02024243

ARS

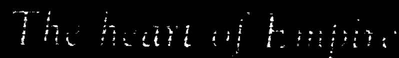
P.E. 12/31/01

REC'D S.E.C.
MAR 2 1 2002

PROCESSED
APR 0 1 2002
THOMSON
FINANCIAL

The heart of Empire

Empire's highest priority, past, present and future, is to provide [illegible] value to our shareholders and outstanding service to our customers. This is the heart of Empire. This book is dedicated to all the employees who have worked to make our vision come alive. Those who first lit the skies with Empire lights in 1909. Those who brought the first earnings to Empire shareholders in 1944. Those who work today to ensure a strong future. These people, and all who served in between, are the soul of Empire.



The heart of Empire

Empire's highest priority, past, present and future, is to provide increasing value to our shareholders and outstanding service to our customers. This is the heart of Empire. This book is dedicated to all the employees who have worked to make our vision come alive. Those who first lit the skies with Empire lights in 1909. Those who brought the first earnings to Empire shareholders in 1944. Those who work today to ensure a strong tomorrow. These people, and all who served in between, are the soul of Empire.

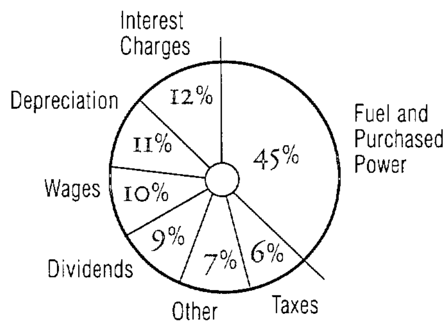
2001 Financial Highlights

December 31,	*2001*	*2000*	*Change*
Operating Revenues	$ 264,254,854	$ 260,003,000	1.64%
Operating Income	$ 43,443,881	$ 45,902,000	-5.36%
Net Income	$ 10,402,914	$ 23,617,000	-55.95%
Earnings Per Average Common Share	$ 0.59	$ 1.35	-56.30%
Earnings Per Average Common Share (1)	$ 0.68	$ 1.37	-50.36%
Dividends Paid	$ 1.28	$ 1.28	0.00%
Return on Common Equity	3.89%	9.83%	-60.43%
Book Value Per Share of Common Stock	$ 13.64	$ 13.62	0.15%
Common Shares Outstanding	19,703,837	17,547,742	12.29%
Weighted Average Common Shares Outstanding	17,777,449	17,503,665	1.56%
Number of Common Shareholders of Record (Year end)	6,832	7,349	-7.03%
Total Construction Expenditures	$ 77,316,000	$ 131,824,000	-41.35%
Gross Utility Plant	$ 1,069,176,000	$ 918,622,000	16.39%
On-System Sales (Thousand kwh)	4,484,065	4,416,053	1.54%
Electric Customers (Year end)	151,734	150,039	1.13%
Total System Capability (Net kw)	1,169,000	1,040,000	12.40%
System Peak Demand (Net kw)	1,001,000	993,000	0.81%
Degree Days, Heating	3,704	3,940	-5.99%
Degree Days, Cooling	1,628	1,773	-8.18%
Number of Employees (Year end)	616	603	2.16%

(1) Excluding merger related expenses, a one-time write-down of construction expenditures, and a tax benefit from prevously incurred merger expenses.

The Empire District Electric Company generates and distributes electricity to over 150,000 customers across a 10,000 square-mile region of southwest Missouri, southeast Kansas, northeast Oklahoma, and northwest Arkansas. We also provide water service to three incorporated Missouri communities. Through EDE Holdings, Inc., a wholly owned subsidiary, we pursue nonregulated business ventures across the region, including products and services related to energy, telecommunications, and home security.

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



2001 Allocation of Revenue

To Our Shareholders

In 1944, the year we became an independent company and established a continuous line of dividends, Empire President James E. Harsh wrote to shareholders regarding the state of the nation and the industry and Empire's place in it. His message was one of war, mergers, brownouts, and "the uncertainty of the fuel situation." In a serious yet positive tone, he said that despite the national turmoil, Empire was growing and had a plan in place for the future. The lights were on.

As I recently read this message from the past, I was struck by the similarities between the issues that mattered then and those that matter today. Once again the nation is at war and the industry in a state of flux. But the lights are on, Empire's dividend is still being paid, and we are growing.

2001 was challenging.

Following termination of the proposed merger by UtiliCorp United Inc. on January 2, we faced five critical tasks: rebuild the senior management team, reestablish our employee workforce, complete the State Line construction project, finalize our Missouri rate case, and add equity to the balance sheet. We've accomplished these things. We've set the stage for a stronger, more profitable future.

Building the team.

As typically happens in such situations, we lost many people during the merger process. Restoring the Empire team topped our list of priorities. Our senior

management team was in place by March. Reassembling a full workforce necessarily took longer but was essentially complete by summer's end.

Adding capacity.

On June 25, we brought online 500 megawatts of combined cycle technology, which is jointly owned with Westar Generating, at our State Line facility, an undertaking that required great levels of planning, teamwork, and all-out effort. I am immensely proud of our people for this accomplishment. State Line is green and efficient, provides fuel diversity, and gives us a distinct advantage in satisfying needs of both customers and shareholders.

Myron McKinney
President and Chief Executive Officer

A growing company.

Our service territory continues to grow at a rate well beyond the national average. For the first time ever, we became a gigawatt company when our summer peak hit 1,001 megawatts on August 9. Our projections call for increased energy growth in the 2.8 percent range over the next several years.

Earnings.

Unfortunately, this healthy growth was not reflected in the year's financial results. Earnings for 2001 were $0.59 per share, compared to $1.35 per share for 2000. This disappointing performance was attributable to four main factors. First, we were unable to capture fuel and purchased power costs that were higher than the amounts contained in our rates, despite our efforts to correct this situation with an interim rate case. Second, there was lag time from the completion of State Line Combined Cycle in June until costs were included in rates in October combined with the writedown of a portion of the construction expenditures for the plant.

Third were payments for long-term maintenance agreements on the combustion turbines along with unplanned maintenance expense at the generating stations. Finally, mild weather in the third and fourth quarters kept demand and sales down.

Securing new rates.

We made significant progress in regaining our financial balance with the completion of our rate case in October. The Missouri Public Service Commission (MPSC) granted an increase of approximately $17.1 million annually in base rates plus approximately $19.6 million annually for two years from an Interim Energy Charge (IEC). The IEC protects us from volatility in our fuel and purchased power expenses by allowing us to collect actual costs within a band.

Our approach to rate relief will continue to be fair but aggressive. In Missouri, we are evaluating our options for recovering approximately $3.6 million overlooked in last year's order due to a regulatory clerical error which the MPSC has refused to rectify, citing "single-issue rate-making" as the reason. In Kansas, we expect a decision from authorities by late August 2002 on a request for an approximate $3.2 million annual increase in revenue.

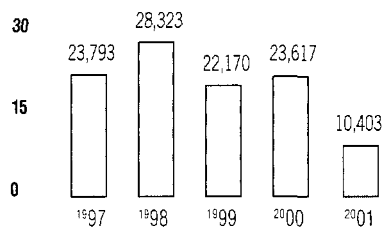
Bill Gipson
Executive Vice President and Chief Operating Officer

Tackling fuel volatility.

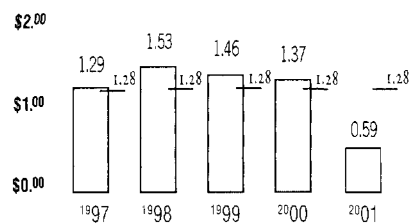
The effect of fuel volatility on earnings has been eased, for the short term, by the IEC. For the longer term, we've set in place a risk management plan for procurement of natural gas that locks in prices. With this approach, we gain predictability, which protects earnings and puts us on more solid ground for future rate case proceedings.

Growing in new ways.

Retail deregulation has definitely moved to the back burner in the four states we serve, but we're still looking to leverage our competitive spirit through nonregulated growth. Last year we moved ahead. We created a wholly owned subsidiary to hold Empire's nonregulated companies and added a top-level management position to oversee this area. We transferred our current nonregulated business accordingly and made our first acquisition, a company that began offering wireless internet service early this year.



Net Income
Dollars in Thousands



☐ DIVIDENDS ☐ EPS

Earnings & Dividends
Paid Per Common Share
Excluding merger related expenses

I must emphasize, however, that nonregulated expansion is intended to augment our earnings, not to change the basic nature of Empire. We are and will remain, first and foremost, a vertically integrated electric utility.

A resolute employee commitment.

During the course of this extraordinary year, Empire employees continued to amaze me with their unfaltering determination, dedication, and enthusiasm for building the Company. Empire's accomplishments are a result of their skills and commitment. They form the true spirit of Empire.

A transition.

On April 30, 2002, I will retire as President and Chief Executive Officer and become Chairman of Empire's Board of Directors. Bill Gipson, currently Executive Vice President and Chief Operating Officer, will assume the helm as President and Chief Executive Officer. Bill is capable, bright, aggressive, and extremely hard working. His background with all facets of our operations and development has prepared him for the road ahead. I leave fully confident he will serve you well. After more than 34 years with Empire, I can honestly say I have been proud every day to be associated with this organization and the wonderful people who make up the Empire family. At Empire, integrity is not a word; it's a way of life. We know who we are and where we are going, and we have stayed true to our mission. We have in place the management, the facilities, the rates, the fuel plan, and the people to give shareholders a stronger 2002. We thank you for the confidence you have placed in us, and please know that we will do everything possible to warrant that confidence.

M.W. McKinney
President and Chief Executive Officer

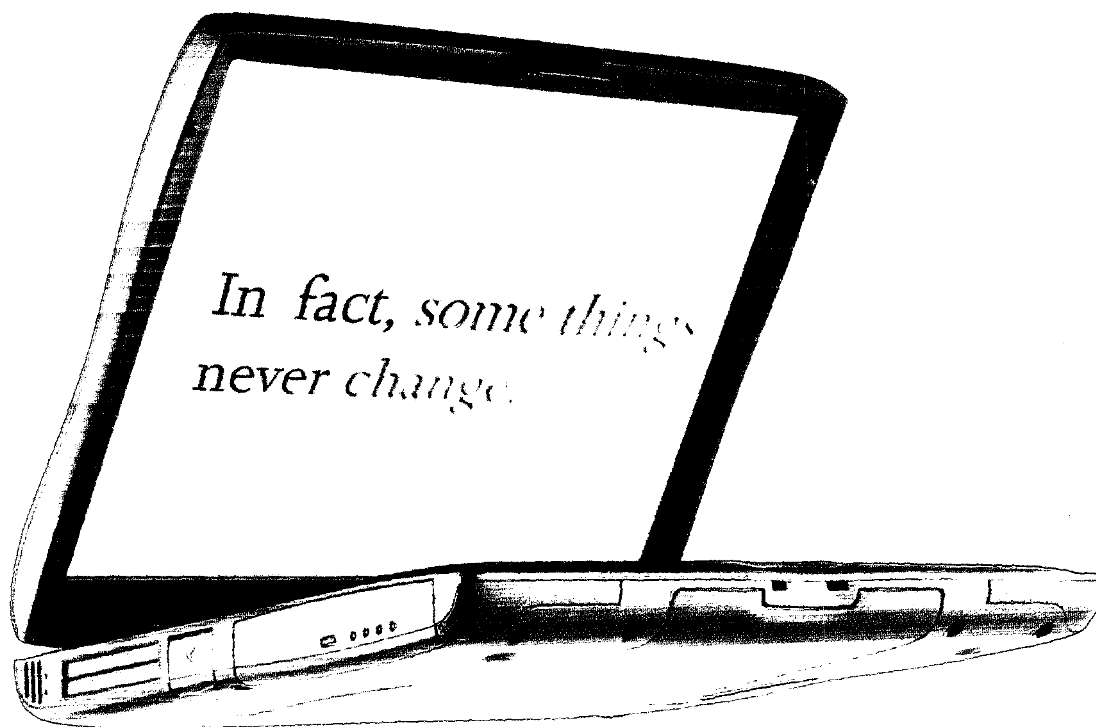
Not everything changes.

Since 1909 Empire has brought power to the heartland of America. We're just the kind of electric company you would expect to find in this region of small towns and down-to-earth people — one where hard-working employees follow a common-sense plan to keep the power on. Our rates are competitive, our service is reliable, and our performance for shareholders is dependable.

In fact, some things never change.
Our goal is, and always has been, to give increasing value to our shareholders while we give excellent service to our customers. We've been doing this pretty well for a very long time. Our approach isn't complicated. Simply put, we use good management, good people, and the latest technology to maximize results.

Our basic plan doesn't change, but the specific strategies we follow are targeted to fit the current business climate. Today, bringing Empire shareholders the best return possible means knowing how to build value in an atmosphere of growing customer demand and unstable fuel prices. We're guided by three basic strategies:

- *Continue to expand generating capabilities*
- *Achieve operational excellence*
- *Add to our existing integrated utility business*


In fact, some things
never change.

☐ **Becky Snyder**
6 years service

the same commitment.

93 years

☐ **Jim Evans**
32 years service

the best management.

☐ **Angela Cloven**
16 years service

☐ **Bob England**
12 years service

the right people.

☐ **Wes Edge**
14 years service

later...

Actions speak louder than words.
Empire's actions prove our dedication to our shareholders and our customers. Over the last 10 years, our customer base has grown by 26 percent and energy consumption has risen 41 percent. As customers' needs have grown, we've moved to ensure that our generation is efficient and our power supply ample. Our largest customer accounts for about 1 percent of total revenue, and our top 10 industrial customers make up about 8 percent of total revenue. This diversity helps insulate us from downturns in any particular sector.

A significant portion of our construction expenditures in recent years has been for new generation units. The newest addition to our generation mix is our 60% share of the 500-megawatt State Line Combined Cycle unit that we own jointly with Westar Generating, a subsidiary of Western Resources. Our State Line Power Plant is one of the most efficient, cleanest burning facilities in the nation and brings economies of scale typically seen in much larger facilities. With the additional capacity that State Line brings, we have greater freedom to choose between our own generation and buying power on the market. This helps keep costs competitive.

☐ **Delmis Brown**
24 years service

And we're not finished.
We announced plans in 2001 to add two 50-megawatt, gas-fired aero derivative combustion turbines to our Energy Center peaking facility. The new turbines will be our most efficient simple-cycle combustion turbines. We expect to have the first unit operational in the spring of 2003 and the second unit in service in 2004. We are exploring our options for baseload generation participation in the 2004-2010 time frame.

State Line Power Plant

The same commitment.

(Securing tomorrow)

Providing for tomorrow starts by working smart today. We strive for top performance by using management expertise and proven technologies geared to getting the best from our facilities and our employees. Last year we conducted maintenance at Asbury to improve combustion and emission performance.

In 2001, we developed a combination approach that calls for putting into action the right fuel procurement plan, managing the rate-making process, and controlling operating costs.

An all-out assault on fuel volatility.

Step 1. Establish hedging strategy. Because fuel and purchased power make up about 55 percent of our operating expenses, volatility in these costs can bring significant volatility to our earnings. In 2001, we implemented a hedging strategy for natural gas, which allows use of both physical purchases and financial tools. Under this strategy, we hedge our future natural gas requirements over time under a set of predetermined percentages. Our aim is to lessen the impact of volatility in our fuel and purchased power expenses on earnings, and establish a more predictable basis for future rate proceedings.

Step 2. Implement regulatory solution. As a regulated business, Empire's strategy is to aggressively pursue regulatory solutions, including rate relief, when necessary. Fuel adjustment clauses are currently in effect for all our customers in Oklahoma and Arkansas and for our wholesale customers throughout our service territory. These fuel adjustment clauses protect both our shareholders and customers from fuel volatility.

During 2001, we were able to implement an Interim Energy Charge (IEC) that protects us from volatility in Missouri. The IEC will be in effect until October 2003. At that point, our actual fuel and purchased power costs will be audited and any amounts collected for the IEC above our actual costs will be refunded with interest to customers. With the addition of the IEC in Missouri, nearly 95 percent of our electric business has protection from fuel cost volatility. In our recent Kansas filing, we requested that our Kansas fuel adjustment clause be reestablished.

Gary Rice
31 years service

Pat Settle
33 years service

Dave Walden
33 years service

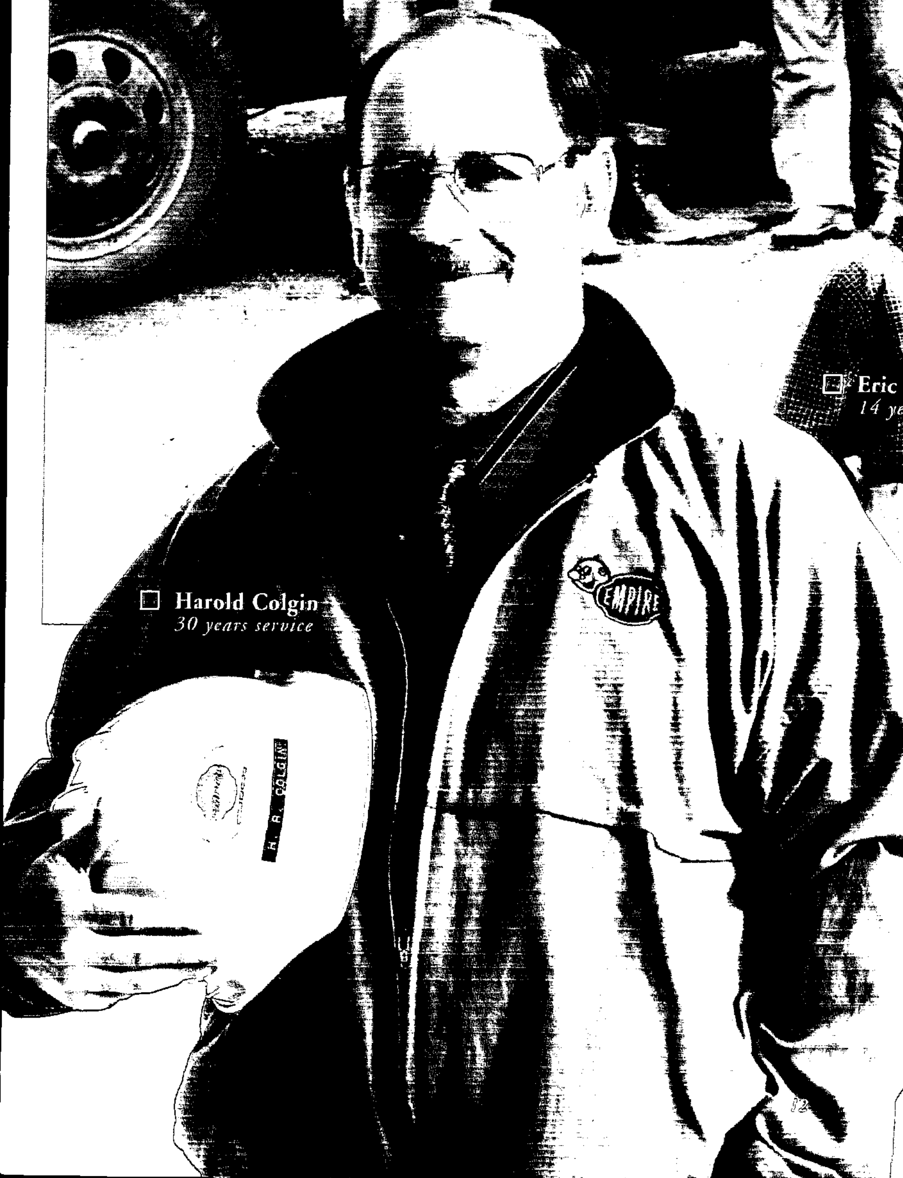
Martha Watts
36 years service

Vicki Williams
35 years service

□ **Kristi Ball**
16 years service

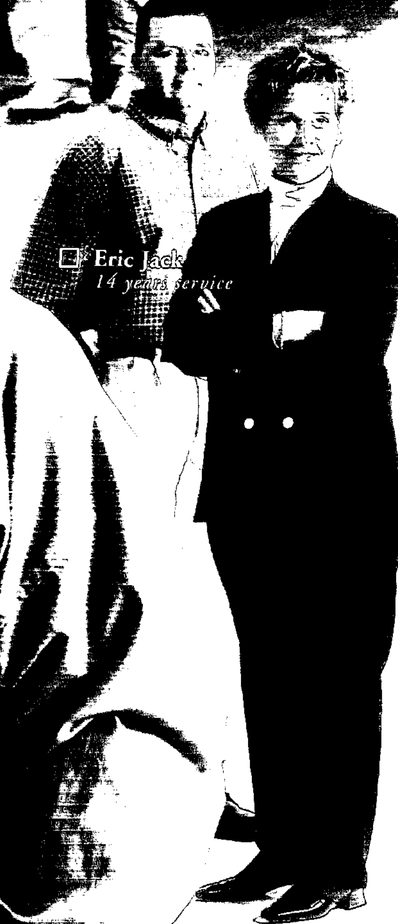
The best management.

(Est. 1909)



□ **Harold Colgin**
30 years service

□ **Eric Jack**
14 years service



□ **Marcia Sadler**
13 years service

□ **Garry Haralson**
23 years service

☐ **Randy Caruthers**
16 years service

☐ **Tina Gaines**
5 years service

☐ **Martin Penning**
21 years service

During our 93 years of service to the four-state region, we have developed a name synonymous with quality customer service. This provides a good foundation for our nonregulated products and services. A senior-level position established in 2001, Vice President - Nonregulated Services, directs these activities.

Last year we launched EDE Holdings, Inc., a holding corporation for our nonregulated businesses. To date, EDE Holdings consists of three companies.

- *EDE Industries, Inc., markets contract lighting services, fiber-optics and telecommunications, and E-Watch, a monitored security program, all formerly offered under The Empire District Electric Company name.*
- *Conversant, Inc., markets the internet-based customer information system software formerly named Centurion that was developed by Empire employees. Conversant began business in early 2002 with offices in Dallas and Joplin.*
- *transaeris, which also began business in early 2002, offers a high-speed internet service previously not available to area communities.*

Managing our financial strength.

We have set goals to restore our equity ratio and bond ratings to the levels where they sat prior to our now-terminated plan to merge with UtiliCorp. Empire has historically maintained an equity to total capitalization ratio between 45 and 50 percent. However, under the provisions of our 1999 merger agreement with UtiliCorp, we were required to redeem our preferred stock and were restricted from issuing common stock. We issued $100 million in unsecured debt in the fall of 1999, which dropped our equity to capitalization ratio to around 40 percent. Our goal is to restore our equity ratio to a level between 45 and 50 percent.

We are also working to restore our bond ratings to pre-merger status. Increased scrutiny due to events in the energy industry (which Empire does not control) makes this a more difficult, long-term goal.

On March 1, 2001, we issued $50 million in Trust Preferred Securities and on December 10, we issued 2,012,500 shares of common stock in an underwritten public offering. Net proceeds were added to our general funds and used to repay short-term debt, including debt incurred in connection with our construction program.

A solid approach to managing is the cornerstone of the Empire commitment.

☐ **Rick Wolfe**
15 years service

☐ **Dale Jasumback**
23 years service

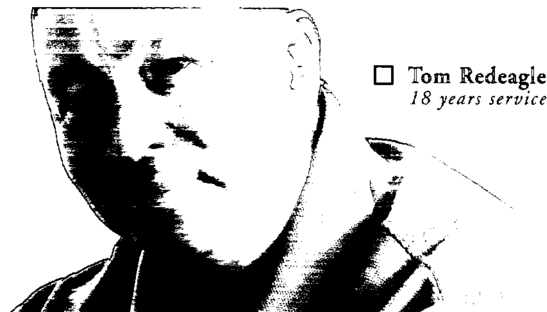
The right people.

(Keeping the commitment alive)

Empire people have always risen to the challenge of excellence. Last year we again made changes to our corporate structure, and employees carried through with adjustments in staffing and functions at all levels.

They implemented new technologies to enhance our already strong customer service: a new treatment applied to our underground cables improves service reliability and our new Call Center-East gives customers a quick response to their inquiries. Soon a new global positioning system will allow us to more quickly pinpoint service interruption problems, and our internet site will allow customers to conduct even more business online.

To develop a new generation of Company leaders, we instituted an extensive in-house management training program. And to further enhance employee skills and confidence, we continued a

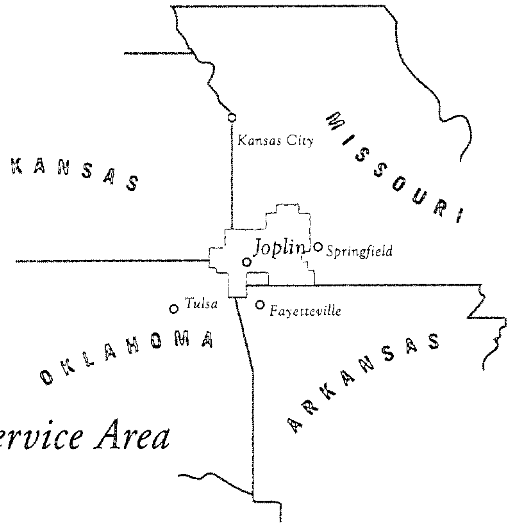


☐ **Tom Redeagle**
18 years service

☐ **Gary Shaver**
28 years service

number of technical training programs.

Employees also did credit to themselves and the Company by contributing their time, talent, and treasures to various community endeavors. Last year, they gave to a record-setting United Way campaign, helped at area schools, donated blood and school supplies, delivered Homebound Meals, presented safety messages, and organized and led the Over 60 Olympics and other charitable activities. They served as coaches, troop leaders, teachers, board members, and mentors, and the list goes on and on.



☐ **Ed Warthen**
11 years service

Nearly a century since we were formed, over half a century since our dividends began, the Empire family stands by its commitments to customers and shareholders. *Not everything changes.*

Officers positioned left to right. Front row: Myron McKinney, Brad Beecher. Back row: Jan Watson, Darryl Coit, Mike Palmer, Bill Gipson, Tony Stark, Greg Knapp (In Truck), Ron Gatz, and Dave Gibson.

Officers

Myron W. McKinney [1]
President,
Chief Executive Officer & Director
(Age 57, 34 years of service)

William L. Gipson [2]
Executive Vice President
& Chief Operating Officer
(Age 45, 21 years of service)

Bradley P. Beecher
Vice President - Energy Supply
(Age 36, Began service in February 2001)

Ronald F. Gatz
Vice President - Nonregulated Services
(Age 51, Began service in March 2001)

David W. Gibson [3]
Vice President - Regulatory Services
(Age 55, 22 years of service)

Gregory A. Knapp [4]
Vice President - Finance
& Chief Financial Officer
(Age 50, Began service in January 2002)

Michael E. Palmer
Vice President - Commercial Operations
(Age 45, 15 years of service)

Clifford A. (Tony) Stark [5]
Vice President - General Services
(Age 57, 21 years of service)

Janet S. Watson
Secretary - Treasurer
(Age 49, 7 years of service)

Darryl L. Coit
Controller, Assistant Secretary
& Assistant Treasurer
(Age 51, 31 years of service)

Committees of the Board of Directors

Audit Committee
Posner, Chairman; Chubb; Hartley; Jeffries; Leon

Compensation Committee
Jeffries, Chairman; Herschend; Lamb; Mayes; Posner

Executive Committee
McKinney, Chairman; Hammons; Hartley; Lamb; Mayes

Nominating Committee
Mayes, Chairman; Chubb; Hammons; Herschend

Retirement Committee
Hammons, Chairman; Hartley; Lamb; Leon

1 Retiring from his position as President and CEO on April 30, 2002, and becomes Chairman of the Board of Directors effective May 1.
2 Becomes President and CEO effective May 1, 2002. Nominated for election to the Board of Directors effective April 25, 2002.
3 Effective March 15, 2002. Previously Vice President - Finance and Chief Financial Officer.
4 Effective March 15, 2002. Previously General Manager - Finance.
5 Retiring effective June 30, 2002.

Directors

Melvin F. (Nick) Chubb, Jr.
Retired Senior Vice President
Eagle-Picher Industries, Inc.
Cincinnati, Ohio
(Age 68, Director since 1991)

William L. Gipson [1]
Executive Vice President
& Chief Operating Officer
The Empire District Electric Company
(Age 45, Nominated 1/31/2002)

R. Dwain Hammons
Retired Chairman
& Chief Executive Officer
Hammons Products Company
Stockton, Missouri
(Age 68, Director since 1983)

Ross C. Hartley
Co-Founder & Director
National Information Consortium
Overland Park, Kansas
(Age 54, Director since 1988)

Jack R. Herschend
Chairman-emeritus & Co-owner
Silver Dollar City, Inc.
Branson, Missouri
(Age 69, Director since 1994)

Francis E. Jeffries
Retired Chairman
Phoenix Duff & Phelps Corporation
Chicago, Illinois
(Age 71, Director since 1984)

Robert L. Lamb
Retired President
The Empire District Electric Company
Joplin, Missouri
(Age 69, Director since 1978)

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

Roy E. Mayes [2]
Retired Chairman
& Chief Executive Officer
Carmar Group Inc.
Carthage, Missouri
(Age 67, Director Since 1991)

Myron W. McKinney [3]
President & Chief Executive Officer
The Empire District Electric Company
Joplin, Missouri
(Age 57, Director Since 1991)

Mary McCleary Posner
President & Principal
Posner-McCleary Inc.
Columbia, Missouri
(Age 62, Director since 1991)

1 Nominated for election April 25, 2002. Becomes Empire's President and CEO effective May 1, 2002
2 Retiring effective April 25, 2002
3 Retiring from his position as President and CEO on April 30, 2002, and becomes Chairman of the Board of Directors effective May 1

Financial Section

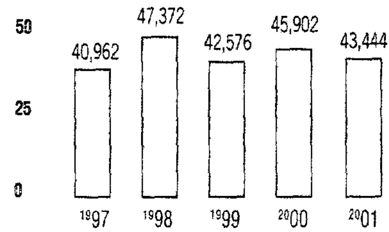
p.19
Management's Discussion and Analysis of Financial Condition and Results of Operations

p.27
Report of Independent Accountants

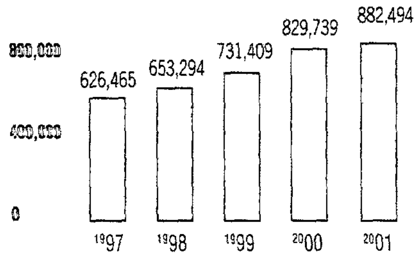
p.28
Financial Statements

p.32
Notes to Financial Statements

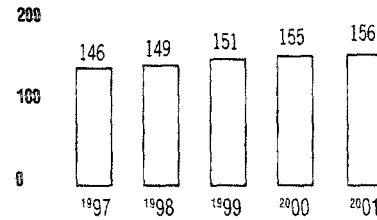
Charted Data.



Operating Income
Dollars in Thousands

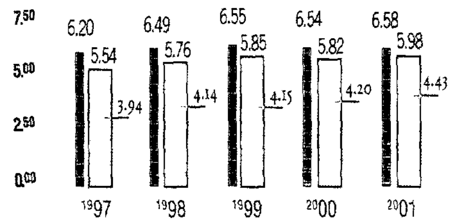


Total Assets
Dollars in Thousands

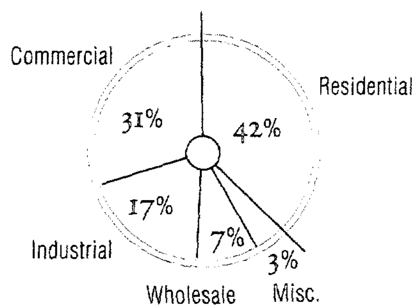


Utility Customers
Thousands

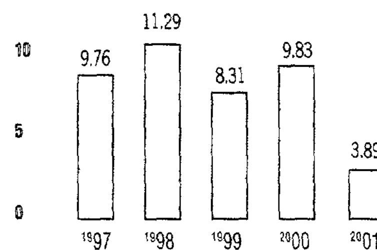
Total Operating Revenue
Dollars in Thousands



Average Rates
Cents per Kilowatt-hour



2001 Sources of Total Revenue



Return on Common Equity
Percent

Management's Discussion and Analysis of Financial Condition and Results of Operations.

Terminated Merger with Utilicorp

Empire and UtiliCorp United Inc. entered into an Agreement and Plan of Merger, dated as of May 10, 1999 which provided for a merger of our company with and into UtiliCorp, with UtiliCorp being the surviving corporation. The merger was conditioned, among other things, upon approvals of various federal and state regulatory agencies, with either company having the right to terminate the merger agreement if all regulatory approvals were not obtained by December 31, 2000. All approvals were not received by this date and UtiliCorp notified us on January 2, 2001, that it was exercising its right to terminate the merger agreement.

As a result of the termination of the merger by UtiliCorp, approximately $6.1 million in merger related expenses that were not tax deductible when incurred by us, became deductible. This deduction was taken in January 2001, decreasing income tax expense and increasing operating income for the first quarter of 2001 by approximately $2.3 million.

Results of Operations

The following discussion analyzes significant changes in the results of operations for the year ended December 31, 2001, compared to the year ended December 31, 2000, and for the year ended December 31, 2000, compared to the year ended December 31, 1999.

Operating Revenues and Kilowatt-Hour Sales

Of our total electric operating revenues during 2001, approximately 42% were from residential customers, 31% from commercial customers, 17% from industrial customers, 5% from wholesale on-system customers, 1.5% from wholesale off-system transactions and 3.5% from miscellaneous sources such as late payment fees and transmission services. The percentage changes from the prior year in kilowatt-hour ("Kwh") sales and revenue by major electric customer class were as follows:

	Kwh Sales		Revenues	
	2001	2000	*2001	2000
Residential	1.2%	10.1%	0.7%	9.9%
Commercial	3.2	5.8	4.4	5.2
Industrial	(1.1)	2.8	1.9	4.1
Wholesale On-System	4.1	4.0	10.0	9.9
Total System	1.6	6.3	2.6	7.1

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

Kwh sales and revenues for our on-system customers increased during 2001 primarily due to unseasonably cold temperatures in the first quarter and warmer temperatures during the second quarter, offset by milder temperatures in the last two quarters of 2001. Customer growth was 1.13% in 2001.

Residential Kwh sales increased 1.2% with revenues increasing 0.7% as compared to 2000 primarily due to these weather conditions. Commercial Kwh sales increased 3.2% with revenues increasing 4.4% due to these weather conditions as well as continued increases in business activity throughout our service territory. Industrial classes showed a 1.1% decrease in Kwh sales due to decreased consumption 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 increased Missouri rates.

On-system wholesale Kwh sales increased 4.1% 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 such FERC regulated sales. This clause permits the pass through to customers of changes in fuel and purchased power costs.

Kwh sales and revenues for our on-system customers increased during 2000 primarily due to above-average temperatures in August and September of 2000 as well as unseasonably cold temperatures in November and December of 2000. Customer growth in 2000 remained at the same rate as experienced in 1999. Residential Kwh sales increased 10.1% with revenues increasing 9.9% as compared to 1999 primarily due to these weather conditions. Commercial Kwh sales increased 5.8% with revenues increasing 5.2% due to these weather conditions as well as increases in business activity throughout our service territory. Industrial classes also showed an increase in Kwh sales and revenues because of the increased business activity.

On-system wholesale Kwh sales increased 4.0% in 2000, reflecting these weather conditions. Revenues associated with these sales increased more than the corresponding Kwh sales as a result of the operation of the fuel adjustment clause mentioned above.

On November 3, 2000, we filed a request with the Missouri Public Service Commission for a general annual increase in rates for our Missouri electric customers in the amount of $41,467,926, or 19.36%. This request sought recovery of expenses resulting from significantly higher natural gas prices than the levels contemplated by our existing rates as well as our investment in the Combined Cycle Unit which was under construction at the State Line Power Plant and other plant additions which had occurred since our last rate increase in September 1997. We also filed a request for interim rate relief in February 2001, which was denied in March.

The Missouri Commission issued a final order on September 20, 2001. The order granted 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 (IEC) of approximately $19.6 million effective October 1, 2001 and expiring two years later. This IEC is $0.0054 per kilowatt hour of customer usage. The recent extraordinarily high natural gas prices and extreme volatility of natural gas led the Missouri Commission to allow forecasted fuel costs to be used rather than the traditional historical costs in determining the fuel portion of the rate increase. At the end of the two year period, the excess money collected from customers, if any, above the greater of the actual and prudently incurred costs or the base cost of fuel and purchased power set in rates, will be refunded to the customers with interest equal to the current prime rate at that time. At December 31, 2001, we had recorded a liability of approximately $2.8 million of the IEC collected in the fourth quarter of 2001 as a provision for rate refunds and are not recognizing that revenue in total electric operating revenue. As of February 18, 2002, approximately 90% of our anticipated volume of natural gas usage for the year 2002 is hedged at an average price of $2.93 per Dekatherm (Dth) while approximately 59% of our anticipated volume of natural gas usage for the year 2003 is hedged at an average price of $3.20 per Dth.

On October 26, 2001, we filed a request with the Missouri Public Service Commission for an additional increase in rates for our Missouri electric customers in the amount of $3,562,983 annually to rectify a regulatory clerical error omitting the cost of off-system sales in the recent rate order. The Missouri Commission, after various proceedings, denied our requests for relief. We are currently evaluating our options for recovering the previously overlooked expenses as well as other capital investments and increased operating expenses which have occurred since our last rate increase.

On December 28, 2001, we filed a request with the Kansas Corporation Commission for a general annual increase in rates for our Kansas electric customers in the amount of $3,239,744, or 22.81%. This request seeks 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 as well as significant additions to the transmission and distribution systems and operating cost increases which have occurred since our last rate increase in September 1994. A hearing is scheduled for June 27-28, 2002. Any rate increase approved as a result of the filing would not become effective until August 2002. We cannot predict the amount of any increase which might be granted as a result of this filing.

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 2001 revenues from such off-system transactions were approximately $7.5 million as compared to approximately $10.6 million in 2000 and approximately $9.6 million during 1999. This fluctuation in revenues is primarily the result of our ability to sell power at market-based rates with the decrease in revenues during 2001 resulting primarily from our peak hour market-based rates being substantially lower this summer than in 2000, milder regional weather conditions in the fourth quarter affecting demand and less power available for sale from the State Line Plant due to the construction of the Combined Cycle Unit during the first half of the year. See "- Competition" below for more information on open-access tariffs.

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

Operating Revenue Deductions

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 of 2001 resulting from milder temperatures and the increased generating capability due to the completion of the State Line Combined Cycle Unit. 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 new Combined Cycle Unit 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 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. Merger related expenses in 2001 were primarily the result of expenses related to severance benefits incurred under our Change in Control Severance Pay Plan in the first quarter of 2001. 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 payments under our new maintenance contracts entered into in July 2001 for the combustion turbines at the Energy Center and State Line Power Plants.

Depreciation and amortization expense increased approximately $1.7 million (6.0%) during 2001 due to increased levels of plant and equipment placed in service. The increase in depreciation and amortization expense caused by increased levels of plant and equipment was partially offset by lower depreciation rates put into effect during the fourth quarter of 2001 as a result of the October rate order issued by the Missouri Commission. Total provision for income taxes decreased approximately $9.7 million (85.3%) during 2001 due primarily to lower taxable income and by the deductibility of approximately $6.1 million in merger related expenses discussed above. See Note 9 of "Notes to Financial Statements" under Item 8 for additional information regarding income taxes. Other taxes increased approximately $0.4 million (3.4%) during the year.

During 2000, total operating expenses increased approximately $19.5 million (15.3%) compared to the prior year. Total purchased power costs increased by approximately $20.5 million (46.0%) during 2000 reflecting increased demand in the third and fourth quarters of 2000. Decreased availability of some of our generating units during the third quarter of 2000 and escalating natural gas prices (which at times made it more economical to purchase power than to run our gas-fired units, particularly in September) added to the increase in purchased power. The Riverton Plant's coal-fired Unit No. 7 was out of service for its scheduled fall outage from September 15 to November 9 and Unit No. 8, also coal-fired, was out of service for its scheduled fall outage from September 29 to October 16. The State Line Plant's Unit No. 2 was taken out of service on September 12, 2000 to begin construction of the Combined Cycle Unit that was placed into commercial operation in June 2001.

Total fuel costs were up approximately $3.6 million (8.1%) during 2000 primarily reflecting increased generation by our gas generation facilities in the fourth quarter of 2000. The extremely cold temperatures in December resulted in a significant increase in the price of purchased power, making it more economical for us to run our gas-fired turbines. Natural gas prices were higher by 31.3% during 2000 as compared to 1999.

Merger related expenses, which were not tax deductible when they were incurred, were $5.4 million (94.3%) less during 2000 as compared to 1999. Other operating expenses increased approximately $0.7 million (2.3%) during 2000, compared to 1999, mainly due to a $0.5 million addition to the bad debt reserve in the third quarter. Maintenance and repairs expense decreased approximately $1.6 million (9.5%) during 2000 primarily due to decreased maintenance on the combustion turbines at Energy Center as well as decreased levels of distribution maintenance.

Depreciation and amortization expense increased approximately $1.4 million (5.4%) during 2000, compared to 1999, due to increased levels of plant and equipment placed in service. Total provision for income taxes decreased approximately $4.5 million (28.3%) during 2000 due primarily to lower taxable income. Other taxes decreased approximately $0.3 million (2.6%) during the year.

Nonoperating Items

Total allowance for funds used during construction ("AFUDC") amounted to approximately 34.7% of earnings applicable to common stock during 2001, 24.5% during 2000, and 6.1% during 1999. Although the percentage of AFUDC compared to earnings applicable to common stock increased in 2001 as compared to 2000, this reflected decreased net income in 2001 rather than increased AFUDC. The amount of AFUDC actually decreased $2.2 million (37.5%) in 2001 reflecting the completion of the State Line Combined Cycle Unit in June. AFUDC increased significantly in 2000 primarily due to the construction of the State Line Combined Cycle. See Note 1 of "Notes to Financial Statements" under Item 8.

Other-net deductions increased $0.6 million (92.3%) during 2001 as compared to 2000 primarily reflecting a loss in the second and third quarters of 2001 caused by the marking to market, required by Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133) of option contracts entered into in connection with our hedging activities that did not qualify for hedge accounting. 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 State Line Combined Cycle Unit. These disallowed costs were part of a stipulated agreement between us and the Missouri Commission in connection with our October rate order. The net effect on earnings after considering the tax effect on this write-down is $2.5 million.

Interest charges on long-term debt were virtually the same for 2001 as for 2000. Interest charges on long-term debt increased $7.0 million (35.8%) during 2000 as compared to 1999 due to the issuance of $100 million of our unsecured Senior Notes in November 1999. Commercial paper interest increased $1.0 million (78.7%) during 2001 due to increased usage of short-term debt for financing our construction program. Interest related to our Trust Preferred Securities issued on March 1, 2001 added $3.5 million to total interest charges during 2001. Interest income decreased $0.4 million (68.9%), reflecting lower balances of cash available for investment.

Earnings

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 State Line 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. Excluding $1.4 million in merger costs for 2001, the one-time write-down of construction expenditures and the tax benefit from merger expenses, earnings per share would have been $0.68. Excluding merger related expenses of $0.3 million, earnings per share would have been $1.37 during 2000.

Basic and diluted earnings per weighted average share of common stock were $1.35 during 2000 compared to $1.13 in 1999. Excluding merger related expenses, earnings per share would have been $1.37 during 2000 compared to $1.46 in 1999. Earnings per share, although higher because of favorable weather conditions, increased AFUDC and decreased merger expenses, were negatively impacted by significantly increased natural gas prices and purchased power costs.

Earnings for the first quarter of 2002 will reflect an aggregate of $1.5 million of merger expenses related to severance benefits accrued under our Change in Control Severance Pay Plan.

Competition

Federal regulation has promoted and is expected to continue to promote competition in the electric utility industry. Oklahoma and Arkansas, however, are the only states in which we operate that have taken action with respect to promoting competition.

Legislation in Oklahoma originally provided for open competition by July 2002. However, the Oklahoma Legislature overwhelmingly approved legislation in June 2001 that indefinitely delays electric restructuring in the state. Approximately 3.19% of our retail electric revenue for 2001 was derived from sales subject to Oklahoma regulation.

The Arkansas Legislature passed a bill in April 1999 that called for deregulation of the state's electricity industry as early as January 2002. A bill was enacted in February 2001, however, delaying implementation of deregulation until October 2003 and giving the Arkansas Public Service Commission (APSC) authority to set further delays in one-year increments until October 2005. The APSC, after conducting hearings, issued a report in December 2001 recommending that the legislature suspend deregulation beyond 2003 or repeal the law mandating deregulation. Approximately 3.13% of our retail electric revenue for 2001 was derived from sales subject to Arkansas regulation.

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 and the Southwestern Power Pool (SPP) have filed these open access transmission tariffs covering wholesale transmission services. Under these tariffs, we share revenues received from most of our transmission services with other members of the SPP. There are, however, limited circumstances where our own tariff still applies, and we receive 100% of the revenues from the transmission services. We will continue to operate under the SPP tariff until a new tariff is filed as part of the Midwest Independent Transmission System Operator, Inc. (MISO), the regional transmission organization, or RTO, which we intend to join.

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 the 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. This new organization will operate our system as part of an interconnected transmission system encompassing over 120,000 megawatts of generation capacity located in 20 states. MISO will collect revenues attributable to the use of each member's transmission system and each member will be able to transmit power purchased, generated for sale or bought for resale in the wholesale market throughout the entire MISO system. Although each member will have priority over the use of its own transmission facilities for selling

power to its wholesale customers or others, each member will be charged the same uniform transmission rate as other energy suppliers who are able to sell power to them. We intend to file 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.

We cannot predict what effect, if any, this will have on our off-system sales and revenues but it could be material. Even though we have historically been able to generate power relatively inexpensively, other suppliers may be able to offer power at more favorable rates and transmit that power along our system at the same price we pay. Approximately 5% of our electric operating revenues are derived from sales to on-system wholesale customers, the type of customer for which the FERC is already requiring wheeling.

Nonregulated Business

We are continuing our investments in nonregulated businesses which we commenced in 1996. We now lease capacity on our broadband fiber optics network and provide electronic monitored security, decorative lighting and other energy services through our wholly owned subsidiary, EDE Holdings, Inc. See Item 1, "Business - General" for further information about these nonregulated businesses.

Liquidity and Capital Resources

Our construction-related expenditures totaled approximately $71.8 million, $133.9 million, and $71.9 million in 2001, 2000 and 1999, respectively.

A breakdown of our 2001 construction expenditures is as follows:

	Construction Expenditures (amounts in millions)
	2001
Distribution and transmission system additions	31.2
New construction - State Line Combined Cycle Unit	24.7
Twin Pac aero units - Energy Center	3.5
Additions and replacements - Asbury	7.7
Additions and replacements - Riverton and Iatan	0.9
Fiber optics	0.8
General and other additions	3.0
Total	$71.8

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

Approximately 20% of construction expenditures and other funds requirements for 2001 were satisfied internally from operations. The other 80% of such requirements were satisfied from short-term borrowings and proceeds from our sale of common stock in an underwritten public offering on December 10, 2001.

We estimate that our construction expenditures will total approximately $72.2 million in 2002, $85.8 million in 2003 and $66.1 million in 2004. Of these amounts, we anticipate that we will spend $18.8 million, $22.3 million and $21.8 million in 2002, 2003 and 2004, respectively, for additions to our distribution system to meet projected increases in customer demand. These construction expenditure estimates also include approximately $19.2 million, $25.8 million and $7.0 million in 2002, 2003 and 2004, respectively, for two Twin Pac aero units at the Empire Energy Center.

On October 25, 2001, we entered into an agreement to purchase two Twin Pac aero units with generating capacity of 50 megawatts each to be installed at the Empire Energy Center. An initial payment of $3.4 million was made at that time. The first unit is scheduled to be delivered in October 2002 and is expected to be operational by April 2003. The second unit is scheduled to be delivered in October 2003 and is expected to be operational by April 2004. Contracts with other vendors will be entered into for construction and installation of the units.

We estimate that internally generated funds will provide at least 55% of the borrowing funds required in 2002 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 public offerings of long-term debt or common stock, including common stock pursuant to our Employee Stock Purchase Plan, our Dividend Reinvestment and Stock Purchase Plan and from internally-generated funds. We will continue to utilize short-term debt as needed to support normal operations or other temporary requirements.

As of December 31, 2001, we had lines of credit aggregating $75 million. Our lines of credit each currently contain certain contingencies which affected our rights and obligations thereunder. In the event that the credit rating on our first mortgage bonds falls below BBB (Standard & Poor's) or Baa3 (Moody's) for a $55 million line of credit or Baa2 for a $20 million line of credit, our obligations under our lines of credit either could become immediately due and payable or are no longer available to us. Our credit ratings are discussed below. Further, one of our lines of credit contains a restriction on availability in the event that we fail to maintain Total Funded Debt to Capital (where Capital is defined as Total Funded Debt plus Equity Capital (including our $50,000,000 of Trust Preferred Securities)) less than 67.5%. We are currently in compliance with this ratio. This line of credit is also subject to cross-default with our other indebtedness (in excess of $10,000,000 in the aggregate). We are currently in the process of seeking to amend and/or replace these lines of credit so as to remove the credit rating conditions. See Note 7 of "Notes to Financial Statements" regarding our lines of credit.

In addition, restrictions in our mortgage bond indenture could also 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. 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. Our earnings for the twelve months ended December 31, 2001 do not permit us to issue new first mortgage bonds based on this test. However, we have not financed with bonds since 1998 and have used unsecured long-term debt rather than first mortgage bonds. See Note 6 to "Notes to Financial Statements" for more information on the mortgage bond indenture.

In February 2001, the SEC declared effective our $80 million shelf registration statement covering our unsecured debt securities and preferred securities of two newly created trusts of which $30 million remains available for issuance. On March 1, 2001, we sold two million 8 1/2% Trust Preferred Securities (liquidation amount $25 per preferred security) in a public underwritten offering. This issuance 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, as well as payments of principal, are made from cash received from corresponding payments made by us on the $50.0 million 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. 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 approximately $41 million. Proceeds from the sale of the common stock were added to our general funds and used to repay short-term debt, including debt incurred in connection with our construction program.

On November 19, 1999, we issued $100 million aggregate principal amount of our unsecured Senior Notes, the net proceeds of which were added to our general funds and were used to repay short-term indebtedness, including indebtedness incurred in connection with our preferred stock redemption and in connection with our construction program.

Following announcement of the merger with UtiliCorp, the credit ratings for our first mortgage bonds (other than the pollution control bonds) were placed on credit watch with downward implications by Moody's Investors Service and Standard & Poor's. Standard & Poor's removed the credit watch but kept the downward implication in January 2001 after the merger was terminated. In May 2001, Moody's Investors Service lowered the credit ratings of our first mortgage bonds (other than the pollution control bonds) to Baa1 from A2, and on our senior unsecured debt to Baa2 from A3. This downgrade was primarily due to the risk to our credit profile associated with our ability to obtain necessary rate relief from the Missouri Public Service Commission to recover our capital expenditures associated with the construction of the Combined Cycle Unit at our State Line Power Plant and our increased operating expenses primarily caused by escalating natural gas prices. As of December 31, 2001, the ratings for our securities were as follows:

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

These ratings indicate the agency's 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 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, 2001:

		Payments Due by Period (in millions)			
Contractual Obligations	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
Long-Term Debt (w/o discount)	$396.1	$37.5	$110.0	$ —	$248.6
Capital Lease Obligations	0.8	0.2	0.6	—	—
Other Long-Term Obligations	257.7	52.4	117.6	32.4	55.3
Total Contractual Obligations	$654.6	$90.1	$228.2	$32.4	$303.9

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).

Pensions. In accordance with Statement of Financial Accounting Standards (SFAS) No. 87, "Employers' Accounting for Postretirement Benefits Other Than Pensions", our pension expense includes a calculation of "amortization of unrecognized net (gain)/loss" which was changed in 2001 as a result of the settlement order in our Missouri rate case. Previously the current year calculation of net gains or losses was amortized over five years. The new calculation requires the use of an average of the previous five years gain or loss, which is then amortized over five years. The result for year 2001 was an increase of $317,135 in pension income.

Provision for Refunds. As discussed under "Operating Revenues and Kilowatt-Hour Sales" above, the Missouri Commission in its September rate case order approved an annual IEC of approximately $19.6 million effective October 1, 2001 and expiring two years later. At the end of the two year period, the excess money collected from customers under the IEC, if any, above the greater of the actual and prudently incurred costs or the base cost of fuel and purchased power set in rates, will be refunded to the customers with interest equal to the current prime rate at that time. At December 31, 2001, we had recorded a liability of approximately $2.8 million of the IEC collected in the fourth quarter of 2001 as a provision for rate refunds and are not recognizing that revenue in total electric operating revenue.

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 for 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.

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 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 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 items detailed below will be afforded similar treatment.

We recorded $37,743,107 in regulatory assets and $12,915,456 in income taxes as a regulatory liability for 2001. These amounts are being amortized over periods of up to 25 years. See Note 3 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.

Recently Issued Accounting Standards

In July 2001, the Financial Accounting Standards Board issued SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Other Intangible Assets". These statements eliminate the amortization of purchased goodwill and instead require an annual review of goodwill and intangibles for impairment or when a change or event occurs that indicates goodwill may be impaired. SFAS No. 142 is required to be adopted no later than the first quarter of fiscal 2002. SFAS No. 141 requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001 and establishes specific criteria for recognition of intangible assets separately from goodwill. We had no recorded goodwill as of December 31, 2001 but will continue to evaluate the total impact of the adoption of these Statements on our financial statements and financial reporting.

In June 2001, the Financial Accounting Standards Board issued SFAS No. 143, "Accounting for Obligations Associated with the Retirement of Long-Lived Assets." This statement establishes standards for accounting and reporting for legal and constructive obligations associated with the retirement of tangible long-lived assets. In August 2001, the Financial Accounting Standards Board issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets", 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 SFAS No. 144 on January 1, 2002 and are required to adopt SFAS No. 143 on January 1, 2003. We will continue to evaluate the total impact of the adoption of these Statements on our financial statements and financial reporting.

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. See Note 13 of "Notes to Consolidated Financial Statements" for further information.

Interest Rate Risk. We are exposed to changes in interest rates as a result of significant financing through our issuance of commercial paper. We manage our interest rate exposure by limiting our variable-rate exposure to a certain percentage of total capitalization, as set by policy, and by monitoring the effects of market changes in interest rates. See Notes 6 and 7 of "Notes to Financial Statements" under Item 8 for further information.

If market interest rates average 1% more in 2002 than in 2001, our interest expense would increase, and income before taxes would decrease by approximately $555,000. This amount has been determined by considering the impact of the hypothetical interest rates on our commercial paper balances as of December 31, 2001. 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.

To the Board of Directors and Shareholders 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 cash flows present fairly, in all material respects, the financial position of The Empire District Electric Company and its subsidiaries at December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, 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

January 29, 2002
St. Louis, Missouri

Consolidated Balance Sheets.

December 31,	2001	2000
ASSETS		
Utility plant, at original cost:		
Electric	$1,072,289,259	$ 921,033,228
Water	7,810,754	7,528,233
Construction work in progress	20,136,645	120,126,571
	1,100,236,658	1,048,688,032
Accumulated depreciation	349,743,785	328,370,253
	750,492,873	720,317,779
Current assets:		
Cash and cash equivalents	11,440,275	2,490,580
Accounts receivable - trade, net of allowance of $895,000 and $964,000, respectively	19,621,889	19,960,839
Accrued unbilled revenues	10,986,746	11,824,546
Accounts receivable - other	7,231,772	3,631,654
Fuel, materials and supplies	20,094,559	14,589,253
Prepaid expenses	1,063,195	3,034,716
	70,438,436	55,531,588
Noncurrent assets and deferred charges:		
Regulatory assets	37,743,107	36,590,292
Unamortized debt issuance costs	5,180,243	3,769,628
Other	18,639,293	13,530,017
	61,562,643	53,889,937
Total Assets	$ 882,493,952	$ 829,739,304
CAPITALIZATION AND LIABILITIES		
Common stock, $1 par value, 20,000,000 shares authorized, 19,759,598 and 17,596,530 shares issued and outstanding, respectively	$ 19,759,598	$ 17,596,530
Capital in excess of par value	208,223,200	168,439,089
Retained earnings	41,906,483	54,117,292
Accumulated other comprehensive loss, net of income tax	(1,581,310)	—
Total common stockholders' equity	268,307,971	240,152,911
Long-term debt:		
Company obligated mandatorily redeemable Trust preferred securities of subsidiary holding solely parent debentures	50,000,000	—
Obligations under capital lease	567,315	—
Other	308,047,363	325,643,766
Total long-term debt	358,614,678	325,643,766
	626,922,649	565,796,677
Current liabilities:		
Current maturities of long-term debt	37,500,000	20,000,000
Obligations under capital lease	158,329	—
Short-term debt	55,500,000	69,500,000
Accounts payable and accrued liabilities	34,520,862	35,782,456
Customer deposits	4,127,061	3,789,583
Taxes accrued	—	1,823,513
Interest accrued	5,091,240	5,402,131
Fair value of derivatives	2,547,300	—
	139,444,792	136,297,683
Commitments and Contingencies (Note 11)		
Noncurrent liabilities and deferred credits:		
Regulatory liability	12,915,456	14,170,175
Deferred income taxes	84,625,946	83,581,349
Unamortized investment tax credits	6,681,000	7,231,000
Postretirement benefits other than pensions	4,884,161	4,835,897
State Line advance payments	—	14,399,757
Other	7,019,948	3,426,766
	116,126,511	127,644,944
Total Capitalization and Liabilities	$ 882,493,952	$ 829,739,304

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

Consolidated Statement of Income.

Year ended December 31,	2001	2000	1999
OPERATING REVENUES:			
Electric (Note 1)	*$263,189,506*	$258,937,329	$241,065,202
Water	*1,065,348*	1,066,129	1,096,338
	264,254,854	260,003,458	242,161,540
Operating revenue deductions:			
Operating expenses:			
Fuel	*56,523,370*	48,899,577	45,251,427
Purchased power	*62,383,952*	65,238,096	44,696,792
Merger related expenses	*1,391,673*	327,397	5,772,292
Other	*36,726,181*	32,570,495	31,833,132
	157,025,176	147,035,565	127,553,643
Maintenance and repairs	*19,094,735*	14,795,210	16,345,268
Depreciation and amortization	*29,455,451*	27,783,573	26,366,695
Provision for income taxes	*1,677,172*	11,375,000	15,862,429
Other taxes (Note 1)	*13,558,439*	13,112,095	13,457,782
	220,810,973	214,101,443	199,585,817
Operating income	*43,443,881*	45,902,015	42,575,723
Other income and (deductions):			
Allowance for equity funds used during construction	*569,961*	2,373,710	56,845
Interest income	*199,447*	641,602	503,355
Loss on plant disallowance	*(4,087,066)*	—	—
Provision for other income taxes	*1,677,172*	(125,000)	(137,571)
Other - net	*(1,390,019)*	(535,285)	(524,547)
	(3,030,505)	2,355,027	(101,918)
Income before interest charges	*40,413,376*	48,257,042	42,473,805
Interest charges:			
Trust preferred distributions by subsidiary holding solely parent debentures	*3,541,667*	—	—
Other long-term debt	*26,384,310*	26,355,901	19,402,734
Allowance for borrowed funds used during construction	*(3,041,298)*	(3,401,325)	(1,135,776)
Other	*3,125,783*	1,685,312	2,036,708
	30,010,462	24,639,888	20,303,666
Net income	*10,402,914*	23,617,154	22,170,139
Preferred stock dividend requirements	—	—	1,403,025
Excess consideration on redemption of preferred stock	—	—	1,304,504
Net income applicable to common stock	*$ 10,402,914*	$ 23,617,154	$ 19,462,610
Weighted average number of common shares outstanding	*17,777,449*	17,503,665	17,237,805
Basic and diluted earnings per weighted average share of common stock	*$ .59*	$ 1.35	$ 1.13
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 Statement of Comprehensive Income.

Year ended December 31,	2001	2000	1999
Net income	$ 10,402,914	$ 23,617,154	$ 22,170,139
Unrealized loss on derivative hedging instrument, net of income taxes of $969,310	(1,581,310)	—	—
Comprehensive income	$ 8,821,604	$ 23,617,154	$ 22,170,139

Consolidated Statement of Common Stockholders' Equity.

Year ended December 31,	2001	2000	1999
Common stock, $1 par value:			
Balance, beginning of year	$ 17,596,530	$ 17,369,855	$ 17,108,799
Stock/stock units issued through:			
Public offering	2,012,500	—	—
Stock purchase and reinvestment plans	150,568	226,675	261,056
Balance, end of year	$ 19,759,598	$ 17,596,530	$ 17,369,855
Capital in excess of par value:			
Balance, beginning of year	$168,439,089	$163,909,731	$156,975,596
Excess of net proceeds over par value of stock issued:			
Public offering	37,023,140	—	—
Stock purchase and reinvestment plans	2,760,971	4,529,358	6,934,135
Balance, end of year	$208,223,200	$168,439,089	$163,909,731
Retained earnings:			
Balance, beginning of year	$ 54,117,292	$ 52,908,432	$ 55,706,779
Net income	10,402,914	23,617,154	22,170,139
	64,520,206	76,525,586	77,876,918
Less dividends declared:			
8 ⅛% preferred stock	—	—	1,349,474
5% preferred stock	—	—	124,642
4 ¾% preferred stock	—	—	126,094
Common stock	22,613,723	22,408,294	22,063,772
	22,613,723	22,408,294	23,663,982
Less: excess consideration on redemption of preferred stock	—	—	1,304,504
Balance, end of year	$ 41,906,483	$ 54,117,292	$ 52,908,432
Accumulated other comprehensive loss:			
Balance, beginning of year	$ —	$ —	$ —
Other comprehensive loss	(1,581,310)	—	—
Balance, end of year	$ (1,581,310)	$ —	$ —

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

Consolidated Statements of Cash Flows.

Year ended December 31,	2001	2000	1999
OPERATING ACTIVITIES			
Net income	$ 10,402,914	$ 23,617,154	$ 22,170,139
Adjustments to reconcile net income to cash flows provided by operating activities:			
Depreciation and amortization	32,855,222	31,354,048	29,672,416
Pension income	(4,366,247)	(7,780,497)	(4,325,229)
Deferred income taxes, net	810,000	2,053,000	4,480,000
Investment tax credit, net	(550,000)	(580,000)	(580,000)
Allowance for equity funds used during construction	(569,961)	(2,373,710)	(56,845)
Issuance of common stock for stock purchase and reinvestment plans	941,823	844,405	837,203
Loss on plant disallowance	4,087,066	—	—
Cash flows impacted by changes in:			
Accounts receivable and accrued unbilled revenues	(2,423,368)	(4,652,024)	(9,309,949)
Fuel, materials and supplies	(5,505,306)	1,389,537	(274,112)
Prepaid expenses and deferred charges	(831,109)	(1,427,249)	(3,050,794)
Accounts payable and accrued liabilities	(1,261,594)	10,550,235	8,135,949
Customer deposits, interest and taxes accrued	(1,796,926)	2,302,180	971,596
Other liabilities and other deferred credits	3,641,446	753,012	434,255
Net cash provided by operating activities	35,433,960	56,050,091	49,104,629
INVESTING ACTIVITIES			
Construction expenditures	(79,362,273)	(133,933,927)	(71,935,978)
Allowance for equity funds used during construction	569,961	2,373,710	56,845
Net cash used in investing activities	(78,792,312)	(131,560,217)	(71,879,133)
FINANCING ACTIVITIES			
Proceeds from issuance of senior notes	—	—	99,818,000
Proceeds from issuance of common stock	41,005,356	3,911,628	6,357,989
Proceeds from issuance of trust preferred securities	50,000,000	—	—
Long-term debt issuance costs	(1,884,756)	—	(797,837)
Redemption of preferred stock	—	—	(32,634,263)
Excess consideration on redemption of preferred stock	—	—	(1,304,504)
Dividends	(22,613,723)	(22,408,294)	(23,663,982)
Repayment of long-term debt	(198,830)	(286,000)	(110,000)
Net (repayments) proceeds from short-term borrowings	(14,000,000)	69,500,000	(14,500,000)
State Line advance payments	—	6,504,516	7,895,241
Net cash provided by financing activities	52,308,047	57,221,850	41,060,644
Net increase (decrease) in cash and cash equivalents	8,949,695	(18,288,276)	18,286,140
Cash and cash equivalents, beginning of year	2,490,580	20,778,856	2,492,716
Cash and cash equivalents, end of year	$ 11,440,275	$ 2,490,580	$ 20,778,856

Cash and cash equivalents include cash on hand and temporary investments purchased with an initial maturity of three months or less. Interest paid was $31,705,000, $26,485,000 and $19,301,000 for the years ended December 31, 2001, 2000 and 1999, respectively. Income taxes paid were $4,343,000, $8,801,000 and $12,221,000 for the years ended December 31, 2001, 2000 and 1999, respectively. Capital lease obligations incurred during the year ended December 31, 2001 for the purchase of new equipment were $748,000. There were no capital lease obligations incurred during the years ended December 31, 2000 and 1999.

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

1. Summary of Accounting Policies

The Company is 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). The accounting policies of the Company are in accordance with the rate-making practices of the regulatory authorities and conform to generally accepted accounting principles as applied to regulated public utilities. The Company's electric revenues in 2001 were derived as follows: residential 42%, commercial 31%, industrial 17%, wholesale on-system 5%, wholesale off-system 1.5% and other 3.5%. The Company's electric revenues for 2001 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 unregulated subsidiary, EDE Holdings, Inc. (EDE Holdings). The consolidated entity is referred to throughout as the Company. Currently, the electric utility accounts for about 99% of consolidated assets. Intercompany balances and transactions have been eliminated.

Effects of Regulation

In accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71), the Company's financial statements reflect ratemaking policies prescribed by the regulatory commissions having jurisdiction over the Company (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, the Company has 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 the Company's regulators to have been prudently incurred have been recoverable through rates in the course of normal ratemaking procedures.

The Company continually assesses the recoverability of its 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 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

The Company uses cycle billing and accrues 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 and 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. 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 as approved by regulatory authorities and are applied to the various classes of assets on a composite basis. Such provisions approximated 3.0%, 3.2% and 3.2% of depreciable property for 2001, 2000 and 1999, respectively. Depreciation expense for the years ended December 31, 2001, 2000 and 1999 was $31,448,830, $29,664,000 and $28,135,000, 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 (AFUDC) when first placed in service. The AFUDC is a utility industry accounting practice whereby the cost of borrowed funds and the cost of equity funds (preferred and common stockholders' equity) applicable to the Company's 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, the Company utilized aggregate rates (on a before-tax basis) of 5.6% for 2001, 8.4% for 2000 and 5.4% for 1999 compounded semiannually.

Asset Impairments
The Company periodically reviews 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.

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.

Liability Insurance
The Company carries 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 loss experience of the Company.

State Line Advance Payments
During fiscal 2000 the Company was receiving advance payments from Westar Generating, Inc. (WGI) for WGI's share of the existing State Line facility (See Note 10).

Franchise Taxes
Franchise taxes are collected for and remitted to their respective cities. Operating revenues include franchise taxes of $4,850,000, $4,560,000 and $4,400,000 for each of the years ended December 31, 2001, 2000 and 1999, respectively. The payments of these amounts are included in other taxes.

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 is 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 stock options and their equivalents. The weighted average number of common shares outstanding used to compute basic earnings per share for the 2001, 2000 and 1999 periods was 17,777,449, 17,503,665 and 17,237,805, respectively. Dilutive securities for the 2001, 2000 and 1999 periods were 54,537, 47,985 and 69,275, respectively.

2. Merger Agreement

The Company and UtiliCorp United, Inc. ("UtiliCorp"), 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 UtiliCorp, with

UtiliCorp being the surviving corporation (the "Merger"). The Merger Agreement required the Company to redeem all of its outstanding preferred stock according to its terms prior to the closing. On August 2, 1999, the Company redeemed all of its outstanding preferred stock for approximately $34,200,000. The Company's 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, UtiliCorp 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, the Company recognized a tax benefit of approximately $2.3 million in the first quarter of 2001.

The stockholder approval of the merger effected a change in control under the Company's Change in Control Severance Pay 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 the Company of its obligations under the Plan. As of December 31, 2000, the Company had incurred approximately $155,000 of obligations to individuals electing voluntary termination under the Plan. Subsequent to that date, the Company incurred approximately $1,275,000 in additional obligations under the Plan. As of December 31, 2001 approximately $1,082,000 of the obligations had been paid and $348,000 of these obligations remained. These remaining obligations will be paid over a two-year period.

3. *Regulatory Matters*

During the three years ending December 31, 2001, the following rate changes were requested or are in effect:

Missouri

On November 3, 2000, the Company filed a request with the MoPSC to increase rates in Missouri by approximately $41,500,000 annually. On September 20, 2001, the MoPSC issued a rate order approving a permanent rate increase of approximately $17,100,000 annually effective October 2, 2001.

In addition, the order approves an annual Interim Energy Charge (IEC) of approximately $19,000,000 effective October 1, 2001 and expiring on October 1, 2003. This IEC is $0.0054 per kilowatt hour of customer usage and is subject to refund with interest at the end of the two-year period. At that time, any excess IEC collections, above the greater of the actual and prudently incurred costs or the base cost of fuel and purchased power set in rates, will be refunded with interest equal to the prime rate then in effect. As of December 31, 2001, the Company has recorded a liability of approximately $2,800,000 for the amount of the IEC collected during fiscal 2001 that is to refund to customers at the end of the two-year period based on current fuel costs.

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 disallowed costs were part of a stipulated agreement between the Missouri Public Service Commission and Empire in connection with our recent rate case and will not be recovered in rates. The net effect on earnings after considering the tax effect on this write-down is $2,500,000.

In accordance with Statement of Financial Accounting Standards (SFAS) No. 71, the Company has deferred approximately $500,000 of expense directly related to the rate case. The Company will amortize this amount over a three-year period.

On October 26, 2001, the Company filed a request with the MoPSC for an additional annual increase in rates for Missouri electric customers in the amount of $3,600,000 to rectify a regulatory clerical error in the September 2001 rate order. The MoPSC, after various proceedings, denied the Company's requests for relief. The Company is currently evaluating its options for recovering the previously overlooked expenses as well as other capital investments and increased operating expenses which have occurred since the Company's last rate increase.

Kansas

On December 28, 2001 the Company filed a request with the KCC to increase rates in Kansas by approximately $3,200,000 annually. The Company expects this case to be concluded in the third quarter of 2002.

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

December 31,	*2001*	*2000*
Regulatory Assets		
Income taxes	*$25,674,064*	$25,724,995
Unamortized loss on reacquired debt	*7,736,457*	8,270,284
Coal contract restructuring costs	*816,697*	1,383,848
Gas supply realignment costs	*288,967*	559,370
Asbury five year maintenance	*2,870,617*	263,105
Other postretirement benefits	*356,305*	388,690
Total Regulatory Assets	*$ 7,743,107*	$36,590,292
Regulatory Liability		
Income taxes	*$12,915,456*	$14,170,175

Deregulation

Should retail electric competition legislation be passed in the states the Company serves, the Company may determine that it no longer meets the criteria set forth in SFAS 71 with respect to continued recognition of some or all of the regulatory assets and liabilities. Any regulatory changes that would require the Company to discontinue application of SFAS 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 the Company's financial condition and results of operations.

Federal regulation has promoted and is expected to continue to promote competition in the electric utility industry. Oklahoma and Arkansas, however, are the only states in which the Company operates that have taken action with respect to promoting competition.

Legislation in Oklahoma originally provided for open competition by July 2002. However, the Oklahoma Legislature overwhelmingly approved legislation in June 2001 that indefinitely delays electric restructuring in the state.

The Arkansas Legislature passed a bill in April 1999 that called for deregulation of the state's electricity industry as early as January 2002. A bill was enacted in February 2001, however, delaying implementation of deregulation until October 2003 and giving the APSC authority to set further delays in one-year increments until October 2005. The APSC, after conducting hearings, issued a report in December 2001 recommending that the legislature suspend deregulation beyond 2003 or repeal the law mandating deregulation.

4. Common Stock

On December 10, 2001, the Company sold 2,012,500 shares of its common stock in an underwritten public offering for $20.37 per share. This sale resulted in proceeds of approximately $39,036,000, net of issuance costs of $1,959,000.

In 1998, the Company 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 100,000 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 the Company's 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 the Company's stock on the dividend's record date. During 2001, 3,569 units were granted under the Director Retirement Plan for services provided in 2001, and 3,404 units were granted pursuant to the provisions of the plan providing for the reinvestment of dividends on stock units in additional stock units.

The Company's 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 the Company into newly issued shares of the Company's 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.

The Company's Employee Stock Purchase Plan, which terminates on May 31, 2003, 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 46,419 shares at $17.73, 40,880 shares at $21.83, 63,985 shares at $23.35 on December 31, 2001, 2000 and 1999, respectively. Shares were issued at $17.78 per share in 2001, $21.26 per share in 2000 and $18.34 per share in 1999.

The Company's 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 2001, February 2000 and February 1999, grants for 2,835, 2,160 and 1,144 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 service with the Company 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 2001, 2000 and 1999, 4,648, 3,368 and 3,300 shares, respectively, were issued under the Stock Incentive Plan. To date, no options have been granted under the Stock Incentive Plan. In 1996, the Company adopted the disclosure-only method under SFAS 123, "Accounting for Stock-Based Compensation." If the fair value based accounting method under this statement had been used to account for stock-based compensation costs, the effect on 2001, 2000 and 1999 net income and earnings per share would have been immaterial.

The Company's Employee 401(k) Retirement Plan (the 401(k) Plan) allows participating employees to defer up to 15% of their annual compensation up to a specified limit. The Company matches 50% of each employee's deferrals by contributing shares of the Company's common stock, such matching contributions not to exceed 3% of the employee's annual compensation. The Company contributed 35,793, 33,926 and 30,404 shares of common stock in 2001, 2000 and 1999, 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, 2001, 2,430,021 shares remain available for issuance under the foregoing plans.

5. Preferred Stock

The Company has 2,500,000 shares of preference stock authorized, including 500,000 shares of Series A Participating Preference Stock, none of which have been issued. The Company has 5,000,000 shares of $10.00 par value cumulative preferred stock authorized.

On August 2, 1999 the Company redeemed all outstanding 5%, 4¾%, and 8⅛% series of cumulative preferred stock. Holders were paid the following amounts per share plus accumulated and unpaid dividends: 5% cumulative – $10.50 (aggregate amount $4,009,110); 4¾% cumulative - $10.20 (aggregate amount $4,080,000); and 8⅛% cumulative – $10 (aggregate amount $24,809,980).

On March 1, 2001 the Company issued 2,000,000 8.5% Trust Preferred Securities. Due to the nature of these mandatorily redeemable securities, the Company has classified the $50,000,000 outstanding at December 31, 2001 as long-term debt (see Note 6).

There was no other preferred stock issued and outstanding at December 31, 2001 or 2000.

Preference Stock Purchase Rights

On April 27, 2000, the Board of Directors approved a new shareholder rights plan replacing an existing shareholder rights plan which 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 the Company's common stock or if certain other events occur. The Rights may be redeemed by the Company 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 the Company's common stock by an Acquiring Person. The Company had 19,703,837 and 17,547,742 Preference Stock Purchase Rights (Rights) outstanding at December 31, 2001 and 2000, 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 common stock of the Company 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 the Company's outstanding common stock, the Board of Directors may, at its option, exchange part or all of the Rights (other than Rights held by the Acquiring Person) for common stock of the Company on a one-for-one basis.

6. Long-Term Debt

At December 31, 2001 and 2000 the balance of long-term debt outstanding was as follows:

	2001	2000
Company obligated mandatorily redeemable Trust Preferred Securities of subsidiary holding solely parent debentures	$ 50,000,000	$ —
Other:		
First mortgage bonds:		
7½% Series due 2002	37,500,000	37,500,000
7.60% Series due 2005	10,000,000	10,000,000
8⅛% Series due 2009 (1)	20,000,000	20,000,000
6½% Series due 2010	50,000,000	50,000,000
7.20% Series due 2016	25,000,000	25,000,000
9¾% Series due 2020	2,250,000	2,250,000
7% Series due 2023	45,000,000	45,000,000
7¾% Series due 2025	30,000,000	30,000,000
7¼% Series due 2028 (2)	13,154,000	13,330,000
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
	246,104,000	246,280,000
Senior Notes, 7.70% Series due 2004	100,000,000	100,000,000
Obligations under capital lease	725,644	—
Less unamortized net discount	(556,637)	(636,234)
	396,273,007	345,643,766
Less current maturities of long-term debt	(37,500,000)	(20,000,000)
Less current obligations under capital lease	(158,329)	—
Total long-term debt	$358,614,678	$325,643,766

(1) Holders of this series had the right to require the Company to repurchase all or any portion of the bonds at a price of 100% of the principal amount plus accrued interest, if any, on November 1, 2001. Holders were required to apply for this redemption during the period September 1, 2001 to October 1, 2001. As no holders applied for this redemption, the amounts have been reclassified as long-term debt at December 31, 2001.

(2) During the period beginning June 1, 1994 and ending May 31, 1995, and each succeeding twelve-month period ending May 31 of each year thereafter, the Company is 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. The Company is not required to repurchase more than $217,500 in the aggregate in any twelve-month period. At December 31, 2001 the Company had repurchased a total of $1,346,000 of bonds related to this requirement.

(3) The Company has entered into capital lease agreements for office and telephone equipment. The leases terminate in August 2005 and have an end of lease buyout option on the equipment.

On March 1, 2001, Empire District Electric Trust I, issued 2,000,000 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 the Company on the $50,000,000 aggregate principal amount of 8.5% Junior Subordinated Debentures due March 1, 2031, issued by the Company to the trust, and held by the trust, as assets. Interest payments on the debentures are tax deductible by the Company. The Company has fully and unconditionally guaranteed the payments due on the outstanding trust preferred securities. The net proceeds of this offering were added to the Company's 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 property, plant and equipment is subject to the lien of the mortgage. The indenture governing the Company's first mortgage bonds contains a requirement that for new first mortgage bonds to be issued, its 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. The indenture 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. The Company's earnings for the twelve months ended December 31, 2001 do not permit the Company to issue new first mortgage bonds based on this test. Other than this limitation, there are no other significant ramifications resulting from not meeting this ratio. The Company is in compliance with all restrictive covenants of its debt agreements.

On November 18, 1999, the Company sold to the public in an underwritten offering $100 million aggregate principal amount of its Senior Notes, 7.70% Series due 2004. The net proceeds of this sale were added to the Company's general funds and were used to repay short-term indebtedness, including indebtedness incurred in connection with the redemption of the Company's preferred stock and the Company's construction program.

The carrying amount of the Company's long-term debt, excluding capital lease obligations, was $395,547,363 and $345,643,766 at December 31, 2001 and 2000, respectively, and its fair market value was estimated to be approximately $387,827,607 and $333,748,477, respectively. This estimate was based on the quoted market prices for the same or similar issues or on the current rates offered to the Company 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.

7. Short-term Borrowings

Short-term commercial paper outstanding and notes payable averaged $58,390,882 and $17,846,995 daily during 2001 and 2000, respectively, with the highest month-end balances being $80,000,000 and $69,500,000, respectively. The weighted daily average interest rates during 2001, 2000 and 1999 were 4.6%, 7.0% and 5.4%, respectively. The weighted average interest rates of borrowings outstanding at December 31, 2001 and 2000 were 2.81% and 7.77%, respectively. At December 31, 2001, the Company had outstanding commercial paper of $25,500,000 with due dates from January 2, 2002 to January 29, 2002.

At December 31, 2001, the Company had a $30,000,000 unsecured line of credit. Borrowings are at the higher of the bank's prime commercial rate or LIBOR and are due 364 days from the date of each loan, not to exceed June 26, 2002, the final credit expiration date. Under this line of credit, in the event that the credit rating on the Company's first mortgage bonds falls below BBB (Standard & Poor's) and Baa3 (Moody's) the Company's obligations become immediately due and payable. The Company also had a $25,000,000 unsecured line of credit at December 31, 2001, bearing interest based on the bank's prime commercial rate. This unsecured line of credit expired on January 31, 2002. The Company also had a $20,000,000 unsecured line of credit at December 31, 2001, bearing interest based on the bank's prime commercial rate. Borrowings under this line of credit are due 370 days from the date of each loan, not to exceed June 30, 2002, the final credit expiration date. The availability of this line of credit is contingent upon (1) the credit rating on the Company's first mortgage bonds remaining at least BBB (Standard & Poor's) and Baa2 (Moody's) and (2) the Company maintaining Total Funded Debt to Capital (where Capital is defined as Total Funded Debt plus Equity Capital including the Company's $50,000,000 of Trust Preferred Securities) less than 67.5%. We are currently in compliance with this ratio. This line of credit is also subject to cross-default with other indebtedness of the Company (in excess of $10,000,000 in the aggregate). On January 25, 2002, this unsecured line of credit was extended to $30,000,000. These arrangements do not serve to legally restrict the use of the Company's cash. The lines of credit are also utilized to support the Company's issuance of commercial paper although they are not assigned specifically to such support. The outstanding borrowings under these agreements at December 31, 2001 were $30,000,000.

8. Retirement Benefits

Pensions

The Company's 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.

The calculation of the component for Amortization of Unrecognized Net (Gain)/Loss was changed in 2001 as a result of requirements of the September 20, 2001 MoPSC rate case. Previously the current year calculation of net gains or losses was amortized over five years. The new calculation requires the use of an average of the previous five years gain or loss, which is then amortized over five years. The result for year 2001 was an increase of $317,135 in pension income.

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

	2001	2000	1999
Benefit obligation at beginning of year	$75,217,964	$ 72,288,124	$ 77,285,598
Service cost	2,172,379	2,182,798	2,516,067
Interest cost	5,604,231	5,579,276	5,368,097
Amendments	—	—	1,744,656
Actuarial loss/(gain)	99,017	(250,025)	(10,076,097)
Benefits paid	(4,802,254)	(4,582,209)	(4,550,197)
Benefit obligation at end of year	$78,291,337	$ 75,217,964	$ 72,288,124
Fair value of plan assets at beginning of year	$98,898,066	$104,485,842	$ 93,153,901
Actual return on plan assets	(1,957,366)	(1,005,567)	15,882,138
Benefits paid	(4,802,254)	(4,582,209)	(4,550,197)
Fair value of plan assets at end of year	$92,138,446	$ 98,898,066	$104,485,842
Funded status	$13,847,109	$ 23,680,102	$ 32,197,718
Unrecognized net assets at January 1, 1986 being amortized over 17 years	(491,158)	(982,313)	(1,473,468)
Unrecognized prior service cost	3,747,210	4,266,641	4,786,072
Unrecognized net loss/(gain)	(1,129,486)	(15,357,002)	(31,683,391)
Prepaid pension cost	$15,973,675	$ 11,607,428	$ 3,826,931

Assumptions used in calculating the projected benefit obligation for 2001, 2000 and 1999 include the following:

	2001	2000	1999
Weighted average discount rate	7.25%	7.75%	8.00%
Rate of increase in compensation levels	4.00%	5.00%	5.50%
Expected long-term rate of return on plan assets	9.00%	9.00%	9.00%

Net pension benefit for 2001, 2000 and 1999 is comprised of the following components:

	2001	2000	1999
Service cost - benefits earned during the period	$ 2,172,379	$ 2,182,798	$ 2,516,067
Interest cost on projected benefit obligation	5,604,231	5,579,276	5,368,097
Expected return on plan assets	(8,672,012)	(9,181,211)	(8,323,982)
Net amortization and deferral	(3,470,845)	(6,361,360)	(3,950,993)
Net pension benefit	$ (4,366,247)	$ (7,780,497)	$ (4,390,811)

Other Postretirement Benefits

The Company provides 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, the Company adopted SFAS 106, which requires recognition of these benefits on an accrual basis during the active service period of the employees. The Company elected to amortize its transition obligation (approximately $21,700,000) related to SFAS 106 over a twenty year period. Prior to adoption of SFAS 106, the Company 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 SFAS 106 costs through rates.

In accordance with the above rate orders, the Company 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. The Company's 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 $18,600,000 at December 31, 2001, $16,100,000 at December 31, 2000 and $10,600,000 at December 31, 1999.

Postretirement benefits, a portion of which have been capitalized and/or deferred, for 2001, 2000 and 1999 included the following components:

	2001	2000	1999
Service cost on benefits earned during the year	$ 828,316	$ 931,469	$ 781,017
Interest cost on projected benefit obligation	2,892,691	3,142,872	2,281,028
Return on assets	(1,260,307)	(1,007,118)	(618,353)
Amortization of unrecognized transition obligation	1,084,017	1,084,017	1,084,017
Unrecognized net (gain)/loss	407,068	1,990,806	1,207,628
Net periodic postretirement benefit cost	$ 3,951,785	$ 6,142,046	$ 4,735,337

The estimated funded status of the Company's obligations under SFAS 106 at December 31, 2001, 2000 and 1999 using a weighted average discount rate of 7.75%, 7.75% and 8.0%, respectively, is as follows:

	2001	2000	1999
Benefit obligation at beginning of year	$ 37,251,254	$ 28,669,028	$ 24,580,797
Service cost	828,316	931,469	781,017
Interest cost	2,892,691	3,142,872	2,281,028
Actuarial (gain)/loss	2,757,072	5,908,539	2,227,896
Benefits paid	(1,413,949)	(1,400,654)	(1,201,710)
Benefit obligation at end of year	$ 42,315,384	$ 37,251,254	$ 28,669,028
Fair value of plan assets at beginning of year	$ 16,055,828	$ 10,552,442	$ 6,803,302
Employer contributions	3,951,785	5,735,695	4,604,982
Actual return on plan assets	2,423	1,168,343	345,870
Benefits paid	(1,413,949)	(1,400,654)	(1,201,710)
Fair value of plan assets at end of year	$ 18,596,087	$ 16,055,826	$ 10,552,444
Funded status	$ (23,719,297)	$ (21,195,426)	$ (18,116,584)
Unrecognized transition obligation	11,924,174	13,008,191	14,092,208
Unrecognized net gain	6,870,118	3,262,230	(494,279)
Accrued postretirement benefit cost	$ (4,925,005)	$ (4,925,005)	$ (4,518,655)

The assumed 2001 cost trend rate used to measure the expected cost of healthcare benefits is 9%. The trend rate decreases through 2003 to an ultimate rate of 6% for 2004 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 $4,100,000 to $5,000,000 and the accumulated postretirement benefit obligation from $37,300,000 to $44,400,000.

9. Income Taxes

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

	2001	2000	1999
Computed "expected" federal provision	$ 3,640,000	$ 12,290,000	$ 13,360,000
State taxes, net of federal effect	125,000	1,090,000	1,180,000
Adjustment to taxes resulting from:			
Merger costs	(2,320,000)	120,000	2,200,000
Investment tax credit amortization	(550,000)	(580,000)	(580,000)
Other	(895,000)	(1,420,000)	(160,000)
Actual provision	$ —	$ 11,500,000	$ 16,000,000

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

	2001	2000	1999
Taxes currently (receivable)/payable			
Included in operating revenue deductions:			
Federal	$ (50,000)	$ 8,852,000	$ 10,761,000
State	30,000	1,203,000	1,329,000
Included in "other-net"	(240,000)	(28,000)	10,000
	(260,000)	10,027,000	12,100,000
Deferred taxes:			
Depreciation and amortization differences	2,986,000	2,136,000	2,991,800
Loss on reacquired debt	(203,000)	(206,000)	(206,000)
Postretirement benefits	844,000	1,408,000	928,000
Other	(1,028,000)	(1,158,000)	(118,371)
Asbury five year maintenance	(100,000)	(241,000)	(241,000)
Software development costs	(252,000)	(39,000)	998,000
Included in "other-net"	120,000	153,000	127,571
Disallowed plant addition	(1,557,000)	—	—
Deferred investment tax credits, net	(550,000)	(580,000)	(580,000)
Total income tax expense	$ —	$ 11,500,000	$ 16,000,000

Under SFAS 109, temporary differences gave rise to deferred tax assets and deferred tax liabilities at year end 2001 and 2000 as follows:

Balances as of December 31,	2001		2000	
	Deferred Tax Assets	Deferred Tax Liabilities	Deferred Tax Assets	Deferred Tax Liabilities
Noncurrent				
Depreciation and other property related	$ 12,065,652	$ 97,737,131	$ 10,661,065	$ 94,692,058
Unamortized investment tax credits	4,200,107	—	4,545,873	—
Miscellaneous book/tax recognition differences	3,026,680	6,181,254	2,548,908	6,645,137
Total deferred taxes	$ 19,292,439	$ 103,918,385	$ 17,755,846	$101,337,195

10. Commonly Owned Facilities

The Company owns a 12% undivided interest in the Iatan Power Plant, a coal-fired 670 megawatt generating unit near Weston, Missouri. The Company is entitled to 12% of the available capacity and is obligated for that percentage of costs which are included in corresponding operating expense classifications in the Statement of Income. At December 31, 2001 and 2000, the Company's property, plant and equipment accounts include the cost of its ownership interest in the plant of $46,139,000 and $45,455,000, respectively, and accumulated depreciation of $31,633,000 and $30,089,000, respectively.

On July 26, 1999, the Company and Westar Generating, Inc. (WGI), a subsidiary of Western Resources, 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 operations 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 taken in the third quarter of 2001 for the disallowed capital costs. The Company's 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, the Company's net cash requirement was approximately $108,000,000, excluding AFUDC. The Company is 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 the Company with approximately 150 megawatts of additional capacity. At December 31, 2001 the Company's property, plant and equipment accounts include the cost of its ownership interest in the unit of $156,194,000 and accumulated depreciation of $5,540,000.

11. Commitments and Contingencies

The Company has entered into long and short-term agreements to purchase coal and natural gas for the Company's 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 commitments total $19.2 million for 2002 and $3.9 million for 2003. The Company has no firm physical commitments for 2004 and beyond. In the event that this gas cannot be used at the Company's plants, the gas would be liquidated at market price. As of December 31, 2001, the total estimated cost to surrender all options and sell off the firm physical committed gas at market value is $10.5 million.

The Company has 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 the company 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 any risk the Company has for not taking the minimum requirements of fuel under the contracts. In the event that the Company cannot exercise its rights under Force Majeure clauses and the coal is not taken, the company would be responsible for 25% of the minimum tonnages in the coal contract and 100% of the rail contracts. The other spot purchases have minimal risk since they expire annually. The total risk for each year through 2005 is approximately $10 million.

The Company currently supplements its on-system generating capacity with purchases of capacity and energy from other utilities in order to meet the demands of its customers and the capacity margins applicable to it under current pooling agreements and National Electric Reliability Council (NERC) rules. The Company has contracted with Western Resources for the purchase of capacity and energy through May 31, 2010. Commitments under this contract total approximately $16 million per year through May 31, 2010. The Company also has a short-term contract with American Electric Power from January 1, 2002 through May 31, 2002. Commitments under this contract total approximately $7 million for the period.

The Company has accrued approximately $1.5 million of additional merger related severance costs that will be recognized in expenses in the first quarter of 2002.

12. Selected Quarterly Information (Unaudited)

A summary of operations for the quarterly periods of 2001 and 2000 is as follows:

(dollars in thousands except per share amounts)

Quarters	First	Second	Third	Fourth
2001				
Operating revenues	$60,552	$58,403	$83,339	$61,960
Operating income	8,318	7,578	18,435	9,114
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
2000				
Operating revenues	$54,030	$57,428	$86,223	$62,322
Operating income	8,033	9,314	19,672	8,853
Net income	2,371	3,583	14,332	3,330
Net income applicable to common stock	2,371	3,583	14,332	3,330
Basic and diluted earnings per average share of common stock	$ .14	$ .21	$ .82	$ .19

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.

13. Derivative Financial Instruments

On January 1, 2001, the Company adopted the provisions of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133) and Statement of Financial Accounting Standards No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities An Amendment of SFAS 133" (SFAS 138). SFAS 133, as amended, requires recognition of all derivatives as either assets or liabilities on the balance sheet measured at fair value. Adoption of these accounting rules in January 2001 had no immediate impact on the Company. However, during the second quarter of 2001, the Company began utilizing derivatives to manage its gas commodity market risk and to help manage its exposure resulting from purchasing most of its natural gas on the volatile spot market.

A derivative is a contract whose value is dependent on, or derived from, the value of some underlying asset. By using derivative financial instruments, the Company is exposed to credit risk and market risk. Credit risk is the risk that the counterparty might fail to fulfill its performance obligations under contractual terms. At December 31, 2001 the Company had minimal exposure to credit risk from counterparties. Market risk is the exposure to a change in the value of commodities caused by fluctuations in market variables, such as price.

As of December 31, 2001, the Company has recorded liabilities of approximately $2,500,000 equal to the fair value of derivative financial instruments held as of that date in Current Liabilities on the balance sheet. As of December 31, 2001, the Company had seven swap contracts and two collar contracts in place that were all designated as cash-flow hedging instruments. An approximately $1,581,000 net of tax, unrealized loss representing the fair market value of these contracts is recognized as Accumulated Other Comprehensive Loss in the capitalization section of the balance sheet. The tax effect of $969,310 on this loss is included in deferred taxes. This amount will be adjusted cumulatively on a monthly basis until the determination periods, beginning January 1, 2002 and ending November 30, 2004. At the end of each determination period, which is the last day of each calendar month in the period, any realized gain or loss for that period related to the contract will be reclassified to fuel expense.

As of December 31, 2001, $417,360 of realized losses relating to settled hedging contracts has been recognized within other income and deductions in the accompanying statement of income.

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

14. Recently Issued Accounting Standards

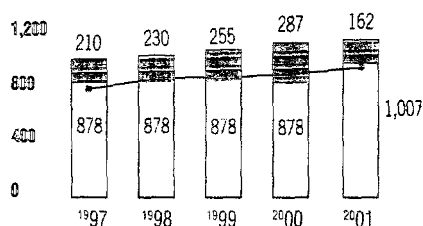
In July 2001, the Financial Accounting Standards Board issued SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Other Intangible Assets". These statements eliminate the amortization of purchased goodwill and instead require an annual review of goodwill and intangibles for impairment or when a change or event occurs that indicates goodwill may be impaired. SFAS No. 142 was required to be adopted no later than the first quarter of fiscal 2002. SFAS No. 141 requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001 and establishes specific criteria for recognition of intangible assets separately from goodwill. The Company had no recorded goodwill as of December 31, 2001, but will continue to evaluate the total impact of the adoption of these Statements on its financial statements and financial reporting.

In June 2001, the Financial Accounting Standards Board issued SFAS No. 143, "Accounting for Obligations Associated with the Retirement of Long-Lived Assets." This statement establishes standards for accounting and reporting for legal and constructive obligations associated with the retirement of tangible long-lived assets. In August 2001, the Financial Accounting Standards Board issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets", 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. The Company adopted SFAS No. 144 on January 1, 2002 and is required to adopt SFAS No. 143 on January 1, 2003. The Company will continue to evaluate the total impact of the adoption of these Statements on its financial statements and financial reporting.

Selected Financial Data.

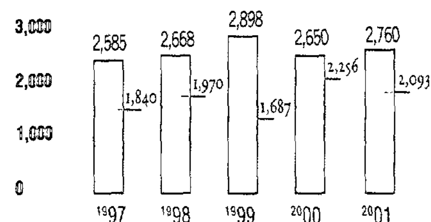
(Dollars in thousands, except per share amounts)	2001	2000	1999	1998
Operating revenues	$ 264,255	$ 260,003	$ 242,162	$ 239,858
Operating income	$ 43,444	$ 45,902	$ 42,576	$ 47,372
Total allowance for funds used during construction	$ 3,611	$ 5,775	$ 1,193	$ 409
Net income	$ 10,403	$ 23,617	$ 22,170 (1)	$ 28,323
Earnings applicable to common stock	$ 10,403	$ 23,617	$ 19,463 (1)	$ 25,912
Weighted average number of common shares outstanding (3)	17,777,449	17,503,665	17,237,805	16,932,704
Basic and diluted earnings per weighted average shares outstanding (3)	$ 0.59	$ 1.35	$ 1.13 (1)	$ 1.53
Cash dividends per common share (3)	$ 1.28	$ 1.28	$ 1.28	$ 1.28
Common dividends paid as a percentage of earnings applicable to common stock	217.4%	94.9%	114.5%	83.7%
Allowance for funds used during construction as a percentage of earnings applicable to common stock	34.7%	24.5%	6.2%	1.6%
Book value per common share outstanding at end of year	$ 13.64	$ 13.62	$ 13.44	$ 13.40
Capitalization:				
Common equity	$ 268,308	$ 240,153	$ 234,188	$ 229,791
Preferred stock without mandatory redemption provisions	$ 0	$ 0	$ 0	$ 32,634
First mortgage bonds	$ 358,615	$ 325,644	$ 345,850	$ 246,093
Ratio of earnings to fixed charges	1.36	2.25	2.70	3.32
Ratio of earnings to combined fixed charges and preferred stock dividend requirements	1.36	2.25	2.40	2.78
Total assets	$ 882,494	$ 829,739	$ 731,409	$ 653,294
Utility plant in service at original cost	$ 1,069,176	$ 918,622	$ 870,329	$ 831,496
Utility plant expenditures during the year (4)	$ 76,519	$ 129,965	$ 69,642	$ 47,366

Note (1): Reflects $5,772,292 of non-tax deductible merger costs associated with the Company's proposed merger with UtiliCorp.
Note (2):Reflects a pre-tax charge of $4,583,000 for certain one-time costs associated with the Company's Voluntary Early Retirement Program.
Note (3): Amounts shown for periods prior to 1992 have been restated to reflect the two-for-one stock split effective January 29, 1992.
Note (4): Does not include $0.8 million in non-utility property in 2001.



PURCHASE CAPACITY
GENERATING CAPACITY
PEAK DEMAND

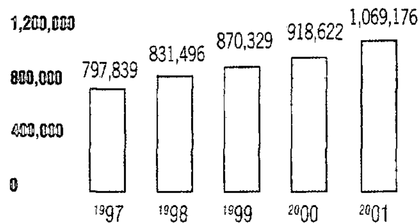
System Capacity & Peak Demand
Megawatts



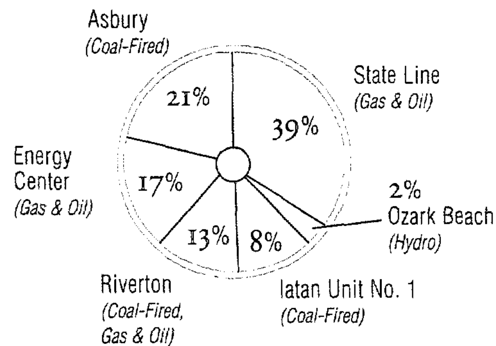
PURCHASES & INTERCHANGE
GENERATED

Total System Input by Source
(Not Including Hydro)
Millions of Kilowatt-hours

1997	1996	1995	1994	1993	1992	1991
$ 215,311	$ 205,984	$ 192,838	$ 177,757	$ 168,439	$ 150,302	$ 150,442
$ 40,962	$ 36,652	$ 33,151	$ 32,005	$ 29,291	$ 30,090	$ 31,761
$ 1,226	$ 1,420	$ 2,239	$ 1,715	$ 229	$ 119	$ 275
$ 23,793	$ 22,049	$ 19,798 (2)	$ 19,683	$ 15,936	$ 16,905	$ 18,768
$ 21,377	$ 19,633	$ 17,381 (2)	$ 18,120	$ 15,551	$ 16,513	$ 18,328
16,599,269	16,015,858	14,730,902	13,734,231	13,415,539	13,119,515	12,812,166
$ 1.29	$ 1.23	$ 1.18 (2)	$ 1.32	$ 1.16	$ 1.26	$ 1.43
$ 1.28	$ 1.28	$ 1.28	$ 1.28	$ 1.28	$ 1.26	$ 1.22
99.4%	104.5%	108.9%	97.0%	110.4%	99.9%	85.3%
5.7%	7.2%	12.9%	9.5%	1.5%	0.7%	1.5%
$ 13.03	$ 12.93	$ 12.67	$ 12.42	$ 12.33	$ 12.26	$ 12.06
$ 219,034	$ 213,091	$ 193,137	$ 173,780	$ 167,861	$ 163,293	$ 156,910
$ 32,902	$ 32,902	$ 32,902	$ 32,902	$ 7,902	$ 7,902	$ 7,902
$ 196,385	$ 219,533	$ 194,705	$ 184,977	$ 165,227	$ 143,619	$ 142,214
3.01	3.11	2.90	3.16	2.73	2.91	3.13
2.50	2.53	2.36	2.70	2.63	2.80	2.99
$ 626,465	$ 596,980	$ 557,368	$ 520,213	$ 463,617	$ 406,731	$ 387,363
$ 797,839	$ 717,890	$ 682,609	$ 611,360	$ 576,083	$ 543,323	$ 515,119
$ 53,280	$ 59,373	$ 49,217	$ 71,649	$ 42,648	$ 29,500	$ 21,991



Utility Plant in Service
Dollars in Thousands



Empire Power Plants
Percent of Capacity

Electric Operating Statistics.[1]

	2001	2000	1999	1998
Electric Operating Revenues (000s):				
Residential	$ 110,584	$ 108,572	$ 98,787	$ 100,567
Commercial	82,237	77,601	73,773	71,810
Industrial	44,509	42,711	41,030	39,805
Public authorities	6,311	5,927	5,847	5,559
Wholesale on-system	12,911	11,738	10,682	10,928
Miscellaneous	5,583	4,546	3,856	4,006
Total system	26,135	251,095	233,975	232,675
Wholesale off-system	3,898	7,842	7,090	6,126
Less Provision for Rate Refunds	2,843	—	—	—
Total electric operating revenues	$ 263,190	$ 258,937	$ 241,065	$ 238,801
Electricity generated and purchased (000s of Kwh):				
Steam	1,969,412	2,193,847	2,378,130	2,228,103
Hydro	53,635	51,132	86,349	70,631
Combustion turbine	790,993	455,678	520,340	439,517
Total generated	2,814,040	2,700,657	2,984,819	2,738,251
Purchased	2,092,955	2,255,076	1,686,782	1,970,348
Total generated and purchased	4,906,995	4,955,733	4,671,601	4,708,599
Interchange (net)	(264)	145	(138)	(1,894)
Total system input	4,906,731	4,955,878	4,671,463	4,706,705
Maximum hourly system demand (Kw)	1,001,000	993,000	979,000	916,000
Owned capacity (end of period) (Kw)	1,007,000	878,000	878,000	878,000
Annual load factor (%)	54.75	55.12	52.16	55.72
Electric sales (000s of Kwh):				
Residential	1,681,085	1,660,928	1,509,176	1,548,630
Commercial	1,375,620	1,333,310	1,260,597	1,246,323
Industrial	1,004,899	1,015,779	988,114	960,783
Public authorities	100,125	96,403	99,739	98,675
Wholesale on-system	322,336	309,633	297,614	299,256
Total system	4,484,065	4,416,053	4,155,240	4,153,667
Wholesale off-system	105,975	161,293	198,234	235,391
Total electric sales	4,590,040	4,577,346	4,353,474	4,389,058
Company use (000s of Kwh)	10,134	8,714	8,583	8,940
Lost and unaccounted for (000s of Kwh)	306,557	369,818	309,406	308,707
Total system input	4,906,731	4,955,878	4,671,463	4,706,705
Customers (average number of monthly bills rendered):				
Residential	125,996	123,618	121,523	119,265
Commercial	22,670	22,504	22,206	21,774
Industrial	337	345	350	354
Public authorities	1,645	1,674	1,759	1,739
Wholesale on-system	7	7	7	7
Total system	150,655	148,148	145,845	143,139
Wholesale off-system	7	6	6	6
Total	150,662	148,154	145,851	143,145
Average annual sales per residential customer (Kwh)	13,342	13,436	12,419	12,985
Average annual revenue per residential customer	$ 877.68	$ 878.29	$ 812.91	$ 843.22
Average residential revenue per Kwh	6.58¢	6.54¢	6.55¢	6.49¢
Average commercial revenue per Kwh	5.98¢	5.82¢	5.85¢	5.76¢
Average industrial revenue per Kwh	4.43¢	4.20¢	4.15¢	4.14¢

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

1997	1996	1995	1994	1993	1992	1991
$ 88,636	$ 86,014	$ 81,331	$ 71,977	$ 68,477	$ 59,645	$ 62,682
64,940	61,811	58,430	54,052	50,264	45,264	43,841
37,192	35,213	32,637	31,317	28,880	26,596	26,289
4,995	4,180	3,745	3,509	3,419	3,177	3,069
9,730	9,482	8,360	8,173	8,038	6,837	6,745
3,341	3,639	3,345	2,393	2,302	1,975	2,052
208,834	200,339	187,848	171,421	161,380	143,494	144,678
5,473	4,595	4,000	5,391	6,244	5,997	4,938
—	—	—	—	—	—	—
$ 214,307	$ 204,934	$ 191,848	$ 176,812	$ 167,624	$ 149,491	$ 149,616
2,372,914	2,231,062	2,374,021	2,495,055	2,322,749	2,307,854	2,243,083
77,578	62,860	71,302	83,556	102,673	77,644	79,865
211,872	162,679	170,479	51,358	39,532	5,048	63,387
2,662,364	2,456,601	2,615,802	2,629,969	2,464,954	2,390,546	2,386,335
1,839,833	1,968,898	1,540,816	1,394,470	1,443,410	1,119,025	1,096,056
4,502,197	4,425,499	4,156,618	4,024,439	3,908,364	3,509,571	3,482,391
1,018	(1,087)	(5,851)	630	11,266	2,657	(2,917)
4,503,215	4,424,412	4,150,767	4,025,069	3,919,630	3,512,228	3,479,474
876,000	842,000	815,000	741,000	739,000	680,000	678,000
878,000	724,000	737,000	656,500	657,300	657,300	657,300
55.38	56.85	55.15	57.32	54.88	52.77	54.02
1,429,787	1,440,512	1,350,340	1,264,721	1,248,482	1,068,595	1,142,752
1,171,848	1,154,879	1,086,894	1,018,052	950,906	850,829	826,774
943,287	923,730	859,017	827,067	760,737	695,271	689,377
101,122	95,652	90,543	86,463	83,239	78,050	77,068
273,035	262,330	243,869	234,228	232,815	220,916	227,087
3,919,079	3,877,103	3,630,663	3,430,531	3,276,179	2,913,661	2,963,058
253,060	219,814	213,590	304,554	366,729	360,251	270,920
4,172,139	4,096,917	3,844,253	3,735,085	3,642,908	3,273,912	3,233,978
9,688	9,584	9,559	9,260	9,117	8,924	9,222
321,388	317,911	296,955	280,724	267,605	229,392	236,274
4,503,215	4,424,412	4,150,767	4,025,069	3,919,630	3,512,228	3,479,474
117,271	115,116	112,605	109,032	105,079	101,943	99,916
21,323	20,758	20,098	19,175	18,447	17,796	17,276
346	346	339	318	283	267	264
1,720	1,696	1,637	1,558	1,517	1,467	1,427
7	7	7	7	7	7	7
140,667	137,923	134,686	130,090	125,333	121,480	118,890
7	9	6	6	5	5	4
140,674	137,932	134,692	130,096	125,338	121,485	118,894
12,192	12,514	11,992	11,600	11,881	10,482	11,437
$ 755.82	$ 747.19	$ 722.27	$ 660.14	$ 651.67	$ 585.08	$ 627.34
6.20¢	5.97¢	6.02¢	5.69¢	5.48¢	5.58¢	5.49¢
5.54¢	5.35¢	5.38¢	5.31¢	5.29¢	5.32¢	5.30¢
3.94¢	3.81¢	3.80¢	3.79¢	3.80¢	3.83¢	3.81¢

Glossary of Terms.

Aero derivative combustion turbine: 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.

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

Edison Electric Institute (EEI): The association of United States investor-owned electric utilities and industry affiliates and associates worldwide. Its U.S. members serve over 90 percent of all customers served by the investor-owned segment of the industry. They generate approximately three-quarters of all the electricity generated by electric utilities in the country and service about 70 percent of all ultimate customers in the nation.

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.

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 25, 2002, at 10:30 a.m., at the Holiday Inn, 3615 South Range Line, Joplin, Missouri.

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 Prices and Dividends

2001 Quarter	*High*	*Low*	*Dividend Paid*
First	26.5625	17.5000	$0.32
Second	20.9900	18.0000	$0.32
Third	21.0500	18.7000	$0.32
Fourth	21.5000	19.7500	$0.32

2000 Quarter	*High*	*Low*	*Dividend Paid*
First	23.1250	18.9375	$0.32
Second	24.5625	19.6875	$0.32
Third	27.0625	22.1250	$0.32
Fourth	30.7500	22.8750	$0.32

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*

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

Dividend Reinvestment and Stock Purchase Plan

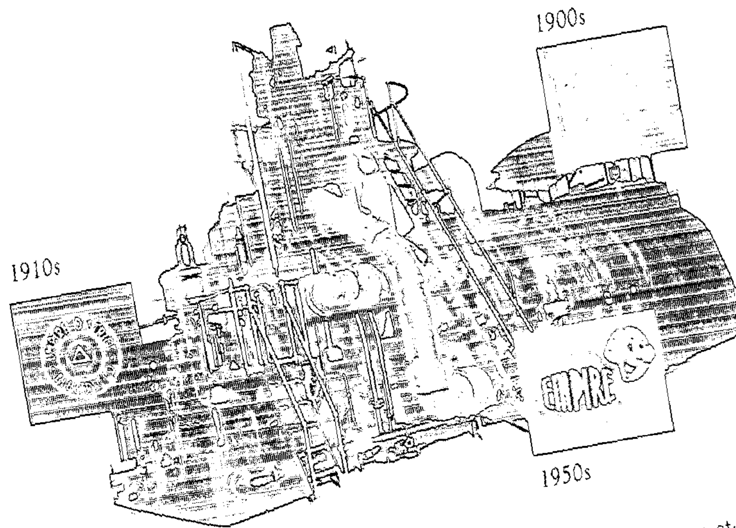
The Dividend Reinvestment and Stock Purchase Plan offers a variety of convenient, low-cost services to make it easier for current shareholders who are long-term investors wishing to invest and build their share ownership over time. The Plan offers a 3% discount on the purchase of shares with reinvested dividends. Optional features 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
85 Challenger Road
Ridgefield Park, New Jersey 07660
(888) 261-6784
www.melloninvestor.com

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 is not intended to induce any securities sale or purchase.

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



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

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