook was revised from negative to stable. Ratings from Moody's Investor Service remained unchanged. Empire's credit rating remains solid investment grade, but we have placed the goal of improving our credit ratings high among our priorities.

Our proactive approach also includes seizing opportunities through our wholly owned subsidiary, EDE Holdings, Inc. 2002 marked the first full year for its line of non-regulated products and services. A full discussion of these activities is included in "Management's Discussion and Analysis of Operations."

True Blue

SECTION 2

True Blue means working for customers. Empire's customer satisfaction has stayed high. A recent survey of residential customers found that over 90% judged our service reliable and dependable. Last year we took steps to ensure they stay satisfied. We are combining the latest technology with a skilled and dedicated workforce. This will help keep the power on and rates competitive as our service territory continues to grow.



True Blue is service you count on 24/7

SERVICE AREA REPORT
Empire's number of customers grew 1.6 percent in 2002. Notably, recent significant growth in Republic and Webb City, Missouri kept line crews busy throughout the year with major and minor line construction and related projects.

Technology brings efficiencies to meeting future demand. Construction for the $55 million addition of two 50-megawatt FT8 peaking units began at the Energy Center during the summer months. FT8s use jet engine technology to produce efficient power with very low emissions when fueled by natural gas. We gained additional efficiencies in the construction by using the existing Energy Center site and some of its current infrastructure. The units are expected to be fully online by spring 2003. They will be our most efficient simple-cycle generating units.

Technology equals productivity. The State Line Combined Cycle Unit, our newest generating plant, was named one of the five lowest-cost providers of combined-cycle generation in the nation by *Power* magazine in 2002. And recent technological improvements at Asbury, like the new digital control system, helped employees set the Plant's second-longest continuous run record in its 30-year history.

Ozark Beach employees replaced two of the hydro facility's water wheels and, in the process, gave the units complete maintenance overhauls. The new wheels have an enhanced design that allows an almost 20 percent increase in output. We'll replace the remaining two wheels over the next two years.

Coming soon: GIS/OMS. One of our most exciting projects-in-progress is the installation of the Geospatial Information System and Outage Management System (GIS/OMS), an electronic map and computerized program that will form the centerpiece of a new, more integrated approach to managing service to our customers. These technologies will provide avenues for significant new efficiencies in functions as diverse as dispatching our service crews, engineering our lines, and targeting our budget dollars. The GIS/OMS is scheduled for launch in late 2003 or early 2004.

We are here.

We are here.

June Thompson, Empire customer and employee. She works at the Ozark Call Center, which operates in coordination with the Joplin facility. In 2002, 81 percent of all customer calls were answered in 30 seconds or less.

True Blue

SECTION 3

We show True Blue every day with the dedication we bring to our communities. We live in the same communities we serve. Keeping them healthy and strong is a personal issue as well as being good for business.

■ **George Thullesen** and **Bob Bromley** implemented a new program that gathers old tires and recycles them into fuel for the Asbury Plant.

Empire is lending a helping hand to the environment through a new Asbury program to burn tire-derived fuel (TDF). TDF is a fuel source made by recycling tire products. Asbury's controlled conditions and continuous emission monitoring system ensure that TDF is environmentally safe.

Plans call for burning up to 10,000 tons of TDF each year, about 1-2 percent of Asbury's total fuel. Our experts estimate that 10,000 tons is equal to just about one million scrap tires.

True Blue is about giving green. We've been helping local communities stay strong ever since we established our first formal economic development program in 1946. Fifty-six years later, we continue to play active roles in the communities we serve. Last year Empire donated an unused tract of land to a Neosho, Missouri not-for-profit development organization that has served the community for over 50 years. And the Joplin Area Chamber of Commerce named Empire its 2002 Industry of the Year, citing contributions toward the success of the local economy.

And True Blue is neighbors helping neighbors. Empire employees and retirees are highly valued by local charities for our volunteer spirit. We raised more than $120,000 for area United Way organizations during 2002 and gave our talents and resources to area schools, providing school supplies, judging science contests, and reading to children. And last year we celebrated the 20th anniversary of Project Help, a joint program with the American Red Cross that has distributed over $570,000 in assistance to the elderly and handicapped for meeting emergency, energy-related needs.

True Blue is being green.

[A] **Rick Wallace** oversaw mapping activities for the GIS/OMS project.

[B] **Kale Bailey** and 30 fellow employees helped a neighboring utility restore power in Kansas City after a January 31 ice storm.

[C] **Amy Miller** helped implement accounting procedures to reflect our new, non-regulated business.

[D] **John Donaldson** engineered two new 69 Kv transmission lines to serve growing customer needs.

We are True Blue.

We – the employees – are a crucial and unique component of True Blue. We are Empire shareholders. We are Empire customers. As such, we work for ourselves when we work for investors and customers. This year we met one of our most important goals when we hit the one-million manhours mark without a lost-time injury. Working safely is one more way we protect shareholder assets and maintain competitively priced service. True Blue. It's Empire's commitment to shareholders and customers. It's a commitment we've been living up to for a long time now.

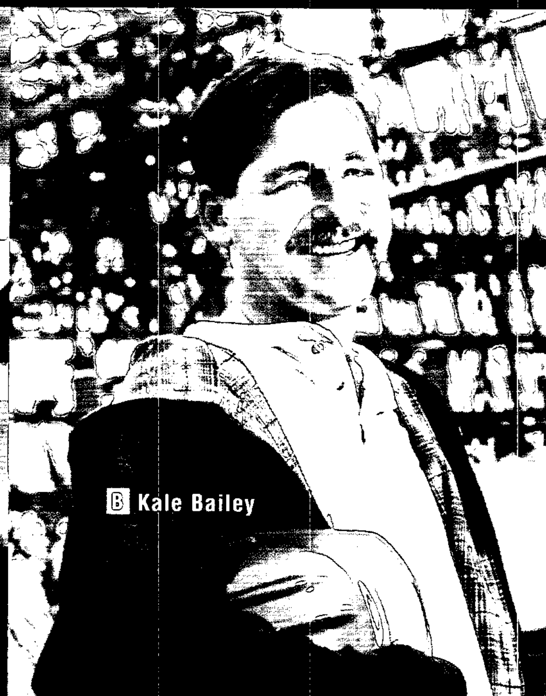
[E] **Rick Sprenkle** operates the Mini-Derrick, a small, multi-purpose utility vehicle that saves time, manpower, and clean up.

[F] **Jay Lewis** was 2002 Water Operator of the Year for the Missouri Water and Wastewater Association.

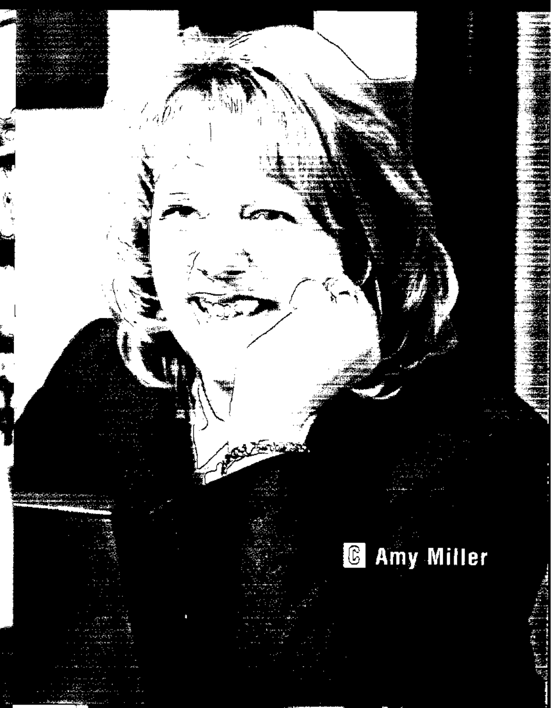
[G] **Dave Russow** installed the Company's new telephone system.

[H] **Katie Barton** is part of the team that implements our natural gas procurement strategy.

Rick Wallace

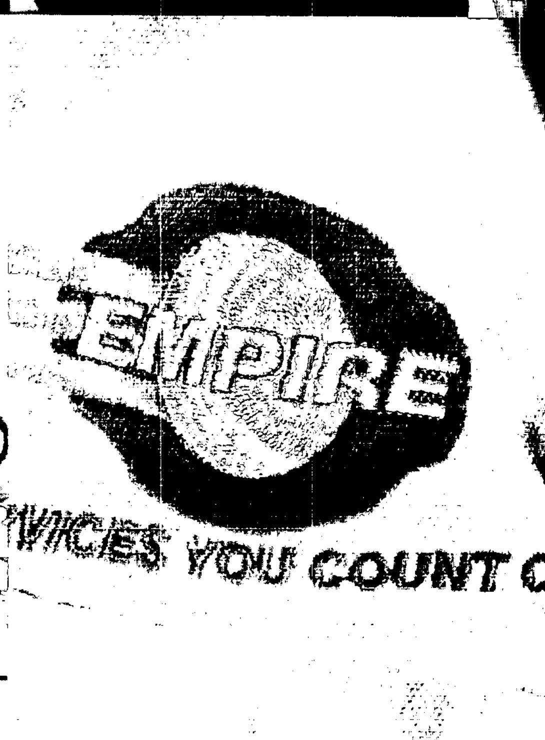


B Kale Bailey



C Amy Miller

John Donaldson



E Rick Sprenkle

Jay Lewis

G Dave Russow

H Katie Barton

Melvin F. (Nick) Chubb, Jr.
Retired Senior Vice President
Eagle-Picher Industries, Inc.
Cincinnati, Ohio
(Age 69, Director since 1991)

William L. Gipson [1]
President and Chief Executive Officer
The Empire District Electric Company
Joplin, Missouri
(Age 46, Director since 2002)

Ross C. Hartley
Co-Founder and Director
NIC Inc.
Overland Park, Kansas
(Age 55, Director since 1988)

Jack R. Herschend [2]
Chairman emeritus of the Board and Co-Owner
Silver Dollar City, Inc.
Branson, Missouri
(Age 70, Director since 1994)

Francis E. Jeffries
Retired Chairman
Phoenix Duff & Phelps Corporation
Chicago, Illinois
(Age 72, Director since 1984)

Robert L. Lamb
Retired President
The Empire District Electric Company
Joplin, Missouri
(Age 70, Director since 1978)

D. Randy Laney [3]
Co-Founder and Chairman
Mercari Technologies
Fayetteville, Arkansas
and Co-Founder and Partner
Bentonville Associates Ventures
Lowell, Arkansas
(Age 48, Nominated on December 30, 2002)

Dr. Julio S. Leon
President
Missouri Southern State College
Joplin, Missouri
(Age 64, Director since 2001)

Myron W. McKinney [4]
Chairman of the Board of Directors
Retired President and Chief Executive Officer
The Empire District Electric Company
Joplin, Missouri
(Age 58, Director Since 1991)

B. Thomas Mueller
Founder and President
SALOV North America Corporation
Hackensack, New Jersey
(Age 55, Appointed effective January 1, 2003)

Mary McCleary Posner
President and Principal
Posner McCleary Inc.
Columbia, Missouri
(Age 63, Director since 1991)

Committees of the Board

Audit Committee — Chubb; Hartley; Jeffries; Leon; Mueller; Posner

Compensation Committee — Herschend; Jeffries; Lamb; Posner

Executive Committee — Gipson; Hartley; Lamb, Leon; McKinney

Nominating / Corporate Governance Committee — Chubb; Herschend

Retirement Committee — Hartley; Lamb; Leon

[1] Elected April 25, 2002; President and CEO effective May 1, 2002.

[2] Retiring effective April 24, 2003

[3] Nominated for election April 24, 2003.

[4] Retired as President and CEO on April 30, 2002, and became Chairman of the Board of Directors effective May 1, 2002.

Directors positioned left to right. Top row: Julio Leon, Ross Hartley, Nick Chubb, Bob Lamb, Randy Laney, Tom Mueller, Bottom row: Myron McKinney, Bill Gipson, Mary Posner, Francis Jeffries.

Officers positioned left to right. Top row: Mike Palmer, Greg Knapp, Darryl Coit, Jan Watson, Dave Gibson. Bottom row: Bill Gipson, Brad Beecher, Ron Gatz.

William L. Gipson [1]
President and Chief Executive Officer
(Age 46, 22 years of service)

Bradley P. Beecher
Vice President – Energy Supply
(Age 37, 13 years of service)

Ronald F. Gatz
Vice President – Strategic Development
(Age 52, 2 years of service)

David W. Gibson [2]
Vice President – Regulatory
and General Services
(Age 57, 23 years of service)

Gregory A. Knapp [3]
Vice President – Finance
and Chief Financial Officer
(Age 51, 23 years of service)

Michael E. Palmer
Vice President – Commercial Operations
(Age 46, 16 years of service)

Janet S. Watson
Secretary – Treasurer
(Age 50, 8 years of service)

Darryl L. Coit
Controller, Assistant Secretary
and Assistant Treasurer
(Age 53, 32 years of service)

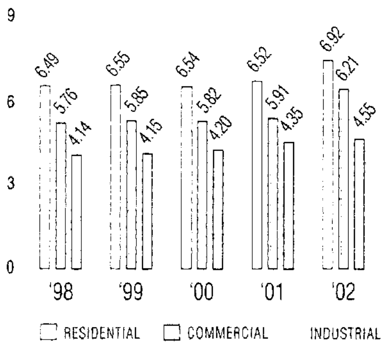
[1] *Effective May 1, 2002.* Previously Executive Vice President and COO.

[2] *Effective July 1, 2002.* Previously Vice President – Regulatory Services and Vice President – Finance and Chief Financial Officer.

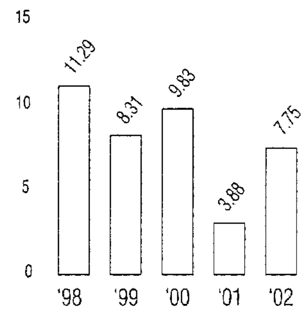
[3] *Effective March 15, 2002.* Previously General Manager – Finance.

Financial Statements

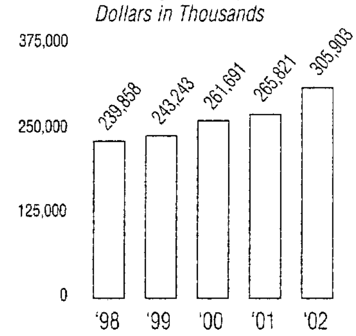
Average Rates
Cents per Kilowatt-hour



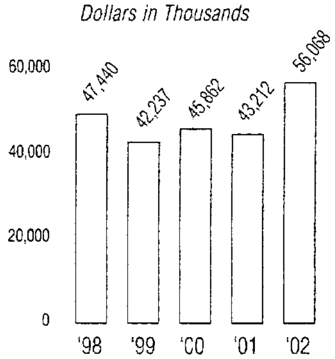
Return on Common Equity
Percent



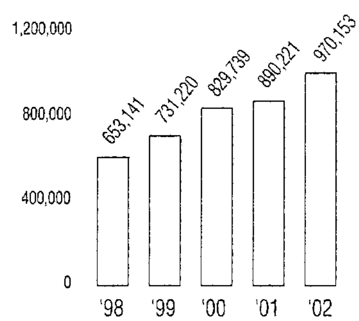
Total Operating Revenue
Including Non-Regulated
Dollars in Thousands



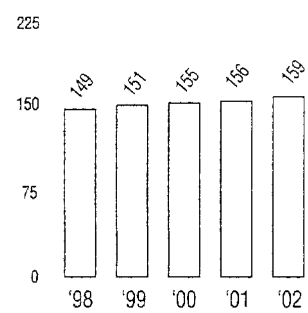
Operating Income
Dollars in Thousands



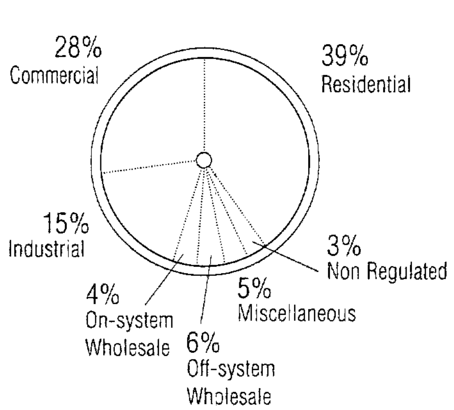
Total Assets
Dollars in Thousands



Electric & Water Utility Customers
Thousands



2002 Sources of Total Revenue



RESULTS OF OPERATIONS

The following discussion analyzes significant changes in the results of operations for 2002, compared to 2001, and for 2001, compared to 2000.

Operating Revenues and Kilowatt-Hour Sales.

Of our total electric operating revenues during 2002, approximately 41% were from residential customers, 29% from commercial customers, 16% from industrial customers, 4% from wholesale on-system customers, 5.5% from wholesale off-system transactions and 4.5% from miscellaneous sources such as transmission services and late payment fees. The percentage changes from the prior year in on-system kilowatt-hour (Kwh) sales and revenue by major electric customer class were as follows:

	On-System			
	Kwh Sales		*Revenues*	
	2002	*2001*	**2002*	**2001*
Residential	2.7%	1.2%	9.1%	0.7%
Commercial	0.2	3.2	5.2	4.4
Industrial	2.2	(1.1)	7.0	1.9
Wholesale On-System	0.2	4.1	(8.1)	10.0
Total On-System	1.6	1.6	6.6	2.6

**Revenues excluding portion of the Interim Energy Charge that is refundable to customers. See discussion below.*

On-System Transactions. Kwh sales for our on-system customers increased during 2002 primarily due to cooler temperatures in April and the fourth quarter (during our heating seasons) and warmer temperatures in June and September (during our air conditioning season) as compared to the same periods in 2001. Revenues for our on-system customers increased primarily as a result of the increased sales and the Missouri and Kansas rate increases discussed below. Our customer growth was 1.60% in 2002 and 1.13% in 2001. We expect our annual customer growth to be 1.4% over the next several years.

The increases in residential and commercial Kwh sales in 2002 were due primarily to the weather conditions 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 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.

On-system wholesale Kwh sales increased 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. This clause permits the pass through to customers of changes in fuel and purchased power costs, which are discussed further below.

Kwh sales and revenues for our on-system customers increased during 2001 as compared to 2000, primarily due to unseasonably cold temperatures in the first quarter of 2001 and warmer temperatures during the second quarter of 2001, offset by milder temperatures in the last two quarters of 2001. Residential and commercial Kwh sales and revenues increased compared to 2000 due to these weather conditions as well as increases in business activity throughout our service territory. Industrial Kwh sales for 2001 decreased due to a general slowdown in economic activity by the manufacturing sector in our service territory during the third and fourth quarters of 2001. Revenues in these classes were favorably impacted by the October 2001 Missouri rate increase.

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

Our future revenues from the sale of electricity will continue to be affected by economic conditions, weather, business activities, competition, fuel costs, changes in electric rate levels, customer growth and changes in patterns of electric energy use by customers and our ability to receive adequate and timely rate relief.

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 Requested*	*Annual Increase Granted*	*Percent Increase Granted*	*Date Effective*
Missouri - Electric	11-03-00	$ 41,467,926	$ 17,100,000	8.40%	10-02-01
Missouri - Electric	03-08-02	19,779,916	11,000,000	4.97%	12-01-02
Missouri - Water	05-15-02	361,000	358,000	33.70%	12-23-02
Kansas - Electric	12-28-01	3,239,744	2,539,000	17.87%	07-01-02

On November 3, 2000, we filed a request with the Missouri Commission for a general annual increase in base rates for our Missouri electric customers in the amount of $41,467,926, or 19.36%. The Missouri Commission issued a final order on September 20, 2001 granting us an annual increase in rates of approximately $17.1 million, or 8.4%, effective October 2, 2001. In addition, the order approved an annual Interim Energy Charge, or IEC, of approximately $19.6 million effective October 1, 2001 and expiring two years later. This IEC was collected subject to refund (with interest) at the end of the two year period to the extent money was collected from customers above the greater of the actual and prudently incurred costs or the base cost of fuel and purchased power set in rates.

On March 8, 2002, we filed a request with the Missouri Commission for an annual increase in base rates for our Missouri electric customers in the amount of $19,779,916 and also asked to have the IEC put into effect in the last rate case reconfigured to reflect a decrease of $9,994,888 in the amount to be billed to customers. The reconfigured IEC would remain subject to refund with interest. This request sought to recover new operating costs and obligations and reflect the changes in our capital structure since the rate increase in October 2001. Also on March 8, 2002, we filed an interim rate case for an annual increase in base rates of $3,562,983, the amount that was erroneously omitted from the increase granted in our 2001 rate case. The Missouri Commission rejected the interim request. After extensive negotiations with the Missouri Commission staff, Office of Public Counsel and other intervening parties, we filed a Unanimous Stipulation and Agreement Regarding "Error" in the 2001 rate case and an Immediate Reduction of the IEC with the Missouri Commission on May 14, 2002. This agreement was approved by the Missouri Commission on June 4, 2002 and provided for a $7 million annual reduction in the IEC.

On October 29, 2002, we filed a Unanimous Stipulation and Agreement, agreed to by the Missouri Commission staff, Office of Public Counsel and other intervening parties, with the Missouri Commission. This Agreement was approved by the Missouri Commission on November 22, 2002 and settled all matters covered by our March 2002 filings, provided us with an annual increase in rates of approximately $11.0 million, or 4.97%, effective December 1, 2002 and eliminated the IEC as of that date. The Agreement also calls for us to refund all funds collected under the IEC, with interest, by March 15, 2003.

At December 31, 2002, we had recorded a current liability of approximately $18.7 million for such rate refunds. We collected $2.8 million in 2001 and recorded $0.75 million as revenue. We collected $15.9 million in 2002 and recorded a revenue reduction of ($0.75) million associated with the revenue recognized in 2001 because it became certain that the entire amount of IEC revenues collected would be refunded. As a result, we have recognized no revenue in the aggregate for combined 2001 and 2002 associated with the IEC collections. The remainder of the funds collected in 2001 and 2002 were set aside as a provision for rate refunds and not recognized in operating revenue. As a result of the non-recognition of these funds, the refunds have already been reflected in our results (except for $0.3 million of interest) and will have no material impact on our earnings in 2003. The Agreement also provided for a change to the summer/winter rate differential for our residential customers with the new rates reflecting a smaller differential between summer and winter rates for usage above 600 kilowatt hours. Each of the parties to the Agreement also agreed not to file a new request for a general rate increase or decrease before September 1, 2003, barring any unforeseen, extraordinary occurrences.

On May 15, 2002, we filed a request with the Missouri Commission for an annual increase in base rates for our Missouri water customers in the amount of approximately $361,000, or 33.9%. This was the first requested increase in rates for our water customers since 1994. On November 7, 2002, we filed an Agreement Regarding Disposition of a Small Company Rate Increase Request, agreed to by the Commission staff, with the Missouri Commission. This agreement was approved by the Missouri Commission effective December 23, 2002 and provides us with an annual increase in rates of approximately $358,000, or 33.7%.

On December 28, 2001, we filed a request with the Kansas Corporation Commission (KCC) for an annual increase in base rates for our Kansas electric customers in the amount of $3,239,744, or 22.81%. This request sought to recover costs associated with our investment in State Line Unit No. 1, State Line Unit No. 2 and the State Line Combined Cycle Unit (SLCC), as well as significant additions to our transmission and distribution systems and operating cost increases which had occurred since our last rate increase in September 1994. We also requested reinstatement of a fuel adjustment clause for our Kansas rates. We filed a Unanimous Stipulation and Agreement, agreed to by the KCC staff and all intervening parties, with the KCC on June 7, 2002. The agreement stipulates that we will not file for general rate relief before November 1, 2003 barring any unforeseen, extraordinary occurrences. This agreement was approved by the KCC on June 27, 2002 providing us an annual increase in rates of approximately $2,539,000, or 17.87%, effective July 1, 2002. It did not provide for the reinstatement of a fuel adjustment clause.

On March 4, 2003, we filed a request with the Oklahoma Corporate Commission for an annual increase in base rates for our Oklahoma electric customers in the amount of $954,540, or 12.97%.

We are currently discussing an increase in rates with our on-system wholesale electric customers, and will make a FERC rate filing in 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 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. During 2002 revenues from such off-system transactions were approximately $25.4 million as compared to approximately $7.5 million in 2001 and approximately $10.6 million during 2000. 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 term purchases of firm energy during 2002 which, when not required to meet our own customers' needs, could be sold in the wholesale market. Revenues for 2001 were less than for 2000 primarily because of our peak hour market-based rates being substantially lower during the summer months of 2001 than in 2000 and milder regional weather conditions in the fourth quarter of 2001 affecting demand. See "- Competition" below.

Operating Revenue Deductions

During 2002, total operating expenses increased approximately $11.8 million (7.4%) compared to the prior year. 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 primarily reflecting 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 is a result of a combination of lower commodity prices during 2002 and our natural gas procurement program.

Expenses relating to the proposed merger with Aquila, Inc., formerly UtiliCorp United Inc. (which was terminated by UtiliCorp on January 2, 2001) 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 2 to "Notes to Financial Statements" for more information on the terminated merger. 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. We anticipate significantly lower pension income in 2003. Expense related to our non-regulated businesses increased approximately $10.4 million during 2002 as compared to 2001. See "- Non-regulated Items" below for more information. 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 10 of "Notes to Financial Statements" under Item 8 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.

During 2001, total operating expenses increased approximately $10.0 million (6.8%) compared to the prior year. Total purchased power costs decreased by approximately $2.9 million (4.4%) during 2001 reflecting both the decreased demand in the third and fourth quarters resulting from milder temperatures and the increased generating capability due to the completion of the SLCC. Total fuel costs were up approximately $7.6 million (15.6%) during 2001 as compared to 2000 primarily reflecting the higher cost of natural gas, increased generation from the SLCC in the third and fourth quarters and less coal generation due to our Asbury Plant being out of service for scheduled and unscheduled repairs and maintenance during 13 weeks late in the year. Natural gas prices (on a per MMBtu basis) were higher by 35.9% during 2001 as compared to 2000.

Merger related expenses were $1.4 million during 2001 as compared to $0.3 million in 2000. Other operating expenses increased approximately $4.2 million (12.8%) during 2001 primarily due to an actuarially determined adjustment to our fully-funded pension benefit expense in the first quarter of 2001, decreased income of approximately $2.5 million from the pension fund caused by a decline in the value of invested funds during 2001 and additions to the bad debt reserve of approximately $0.7 million during 2001. Maintenance and repairs expense increased approximately $4.3 million (29.1%) during 2001 primarily due to initial operation of the SLCC and subsequent payments under our long-term maintenance contracts entered into in July 2001 for the SLCC combustion turbines.

Depreciation and amortization expense increased approximately $1.7 million (6.0%) during 2001 due to increased levels of plant and equipment placed in service. This increase was partially offset by lower depreciation rates put into effect during the fourth quarter of 2001 as a result of the October Missouri rate order. Total provision for income taxes decreased approximately $9.7 million (85.3%) during 2001 due primarily to lower taxable income and by the deductibility in 2001 of approximately $6.1 million in merger related expenses discussed above. Other taxes increased approximately $0.4 million (3.4%) during the year.

Non-regulated Items

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. 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 consolidation of the financial statements of Mid-America Precision Products, LLC (MAPP), which was acquired in July 2002. MAPP specializes in close-tolerance custom manufacturing for the aerospace, electronics, telecommunications and machinery industries, including components for specialized batteries for Eagle Picher Technologies. The increase in expense was also due to the activities of our wholly owned subsidiary, Conversant, Inc., a software company that began business in early 2002. Conversant markets the Internet-based customer information system software formerly named Centurion that was developed by Empire employees. 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 are merging Transaeris and Joplin.com into one company named Fast Freedom, Inc. We began investing in non-regulated businesses in 1996 and now lease capacity on our fiber optics network and provide Internet access, utility industry technical training, close-tolerance custom manufacturing, surge suppressors and other energy services through our wholly owned subsidiary, EDE Holdings, Inc. See Item 1, "Business - General" for further information about these non-regulated businesses.

Nonoperating Items

Total allowance for funds used during construction (AFUDC) decreased $3.0 million in 2002 and $2.2 million in 2001 reflecting the completion of the SLCC in June 2001. See Note 1 of "Notes to Financial Statements" under Item 8.

Other-net deductions decreased $1.5 million (145.8%) during 2002 primarily reflecting a $1.2 million unrealized gain on derivatives in December 2002 as compared to a $0.4 million loss in the second and third quarters of 2001. This loss was caused by the marking to market, required by Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" of option contracts entered into in connection with our hedging activities that did not qualify for hedge accounting. The $1.2 million unrealized gain on derivatives resulted from anticipated natural gas usage that was financially hedged but no longer necessary because we were able to purchase power in the wholesale market more economically than generating it ourselves. As a result of our use of derivatives to manage our gas commodity risk and our exposure to gas and purchased power cost volatility (including hedging) and the use of mark-to-market accounting, revenues and earnings may fluctuate. Although our purpose is to minimize our risk from volatile natural gas prices and protect earnings, 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.

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 the 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 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. Total interest charges on long-term debt were virtually the same for 2001 as for 2000. Commercial paper interest decreased $1.5 million (68.0%) during 2002 reflecting decreased usage of short-term debt as well as lower interest rates. Interest related to our Trust Preferred Securities issued on March 1, 2001 increased $0.7 million (20.0%) during 2002 reflecting twelve months of interest as compared to the ten months in 2001. Interest income decreased $0.1 million (56.2%), reflecting the lower interest rates.

Other Comprehensive Income

The change in the fair market value of open contracts related to our gas procurement program and the amount of the contracts settled during the period 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 in Accumulated Other Comprehensive Income in the capitalization section of our balance sheet and does not affect earnings per share. The unrealized gains and losses accumulated in comprehensive income are reclassified to fuel expense in the periods in which they are actually realized. We had a net change in unrealized gain/(loss) of $8.2 million at the end of 2002 as compared to a net change of $(1.6) million at the end of 2001, the first year we recorded such contracts.

Earnings

Basic and diluted earnings per weighted average share of common stock were $1.19 during 2002 compared to $0.59 in 2001. This increase in earnings per share was primarily due to 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. 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 the $1.2 million unrealized gain on derivatives in December 2002. Earnings per share for 2002 were negatively impacted by $1.5 million in merger-related expenses as well as planned increased maintenance costs for our combustion turbine and combined cycle units. Excluding the $1.5 million in merger-related expenses and related taxes, earnings per share would have been $1.24 during 2002. 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. Excluding $1.4 million in merger costs ($1.0 million net of taxes) for 2001, $2.5 million, net of related income taxes, from the write-down of the State Line construction expenditures and the one-time tax benefit, earnings per share would have been $0.66 in 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.

Basic and diluted earnings per weighted average share of common stock were $0.59 during 2001 compared to $1.35 in 2000. 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 the one-time non-cash charge of $2.5 million, net of related income taxes, from the write-down of the SLCC construction expenditures. Positively impacting earnings in 2001 was the one-time tax benefit of approximately $2.3 million from previously incurred merger-related costs and favorable weather conditions in the first and second quarters of 2001.

Our actual net income and basic and diluted earnings per share are determined in accordance with generally accepted accounting principles (GAAP). The earnings per share amounts described above that exclude merger expenses, the one-time tax benefit and the write-down of construction expenditures (and the corresponding adjusted net income amounts) are non-GAAP measures. These non-GAAP measures are presented because we believe they provide a more accurate picture of our underlying financial performance. The following table provides a reconciliation of the differences between net income and basic and diluted earnings per share, as determined in accordance with GAAP, and these non-GAAP measures:

	Twelve Months Ended December 31, 2002	2001	2000
Net income	$ 25,524,000	$ 10,403,000	$ 23,617,000
Merger expenses (net of income taxes for 2001 and 2002)	1,002,000	1,081,000	327,000
Net loss from State Line Combined Cycle Plant disallowance	—	2,530,000	—
Tax benefit from merger expense	—	(2,324,000)	—
Net income (excluding merger expenses, disallowance and tax benefit)	$ 26,526,000	$ 11,690,000	$ 23,944,000
Weighted average common shares outstanding	21,433,889	17,777,449	17,503,665
Basic and diluted earnings per share	$ 1.19	$ 0.59	$ 1.35
Merger expenses per share (net of income taxes)	$ 0.05	$ 0.06	$ 0.02
Net loss per share from State Line Combined Cycle Plant disallowance	$ —	$ 0.14	$ —
Tax benefit per share from merger expenses	$ —	$ ($0.13)	$ —
Basic and diluted earnings per share (excluding merger expenses, disallowance and tax benefit)	$ 1.24	$ 0.66	$ 1.37

Competition

Federal regulation has promoted and is expected to continue to promote competition in the electric utility industry. However, none of the states in our service territory have legislation that could require competitive 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 all other electric utilities with interstate transmission facilities, operate under FERC regulated open access tariffs that offer all wholesale buyers and sellers of electricity the same transmission services (at the same rates) that the utilities provide themselves. We are a member of the Southwest Power Pool (SPP), a regional division 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. Since we are a transmission provider for our zone and are currently the only transmission customer taking service from that zone, we are currently being assessed 100 per cent of the zonal costs and receiving it back as revenue. To the extent that we are incurring these revenues and charges to serve our on-system wholesale and retail power customers, the associated costs are netted against the revenues collected and only the difference, if any, is recorded. In 2002, these total transmission costs and the associated revenues were approximately $4.7 million. In the event that other transmission customers take Network Integration Transmission Service in our zone, the revenues received will be reflected in electric operating revenues and the related charges will be expensed.

In December 1999, the FERC issued Order No. 2000 which encourages the development of RTOs. RTOs are designed to control the wholesale transmission services of the utilities in their regions thereby facilitating open and more competitive markets in bulk power. After the FERC rejected several attempts by the SPP to seek RTO status, the SPP and Midwest Independent Transmission System Operator, Inc. (MISO) agreed in October 2001 to consolidate and form an RTO. In December 2001, the FERC approved this newly formed MISO as the first RTO. The agreement to consolidate was completed in February 2002. MISO filed the necessary documents with the FERC on March 29, 2002 and the consolidation is still in progress. This new organization would operate our system as part of an interconnected transmission system encompassing over 120,000 megawatts of generation capacity located in 20 states. MISO would collect revenues attributable to the use of each member's transmission system and each member would be able to transmit power purchased, generated for sale or bought for resale in the wholesale market throughout the entire MISO system. MISO and SPP filed a combined tariff for the new resulting company on November 1, 2002 as directed by the FERC. This new tariff would eliminate rate pancaking for transactions that occur between MISO and SPP customers, preserve the zonal rate structure under the current MISO and SPP tariffs, preserve the existing rates for certain long-term firm SPP service agreements, preserve the grandfathered contract provisions under both organizations' tariffs and continue the stated rates currently on file under the SPP tariff. The FERC conditionally accepted the filing on December 19, 2002. We have filed with the FERC and the utility commissions in the four states in which we operate to transfer control over the operation of our transmission facilities to MISO. The Kansas Corporation Commission and the FERC have approved our requests while the filings in Missouri and Arkansas are still pending. Although we were not required to file in Oklahoma, we did a courtesy filing for informational purposes. If, however, the consolidation does not occur, we may operate our transmission separately while continuing to search for an RTO to join. We are unable to quantify the potential impact of either joining or not joining an RTO on our future financial position, results of operation or cash flows.

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. Our two largest wholesale customers accounted for 87% of our wholesale business in 2002. We have contracts with these customers that run through the first quarter of 2008.

LIQUIDITY AND CAPITAL RESOURCES

Our construction-related expenditures, including AFUDC, totaled approximately $73.7 million, $71.8 million, and $133.9 million in 2002, 2001 and 2000, respectively.

A breakdown of these construction expenditures for 2002 is as follows:

	Construction Expenditures (amounts in millions)
	2002
Distribution and transmission system additions	$25.5
FT8 peaking units - Energy Center	31.7
Additions and replacements – Asbury	3.0
Additions and replacements – Riverton, Iatan and Ozark Beach	2.2
Additions and replacements – SLCC	2.0
Combustor system upgrade – SL	1.8
Fiber optics (non-regulated)	2.0
Computer services projects	2.1
General and other additions	3.4
Total	$73.7

Approximately 63% of construction expenditures for 2002 were satisfied internally from operations. The other 37% of such requirements were satisfied from short-term borrowings and proceeds from our sales of common stock and unsecured Senior Notes discussed below.

We estimate that our construction expenditures, including AFUDC, will total approximately $50.2 million in 2003, $31.2 million in 2004 and $32.6 million in 2005. Of these amounts, we anticipate that we will spend $13.8 million, $15.7 million and $18.0 million in 2003, 2004 and 2005, respectively, for additions to our distribution system to meet projected increases in customer demand. These construction expenditure estimates also include approximately $22.0 million in 2003 for two FT8 peaking units at the Empire Energy Center. In October 2001, we entered into an agreement to purchase these two FT8 peaking units, each having generating capacity of 50 megawatts. Both units have been delivered and are scheduled to be operational in the second quarter of 2003. We estimate that the cost of both of these units will be approximately $55.0 million, excluding AFUDC.

Our net cash flows provided by operating activities increased $40.6 million during 2002 as compared to 2001 due mainly to a $15.1 million increase in net income and a $13.0 million increase in the amount of the IEC collected from Missouri electric customers. The refund of this IEC (which totals $18.7 million) during the first quarter of 2003 will have a material impact on our cash flows for the quarter although it will not have a material impact on earnings per share due to the non-recognition of these funds as operating revenue.

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

Our net cash flows provided by financing activities decreased $48.5 million during 2002 as compared to 2001 mainly due to the repayment of $37.5 million of our First Mortgage Bonds due July 1, 2002 and the repayment of $33.0 million of short-term debt in 2002 as compared to $14.0 million in 2001. We sold common stock in May 2002 and December 2001, Senior Notes in December 2002 and Trust Preferred Securities in March 2001 as described below. The proceeds from such sales in 2002 totaled $12.3 million more than the proceeds from the 2001 sales.

We estimate that internally generated funds will provide at least 63% of the funds required in 2003 for construction expenditures. As in the past, we intend to utilize short-term debt to finance the additional amounts needed for such construction and repay such borrowings with 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) and internally generated funds. 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.

On March 1, 2001, we sold two million of 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 liquidation amount. Quarterly payments of dividends by the trust which issued the securities, 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.

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 7, 2002 we entered into a 370-Day $100,000,000 unsecured revolving credit facility. This credit facility replaced all of our existing lines of credit. The facility is used for working capital, general corporate purposes and to back-up our use of commercial paper. This facility requires our total indebtedness (which does not include 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 will result in an event of default under the credit facility and will prohibit us from borrowing funds thereunder. We are in compliance with these ratios. This credit facility is also subject to cross-default with our other indebtedness (in excess of $5,000,000 in the aggregate). There are no borrowings outstanding under this revolver as of December 31, 2002. However, $23 million of the facility as of that date was used to back up our commercial paper and was not available to be borrowed. See Note 8 of "Notes to Financial Statements" regarding our lines of credit.

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 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 is the guarantor for 50.01% of a $2.7 million long-term note payable and a $0.5 million revolving short-term credit facility.

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.

We have an effective shelf registration under which approximately $100 million of common stock and unsecured debt securities remain available for issuance.

On December 24, 2002, we received approval from the Kansas Corporation Commission for the issuance of an additional 100,000 shares of our common stock for our Director's Stock Unit Plan and an additional 200,000 shares of our common stock for our 401(k) Plan and ESOP.

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, 2002 would permit us to issue approximately $187.2 million of new first mortgage bonds based on this test with an assumed interest rate of 7.0%. 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. We have no plans to issue any first mortgage bonds. See Note 7 to "Notes to Financial Statements" for more information on the mortgage bond indenture.

Moody's Investors Service currently rates our first mortgage bonds (other than the pollution control bonds) Baa1 and our senior unsecured debt Baa2. Standard & Poor's downgraded our first mortgage bonds (other than the pollution control bonds) on July 2, 2002 from A- to BBB, our senior unsecured debt from BBB+ to BBB- and our Trust Preferred Securities from BBB to BB+. Standard & Poor's outlook, however, was revised from negative to stable. In July 2001, Moody's adjusted the credit rating of our Trust Preferred Securities from Baa1 to Baa3 due to technical changes in Moody's methodology for rating this classification of security.

As of December 31, 2002, the ratings for our securities were as follows:

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

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, 2002:

		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)	$358.5	$ —	$110.0	$ —	$248.5
Trust Preferred Securities	50.0	—	—	—	50.0
Capital Lease Obligations	0.7	0.2	0.5	—	—
Operating Lease Obligations	—	—	—	—	—
Purchase Obligations*	265.5	50.0	96.4	51.2	67.9
Other Long-Term Obligations**	2.7	0.2	0.5	2.0	—
Total Contractual Obligations	$677.4	$50.4	$207.4	$53.2	$366.4

**includes fuel and purchased power contracts, including a long-term coal contract signed February 21, 2003.*

***Other Long-term Obligations represent 100% of the long-term debt issued by Mid-America Precision Products, LLC. EDE Holdings, Inc. is the 50.01% guarantor of a $2.6 million note included in this total amount.*

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. Our policy is consistent with the provisions of SFAS 87, "Employers' Accounting for 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 and discount rates.

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 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.

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 (under a set of predetermined percentages) that lock in prices in an attempt to lessen the volatility in our fuel expense and gain predictability, thus protecting earnings. 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 instruments are recognized as the fair value of the derivative instrument changes. Our policy is consistent with the provisions of SFAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities, An Amendment of SFAS 133".

As of February 17, 2003, 84% of our anticipated volume of natural gas usage for the remainder of year 2003 is hedged at an average price of $3.17 per Dekatherm (Dth). In addition, approximately 60% of our anticipated volume of natural gas usage for the year 2004 is hedged at an average price of $3.25 per Dth, and approximately 16% of our anticipated volume of natural gas usage for the year 2005 is hedged at an average price of $3.76 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. 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 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, 2002, we have recorded $36,169,683 in regulatory assets and $11,840,810 in income taxes as a regulatory liability. These amounts are being amortized over periods of up to 25 years. See Note 4 of "Notes to Financial Statements" under Item 8 for detailed information regarding our regulatory assets and liabilities.

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

Risks and uncertainties affecting the application of this accounting policy include: regulatory environment, external 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 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 and constructive obligations associated with the retirement of tangible long-lived assets. We adopted FAS 143 on January 1, 2003 and 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 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, we recorded a non-recurring discounted liability of approximately $400,000 in the first quarter of 2003. There will be no material effect to the Consolidated Statements of Income.

In August 2001, the Financial Accounting Standards Board 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. This statement eliminates the requirement under SFAS 121 to allocate goodwill to long-lived assets to be tested for impairment. We adopted FAS 144 on January 1, 2002 and there was no impact of the adoption of this Statement on our financial condition and results of operations.

In April 2002, the Financial Accounting Standards Board issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" (FAS 145). This statement eliminates the requirement (in both FAS 4 and FAS 64) that gains and losses from the extinguishment of debt be aggregated and, if material, classified as an extraordinary item, net of the related income tax effect. Further, FAS 145 eliminates an inconsistency between the accounting for sale-leaseback transactions and certain lease modifications that have economic effects that are similar to sale-leaseback transactions. FAS 145 also makes several other technical corrections to existing pronouncements that may change accounting practice and is effective for transactions occurring after May 15, 2002. We do not believe that the adoption of this Statement will have a material impact on our financial condition and results of operations.

In June 2002, the Financial Accounting Standards Board issued SFAS No. 146 "Accounting for Costs Associated with Exit or Disposal Activities" (FAS 146). FAS 146 addresses significant issues regarding the recognition, measurement, and reporting of costs that are associated with exit and disposal activities, including restructuring activities that are currently accounted for pursuant to the guidance that the Emerging Issues Task Force has set forth. The scope of FAS 146 also includes costs related to terminating a contract that is not a capital lease and termination benefits that employees who are involuntarily terminated receive under the terms of a one-time benefit arrangement that is not an ongoing benefit arrangement or an individual deferred-compensation contract. FAS 146 is effective for exit or disposal activities that are initiated after December 31, 2002. We will continue to evaluate FAS 146 but do not believe that the adoption of this Statement will have a material impact on our financial condition and results of operations.

In December 2002, the Financial Accounting Standards Board issued SFAS No. 148 "Accounting for Stock-Based Compensation-Transition and Disclosure" (FAS 148). 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. We do not have any transition issues and, accordingly, we do not believe FAS 148 will have a material impact on our financial condition and results of operations.

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 recession 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. FIN 45 rescinds all the provisions of FIN 34, Disclosure of Indirect Guarantees of Indebtedness of Others; as it has been incorporated into the provisions of FIN 45. The provisions of FIN 45 are effective for all guarantees issued or modified subsequent to December 31, 2002. The disclosure requirements of FIN 45 are effective for the financial statements of interim and annual periods ending after December 15, 2002. We do not have any commitments within the scope of FIN 45.

In January 2003, the FASB issued FASB Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities, an interpretation of ARB 51". The primary objectives of FIN 46 are to provide guidance on the identification of entities for which control is achieved through means other than through voting rights ("variable interest entities" or "VIEs") and how to determine when and which business enterprise should consolidate the VIE (the "primary beneficiary"). This new model for consolidation applies to an entity which either (1) the equity investors (if any) do not have a controlling financial interest or (2) the equity investment at risk is insufficient to finance that entity's activities without receiving additional subordinated financial support from other parties. In addition, FIN 46 requires that both the primary beneficiary and all other enterprises with a significant variable interest in a VIE make additional disclosures. FIN 46 may require more enterprises to consolidate entities with which they have contractual, ownership, or other pecuniary interests that absorb a portion of that entity's expected losses or receive a portion of the entity's residual returns. We are not the primary beneficiary of any VIEs.

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 market risk in accordance with established policies, which may include entering into various derivative transactions. During the second quarter of 2001, we began utilizing 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 7 and 8 of "Notes to Financial Statements" under Item 8 for further information.

If market interest rates average 1% more in 2003 than in 2002, our interest expense would increase, and income before taxes would decrease by approximately $226,000. This amount has been determined by considering the impact of the hypothetical interest rates on our commercial paper balances as of December 31, 2002. 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.

REPORT OF INDEPENDENT ACCOUNTANTS

The Empire District Electric Company

To the Board of Directors and Stockholders of
The Empire District Electric Company

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, common stockholders' equity and of cash flows present fairly, in all material respects, the financial position of The Empire District Electric Company and its subsidiaries at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with 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.

PricewaterhouseCoopers LLP

February 4, 2003
St. Louis, Missouri

CONSOLIDATED BALANCE SHEETS

The Empire District Electric Company

Year ended December 31,	*2002*	*2001*
ASSETS		
Plant, at original cost:		
Electric	$ 1,099,983,796	$ 1,061,452,770
Water	8,400,720	7,810,754
Non-regulated	17,075,955	10,836,489
Construction work in progress	41,504,451	20,136,645
	1,166,964,922	1,100,236,658
Accumulated depreciation	372,892,648	349,743,785
	794,072,274	750,492,873
Current assets:		
Cash and cash equivalents	14,439,227	11,440,275
Accounts receivable - trade, net of allowance of $679,000 and $895,000, respectively	21,993,819	19,621,889
Accrued unbilled revenues	9,543,729	10,986,746
Accounts receivable - other	9,979,840	7,231,772
Fuel, materials and supplies	31,227,447	20,094,559
Unrealized gain in fair value of derivative contracts	5,983,490	20,000
Prepaid expenses	1,640,745	1,063,195
	94,808,297	70,458,436
Noncurrent assets and deferred charges:		
Regulatory assets	36,169,683	37,743,107
Unamortized debt issuance costs	6,287,639	5,180,243
Unrealized gain in fair value of derivative contracts	16,949,388	7,706,580
Other	21,866,142	18,639,293
	81,272,852	69,269,223
Total Assets	$ 970,153,423	$ 890,220,532
CAPITALIZATION AND LIABILITIES		
Common stock, $1 par value, 100,000,000 shares authorized, 22,567,179 and 19,759,598 shares issued and outstanding, respectively	$ 22,567,179	$ 19,759,598
Capital in excess of par value	260,559,197	208,223,200
Retained earnings	39,544,819	41,906,483
Accumulated other comprehensive income (loss), net of income tax	6,643,467	(1,581,310)
Total common stockholders' equity	329,314,662	268,307,971
Long-term debt:		
Company obligated mandatorily redeemable trust preferred securities of subsidiary holding solely parent debentures	50,000,000	50,000,000
Obligations under capital lease	462,618	567,315
First mortgage bonds and secured debt	210,535,477	208,047,363
Unsecured debt	150,000,000	100,000,000
Total long-term debt	410,998,095	358,614,678
Total long-term debt and common stockholders' equity	740,312,757	626,922,649
Current liabilities:		
Current maturities of long-term debt	—	37,500,000
Obligations under capital lease	194,143	158,329
Commercial paper	22,541,000	55,500,000
Accounts payable and accrued liabilities	37,496,190	34,520,862
Customer deposits	4,644,105	4,127,061
Interest accrued	3,990,184	5,091,240
Provision for rate refund	18,718,679	2,843,444
Unrealized loss in fair value of derivative contracts	64,000	1,279,430
	87,648,301	141,020,366
Commitments and contingencies (Note 12)		
Noncurrent liabilities and deferred credits:		
Regulatory liability	11,840,810	12,915,456
Deferred income taxes	103,144,549	84,625,946
Unamortized investment tax credits	6,131,000	6,681,000
Postretirement benefits other than pensions	4,928,965	4,884,161
Unrealized loss in fair value of derivative contracts	10,914,668	8,994,450
Minority Interest	806,319	—
Other	4,426,054	4,176,504
	142,192,365	122,277,517
Total capitalization and liabilities	$ 970,153,423	$ 890,220,532

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,	*2002*	*2001*	*2000*
OPERATING REVENUES:			
Electric	$ 294,571,794	$ 263,189,506	$ 258,937,329
Water	1,075,671	1,065,348	1,066,129
Non-regulated	10,255,530	1,566,028	1,687,469
	305,902,995	265,820,882	261,690,927
Operating revenue deductions:			
Operating expenses:			
Fuel	50,994,406	56,523,370	48,899,577
Purchased power	62,765,107	62,383,952	65,238,096
Non-regulated	11,911,021	1,478,978	1,408,524
Expenses related to terminated merger	1,524,355	1,391,673	327,397
Other	43,064,291	36,726,181	32,570,495
	170,259,180	158,504,154	148,444,089
Maintenance and repairs	24,395,974	19,094,735	14,795,210
Depreciation and amortization	26,084,430	29,868,851	28,106,919
Provision for income taxes	12,920,001	1,551,165	11,475,586
Other taxes	16,175,446	13,590,023	13,006,942
	249,835,031	222,608,928	215,828,746
Operating income	56,067,964	43,211,954	45,862,181
Other income and (deductions):			
Allowance for equity funds used during construction	—	569,961	2,373,710
Interest income	87,336	199,447	641,602
Loss on plant disallowance	—	(4,087,066)	—
Provision for other income taxes	(390,000)	1,551,165	(149,414)
Minority interest	(142,463)	—	—
Other – net	472,387	(1,032,085)	(471,037)
	27,260	(2,798,578)	2,394,861
Income before interest charges	56,095,224	40,413,376	48,257,042
Interest charges:			
Trust preferred distributions by subsidiary holding solely parent debentures	4,250,000	3,541,667	—
Other long-term debt	24,957,961	26,384,310	26,355,901
Allowance for borrowed funds used during construction	(570,808)	(3,041,298)	(3,401,325)
Other	1,933,953	3,125,783	1,685,312
	30,571,106	30,010,462	24,639,888
Net income	$ 25,524,118	$ 10,402,914	$ 23,617,154
Weighted average number of common shares outstanding	21,433,889	17,777,449	17,503,665
Basic and diluted earnings per weighted average share of common stock	$ 1.19	$ 0.59	$ 1.35
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,	*2002*	*2001*	*2000*
Net income	$ 25,524,118	$ 10,402,914	$ 23,617,154
Derivative contracts settled	337,660	690,400	—
Change in fair value of open derivative contracts for period	12,928,110	(3,240,900)	—
Income taxes	(5,040,993)	969,190	—
Net change in unrealized gain/(loss) on derivative contracts	8,224,777	(1,581,310)	—
Comprehensive income	$ 33,748,895	$ 8,821,604	$ 23,617,154

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY
The Empire District Electric Company

Year ended December 31,	*2002*	*2001*	*2000*
Common stock, $1 par value:			
Balance, beginning of year	$ 19,759,598	$ 17,596,530	$ 17,369,855
Stock/stock units issued through:			
Public offering	2,500,000	2,012,500	—
Stock purchase and reinvestment plans	307,581	150,568	226,675
Balance, end of year	$ 22,567,179	$ 19,759,598	$ 17,596,530
Capital in excess of par value:			
Balance, beginning of year	$ 208,223,200	$ 168,439,089	$ 163,909,731
Excess of net proceeds over par value of stock issued:			
Public offering	46,857,626	37,023,140	—
Stock purchase and reinvestment plans	5,478,371	2,760,971	4,529,358
Balance, end of year	$ 260,559,197	$ 208,223,200	$ 168,439,089
Retained earnings:			
Balance, beginning of year	$ 41,906,483	$ 54,117,292	$ 52,908,432
Net income	25,524,118	10,402,914	23,617,154
	67,430,601	64,520,206	76,525,586
Less common stock dividends declared	27,885,782	22,613,723	22,408,294
Balance, end of year	$ 39,544,819	$ 41,906,483	$ 54,117,292
Accumulated other comprehensive income (loss):			
Balance, beginning of year	$ (1,581,310)	$ —	$ —
Derivative contracts settled	337,660	690,400	—
Change in fair value of open derivative contracts for period	12,928,110	(3,240,900)	—
Income taxes	(5,040,993)	969,190	—
Balance, end of year	$ 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,	*2002*	*2001*	*2000*
OPERATING ACTIVITIES			
Net income	$ 25,524,118	$ 10,402,914	$ 23,617,154
Adjustments to reconcile net income to cash flows provided by operating activities:			
Depreciation and amortization	29,301,526	32,855,222	31,354,048
Pension income	(3,581,781)	(4,366,247)	(7,780,497)
Deferred income taxes, net	12,180,000	810,000	2,053,000
Investment tax credit, net	(550,000)	(550,000)	(580,000)
Allowance for equity funds used during construction	—	(569,961)	(2,373,710)
Issuance of common stock and stock options for incentive plans	1,195,752	941,823	844,405
Loss on plant disallowance	—	4,087,066	—
Unrealized gain on ineffective derivative contracts	(1,238,940)	—	—
Cash flows impacted by changes in:			
Accounts receivable and accrued unbilled revenues	(2,668,531)	(2,423,368)	(4,652,024)
Fuel, materials and supplies	(2,098,946)	(5,505,306)	1,389,537
Prepaid expenses and deferred charges	559,689	(831,109)	(1,427,249)
Accounts payable and accrued liabilities	1,686,387	(1,261,594)	10,550,235
Customer deposits, interest and taxes accrued	(584,012)	(1,796,926)	2,302,180
Other liabilities and deferred credits	436,818	798,001	753,012
Accumulated provision for rate refunds	15,875,234	2,843,445	—
Net cash provided by operating activities	76,037,314	35,433,960	56,050,091
INVESTING ACTIVITIES			
Construction and other expenditures	$ (72,805,389)	$ (78,569,879)	$(132,076,082)
Non-regulated construction and other	(4,071,514)	(792,394)	(1,857,845)
Allowance for equity funds used during construction	—	569,961	2,373,710
Net cash used in investing activities	(76,876,903)	(78,792,312)	(131,560,217)
FINANCING ACTIVITIES			
Proceeds from issuance of senior notes	50,000,000	—	—
Proceeds from issuance of common stock	56,465,200	42,964,341	3,911,628
Proceeds from issuance of trust preferred securities	—	50,000,000	—
Long-term debt issuance costs	(1,574,401)	(1,884,756)	—
Common stock issuance costs	(2,517,374)	(1,958,985)	—
Dividends	(27,885,782)	(22,613,723)	(22,408,294)
Repayment of long-term debt	(37,690,102)	(198,830)	(286,000)
Net (repayments) proceeds from short-term borrowings	(32,959,000)	(14,000,000)	69,500,000
State Line advance payments	—	—	6,504,516
Net cash provided by financing activities	3,838,541	52,308,047	57,221,850
Net increase (decrease) in cash and cash equivalents	2,998,952	8,949,695	(18,288,276)
Cash and cash equivalents, beginning of year	11,440,275	2,490,580	20,778,856
Cash and cash equivalents, end of year	$ 14,439,227	$ 11,440,275	$ 2,490,580

Cash and cash equivalents include cash on hand and temporary investments purchased with an initial maturity of three months or less. Interest paid was $30,943,000, $31,705,000, and $26,485,000 for the years ended December 31, 2002, 2001, and 2000, respectively. Income taxes paid were $1,767,000, $4,343,000, and $8,801,000 for the years ended December 31, 2002, 2001 and 2000, 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, 2002 and 2000.

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

1. SUMMARY OF ACCOUNTING POLICIES

We 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). 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 2002 were derived as follows: residential 41%, commercial 29%, industrial 16%, wholesale on-system 4%, wholesale off-system 5.5% and other 4.5%. Our electric revenues for 2002 by jurisdiction were as follows: Missouri 88%, Kansas 6%, Arkansas 3%, and Oklahoma 3%. 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 its wholly owned non-regulated subsidiary, EDE Holdings, Inc. (EDE Holdings). The consolidated entity is referred to throughout as "we" or the "Company". Currently, the electric utility accounts for about 98% of consolidated assets and 97% of consolidated revenues. Through the non-regulated subsidiary, we lease capacity on our fiber optics network and provide Internet access, utility training, close-tolerance custom manufacturing, surge suppressors and other energy services. For discussion of the acquisition of certain non-regulated operations in 2002 see Note 3. See Non-Regulated Information later in this footnote for additional information regarding non-regulated results of operations.

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

Certain expenses and credits, normally reflected in income as incurred, are recognized when included in rates and recovered from or refunded to customers. As such, we have recorded certain regulatory assets that 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.

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. Actual amounts could differ from those estimates.

Revenue Recognition. We use cycle billing and accrue estimated, but unbilled, revenue and also a liability for the related taxes at the end of each period.

Property and Plant. The costs of additions to property, plant 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). Maintenance expenditures and the renewal of items not considered units of property are charged to income as incurred. The cost of units retired is charged to accumulated depreciation, which is credited with salvage and charged with removal costs.

Depreciation. Provisions for depreciation are computed at straight-line rates in accordance with GAAP consistent with rates approved by regulatory authorities and are applied to the various classes of assets on a composite basis. Such provisions approximated 2.6%, 3.0% and 3.2% of depreciable property for 2002, 2001 and 2000, respectively. Depreciation expense for the years ended December 31, 2002, 2001 and 2000 was $27,693,556, $31,448,830 and $29,663,792, respectively.

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 2.4% for 2002, 5.6% for 2001 and 8.4% for 2000 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 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. This statement eliminates the requirement under SFAS No. 121 to allocate goodwill to long-lived assets to be tested for impairment. We adopted FAS 144 on January 1, 2002. We believe there is no impairment of long-lived assets at December 31, 2002.

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

Liability Insurance. We carry excess liability insurance for workers' compensation and public liability claims. In order to provide for the cost of losses not covered by insurance, an allowance for injuries and damages is maintained based on our loss experience.

Franchise Taxes. Franchise taxes are collected for and remitted to their respective cities and are included in other taxes in the consolidated statement of income. Operating revenues also include franchise taxes of $5,464,000, $4,850,000 and $4,560,000 for each of the years ended December 31, 2002, 2001 and 2000, 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.

Investment tax credits utilized in prior years were deferred and are being amortized over the useful lives of the properties to which they relate.

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 and subscribed shares. The weighted average number of common shares outstanding used to compute basic earnings per share for the 2002, 2001 and 2000 periods was 21,433,889, 17,777,449 and 17,503,665, respectively. Dilutive shares for the 2002, 2001 and 2000 periods were 3,821, 8,118 and 7,105, respectively. In 2002, 69,700 options to purchase shares of common stock, with an exercise price of $20.95, were excluded from the calculation of diluted earnings per share as the exercise price was greater than the average market price.

Stock-Based Compensation. At December 31, 2002, we had several stock-based compensation plans, which are described in more detail in Note 5. We apply the recognition and fair-value measurement principles of SFAS No. 123, "Accounting for Stock-Based Compensation" (FAS 123), for all stock option issuances on or subsequent to January 1, 2002 and APB 25 "Accounting for Stock Issued to Employees", 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 and 2000 net income and earnings per share would have been immaterial.

Non-Regulated Information. As discussed earlier, the Consolidated Financial Statements include the accounts of our wholly owned non-regulated subsidiary, EDE Holdings, Inc. The table below presents information about the reported revenues, net income, total assets, and related minority interest of the non-regulated businesses of the Company.

As of and for the year ended December 31,	*2002*		*2001*	
	Non-regulated	*Total Company*	*Non-regulated*	*Total Company*
Statement of Income Information				
Revenues	$ 10,255,530	$ 305,902,995	$ 1,566,028	$ 265,820,882
Operating income (loss)	$ (2,317,561)	$ 56,067,964	$ (334,357)	$ 43,211,954
Net income (loss)	$ (1,489,325)	$ 25,524,118	$ (208,350)	$ 10,402,914
Minority interest	$ 142,463	$ 142,463	$ —	$ —
Balance Sheet Information				
Construction expenditures	$ 1,967,405	$ 73,579,019	$ 796,421	$ 77,315,877
Total assets	$ 22,210,566	$ 970,153,423	$ 10,927,945	$ 890,220,532
Minority interest	$ 806,319	$ 806,319	$ —	$ —

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 establishes standards for accounting and reporting for legal and constructive obligations associated with the retirement of tangible long-lived assets. We adopted FAS 143 on January 1, 2003 and 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 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, we recorded a non-recurring discounted liability of approximately $400,000 in the first quarter of 2003. There will be no material effect to the Consolidated Statements of Income.

In August 2001, the Financial Accounting Standards Board 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. This statement eliminates the requirement under FAS 121 to allocate goodwill to long-lived assets to be tested for impairment. We adopted FAS 144 on January 1, 2002 and there was no impact of the adoption of this Statement on our financial condition and results of operations.

In April 2002, the Financial Accounting Standards Board issued SFAS No. 145, "Rescission of SFAS No. 4, 44, and 64, Amendment of SFAS No. 13, and Technical Corrections" (FAS 145). This statement eliminates the requirement (in both FAS 4 and FAS 64) that gains and losses from the extinguishment of debt be aggregated and, if material, classified as an extraordinary item, net of the related income tax effect. Further, FAS 145 eliminates an inconsistency between the accounting for sale-leaseback transactions and certain lease modifications that have economic effects that are similar to sale-leaseback transactions. FAS 145 also makes several other technical corrections to existing pronouncements that may change accounting practice and is effective for transactions occurring after May 15, 2002. We do not believe that the adoption of this Statement will have a material impact on our financial condition and results of operations.

In June 2002, the Financial Accounting Standards Board issued SFAS No. 146 "Accounting for Costs Associated with Exit or Disposal Activities" (FAS 146). FAS 146 addresses significant issues regarding the recognition, measurement, and reporting of costs that are associated with exit and disposal activities, including restructuring activities that are currently accounted for pursuant to the guidance that the Emerging Issues Task Force has set forth. The scope of FAS 146 also includes costs related to terminating a contract that is not a capital lease and termination benefits that employees who are involuntarily terminated receive under the terms of a one-time benefit arrangement that is not an ongoing benefit arrangement or an individual deferred-compensation contract. FAS 146 is effective for exit or disposal activities that are initiated after December 31, 2002. We will continue to evaluate FAS 146 but do not believe that the adoption of this Statement will have a material impact on our financial condition and results of operations.

In December 2002, the Financial Accounting Standards Board issued SFAS No. 148 "Accounting for Stock-Based Compensation-Transition and Disclosure" (FAS 148). FAS 148 amends SFAS No. 123, "Accounting for Stock-Based Compensation" 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. We do not have any transition issues and, accordingly, we do not believe FAS 148 will have a material impact on our financial condition and results of operations.

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 recession 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. FIN 45 rescinds all the provisions of FIN 34, "Disclosure of Indirect Guarantees of Indebtedness of Others"; as it has been incorporated into the provisions of FIN 45. The provisions of FIN 45 are effective for all guarantees issued or modified subsequent to December 31, 2002. The disclosure requirements of FIN 45 are effective for the financial statements of interim and annual periods ending after December 15, 2002. We do not have any commitments within the scope of FIN 45.

In January 2003, the FASB issued FASB Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities, an interpretation of ARB 51". The primary objectives of FIN 46 are to provide guidance on the identification of entities for which control is achieved through means other than through voting rights ("variable interest entities" or "VIEs") and how to determine when and which business enterprise should consolidate the VIE (the "primary beneficiary"). This new model for consolidation applies to an entity which either (1) the equity investors (if any) do not have a controlling financial interest or (2) the equity investment at risk is insufficient to finance that entity's activities without receiving additional subordinated financial support from other parties. In addition, FIN 46 requires that both the primary beneficiary and all other enterprises with a significant variable interest in a VIE make additional disclosures. FIN 46 may require more enterprises to consolidate entities with which they have contractual, ownership, or other pecuniary interests that absorb a portion of that entity's expected losses or receive a portion of the entity's residual returns. We are not the primary beneficiary of any VIEs.

2. MERGER AGREEMENT

We and UtiliCorp United, Inc. (now known as Aquila, 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. These remaining obligations will be paid over a three-year period.

3. ACQUISITION OF NON-REGULATED BUSINESSES

On July 17, 2002 EDE Holdings, Inc., a Company subsidiary, 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% guarantor of a $2.6 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. For the period of July 17, 2002 through December 31, 2002, MAPP's operating income was $0.3 million and revenues were $7.7 million.

4. REGULATORY MATTERS

During the three years ending December 31, 2002, the following rate changes were requested or are in effect:

Missouri. On November 3, 2000, we filed a request with the MoPSC for a general annual increase in base rates for our Missouri electric customers in the amount of $41,467,926, or 19.36%. The MoPSC issued a final order on September 20, 2001 granting us an annual increase in rates of approximately $17.1 million, or 8.4%, effective October 2, 2001. In addition, the order approved an annual Interim Energy Charge, or IEC, of approximately $19.6 million effective October 1, 2001 and expiring two years later. This IEC was collected subject to refund (with interest) at the end of the two-year period to the extent money was collected from customers above the greater of the actual and prudently incurred costs or the base cost of fuel and purchased power set in rates.

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 Statement of Financial Accounting Standards FAS No. 71, we have deferred approximately $660,000 of expense directly related to Missouri rate cases. We amortize this amount over varying periods.

On March 8, 2002, we filed a request with the MoPSC for an annual increase in base rates for our Missouri electric customers in the amount of $19,779,916 and also asked to have the IEC put into effect in the last rate case reconfigured to reflect a decrease of $9,994,888 in the amount to be billed to customers. The reconfigured IEC would remain subject to refund with interest. This request sought to recover new operating costs and obligations and reflect the changes in our capital structure since the rate increase in October 2001. Also on March 8, 2002, we filed an interim rate case for an annual increase in base rates of $3,562,983, the amount that was erroneously omitted from the increase granted in our 2001 rate case. The MoPSC rejected the interim request. After extensive negotiations with the MoPSC staff, Office of Public Counsel and other intervening parties, we filed a Unanimous Stipulation and Agreement Regarding "Error" in the 2001 rate case and an Immediate Reduction of the IEC with the MoPSC on May 14, 2002. This agreement was approved by the MoPSC on June 4, 2002 and provided for a $7 million annual reduction in the IEC.

On October 29, 2002, we filed a Unanimous Stipulation and Agreement, agreed to by the MoPSC staff, Office of Public Counsel and other intervening parties, with the MoPSC. This Agreement was approved by the MoPSC on November 22, 2002 and settled all matters covered by our March 2002 filings, provided us with an annual increase in rates of approximately $11.0 million, or 4.97%, effective December 1, 2002 and eliminated the IEC as of that date. The Agreement also calls for us to refund all funds collected under the IEC, with interest, by March 15, 2003. At December 31, 2002, we had recorded a current liability of approximately $18.7 million for such rate refunds. We collected $2.8 million in 2001 and recorded $0.75 million as revenue. We collected $15.9 million in 2002 and recorded a revenue reduction of ($0.75) million associated with the revenue recognized in 2001 because it became certain that the entire amount of IEC revenues collected would be refunded. As a result, we have recognized no revenue for combined 2001 and 2002 associated with the IEC collections. The remainder of the funds collected in 2001 and 2002 were set aside as a provision for rate refunds and not recognized in operating revenue. As a result of the non-recognition of these funds, the refunds have already been reflected in our results (except for $0.3 million of interest) and will have no material impact on our earnings in 2003. The Agreement also provided for a change to the summer/winter rate differential for our residential customers with the new rates reflecting a smaller differential between summer and winter rates for usage above 600 kilowatt hours. Each of the parties to the Agreement also agreed not to file a new request for a general rate increase or decrease before September 1, 2003, barring any unforeseen, extraordinary occurrences.

On May 15, 2002, we filed a request with the MoPSC for an annual increase in base rates for our Missouri water customers in the amount of approximately $361,000, or 33.9%. This was the first requested increase in rates for our water customers since 1994. On November 7, 2002, we filed an Agreement Regarding Disposition of a Small Company Rate Increase Request, agreed to by the Commission staff, with the MoPSC. This agreement was approved by the MoPSC effective December 23, 2002 and provides us with an annual increase in rates of approximately $358,000, or 33.7%.

Kansas. On December 28, 2001, we filed a request with the Kansas Corporation Commission (KCC) for an annual increase in base rates for our Kansas electric customers in the amount of $3,239,744, or 22.81%. This request sought to recover costs associated with our investment in State Line Unit No. 1, State Line Unit No. 2 and the State Line Combined Cycle Unit (SLCC), as well as significant additions to our transmission and distribution systems and operating cost increases which had occurred since our last rate increase in September 1994. We also requested reinstatement of a fuel adjustment clause for our Kansas rates. We filed a Unanimous Stipulation and Agreement, agreed to by the KCC staff and all intervening parties, with the KCC on June 7, 2002. The Agreement stipulates that we will not file for general rate relief before November 1, 2003 barring any unforeseen, extraordinary occurrences. This Agreement was approved by the KCC on June 27, 2002 providing us an annual increase in rates of approximately $2,539,000, or 17.87%,, effective July 1, 2002. It did not provide for the reinstatement of a fuel adjustment clause.

Oklahoma. 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%.

FERC. We are currently discussing an increase in rates with our on-system wholesale electric customers, and will make a FERC rate filing in 2003.

We recorded the following regulatory assets and regulatory liability, which are being amortized over periods of up to 25 years:

December 31,	*2002*	*2001*
Regulatory assets		
Income taxes	$ 25,915,508	$ 25,674,064
Unamortized loss on reacquired debt	7,293,862	7,736,457
Coal contract restructuring costs	249,546	816,697
Gas supply realignment costs	18,563	288,967
Asbury five-year maintenance	2,368,284	2,870,617
Other postretirement benefits	323,920	356,305
Total regulatory assets	$ 36,169,683	$ 37,743,107
Regulatory liability		
Income taxes	$ 11,840,810	$ 12,915,456

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 electric utility industry. However, none of the states in our service territory have passed legislation that could require competitive 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.

5. COMMON STOCK

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.

In 1998, we implemented a stock unit plan for directors (the Director Retirement Plan) to provide directors the opportunity to accumulate retirement benefits in the form of common stock units in lieu of cash. 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 the director's retainer fee 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. During 2002, 6,466 units were granted under the Director Retirement Plan for services provided in 2002, and 3,879 units were granted pursuant to the provisions of the plan providing for the reinvestment of dividends on stock units in additional stock units.

Our Dividend Reinvestment and Stock Purchase Plan (the Reinvestment Plan), which was implemented June 1, 2001 (replacing the plan discontinued as of October 1, 2000), allows holders of common stock to reinvest dividends paid by us into newly issued shares of our common stock at 97% of the market price average of the high and low market price for each of the three trading days immediately preceding the dividend payment. Stockholders are also allowed to purchase on a weekly basis, for cash and within specified limits, additional stock at 100% of the market price average of the high and low price on the day of purchase. Participants in the Reinvestment Plan pay nominal service charges in connection with purchases under the Reinvestment 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. Contingent employee stock purchase subscriptions outstanding and the maximum prices per share were 40,574 shares at $17.91, 46,419 shares at $17.73, 40,880 shares at $21.83 on December 31, 2002, 2001 and 2000, respectively. Shares were issued at $17.73 per share in 2002, $17.78 per share in 2001 and $21.26 per share in 2000.

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. During February 2002, February 2001 and February 2000, grants for 2,669, 2,835 and 2,160 shares, respectively, 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. During 2002, 2001 and 2000, 7,952, 4,648 and 3,368 shares, respectively, were issued under the Stock Incentive Plan.

In February 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 shareholders of Empire over a three-year period compared with an investor-owned utility peer group. Under the award for 2002, a maximum of 37,800 shares could be issued.

During 2002, we adopted SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – and 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 will recognize compensation expense over the vesting period of all future stock-based compensation awards issued subsequent to January 1, 2002 based upon the fair-value of the award as of the date of issuance.

Prior to 2002, no options had been granted under the Stock Incentive Plan. During 2002, options consisting of the right to purchase 69,700 shares of common stock were issued under the Stock Incentive Plan to qualified individuals. The options were issued with an exercise price equal to the fair market value of the shares on the date of grant, become exercisable after three years and expire ten years after the date granted. Participants' options that are not vested become forfeited when participants leave Empire except for terminations of employment under certain specified circumstances. The exercise price for the options outstanding at December 31, 2002 was $20.95. Dividend equivalent awards were also issued to the recipients of the stock options under which dividend equivalents will be accumulated for the three-year period until the option becomes exercisable and will then be converted to restricted shares of our common stock based on the fair market value of the shares on the date converted. Such restricted shares vest on the eighth anniversary of the grant of the dividend equivalent award or, if earlier, upon exercise of the related option in full. The restricted shares are subject to forfeiture if the related option terminates without having been exercised in full prior to the vesting of these shares. The value of the options granted during 2002 was determined using the Black-Scholes pricing method and resulted in the Company recognizing $0.1 million in compensation expense in 2002.

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 annual compensation. We contributed 40,086, 35,793 and 33,926 shares of common stock in 2002, 2001 and 2000, respectively, valued at market prices on the dates of contributions. The stock issuances to effect the contributions were not cash transactions and are not reflected as a financing source of cash in the Statement of Cash Flows.

At December 31, 2002, 2,524,568 shares remain available for issuance under the foregoing plans.

6. 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, 2002 or 2001.

On March 1, 2001 Empire District Electric Trust I, a wholly owned trust, issued 2,000,000 of its 8.5% Trust Preferred Securities. Due to the nature of these manditorily redeemable securities, the Company classified $50,000,000 outstanding at December 31, 2001 as long-term debt (see Note 7).

Preference Stock Purchase Rights. On April 27, 2000, the Board of Directors approved a new shareholder rights plan replacing an existing shareholder rights plan that expired on July 25, 2000. The new shareholder rights plan provides each of the common stockholders one Preference Stock Purchase Right ("Right") for each share of common stock owned as compared to one-half of one right per common share under the prior shareholder rights plan. 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 22,509,230 and 19,703,837 Rights outstanding at December 31, 2002 and 2001, respectively.

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

7. LONG-TERM DEBT

At December 31, 2002 and 2001 the balance of long-term debt outstanding was as follows:

	2002	2001
Company obligated mandatorily redeemable Trust Preferred Securities of subsidiary holding solely parent debentures	$ 50,000,000	$ 50,000,000
Other:		
First mortgage bonds:		
$7\frac{1}{2}$% Series due 2002	—	37,500,000
7.60% Series due 2005	10,000,000	10,000,000
$8\frac{1}{8}$% Series due 2009	20,000,000	20,000,000
$6\frac{1}{2}$% Series due 2010	50,000,000	50,000,000
7.20% Series due 2016	25,000,000	25,000,000
$9\frac{3}{4}$% Series due 2020	2,250,000	2,250,000
7% Series due 2023	45,000,000	45,000,000
$7\frac{3}{4}$% Series due 2025	30,000,000	30,000,000
$7\frac{1}{4}$% Series due 2028(1)	13,076,000	13,154,000
5.3% Pollution Control Series due 2013	8,000,000	8,000,000
5.2% Pollution Control Series due 2013	5,200,000	5,200,000
	$ 208,526,000	$ 246,104,000
Senior Notes, 7.70% Series due 2004	100,000,000	100,000,000
Senior Notes, 7.05% Series due 2022(2)	50,000,000	—
Long-Term Debt – Mid-America Precision Products(3)	2,723,389	—
Obligations under capital lease	656,761	725,644
Less unamortized net discount	(477,040)	(556,637)
	411,429,110	396,273,007
Less current obligations of long-term debt	(236,872)	(37,500,000)
Less current obligations under capital lease	(194,143)	(158,329)
Total long-term debt	$ 410,998,095	$ 358,614,678

(1) During the twelve-month period ending May 31 of each year, we are required to repurchase up to $25,000 in principal amount of the bonds of this series per holder per year, upon the death of such holder. We are not required to repurchase more than $217,500 in the aggregate in any twelve-month period. At December 31, 2002 we had repurchased a total of $1,424,000 of bonds related to this requirement.

(2) We may redeem some or all of the notes at any time and from time to time on or after December 15, 2006 at 100% of their principal amount, plus accrued and unpaid interest to the redemption date. 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, 2002, we had not repurchased any of the notes related to this requirement.

(3) EDE Holdings is the guarantor of 50.01% of a secured long-term note payable of MAPP. The 2002 current obligations of long-term debt represent the current obligation of this debt.

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 $1,885,000. Holders of the trust preferred securities are entitled to receive distributions at an annual rate of 8.5% 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 8.5% 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 fully and unconditionally 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 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 EDEC'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 indenture) for any twelve consecutive months within the 15 months preceding issuance must be two times the annual interest requirements (as defined in the indenture) 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, 2002 would permit us to issue $187.2 million of new first mortgage bonds based on this test. The indenture provides an exception from this earnings requirement in certain instances, relating to the issuance of first mortgage bonds which have been or are to be retired. 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 Senior Notes, 7.05% Series due 2022. The net proceeds of this sale were added to our general funds and were used to repay short-term indebtedness.

The carrying amount of our long-term debt exclusive of capital leases was $410,535,477 and $395,547,363 at December 31, 2002 and 2001, respectively, and its fair market value was estimated to be approximately $414,125,000 and $387,828,000, 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*
Company obligated mandatorily redeemable trust preferred securities of subsidiary holding solely parent debentures	$ 50.0	$ —	$ —	$ —	$ 50.0
Long-term debt	358.5	—	110.0	—	248.5
Capital lease obligations	0.7	0.2	0.5	—	—
Other long-term obligations	2.7	0.2	0.5	2.0	—
Total long-term debt obligation	$411.9	$ 0.4	$111.0	$ 2.0	$298.5
Less current obligations and unamortized discount	0.9				
Total long-term debt	$411.0				

8. SHORT-TERM BORROWINGS

Short-term commercial paper outstanding and notes payable averaged $46,551,748 and $58,390,882 daily during 2002 and 2001, respectively, with the highest month-end balances being $62,000,000 and $80,000,000, respectively. The weighted daily average interest rates during 2002, 2001 and 2000 were 2.4%, 4.6% and 7.0%, respectively. The weighted average interest rates of borrowings outstanding at December 31, 2002 and 2001 were 2.0% and 2.8%, respectively. At December 31, 2002, we had outstanding commercial paper of $22,541,000 with due dates from January 2, 2003 to January 30, 2003.

At December 31, 2002, we had a 370-day $100,000,000 unsecured revolving credit facility. Borrowings are at the bank's prime commercial rate or LIBOR plus 100 basis points based on our current ratings and the pricing schedule in the line of credit document. We may borrow at our discretion from time to time during the period from May 7, 2002 to and including May 12, 2003, the revolving credit termination date. The credit facility is used for working capital, general corporate purposes and to back-up 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 our 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 thereunder. As of December 31, 2002, we are in compliance with these ratios. This credit facility is also subject to cross-default with our other indebtedness (in excess of $5,000,000 in the aggregate). This arrangement does not serve to legally restrict the use of our cash. There were no outstanding borrowings under this agreement at December 31, 2002. However $22,541,000 of the facility as of that date was used to back up our commercial paper and was not available to be borrowed.

9. 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.

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. The Company's policy is consistent 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.

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

	2002	*2001*	*2000*
Benefit obligation at beginning of year	$ 78,291,337	$ 75,217,964	$ 72,288,124
Service cost	2,190,415	2,172,379	2,182,798
Interest cost	5,601,019	5,604,231	5,579,276
Actuarial loss/(gain)	6,401,833	99,017	(250,025)
Benefits paid	(5,010,057)	(4,802,254)	(4,582,209)
Benefit obligation at end of year	$ 87,474,547	$ 78,291,337	$ 75,217,964
Fair value of plan assets at beginning of year	$ 92,138,446	$ 98,898,066	$104,485,842
Actual return on plan assets	(8,910,788)	(1,957,366)	(1,005,567)
Benefits paid	(5,010,057)	(4,802,254)	(4,582,209)
Fair value of plan assets at end of year	$ 78,217,601	$ 92,138,446	$ 98,898,066
Funded status	$ (9,256,946)	$ 13,847,109	$ 23,680,102
Unrecognized net assets at January 1, 1986 being amortized over 17 years	—	(491,158)	(982,313)
Unrecognized prior service cost	3,227,779	3,747,210	4,266,641
Unrecognized net loss/(gain)	25,584,623	(1,129,486)	(15,357,002)
Prepaid pension cost	$ 19,555,456	$ 15,973,675	$ 11,607,428

At December 31, 2002 our accumulated benefit obligation was $74,076,943 and our plan asset value was $78,217,601.

Assumptions used in calculating the projected benefit obligation for 2002, 2001 and 2000 include the following:

Weighted average discount rate	6.75%	7.25%	7.75%
Rate of increase in compensation levels	4.00%	4.00%	5.00%
Expected long-term rate of return on plan assets	9.00%	9.00%	9.00%

Net pension benefit for 2002, 2001 and 2000 is comprised of the following components:

Service cost - benefits earned during the period	$ 2,190,415	$ 2,172,379	$ 2,182,798
Interest cost on projected benefit obligation	5,601,019	5,604,231	5,579,276
Expected return on plan assets	(8,048,645)	(8,672,012)	(9,181,211)
Net amortization	(3,324,570)	(3,470,845)	(6,361,360)
Net pension income	$ (3,581,781)	$ (4,366,247)	$ (7,780,497)

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 benefits costs allowed in rates. Assets in these trusts amounted to approximately $21,500,000 at December 31, 2002, $18,600,000 at December 31, 2001 and $16,100,000 at December 31, 2000.

Postretirement benefits, a portion of which have been capitalized for 2002, 2001 and 2000 included the following components:

Service cost on benefits earned during the year	$ 1,141,158	$ 828,316	$ 931,469
Interest cost on projected benefit obligation	3,095,057	2,892,691	3,142,872
Return on assets	1,350,634	(1,260,307)	(1,007,118)
Amortization of unrecognized transition obligation	1,084,017	1,084,017	1,084,017
Unrecognized net (gain)/loss	896,316	407,068	1,990,806
Net periodic postretirement benefit cost	$ 4,865,914	$ 3,951,785	$ 6,142,045

The estimated funded status of our obligations under FAS 106 at December 31, 2002, 2001 and 2000 using a weighted-average discount rate of 6.75%, 7.25% and 7.75%, respectively, is as follows:

	2002	*2001*	*2000*
Benefit obligation at beginning of year	$ 42,315,384	$ 37,251,254	$ 28,669,028
Service cost	1,141,158	828,316	931,469
Interest cost	3,095,057	2,892,691	3,142,872
Actuarial (gain)/loss	9,029,864	2,757,072	5,908,539
Benefits paid	(1,780,913)	(1,413,949)	(1,400,654)
Benefit obligation at end of year	$ 53,800,550	$ 42,315,384	$ 37,251,254
Fair value of plan assets at beginning of year	$ 18,596,087	$ 16,055,828	$ 10,552,442
Employer contributions	5,233,834	3,951,785	5,735,695
Actual return on plan assets	(586,872)	2,423	1,168,343
Benefits paid	(1,748,934)	(1,413,949)	(1,400,654)
Fair value of plan assets at end of year	$ 21,494,115	$ 18,596,087	$ 16,055,826
Funded status	(32,306,435)	$ (23,719,297)	$ (21,195,426)
Unrecognized transition obligation	16,915,842	11,924,174	13,008,191
Unrecognized net gain	10,840,157	6,870,118	3,262,230
Accrued postretirement benefit cost	$ (4,550,436)	$ (4,925,005)	$ (4,925,005)

The assumed 2003 cost trend rate used to measure the expected cost of healthcare benefits is 10%. The trend rate decreases through 2012 to an ultimate rate of 5% for 2013 and subsequent years. The effect of a 1% increase in each future year's assumed healthcare cost trend rate would increase the current service and interest cost from $4,200,000 to $5,300,000 and the accumulated postretirement benefit obligation from $53,800,000 to $66,300,000. 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 $4,200,000 to $3,300,000 and the accumulated benefit obligation from $53,800,000 to $43,300,000.

10. 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:

Computed "expected" federal provision	$ 13,590,000	$ 3,640,000	$ 12,290,000
State taxes, net of federal effect	1,190,000	125,000	1,090,000
Adjustment to taxes resulting from:			
Merger costs	—	(2,320,000)	120,000
Investment tax credit amortization	(550,000)	(550,000)	(580,000)
Other	(920,000)	(895,000)	(1,420,000)
Actual provision for income taxes	$ 13,310,000	$ —	$ 11,500,000

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

Taxes currently (receivable)/payable			
Included in operating revenue deductions:			
Federal	$ 1,590,000	$ (50,000)	$ 8,852,000
State	170,000	30,000	1,203,000
Included in "other - net"	(80,000)	(240,000)	(28,000)
	1,680,000	(260,000)	10,027,000
Deferred taxes:			
Depreciation and amortization differences	11,479,000	2,986,000	2,136,000
Loss on reacquired debt	(169,000)	(203,000)	(206,000)
Postretirement benefits	559,000	844,000	1,408,000
Other	(964,000)	(1,028,000)	(1,158,000)
Asbury five-year maintenance	902,000	(100,000)	(241,000)
Software development costs	(190,000)	(252,000)	(39,000)
Included in "other - net"	563,000	120,000	153,000
Disallowed plant addition	—	(1,557,000)	—
	12,180,000	810,000	2,053,000
Deferred investment tax credits, net	(550,000)	(550,000)	(580,000)
Total income tax expense	$ 13,310,000	$ —	$ 11,500,000

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 2002 and 2001 as follows:

Balances as of December 31,	*2002*		*2001*	
	Deferred Tax Assets	*Deferred Tax Liabilities*	*Deferred Tax Assets*	*Deferred Tax Liabilities*
Noncurrent				
Depreciation and other property related	$ 11,748,535	$ 109,531,527	$ 12,065,652	$ 97,737,131
Unamortized investment tax credits	3,854,342	—	4,200,107	—
Miscellaneous book/tax recognition differences	7,198,842	16,414,743	7,137,872	10,292,446
Total deferred taxes	$ 22,801,719	$ 125,946,270	$ 23,403,631	$ 108,029,577

11. COMMONLY OWNED FACILITIES

We own a 12% undivided interest in the Iatan Power Plant, a coal-fired, 670-megawatt generating unit near Weston, Missouri. Great Plains Energy Inc. 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, 2002 and 2001, our property, plant and equipment accounts included the cost of our ownership interest in the plant of $48,338,000 and $46,139,000, respectively, and accumulated depreciation of $32,436,000 and $31,633,000, 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. At December 31, 2002 and 2001, our property, plant and equipment accounts include the cost of our ownership interest in the unit of $153,103,000 and $156,194,000, respectively, and accumulated depreciation of $9,700,000 and $5,540,000, respectively.

12. COMMITMENTS AND CONTINGENCIES

By letters dated October 31, 2002 and January 17, 2003, Enron North America Corp. (Enron) and their counsel demanded that we pay Enron $6,113,850, an amount which Enron claimed it is owed as a result of our early termination of all transactions under the Enfolio Master Firm Purchase/Sale Agreement dated June 1, 2001 between us and Enron. We dispute that any amounts are owed to Enron as a result of such termination and have responded to Enron stating that there was no contractual basis for Enron to assert that it was entitled to any such payment. We intend to vigorously oppose any attempt by Enron to collect the claimed amounts.

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.

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 $12.7 million for 2003, $25.3 million for 2004 through 2006 and $55.8 million for 2007 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 2003, 2004 and 2005 are $16.1 million, $22.6 million and $8.0 million, respectively.

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 $16.2 million per year through May 31, 2010. We also have a short-term contract with American Electric Power from January 1, 2003 through March 31, 2003. Commitments under this contract total approximately $5 million for the period.

13. SELECTED QUARTERLY INFORMATION (UNAUDITED)

A summary of operations for the quarterly periods of 2002 and 2001 is as follows:

	Quarters			
(dollars in thousands except per share amounts)	*First*	*Second*	*Third*	*Fourth*
2002:				
Operating revenues	$ 65,297	$ 68,905	$ 99,823	$ 71,878
Operating income	7,644	11,783	26,258	10,383
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	$ (.03)	$ .19	$ .82	$ .16

	Quarters			
(dollars in thousands except per share amounts)	*First*	*Second*	*Third*	*Fourth*
2001:				
Operating revenues	$ 60,974	$ 58,695	$ 83,821	$ 62,331
Operating income	8,409	7,527	18,414	8,862
Net income	2,207	741	7,359	96
Net income applicable to common stock	2,207	741	7,359	96
Basic and diluted earnings per average share of common stock	$ .13	$ .04	$ .42	$ .01

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. Operating revenues and operating income amounts may not agree with amounts previously reported due to minor reclassifications.

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) and SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities and Amendment of SFAS 133" (FAS 138). 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 on the volatile spot market.

FAS 133 requires all derivatives to be recognized on the balance sheet at their fair value. On the date the 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 hedge instrument, because it is unlikely that a forecasted transaction will occur; or (4) management determines that designation of the derivativd as a hedge instrument is no longer appropriate.

As of December 31, 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.

Current assets	$ 5,983,490	Current liabilities	$ 64.000
Noncurrent assets	$16,949,388	Noncurrent liabilities	$10,914,668

A $6,643,467 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 $4,071,803 on this gain is included in deferred taxes. These amounts will be adjusted cumulatively on a monthly basis until the determination periods beginning January 1, 2003 and ending on December 31, 2004. At the end of each determination period any gain or loss for that period related to the contract will be reclassified to fuel expense.

As of December 31, 2002, $1,238,940 of unrealized gains relating to non-qualifying hedging instruments has been recognized within other income and deductions in the accompanying statement of income. This gain resulted from anticipated natural gas usage that was financially hedged but no longer necessary because we were able to purchase power in the wholesale market more economically than generating it ourselves.

As of December 31, 2002, $52,210 of realized losses relating to non-qualifying hedging instruments has been recognized within other income and deductions in the accompanying statement of income.

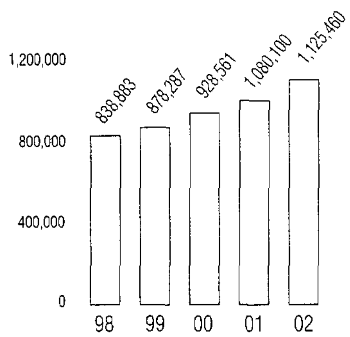
We have also entered into fixed-price forward physical contracts for the purchase of natural gas, coal and purchased power. These contracts are not subject to the reporting requirements of FAS 133 because they are considered to be normal purchases and normal sales.

SELECTED FINANCIAL DATA
The Empire District Electric Company

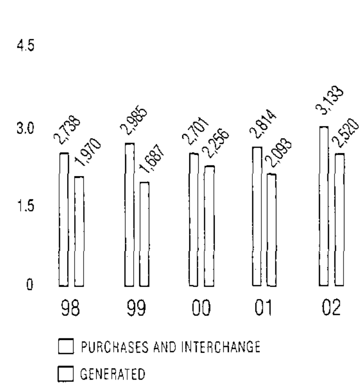
(Dollars in thousands, except per share amounts)	*2002*	*2001*	*2000*	*1999*
Operating revenues(1)	$ 305,903	$ 265,821	$ 261,691	$ 243,243
Operating income(1)	$ 56,068	$ 43,212	$ 45,862	$ 42,237
Total allowance for funds used during construction	$ 571	$ 3,611	$ 5,775	$ 1,193
Net income	$ 25,524	$ 10,403	$ 23,617	$ 22,170
Earnings applicable to common stock	$ 25,524	$ 10,403	$ 23,617	$ 19,463
Weighted average number of common shares outstanding	21,433,889	17,777,449	17,503,665	17,237,805
Basic and diluted earnings per weighted average shares outstanding	$ 1.19	$ 0.59	$ 1.35	$ 1.13
Cash dividends per common share	$ 1.28	$ 1.28	$ 1.28	$ 1.28
Common dividends paid as a percentage of earnings applicable to common stock	109.3%	217.4%	94.9%	114.5%
Allowance for funds used during construction as a percentage of earnings applicable to common stock	2.2%	34.7%	24.5%	6.2%
Book value per common share outstanding at end of year	$ 14.28	$ 13.64	$ 13.62	$ 13.44
Capitalization:				
Common equity	$ 329,315	$ 268,308	$ 240,153	$ 234,188
Preferred stock without mandatory redemption provisions	$ 0	$ 0	$ 0	$ 0
Long-term debt	$ 410,998	$ 358,615	$ 325,644	$ 345,850
Ratio of earnings to fixed charges	2.25	1.36	2.25	2.70
Ratio of earnings to combined fixed charges and preferred stock dividend requirements	2.25	1.36	2.25	2.40
Total assets(1)	$ 970,153	$ 890,221	$ 829,739	$ 731,220
Plant in service at original cost(1)	$ 1,125,460	$ 1,080,100	$ 928,561	$ 878,287
Plant expenditures (including AFUDC)(1)	$ 73,579	$ 77,316	$ 131,824	$ 70,127

(1): Prior years 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.

Plant in Service
Dollars in Thousands

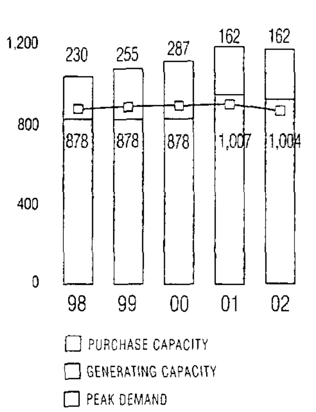


Total System Input by Source
Millions of Kilowatt-hours

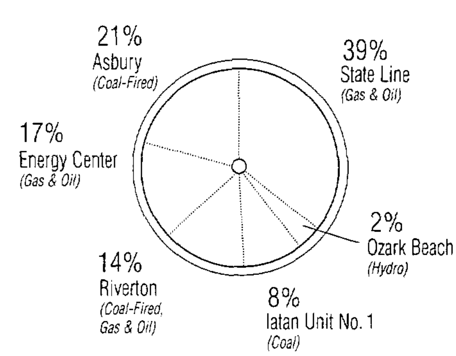


1998	1997	1996	1995	1994	1993	1992
$ 239,858	$ 215,311	$ 205,984	$ 192,838	$ 177,757	$ 168,439	$ 150,302
$ 47,440	$ 40,962	$ 36,652	$ 33,151	$ 32,005	$ 29,291	$ 30,090
$ 409	$ 1,226	$ 1,420	$ 2,239	$ 1,715	$ 229	$ 119
$ 28,323	$ 23,793	$ 22,049	$ 19,798(2)	$ 19,683	$ 15,936	$ 16,905
$ 25,912	$ 21,377	$ 19,633	$ 17,381(2)	$ 18,120	$ 15,551	$ 16,513
16,932,704	16,599,269	16,015,858	14,730,902	13,734,231	13,415,539	13,119,515
$ 1.53	$ 1.29	$ 1.23	$ 1.18(2)	$ 1.32	$ 1.16	$ 1.26
$ 1.28	$ 1.28	$ 1.28	$ 1.28	$ 1.28	$ 1.28	$ 1.26
83.7%	99.4%	104.5%	108.9%	97.0%	110.4%	99.9%
1.6%	5.7%	7.2%	12.9%	9.5%	1.5%	0.7%
$ 13.40	$ 13.03	$ 12.93	$ 12.67	$ 12.42	$ 12.33	$ 12.26
$ 229,791	$ 219,034	$ 213,091	$ 193,137	$ 173,780	$ 167,861	$ 163,293
$ 32,634	$ 32,902	$ 32,902	$ 32,902	$ 32,902	$ 7,902	$ 7,902
$ 246,093	$ 196,385	$ 219,533	$ 194,705	$ 184,977	$ 165,227	$ 143,619
3.32	3.01	3.11	2.90	3.16	2.73	2.91
2.50	2.50	2.53	2.36	2.70	2.63	2.80
$ 653,141	$ 626,465	$ 596,980	$ 557,368	$ 520,213	$ 463,617	$ 406,731
$ 838,883	$ 797,839	$ 717,890	$ 682,609	$ 611,360	$ 576,083	$ 543,323
$ 50,899	$ 53,280	$ 59,373	$ 49,217	$ 71,649	$ 42,648	$ 29,500

System Capability and Peak Demand
Megawatts



Empire Power Plants
Percent of Capacity



ELECTRIC OPERATING STATISTICS

The Empire District Electric Company

	2002	2001	2000	1999
Electric Operating Revenues (000s):				
Residential	$ 126,088	$ 110,584	$ 108,572	$ 98,787
Commercial	91,065	82,237	77,601	73,773
Industrial	50,155	44,509	42,711	41,030
Public authorities	7,099	6,311	5,927	5,847
Wholesale on-system	11,868	12,911	11,738	10,682
Miscellaneous	6,987	5,583	4,546	3,856
Total system	293,262	262,135	251,095	233,975
Wholesale off-system	17,185	3,898	7,842	7,090
Less Provision for IEC Refunds	15,875	2,843	—	—
Total electric operating revenues	$ 294,572	$ 263,190	$ 258,937	$ 241,065
Electricity generated and purchased (000s of Kwh):				
Steam	2,143,323	1,969,412	2,193,847	2,378,130
Hydro	45,430	53,635	51,132	86,349
Combustion turbine	943,924	790,993	455,678	520,340
Total generated	3,132,677	2,814,040	2,700,657	2,984,819
Purchased	2,520,421	2,092,955	2,255,076	1,686,782
Total generated and purchased	5,653,098	4,906,995	4,955,733	4,671,601
Interchange (net)	(69)	(264)	145	(138)
Total system input	5,653,029	4,906,731	4,955,878	4,671,463
Maximum hourly system demand (Kw)	987,000	1,001,000	993,000	979,000
Owned capacity (end of period) (Kw)	1,004,000	1,007,000	878,000	878,000
Annual load factor (%)	56.88	54.75	55.12	52.16
Electric sales (000s of Kwh):				
Residential	1,726,449	1,681,085	1,660,928	1,509,176
Commercial	1,378,165	1,375,620	1,333,310	1,260,597
Industrial	1,027,446	1,004,899	1,015,779	988,114
Public authorities	101,188	100,125	96,403	99,739
Wholesale on-system	323,103	322,336	309,633	297,614
Total system	4,556,352	4,484,065	4,416,053	4,155,240
Wholesale off-system	735,154	105,975	161,293	198,234
Total electric sales	5,291,506	4,590,040	4,577,346	4,353,474
Company use (000s of Kwh)	9,960	10,134	8,714	8,583
Lost and unaccounted for (000s of Kwh)	351,563	306,557	369,818	309,406
Total system input	5,653,029	4,906,731	4,955,878	4,671,463
Customers (average number of monthly bills rendered):				
Residential	127,681	125,996	123,618	121,523
Commercial	22,858	22,670	22,504	22,206
Industrial	349	337	345	350
Public authorities	1,690	1,645	1,674	1,759
Wholesale on-system	7	7	7	7
Total system	152,585	150,655	148,148	145,845
Wholesale off-system	16	7	6	6
Total	152,601	150,662	148,154	145,851
Average annual sales per residential customer (Kwh)	13,522	13,342	13,436	12,419
Average annual revenue per residential customer	$ 936.21	$ 877.68	$ 878.29	$ 812.91
Average residential revenue per Kwh	6.92¢	6.52¢	6.54¢	6.55¢
Average commercial revenue per Kwh	6.21¢	5.91¢	5.82¢	5.85¢
Average industrial revenue per Kwh	4.55¢	4.35¢	4.20¢	4.15¢

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

1998	*1997*	*1996*	*1995*	*1994*	*1993*	*1992*
$ 100,567	$ 88,636	$ 86,014	$ 81,331	$ 71,977	$ 68,477	$ 59,645
71,810	64,940	61,811	58,430	54,052	50,264	45,264
39,805	37,192	35,213	32,637	31,317	28,880	26,596
5,559	4,995	4,180	3,745	3,509	3,419	3,177
10,928	9,730	9,482	8,360	8,173	8,038	6,837
4,006	3,341	3,639	3,345	2,393	2,302	1,975
232,675	208,834	200,339	187,848	171,421	161,380	143,494
6,126	5,473	4,595	4,000	5,391	6,244	5,997
—	—	—	—	—	—	—
$ 238,801	$ 214,307	$ 204,934	$ 191,848	$ 176,812	$ 167,624	$ 149,491
2,228,103	2,372,914	2,231,062	2,374,021	2,495,055	2,322,749	2,307,854
70,631	77,578	62,860	71,302	83,556	102,673	77,644
439,517	211,872	162,679	170,479	51,358	39,532	5,048
2,738,251	2,662,364	2,456,601	2,615,802	2,629,969	2,464,954	2,390,546
1,970,348	1,839,833	1,968,898	1,540,816	1,394,470	1,443,410	1,119,025
4,708,599	4,502,197	4,425,499	4,156,618	4,024,439	3,908,364	3,509,571
(1,894)	1,018	(1,087)	(5,851)	630	11,266	2,657
4,706,705	4,503,215	4,424,412	4,150,767	4,025,069	3,919,630	3,512,228
916,000	876,000	842,000	815,000	741,000	739,000	680,000
878,000	878,000	724,000	737,000	656,500	657,300	657,300
55.72	55.38	56.85	55.15	57.32	54.88	52.77
1,548,630	1,429,787	1,440,512	1,350,340	1,264,721	1,248,482	1,068,595
1,246,323	1,171,848	1,154,879	1,086,894	1,018,052	950,906	850,829
960,783	943,287	923,730	859,017	827,067	760,737	695,271
98,675	101,122	95,652	90,543	86,463	83,239	78,050
299,256	273,035	262,330	243,869	234,228	232,815	220,916
4,153,667	3,919,079	3,877,103	3,630,663	3,430,531	3,276,179	2,913,661
235,391	253,060	219,814	213,590	304,554	366,729	360,251
4,389,058	4,172,139	4,096,917	3,844,253	3,735,085	3,642,908	3,273,912
8,940	9,688	9,584	9,559	9,260	9,117	8,924
308,707	321,388	317,911	296,955	280,724	267,605	229,392
4,706,705	4,503,215	4,424,412	4,150,767	4,025,069	3,919,630	3,512,228
119,265	117,271	115,116	112,605	109,032	105,079	101,943
21,774	21,323	20,758	20,098	19,175	18,447	17,796
354	346	346	339	318	283	267
1,739	1,720	1,696	1,637	1,558	1,517	1,467
7	7	7	7	7	7	7
143,139	140,667	137,923	134,686	130,090	125,333	121,480
6	7	9	6	6	5	5
143,145	140,674	137,932	134,692	130,096	125,338	121,485
12,985	12,192	12,514	11,992	11,600	11,881	10,482
$ 843.22	$ 755.82	$ 747.19	$ 722.27	$ 660.14	$ 651.67	$ 585.08
6.49¢	6.20¢	5.97¢	6.02¢	5.69¢	5.48¢	5.58¢
5.76¢	5.54¢	5.35¢	5.38¢	5.31¢	5.29¢	5.32¢
4.14¢	3.94¢	3.81¢	3.80¢	3.79¢	3.80¢	3.83¢

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

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. An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

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, especially the management and the shareholders.

Deregulation: The elimination of regulation from a previously regulated industry.

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

Fuel adjustment clause: A clause in a rate schedule that provides for adjustment of 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 an computerized program for managing service to customers.

Independent power producers (IPP): Non-utility companies that generate and market power at the wholesale level.

Interim Energy Charge (IEC): Effective October 2001 through October 2003, a charge approved by the Missouri Public Service Commission and added to customers bills in Missouri that allows 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.

Nonregulated business: Those aspects of the company's business activities that are not regulated by FERC, state utility commissions, or governmental agencies.

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

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 activities that are regulated by FERC, state utility commissions, or governmental agencies.

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) is equal to one thousand volts.

Watt: A measure of the amount of electrical power that is generated or consumed. A kilowatt (kw) equals one 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 corporation 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.

Annual Meeting

The annual meeting of shareholders will be held Thursday, April 24, 2003, 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

Mellon Investor Services LLC
85 Challenger Road
Ridgefield Park, New Jersey 07660
(888) 261-6784
For hearing impaired: (800) 231-5469
Foreign shareholder questions: (201) 329-8660
www.melloninvestor.com

Stock Trading

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

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

Stock Prices and Dividends

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

2001 Quarter	*High*	*Low*	*Dividend Paid*
First	26.56	17.50	$0.32
Second	20.99	18.00	$0.32
Third	21.05	18.70	$0.32
Fourth	21.50	19.75	$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 to make it easier for current shareholders who are long-term investors wishing to invest and build their share ownership over time. All registered holders of Empire common stock can participate in the Plan. If you are a beneficial owner of shares in a brokerage account and wish to reinvest your dividends, you can request that your shares become registered or make arrangements with your broker or nominee to participate on your behalf. The Plan offers a 3 percent discount on the purchase of shares with reinvested dividends. Optional features (applicable to registered holders only) include:

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

A prospectus describing the Plan and enrollment forms are available upon written request from the Plan Administrator:

Mellon Investor Services LLC
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Ridgefield Park, New Jersey 07660
(888) 261-6784
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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, Secretary-Treasurer, The Empire District Electric Company, P.O. Box 127, Joplin, Missouri 64802-0127. This report and the Annual Report on Form 10-K 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 available from:

The Empire District Electric Company
Janet S. Watson, Secretary-Treasurer
P.O. Box 127
Joplin, Missouri 64802-0127
or telephone: (417) 625-5108

Internet

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

SERVICES YOU COUNT ON

www.empiredistrict.com

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